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MEDIUM-TERM OIL SUPPLY OUTLOOK IN THE MIDDLE EAST AND NORTH AFRICA

CONTENTS

INTRODUCTION

Middle East and North Africa (MENA) oil producers are expected to increase oil production capacity by 5.7 per cent over the next five years (up to 2025), to 33.5 million barrels per day (mb/d) from the current 31.7 mb/d, this Forum's survey of regional producers' upstream planning shows. All growth estimates are predicated on political and fiscal stability and current expansion plans by governments and international oil companies (IOCs) and are therefore subject to change and potential underperformance. But a realistic best-case scenario for the selected countries shows capacity growth led by the UAE, itself able to deliver 0.6 mb/d of growth over the outlook period, while Libya and Kuwait increase by 0.5 mb/d and Iraq by 0.3 mb/d. The growth more than offsets modest capacity declines for some of the smaller regional producers, especially where those countries have chosen to switch their focus away from sustaining crude oil output in favour of gas and unconventional hydrocarbons development.

Of course, the impact of sanctions, years of underinvestment due to civil war, poor sectoral management and (where applicable) present and future OPEC production policies will all continue to weigh heavily on growth prospects. The highest potential growth country, Iraq, is characterized by high security and political risk and it is for that reason that it is not the leading growth prospect. This conservative forecast still acknowledges that Baghdad has been able to successfully expand its upstream sector, despite the political tensions between regions and the federal government, and despite years of civil war in the north of the country. In the same way, Libya's civil war has for periods disrupted the recovery of the oil sector and forced the suspension of oilfield operations and exports. But these interruptions have been the exception rather than the rule and, in a best-case scenario, Libya's National Oil Corporation should be able to continue to expand production from existing fields over the medium term, restoring pre-2011 capacity levels.

MENA oil production capacity outlook, 2019–2025 (mb/d)

	2019	2025	Difference
UAE	3.4	4.0	0.6
Libya	1.1	1.6	0.5
Kuwait	2.7	3.2	0.5
Iraq	4.9	5.2	0.3
Oman	1.0	1.1	0.1
KRG	0.5	0.6	0.1
Saudi Arabia	12.5	12.5	0.0
Iran	3.2	3.2	0.0
Algeria	1.0	0.9	-0.1
Bahrain, Egypt, Qatar	1.5	1.2	-0.3
	31.7	33.5	1.8

Source: Authors.

This issue of the Forum is led by the growth countries and opens with an article by *Robin Mills* and *Roa Ibrahim,* who give a detailed, bottom-up assessment of the United Arab Emirates' multi-pronged quest for growth in the hydrocarbons sector. Abu Dhabi's decision to supercharge the Abu Dhabi National Oil Company's (ADNOC's) growth strategy since 2014 is behind the projected capacity gains, which will see the federation lift output by 0.6 mb/d by 2025, if projects are delivered on time. The diversification of IOCs operating in both the onshore and offshore concessions is a major change from the status quo, as is the shift to build out a more integrated, vertical value chain across both domestic and international assets. Major targets for upstream growth include the Upper Zakum field, ADNOC Onshore fields, and ADNOC Offshore, aside from Upper Zakum.

Another realistic growth country is Libya, where *Derek Brower* assesses prospects for the oil sector in light of the country's continuing civil war. While Libya's success at sustaining output in 2019 above 1 mb/d has been an achievement in its own right, more favourable political and security conditions would allow for activation of long-standing upstream plans for a recovery to pre-2011 production levels and even beyond. One swift way of increasing sustainable production capacity would be the repair of pipelines and storage tanks at export terminals. Damage from fighting has limited offtake from these ports. Some of the mature fields are also in the frame for remedial work that could lift output by significant amounts. This is under way at several Sirte Basin fields. Ultimately, it will be political progress that unlocks Libya's real upstream potential. As long as the military stand-off

between the eastern-based Libyan National Army led by Khalifa Hafter and the internationally recognized government in Tripoli remains unresolved, prospects for a political settlement are poor. That said, the military stalemate has also meant that oil production and exports have been maintained—a breakthrough by either side could bring the risk of disruption back into view.

Kuwait upstream growth targets centre on enhanced oil recovery at the giant Burgan field, on top of expansion of sour and heavy oilfields elsewhere. *Teresa Malyshev*, *Yousef M. Al-Abdullah,* and *Sreekanth K. J.* lay out in detail Kuwait's plans for capacity expansion both in the upstream sector and downstream, where the start-up of the fourth refinery project is imminent.

Ahmed Mehdi assesses the oil sector prospects in Iraq. Iraq's upstream progress since opening up its giant fields to international oil companies a decade ago has defied the often-poor governance and security conditions across the country. Delays to shared oil sector infrastructure, including gas handling and water injection, and structural weaknesses in public finances have kept a lid on growth. Some 0.3mb/d can be expected from the major southern oil projects over the outlook period to 2025, a number that would be higher if not for the weak political and security environment. Aside from boosting water availability for injection, further renovation work will be required at the southern oil terminals, particularly on pumping capacity to increase the number of Single Point Moorings (SPMs) that can be utilized at the same time.

The ongoing process of contract optimization for IOCs is also important. Iraq has seen the departure of some of its highest-profile IOC partners due to weak investment terms, and that process is likely to continue if not addressed seriously by a new Iraqi government in 2020. Iraq's weak compliance with OPEC production targets could also be a hurdle for the country in the coming years. Baghdad will need to argue its corner effectively if it is to receive special allowances for its growth profile—a strategy with which it has had mixed success in recent years.

In Oman, modest growth of just 0.1 mb/d over the next five years reflects determination by Muscat to continue to mitigate output declines from mature oilfields with effective enhanced oil recovery projects and some new oil developments. According to *Paul Mollet* and *Colin Ward*, Omani officials accept that, while there will be some modest growth in the medium term, the Sultanate's primary objective now is to sustain its production plateau as close to 1 mb/d as it can for as long as possible. As with other gas-focused producers, natural gas liquids and condensate output will continue to rise as liquid-rich gas fields are brought onstream. Another major development that will undercut crude export levels will be the start-up of the 230,000 b/d Duqm refinery in 2022.

The Kurdistan Regional Government (KRG) in northern Iraq has had a year of oil sector consolidation and has made recent progress in agreeing a way forward for its oil exports with the federal government in Baghdad, writes *Patrick Osgood*. However, the durability of arrangements with Iraq's federal government will be key to sustaining output in the medium term. If IOCs can be paid and fiscal transfers from Baghdad continue in return for crude allocated to Iraq's State Oil Marketing Organization by the KRG at Ceyhan, the prospects for slight growth are reasonable. But a return to the confrontation that characterized the Barzani government could undercut the KRG oil sector, which has to balance its relations with Ankara as well as its obligations to Baghdad. It is a precarious outlook, even if prospects are more buoyant in 2020 than in recent years.

The MENA region's dominant producer by far, Saudi Arabia, has no plans for an expansion of existing capacity, which is officially pegged at 12.5 mb/d. In his article, *Bassam Fattouh and Andreas Economou* outline the arguments in favour of the Kingdom maintaining existing capacity, managing a decline in capacity, or expanding capacity (in essence a fast monetization strategy). By building out scenarios for each of these, it becomes clear that an aggressive monetization policy that prioritized market share would be highly detrimental to oil revenue, while a managed capacity scenario akin to current policy would see market share decline in the medium term. Allowing spare capacity to erode over time is optimal for revenue flows but would limit the kingdom's status, forcing it to become a price taker. At the heart of this discussion is the uncertainty around the longer-term outlook for oil demand and the energy transition and what it means for major reserve holders.

Across the Gulf, Iran's prospects for oil production are almost entirely a derivative of US sanctions policy against the country, as *David Jalilvand* explains. As such, any change in the White House would be key to prospects for a recovery of Iranian oil production and exports—more so than domestic factors. Current production of around 1.5 mb/d reflects mostly domestic consumption, and a recovery to pre-sanctions levels implies production recovering to 3.2 mb/d (above 4 mb/d including condensates).

Algeria faces a slight decline in production capacity over the medium term, as *Chloe Teevan* and *Marc Chevillot* discuss. Algeria's economic reliance on oil and gas exports has left the country economically exposed as oil production capacity slips and amid political protests that dominated the country for much of 2019. The high turnover among senior Sonatrach and

government officials has left the sector rudderless at precisely the time when it needs invigoration to drive new IOC investment. While prospects for unconventional oil and gas are strong, protests against shale oil development have put the sector on hold for now, ruling out one key means by which Algeria could mitigate declines in output from mature fields.

Finally, *Bill Farren-Price* explores the prospects for the region's smallest oil producers—Bahrain, Egypt, and Qatar—all of which have in different ways switched their focus away from oil towards gas development and unconventional resources. All three of these smaller oil producers have experienced declining crude oil output and offer limited scope for upstream growth. All have for periods been able to mitigate declines in output from mature fields, but have now chosen different strategic paths for their energy sectors, even if maintaining oil production remains the stated aim. Bahrain's oil output will increase slightly over the period to 2025, reflecting Aramco expansion work on shared oilfield Abu Safah; Egypt will see declines in output after 2022; and Qatar's crude oil output is set to fall fastest as the emirate focuses its strategic efforts on gas and gas liquids growth. In total, an aggregate loss in output by 2025 from these three countries will amount to 240,000 b/d.

MEDIUM TERM OIL SUPPLY PROSPECTS FOR UAE

Robin Mills and Roa Ibrahim

Introduction

Since the oil price dip in 2014, the United Arab Emirates (UAE)'s petroleum sector has undergone a major shift. Abu Dhabi's oil production capacity is set to rise. With capacity now a little short of the intended 3.5 mb/d target, actual production is constrained by the OPEC agreement to 3.072 mb/d. This is planned to rise to 4 mb/d by 2020 and 5 mb/d by 2030, the biggest gain of any OPEC country other than Iraq. New exploration blocks, likely to contain both oil and gas, are being awarded to international oil companies (IOCs) in competitive bidding rounds in Abu Dhabi. The other emirates, which have much smaller petroleum sectors, have also made moves on new exploration.

ADNOC's transformation into a world-class national oil company

Abu Dhabi National Oil Company (ADNOC) started executing a fast-paced corporate and strategy restructuring programme over the past four years. This has primarily been due to the leadership of CEO Sultan Al Jaber (appointed February 2016), who has driven a new strategic plan. The strategy centres on four pillars: expansion of oil capacity; a drive to gas self-sufficiency; expansion in downstream; and a more commercial mindset linked to new partner relationships. Since then, ADNOC has moved a long way to being more commercially astute, flexible and faster-moving. Nevertheless, there is still a legacy of older processes to be overcome to speed up new developments.

Abu Dhabi completed re-awarding its legacy concessions (onshore ADCO and offshore ZADCO and ADMA, plus some smaller assets) during 2014-17. Operationally, ADMA and ZADCO were merged into ADNOC Offshore, a new operating unit. Notable outcomes were the continued joint-venture (JV) approach with IOCs, the new and enhanced cooperation with Asian companies (both NOCs and IOCs), and a relative shrinkage and shift both away from and within the European and American firms. This means its main customers have long-term stakes in its fields, and politically, its relations with key Asian countries are better balanced. ADNOC chose IOCs that strike a balance between capital, technology, markets and political relations. It retained its Western partners (ExxonMobil, Total, BP – though Shell and ExxonMobil left ADCO), included new European players ENI, OMV, Wintershall and CEPSA (owned by Mubadala), and kept Japan's Inpex.But it also added South Korean, Chinese, Indian and Russian firms. The introduction of Indian and Russian players is a first in Abu Dhabi's upstream.

ADNOC also launched and completed its first competitive bid round in 2018, and its second competitive bid round is ongoing, offering unconventional reserves (Onshore Block 2) for the first time as it seeks to boost gas production. In the 2018 licensing awards, five of the eight companies partnered in awarded blocks are Asian. Awards for the second bidding round will be in early 2020 and could see participation from Russian companies. Most recently, ADNOC awarded Lukoil 5% of its stake in the sour gas Ghasha concession for $190 million and signed a framework agreement with Russia's Gazprom Neft for sour gas and enhanced oil recovery (EOR) technology. The involvement of Lukoil in Ghasha is more political, as the Russian firm has little experience in sour gas. As Donald Trump's Middle East strategy diminishes the US's clout, Russia is taking this opportunity to exert more influence in the region. The Abu Dhabi government is also likely trying to keep up with the growing relationship between Saudi Arabia and Russia.

ADNOC is progressively shoring up its upstream profitability through its downstream business, including an expansion of both domestic and international refining and petrochemical capacity. The 'crude flexibility project' at the Ruwais refinery will allow it to run heavier grades, and possibly even imports, freeing up more of the flagship light Murban grade for export.

To boost its downstream business, ADNOC set up ADNOC Trading in 2018 for crude and refined oil products within its marketing department, but signed agreements with ENI and OMV to develop a new trading venture from the Port of Fujairah (ADNOC Global Trading). Similar to its upstream strategy, ADNOC will partner in this new exchange (ICE Futures Abu Dhabi) with international oil companies. The company seeks to establish Murban as a global benchmark by end-2020 to complement Dubai-Oman, Brent and WTI. ADNOC will drop destination restrictions on its oil, allowing it to trade freely on the open market and move to forward rather than retroactive pricing. ADNOC will also buy 10% in Vitol's storage business VTTI to gain access to their worldwide storage facilities in the Netherlands, the US, Asia and Africa and is expanding its storage facilities in Fujairah, India and Jordan.

As the company has generally been a slow-moving, traditional one, the upshot of the transformation will be seen gradually. The necessity to become more adept to external dynamics, more transparent for innovative financing, more able to operate internationally and the need to cultivate a commercial growth mindset, as opposed to the historical risk-averse culture, are all major changes.

Upstream production outlook

Under the revised 2019 OPEC production cuts, the UAE is constrained to produce 3.072 mb/d of crude oil up until the end of March 2020. There are already strong market indicators that OPEC will need to extend its cuts to the end of 2020 at current production allocation levels. So far this year, from January to September 2019, UAE's actual crude production averaged 3.069 mb/d (including a small contribution from Dubai), producing a record 3.238 mb/d in December 2018 (this was when markets expected greater Iranian crude and condensate disruptions following US oil sanctions and before unexpected waivers were extended by the US to some importers). Current capacity stands at 3.41 mb/d which is up from 3.35 mb/d by end-2018 and 3.22 mb/d by end-2017. UAE's spare capacity of around 0.34 mb/d in September 2019 signals strong compliance with OPEC cuts.

ADNOC's current oil capacity is still below its 2018 target of 3.5 mb/d. The target has not been reached yet due to slower than expected start-up of new fields and brownfield expansions, but this has not been problematic as the OPEC cuts have constrained output anyway. ADNOC still aims to reach its 3.5 mb/d target by the end of 2019 and plans for capacity to reach 4 mb/d by end-2020 and 5 mb/d by 2030. ADNOC could fall short of the 3.5 mb/d target in 2019 as well if the first phase of the Upper Zakum expansion project sees further delays. ADNOC Drilling, the in-house drilling company (Baker Hughes holds 5%) is acquiring additional rigs to support these production increases.

ADNOC Onshore's capacity is intended to gain 200 kb/d. In November 2019, a contract was awarded to Archirodon to maintain long-term output at the Bab field, which produces Murban crude, at 485 kb/d by about 2022. Bab is currently being expanded from 420 kb/d to 450 kb/d, and Bu Hasa from 550 kb/d to 650 kb/d by 2020.

The offshore Upper Zakum field (ADNOC 60%, Exxon Mobil 28%, and JODCO 12%) is one of the most important expansions. The stakeholders are looking to spend up to $22 billion to raise production capacity to 1 mb/d by 2024. The field is currently undergoing the first phase to 750 kb/d to be completed this year, from the current 670 kb/d, but the project timeline has slipped from 2018 to 2019 due to delays by Engineering, Procurement and Construction (EPC) contractor Petrofac. This was a significant contributor to the delay in reaching the 3.5 mb/d level. The second phase of Upper Zakum expansion accounts for 250 kb/d, half the remaining increment to ADNOC's overall target of 4 mb/d.

ADNOC is boosting oil output from its offshore SARB and Umm Lulu fields (ADNOC 60%, CEPSA 20%, OMV 20%). Production from the fields achieved around 125 kb/d by the end of 2018 (Umm Lulu was producing since 2016 and SARB started production in late 2018). Umm Lulu is expected to produce up to 105 kb/d when fully developed and in the longer term, ADNOC has said it wants to reach a combined 215 kb/d from both fields by 2023. If Umm Lulu meets its target of 105 kb/d by 2021, that means another 105 kb/d from SARB by 2023 from the current 50 kb/d. Meanwhile Nasr, which began production in 2015, is being expanded from 22 kb/d to 65 kb/d during 2019.

Another vital field for ADNOC is Ghasha, awarded in December 2018 (ADNOC 55%, ENI 25%, Wintershall 10%, OMV 5% and Lukoil 5%). Ghasha is vital for ADNOC's gas strategy (and Mubadala's since it owns 24.9% of OMV), but it will also yield sizable amounts of gas condensate as well. Once fully developed, the field will produce 120 kb/d in crude and condensate. The project is expected to start up in 2024-25, with final investment decisions taken in 2019-20.

Smaller fields are also making progress. The ADNOC and CNPC JV, Al Yasat Corporation for Petroleum Operations, started producing 8 kb/d in 2018. It awarded an engineering, procurement, construction and commissioning (EPCC) contract to local National Petroleum Construction Company to increase production from the offshore Bu Haseer field to 16 kb/d by 2020. In addition to Bu Haseer, the concession includes Belbazem, Umm Al Dholou and Umm Al Salsal fields, which are under appraisal. In July 2019, the Al Dhafra Petroleum JV with Korea National Oil Corporation, (KNOC 30%) and GS Energy (10%), started producing from the Haliba field and plans to reach 20 kb/d in 2020 and 40 kb/d in 2022. The exploration rights also include the discovered Al Humrah, Bu Tasah, and Bu Nikhelah fields.

ADNOC will likely reach its 2020 target by 2023-24, with capacity just above 4 Mb/d based on current expansion plans:

- 1.6-1.8 mb/d from ADNOC Onshore
- 0.67-1.0 mb/d from Upper Zakum
- 0.65-1.13 mb/d from other fields of ADNOC Offshore
- and 91 kb/d from smaller new onshore and offshore fields.

