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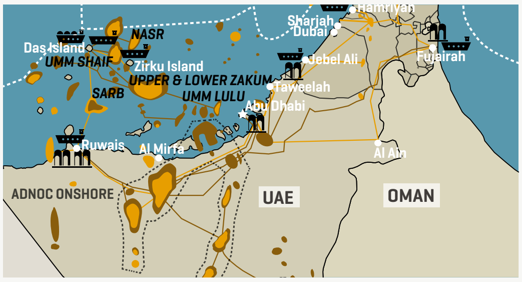
DOWNSTREAM

Adnoc Finalizes Ruwais Crude Flexibility Project

Commissioning of Adnoc's Crude Flexibility Project is imminent, enabling Adnoc to switch out Murban crude for heavier barrels at its Ruwais West refinery. But with light crudes attracting little-to-no premium at present, the economic case for making the switch is currently limited. ***Page 14***



UPPER ZAKUM OSP'S ($/B) DISCOUNT TO MURBAN HAS NARROWED SIGNIFICANTLY IN 2023

GEOPOLITICAL RISK

Israel Gas Rebound With Tamar Restart

Israel's key Tamar gas field restarted on 9 November and the EMG pipeline five days later. As Egypt flows rebound, Cairo hopes this will enable LNG exports. ***Page 8***

UPSTREAM OIL & GAS

Saudi Aramco's Unconventional Revolution

Unconventional gas could account for the next big wave of upstream development in Saudi Arabia. South Ghawar start-up is key to Saudi Arabia's unconventional revolution. ***Page 2***

GEOPOLITICAL RISK

Conflict Fears As W Sahara Tensions Rise

New attacks in Western Sahara have raised fears of renewed open warfare in the disputed territory and heightened hostility between neighbors Morocco and Algeria. ***Page 10***

UPSTREAM OIL & GAS

Oxy's Oman Struggles Continue

US independent Occidental is set for 8-year low Oman gas output. 2024 will see new output but Oxy will have its work cut out to offset decline at legacy assets. ***Page 4***

POWER & WATER

Saudi Seeks 3.7GW Solar Prequalifiers

Saudi Arabia's ambitious 2030 renewables target requires an expanding project pipeline. Having just signed contracts on a fourth solar round, it has kicked off a fifth. ***Page 16***

CORPORATE

Majors Cement Permian Shale Dominance

Recent M&A puts the Permian increasingly in the hands of majors. Whilst independents prioritize frugality, majors have their eyes on growth. ***Page 6***

ECONOMY & FINANCE

Exxon Iraq Exit As PetroChina Takes Over

Exxon has finally reached the exit from Iraq after finalizing a deal to sell its remaining 22.7% West Qurna-1 stake. PetroChina will take over as operator. ***Page 17***

OPEC & GLOBAL MARKETS

Demand Dominates Opec+ Buildup

Widely divergent global demand forecasts are muddying the waters ahead of the upcoming 26 November Opec+ meeting. ***Page 7***

Saudi Aramco's Unconventional Revolution Surges Forward With South Ghawar Start Up

Unconventional gas is set to account for the next big wave of upstream development in Saudi Arabia according to a key contractor. The start-up of the South Ghawar development is a big step forward for Saudi Arabia's unconventional revolution, which forms a key plank of its efforts to end wasteful oil burn.

Saudi Aramco has brought online its second unconventional gas development, announcing first gas from the South Ghawar project on 14 November. The start of production at South Ghawar will amplify other recent gas gains in the kingdom, helping tackle stubbornly high levels of domestic oil burn for power generation and water desalination.

Aramco declined to comment on current output from South Ghawar, but states that "Commissioned facilities at South Ghawar have 300mn cfd of raw gas processing capacity and 38,000 b/d of condensate processing capacity." The firm has plans to increase processing capacity to 750mn cfd "in the near future", but it didn't disclose the planned timeframe for this expansion work.

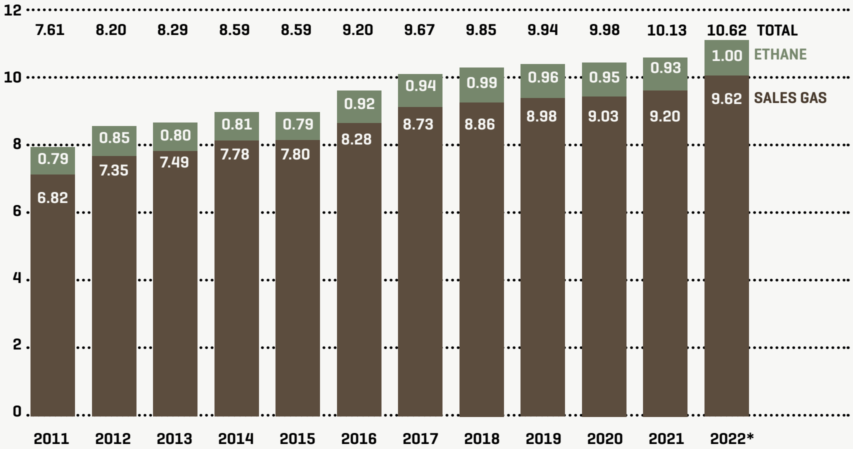
Speaking on the occasion of South Ghawar's first gas, Aramco Upstream President Nasir al-Naimi said "this first production of unconventional tight gas from South Ghawar is a milestone that demonstrates real progress on our gas expansion strategy, which we believe has a role to play in meeting the kingdom's needs for lower-emission energy and supporting growth in the chemicals sector."

Aramco sees considerable potential from its unconventional gas reserves, and South Ghawar is the second unconventional gas development to begin commercial production. Production from the North Arabia unconventional development began in 2018 (MEES, 24 August 2018), supplying local industrial sites around the Wa'ad al-Shamal phosphate production facilities. Aramco puts current North Arabia unconventional gas output at 240mn cfd.

Saudi Aramco's third unconventional gas project, and by far the largest, is the 200tcf Jafurah Basin gas development. Jafurah is slated to have a 3.1bn cfd raw gas processing plant by 2027, with initial volumes of 200mn cfd targeted in 2025. Once fully operational in 2030, Aramco expects output of 2bn cfd sales gas alongside 418mn cfd of ethane and 630,000 b/d of NGLs and condensate (MEES, 10 November).

Underlining the focus that Aramco is placing on its unconventional developments, leading Saudi drilling firm Arabian Drilling says it expects the sector to be the key near-term growth area in the kingdom. "Unconventional is the second wave of growth for Saudi Arabia," CEO Ghassan Mirdad told the firm's recent Q3 earnings call. The firm has submitted a bid in an open tender for ten more rigs for unconventional drilling, and it expects further waves of such tenders to come.

1: SAUDI ARABIA GAS OUTPUT SOARED TO A NEW RECORD HIGH FOR 2022 (BN CFD)



*FOR 2022, SAUDI ARAMCO PROVIDES TOTAL SALES GAS & ETHANE OUTPUT OF 10.62BN CFD - BREAKDOWN BASED ON ASSUMPTION OF SLIGHT ETHANE INCREASE. SOURCE: SAUDI ARAMCO, MEES.

SOUTH GHAWAR BOOST

The start-up of South Ghawar production is a major development for Saudi Arabia, marking the first volumes of unconventional gas entering the kingdom's master gas system (MGS), which links producing areas in the east with demand centers in central and western areas. The North Arabia development's remote northern location means that it only supplies local facilities, and there are no plans to connect it to the MGS.

Mr Naimi says "The ability to commence production two months ahead of schedule and below budget is testament to the unwavering dedication of our people and their determination to continuously enhance our upstream operations."

The firm had previously stated that a first phase would produce 320mn cfd of raw gas and that after processing this will yield 200mn cfd of sales gas and 34,000 b/d of condensate – broadly in line with this week's statement (MEES, 3 December 2021).

SAUDI ARABIA RAW GAS PROCESSING DEVELOPMENT PLANS (BN CFD)

	Start-up	Capacity
2022 Capacity		**18.3**
Hawiyah Expansion	2023	1.1
South Ghawar	2023	0.3
Current Capacity		**19.7**
Tanajib	2025	2.6
Jafurah Basin	2030	3.1
South Ghawar - Phase 2	by 2030	0.45
Planned Additions		**6.2**
2030 Capacity		**25.8**

SOURCE: SAUDI ARAMCO, MEES.

NEW GAS WAVE INCOMING

South Ghawar is the second major gas development announcement from Saudi Aramco in as many weeks. It follows the firm's announcement in its Q3 results that it had completed development of the 1.07bn cfd Hawiyah Gas Plant expansion project, with accompanying work on the 1.3bn cfd Hawiyah and Haradh gas compression projects

Continued on – p3

Continued from – p2

nearly complete (MEES, 10 November).

That Hawiyah expansion project should have taken Aramco's raw gas processing capacity up to 19.4bn cfd, and this should now have risen further to 19.7bn cfd with the start of the South Ghawar first phase.

These two projects will push Aramco well ahead in its effort to boost sales gas output by more than 50% from 2021 levels by 2030. Given 2021 sales gas production of 9.2bn cfd (see chart 1) this implies the addition of at least 4.6bn cfd to achieve 13.8bn cfd output, and MEES estimates that the firm has a sufficiently strong pipeline of projects to achieve this. Jafurah will add 3.1bn cfd of raw gas processing capacity by 2030, and the 2.6bn cfd Tanajib gas processing plant is due online in 2025. These projects should yield enough sales gas to hit Aramco's target.

Along with the next phase of South Ghawar development, these projects are set to bring gas processing capacity up to 25.8bn cfd by 2030 (see table).

TACKLING OIL BURN

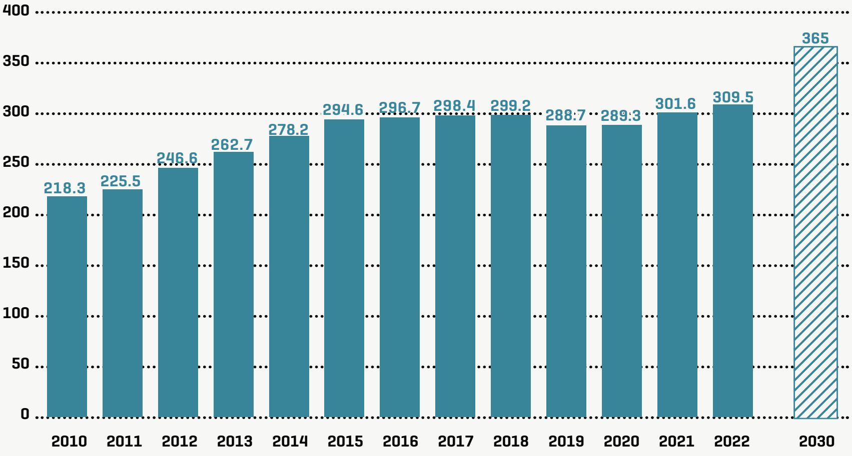
Saudi Arabia burns more than 1mn b/d of crude and fuel oil in its power generation and water desalination plants, but aims to virtually bring this practice to an end by 2030. Its supply-side strategy is two pronged: development of gas and of renewable power plants, with the intention of achieving a 50:50 mix by 2030 (see p16).

The economic benefits of this strategy are clear, given that in burning 1mn b/d of oil in its utilities sector, Saudi Arabia has less to export to global markets. Aramco CEO Amin Nasser has repeatedly highlighted this point when emphasizing the work that the firm is doing to bolster oil supplies to global markets amid concerns over a lack of industry investment. "We are looking by 2030 to increase gas [output] by more than 50%, I would say 50 to 70%. That will eliminate almost 1mn barrels [/day] of liquid burning, generate a lot of value and also reduce our emissions significantly," Mr Nasser said last year (MEES, 19 August 2022).

Adding to the scale of the challenge is that Saudi Arabia's ambitious Vision 2030 economic development plans mean that electricity demand in the kingdom is set to rise considerably by 2030. Having hit a record 309.5TWh last year, Saudi think tank Kapsarc estimates electricity consumption will hit 365TWh in 2030 (see chart 2).

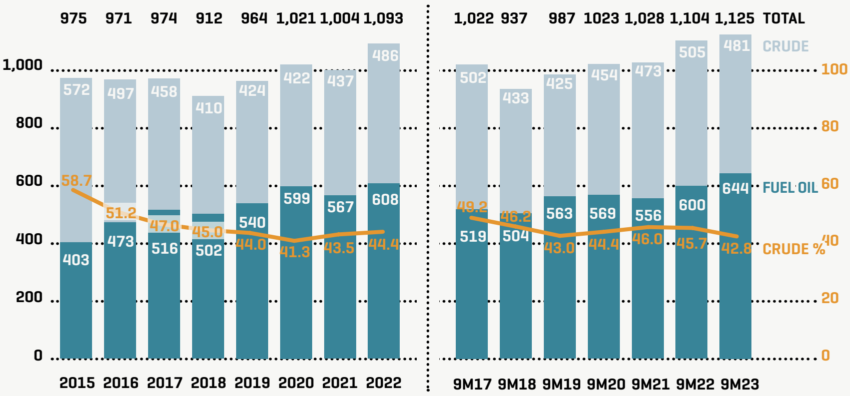
Oil burn is highly seasonal, peaking in the hot summer months when air conditioning use drives a surge in electricity demand. This year's peak was 1.397mn b/d in September, well below 2022's peak of 1.481mn b/d, but a record high for that time of year according to the latest Jodi figures (see p19 for full data). For the year as a whole, volumes are on course to exceed last year's record 1.09mn b/d

2: SAUDI ELECTRICITY CONSUMPTION (TWh) INCREASED TO NEW RECORD LEVELS IN 2022 AND IS FORECAST* TO RISE STRONGLY TO THE END OF THE DECADE



*FORECAST BY KAPSARC. SOURCE: WERA, KAPSARC, MEES.

3: SAUDI OIL BURN*: TOTAL OIL BURN ('000 B/D) HAS RISEN AHEAD OF 2022 LEVELS OVER THE FIRST NINE MONTHS OF THE YEAR FOLLOWING A RECORD-BREAKING SEPTEMBER



*PRESUMES ALL FUEL OIL CONSUMPTION IS BURNED, ALTHOUGH SOME IS USED IN MARINE BUNKERING. EXCLUDES SMALL VOLUMES OF DIESEL. SOURCE: JODI, MEES. SEE DATA, P19.

absent a sharp Q4 slowdown (see chart 3).

Aramco has also been investing to smooth out this seasonality, and this could begin to yield benefits next year. The Hawiyah Unayzah Gas Reservoir Storage facility is now online, with injection rates of up to 1.5bn cfd this year, and Aramco aims to be able to withdraw up to 2bn cfd to meet domestic requirements next summer (MEES, 11 August).

More than this, the gas facilities that Aramco has brought online this year stand to displace considerable volumes of oil from power plants. A rough calculation suggests that at maximum output the sales gas produced from the Hawiyah expansion and South Ghawar Phase 1 projects could displace around 200,000 b/d of oil from simple open cycle gas turbine power plants, or as much as 300,000 b/d if the gas is burnt in more efficient combined cycle gas turbine (CCGT) plants.

In reality the impact may be more muted, given that it is unclear whether these facilities will be running at full capacity next year, while their start-up may also enable Aramco to ease back on operations at other facilities. Likewise, strong electricity demand growth could offset some of the gains. However, the two facilities should certainly have a visible impact on oil burn in 2024, partially offsetting the impact of the likely exten-

SAUDI ARABIA KEY OIL & GAS INFRASTRUCTURE

sion of the kingdom's voluntary 1mn b/d production cuts (see p7) on export levels.

At the very least, the additional gas should prevent strong oil burn gains next year and enable the first year-on-year drop since 2021.

Oxy's Oman Strategy Struggles To Hit Its Stride

US independent Occidental is set for 8-year low Oman gas output alongside stable crude production. Fresh output is slated to come in 2024 from the delayed start-up of new fields. But Oxy will have its work cut out to offset decline at legacy assets.

The long history of US independent Occidental (Oxy) in the Mena region turned a corner in 2016 with the firm shedding assets in Iraq, Bahrain, Yemen and Libya in order to focus on core regional assets in Qatar, Oman, and the UAE (MEES, 12 August 2016). This new focus was narrowed further after Qatar opted against renewing Oxy's contract for the 100,000 b/d Idd al-Sharghi assets in 2019 (MEES, 11 October 2019).

With its Mena focus on Oman and the UAE, Oxy has snapped up a swathe of blocks stretching across Abu Dhabi and northern Oman in recent years. The company holds eight near-contiguous blocks stretching from Onshore 3 in Abu Dhabi to Block 51 in eastern Oman (see map and MEES, 11 December 2020). Further south in Oman, Oxy also holds an exploration and appraisal contract for Block 72 and operates Block 53 which is home to the 10-12° API 120,000 b/d Mukhaizna heavy oil field.

In closing the books on 2020 the company said that its "northern Oman exploration program is among the most successful in company history," adding that first new output from the blocks was set for 2023 (MEES, 26 February 2021). However, with Oxy still waiting for output from some assets to begin, the firm's overall net Oman production has since declined.

GAS OUPTUT SLIPS

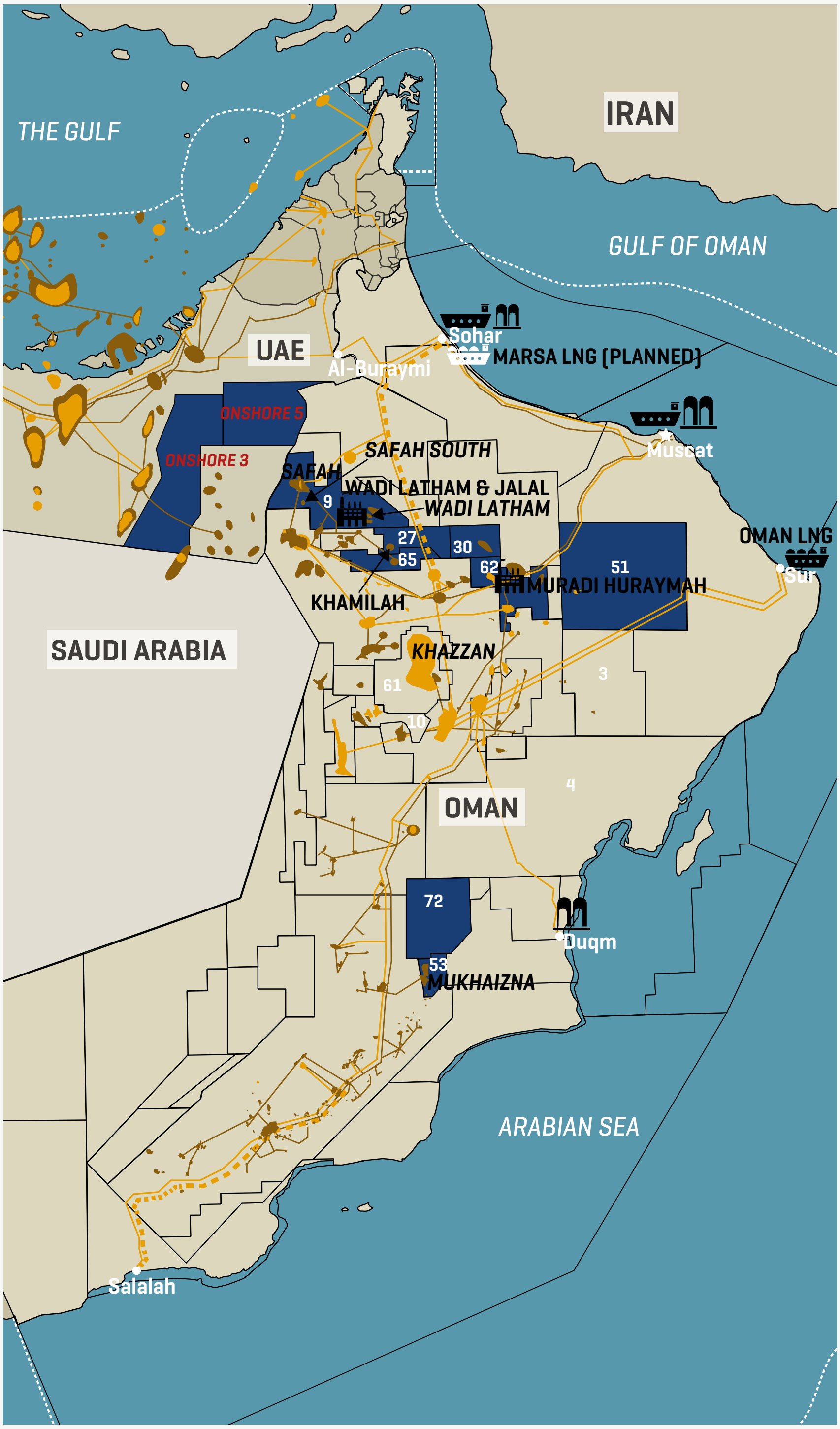
Natural gas production from Oxy's assets in Oman have seen a marked decline since Q4 2019 when it reached an all-time high of 152mn cfd. Over the two following years Oxy's net output plummeted to around 70mn cfd, a level which it held until its most recent dip to 53mn cfd for Q2 and Q3 this year (see chart 1). Oxy did not respond to MEES's request for comment on the decline in output.

The company holds three producing gas assets: Block 9 (Occidental 50%op, OQ 45%, Mitsui E&P 5%), Block 27 (Occidental 65%, Mitsui E&P

Continued on – p5

OCCIDENTAL'S MIDDLE EAST BLOCKS

GAS FIELD/PIPELINE | OIL FIELD/PIPELINE | OCCIDENTAL | OIL TERMINAL | REFINERY | LNG TERMINAL | GAS PLANT



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35%), and Block 62 (Occidental 48%, Mubadala 32%, OQ 20%). Its key assets are the Safah and Wadi Latham fields on Block 9, the Khamilah field on Block 27 and the Muradi Huraymah gas processing plant on Block 62.

While Oxy does not separate out assets in its quarterly production figures, it is possible to identify a trend between the blocks. Back in 2020 Omani state firm OQ published updated production figures for both Blocks 9 and 62, putting gas output at 37mn cfd and 90mn cfd respectively. These numbers were updated under OQ Gas Network's recently published prospectus which show that each block supplied 43mn cfd to the gas network for 2022.

Back of the envelope calculations imply that this equates to 43mn cfd net to Oxy for both blocks combined. Associated gas from Block 27 likely constitutes the remainder of Oxy's Oman gas output to give the overall 53mn cfd net figure – the lowest since 4Q 2015.