BP maintains that ADNOC Onshore's 1.8 mb/d has already been achieved (up from 1.7 mb/d in 2018) while work on the Total-operated Bu Hasa field should add another 0.1 mb/d by early 2021. Otherwise, there are no firm plans for the extra 1 mb/d required to reach 5 mb/d capacity, which would have to rely on further expansions of the main fields, development of the smaller non-producing fields, success in the six exploration blocks awarded and the blocks currently being offered, and perhaps unconventional (tight) oil production from the recently awarded Ruwais-Diyab block with Total (though this is intended to yield gas), or other tight oil.

ADNOC awarded a $1.6 billion contract to the Chinese Petroleum National Company (CNPC) in July 2018 to conduct a 3D onshore and offshore seismic survey to find new oil and gas reserves. The survey is planned to be completed by 2024 and will help boost its exploration activity to meet its longer-term, 2030 target. The Supreme Petroleum Council (SPC) which oversees the implementation of Abu Dhabi's petroleum policy, has recently increased its estimates of crude oil and conventional natural gas reserves which will boost interest in upcoming exploration projects. Reserves are now estimated at 105 billion barrels for oil, up 7 billion barrels, 273 trillion cubic feet (Tcf) for conventional gas, up 58 Tcf, and more than 160 Tcf of recoverable unconventional gas.

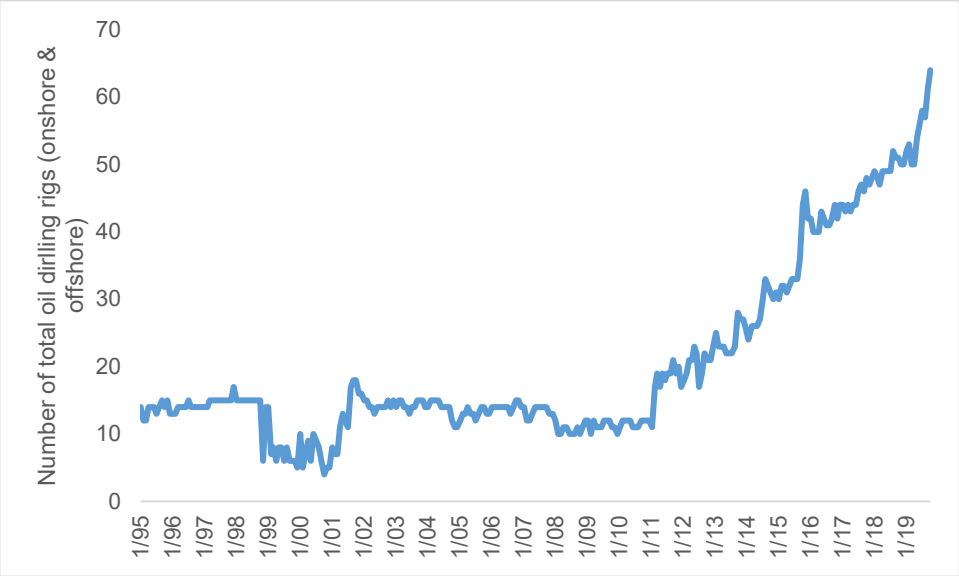
Other UAE emirates have much smaller petroleum sectors but have also made notable progress. Most notably, Sharjah National Oil Company (SNOC) awarded all three blocks in its debut exploration round to Italy's ENI in January 2019. An exploration well is currently being drilled, with a likely target of gas-condensate. Ras Al Khaimah offered all its onshore and offshore territory, divided into 7 blocks, and has so far awarded Block 5 to PGNIG of Poland and offshore Block A to ENI. Both emirates have been struggling with declining local gas production and high costs for imported gas. Dubai does not disclose its production, but this is likely below 50 kb/d and in slow decline.

Conclusions

To fund the expansion plans, the SPC approved ADNOC's new five-year business plan and capital investment commitment of $132.33 billion between 2019-2023, amounting to around $26.5 billion per year. For comparison, the financing plan is higher than US oil major Chevron's capital and exploratory expenditures of between $19-22 billion per year in the period of 2021 to 2023. This level of capital spending is therefore commensurate with the planned growth, although it is significant compared to crude oil sales of about $66 billion annually. ADNOC has raised outside capital over the past two years in various places, including IPOs and sales of strategic stakes in subsidiaries and by issuing bonds.

To support this growth, ADNOC's oil-focused drilling rigs reached record highs at end-2019 (see the figure below). Moreover, ADNOC already started becoming more commercially astute. In August 2019 it awarded contracts to three companies for the procurement of casing and tubing for drilling activities valued at $3.6 billion following a competitive bid process ($15 billion of the SPC approved capex target will go to ADNOC Drilling). Additionally, ADNOC Drilling completed its first integrated drilling services (IDS) well offshore at the Umm Lulu field in addition to four onshore IDS wells drilled over the course of this year.

Abu Dhabi Oil Drilling Rigs



Source: Author.

ADNOC's proposed production expansion would probably consolidate the UAE as OPEC's third-largest producer after Saudi Arabia and Iraq, overtaking Iran. It is justified by projections of an increased call on OPEC later in the 2020s, though there is of course the issue of rising UAE spare capacity in the intervening years while production caps remain. The planned growth in oil production by 2024 would additionally increase associated gas output, though possibly also requiring more gas injection for improved oil recovery. The oil capacity increase by 2024 is quite solid, even if experiencing some delays. The growth to 5 mb/d beyond that requires new, as yet undefined, projects.

LIBYA: POTENTIAL VERSUS POLITICS

Derek Brower

For much of the past year, Libyan crude oil production defied political gravity. From March 2019 onwards, output remained comfortably above 1 million barrels per day (mb/d), even as civil conflict flared up once again and warring factions vied for control of the country's oil assets. This resilience to conflict and instability has instilled some confidence in Libya's energy sector and its leadership. Mustafa Sanalla, head of the National Oil Corporation (NOC), the state oil company, and his senior team enter 2020 hopeful that big upstream plans—on the drafting table for years—can at last be advanced. But they will also remain conscious that merely sustaining current output would represent a triumph against many odds.

This is not to discount Libya's profound upstream potential. In percentage terms, only Guyana, soon to make its entry to the ranks of oil-producing countries, is likely to exceed the kind of production growth Libya could, in favourable circumstances, achieve in the next five years. Assuming political stability and an attractive investment climate, it is conceivable, for example, that Libya's oil output could rise swiftly from around 1.2 mb/d in October 2019 to almost 1.6 mb/d by the end of 2020. By 2024, 2 mb/d, or slightly less than NOC's own 2.1 mb/d target, is achievable.

But this is a scenario predicated on some resolution of Libya's political crisis, now almost a decade old. This appears far from imminent. The reality of Libya's oil sector is therefore unlikely to match its promise. In fact—given the current Libyan civil conflict and weak security; the impoverishment of state finances (and therefore the availability of money for NOC); the competition between factions for control of energy installations, assets, and exports; the lingering reluctance, with a few exceptions, of many foreign investors to return to the country; and even the possibility of a split in the country's territory—it would be risky to bet on major near-term production growth in Libya. On the contrary, another collapse in output is as probable as significant new growth in production, a fact often acknowledged by NOC.

In short, a realistic or risked outlook for Libyan oil output would see small growth towards a sustainable 1.4 mb/d by the end of 2020 and recovery to the pre-2011 level of 1.6 mb/d within the next five years—but with risks sharply balanced to the downside.

Sirte Basin

Some activity is already under way that can yield oil-production growth, absent a significant worsening of the civil conflict. In the very near term, production gains can be made through remedial work on damaged pipelines and storage facilities; workovers, infill drilling, enhanced oil recovery and uplift at some producing assets; greater provision of power supply to key assets, such as the Sarir/Misla complex of fields in Libya's southeast; and the activation (or in some cases reactivation and enhancement) of several fields that, according to NOC, are ready to be brought on stream.

The Sirte Basin, Libya's most prolific oil-producing region, will be the critical component of any production gains in the next 12 months. At the Waha complex of fields, run by the Waha Oil Company (led by NOC with a majority stake and including ConocoPhillips, Marathon, and Hess), plans are under way to expand production by as much as 100,000 b/d by late 2020. Waha's current output is reportedly around 300,000 b/d, but engineering and rehabilitation work at the North Gialo, Dahra, and Bahi fields—the latter two damaged by Islamic State (IS) terrorists in 2015—has been commissioned. The UK firm Petrofac and local engineering firm Taknia are involved. Precise field-by-field targets are not public.

Beyond Waha, but still in the Sirte Basin, other assets also await rehabilitation or activation. Total's Mabruk field sustained heavy damage to surface facilities during one IS attack in 2015 and is thought still to need considerable work to repair it. Mabruk's 50,000 b/d of capacity may therefore not be available in the near term. By contrast, the nearby Ghani field, belonging to the Harouge Oil Operations (a joint venture between NOC and Suncor), was also attacked in 2015 but is thought closer to restoration. It could swiftly produce 10,000 b/d, according to NOC's Sanalla. Harouge has also issued several tenders for work on surface facilities at the Amal field, where production of up to 25,000 b/d could be brought back on stream quickly, according to some reports. In total, Harouge's fields produced more than 80,000 b/d in 2012, after their restoration following the 2011 civil war. The assets reportedly produce less than half that figure now. Fields in the NC-74 block, meanwhile, operated by Zueitina Oil Company (NOC and OMV), should also yield some incremental supply; Sanalla said recently they too could be connected relatively quickly to export infrastructure.

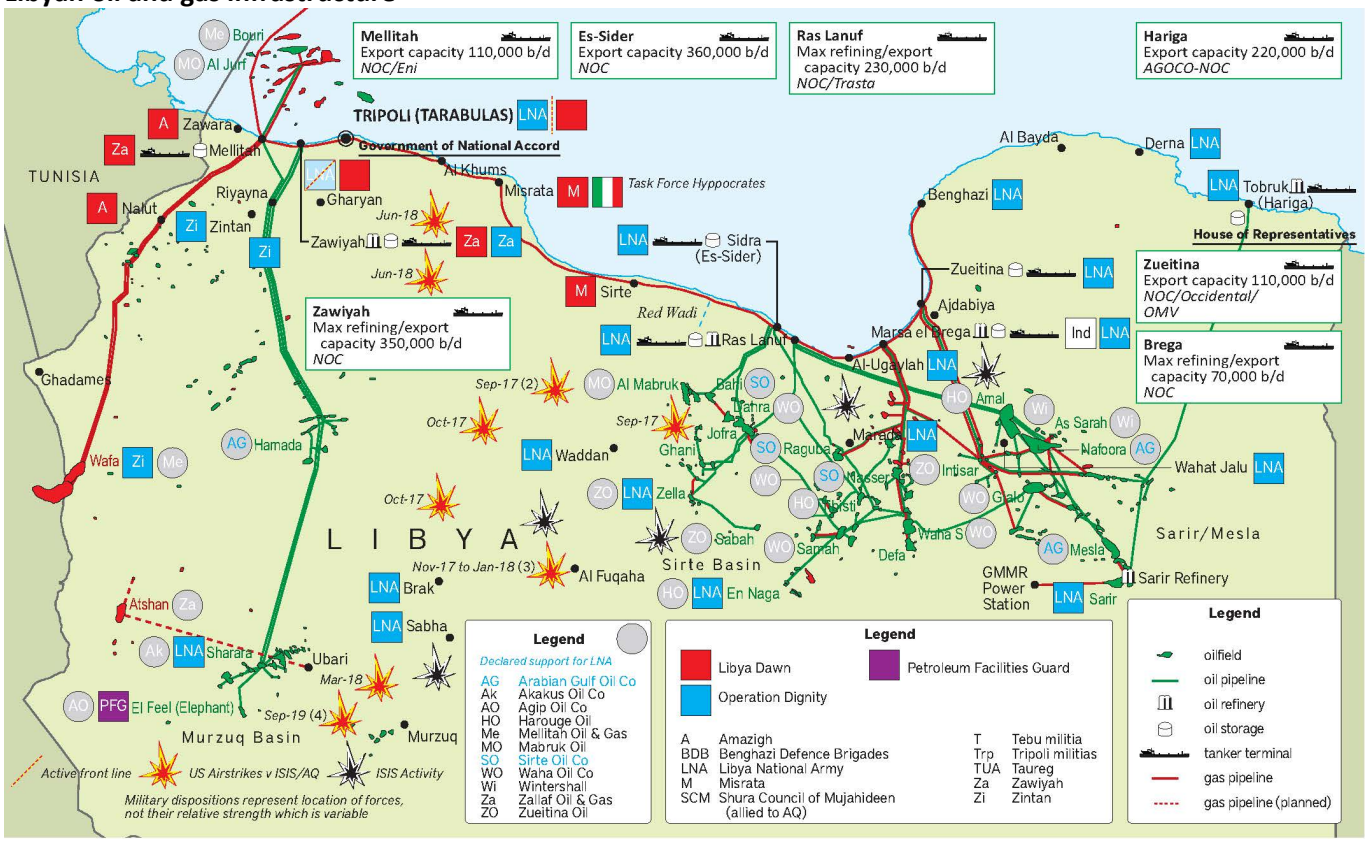
Midstream bottlenecks

Despite the myriad upstream plans, it is unclear how big a jump in oil production to expect from the restart of these shut-in or damaged fields. Libya's 1.6 mb/d of pre-2011 capacity implies latent or pent-up (damaged, under repair, or constrained by power shortages or insufficient take-away capacity) nominal production of 300,000–400,000 b/d compared with the output highs struck in 2019. But upstream progress can only come in tandem with repairs to the midstream, especially the replacement of storage facilities at Ras Lanuf and Es-Sider export terminals in the Sirte Basin.

Damage to storage capacity at both ports has been extensive in recent years. Until it became a contested asset in Libya's oil conflict, Ras Lanuf (home also to an export-oriented refinery shut in recent years because of a commercial dispute) consisted of 13 storage tanks giving capacity of 7 million barrels and allowing exports up to 220,000 b/d. But several attacks on the facilities in the past five years have destroyed much of the storage. Thanks to Harouge's recent replacement of one of its tanks at Ras Lanuf, total capacity has now reached just over 1 million barrels.

NOC is presently trying to replace two other tanks; but even after they come on line, capacity will still be a fraction of the pre-2011 level. Es-Sider, also serving some Sirte Basin fields and about 30 km north-west along the coast from Ras Lanuf, has also suffered. It had original capacity of 6 million barrels from 19 tanks. Seven are reportedly operational now—the rest also damaged by fighting—and capacity is around 1 million. This lack of storage at the two main export terminals for the Sirte Basin creates problems when bad weather prevents shippers lifting cargoes and tanks begin to fill, crimping flows from the fields to the port or even forcing production shutdowns until the bottleneck clears. Workarounds and rerouting of pipelines to Zueitina have helped, but the storage problem will be a headwind for Libyan upstream development until it is fixed.

Libyan oil and gas infrastructure



Source: Petroleum Economist.

Conflict hinders progress

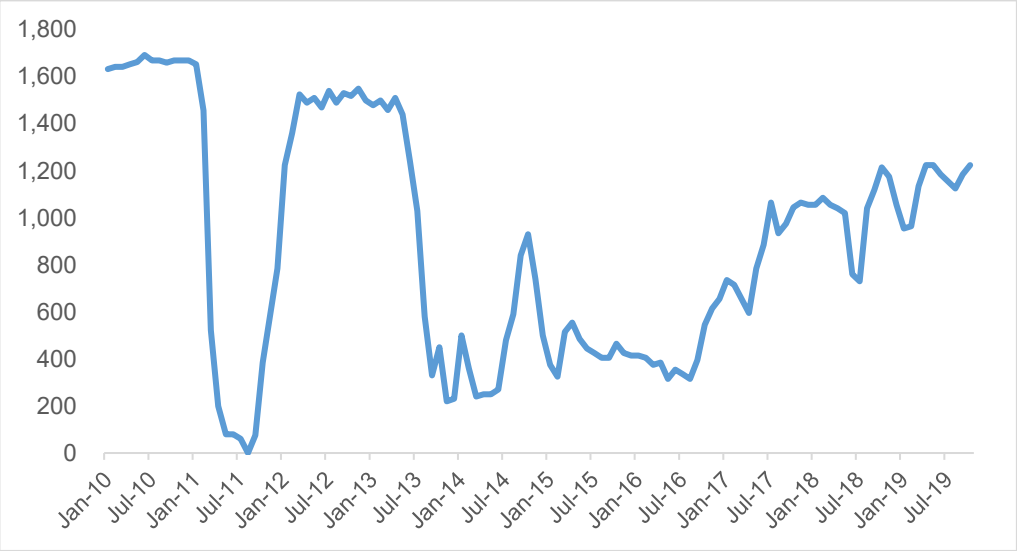
Efforts to repair or replace tanks at Es-Sider and Ras Lanuf have been slow for good reason. For more than three years, the infrastructure has been contested by Libya's warring factions. In September 2016, the terminals and much of the Sirte Basin were captured from warlord Ibrahim Jadhran and his rogue Petroleum Facilities Guards by the Libyan National Army (LNA), a collection of militias allied with the eastern parliament in opposition to the UN-appointed government in Tripoli. At that point, the LNA handed over operational control of the oil assets to NOC, enabling a recovery in oil production.

Although the LNA's capture of the Sirte Basin in September 2016 was critical to the rise and eventual stabilization of oil production over the past three years, it also rendered the area and its energy infrastructure a focal point of the factional rivalries and, ultimately, conflict. Repeatedly, Jadhran and others sought to wrest back control of the ports, sometimes damaging them in the process. IS attacks have done the same. In June 2018, the LNA recaptured the Sirte Basin oil terminals after their brief seizure by Jadhran and promptly decided to hand them over to the control not of Tripoli's NOC but of the breakaway NOC in the east of Libya. This decision was quickly reversed, but demonstrated again the precariousness of the country's infrastructure and unity.

Indeed, the fighting for the Sirte Basin and its oil-export facilities is symptomatic of the main political problem facing NOC as it seeks to expand production. This has been especially pronounced since spring 2019, when the commander of the LNA, Khalifa Hafter, launched an assault on Tripoli. The LNA believed its attempt to 'liberate' (Hafter's term) the capital, backed by some foreign support and supposedly superior air power, would be successful within days. Instead, by November 2019 the battle for Tripoli had morphed into a wider conflict on the lines of the fighting that occurred in 2014–15, drawing in Misrata and other Libyan cities. At the time of writing, this conflict, in which the support of Qatar, the United Arab Emirates, Russia, Egypt, Turkey, and other foreign countries has also been a factor, shows little sign of ending, despite UN efforts.

Although Libyan oil production has remained largely unscathed during this period—despite the LNA reportedly using airstrips and other facilities at Sirte Basin oil installations, thus making them war targets—the fighting has understandably hindered NOC in its efforts to repair storage facilities and some other damaged mid- and upstream assets.