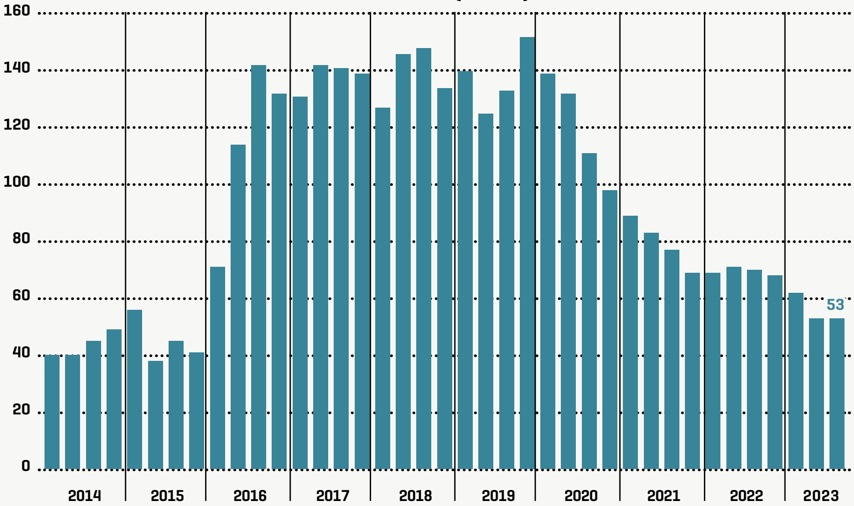
What these figures imply is that moderate increases since 2020 in Block 9 output have been insufficient to offset the sharp drop in gas production from Block 62, which shed half its total in two years. The Ministry of Energy and Minerals in 2020 predicted that gas output from Block 27 would start a definite slump from 2024 – the slump has evidently begun well in advance of this. As such any gas rebound from Oxy's Oman portfolio will likely depend on the development of discoveries from its exploration assets.

FUTURE PRODUCTION PLANS

The energy ministry's latest annual report for 2022 says that Oxy's key development work last year was on developing production gathering facilities at the Safah South Wedge E Area, as well as "progressing additional gas compression facilities (Wadi Latham and Jalal Gas Compressions) which added 90mn cfd compression capacity in Block 9 for gas lift and sale." However, any gains from this work have evidently been more than offset by declines elsewhere.

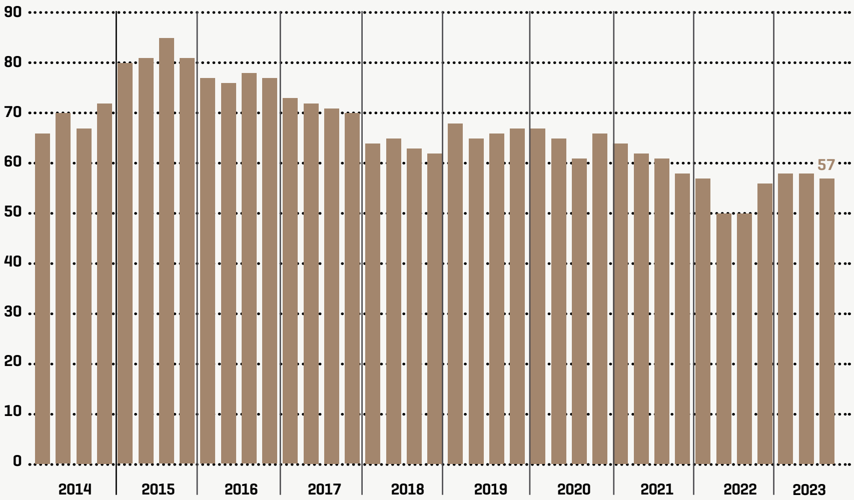
Oxy still holds three blocks it is exploring which could make the difference. The company picked up Block 51 under Oman's 2017 bid round (MEES, 21 December 2018). Oxy last year flagged up plans for a seismic survey during 2023: it is unclear if this has taken place. Block 30 (Occidental 72.86%, OQEP 27.14%) was awarded to the firm in the same bid round as a prospective gas play (MEES, 24 November 2017). After completing 3D seismic survey in 2021, it now predicts first production in 2024, with output processed at facilities on the neighboring Block 62.

1: OXY OMAN'S NET GAS PRODUCTION CONTINUES SLUMP (MN CFD)...



SOURCE: OXY, MEES.

2: ...WHILE ITS CRUDE OUTPUT RECEIVES SMALL BOOST FROM BLOCK 65 ('000 B/D)



SOURCE: OXY, MEES.

Also slated for first production next year is Block 72 which Oxy gained after it was carved out of PDO's mammoth Block 6 (MEES, 9 November 2018). The carved-out block's proximity to the Mukhaizna heavy oil field suggests a possible oil play which will depend on the results of the completed 2D seismic last year.

Oil output has been more consistent for Oxy in Oman. While steadily dropping since peaking at 85,000 b/d in Q3 2015, Oxy's Oman crude figures have managed to remain more stable in recent quarters. After dropping to their lowest level of 50,000 b/d in the middle of 2022, levels have stabilized at around 57,000 b/d so far this year (see chart 2).

Recent successes in upping output come from Block 65's startup earlier this year (MEES, 11 August). After a well tested at 6,000 boe/d early this year, the firm brought it to commercial production in Q2 via tieback to nearby facilities on Block 27. However, given that Oxy's 47% share of the 120,000 b/d Mukhaizna heavy oil field should yield around 56,000 b/d, it appears that Block 65's volumes so-far have been modest. The lack of an update in Oxy's Q3 results indicates that volumes haven't moved the needle.

Despite Oxy's Oman crude oil output having fallen significantly since 2015, it is still the largest contributor to Oxy's net Mena volumes. The only comparable source of late is Algeria which helped the firm replace lost barrels from Qatar, but has also been in decline, though the fall in the firm's net output to a new low of 25,000 b/d for Q3 in part reflects new contractual terms (MEES, 14 July).

For gas the UAE remained by far the largest source with the country contributing 284mn cfd in Q3. Volumes were recently boosted to record highs when Adnoc Sour Gas (Adnoc 60%, Oxy 40%) completed expansion work at the ultra-sour Shah gas field to lift capacity to 1.45bn cfd (MEES, 4 August).

Oxy is also very optimistic over its exploration acreage in the UAE, having announced major exploration successes at Onshore 3 last year and in 2021 (MEES, 20 May 2022). Development work is slated to continue through 2024, alongside ongoing exploration drilling at Onshore 3 and Onshore 5. However, new commercial output here is unlikely before 2025 at the earliest.

MAJORS CEMENT THEIR DOMINANCE OF KEY US PERMIAN SHALE BASIN

CORPORATE

Recent M&A deals, and talk of more, are putting the Permian and other key US shale basins increasingly in the hands of majors. And whilst independent players continue to prioritize frugality, the likes of ExxonMobil, Chevron and ConocoPhillips have their eyes on growth.

Both US supermajors, ExxonMobil and Chevron, have put expansion of their US shale output front and center of their global growth plans: Exxon via its $59.5bn purchase of Pioneer Resources announced 11 October (MEES, 13 October), and Chevron via the $53bn 23 October purchase of fellow US firm Hess. This comes as overall US output tops 13mn b/d for the first time with that from the Permian approaching 6mn b/d (MEES, 3 November).

Pioneer is a Permian pureplay producer, whose 721,000 boe/d of Q3 output put it around 100,000 boe/d ahead of Exxon as the basin's number three producer – indeed Pioneer had been tied with Chevron for number one spot for 2021, before a spending surge from Chevron and fellow major ConocoPhillips saw them pull ahead (see chart).

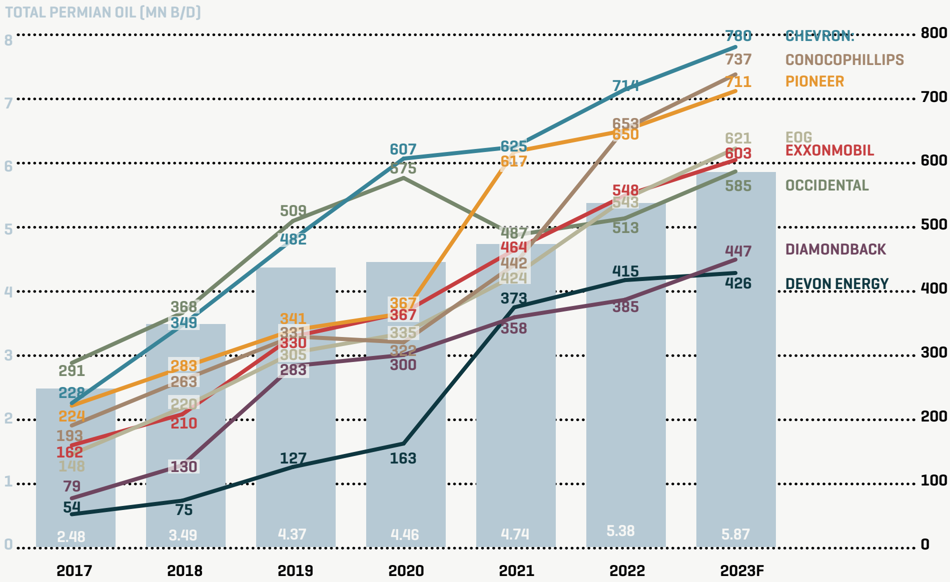
ExxonMobil was also part of this divergence in strategy between majors and the rest with both Exxon and Chevron having long flagged up plans to hike their Permian output to over 1mn boe/d (MEES, 3 February). Exxon is now doubling down on this strategy. From a pro-forma (including Pioneer) figure of 1.3mn b/d for Q3, it now targets a whopping 2mn boe/d Permian output by 2027 (MEES, 20 October). For 2023, that is to say before factoring in the Pioneer volumes, Exxon says that the "Permian [is] on track to deliver 10% year on year growth."

For Chevron, the Hess deal sees it acquire a leading position in the US number two Bakken shale play as well as a dominant position alongside Exxon offshore Guyana – alongside the Permian, Exxon also flags up Guyana as its key source of global output growth. All Guyana output, both now and for the foreseeable future, comes from the Stabroek block where Exxon and Hess are partners. Here a second field, Payara, began production this week with Exxon saying that as a result total Guyana output had hit 620,000 b/d.

Though the Hess deal sees Chevron spread its focus elsewhere, the previous acquisition of PDC Energy which completed in early August saw Chevron post record Permian output of 777,000 boe/d for Q3. That said, excluding the 28,000 boe/d PDC boost, Chevron's like-for-like Permian output was down 2% on Q2 "due to lower non-operated production."

Nevertheless, CEO Mike Wirth's updated Permian output guidance of 780,000 boe/d for 2023 as a whole implies a quarter-on-quarter leap of 10% to a new record of around 850,000 boe/d for Q4. "Permian production is expected to ramp up in the fourth quarter," he says. PDC's key asset was a dominant 240,000 boe/d position in the number four US shale basin, Colorado's DJ/Niobrara, boosting Chevon's post deal output in the basin to around 400,000 boe/d.

MAJORS CHEVRON AND CONOCO HAVE SURGED AHEAD AS TOP PERMIAN PRODUCERS, WITH EXXON SET TO LEAPFROG THEM FOR TOP SPOT WITH PIONEER PURCHASE ('000 BOE/D)



Number two Permian producer Conoco is also on track to post record output for 2023. Permian output leapt by almost 10% from Q2's previous record to 772,000 boe/d for Q3, up 16% year-on-year. Bakken output of 111,000 boe/d was also a record, whilst Eagle Ford output of 232,000 boe/d was just shy of the record 235,000 boe/d set the previous quarter. The company says it plans steady 7%/year 'Lower 48' output growth going forward, with this concentrated on the Permian.