Libyan oil production, 2010–2019 ('000 b/d)



Source: IEA.

Political dysfunction

Libya's political dysfunction has also caused other problems, further hindering recovery and growth efforts in Libya's upstream. The animosity between the UN-appointed Government of National Accord and the House of Representatives, the parliament that fled Tripoli for Tobruk in 2014, has prompted efforts by eastern separatists to establish their own oil industry and to install their own NOC to run it. This has involved efforts to sell oil independently from the east and to sign oil-export deals with buyers in politically sympathetic countries. Although these attempts have to date all failed—not least because the breakaway eastern NOC lacks both institutional capacity and knowhow to sell oil, as well as legal entitlement to do so—they have engendered distrust in the sector.

Reverberating through the country's politics is the fundamental geographical reality of Libya's oil: except for the two large fields of the Murzuq Basin (Sharara and El Feel) and offshore developments, where Eni's and NOC's Bahr Essalam gas project is delivering significant gas output, the country's prolific producing assets lie predominantly either within eastern Libya (Cyrenaica) or, in recent years, in areas under the control of eastern Libyan militias; and yet control of the oil income is handled by Tripoli.

That geological, geographical, and therefore geopolitical reality is the crucial backdrop to the years-long conflict between eastern-allied forces and those allied with the government in Tripoli. It is significant in two other ways that are important to oil production. First, because the central bank continues to disburse money to all militias and forces in Libya, it is in the broad interest of all parties to ensure oil exports continue. However, it also means that Libya's oil production, especially in the Sirte Basin, remains vulnerable to any major shift in the balance of power in the country's conflict. Indeed, during the latest phase of the war—since the LNA's attempt to 'liberate' Tripoli—it may be the failure of either side to secure a decisive advantage that, ironically, has allowed oil production to carry on unscathed. If the equilibrium is broken, the losing side would have every incentive to stop its opponents from securing total control of the commanding heights of Libya's economy. In the event of this kind of breakdown, the bulk of Libya's onshore output could be considered vulnerable to disruption.

Deterrent to investment

For somewhat different reasons, producing fields outside the Sirte Basin and further from the frontlines of the main conflict also continue to be at risk. In the southern Fezzan region, where neither Tripoli nor the LNA has full control, the Repsol-operated Sharara and Eni-operated El Feel fields remain at risk from militias seeking payment from NOC or to advance their regional causes. Indeed, the 300,000 b/d Sharara field was, until Hafter's forces captured it early in 2019, repeatedly shut down in recent years (and indeed suffered another outage in July 2019), disrupting the flow of crude oil to export infrastructure and the Zawiyah refinery, west of Tripoli. The 70,000 b/d El Feel was most recently shut in December 2019. Such fields, distant from the centre and lacking security—particularly fields in the south of the Sirte Basin—also remain vulnerable to IS, whose numbers have reportedly grown in southern Libya after the terror group's defeat in Sirte in 2016. The most recent significant attack was in May 2018, when IS struck Zueitina's Zella field.

Serious incidents of insecurity, beyond the underlying conflict itself, have punctuated Libya's recent history too, undermining NOC's own efforts to market the country as an investment opportunity abroad. Although Sanalla has been tireless in promoting Libya, in September 2018 the extent of Libya's security problems was made plain when IS forces penetrated the perimeter of NOC's headquarters in Tripoli, reaching the outside of the chairman's own office (Sanalla was inside but survived unscathed).

Against this kind of backdrop, it is no surprise that, aside from the offshore, where Eni and others continue to advance projects, new inward investment has been slow to return. Eni and BP both pledged in October 2018 to begin exploration of blocks in the Ghadames Basin and offshore the Sirte Basin, but little progress has been made. Algeria's Sonatrach remains a potential investor. Canada's Suncor maintains a watching brief on the producing assets it inherited from PetroCanada in the Sirte Basin. Repsol, OMV, and Eni all operate big producers but without deploying significant crews of expatriate workers. Russian companies may be more resilient in the face of the insecurity—partly reflecting Moscow's significant engagement in the Libya conflict (sometimes on both sides), including a growing presence of mercenary soldiers. Tatneft has resumed work in the Hamada area of the Ghadames Basin, carrying out seismic exploration. Gazprom, a partner with Wintershall Dea in blocks in the Sirte Basin, recently met with NOC to discuss more investmentin to Libya. It will be unsurprising if companies from China, an increasingly significant export destination for Libyan crude oil, renew their interest in the country's upstream.

Talk of revamping upstream terms to improve the EPSA IV contracts, or of promoting exploration near Benghazi and elsewhere, has mostly dried up. Although Sanalla recently secured more funding from the Government of National Accord and the central bank (about $1 billion was committed), it is not enough, given the chairman's previous comments that up to $60 billion of spending would be necessary for NOC to carry out all repair and development work. NOC is not self-financing. Income, which amounted to about $24 billion in 2018 and should come in above $20 billion for 2019, is handed to the central bank, to which NOC then applies for funding. If it can find the money, NOC hopes its wholly owned subsidiary, Zallah Oil & Gas—now also responsible for some blocks, especially in the south and west of Libya—will lead the recovery. More realistically, the bulk of remedial processes will await the return of international oil companies and their deeper pockets. But that, in turn, will depend on security and political predictability—both of which are still lacking.

Conclusion

Libya's potential remains great. Its high-quality oil, rich in gasoline, remains much favoured as a blendstock, especially in Europe. It has expanded its exports to Asia, in particular China, and much lengthened the list of traders to which it sells oil—a strategic and commercial success. Its producing assets are well located, with extensive export infrastructure in place. With supporting tailwinds, production could easily return from the current 1.2 mb/d to 1.6 mb/d, its pre-crisis level in 2011.

But politics transcends the outlook. The dysfunction of the state—the centre's fundamental loss of the monopoly on violence, the capital's capture by militias, the cleavage in the country's political and regional structures, and the competition for control of the oil sector and the Libyan economy—and the prevailing insecurity will hinder inward investment. NOC has done well under chairman Sanalla's stewardship to plot an autonomous course between the country's warring factions. To the surprise of not just outside observers but also some of Libya's own oil leaders, production has continued to defy the profound political and security deterioration. But significant output growth will depend on major remedial investment in everything from electricity provision at oilfields to installation of metering and new surface facilities, pigging of pipelines, infill drilling and well workovers, enhanced oil recovery, and, especially, replacement of oil-storage capacity. Peace is the prerequisite—but does not appear imminent.

KUWAIT: TARGETING HEAVY OIL GROWTH

Teresa Malyshev, Yousef M. Al-Abdullah, and Sreekanth K.J.

Kuwait is one of the world's top 10 oil producers and holds the sixth-largest proven conventional oil reserves (some 101.5 billion barrels) in the world. With its relatively small population, Kuwait has a very prosperous economy, but it is heavily dependent on oil-export revenues. The oil sector accounts for about 90 per cent of export revenues, and net oil-export revenues are approximately 40 per cent of GDP. Kuwait (like all oil-producing countries) is facing a changing energy world: shifting supply, demand, and technology trends have ushered in an energy world where oil-price volatility and market uncertainty are the defining features. To ensure economic development and social prosperity in the years to come, Kuwait will require a new energy strategy, combined with a plan to foster economic diversification and reduce fossil fuel dependency. This article summarizes Kuwait's medium-term oil supply prospects, summarising key insights from the 2019 *Kuwait Energy Outlook: Sustaining Prosperity through Strategic Energy Management*.

Current supply situation

The Kuwait Petroleum Corporation (KPC) estimates that Kuwait had a production-to-reserves ratio of 1 per cent in 2017. According to the *OPEC Annual Statistical Bulletin 2019*, Kuwait produced 2.74 million barrels per day (mb/d) of crude oil in 2018, up from 1.95 mb/d in 2001. Of this, 2.05 mb/d was exported, with the majority (around three-quarters) going to the Asia-Pacific region.

Currently, all of Kuwait's crude oil production comes from onshore fields—the Kuwait Oil Company (KOC) manages production and exports from around 12 developed oilfields. The oilfields are divided into north, west, south, and east fields, and each is locally administered. The Burgan field in the south of Kuwait is considered the world's second-largest oilfield, surpassed only by Saudi Arabia's Ghawar field. Greater Burgan accounts for about half of Kuwait's total production, and the field can produce as much as 1.7 mb/d. In 2018, KOC also produced 14.2 million cubic metres per day of natural gas and 11.3 million cubic metres per day of non-associated gas.

Kuwait produces a range of light to heavy crudes, which are blended into a single grade. Exports have an American Petroleum Institute (API) gravity of 31°, typical of medium-grade Middle Eastern crude. The country's main port for exporting crude oil is Mina al-Ahmadi. Kuwait exported 2.05 mb/d of crude oil in 2018. Most Kuwaiti crude oil is sold on term contracts and is destined for the Asian market.

According to the *OPEC Annual Statistical Bulletin 2019*, Kuwait's oil product exports totalled around 630,000 b/d in 2018. Kuwait's nameplate refining capacity in 2018 was 736,000 b/d, from its two refinery complexes, Mina al-Ahmadi and Mina Abdullah. The refineries are located near the coast, about 30 miles south of Kuwait City, and are owned and operated by Kuwait National Petroleum Company (KNPC), a subsidiary of KPC. The larger refinery, Mina al-Ahmadi, was built in 1949 and has a refining capacity of 466,000 b/d. Mina Abdullah has a nameplate refining capacity of 270,000 b/d. KNPC also completed the planned closure of its 200,000 b/d Al-Shuaiba refinery in 2017, converting the facility to a storage terminal; this probably contributed to a dip in product exports.

As mentioned above, the Asia-Pacific region receives approximately three-quarters of total Kuwaiti exports. South Korea receives about 21 per cent of total exports, followed by China at 16 per cent and Japan at 12 per cent. With most of its crude oil-export volumes headed to Asian markets, Kuwait's most significant price benchmarks for exports are average Dubai/Oman Crudes or Saudi Arab Medium. Generally, Kuwaiti oil exports are priced at a slight discount. In July 2018, Kuwait also exported ultra-light crude oil (with an API gravity of ~50°) for the first time.

Plans for production and upstream development

KOC plans to boost the Greater Burgan field's capacity through enhanced oil recovery methods such as injection of seawater and carbon dioxide. KPC plans to increase crude oil production capacity to 4 mb/d in the next decade, where the additional production capacity is expected to come from technically challenging sour and heavy fields. The country has awarded enhanced technical service agreements to international firms for the development of heavy oil and Jurassic fields. Three early production facilities (EPFs) were brought online in 2018. They were constructed under contracts that KOC signed with private firms in 2016—two went to US-based contractor Schlumberger and the third to domestic firm Spetco—to develop Kuwait's sour northern Jurassic fields. These three EPFs will produce a combined 120,000 b/d of ultra-light crude oil and more than 300 million cubic feet per day of sour gas. Four more Jurassic EPFs are planned to ramp up ultra-light crude oil production to 320,000 b/d and gas to more than 630 million cubic feet per day. Another EPF was commissioned in early 2017 for the production of about 25,000 b/d of heavy oil from the northern Um Niqa field, where additional production will come from the development of the Ratqa heavy oilfield. The expansion of the Ratqa field would have added about 60,000 b/d by the end of 2019 but has been delayed. Hence, Kuwait's total heavy crude oil production is expected to reach 85,000 b/d.

The Clean Fuels Project, which is due for start-up in 2020, aims to transform Kuwait's two operational refineries into a single integrated merchant-refining complex. As part of this integration project, the Mina al-Ahmadi refinery will shed 120,000 b/d and the Mina al-Abdulla refinery will add 184,000 b/d. This will result in a net gain of 64,000 b/d with a total of 800,000 b/d refining capacity at the new integrated complex. The project will upgrade conversion capabilities, operational integrity, energy efficiency, and safety performance. The oil products will conform to Euro-5 specifications. The upgrade will lead to a reduction in local emissions of SO_x, NO_x, and other pollutants. According to KPC, the upgrades will reduce the sulphur content in gasoline from 500 ppm to 10 ppm and in diesel from 5,000 ppm to 10 ppm.

A third refinery, Al Zour, is under construction in the south of the country. This $16 billion refinery is expected to be completed in 2020, producing a nameplate capacity of 615,000 b/d. In late 2016, KPC formed the Kuwait Integrated Petroleum Industries Company (KIPIC) to manage refinery, petrochemicals, and LNG import operations at Al Zour. Al Zour will produce low-sulphur fuel oil that will replace the high-sulphur fuel oil used in local power plants. KIPIC is also charged with securing Kuwait's local demand for energy and contributing to the growth of the private sector.

Impact of rising domestic demand

Total primary energy demand in Kuwait grew by an average annual rate of 4.3 per cent from 2000 to 2015, reaching 34.9 million tonnes of oil equivalent (toe) in 2015, and nearly doubling from its 2000 levels of demand (18.7 million toe). Kuwait relies almost solely on oil and gas to meet its energy needs. The country consumes only a small portion of its total petroleum production, but domestic oil consumption has been steadily increasing, partly as a result of increased petroleum-fired electricity generation as average temperatures rise. According to the *Kuwait Energy Outlook*, oil demand in Kuwait rose from 230,000 b/d in 2000 to 370,000 b/d in 2016. Although oil dominated the domestic energy mix in the 1990s and early 2000s, natural gas has made recent inroads, with its share in Kuwait's energy mix increasing from 40 per cent in 2005 to 48 per cent in 2015.

Per capita energy consumption in Kuwait is among the highest in the world. In 2015, it was 8.9 toe per capita, compared with 4.1 toe per capita in OECD countries on average and the Middle East average of 3.2 toe per capita. Consumption of electricity and oil products is heavily subsidized, which leads to overconsumption and a misallocation of energy resources. Total final consumption was 18.4 million toe in 2015. Industrial energy demand accounted for the largest portion (around 31 per cent). Final energy demand in the transport sector (dominated by the use of private passenger vehicles due to underdeveloped mass public transportation) was a quarter of total energy demand and was comprised entirely of oil products. The residential and services sectors accounted for 21 per cent of total final energy consumption. Energy demand in these sectors is met mainly by electricity, with limited consumption of oil products in the residential sector. Non-energy use made up 16 per cent of total final demand in 2015, and energy use in desalination accounted for 7 per cent.

Kuwait relies on oil and natural gas to generate electricity, with oil accounting for 64 per cent of the generating capacity in 2015. Given Kuwait's dependence on oil-export revenues, there are significant financial incentives to move away from burning oil for domestic power use. Kuwait is seeking to diversify its electricity generation supply portfolio by replacing petroleum products with more natural gas, but shortfalls in natural gas production have forced the country to rely on LNG imports for gas-fired power generation.

In 2018, Kuwait had an installed electric generation capacity of 18.8 gigawatts, with nine power plants. Steam generation accounted for nearly half of total capacity, with combined-cycle steam and gas plants making up another 40 per cent. Open-cycle gas-fired generation accounted for some 8 per cent in 2018. The country has a target of meeting 15 per cent of its domestic energy demand from renewable energy by 2030, but progress has been slow. In 2017, the Umm Gudair photovoltaic plant and Phase 1 of the Shagaya plant, based on photovoltaic and wind, came online, although the Umm Gudair plant is not connected to the national grid. In 2018, a concentrating solar power plant at Shagaya joined the grid. The total contribution of renewables to Kuwait's power generation mix in 2018 was 80 MW, or less than 1 per cent of total generating capacity.

Water needs for residential and commercial use—a key driver of energy demand—are met predominantly through desalination. Kuwait has eight desalination plants, producing 627 million imperial gallons per day of desalinated water in 2018. Desalination plants meet over 90 per cent of water demand in the residential and services sectors and 60 per cent of water demand in the industry sector.

Energy supply outlook and risks

With a current production-to-reserves ratio of about 1 per cent, Kuwait will remain one of the world's leading oil producers to 2035. In addition to KOC's enhanced technical service agreements with international firms, it is also developing its offshore fields. Natural gas production is expected to increase, although the pace at which Kuwait can ramp up its gas production is more uncertain, given that its gas infrastructure is underdeveloped. Vast discoveries of non-associated gas in the Jurassic field in the northern region have attracted foreign interest, but the resources are mainly in tight and sour natural gas deposits that require sophisticated development and have higher capital costs.

KOC has outlined plans for major developments to increase oil and natural gas production at the Raudhatain, Sabriyah, Bahrah, Abdali border, Burgan, Umm Gudair, South Ritqa, and Mutriba fields over the period to 2035, and enhanced oil recovery

projects are a major component of these plans. In the same time period, Kuwait Gulf Oil Company plans to implement the Wafra 1st Eocene steam-flood and the Wafra Ratawi chemical enhanced oil recovery programs, and an increased oil recovery project at the South Fawares field. KOC has ambitious plans to further develop the Jurassic natural gas reserves with contracts for additional early production facilities. Currently, four production facilities are being developed, two of which are anticipated to be on-stream by the end of 2022. The capacity of the new facilities is about 6.5 billion cubic meters (bcm) per year. KOC's ultimate objective is to increase its output of non-associated gas to 20.5 bcm per year by 2040. Over the outlook period, the oil sector will continue to get priority in the allocation of domestic gas supplies.

Natural gas supply to the power generation and industry sectors over the outlook period

	2020	2025	2030	2035
Power generation ('000 toe/day)				
Fuel gas	13.9	13.7	15.1	1.3
LNG	11.3	32.1	39.1	57.7
Industry ('000 toe/day)				
Oil	26.7	37.0	40.8	52.1
Other industries	0.3	0.3	0.3	0.3

Source: Kuwait Energy Outlook 2019.

According to a business-as-usual case presented in the *Kuwait Energy Outlook*, crude oil production in Kuwait is expected to increase from 2.7 mb/d in 2017 to 3.5 mb/d in 2035, growing at an average rate of 1.5 per cent per year. Thus, production in 2024/2025 is expected to reach 3.2 mb/d.

Crude oil and natural gas production in the business-as-usual case

	2017	2025	2035	2017–2035 annual average growth rate
Oil (mb/d)	2.7	3.2	3.5	1.5%
Gas (bcm per year)	17.4	21.5	27.3	2.5%

Source: Kuwait Energy Outlook 2019.

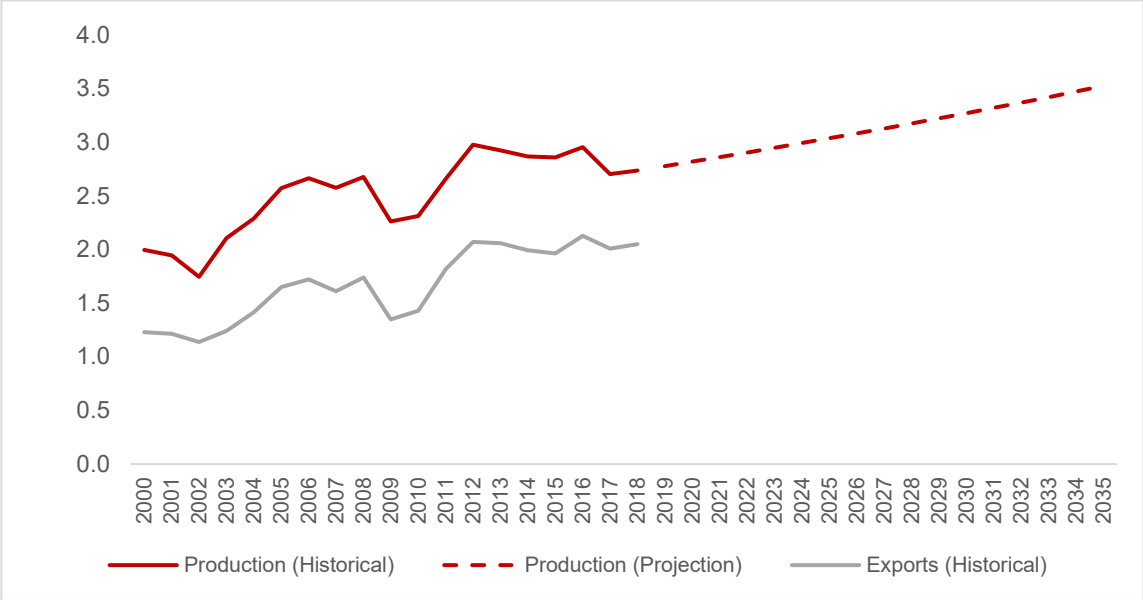
Natural gas production increases, on average, by 2.5 per cent per year, from 17.4 bcm in 2017 to 27.3 bcm in 2035, with LNG imports expected to continue to be an important source of natural gas supply. In anticipation of this, KIPIC is building a new LNG import terminal at Al-Zour with a capacity equivalent to 3,000 billion British thermal units per day. The terminal, which is expected to come online in 2021, will have eight storage tanks. In addition, KPC has signed a 15-year import contract with Shell to supply Kuwait an undisclosed volume of LNG from 2020.

The business-as-usual estimate for future production is based on the country's plans to increase production capacity to 4 mb/d in the next decade, and it reflects the global oil industry's assessment of future production levels in Kuwait. The main factors influencing this assessment are:

- a likely deceleration in global demand for oil, particularly in Asian countries, as governments strive to meet their climate-change-related commitments under the Paris Agreement and as breakthroughs occur in cleaner and more cost-effective energy options;
- increasing competition from unconventional oil supplies and from non-OPEC suppliers, who have significant upside production potential, especially over the medium term.

The global economic environment will also influence the outlook—as occurred, for instance, when the economic crisis of 2008/2009 precipitated a downturn in global oil demand.

Kuwait oil production and crude oil exports, historical and projected, 2000–2034 (million b/d)



Source: Data from OPEC Annual Statistical Bulletin 2019; assumption of 1.5 per cent average annual growth in production from Kuwait Energy Outlook 2019.

In the period to 2035, energy demand in Kuwait is projected to increase by a third in the business-as-usual case, but growing at a much slower pace than over the past couple of decades, due to decelerating GDP and population growth. The share of oil in total primary energy demand steadily declines, to just over 40 per cent in 2035, a result of the government's push to switch from oil to natural gas and solar energy for power generation. Natural gas demand is expected to grow by 2.2 per cent per year in 2015–2035. While Kuwait's natural gas production will grow under the business-as-usual scenario, domestic supply will likely be unable to meet the expected increase in demand, and LNG imports are expected to continue to be an important source of natural gas supply. Despite some progress in adding renewables to the generation mix over the projection period, their share in total primary energy demand remains low in 2035, only 3 per cent in the business-as-usual case.

IRAQ: A CHALLENGING DECADE AHEAD

Ahmed Mehdi

It has been just over a decade since Iraq opened its super-giant fields to international investment. Since then, international oil companies (IOCs), operating under technical service contracts (TSCs), have been the main contributors to Iraqi liquids growth, adding 300,000 barrels per day (b/d) year-on-year from 2010–15 and around 185,000 b/d in 2016 and 2017 alone. This supply growth—while taking place against the backdrop of the 2014 oil crash and a volatile geopolitical climate—has cemented Iraq's position as OPEC's second largest producer.

With federal production capacity now just under 5 million b/d (mb/d), and southern exports averaging 3.5 mb/d, what is the medium-term outlook for Iraqi crude supply?

Key developments in 2019

Iraq entered 2019 with a new government, following parliamentary elections in May 2018, and a massive federal budget expansion ($111.8 billion) – driven by a rising public wage bill and a range of investment needs across the country (housing, infrastructure, electricity, and other oil and non-oil sector requirements). The annual capital budget allocated to Iraq's Ministry of Oil also improved (increasing $1.5 billion year-on-year)—a healthy corrective to the fiscal retrenchment Iraq's oil sector faced in 2015–18.

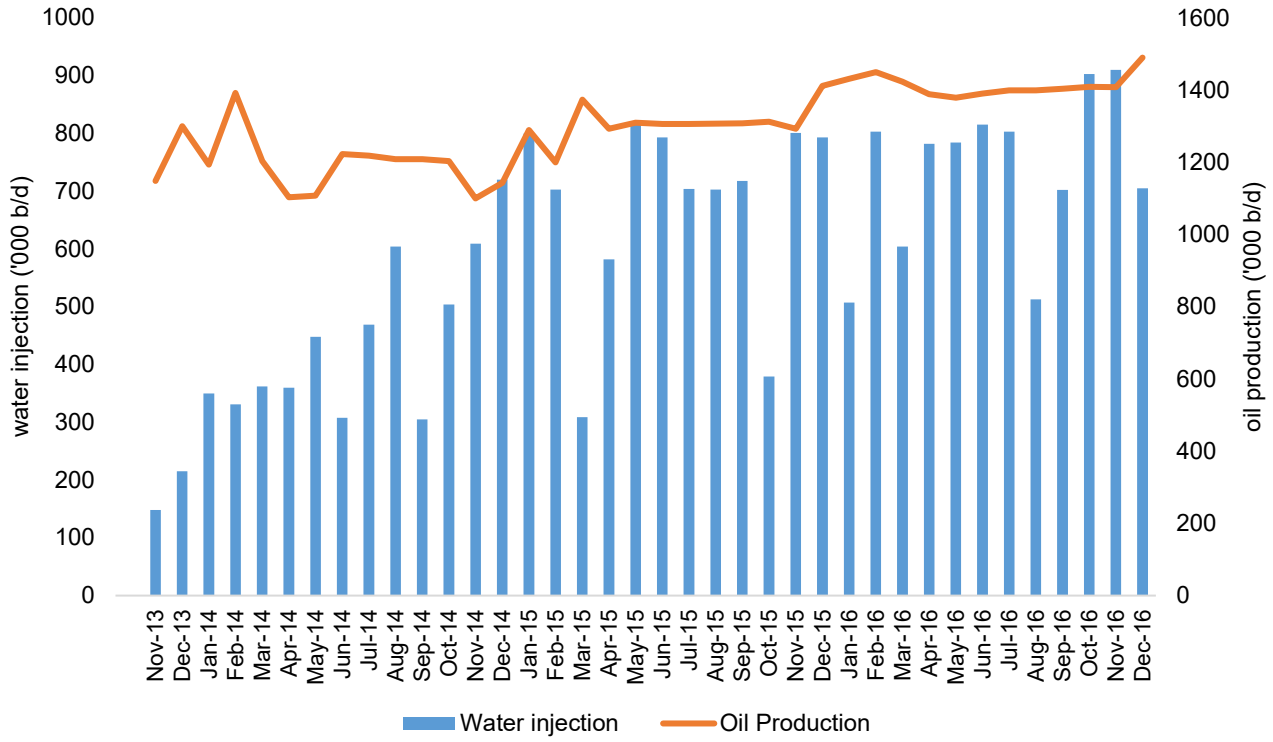
However, this fiscal expansion (supported by GDP growth from higher oil prices and exports) belied ongoing structural weaknesses: a rising public payroll, subsidies, low levels of capital investment, weak institutional and absorptive capacity across state institutions, and a highly complex and inefficient bureaucracy.

The year 2019 also highlighted the growing cost and complexity of field operations in Iraq's upstream: a growing number of fields entering secondary recovery, the need to source water to sustain reservoir pressure, and the growing cost of integrating gas (processing/treatment) and power operations at fields—a signal that Iraq's next chapter of production growth will prove more expensive.

A snapshot of these challenges was evident at the BP-operated Rumaila field. In 2019, output at the field reached approximately 1.5 mb/d, representing around 30 per cent of total Iraqi crude production. With a field decline rate of around 17 per cent, well management is becoming more complex as operational focus shifts from the productive northern Main Pay reservoir, which is supported by a natural aquifer, to the Mishrif (24–28° API gravity, 4 per cent sulphur), which suffers from weak aquifer support. To address these challenges, the BP Rumaila Operating Organisation have implemented a number of measures:

- executing upgrades to the Qarmat Ali Water Treatment Plant (currently able to treat up to 1.3 mb/d of river water);
- increasing the use of electric submersible pumps to create artificial upward pressure to support well productivity;
- increasing the use of water handling and separation technologies—such as free water knockouts—to handle the growing water content in crude streams and recycle produced water for reservoir injection.

Rumaila oil production and water injection, November 2013–December 2016 ('000 b/d)



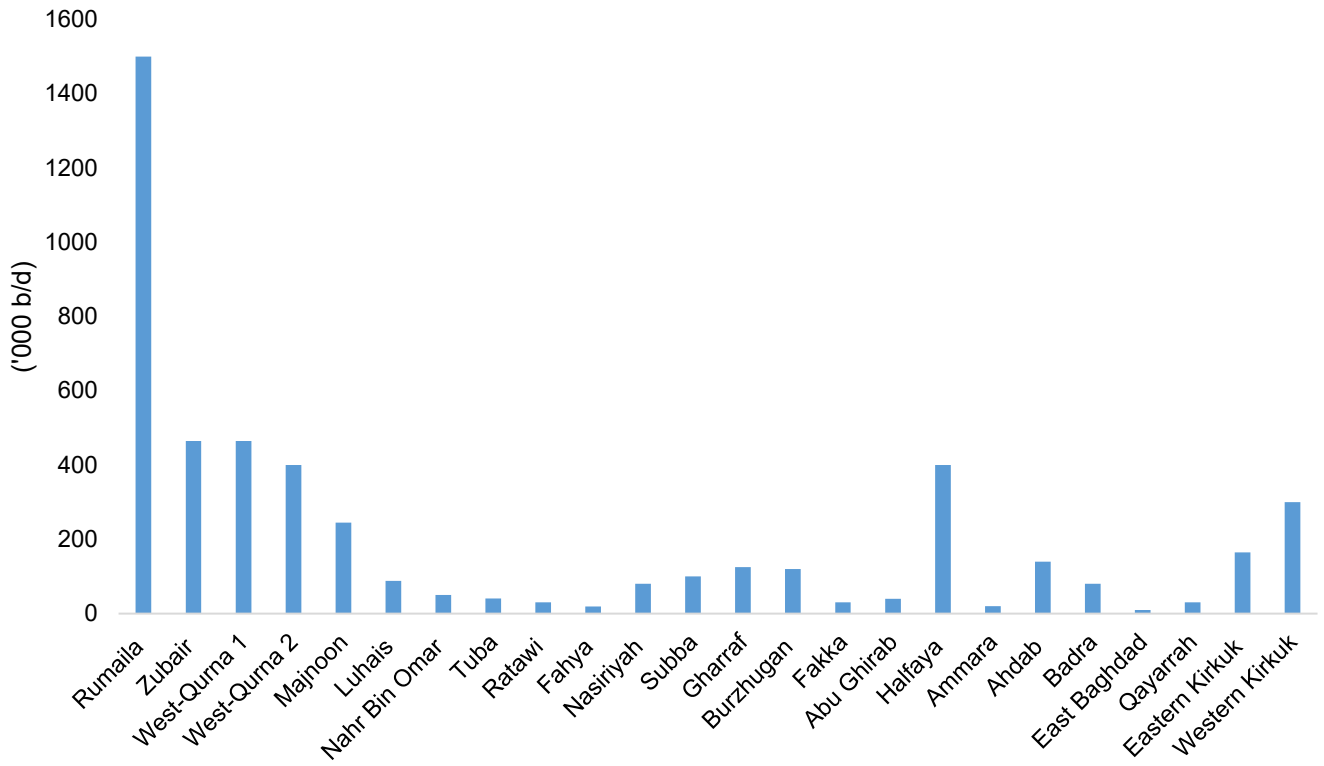
Source: BP Rumaila Operating Organisation, Author's analysis.

Another trend in 2019 was the growth of heavier crude production in Iraq's total liquids profile. Growth came primarily from the Halfaya field, operated by the China National Petroleum Corporation, which saw an 80,000 b/d year-on-year increase, with 2019 output around 400,000 b/d. Production growth from both Halfaya (22.5° API gravity), and West Qurna 2 (22.8° API gravity), a greenfield with output currently at 400,000 b/d, represents the growing role of Basra Heavy crude in Iraq's crude export mix.

Work in 2019 also accelerated at Majnoon. Previously operated by Shell (who exited the asset in mid-2018 due to poor fiscal terms), Iraq's Basra Oil Company (BOC) awarded two contracts to manage the field towards the end of 2018—one to KBR and another to Anton Oilfield Services Group. The significant well-workover program conducted by Shell—including restoring legacy wells and improving safety—has helped BOC's new partners. BOC has also provided Chevron, a potential future entrant to Iraq's upstream, technical data to conduct reservoir simulation and modelling of the field, helping improve BOC's understanding

of the asset. Throughout the year, work also progressed on the development of a new central processing facility at Majnoon, built by Petrofac, to accommodate an increase in Majnoon's capacity from its current 240,000 b/d to 400,000 b/d by 2022.

Federal Iraq's oil production by field, 2019 ('000 b/d)



Source: Author's analysis.

Medium-term supply prospects

Iraq's medium-term supply prospects depend on several factors, including the availability of water for reservoir injection, midstream and offshore export capacity, the role of gas in Iraq's energy mix, the involvement of IOCs, Iraq's political transition, and the country's compliance with OPEC quotas. These are discussed in more detail below.

Taking these factors into account, Iraq's federal production capacity is expected to reach approximately 5.2 mb/d by 2024.

The growing need for water for reservoir injection

Iraq is currently undergoing a transition from primary to secondary oil recovery. Despite its significant resource base, approximately 80 per cent of Iraq's producing fields have ultimate recovery factors in the range of 15–40 per cent.[1] A growing consensus is forming among operators that secondary oil recovery methods—whereby water is injected into oil formations to sustain reservoir pressure—will be key to the next phase of Iraqi production growth. While gas injection is a potential method for maintaining reservoir pressure, Iraq's ongoing challenge of gas flaring and the call on gas for Iraq's power sector undermine this option.

A proposed megaproject often touted as the key to unlocking Iraqi production growth is the Common Seawater Supply Project (CSSP), a multi-phased project to process seawater from the Gulf and transport it to southern fields. Multiple conflicts between Iraq's government and CSSP investors have occurred over the past few years, primarily relating to the project's financing, scale, and contractual terms. If the megaproject is approved, its first phase (processing 5 mb/d of water) would take at least three to four years to complete.

Iraq currently needs approximately 1.3–1.5 barrels of injected water for every barrel of oil extracted. In 2018, water injection

[1] IEA, Iraq Energy Outlook, April 2019

rates were around 3.5-4 mb/d. This is sufficient to support current production capacity levels of around 5 mb/d. While CSSP may be further delayed, undermining further capacity gains, a number of short-term solutions can be implemented to support water management:

- expanding capacity at the Qarmat Ali water treatment facility from 1.3 mb/d to 2.6 mb/d to support injection rates at Rumaila and Zubair;
- expanding the use of industrial water and increasing the recycling of produced water.

However, these short-term solutions belie the scale of the challenge. For example, the BP-operated Rumaila will need around 2m b/d of water by 2025; water requirements at West-Qurna 1 and 2 are set to double over the next five years; and for Majnoon, its water requirements are set to quadruple from a current rate of around 200,000 b/d to just over 850,000 b/d by 2025.

Midstream and offshore export capacity expansion

Iraq's upstream growth has rapidly outpaced its midstream capacity. While a number of tie-in pipelines have been built to transport crude from fields to the Fao depot for export, onshore bottlenecks continue within the sector. In particular, the medium-term forecast will depend on a number of midstream developments, including the following:

- Construction of a new pipeline from Tuba tank farm to Fao to accommodate growth from West Qurna 2.
- Expansion of storage tank capacity at Fao, Zubair, and Tuba. With current operating storage capacity of around 12 million barrels, further increases are planned at Fao to both accommodate growth and provide a buffer during bad weather.
- An increase in onshore pumping capacity at Fao to increase flows to offshore export facilities.
- Reaching a deal with ExxonMobil and its partners to fast-track the Southern Iraq Integrated Project, a multi-billion-dollar megaproject designed to upgrade infrastructure, construct a water injection project (separate from CSSP), and expand storage capacity. In return, Exxon and its partners would gain upstream equity at southern fields.

Midstream asset build-out will be key to increasing Iraq's exports in the medium term, particularly given the successful work being done at offshore export facilities. At present, Iraq's southern export infrastructure is made up of the 1.7 mb/d Basra Oil Terminal and a network of subsea pipelines connecting four single point mooring (SPM) systems, each with a design capacity of 900,000 b/d. At present, not all the SPMs are being utilized due to insufficient onshore pumping capacity; however, pumping capacity upgrades, currently being assessed by Japan's Toyo Engineering, and the completion in Q3 2020 of a new 1 mb/d subsea pipeline will help move crude from Fao to North Basra Oil Terminal and SPM-4. Moreover, BP and Eni are working on construction of two additional subsea pipelines (Sealine 4 and 5), which will be financed through their existing TSCs.

The growing role of gas in Iraq's energy mix

Increased oil production has also meant increased associated gas output. The failure to capture and process associated gas over the years has led to high levels of gas flaring—which increased from 12 to 16 billion cubic metres per year in 2018. The lack of fuel availability for Iraq's gas-powered generation plants has put the spotlight on the importance of Iraq's long-term gas strategy and the need to coordinate increases in oil production with requisite gas capture, processing, and treatment.