BP: JANUS FACED

Of the European majors, only BP has a sizeable US shale position. And though 'BPX' shale output, at a record 363,000 boe/d for Q3, is less than half that of the US big three, the UK major also has ambitious growth plans.

At a two-day (10-11 October) investors' jamboree in Denver last month, BP placed the key focus on plans to grow its US upstream output to 1mn boe/d by the end of the decade. (Whilst BP is not the only European major to have presented a much more upstream-focused face to US investors than its 'green' focus back home – Total and Shell have also held similar events – the contrast is perhaps the most striking).

"Some have a view that the value of our oil and gas business is declining through the decade – we see a huge opportunity to grow and sustain value from this business, underpinned by a high-quality, distinctive resource base and a differentiated delivery model," acting CEO Murray Auchincloss told US investors.

INDIES: CASH CONSCIOUS

In contrast, the remaining Permian-focused independents remain more focused on conserving cash than raising output.

Devon Energy CEO Rick Muncrief told his firm's Q3 call on 7 November that the aim of the game for 2024 is "to maintain production at around 650,000 boe/d [of which around 440,000 boe/d from the Permian] and oil at approximately 315,000 b/d" despite a 10% cut to $3.3-3.6bn in the firm's planned capex, thanks to an anticipated 5-10% increase in average well productivity. Though Devon has assets in the Bakken and Eagle Ford basins, the Permian's Delaware basin will account for 60% of capex for 2023, rising to 70% for 2024.

"We plan to refine our capital allocation by further concentrating investment in the Delaware Basin. By shifting more capital to the core of this world-class basin and high-grading activity across our diversified portfolio... we are well positioned to generate growth in free cash flow that can once again be harvested for shareholders," Mr Muncrief adds.

Billy Helms, CEO of Permian number four EOG Resources (around 640,000 boe/d for Q3), says that his firm's default 2024 outlook is to maintain current activity levels at the firm's "core" Permian and Eagle Ford assets. "We invest to generate returns and [production] growth is a byproduct of the investments in our highly economic multi-basin portfolio," he says, adding that "some softening on well cost" may enable the firm to add "a few additional wells next year in our emerging plays, such as the Utica and maybe Dorado."

For number seven Permian producer Diamondback, meanwhile, the picture is also one of modest growth, but only when cash constraints allow. "We continue to expect to grow oil production organically at a low single digit annual pace next year with a similar level of activity to this year," the firm says. ◆◆

DEMAND SPECULATION DOMINATES BUILD UP TO OPEC+ MEETING

Widely divergent global demand forecasts are muddying the waters ahead of the upcoming 26 November Opec+ meeting. Although Opec itself forecasts extremely strong demand growth for 2024, most observers expect to see Saudi Arabia once again extend its voluntary production cuts in order to support prices.

When Opec+ gathers in Vienna for its next ministerial meeting on 26 November, the alliance will be faced with more demand-side uncertainty than it would have wished. Prices have weakened considerably in recent weeks due to a combination of strong supply gains from outside the grouping and gathering economic uncertainty, dealing a blow to any hopes of easing output cuts.

The group's formal and voluntary cuts run until end-2024, but Saudi Arabia's additional 1mn b/d voluntary cuts and accompanying 300,000 b/d export cuts from Russia are due to expire at the end of this year. However, with global demand seasonally weakening in Q1, most observers reckon an imminent return of these barrels would flip the market into a surplus of as much as 1mn b/d through the first half of 2024.

When reaffirming at the beginning of this month that the voluntary cuts would remain in force until end-December, Saudi Arabia noted that "this voluntary cut decision will be reviewed next month to consider extending the cut, deepening the cut, or increasing production." Given current market perceptions, any move towards bringing output back online in early 2024 would risk sparking a market sell-off. Indeed, there has even been speculation that Saudi Arabia might consider either deepening its own cuts or seek to convince others to cut deeper during Q1.

In a 16 November research note, Giovanni Staunovo, commodity analyst at UBS, stated "Our view is that the voluntary Saudi and Russian supply cuts are extended into 2024. That said, we cannot exclude a surprise additional cut decision at the meeting."

DEMAND GROWTH UNCERTAINTY

Most agencies forecast a steep slowdown in demand growth next year, but the most notable exception is Opec itself. The group's Monthly Oil Market Report (MOMR) forecasts strong demand growth of 2.25mn b/d next year, down only incrementally from this year's 2.46mn b/d.

Opec's demand outlook is much more bullish than other agency forecasts. For 2024 Opec's demand growth figure is more than double the 930,000 b/d forecast by the IEA and around 800,000 b/d more than the US Energy Information Administration's (EIA) 1.40mn b/d (see tables). Opec's initial outlook for 2023 was also much more bullish, although this was swiftly revised down (see chart 1).

Investment bank Citi notes that "Opec continues to expect outsized strong oil demand in 2024, that does not seem to match the [weak] global macroeconomic growth outlook."

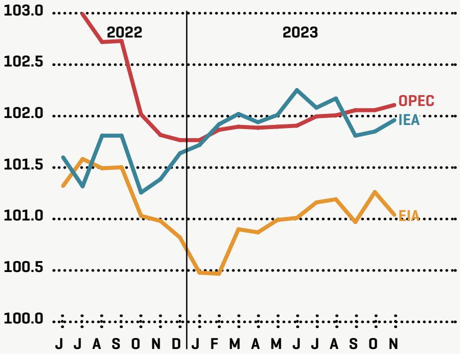
IEA SUPPLY & DEMAND FORECASTS, NOVEMBER 2023 (MN B/D) SOURCE: IEA, OPEC, MEES.

	2022	2023	vs 22	2024	vs 23	1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24
World Oil Demand	**99.59**	**101.96**	*+2.37*	**102.89**	*+0.93*	**100.35**	**101.71**	**102.99**	**102.75**	**101.51**	**102.39**	**103.53**	**104.10**
vs Oct23 report	*-0.00*	*+0.11*	*+0.11*	*+0.16*	*+0.05*	*-0.03*	*-0.04*	*+0.33*	*+0.17*	*+0.17*	*+0.23*	*+0.06*	*+0.17*
Non-Opec Supply	65.59	67.69	*+2.10*	68.86	*+1.17*	67.01	67.47	68.05	68.20	68.18	68.94	69.27	69.05
vs Oct23 report	*-0.00*	*+0.14*	*+0.14*	*+0.07*	*-0.08*	*-0.01*	*-0.06*	*+0.21*	*+0.41*	*+0.14*	*+0.10*	*+0.03*	*+0.00*
Opec NGLs	5.43	5.55	*+0.12*	5.63	*+0.09*	5.49	5.52	5.58	5.60	5.63	5.63	5.64	5.64
Call on Opec	**28.58**	**28.73**	*+0.15*	**28.40**	*-0.33*	**27.85**	**28.72**	**29.37**	**28.96**	**27.71**	**27.82**	**28.62**	**29.42**
vs Oct23 report	*-0.00*	*-0.05*	*-0.04*	*+0.07*	*+0.11*	*-0.02*	*+0.00*	*+0.09*	*-0.26*	*+0.01*	*+0.10*	*+0.01*	*+0.14*
Opec Crude Prod	29.08	n/a	*n/a*	n/a	*n/a*	29.38	28.89	28.01	n/a	n/a	n/a	n/a	n/a
Opec vs Call	**+0.50**	**n/a**	*n/a*	**n/a**	*n/a*	**+1.53**	**+0.16**	**-1.35**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
World Oil Supply	100.09	n/a	*n/a*	n/a	*n/a*	101.88	101.88	101.64	n/a	n/a	n/a	n/a	n/a

OPEC SUPPLY & DEMAND FORECASTS, NOVEMBER 2023 (MN B/D)

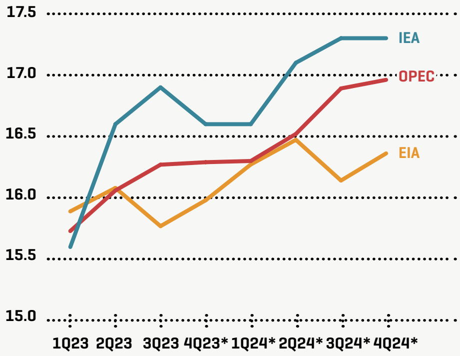
	2022	2023	vs 22	2024	vs 23	1Q23	2Q23	3Q23	4Q23	1Q24	2Q24	3Q24	4Q24
World Oil Demand	**99.66**	**102.11**	*+2.46*	**104.36**	*+2.25*	**101.58**	**101.47**	**102.11**	**103.28**	**103.60**	**103.64**	**104.79**	**105.38**
vs Oct23 report	*+0.03*	*+0.05*	*+0.02*	*+0.05*	*-0.00*	*-0.01*	*+0.13*	*-0.06*	*+0.15*	*-0.01*	*+0.13*	*-0.06*	*+0.15*
Non-Opec Supply	65.81	67.59	*+1.78*	68.97	*+1.38*	67.72	67.63	68.11	66.92	68.48	68.47	69.12	69.81
vs Oct23 report	*-0.00*	*+0.10*	*+0.10*	*+0.10*	*-0.00*	*+0.00*	*+0.02*	*+0.34*	*+0.04*	*+0.14*	*+0.10*	*+0.09*	*+0.07*
Opec NGLs	5.39	5.44	*+0.05*	5.51	*+0.07*	5.44	5.47	5.43	5.43	5.49	5.54	5.50	5.50
Call on Opec	**28.45**	**29.08**	*+0.63*	**29.88**	*+0.80*	**28.42**	**28.37**	**28.58**	**30.93**	**29.63**	**29.63**	**30.17**	**30.07**
vs Oct23 report	*+0.03*	*-0.05*	*-0.08*	*-0.05*	*+0.00*	*-0.01*	*+0.11*	*-0.40*	*+0.11*	*-0.15*	*+0.03*	*-0.15*	*+0.08*
Opec Crude Prod	28.86	n/a	*n/a*	n/a	*n/a*	28.84	28.27	27.56	n/a	n/a	n/a	n/a	n/a
Opec vs Call	**+0.41**	**n/a**	*n/a*	**n/a**	*n/a*	**+0.42**	**-0.10**	**-1.02**	**n/a**	**n/a**	**n/a**	**n/a**	**n/a**
World Oil Supply	100.07	n/a	*n/a*	n/a	*n/a*	101.99	101.37	101.09	n/a	n/a	n/a	n/a	n/a

1: 2023 GLOBAL OIL DEMAND FORECASTS (MN B/D, BY DATE OF REPORT)



SOURCE: IEA, OPEC, EIA, MEES.

2: CHINA OIL DEMAND FORECASTS: THE IEA IS FAR MORE BULLISH THAN OPEC OR THE EIA (MN B/D)



*FORECASTS. SOURCE: IEA, OPEC, EIA, MEES.

Despite having the most conservative estimate for 2024 global demand growth, the IEA is by far the most bullish when it comes to Chinese demand (see chart 2). Of its 930,000 b/d global demand growth forecast for 2024, a massive 700,000 b/d of this comes from China; far outstripping expectations from Opec and the EIA. Yet major question marks remain over the health of the Chinese economy, and the prospects for it remaining the engine of global oil demand growth.