IOC portfolios and fiscal competitiveness

Iraq's low-cost oil production and high level of reserves present a major comparative advantage to attract international capital. Despite this, the harsh fiscal terms which underpin Iraq's TSCs have undermined IOC confidence. IOCs initially accepted the small per-barrel remuneration fees as part of the TSCs on the assumption that cost recovery would be swift, helping offset project financing risk and helping keep project internal rates of return within an acceptable range. Poor fiscal terms and IOC portfolio adjustment following the oil price crash of 2014 have already led to the exit of one major IOC (Shell in mid-2018). Given that Iraq is largely non-core to IOC portfolios, the need to sweeten fiscal terms to keep Iraq's investment landscape competitive will be key over the next decade.

The rapid cost deflation in the oil industry since 2015 has also flattened the industry's cost curve, eroding some of Iraq's comparative advantage as a low-cost producer. A more competitive pool of global capital and offers of more attractive returns in other resource plays will also put pressure on Iraq's Petroleum Contract and Licensing Division to amend its existing fiscal terms to keep Iraq competitive.

While Iraq may fail to attract new IOC entrants over the next decade, it is possible that Asian national oil companies, with much lower investment hurdle rates, will seek to expand their upstream footprint in the country, particularly given Asia's downstream investment schedule and Iraq's contribution to medium-heavy crude balances out to 2030.

Ongoing political transition and geopolitical outlook

Iraq is currently witnessing one of the largest protest movements in its post-2003 political history. Unlike previous protest movements (2015–16), which focused on jobs and services, the current protest movement engulfing Baghdad (and parts of southern Iraq) is youth-led, largely leaderless, Shi'ite in composition, and maximalist in its demands. This protest movement is also taking place against the backdrop of a rapidly shifting geopolitical outlook for Iraq's energy sector – a dynamic triggered by US decision in January 2020 to assassinate Qassem Soleimani, commander of the Iranian Revolutionary Guards' Quds force and Abu Mahdi al-Muhandis, deputy head of Iraq's Popular Mobilisation Forces (PMF).

While events remain fast moving, several important points can be made:

- Iraq's protest movement has put the spotlight on the limits of Shi'ite-centric state building and the legitimacy deficit of the post-2003 political model of *muhasasa ta'ifia* (sectarian apportionment), a political formula which allocates public offices and government ministries along ethno-sectarian lines. The protest movement has already triggered the resignation of Iraq's Prime Minister, Adel Abdul Mahdi.
- The escalation of the US-Iran confrontation on Iraqi soil has put the spotlight on the future of Iraq-US relations. For Iraq's various Shi'ite parties, growing momentum to force a US withdrawal sits uneasily with anxieties that such an outcome would trigger investment withdrawals, negatively impacting Iraq's rentier economy - one that feeds Shi'ite political power and the *muhasasa* system itself.
- While Iraq's complex political system defies neat categorisation, inter-Shi'ite rivalry has been a key theme of Iraqi politics since the mid-2000s. In this light, even without any major shift in US-Iraq relations, political competition for state resources among various parties is likely to continue. The emergence of a 'political marketplace' to consolidate power is reflected by Iraq's rising public wage bill and party-related interference in the affairs of technical government departments, e.g. Iraq's State Oil Marketing Organisation.

With Iraq showing no signs of reforming its pro-cyclical fiscal policy, both oil price volatility and growing capital misallocation risks undermining the case for much-needed investment in Iraq's oil infrastructure – particularly onshore pumping capacity, pipelines and water facilities.

OPEC

As part of OPEC's production cuts since November 2016, Iraq agreed to a production ceiling of 4.51 mb/d, and from January 2020 of 4.46 mb/d. Iraqi compliance with OPEC has been weak, with output consistently above its quota. While Iraq has vowed to improve compliance, particularly since the December 2019 OPEC meeting, any potential cuts are likely to be from state-operated fields, not IOC-operated fields, as contractors would still receive remuneration for any lost production. Iraqi compliance with OPEC is unlikely to be strong, particularly given OPEC's lack of an effective enforcement mechanism.

Conclusion

Despite Iraq's enormous resource base, it faces a number of geological, financial, and political challenges over the medium to long term. It is important to remember that despite the challenges outlined above, IOCs who entered Iraq over the past decade have reached an advanced stage in their capital investment cycle. It will not prove challenging for Iraq to maintain its current production levels at the current rate of upstream investment (~$8-10bn/yr); however, moving beyond 5.2m b/d over the medium-term will require significant midstream and infrastructure investment – a need made more challenging by Iraq's uncertain (geo)political future.

OMAN: MITIGATING OUTPUT DECLINES

Paul Mollet and Colin Ward

Oman's oil production is likely to remain relatively steady over the coming five years, with output likely to peak at 1.1 million barrels per day (b/d), according to the KAPSARC (King Abdullah Petroleum Studies and Research Center) Oil Market Outlook (KOMO). By comparison, output during 2019 averaged 980,000 b/d. KOMO projections are technical estimates based on known planned projects and do not take into account risk factors or other external factors such as OPEC (Organization of Oil Exporting Countries) production cuts. While Oman is not a member of OPEC, it agreed in 2018 to adhere to production cuts set by OPEC+, a group made up of OPEC members and 10 additional producers including Russia, Mexico, and Kazakhstan. Its current quota or production target is 970,000 b/d, but for much of 2019, this was not adhered to.

Oman will need to make a major new oil discovery and bring it onstream quickly if the 1.1 million b/d KOMO projection is to be surpassed. Oman's state-controlled oil company Petroleum Development Oman (PDO), a joint venture with Shell, Total, and PTT of Thailand, exported its first cargo of crude oil in 1967, and many of the country's legacy oilfields have long since reached maturity. At present, it operates 178 oilfields, 14 gas fields, and 21 production stations, with more than 10,000 active wells. For over a decade, PDO has been implementing enhanced oil recovery (EOR) projects at its oilfields and has managed to maintain production levels, even raising output from EOR projects to a peak in 2018 of 61,000 b/d. Such techniques are expected to lead to an increased EOR production as a share of PDO's overall output from 10 per cent in 2018 to at least 23 per cent by 2025.

But barring a major new discovery, Oman will have to accept that it is close to plateau production. Many of the country's current hydrocarbon development projects, including PDO's megaprojects at Rabab-Harweel and Yibal Khuff, are primarily gas projects, with the latter delivering 50 million standard cubic feet per day of natural gas. Other major gas projects include the Mabrouk gas field (4.5 trillion cubic feet), a recent discovery in the northeast of Oman. A master agreement covering the development of the field, expected to include Shell, Total, and Oman Oil, is expected to be signed in early 2020.

Looking ahead, the lack of new oil means that the country's legacy producers such as PDO will have to continue to invest in EOR to increase or even maintain production from existing fields. This is a task well suited to PDO, which has an established track record in maintaining production from mature reservoirs. One example is at its oldest field at Fahud, where declining production of crude oil is being offset by a 21,000 b/d increase in natural gas liquid (NGL) production. This means that total output from the field is set to increase from 52,000 b/d to 67,000 b/d within the coming years. At the Amal field, a new EOR project will add 7,000 b/d of crude, according to Rystad Energy.

Oman's existing crude oil slate places it at a competitive advantage to many producers dependent on a single export grade. At 265,000 b/d, extra-heavy crude accounts for over a quarter of Oman's production, meaning the Sultanate is well placed to increase market share in a sector traditionally dominated by heavy oil producers such as Iran and Venezuela. Oman produces a grade comprised of light oil, condensates, and NGLs, totalling 263,000 b/d, which is sold largely to Asian refiners as petrochemicals feedstock. But this grade has to compete increasingly with light oil exports from US tight oil resources. Regular and heavy oil accounts for around half of Oman's overall oil production.

But the country's crude oil slate is set to change. A mixed picture emerges for crude grades that will rise or fall over the next five years in terms of production. Extra-heavy crude will remain unchanged at 265,000 b/d, while heavy crude will fall by 20,000 b/d to 105,000 b/d. Production of medium crude will rise by 43,000 b/d to 448,000 b/d, while light crude output will slump from 126,000 b/d to 76,000 b/d. The large number of new gas projects means that the biggest gains in Oman's condensate and NGL production will drive a rise from 135,000 b/d to 178,000 b/d, with PDO's Rabab Harweel project delivering 48,000 b/d and BP's Khazzan/Makarem adding a further 15,000 b/d.

In terms of geopolitical risk (a factor not considered in KOMO technical projections), Oman benefits from close historic relations with both Iran and Saudi Arabia, while at the same time managing to be seen as strictly neutral. Oman has recently had minor diplomatic disputes with its other important neighbour, the United Arab Emirates, but these pose no risks to energy production. Its relations with Qatar, which is under embargo by Saudi Arabia and the United Arab Emirates, are cordial, and Oman continues to buy gas from the emirate through the Dolphin pipeline project. Additionally, the fact that its export terminals are located outside the Persian Gulf means that Oman is less subject to the risks associated with the potential closure of the Strait of Hormuz.

Oman's membership in OPEC+ is a primarily diplomatic and symbolic gesture, driven largely by its concerns about low oil

prices. Oman's compliance with its relatively small 25,000 b/d OPEC+ production cut commitment in September was 64 per cent, which means that it will be able to pick up production quickly should the constraint be eased. In the medium term, Oman is unlikely to allow itself to be constrained by such agreements as it seeks to maximize oil revenues.

Oman is clearly determined to mitigate any potential supply risk with plans for a major oil storage facility at Ras Markaz, 600 km south of Muscat and far from the Persian Gulf. The Oman Tank Terminal Company, a wholly owned subsidiary of Oman Oil, is developing one of the world's largest crude oil storage projects, a tank farm that will have a total capacity of 200 million barrels of crude oil upon completion. Development is planned in five phases, with total investment estimated at around $5 billion.

In recent years, Oman's Ministry of Oil and Gas has sought interest from foreign and local oil exploration companies for areas outside the PDO concession. Four concession areas were opened in November 2017. The first, the onshore 15,449 km^2 Block 49, was awarded to Tethys Oil of Sweden. The others were offshore Block 52, awarded to Italy's Eni and local firm Oman Oil Exploration and Production (OOCEP), covering 90,760 km^2; onshore 1,185 km^2 Block 30 to OOCEP in a joint venture with Occidental Petroleum; and onshore 8,528 km^2 Block 31 for local ARA Petroleum. In January 2018, Lebanon's Petroleb won the concession for onshore Block 57, which spans 2,262 km^2. However, none of these exploration blocks is expected to contribute new oil within the next five years.

Notwithstanding the anticipated modest increase in Oman's oil production, crude oil exports are likely to fall in 2022 when the 230,000 b/d refinery currently under construction in Duqm comes onstream. Oman currently exports 84 per cent of the crude oil that it produces, and the new refinery will absorb a sizeable proportion of the Sultanate's oil production, allowing it to export a greater proportion of its crude in the form of refined products. Oman's economic growth—and domestic energy consumption—is closely correlated to global oil prices, with GDP growth in 2019 expected to be largely static at 0.3 per cent, according to the World Bank. Unless there is a major uptick in global oil prices, Oman's economy is likely to grow at modest rates, meaning that exports of oil and petroleum products are likely to remain stable for the foreseeable future.

KURDISTAN REGIONAL GOVERNMENT: BALANCING REGIONAL RELATIONS

Patrick Osgood

After a year of consolidation, the Kurdistan Regional Government's (KRG's) oil export picture has decidedly improved. But political instability in Baghdad and a reshuffle in the regional geopolitical order may cap the KRG's long-run oil and gas export potential.

Foundational assumptions for the region's oil sector were thrown into disarray in late 2017 as federal forces took control of several oilfields in Kirkuk province that had formed the bedrock of KRG crude supply. The KRG leadership was chastened by this military response to a referendum on independence but recovered—winning a favourable oil settlement in the 2018 and 2019 budgets, recommitting to stable payments to international oil companies (IOCs), and inviting new investment from Russia's Rosneft.

The government's speculative projections from the heyday of the exploration boom—by which the KRG forecast production of 1 million barrels per day (mb/d) by 2015 and 2 mb/d by 2020—are a now distant memory. But overall the KRG increased oil production by about 50,000 b/d to around 515,000 b/d in 2019, making steady, private sector-led progress. And the KRG is now capable of exporting almost 480,000 b/d of oil autonomously, while transferring between 80,000 b/d and 100,000 b/d of federal North Oil Company crude through its pipeline to Iraq's State Oil Marketing Organization (SOMO) in Ceyhan, Turkey.

Through 2019, the main operators have seen revenues rise by a third or more, on stable payment and increased production, despite broadly flat realized prices. With security of payment, the low-cost economics of further development look good. Surging IOC revenues have been partly reinvested to unlock the next phases of operators' field development plans, with several fields upping drilling programmes and commissioning surface production facilities.

The region's midstream infrastructure has also been expanded, with new spur lines to its export pipeline cutting down on road trucking. Eventually more spur lines to link the south-eastern oilfields will complete the network.

The KRG, under a new administration headed by Masrour Barzani, was able to restart full salary payments to public-sector employees, allocate money for new infrastructure spending, and acquire fuel needed to restart idle power plant capacity ahead of winter.

As part of a broad government reshuffle in which Masrour is consolidating power, former minister of natural resources Ashti Hawrami has been moved into a senior advisory role as assistant prime minister for energy affairs. He maintains his senior operational role while concentrating energy policy and major decision-making with the prime minister. Hawrami no longer serves on the region's senior oil council and is no longer a cabinet minister. Baz Karim, the CEO of the Kurdish conglomerate Kar Group, is slated to take Hawrami's place.

The moves signal a less antagonistic stance towards Baghdad with a much lower profile for the minister of natural resources, though it remains unclear how the KRG might square oil deals in Baghdad with offtake obligations to traders.

2019 upstream developments

The KRG's lynchpin oilfield remains the Khurmala Dome, operated by the KAR Group. Production there is holding steady at 175,000 b/d. Besides Khurmala, the five-year outlook for KRG oil relies on a patchwork of smaller independents, many of whom are focused mainly on the Kurdistan region.

With more than 60 wells drilled and 300 million barrels produced, Tawke field production has matured. Decline has been more than offset by the start-up of nearby Peshkabir, with operator DNO quickly bringing 50,000 b/d online tied into the Tawke facilities. Together, they produce 120,000 b/d. Gas reinjection from Peshkabir to Tawke from March 2020 will stabilize Tawke output as Peshkabir production grows further.

DNO is also pressing ahead with appraisal at the Bashiqa license, after taking operatorship and a larger stake from ExxonMobil. A leaked internal memo by the Turkish Energy Company, a minority partner in the block, said the field may hold 580 million barrels of oil equivalent. If the geology holds up and politics permits, the field could be well into first-stage production by 2025.

Gulf Keystone Petroleum, once the poster child of the KRG's speculative heyday, has hiked Shaikan production to around 42,000 b/d and connected the field to the main export pipeline, ending years of costly trucking. Output there is on track to increase to 55,000 b/d in the second half of 2020.

Taking up the impetus from more mature fields and some high-profile disappointments—like Genel Energy's Taq Taq field—much of the KRG's recent and future growth is set to come from secondary fields that made slow progress until 2019. The TAQA-operated Atrush field quickly scaled up output from 30,000 b/d to 45,000 b/d in October. Fast-tracking a second production facility allowed TAQA to bring production up to capacity, making it the third-largest producer in the region. Atrush has significant room to grow by about another 50 per cent.

Sarsang, close to Atrush in Kurdistan's mountainous northeast, is also being developed after years of slow progress by HKN Energy. A $50 million US Overseas Private Investment Corporation loan granted in spring 2019 helped finance a new 25,000 b/d production facility that will double capacity to 50,000 b/d in 2020. At the time of writing, a pipeline spur to the KRG export line was being tested. The field has room to grow further by 2025.

Genel Energy has bounced back, with the company's non-operated stake in Tawke allowing it to start paying out a modest dividend after regrouping financially in the wake of the Taq Taq failure. Genel is also starting exploration drilling at the Qara Dagh field, which it took a 40 per cent stake in from Chevron. Chevron also sold Genel a 30 per cent non-operated stake in the Sarta field, which should be into first phase production of around 20,000 b/d within two years. The company continues to negotiate with the KRG over starting development of the Bina Bawi gas field, with an emphasis on early light oil production.

Risks and potential barriers

More than perhaps any other major producer, the KRG's oil future is dominated by politics, with projections for about 450,000 b/d of medium-term production capacity and around 400,000 b/d of exports at the mercy of political factors.

The risks lie mainly in Baghdad. Nothing that touches the KRG's oil sector—including territory, contract and exploration rights, pipeline systems, and revenue sharing—is close to final settlement. Instead, the KRG makes and breaks deals, mostly relating to Iraq's annual budgets. Sometimes this strategy has worked, sometimes not.

While the KRG is doing well fiscally at present, it still has mammoth monthly wage and services bills, while IOC payments, loan repayments, and pipeline tariffs will all take a large chunk out of gross revenue for the foreseeable future: half of gross sales, according to an analysis of the KRG's last public oil accounts for Q4 2018. This means that relatively small variations, in oil prices or the political scene, can put the fiscal stability of the KRG's oil system at risk.

At the time of writing, the KRG gets about $380 million a month, about 40 percent of its full budget share, under the 2019 budget law. The KRG has also avoided transferring crude to the federal system for over a year, instead marketing and selling it independently. The budget law requires the KRG to transfer an average 250,000 b/d to a federal oil export terminal in Ceyhan, Turkey, in exchange for the KRG's full budget share, but instead the KRG relies on a fallback provision to transfer nothing and still get a large payment. It's a deal that currently works thanks to a good relationship with caretaker Prime Minister Adel Abd al-MahdiIn return, Kurdish members of parliament in Baghdad helped prop up Mahdi's unpopular government, and may end up keeping him or a similar figure amenable to Iranian interests in power.

The deal worked well for the KRG. It is taking 80,000–100,000 b/d of Kirkuk crude into its pipeline, blending it with KRG crude, and transferring equivalent amounts to SOMO at Ceyhan, while running its own exports alongside. The deal has also led Baghdad to lean on a federal court to stymie a lawsuit brought by the Ministry of Oil which sought to have KRG exports declared unlawful.