Opec sought to dismiss negative economic sentiment in its latest Monthly Oil Market Report (MOMR). The report's Feature Article pointed to what it said were "robust major global growth trends and healthy oil market fundamentals," adding that "On the global economic growth front, and as the US economy continues the very strong growth it experienced in 3Q23, the IMF has recently upgraded Chinese economic growth projection for 2023 to 5.4%. However, potential downside risks to current robust global economic growth forecasts, although minor, may include sustained restrictive monetary policies to fight inflation, and geopolitical developments."

The IEA's commentary was much more cautious, noting that recent sharp falls in oil prices "came as market concerns shifted from supply risks to the global economy and oil demand. In addition, front month paper market trade has moved to 1Q24 when markets appear more or less in surplus, adding to the downward pressure on prices." It did however note that "While this more bearish mood may be justified, world oil demand continues to exceed expectations."

Indeed, despite renewed negativity over the health of the global economy, both the IEA and Opec revised up their 2024 demand expectations this month. ◆◆

Israel Gas Rebound With Tamar & Pipeline Restart

Israel's second largest gas field Tamar restarted on 9 November with the Israel-Egypt pipeline following suit five days later. As Egypt flows rebound to pre-conflict levels, Cairo hopes this will enable it to resume LNG exports.

As the war between Israel and Hamas enters its second month, and with the military threat from the group heavily degraded, Israel's Ministry of Energy on 9 November notified operator Chevron that it could restart gas output from the 1.1bn cfd Tamar field. With Tamar's production platform just 25km north of Gaza, Chevron had been ordered to halt production on 9 October.

With the direct 500mn cfd EMG offshore Israel-Egypt pipeline, which skirts Gaza (see map), also shut in following Hamas' 7 October assault on Israel (MEES, 13 October), deliveries of Israeli gas to Egypt collapsed from pre-conflict levels of 800-900mn cfd to just 100-200mn cfd via Jordan for much of October (see chart 1). Jordan itself has continued to receive its full 200-250mn cfd contractual volumes (MEES, 27 October).

Deliveries to Egypt have not only been low but also erratic. Volumes doubled to 400mn cfd for the fourth week of October before again dropping to around 150mn cfd the following week and then rebounding to 400-450mn cfd for the week ending 11 November. This rebound enabled Cairo to shelve hastily drawn-up plans to import its first LNG cargo in five years (MEES, 10 November).

Chevron, which also operates Israel's other key field, 1.2bn cfd Leviathan, and Energean which operates the country's third field, Karish, were asked to max output to help compensate for the loss of production from Tamar, whose production had been running at around 1bn cfd prior to the start of the conflict. Leviathan output hit 2.92bcm (1.12bn cfd) for Q3, with a record 960mn cfd exported, and it appears to have risen further since.

But Karish output has been more turbulent with an end-October outage the key reason for that week's collapse in deliveries to Egypt (MEES, 3 November). 45.34% Leviathan partner NewMed Energy cites "operational events" at Karish as the key reason for recent weeks' fluctuations in Israel-Egypt volumes.

Energean on 16 November reported record quarterly Karish output of 517mn cfd for Q3 with output ramping up to average 570mn cfd "over the past two months." This 570mn cfd figure is in line with a then-record figure reported in early September (MEES, 15 September).

For October as a whole, Israel-Egypt volumes averaged 410mn cfd, less than half the 869mn cfd September figure. NewMed says in its Q3 report on 16 November that "the gas quantity supplied to Egypt in October was around 82% of the monthly contract quantity of gas that the Leviathan partners are obligated to supply." This implies monthly contract quantities of 500mn cfd, somewhat in excess of the 450mn cfd average implied by the Leviathan partners' long-term sales deal with Egyptian importer Blue Ocean Energy (MEES, 4 October 2019). Gas from the Karish field is not exported, rather any output increase (or decrease) from Karish will have meant more (or less) Leviathan volumes were available for export.

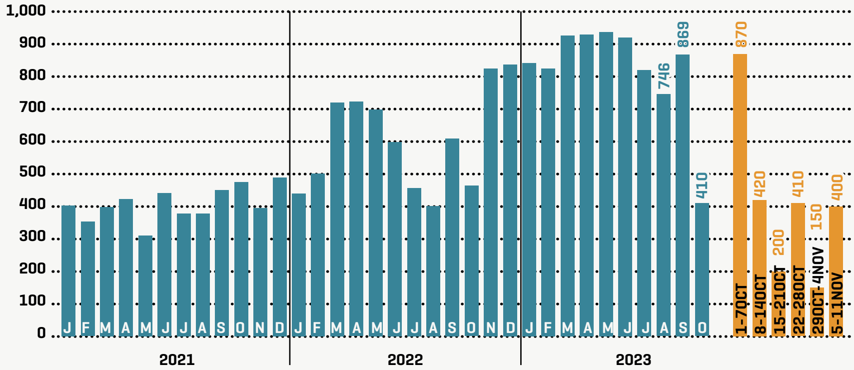
EXPORT REBOUND

With the restart of Tamar, and the EMG pipeline five days later on 14 November, deliveries to Egypt have been edging higher according to MEES Egyptian sources, who estimate it will take until the end of November before the field is able to regain pre-conflict output levels of 950mn cfd and EMG flows approach the route's 5bcm/y (480mn cfd) capacity.

Not surprisingly, NewMed says in its Q3 report that work to expand deliverable EMG capacity to 8 bcm/y (770mn cfd) with the completion of a 46km offshore pipeline link between Ashdod and Ashkelon "has been suspended, and therefore a further postponement of the scheduled date of completion of this project is expected." Following previous delays the target completion date was end-2023 although the official deadline given by INGL was end-April 2024 (MEES, 25 August).

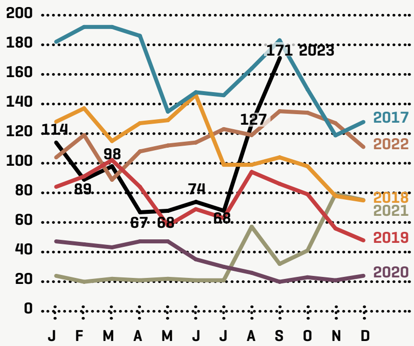
Start-up will not now happen until well into 2024, NewMed CEO Yossi Abu revealed during his firm's earnings call on 16 November. Chevron received notice in October that as "a result of the War, work on such a project had been suspended and that the expected date of commencement of the flow is about four months from the date of

1: ISRAEL-EGYPT GAS SHIPMENTS HAVE BEEN LOW AND UNSTABLE SINCE HAMAS' 7 OCTOBER ATTACK BUT WITH TAMAR & EMG RESTART THEY SHOULD REGAIN PRE-CONFLICT LEVELS BY END-NOVEMBER (MN CFD)



SOURCE: JODI, NEWMED ENERGY, MEES ESTIMATES & CALCULATIONS.

2:EGYPT FUEL OIL USE HITS 6-YR HIGH 171,000 B/D FOR SEP AMID GAS FUEL SHORTAGE



SOURCE: JODI, MEES.

ISRAEL GAS FLOWS TO JORDAN & EGYPT

*WORK SUSPENDED. START-UP PUSHED BACK FROM END-2023 TO 2Q 2024 AT THE EARLIEST (SEE STORY TEXT).

Continued on – p9

Continued from – p8

resumption of the work," NewMed says.

Including the via-Jordan route, current deliverable Israel-Egypt capacity is around 1bn cfd. Given that Israel managed to deliver over 900mn cfd for March-June this year and that Karish has since (haltingly) ramped up, this capacity figure may well be tested over the coming months.

The resumption of flows to Egypt should help Cairo put an end to blackouts that have plagued the country since the end of July when gas consumption soared ahead of available supply – imports from Israel plus domestic output (MEES, 28 July). The latter slumped to a three-year low 5.64bn cfd for September (MEES, 3 November) versus gas consumption of 6.30bn cfd including 3.96bn cfd used for power generation.

The latter figure has been capped in recent months both by load shedding and by Cairo burning increased volumes of fuel oil for power generation (MEES, 4 August). Egypt's fuel oil consumption soared to a six-year high 171,000 b/d for September (see chart 2).

Italian firm Eni, operator of the 5mn t/y Segas LNG export facility at Damietta says that LNG exports could resume before the end of 2023.

"Consumption in Egypt is reducing and we would expect by December, possibly January, exports could resume," Eni's global gas and LNG portfolio director Cristian Signoretto told Reuters on 14 November. However, though seasonal power demand trends would normally see gas consumption fall through Q4, working against this is a likely desire to replace recent high levels of oil burn with more efficient gas before considering exports.

RESILIENT OUTPUT

Even before the recent call to hike output, already for Q3 Leviathan's output figure of 1.12bn cfd was just shy of the quarterly record set a year earlier, with Q3 seeing quarterly record exports of 960mn cfd (see chart 3). This included record volumes to both Egypt (653mn cfd) and Jordan (307mn cfd) as operator Chevron (39.66%) and its partners did their best to cover for lost Tamar volumes to both countries.

"Since the fighting began, the Leviathan reservoir has helped maintain a regular and stable supply of natural gas to the Israeli economy alongside the continuation of regional exports," NewMed's Mr Abu says. "The continuous supply of natural gas from the Leviathan reservoir allowed the continued operation of [Israel's] power plants and the maintenance of a continuous energy supply," he adds. Natural gas' share of Israel's power generation mix hit 72% for October (see box).

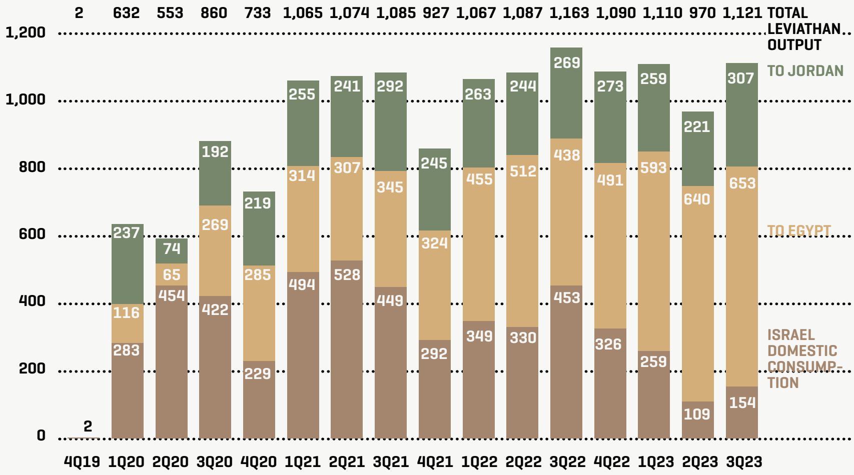
Ramp up at Karish has lessened the need for Leviathan gas on the domestic market. Though domestic sales rose from 109mn cfd for Q2 to 154mn cfd for Q3 this remains well below Q2 2021's peak of 528mn cfd. For Q4 the situation will have been significantly altered with much more Leviathan gas heading to the domestic market amid the post-war reduction to Egypt flows.

At Karish, Energean continues to work on capacity expansion via tie-back of the 1.2tcf Karish North satellite field, which should enable the Karish FPSO to produce at full 8bcm/y (780mn cfd) capacity.

"Karish North and the second gas export riser remain on track for completion for the end of the year," the firm says, adding that "all infrastructure associated with these projects is in place ahead of final commissioning planned for early December."

But the current conflict has meant a delay to the installation of the second oil train on the FPSO. "Construction of the second oil train has been completed and the module was scheduled to leave Dubai in early October. However, because of the security situation in Israel, it has impacted the timing of the installation," the firm says, adding it "will be installed once the security situation allows." ◆◆

3: LEVIATHAN EXPORTS HIT RECORD 960MN CFD FOR Q3 WITH NEW HIGHS TO BOTH EGYPT AND JORDAN (MN CFD)



SOURCE: CHEVRON, NEWMED, RATIO, MEES.

ISRAEL GAS USE RISES DESPITE RENEWABLES START-UP

With the 9 October-9November shutdown of the 1.1bn cfd Tamar field, Israel's two other fields, 1.2bn cfd Leviathan and 600mn cfd Karish were called on to max output (see p8). This saw the share of natural gas in the country's energy mix rise to 72% for October, versus an average of 70% for the first ten months of 2023 and 68.5% for 2022 (see chart).

The other two key elements of Israel's powergen mix are coal, and renewables (solar and wind). Coal demand has been falling amid the progressive shutdown and conversion to gas of older plants (MEES, 7 April) though still accounted for 17.5% of the country's power output for the first 10 months. This fell to 16% for October, perhaps suggesting that one reason for maxing gas was to avoid the exhaustion of the country's coal stockpile, much of which is situated at (and imported via) the Ashkelon terminal just north of the Gaza Strip (see map, p8).

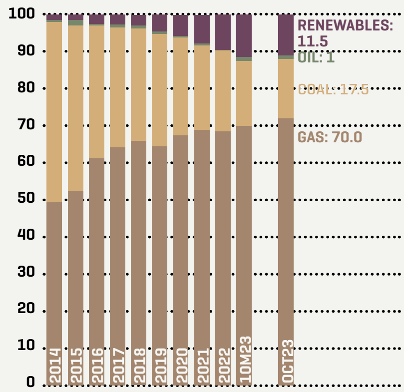
The renewables share hit an annual record 9.5% for 2022 (MEES, 1 September), and rose further to 11.5% for 10M 2023.

Ramp up of solar PV capacity in particular, saw overall renewables capacity hit 4.80GW at end-2022, up from 3.66GW a year earlier, with the figure set to top 6GW by the end of this year, putting Israel neck-and-neck with the UAE as regional renewables leader (see p18).

The key recent start-up came last month with Enlight's Genesis wind farm in the occupied Golan Heights. Current capacity is 180MW, and "the remaining five turbines are expected to be operational after the completion of final tests, raising capacity to 207MW" the Israeli firm says. Enlight does not clarify whether full 207MW capacity will be reached before the end of the year.

With not only 'Genesis' but an additional 213MW of Golan wind capacity either under construction or having recently started up (MEES, 11 August), a "new 27km underground high-voltage transmission cable has been built connecting the Golan Heights to Israel's national grid" to "enable the development of additional renewable energy projects in the region," Enlight says.

ISRAEL POWERGEN FUEL MIX (%): DESPITE TAMAR SHUT-IN GAS SHARE GREW IN OCTOBER AS ISRAEL MAXED OUT OUTPUT FROM LEVIATHAN AND KARISH



T= GOVERNMENT TARGET. SOURCE: IEC, NOGA, MEES.

◆◆

Western Sahara Flare-Up Raises Morocco-Algerian Tension

New attacks in Western Sahara have raised fears of renewed open warfare in the disputed territory and heightened hostility between neighbors Morocco and Algeria.

Last month, when UN Secretary-General António Guterres submitted his annual report on the situation in Western Sahara to the Security Council, he noted a "deteriorated state of affairs" in the disputed North African territory which has been occupied by Morocco since 1975.

Mr Guterres warned of a "real risk of escalation" over "continued hostilities" between the Moroccan military and the separatist Polisario Front. These included aerial strikes and gunfire across the berm, a 2,700km sand wall separating the Moroccan controlled areas on the west (80% of the total area including all of the coast) and the Polisario-controlled areas on the east (20%).

The territorial dispute over Western Sahara is not new, with deep roots in the competing regional ambitions of post-independence Morocco and Algeria. With the withdrawal of former colonial power Spain in 1975, Rabat asserted its claim with an invasion known as the 'Green March'.

Algiers has ever since opposed the Moroccan "occupation" and continues to support – and host – the Polisario Front, which has for decades sought an independent state for the indigenous Sahrawi people.

But recent security incidents, arms deals, and diplomatic advances are raising concerns about a flare-up of the long-dormant dispute, though analysts remain divided over the probability of a full-scale armed conflict between the long-time regional rivals.

ALGERIA-MOROCCO-WESTERN SAHARA: MAPPING A RELATIONSHIP

GAS FIELD/PIPELINE ■ OIL FIELD/PIPELINE

NEW SAHRAWI MILITARY BASE

Polisario declared a renewed war on Morocco in mid-November 2020 after the latter launched a military operation in the buffer zone of Guerguerat, near the southernmost tip of Western Sahara, in which Moroccan army forces drove out a group of Sahrawi protesters who were blocking a transit route to neighboring Mauritania. Polisario at the time accused the Moroccan army of shooting at unarmed civilians, violating a UN-brokered ceasefire and effectively ending a 29-year truce.

On 13 November the Sahrawi People's Liberation Army (SPLA), the armed wing of the Polisario Front, issued a statement marking three years since the "resumption of the armed struggle." The statement claimed the SPLA had "carried out more than 3,457 military actions and targeted more than 922 hostile sites" since the Guerguerat crisis of 13 November 2020.

A day later, the SPLA announced the inauguration of the "13 November military base," which aims to "reinforce the combat capabilities of the Sahrawi fighter... taking into account the current reality of war."

Although the SPLA did not specify the location of the new base, local media reports suggest it is located on Algerian territory, near the Algerian border city of Tindouf, which has served as the rear-base of the Polisario Front since the 1970s, and the de-facto capital of the self-proclaimed Sahrawi Arab Democratic Republic (SADR).

The announcement raised concerns in Morocco, with local analysts considering it an Algerian declaration of war.

MORROCAN STRIKES

Since the resumption of hostilities in 2020, multiple media and official reports have documented Moroccan drone strikes against Polisario targets in Western Sahara, with the strikes intensifying over the past year.

In his report, which covered the period between October 2022 and October 2023, Guterres said the UN mission in Western Sahara (MINURSO) "continued to receive reports of strikes conducted by Royal Moroccan Army [RMA] unmanned aerial vehicles east of the berm."

The most recent strike took place in September, when Moroccan drones reportedly hit a target in the Polisario-controlled settlement of Bir Lehlou, killing an SPLA commander and three Sahrawi fighters. Earlier in November 2021, Algiers accused Rabat of killing three Algerian truck drivers on a desert highway using a "sophisticated weapon."

In letters to Guterres, the Polisario Front accused Morocco of "using all types of weapons, including unmanned aerial vehicles, to callously kill, not only dozens of Sahrawi civilians, but also civilians of neighboring countries in transit" via the Polisario-controlled sliver of Western Sahara. Meanwhile, Morocco has accused Polisario of putting into practice a "new modus operandi [...] notably the use of unmarked vehicles, [and] the hiring of fighters disguised as civilians," to "deceive RMA units and tarnish their image in the event of casualties."

The UN also noted a "new 3.2km-long airstrip" near Morocco's base in Bir Anzarane, 75km from the berm. "Analysis of satellite imagery confirmed that the airstrip had been constructed after the resumption of hostilities in 2020," the report said. "MINURSO also observed buildings that appeared to be aircraft hangars and a

Continued on – p11

Continued from – p10

physically hardened perimeter, including guard towers and external walls, through the satellite imagery." The Moroccan army told the UN that the airstrip was "a civilian facility constructed by a civilian company, not serving military purposes," and that construction began in April 2021 as part of the "development projects" initiated by the Moroccan government.

DEEP-ROOTED RIVALRY

Tensions between Morocco and Algeria predate the Western Sahara conflict, which has been a symptom rather than a cause of their poor relations. The rivalry is deeply rooted in a wider competition for regional leadership and unresolved colonial-era disputes.

Already strained relations have deteriorated further since 2020 (MEES, 31 January 2020). In December that year, only weeks after the resumption of hostilities with the Sahrawis, Morocco signed the Abraham Accords peace deal with Israel as part of which both Israel and the US recognized Morocco's claim to Western Sahara (MEES, 11 December 2020).

Algiers, already fiercely anti-Israel, condemned Israeli and US backing of Morocco's "claimed sovereignty" over the disputed territory as a "flagrant violation" of international law.

By 2021, relations between the neighboring rivals hit a new low, when Algiers suspended diplomatic relations with Rabat citing a string of grievances related to Western Sahara, Morocco's relationship with Israel (MEES, 26 November 2021), as well as the kingdom's alleged support for a pro-independence Berber group in Algeria (MEES, 27 August 2021).

Later that year, Algeria stopped sending gas through Morocco to Spain after a 25-year-old contract governing flows through the 11.5bcm/y Gaz Maghreb Europe (GME) pipeline ended (MEES, 5 November 2021). Algiers then in 2022 suspended a 20-year-old "treaty of friendship" with Spain over Madrid's April decision to back Morocco's "illegitimate" autonomy plan for Western Sahara (MEES, 10 June 2022). Algeria-Spain gas flows via a second pipeline have continued, however (see column).

Since then, the two countries have significantly increased their defense budgets and amped up their military power amid concerns of escalation, especially with backing from opposing world powers. According to 2022 data from the Stockholm International Peace Research Institute (SIPRI), the US provides 76% of Morocco's arms imports, while Algiers is one of Moscow's biggest clients, with Russia accounting for 73% of Algeria's arms imports.

'PANDORA'S BOX'

Despite major concerns over recent tensions and arms deals, a full-fledged armed conflict remains unlikely. An open conflict would further add to economic pressures at home and strain ties with international powers. Algeria already faces US criticism and demands for sanctions over its military and business ties with Russia. The European Union will also be highly wary of an open conflict on its southern borders.

A more probable scenario would be the continuation of low-intensity hostilities and skirmishes, while Rabat and Algiers carry on with diplomatic efforts to advance their positions at the international level.

Dr Ahmed Morsy, Senior Mena Researcher at SIPRI, rules out an armed conflict between the Moroccan army and the Polisario Front. "There has been some escalation and small attacks here and there but nothing too concerning at the moment," he tells MEES.

"Even in light of recent armaments, particularly the Moroccans acquiring drones," he adds, "there is little interest in opening Pandora's box, even from the Algerian side."

Dr Meriem Naili, an international law researcher specializing in the Western Sahara, also believes an armed escalation is unlikely, especially in light of the wider regional context and the current war in Gaza. "We cannot rule out completely a conflict between Algeria and Morocco on that particular issue," she tells MEES. "But I think to a certain extent what is happening in the Middle East [Israel/Gaza] has given some perspective to both countries in terms of what they may foresee in the future Western Sahara."

Both agree that other issues will become a priority and soon determine the future of the dispute. According to Dr Morsy, Sahrawi leaders will likely focus on EU lobbying in terms of human rights and Morocco-EU trade agreements, "which they believe extract and misuse Sahrawi shores and lands to export goods to the EU," he explains.

In particular, Dr Naili refers to the much-anticipated ruling of the European Court of Justice on a Morocco-EU fishing agreement, which the Court annulled in 2021 due to its inclusion of Western Saharan waters without obtaining the consent of its population. The ruling has since been appealed, and next spring the Court is set to determine whether negotiations to renew the agreement, which expired in July, can proceed. According to Dr. Naili, the ruling will have a major impact on how the dispute unfolds.