But on 1 December 2019 Mahdi resigned, after two months of protests across Baghdad and the south. He leaves behind a government in disarray, with no clear path to passing a 2020 budget. Whoever takes over from Mahdi as federal prime minister may take a harder line against the KRG on oil transfers and constitutional issues. The KRG is keen to push a new oil settlement, under which it will hand off the full 250,000 b/d and receive its full budget allocation, essentially swapping out some private revenue for federal transfers. Kurdish leverage in Iraq's parliament may make this work, though there is no real prospect of permanent resolution to the Erbil-Baghdad energy dispute and no guarantee that the KRG's current deal will survive. A U.S. air strike that killed Iran's Islamic Revolutionary Guard Corps General Qassem Suleimani and other senior Iran-axis officers has thrown the Iraqi political scene into turmoil. Kurdish officials fear the advent of a chauvinist majoritarian government beholden more directly to Iran, that will marginalize or expel the U.S. military presence and tear up federal deal making with the KRG on oil. Current federal pipeline plans include a new oil spur to link Iraq's southern fields to Turkey. While this would be several years away, if it ever happens, it is a reminder to the KRG that it cannot count on its northern export monopoly indefinitely.

It is also worth noting that the KRG has fallen short of its own transparency targets. Since the new government took office, all oil sector data reporting, imperfect as it was, has stopped. The Ministry of Natural Resources has not updated reporting on its activities for over a year, and promised public accounts remain undelivered. Worse, it emerged in November that the KRG's main oil broker IMMS is suing to recover $1 billion of imprudently placed deposits—much of them the KRG's—that have been frozen by a Lebanese bank, causing delays to IOC payments for the first time in years. The KRG's opacity and failure to properly formalize oil operations will continue to hinder the institutional investment needed to fully develop Kurdistan's resources.

Turkey's influence

Kurdistan owes its ability to export autonomously to Turkey. As part of a series of energy protocols signed in November 2013, Turkey established the Turkish Energy Company (TEC)—a special-purpose entity linked to state pipeline company Botas—to invest in KRG oilfields and cooperate on Kurdistan's commandeering of the Iraq-Turkey pipeline. The KRG-TEC arrangement clearly breached the treaties between Iraq and Turkey that govern the use of the pipeline, and the Ministry of Oil eventually sued, with arbitration in Paris continuing at the time of writing. An adverse decision could lead to massive penalties against Ankara and an end to TEC/KRG control of the line. More dangerously, the KRG-TEC agreements include an indemnity against precisely these losses, potentially leaving the KRG in hock to Turkey as it pays off Baghdad.

Turkey is lobbying Baghdad to drop the suit, but Iraq will want something in return. Turkey-KRG relations have passed the high-water mark, even while Turkey expands military operations against the Kurdish militant group PKK deep inside northern KRG territory. The KRG is still paying off overdue pipeline tariffs to TEC, which is yet to see any upside to its upstream investments. As the TEC investments soured and Turkish domestic gas demand dropped, so the interest in sponsoring a KRG independent energy policy has waned. Russia has increased gas supplies to Turkey through the Turkstream pipeline and has accommodated Erdogan over northeast Syria, while gaining a say in KRG energy affairs.

Rosneft's opportunistic investments in the KRG since 2016 have given Russia options, none of which it has yet taken. Prior investments in the KRG export line and oil prepays have helped finance expansion of the KRG's export capacity to 1 mb/d while unblocking domestic gas development, but upstream oil activity remains modest. Exploration drilling is minimal. Early production at the Akri-Bijeel field is outsourced to a local services company. Rosneft is taking its time with exploration, while demanding a high rate of return on any investment in an expanded domestic gas pipeline.

Moscow looked favourably on KRG independence in 2017 but is no longer supportive. Foreign Minister Lavrov's October visit to the KRG included a message for the KRG to work for the 'harmonization of the regional and Iraq's nationwide interests,' according to an official readout, signaling a Russian preference for the KRG to work in lockstep with Baghdad in future, sticking inside the national budget system for oil and working to send surplus gas southward instead of exporting it to Turkey or beyond. These policies may limit the upside to future upstream investment, especially for gas.

Five-year production outlook

Political volatility—being so interconnected with management of oil fields, the security of export arrangements, and the KRG's revenue sustainability—makes predictions uniquely difficult. With that caveat, a range of projections can be offered, taking into account recent production history.

Recent and forecast oil production (b/d)

					2025 forecast		
	2016	2017	2018	2019	Low	Medium	High
Refining	65,000	61,600	20,000	20,000	20,000	40,000	60,000
Exports	600,200	280,200	447,000	481,500	396,000	572,000	828,000
Total production	665,200	341,800	467,000	501,500	416,000	612,000	888,000

Source: oil company disclosures, oil executives, author's estimates.

The high projection assumes that the region's geological and projected field development upside matches the more optimistic projections given by IOCs publicly and in interviews with IOC officials. It also assumes that the KRG maintains contractual oil payments and that the Ministry of Natural Resources manages future production issues around gas flaring and reinjection.

The medium (and most likely) projection is that the status quo remains essentially unchanged. Stable payments to IOCs will continue, allowing for continued planned and predicted upstream developments across IOC-operated fields. While no durable settlement is realized over the fate of Kirkuk oilfield under federal control, limited oil transfers will continue from the North Oil Company to the KRG. No action is taken by Baghdad to curtail the KRG's independent exports. And the KRG manages its commitments to the federal system on its own terms, essentially transferring the minimum amount of oil that political deal-making allows to SOMO at Ceyhan. This scenario does not assume any materially new exploration upside beyond that already documented by IOCs.

The low projection assumes a broad breakdown in KRG-federal relations. This could both choke off federal budget revenues and increase pressure on the KRG's oil sector through renewed federal legal and political action against independent oil exports. In turn, this would likely forestall investment and renew insecurity over stable payments to IOCs. This projection also takes a pessimistic view on resource estimates and plateau production stability and assumes a high risk of increasing water cut in reservoirs of eastern oil fields, as seen previously at Taq Taq and Sheweshan.

SAUDI ARABIA: CAPACITY MANAGEMENT

Bassam Fattouh and Andreas Economou

Saudi Arabia's key position in global oil markets cannot be overstated. In 2018, the Kingdom's crude oil reserves and condensates stood at 268.5 billion barrels (including reserves in the Neutral Zone). In the same year, Saudi Arabia produced 10.3 million barrels per day (mb/d) of crude oil (including blended condensate), an additional 0.2 mb/d of unblended condensate, and 1.1 mb/d of natural gas liquids. Saudi Arabia produces a wide array of crudes, ranging from Arab Super Light (API gravity >40° and sulphur content <0.5%) all the way to Arabian Heavy (API gravity <29° and sulphur content >2.9%). Despite rising domestic demand in the past few decades, Saudi Arabia exports the bulk of its crude production and thus has a dominant position in international trade: exports averaged more than 7.3 mb/d in 2018. Saudi Arabia is the only country that has an official policy of maintaining spare capacity that can be utilized within a relatively short time.

In contrast to some neighbouring countries, such as Iran and Iraq, Saudi Arabia has not experienced conflict or political instability and has not been subject to international sanctions. It has thus been able to invest heavily in its oil sector and

integrate the upstream sector with refining and downstream assets, both in the Kingdom and overseas. The oil and gas sectors are also heavily integrated, given the large volumes of associated gas produced, though Saudi Aramco has been investing heavily in developing non-associated and shale gas, thereby increasing the flexibility of its oil policy.

Although Saudi Arabia's output has not been affected by political or military shocks (the September 2019 attacks on Saudi Aramco facilities disrupted output only briefly), it has been highly variable, reflecting the Kingdom's role as a shock absorber—increasing in times of disruption and decreasing in times of weak market conditions, with some exceptions. Saudi Arabia's role in OPEC is paramount, and the organization's key decisions have historically been driven by the Kingdom.

Saudi Arabia's reserves are also among the cheapest in the world to find, develop, and produce. Saudi Aramco's average upstream lifting cost is estimated at $2.8 per barrel of oil equivalent produced. The wedge between the production cost and price in the international market generates high rents for the Kingdom, whose economy still relies heavily on oil revenues. For the year ended 31 December 2018, Saudi Aramco's net income was $111.1 billion; it is the key source of government revenue in the form of royalties, taxes, and dividends.

Expanding oil productive capacity: the trade-offs

Given its large oil reserves, the relatively low cost of developing them, its stable investment environment, and a competent national oil company that has a strong record in executing megaprojects, there are no technical, financial, or geopolitical barriers that would prevent the Kingdom from increasing its productive capacity above the stated current level of 12.5 mb/d. The investment cycle, however, is longer than for US shale, and any plans to expand capacity beyond the current levels would take time to implement and require heavy investment—not only in the upstream sector, but also in calibrating the entire system, including increasing the capacity of gas-processing plants and building storage facilities, pipelines, and terminals.

For instance, Saudi Arabia decided in 2004 to gradually increase its sustainable productive capacity from 11 mb/d to 12.5 mb/d and completed the expansion by approximately 2010. This involved the development of megaprojects including the Haradah Increment III (0.3 mb/d), the Abu Hadriya, Fadhili, and Khursaniya Project (0.5 mb/d), Khurais (1.2 mb/d), the Shaybah Increment (0.3 mb/d), and Nuayyim (0.1 mb/d). During this period, the gross additions amounted to around 2.35 mb/d, with 0.8 mb/d of this earmarked to make up for decline rates in mature fields. Of the new capacity additions, 1.1 mb/d was Arab Light quality, while the rest consisted of Arab Extra and Arab Super Light crudes.

Thus, the decision to expand productive capacity and how fast is primarily one of policy. Decisions on optimal sustainable production capacity and spare capacity involve a challenging trade-off. On the one hand, spare capacity should not be so small that Saudi Arabia loses control of the market on the upside and risks higher and more volatile prices causing demand destruction in times of disruption. The ability to ramp up production could also serve as a mechanism to enforce discipline within OPEC. Also, spare capacity allows the Kingdom to offer additional supplies during disruptions, when prices are usually high, boosting its revenues and its geopolitical standing. By utilizing its spare capacity, Saudi Aramco generated an estimated $35.5 billion of additional revenues from 2013 to 2018.

On the other hand, productive capacity should not be so large that Saudi Arabia ends up with idle capacity that is costly to maintain and could adversely affect the Kingdom's long-term revenues by putting downward pressure on prices. Also, as Saudi Arabia increases its productive capacity, cutting production becomes more challenging, as no producer wants to operate well below its maximum sustainable capacity.

Managing this trade-off is especially challenging given the current uncertainty about oil demand prospects. The speed of the energy transition, the potential growth in US tight oil production and other supply sources, and the dynamics within OPEC are generating a high degree of uncertainty regarding the medium- and long-term demand for Saudi crude. Decisions are also shaped by internal factors, particularly the expected growth in domestic energy demand, which in turn is closely tied to a wide range of policies including energy pricing reform, energy efficiency measures, and increases in the share of gas and renewables in the power mix. Such policies in turn will determine the volume of crude available for exports and thus the Kingdom's foreign currency receipts.

In this environment, with highly uncertain domestic and international demand prospects, Saudi Arabia has no plans to increase its productive capacity above 12.5 mb/d, the target set by the National Transformation programme for upstream capacity through 2020. Former Saudi energy minister Khalid Al-Falih stated in several interviews that the crude programme is designed to maintain capacity at 12.5 mb/d, and although he did not rule out building incremental capacity, this would depend on the expected call on Saudi crude.

This does not imply that the Kingdom is not investing in new projects and developing new fields. In addition to demand considerations, the investment decision is guided by the availability of oil development opportunities and by oilfield and reservoir factors. In 2017, Saudi Aramco announced plans to raise its spending to $414 billion over the next 10 years, including $134 billion on drilling and well services and $78 billion to maintain oil output potential. Saudi Aramco regularly brings on fields to relieve pressure and output from mature fields, and maintains production plateaus for longer, thereby optimizing the utilization of the reserve base over the longer term and achieving higher ultimate oil recovery rates.

Also, by bringing on new projects, Saudi Arabia can rebalance the quality of its crude production mix so it matches domestic refineries' needs and the changing conditions in international markets. In 2019, Saudi Aramco awarded $18 billion in contracts aimed at increasing production capacity by 0.55 mb/d at its Berri and Marjan fields. The Berri field, which is expected to start producing in early 2023, will add 0.25 mb/d of Arabian Light capacity. There is no specific date as to when Marjan will start production, but once on stream, it will increase Arab Medium capacity by 0.3 mb/d. In 2018, Saudi Aramco awarded the contract for the development of the Zuluf increment of 0.6 mb/d of Arab Heavy crude. These plans come on the back of the completion of some recent megaprojects such as Sheybah and Manifa. Following a major oilfield expansion project, Sheybah boosted Arabian Extra Light production by 0.25 mb/d in 2016 to reach 1 mb/d. Arab Heavy production from Manifa started in 2013 and reached the target of 0.9 mb/d in 2017.

Another factor that has affected the crude quality mix has been the shutdown of production from the shared fields in the Neutral Zone in 2014 and 2015 after disagreements between Saudi Arabia and Kuwait. Before the Neutral Zone production was shut down, production had fallen to below 0.5 mb/d across the offshore Khafji and onshore Wafra fields, despite the fields' overall capacity of 0.6 mb/d. The two main oilfields produce Arab Heavy sour crude. The impact of the shutdown of these two fields on oil markets has been magnified, given that the sanctions on Venezuela and Iran have tightened the supply of sour medium/heavy crude. But in December 2019, Saudi Arabi and Kuwait signed a new agreement to divide the area between them and a memorandum of understanding to resume oil production from shared fields.

To increase or not to increase

Much of the recent discourse has focused on the upside potential of Saudi Arabia's productive capacity, and every time Saudi Aramco announces plans to expand an existing field or develop a new field, there is much speculation whether this would represent a net capacity addition. Also, at times when expectations about global oil demand peaking soon are rife, many have argued that this would induce a shift in the output strategies of large resource owners. Specifically, large reserve holders will focus on monetizing their reserves as quickly as possible so as not to be left with stranded assets. And who is better placed than Saudi Arabia to pursue such a strategy, given the size of its reserves, its stable investment environment, Saudi Aramco's technical capability, and its strong financial position?

However, Saudi Arabia would face considerable constraints in pursuing such a strategy, given the government's heavy reliance on oil revenues. Aggressive monetization, alongside slower demand growth, would result in a sharp decline in oil prices and oil revenues and thus act as a constraint on high investment/high output policy. It would also induce a reaction from some OPEC producers who will also have the incentive to monetize reserves quickly by improving the fiscal terms and the investment environment. Under this strategy, there is no room for cooperation among low-cost producers, competitive forces will prevail, and margins will fall.

Thus, for Saudi Arabia to pursue such a strategy, it needs to diversify its sources of income away from oil exports, for instance by heavily taxing businesses and individuals, without jeopardizing political and social stability. This requires deep economic and political structural transformations, which will take a long time to implement with no guarantee of success. Were Saudi Arabia's economy highly diversified and its income less reliant on oil revenues, a fast monetization strategy would become more feasible and, given its status as one of the world's lowest-cost producers, it could continue to put more oil in the market, though the rents generated from oil would be lower.

Given the current uncertainty about global oil demand and the speed of the energy transition, and the limited diversification of the government's income, is there a case for Saudi Arabia to reduce its capacity and/or let its spare capacity erode?

To explore this possibility, consider a medium-term scenario where global oil demand plateaus in 2021 and shifts to a permanent decline around 2024. (This is unlikely; the date is hypothetical and offered only for the purposes of this exercise.) Saudi Arabia could then face the following three options (among others):

- It could pursue a fast monetization strategy in which it ramps up production to 12.0 mb/d in 2020 and sustains that level towards 2024 (the *monetize capacity* scenario).
- It could limit its production to 10.0 mb/d throughout the period and let its spare capacity cushion of more than 2.0 mb/d erode—for example, by not offsetting decline rates (the *reduce capacity* scenario).
- It could maintain its current balancing role and keep managing its capacity and output conditional to the prevailing supply and demand conditions, in which case as oil demand deteriorates after 2021, it could progressively reduce output from 10.7 mb/d to 9.5 mb/d by 2024, while maintaining its productive capacity at 12.0 mb/d (the *manage capacity* scenario).

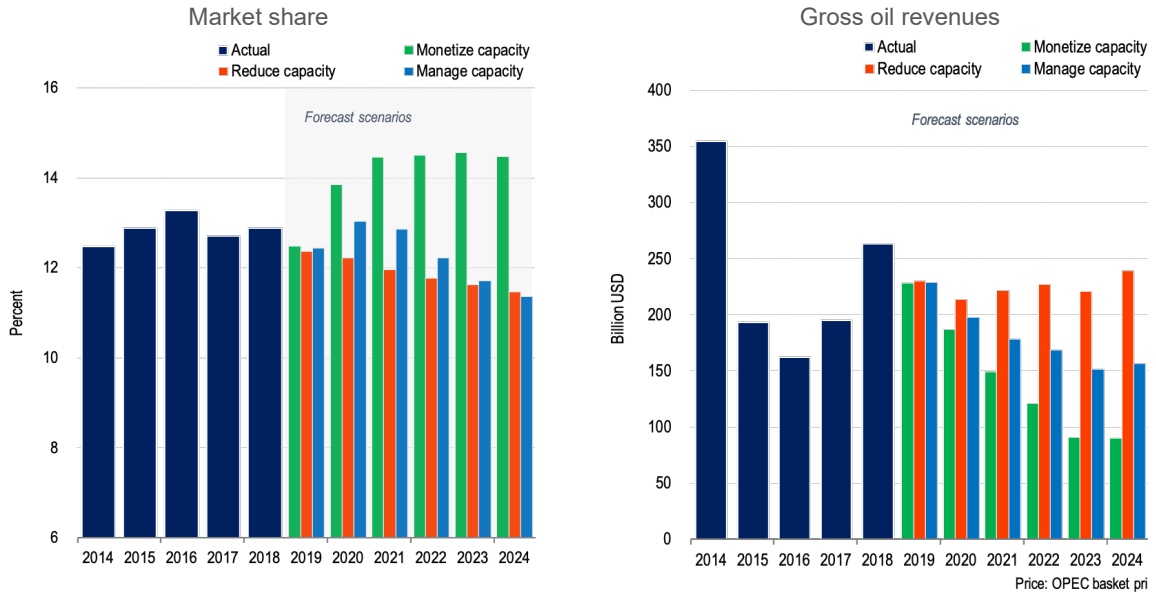
The *monetize capacity* scenario would be expected to result in a higher market share for Saudi Arabia (around 14 per cent on average) from 2019 to 2024, albeit at a detriment to its oil revenues, as oil prices would be expected to slide to $25 per barrel by 2024. Saudi Arabia's gross oil revenues could be expected to fall below $100 billion after 2022 and be $138 billion lower in 2024 than in 2019 ($230 billion).

This simple scenario ignores important market feedbacks. For instance, the lower oil price under rapid monetization is likely to improve the long-term survivability of the oil sector even in the presence of carbon taxation, as demand will be higher. Also, in a low-price environment, there will be limits on how quickly high-cost producers will be able to expand their capacity, and the higher share will compensate for some of the revenue losses.

In the *reduce capacity* scenario, Saudi Arabia's market share would be expected to decline towards 11 per cent by 2024, but it would preserve a constant flow of revenues of $225 billion on average between 2019 and 2024, netting almost $150 billion more in 2024 compared to the previous scenario. This is because the oil price would be expected to average around $64 per barrel, as the impact of the deterioration in global demand was offset by the erosion of spare capacity. In this scenario, there would also be more room for cooperation with other low-cost producers, which could engage in a similar strategy.

In the *manage capacity* scenario, if Saudi Arabia reacted only to weakening global demand, not only would it fail to offset the price decline towards $40 per barrel by 2024, but both its market share and revenues would fall by 11 per cent and $155 billion, compared with 13 per cent and $220 billion in 2020, while spare capacity would continue to build amid unfavourable market conditions.

Market share and oil revenues, actual and forecast under three scenarios, 2014–2024



Source: Author's calculations.

Costs and benefits

Managed reduction of output capacity could maximize revenues over the medium term, especially given the low capital costs of implementing it, but there would be adverse consequences. For instance, Saudi Arabia would become a price taker; it would

end up with a lower market share; its geopolitical status would be undermined; and it would lose an important disciplinary mechanism. These are all significant costs. This strategy may also require coordination with other low-cost producers that would be eager to increase capacity. Such coordination is extremely difficult if not impossible.

Fast monetization of reserves also has a high cost in terms of lower revenues. Also, what induces all these effects in the first place is the declining importance of oil in the energy mix through a continuous series of negative oil demand shocks. In a world of declining demand, these costs cannot be large. For instance, if oil is no longer a strategic commodity, the value of holding spare capacity is reduced. Finally, Saudi Arabia cannot afford to be reactive if the impacts of energy transition fully materialize, as the costs of absorbing such a shock are too high, not only in absolute terms but also relative to other options.

Timing is key

For now, Saudi Arabia's official policy is to neither increase nor decrease its productive capacity of 12.5 mb/d. While it will continue to develop and expand new fields, these will not represent net additions, but they will change the quality mix. With Saudi Arabia producing below its OPEC quota and ample spare capacity in the system (notwithstanding the recent attacks on Saudi Aramco, which temporarily reduced spare capacity), there is even less incentive to increase capacity.

But given the uncertainty about demand and the speed of the energy transition, while there might be a case for Saudi Arabia to increase its productive capacity—for instance to monetize its reserves, manage prices on the upside, and/or fill the gap during disruptions—there is also a case for a managed reduction of output capacity by, for instance, not offsetting the decline rates from some mature fields. This does not involve high direct costs (Saudi Arabia does not need to invest in new capacity), and if demand turns out to be stronger than expected, the payoffs could be even higher than in the monetize capacity scenario. The trade-off would change over time, depending on changes in global oil market conditions but also on transformations in the domestic economy.

Of course, these are extreme strategies, and Saudi Arabia does not need to commit to one or the other. Also, any decision that Saudi Arabia makes must take into consideration the potential responses of other market players and the preferences of domestic constituencies.

Prospects for global oil demand have changed, but almost all projections still expect oil demand to continue to grow, or at least not to drop suddenly even in a carbon constrained world. In this environment, Saudi Arabia will most likely continue to wait until some of the key uncertainties are resolved or subside, especially given that investments in new productive capacity are irreversible. But if and when this uncertainty is resolved, the strategy of doing nothing will become very costly, and Saudi Arabia will need to proactively adjust its investment programme to a changing world sooner rather than later. The decision to be made is much more complex than has been suggested in the simple scenarios presented here, as it involves not only the choice of a strategy but the timing of its implementation.

IRAN: US SANCTIONS KEY TO OUTLOOK

David Jalilvand

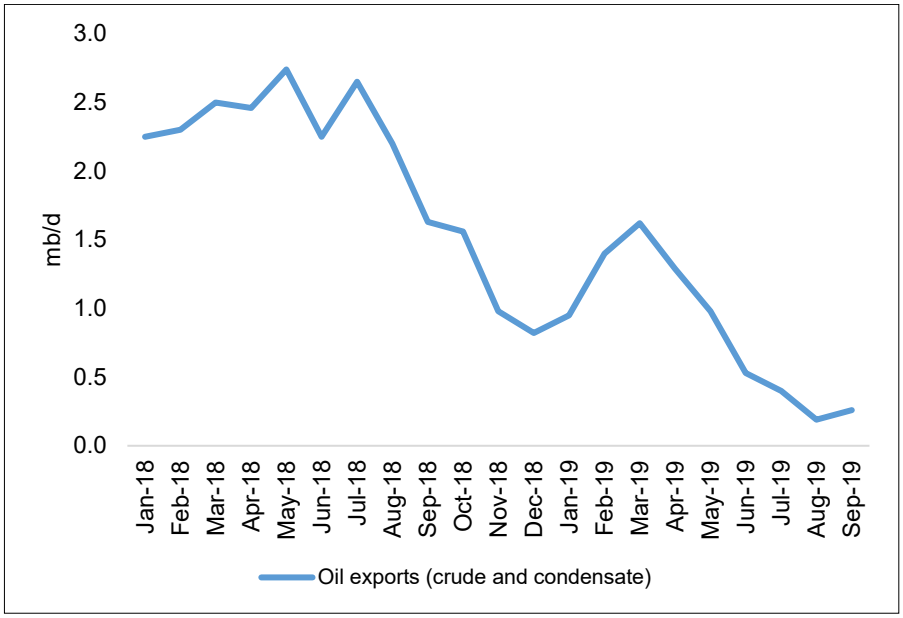
Iran's supply outlook until 2024 is largely defined by US sanctions. These confront the country with profound challenges in utilizing output and in financing projects. A pre-sanctions crude oil production level of around 3.2 million barrels per day (mb/d) in 2017 remains the upper limit (4.1 mb/d including condensate). Most likely, actual output will be significantly below this threshold—for the foreseeable future at current levels of around 1.5 mb/d (2.25 mb/d including condensate). Hence, Iran's oil production is set to stay below its potential at a time when global competition over market share is growing. This places Iran at a distinct disadvantage vis-à-vis its competitors.

2019: a further decline in oil production due to sanctions

Having already suffered great losses in the year before, Iran saw its oil production decline further in 2019. US energy and finance sanctions, re-imposed on the country following Washington's decision to quit the JCPOA nuclear deal in May 2018, sent Iran's oil exports into freefall. Oil production also dropped in the wake of this, to a somewhat lesser degree.

In May this year, the US ended all oil waivers which had allowed eight countries to continue importing Iranian oil without running afoul of US nuclear sanctions. This reversed the modest recovery in oil exports at the beginning of the year and resulted in a new low of 200 thousand barrels per day (kb/d) in August. Production, meanwhile, continued to decline.

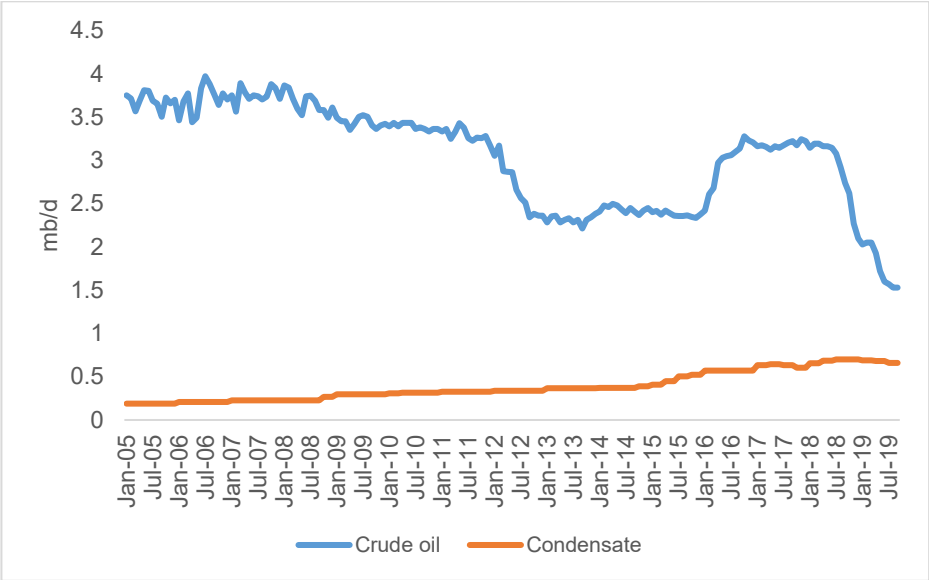
Iranian oil exports, January 2018–September 2019



Sources: IEA, OIES.

Following losses of 1.0 mb/d in 2018, Iranian crude oil production had shrunk by another 0.5 mb/d by September 2019 (including condensate, since January 2018 production declined by 1.6 mb/d to 2.2 mb/d). At 1.5 mb/d in September 2019, crude oil production amounted to less than half of the 2017 daily average. Worse, Iran's crude oil output has shrunk to levels as low as during the 1980–88 war with Iraq – and thus beneath the low point during the 2012–15 sanctions-round. In the case of condensate, in the first three quarters of 2019, Iranian production declined as well, from 690 kb/d at the beginning of the year to 660 kb/d (after Iran lost its key export market, South Korea). Negative growth in condensate occurred for the first time in the history of Iranian energy.

Iranian oil supply, January 2005–September 2019



Sources: IEA, OIES.

Moreover, the full reimposition of US nuclear sanctions against Iran dashed all Iranian hopes of large-scale foreign investments in the energy sector. Iran requires finance and technology to apply enhanced oil recovery methods at numerous mature oilfields, as well as capital to develop greenfields. Officials in Tehran have estimated the industry's investments requirement at $200 billion.

In November, Iran announced the discovery of a major new oilfield, the Namavaran reservoir in the southwest of the country near the Iraqi border. Holding 22 billion barrels of crude in total, the field is the country's second largest. Some 10 per cent or 2.2 billion barrels are recoverable, according to Iran's oil ministry. However, as Tehran is struggling to utilize output from fields that are already in production, the additional barrels from the Namavaran find will not meaningfully impact Iran's supply outlook until 2024.

Supply outlook until 2024

Over the next years, sanctions remain the decisive factor for Iran's oil production. All other aspects relevant for the industry—such as access to markets, finance, and technology—are conditioned by the geopolitical confrontation between Tehran and Washington.

There is huge uncertainty about the level of Iranian oil production over the next years, as it is unclear how long US sanctions will stay in place. Almost all Democratic Party contenders for the 2020 US presidential election declared their intention to rejoin the nuclear deal. This could result in the renewed lifting of US energy and finance sanctions against Iran at some point after 2021.

Meanwhile, Tehran's strategy over the next years will continue to focus on producing as much oil as possible. In upstream, Iranian oil policy seeks to avoid losses of pressure at the country's numerous mature oilfields. Iran also needs to maintain as much production (and production capacity) as possible in order to be able to realize its key objective on the international stage: to arrest, and ideally reverse, the loss of market share. This goal is motivated by several factors, including the need to generate hard-currency revenues and alleviate the risk of stranded assets if Iran permanently loses customers in light of peak-demand scenarios. Related to this, Iran seeks to grow domestic refining capacity in order to reduce dependency on the export of unprocessed crude oil and condensate—both to cope with sanctions and to promote economic activity at home. Beyond this, an expansion of oil production capacity might remain a nominal objective of Iranian oil policy. But it appears highly unlikely that Tehran will be able to take meaningful steps in this direction until 2024.

At any rate, the supply outlook until 2024 is effectively defined by the extent to which Iran can utilize current production capacity. Meanwhile, the performance of domestic companies is undercut by sanctions-related capital constraints.

Against this backdrop, current sanctions-constrained output levels remain the reference point for the time being. In parallel, the possibility of a game changer, the lifting of US sanctions at some point between now and 2024, has to be considered as well. Thus, a relatively broad range of Iranian oil production levels has to be taken into account, estimated here at between 1.5 and 3.2 mb/d (between 2.25 and 4.1 mb/d including condensate).

Lower estimate—1.5 mb/d (2.25 mb/d including condensate)

In essence, this figure reflects the continuation of the status quo, with sanctions massively undercutting Iran's ability to fully utilize oil production capacity.

Under sanctions, domestic refining will continue to account for the bulk of oil utilization. Iran plans to grow crude oil refining capacity from its current 1.7 mb/d to 1.9 mb/d (2.15 to 2.44 mb/d including condensate) by March 2020 and to continue the expansion afterwards. Notably, Iranian crude oil production today is somewhat below the country's nameplate refining capacity, largely due to the overhaul of facilities. Although they have had a history of delays, domestic companies proved capable of realizing refinery projects. In light of this, a total crude oil refining capacity of 2.0 mb/d by 2024 appears to be a realistic benchmark (actual refining capacity could be higher). On the whole, throughput is set to grow but will on average certainly remain below nameplate capacity.

In contrast to the growth trajectory in domestic refining, Iran's oil exports are suffering tremendously from sanctions. Nevertheless, Tehran was able to continue to export an average 500 kb/d even after Washington revoked all waivers in May—mainly to China, and to a lesser extent to Syria. The overall trajectory is downward, though. In September, Iran's oil exports amounted to merely 300 kb/d. There is a possibility of exports declining beyond this, for instance if Beijing decides to sacrifice oil deliveries from Iran for a bigger trade deal with the US or in the face of greater pressure from Washington.

Efforts at enhancing storage will offer modest relief in the short term. But they are no solution for the ongoing utilization of oil production in the mid to long run. As such, they do not meaningfully play a role with respect to Iranian oil production levels in 2024.

There is huge uncertainty regarding the production of condensate. In past decades, parallel to the expansion of output at the South Pars natural gas field, Iran saw robust growth in associated condensate production. Even under sanctions, condensate

output grew between 2010 and 2015 by almost 50 per cent. Iran plans to continue growth at South Pars. But unlike in the past, there is uncertainty now about Iran's ability to adequately utilize the associated condensate. Tehran did not announce any specific plans to increase condensate refining capacity above 540 kb/d, which would be reached once the Persian Gulf Star refinery is fully brought into production (planned for 2020). Iran may continue to export limited volumes of condensate under the radar, for instance by blending it with oil from other countries. Generally, though, it appears the country will not be able to maintain condensate growth rates going forward as it did under sanctions in the past.

As Iran is set to increase condensate refining capacity by some 90 kb/d, it can be expected to use the additional capacity to increase condensate production. The underlying assumption is that Iran can continue to bridge the gap between condensate production and refining capacity, as it apparently does at the moment. Added to current production levels, this would amount to condensate production of at least 0.75 mb/d in 2024.

Taken together, current oil production levels will have to remain the reference point for Iran under sanctions. There is a possibility that even under sanctions, output will be higher than this. Both in crude oil and condensate, this would be the case if Iran succeeds in ramping up refining capacity and marketing oil products. Gains in domestic refining, however, could also be offset by further losses in exports. As such, if only vaguely, the estimate of 1.5 mb/d (2.25 mb/d including condensate) offers some orientation for Iran's oil production levels under sanctions.

Upper estimate—3.2 mb/d (4.1 mb/d including condensate)

If sanctions are lifted before 2024, the supply outlook is largely defined by the extent to which Iran can regain export markets and ramp up production, while increasing domestic refining capacity. Based on previous experience, it seems reasonable to assume Iran would offer steep discounts to regain market share.

At the same time, production capacity in 2024 will likely not be significantly above pre-sanctions levels. Marketing and utilization questions aside, it is unlikely that Iran will be able to attract the investments required for this over the next five years, even if sanctions are lifted around 2021. In this context, after an end to sanctions, the domestic debate surrounding Iran's petroleum fiscal regime would very likely come to the forefront again. Iranian efforts at attracting foreign investments would probably be severely hampered and delayed, as Iran's fiscal framework and the politics surrounding it would not be straightforward. Either way, even if Iran were to conclude contracts before 2024, it is unlikely that projects that add to the country's production capacity will be completed by 2024. Thus, even in a best-case scenario, Iran is unlikely to have improved production capacity above pre-sanctions levels.

In contrast to crude oil, there might be additions in condensate, as Iran is set to maintain growth in natural gas production despite sanctions. If, after a lifting of sanctions, Tehran is able to regain its key export market for condensate, South Korea, this would free growing domestic condensate refining capacity and pave the way for further growth in condensate production. An extrapolation of average annual growth in condensate from the past decade suggests Iran could add some 177 kb/d to its production in this case (a figure that corresponds with the expansion plans for South Pars).

Overall, though, by 2024 Iran is unlikely to have overcome the various barriers to the expansion of crude oil production above pre-sanctions levels. For the time being, therefore, 3.2 mb/d remains the ceiling. The situation with condensate production differs. If Iran manages to adequately utilize output, there is a possibility of further growth, perhaps to around 847 kb/d. Combined, this would amount to some 4.1 mb/d.

Risks and uncertainties

The biggest uncertainty regarding Iran's medium-term supply outlook is the evolution of US sanctions against Tehran, including with respect to enforcement. On the one hand, it is possible that sanctions will stay in place until 2024, especially if US President Donald Trump is re-elected. On the other hand, sanctions could be lifted sooner, for instance if a Democrat takes over the White House in January 2021 or, though less probable, if Trump and Iran were to reach a deal.

The range of potential oil production levels presented above seeks to reflect these uncertainties. Yet unforeseen events in this context could occur over the next five years, in particular pertaining to the lower end of the oil production range. Washington could take a more assertive stance towards sanctions enforcement, for example. In September, the US imposed sanctions on a number of Chinese companies involved with the import of Iranian oil. As Beijing has created a parallel architecture for oil trade with Iran (the companies operate more-or-less independently from the US financial system), the consequences of being sanctioned are less than, for instance, they would be for European multinationals. The US could, however, up the ante and

target the Chinese energy industry more broadly, and Beijing could respond to this by lowering imports from Iran, which could drag Iran's oil production below the benchmark defined above.

It is also unclear how quickly Iran is able to expand domestic refining capacity—or, as refining capacity grows, whether Tehran can find adequate commercial outlets for increasing volumes of oil products. Domestically, Iranian efforts at economic diversification are based on natural gas. There are no ambitions to increase the role of oil in the domestic fuel mix. To the contrary, Iran seeks to continue to replace oil with natural gas. Ultimately, therefore, Iran will need to market the bulk of additional oil products abroad. Unlike the case of crude oil, Iran was able to maintain exports of oil products to a large extent (at levels above 400 kb/d in the summer of 2019). But the growth potential under sanctions appears limited.