Algeria will have an additional international forum when it assumes a temporary seat on the UN security council from 1 January. "The Algerians will definitely attempt to use their position in the UNSC to bring light to the Western Sahara issue. However, in light of the Israeli onslaught on Gaza, they might shift gear to show their support for Palestine. Algeria might also attempt to use its membership to sponsor resolutions or council statements on African issues as well," Dr Morsy says. ◆◆

ALGERIA-ITALY GAS SLUMP

*Italy's Eni previously flagged up that Algeria-Italy gas deliveries would rise from Q4 this year following a 2022 deal (MEES, 21 April). But, though volumes hit bumper levels for Q2 and Q3 (MEES, 6 October), they have slumped rather than risen since the start of October – last month saw deliveries fall to a six-month low of 1.87bcm (2.13bn cfd), whilst volumes fell again to 1.83bn cfd for the first half of November (see chart 1).

*But deliveries to number two pipeline market Spain have picked up in recent months despite continued political tensions (see p10). At 980mn cfd for October, volumes were a 20-month high, though year-to-date deliveries of 780mn cfd remain down year-on-year and just half the level from five years earlier. Upstream operator Repsol, having expanded its operator's stake in the Reggane project earlier this year says the move "is part of the European strategy of searching for opportunities to increase its participation in gas supplies to Europe."

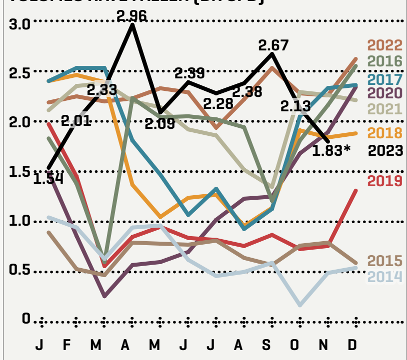
*LNG exports of 11.3mn tons for 10M 2023 also put this year on track for the highest figure since 2010.

*As for the country's key upstream IOCs, Occidental reported a slump in output to just 30,000 boe/d (including 25,000 b/d oil) for Q3, implying multi-decade low gross output for the key Berkine basin fields where its key partners are Eni and TotalEnergies.

*Spain's Cepsa, which operates one of these fields, Ourhoud, reported Q3 net Algeria output level with Q2 at 26,300 b/d for an implied 60,000 b/d gross Ourhoud figure, less than half 2017 levels. Cepsa cites "scheduled maintenance turnarounds in Algeria" as a key reason for a fall in 9M 2023 upstream output versus a year earlier, as well as the sell-off of its UAE assets (MEES, 3 March).

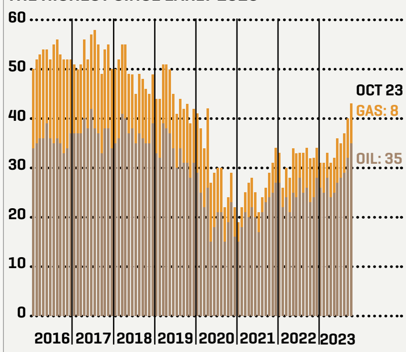
*Algerian state giant Sonatrach sees increased exploration drilling as key to a turnaround with the country's rig count hitting a four-year high of 43 for October (see chart 2).

ALGERIA PIPED GAS EXPORTS TO KEY MARKET ITALY: FAR FROM THE PROMISED Q4 SURGE, VOLUMES HAVE FALLEN (BN CFD)



*1-16 NOVEMBER. SOURCE: SNAM, MEES.

ALGERIA'S RIG COUNT HIT 43 FOR OCTOBER, THE HIGHEST SINCE EARLY 2019



*ACTIVE DRILLING RIGS. SOURCE: BAKER HUGHES.

◆◆

Iraq-Turkey Pipeline Hopes Fade

Baghdad's insistence that IOCs in Kurdistan replace their existing production sharing contracts (PSCs) is continuing to prevent the restart of the Iraq-Turkey Pipeline (ITP) which has been shut since March. A new round of meetings between Iraqi officials and their counterparts from the Kurdistan Regional Government (KRG) in recent days had raised hopes of a breakthrough, but there is no sign of Iraq compromising on its stance.

The high-level meetings were kicked-off by a two-day visit to Erbil by Iraqi Prime Minister Mohammed al-Sudani on 9 November, followed by another two-day round of talks led by Oil Minister Hayan Abdulghani. Accompanied by senior ministry officials, Mr Abdulghani on 12 November met Kamal Salih, the KRG's acting Minister of Natural Resources as well as Kurdish PM Masrour Barzani, followed by President Nechirvan Barzani on 13 November. Discussions revolved around "mechanisms to resume production and export operations," the Iraqi oil ministry says.

The visits came on the heels of an 8 November meeting in Dubai between an oil ministry delegation and representatives from the Association of the Petroleum Industry of Kurdistan (Apikur), an industry group representing IOCs operating in Kurdistan (MEES, 10 November).

BAGHDAD-IOC DEAL FACES LEGAL CHALLENGES

Apikur is proposing that Iraqi state crude marketer Somo enters into oil purchase contracts with its members for their entitled volumes of produced oil as per PSC terms, and that debts owed to them by the KRG are honored.

The Apikur proposal however may be legally challenging for Baghdad to implement. Honoring the PSCs would fly in the face of a 2022 ruling by Iraq's Supreme Court (MEES, 18 February 2022), and provide an implicit recognition of the PSC contracts' validity that Baghdad has always refused.

Buying oil directly from the firms is also complicated by Iraq's bureaucratic government contracting regulations that often do not allow single-sourced purchases without tendering. It's doubtful that such contracts would stand a legal challenge by any of the many anti-KRG MPs at the country's politically active Supreme Court (see column).

Even were a deal struck, Baghdad will need to involve Erbil, something Apikur said the ministry's delegation also stressed. Volumes would need to go through the KRG-controlled pipeline to the Iraq-Turkey border. The pipeline is operated by the Kurdistan Pipeline Company (KPC: 40% Kar, 60% Rosneft).

Arguably, involving the KRG as a middleman could resolve Baghdad's contractual dilemma with the IOCs, but this would leave cash-flow in Erbil's hands; something neither Baghdad nor the IOCs want to see. Iraq has fought hard to secure control over Kurdistan's oil reserves, while IOCs are wary of the risk of non-payment.

Speaking to the Kurdish Rudaw news agency on 13 November, Mr Abdulghani said Baghdad's oil ministry is now looking to adjust the PSCs "with the laws that are allowed by the Iraqi constitution." MEES understands that Baghdad has offered the IOCs its 'profit-sharing' development and production contract model, recently signed with TotalEnergies at Ratawi (MEES, 10 March), but this was turned down by the companies which insist on the legal validity of their PSCs.

While the three parties support a resolution, an oil ministry source says they lack a "shared vision" for how to resolve all contentious issues. Mr Abdulghani says that another round of meetings between all parties has been agreed, adding that "we are serious with our brothers in the region to resume production and exports as quickly as possible."

Turkey is not participating in the talks, having notified Baghdad in October that the pipeline is ready to receive oil flows (MEES, 20 October). As a result, Baghdad is obliged to make minimum throughput tariff payments of around $23mn/month to Ankara under the ITP treaty. Mr Abdulghani met Turkey's ambassador to Iraq, Ali Rıza Günay, on 16 November to discuss "opportunities for cooperation in the energy sector."

BAGHDAD DRAGS ITS FEET

In the aftermath of the stoppage, Baghdad ramped up its southern oil output in compensation for lost production, maxing its Gulf exports in the process. October's Basra exports of 3.48mn b/d were almost 300,000 b/d above March levels. These additions have seen Iraqi output repeatedly top its 4.22mn b/d voluntary ceiling under Opec+ restrictions. MEES estimates that Iraqi output fell by 110,000 b/d to 4.32mn b/d for October on receding oil burn.

The federal government feels in no hurry to reach an agreement which would see northern production restored and as such require a reduction in southern output that it currently fully monetizes as revenue to the federal budget. But with the Kurdistan IOCs bringing their output close to 200,000 b/d, Iraq's overall output is nevertheless on an upward trajectory, potentially leaving Iraq facing awkward questions at the upcoming 26 November Opec+ ministerial meeting. ◆◆

Iraqi Court Ousts Halbousi

Iraq's Supreme Court shocked the country's political scene with a 14 November decision to end the term of Parliament Speaker Mohammed al-Halbousi. Mr Halbousi heads the Takadom bloc which has 39 seats. In a departure from custom, no detailed document of the ruling was provided.

Instead, the court published a video explaining that Mr Halbousi's tenure was terminated on the basis that he had forged a former Takadom party member's resignation from parliament. Mr Halbousi denies accusations of forcing his party's MPs to sign "undated" resignation letters as a tool of political extortion.

In the aftermath of the announcement, Takadom's ministers of planning, industry and culture handed their resignations to PM Mohammed al-Sudani with the party's heads of parliamentary committees following suit in an act of protest. Mr Halbousi has called the decision unconstitutional. The Supreme Court's decisions in Iraq are final, with its legality de facto recognized by political actors through lawsuits and litigation (MEES, 10 June 2022).

Mr Halbousi is considered to be the country's most influential Sunni politician, and the decision risks fomenting another crisis just as Iraq gears up for provincial council elections on 18 December. A protracted crisis after August 2021 parliamentary elections only saw a government formed a year later (MEES, 28 October 2022).

At the time Anbar-native Halbousi joined an alliance with frontrunner Shia cleric Muqtada al-Sadr and the Barzani-led Kurdistan Democratic Party (KDP). But the alliance broke up when Mr Sadr pulled his 73 MPs from parliament (MEES, 17 June 2022). Both the KDP and Mr Halbousi pivoted to align with the Iran-backed Shia Coordination Framework (SCF) under the fragile State Administration Coalition (SAC).

On 13 November, populist Mr Sadr asked his supporters to boycott the upcoming provincial elections, and the ouster of Mr Halbousi is seen as a coup by SCF-backed Sunni politicians to fill the void. The Supreme Court is accused of implicitly siding with the SCF as seen in rulings against the KRG (see main story). In a tweet, KRG PM Masoud Barzani called the ruling against Mr Halbousi "a farce."

It remains unclear whether the ruling will prevent Mr Halbousi from running in the future, but the Court has allowed another case against him to proceed, in which he is accused of soliciting the services of US lobbyist BGR Group which has former Israeli PM Ehud Barak on its advisory board. ◆◆

Kuwait's Al-Zour Refinery Suffers New 10-Day Outage

Kuwait's 615,000 b/d Al Zour refinery is bringing its units back online over a ten-day period following an abrupt shutdown. Officials are confident that they can tap into inventories to prevent supplies from being disrupted.

Kuwait's 615,000 b/d Al Zour refinery has seen output virtually grind to a halt after a gas malfunction in a main valve operated by state-firm Kuwait Oil Company (KOC) led to a sudden interruption of gas supplies. In a 12 November statement, state operating firm Kipic said that it would take ten days for capacity to be brought back to previous levels.

Al Zour has three 205,000 b/d CDUs. These have been brought online successively from November last year with the third and last entering service in July (MEES, 14 July). KPC CEO Sheikh Nawaf Al Sabah last month said that an announcement on full capacity being achieved was imminent (MEES, 20 October).

But, far from achieving this, Head of Operations Mohammed Hazzam al-Hajiri said on 15 November that the refinery had entered a "safe shutdown." CEO Walid al-Bader's phlegmatic take was that "these issues happen in this industry." This is the second major outage at Al Zour this year, after the first two CDUs suffered unplanned shutdowns in April (MEES, 14 April).