Other questions remain regarding the upper end of the range. It is unclear to what extent Iran's mature oilfields are suffering from losses of pressure due to production declines. This results in uncertainty about Iran's ability to swiftly ramp up output when sanctions are lifted.

Finally, at a more fundamental level, there is also uncertainty about the reliability of Iranian energy data. To circumvent US sanctions, Iran seeks to conceal exports, including by making tankers switch off their automatic identification systems, carrying out ship-to-ship transfers on the open sea, and other measures. In July, the oil ministry defined oil data as 'war information' and stopped releasing industry statistics. This has to be taken into account when assessing the production outlook.

Growing regional geopolitical risks

Adding to the uncertainties surrounding Iran's energy industry, geopolitical risks at the regional level are on the rise. Tehran changed its strategy towards the nuclear deal in May 2019, replacing what Iranian officials described as 'strategic patience' with a more assertive approach. Before May, Iran remained in full compliance with the nuclear deal in the hope that Europe would mitigate at least part of the economic damage from the US sanctions. Having lost faith in Europe's ability and willingness to act meaningfully to this end, Iran upped the ante this summer.

Tehran now seeks to inflict costs on Washington and its allies by creating a lose–lose nexus between US economic sanctions, the non-proliferation dimension of the nuclear deal, and regional security. In recent months, not only has Iran begun to reduce implementation of its commitments under the nuclear deal, but the Persian Gulf region's already volatile security situation has deteriorated. A US drone was shot down by Iran in June. Moreover, Saudi Arabia and the United Arab Emirates, two staunch supporters of the US 'maximum pressure' campaign against Iran, suffered a series of attacks on energy infrastructure and tankers. Western governments blame Tehran for most of the attacks, an allegation Iran rejects. Tensions reached a new high in the first weeks of 2020, following the US assassination of Iranian General Qasem Soleimani in Baghdad and retaliatory Iranian missile attacks against US bases in Iraq.

Geopolitical tensions around the Persian Gulf are thus mounting, which also increases risks for Iran's energy sector. In the second half of 2019, three Iranian oil tankers were attacked in the Red Sea, according to officials in Tehran. News reports, so far unverified, also suggest the country's energy industry was targeted by cyber-attacks, potentially of US origin. A direct military confrontation between Iran, the US, and Washington's regional allies does not seem very likely at this point. However, strikes against Iranian energy infrastructure remain a possibility. Such strikes, depending on the type of damage they inflict, could obviously have profound consequences for Iran's supply outlook.

In Iran, meanwhile, numerous public protests have taken place recently, including in the oil-producing Khuzestan province in southwestern Iran on the border with Iraq. The protests, which are centred on socio-economic issues, saw occasional outbursts of violence. Over the past years, radical groups also conducted several terror attacks, including against energy infrastructure. So far, there has been no serious threat to the Iranian oil industry on the whole. This could change, however, if local rebel groups were to receive more substantial support from abroad—a scenario Iranian strategists take seriously. Similar to attacks against Iranian energy assets from outside the country, this could affect the supply outlook.

Conclusion

Iran's supply outlook is defined by the geopolitics surrounding the sanctions and the US 'maximum pressure' campaign against the country. At least in the very short term, geopolitical risks are on the increase; Iran's oil production will continue to suffer from this. There is also the possibility that sanctions will be lifted before 2024. This would pave the way for Iranian energy to return to its position before the reimposition of sanctions. As growth above pre-sanctions levels appears highly unlikely, Iran's oil industry will be constrained by sanctions, in one way or another, all the way to 2024.

ALGERIA: SEEKING STABILITY POST-BOUTEFLIKA

Chloe Teevan and Marc Chevillot

Since the beginning of the outbreak of protests in Algeria, widely known as the Hirak, on 22 February 2019, international media have raised alarms about the Algerian economy, including the worrisome state of its hydrocarbon sector and the lack of economic diversification, which predates the Hirak. Oil and gas exports make up 94 per cent of export earnings for the country, but reforms and investments in this essential sector have been delayed repeatedly for many years due to political factors, mismanagement, and high staff turnover at the state hydrocarbons firm, Sonatrach, and more recently due to a growing political impasse.

In October, the hydrocarbons sector took centre stage when the acting government announced plans to push through a new law governing the sector with the aim of attracting new investors. The law was passed by the Council of Ministers on 13 October 2019 and by the Algerian National Assembly on 14 November 2019 despite a high level of resistance to the law from the protest movement. Political stability is unlikely for some time following highly contested presidential elections on 12 December 2019. The new president, Abdelmadjid Tebboune, lacks political legitimacy in the eyes of many due to the lack of transparency during the election and the apparent fabrication of results. Thus, while the new hydrocarbons law will facilitate contracts for international firms and the maintenance of Mohamed Arkab as Minister of Energy in the newly appointed government, is a positive sign to international investors, it does not address the continued potential for political instability, nor will it address the bureaucratic hurdles international investors face or ensure institutional stability at Sonatrach, where yet another new director was named on 14 November 2019.

While domestic political considerations currently dominate decision-making in the Algerian energy sector, other factors — the failure of the oil price to reach anything close to the $130 mark necessary to balance the Algerian budget, continued high domestic consumption, and growing concerns about a downturn in the global economy — further complicate Algeria's economic choices, including the reform agenda for the energy sector and the outlook for oil production.

The political crisis in Algeria does not appear to have substantially affected Algerian oil production for 2019, which was already constrained by OPEC quotas. The 2016 quotas limited Algeria's oil production to 1.08 million barrels per day (b/d) (actual output was 1.04 million b/d, according to OPEC), while a further 25,000 b/d cut was agreed starting 1 January 2018. Algeria also produces over 500,000 b/d of lease condensate and non-crude oil liquids. However, the failure to reform the energy sector — and particularly the freezing of talks with international investors regarding major oil contracts, despite ongoing discussions and the confirmation of minor partnerships — is likely to have negative effects on production in Algeria's maturing oilfields, where as little as 30 per cent of oil wells are currently productive. This may result in falling production over the next five years.

Thus far the protests and the atmosphere of economic uncertainty in the country have mainly affected production in Algeria's gas sector rather than its oil sector. However, there is no doubt that this year's events will have a major impact on Algeria's hydrocarbons sector as a whole, further delaying essential reforms, including exploration, investments in existing oilfields, and efforts to improve the vertical integration of the value chain in its oil industry. Algeria's oilfields are mature and have produced consistently as a result of field expansions and enhanced oil recovery techniques, but further upstream investments would be necessary even to maintain the current rate of production. No investments are currently under way; this may not yet affect output in 2020, but unless Sonatrach manages to implement drastic measures to increase the extraction rate of currently exploited fields, production is likely to gradually decline.

Before the beginning of protests, Sonatrach was planning major investments in exploration and had begun to sign new contracts with international oil majors to improve technology and boost output in some of its maturing oilfields. It also aimed to begin to exploit its considerable shale oil and gas reserves — estimated by the US Energy Information Administration to be the third-largest known reserves in the world, including 20 trillion cubic metres of technically recoverable gas and 5.7 billion barrels of technically recoverable oil.

However, even against the backdrop of fear that characterized most of the Bouteflika presidency, the potential exploitation of Algeria's shale gas reserves was met with deep-seated resistance by environmental activists and residents of areas close to the reserves, such as those of In Salah, who organized some of Algeria's biggest and most intense pre-2019 protests in 2015. Those protests ultimately resulted in the abandonment of efforts to exploit the country's shale reserves at the time. Given the current political environment, it is very likely that any further attempts to exploit the country's shale reserves would be met with

even greater resistance. Political considerations appear to have played a role in Exxon Mobil's decision to pull out of negotiations with Sonatrach on a joint gas project. Sonatrach had been hoping to tap into the American firm's expertise in fracking.

Sonatrach's strategy of working closely with international partners has the potential to be deeply controversial due to the strong attachment of the Algerian public to the concept of national sovereignty and the renewed force with which this is being expressed throughout the protest movement. This was very clear in the recent debates and protests surrounding the proposed new hydrocarbons law. The law, which had been long awaited even before the protests broke out, aimed to introduce three basic types of contract in order to simplify investments in the sector and facilitate international investments.

Investing in Algeria continues to be a high-risk affair due not only to the current political instability, but also to the longer-term legislative and institutional instability that was evident before the Hirak began. The hydrocarbons law was frequently changed or updated (2005, 2006, and 2013), while Sonatrach has had close to a dozen directors in the past 10 years, with two new directors appointed in 2019. President Tebboune could potentially decide to change the law again in a matter of months, or could be forced to resign within a short period should he fail to establish some degree of political and economic stability, opening the way for further changes. Legislative and institutional instability at Sonatrach is thus even more likely in the coming years, making it difficult to envisage many large international investments in the oil and gas sector.

Sonatrach was also undertaking reforms aimed at improving the value chain and therefore the profitability of Algeria's oil industry. The company was in the process of modernizing and building a number of refineries in Algeria, and had taken over the Alberta oil refinery in Sicily in order to reduce Algeria's fuel import bill, which had tripled from $800 million in 2016 to $2.5 billion in 2017. Sonatrach was also investing to improve vertical integration of the value chain with projects in petrochemical transformation plants using LPG to produce plastics and the increased digitalization of the exploration and production processes to improve in-house expertise.

Under the leadership of Abdelmoumen Ould Kaddour between March 2017 and April 2019, Sonatrach was also reforming its human resources practices in order to train and hold on to talented personnel after experiencing years of brain drain. This was part of the Sonatrach-SH30 initiative, which was supposed to transform the company into an international player. One part of the project was to improve initial training to match the new strategy requirements in vertical integration, staff acquisition and retention, and general working conditions. With the return of frequent turnover among top managers, the company returns to its old patterns and will struggle to hold onto personnel who have employment opportunities in the Gulf or elsewhere.

All of these domestic factors combine to make it highly likely that Algeria will struggle to maintain its oil production over the next five years. However, international factors, including the geopolitical context, are also likely to affect the Algerian hydrocarbons industry and slow further investments in oil exploration and extraction. The terrorist attack at In Amenas in 2013 left a lasting negative impression with potential partners, while the potential for further instability in neighbouring Libya and the development of the terrorist threat in Mali and Niger adds a further element of regional insecurity, including in the far south of Algeria, where some of the new reserves are located. At a time when Algeria is facing domestic political challenges, this might raise questions amongst international companies regarding the potential weakening of the country's defences. On the demand front, major energy agencies are expecting a marginal increase in demand in the next five years, but the United States will be able to cover up to 70 per cent of this with shale oil.

Conclusion

Despite passing a new hydrocarbons law on 14 November 2019, Algeria will continue to struggle to attract large international investments in the coming years, although some smaller investments may be forthcoming. The lack of upstream investment in the country's aging oilfields makes it likely that over the next five years, Algeria's production will fall slightly from its current output of just over 1 million b/d of crude. Any attempt at developing the country's shale resources would be costly, time-consuming, and extremely controversial. It is thus unlikely that any shale oil production will come online in the next five years. Building renewed confidence amongst international investors may take a considerable amount of time and will require a level of legislative and institutional stability in Algeria and at Sonatrach that seems highly unlikely at present.

BAHRAIN, EGYPT, AND QATAR: SHIFT IN STRATEGIC FOCUS

Bill Farren-Price

While MENA's largest oil producers look to accelerate upstream capex and downstream strategic investments to build value, the region's smaller producers are already familiar with the challenges presented by declining crude oil output and limited scope for upstream growth. In Bahrain, Egypt, and Qatar, a focus on remediation of declining oil output has been successful for periods—but the strategic investment focus has switched either to maximizing the value of gas developments (Egypt and Qatar) or unconventional resources (Bahrain).

These shifts are driven by country-specific rather than generic regional circumstances, but they do demonstrate the extent to which smaller oil producers are struggling to deliver against stated targets. In many cases, international oil companies (IOCs) have faded as major operators, leaving national oil companies to take up the slack. Lack of capital, technology and skills—or lack of midstream infrastructure—has then taken its toll. In some cases, the investment environment is simply not fit for the twilight of these countries' oil sectors, with fiscal terms still excessively onerous given the limited prospects for major new discoveries.

Of the three producers, we expect Bahrain's oil output to increase slightly to 2025, reflecting Aramco expansion work on shared oilfield Abu Safah; Egyptian declines to emerge after 2022, bringing output down from the current 625,000 barrels per day (b/d) to 535,000 b/d; and Qatar's crude oil output to fall fastest, from the present 620,000 b/d to 450,000 b/d in 2025, as the emirate focuses on gas and gas liquids growth. In total, the aggregate loss in output by 2025 from these three countries will amount to 240,000 b/d.

Bahrain

Despite its small upstream sector, Bahrain punched above its weight in 2019. The state oil regulator Noga signed an exploration and production sharing agreement with Eni in April, following on from similar agreements with Total (Khalij al-Bahrain Basin) and Chevron (unconventional assets). In a bid to attract foreign operators, the kingdom in 2019 changed the terms of investment to allow IOCs to fully own their oil and gas projects in the country, an unusual stance for a region where national oil companies usually hold majority stakes in all development projects.

The kingdom's existing oil production is centred on the onshore Bahrain oilfield (formerly Awali, the oldest producing oilfield in the Gulf), which produced 42,000 b/d in 2018, well down from its peak of 75,000 b/d in the early 1970s. The outlook for the Bahrain oilfield is flat, despite discussions with Saudi Aramco around supplying carbon dioxide for injection to improve recovery rates and talks with service companies aimed at increasing output. Bahrain has targeted total domestic oil production of 100,000 b/d, but this seems unlikely if it is to come from the Bahrain field.

The bulk of Bahraini oil production comes from the offshore Abu Safah oilfield, shared with Saudi Arabia and operated by Saudi Aramco, from which Manama markets half of the field's 320,000 b/d of Arab Medium output from the Saudi terminal of Ras Tanura. Bahrain imports Arabian Light crude from Saudi Arabia by pipeline to feed its Sitra refinery, which is undergoing a major expansion. Saudi Aramco meanwhile plans to expand Abu Safah output and tendered new engineering, procurement, and construction contracts earlier this year.

But for Bahrain, the biggest upstream prize will be the shift into unconventional resources after the discovery of 80 billion barrels of tight oil and 10–20 trillion cubic feet of tight gas reserves off the west coast of the island in 2018. Work to appraise the discovery and establish flow tests on its onshore segment is under way, with plans to bring forwards development planning next year with the aim of bringing the structure onstream by the middle of this decade.

While recovery factors are likely to be low, this is still the kingdom's largest hydrocarbon discovery, and a focus shift into horizontal drilling and fracking would mark a step change for Gulf producers. While appraisal work is incomplete, future production levels are difficult to estimate. But Bahraini officials have estimated the Khalij al-Bahrain discovery could yield flows as high as 200,000 b/d, dwarfing current output from the Bahrain field.

Given the time frame for developing the unconventional resources, expectations for Bahraini output in 2025 assume that Awali output flatlines around 40,000 b/d and Bahrain's share of Abu Safah production increases slightly to 180,000 b/d, reflecting expansion plans being carried out by Saudi Aramco. This puts Bahrain's total production at 220,000 b/d in 2025.

Egypt

Despite aggressive government targets for oil production, Egypt's oil sector has continued to weaken, just as new gas discoveries, boosted by a wave of new gas exploration and developments, ramp up. Oil production fell in 2019, with Q3 output of 625,000 b/d, a multi-year quarterly low as output from the key Western Desert projects fell.

Egyptian oil output was highest at 930,000 b/d in late 1996 but declined in the following years to hold at 600,000–700,000 b/d since 2005. More recently, monthly production has occasionally fallen below 600,000 b/d before rebounding somewhat. Government plans to hit 690,000 b/d by mid-2020 look unachievable, even though that represents a scaling back of the original oil ministry target of 720,000 b/d.

Egypt's major operating companies, which consist of the state-owned Egyptian Petroleum Corporation and partner IOCs, are struggling to maintain output in the Western Desert, Gulf of Suez, and Nile Delta areas as high decline rates take their toll on production levels despite increasing capex. Drilling programs and continued exploration work on producing blocks have yet to translate into the sort of gains seen in Egypt's gas sector over the last few years.

If operating companies manage to stem further declines in 2020–21, and assuming no new major discoveries are made and developed over the five-year time frame, oil production is likely to decline to around 535,000 b/d by 2025, assuming a 5 per cent annual decline from 2022.

Qatar

Qatar Petroleum (QP) has in recent years consolidated its operatorship of several of its key oilfields, putting the state-owned firm in the driving seat as it battles flatlining output onshore and offshore. The company is also pursuing a major international upstream investment strategy—indicating an acceptance that volume growth will be achieved more easily outside the emirate than within. While crude oil remains an important revenue stream, Qatar's strategic focus is on gas and gas liquids, particularly the expansion of the LNG system to a capacity of 126 million tonnes per annum, the first production from which is scheduled to be delivered in 2024.

In terms of the domestic oil sector, the most recent development was the acquisition by QP of the operatorship of the Idd al-Shargi north and south domes from Occidental in October 2019. The fields produce 100,000 b/d and are a main contributor to the Qatar Marine export grade. The reduction in the presence of IOCs in Qatar's oil sector means that only Al-Shaheen field now has an international component—with Total and QP partnered in North Oil Company, which operates the 300,000 b/d field. Total also has a 40 per cent stake in the 20,000 b/d Al-Khaleej field. The onshore Dukhan oilfield, which supplies the domestic-market-focused Messaieed refinery, has been in decline for years, and enhanced oil recovery work is under way through CO_2 injection pilots.

In terms of liquids, growth will come from condensates produced through the continued expansion and development of the North Field gas reserves. In November, QP upgraded its LNG expansion plans from a target of 110 to 126 million tonnes per annum by 2027, which will imply further growth in North Field condensates production, most of which will be exported to Asian clients. But in terms of crude oil, sustaining plateaus and reducing decline rates at mature fields are now the biggest focus for QP.

In terms of its international presence, QP entered two offshore blocks in Guyana over the summer, when it also acquired a position in the deep water offshore Kenya. The year 2018 saw deals for assets in Argentina, Brazil, Mexico, Mozambique, and South Africa.

In summary, we expect declines from Qatar's existing crude oilfields to continue through the five-year horizon at an average rate of 6 per cent annually, reflecting the average decline rate for crude since 2010. With current crude output at 620,000 b/d, this would imply crude output of ~450,000 b/d in 2025. This loss, however, will be compensated for by the increase in condensate volumes over the same period and beyond.

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