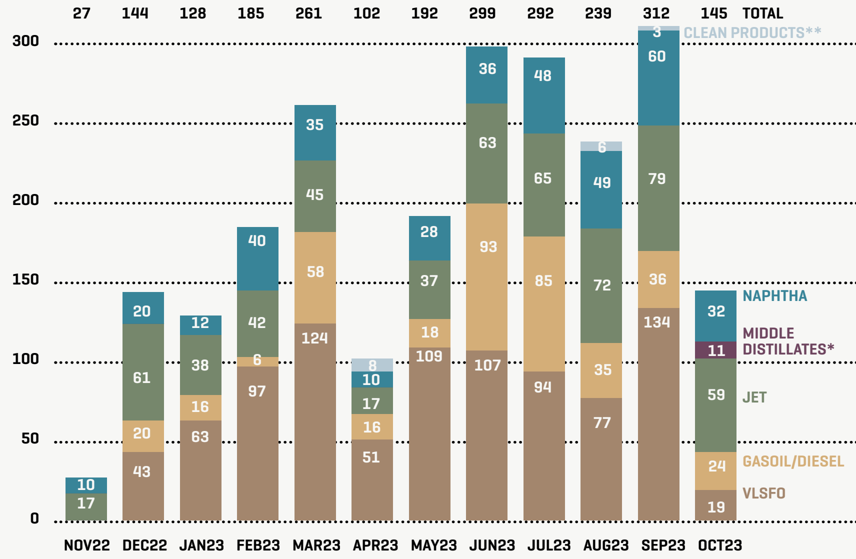
Speaking to Reuters on 16 November, Mr Bader added that his firm has sufficient stocks to ensure continued supplies to customers. Kipic says that it can dip into inventories to ensure that domestic deliveries and exports remain unaffected by the outage. Mr Hajiri says that exports of very low sulfur fuel oil (VLSFO) and supplies to the Ministry of Electricity and Water (MEW) will continue as planned.

Mr Hajiri added that already by 15 November Kipic has managed to bring back auxiliary units, with a comprehensive plan to have other processing units back within the announced 10-day timeframe.

Al Zour was designed to produce substantial volumes of VLSFO (0.5% sulfur) and middle distillates. Whilst its 45% yield of fuel oil (up to 275,000 b/d at peak) had always been intended for domestic power plants, KPC had stated in May (MEES, 26 May) that it was aiming to export around two-thirds of Al Zour's VLSFO output – approximately 162,000 b/d.

VLSFO exports began in December 2022 and hit a 134,000 b/d peak in September. However, they slumped to just 19,000 b/d in October, coinciding with an announcement of the completion of a key pipeline connection enabling power plants to switch from HSFO to VLSFO (MEES, 3 November). Both VLSFO cargoes exported last month were shipped to Qatar for its bunker fuel requirements.

KUWAIT'S AL ZOUR REFINERY SAW EXPORTS SLUMP BY MORE THAN 50% IN OCTOBER ('000 B/D)



*YET TO BE IDENTIFIED. **INCLUDES GASOLINE EXPORTS. SOURCE: KPLER, MEES.

The drop in VLSFO exports enabled Kuwait to increase exports of HSFO from 11,000 b/d in September to 58,000 b/d, and the IEA's latest Oil Market Report speculates that the additional volumes weighed on Asian prices.

STOCKPILING AT POWER PLANTS

Kuwait's power plants run on a mix of domestic gas, imported LNG and fuel oil. The completion of the 100,000 b/d pipeline from Al Zour to storage facilities at Mina al-Ahmadi for onward distribution was announced in September, and MEW targeted end-October for the full switch. At peak power demand in summer, volumes earmarked could amount to 150,000 b/d, with 50,000 b/d fed to the nearby Az-Zour South power plant. If run at full capacity, this would leave just 125,000 b/d available for export during the summer peak electricity demand season.

The recent dip in exports is explained by a note from consultancy FGE as part of VLSFO stockpiling at power complexes. Data intelligence firm Kpler indicates that so far this month just one cargo has loaded VLSFO at Al Zour, with the Rustaq Silver (IMO: 9718753) sailing on 7 November to deliver 300,000 barrels to Qatar. However, middle distillate exports have continued since the outage.

OTHER PRODUCTS REBOUNDING

The 115,000 b/d reduction in VLSFO cargos from Al Zour last month drove a steep fall in total exports from the refinery. Overall exports hit a record 312,000 b/d in September, only to drop by more than 50% to 145,000 b/d in October (see chart).

For the past ten months, Al Zour's exports have mainly headed to Asia (134,000 b/d) with Europe coming second (44,000 b/d. Al Zour has enabled Kuwait to massively ramp up overall mid-distillate flows to Europe as well.

These have been on the rise this year, benefiting from an EU ban on Russian distillates that came just as the emirate concluded its $15.6bn Clean Fuels Project (CFP) upgrades at its legacy Mina Abdulla and Mina al-Ahmadi refineries at end-2022. ◆◆

Adnoc Finalizes Ruwais Crude Flexibility Project

Commissioning of Adnoc's Crude Flexibility Project is imminent, enabling Adnoc to switch out Murban crude from its Ruwais West refinery for heavier barrels. Crude differentials mean that the economic case for making the switch is currently limited.

Abu Dhabi state energy firm Adnoc is finalizing its $3.5bn crude flexibility project (CFP) which is intended to free up additional volumes of its flagship Murban grade for export. The multi-year project to upgrade the 417,000 b/d Ruwais West refinery to run on heavier grades is nearing completion and could have a profound impact on the balance of crude exports from the UAE in 2024.

Ruwais West currently runs entirely on a feedstock of light crude, primarily Adnoc's Murban (40°API, 0.7% sulfur) and domestically produced condensate alongside modest volumes of imported cargoes such as CPC blend from Kazakhstan. With the neighboring Ruwais East refinery's 140,000 b/d CDU also running on Murban (the plant also has two condensate splitters totaling 280,000 b/d), as much as 557,000 b/d of Abu Dhabi's premium crude is refined domestically rather than exported.

In order to address this, Adnoc awarded an EPC contract to Korea's Samsung Engineering and US firm CB&I (now McDermott) for the CFP in 2018 (MEES, 9 February 2018). Work includes installation of a 177,000 b/d atmospheric residue desulfurization (ARDS) unit to enable the processing of heavier crudes, as well as a hydrogen manufacturing unit (HMU), sulfur recovery unit (SRU) and tail gas treating unit (TGTU).

Adnoc says the work will enable it to process its heavier "Upper Zakum crude [34° API, 1.75% Sulfur] or other similar crudes from the market" in Ruwais West. With Upper Zakum crude produced from the eponymous offshore field and exported from the Zirku Island terminal, any such volumes would have to be supplied to Ruwais on tankers. Adnoc has also been looking to build up its crude oil trading arm's capabilities in order to maximize the potential economic benefits of running third party non-system crudes in the refinery.

As well as enabling Adnoc to boost its revenues through higher exports of its premium Murban crude, increased availability of the grade is also intended to bolster the Murban futures contract which was launched in 2021, and the ICE Futures Abu Dhabi (IFAD) exchange on which it trades (MEES, 2 April 2021). Adnoc has capacity to produce more than 2mn b/d of Murban from its onshore operations, primarily from the massive Adnoc Onshore concession (Adnoc 60%, TotalEnergies 10%, BP 10%, CNPC 8%, Inpex 5%, Zhenhua 4%, GS Energy 3%).

CFP COMMISSIONING NEARS

With the CFP's potential to impact exports of both Murban and Upper Zakum, the project is one of the most eagerly anticipated developments in the region's oil sector. Multiple sources confirm that work on the CFP has now been largely completed, with commissioning set to take place from now until early-2024, although Adnoc declined to comment.

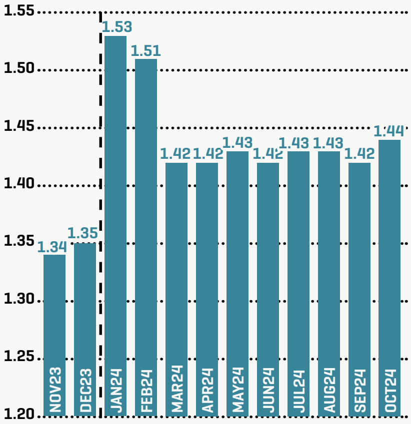
This timeframe is supported by trade flows from data intelligence firm Kpler which show that 1.8mn barrels of Upper Zakum were delivered to the Jebel Dhanna oil terminal at Ruwais in both September and October.

Commissioning of the CFP is set to take place during upcoming planned maintenance at the refinery in January and February. This maintenance work means there will be a significant increase in the near-term availability of Murban crude. Exports of the grade were already slated to increase in 2024 due to the UAE's Opec+ quota increasing by 200,000 b/d from January (MEES, 9 June), with around 50% of this increase coming from Murban-producing fields. However, the increase is amplified in the first two months of 2024 due to the refinery's turnaround, with record Murban availability of 1.53mn b/d for January (see chart 1). Murban availability is then slated to drop back to 1.42mn b/d in March, indicating a continuation of normal operations at Ruwais.

Refiners and traders (Adnoc crude

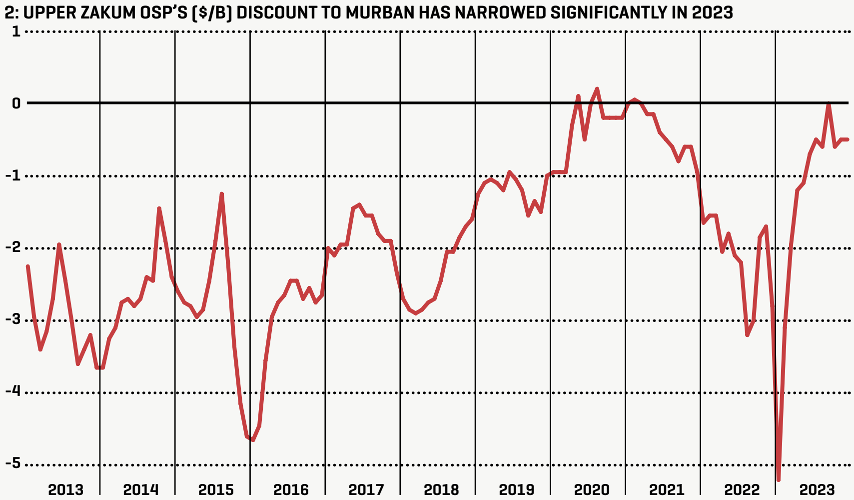
Continued on – p15

1: MURBAN CRUDE AVAILABILITY REPORT: VOLUMES UP SHARPLY FOR JAN, FEB 2024 DUE TO NEW OPEC+ QUOTA AND RUWAIS MAINTENANCE (MN B/D)



SOURCE: ADNOC, MEES.

2: UPPER ZAKUM OSP'S ($/B) DISCOUNT TO MURBAN HAS NARROWED SIGNIFICANTLY IN 2023



SOURCE: ADNOC, MEES.

Continued from – p14

oil grades are now freely tradeable) are therefore eagerly watching for signs of how Adnoc will proceed once the CFP is complete. Adnoc has reduced Upper Zakum term volume availability for clients in 2024 according to market sources, bolstering speculation that at least some volumes will be destined for Ruwais next year.

However, MEES understands that while the CFP work is set to be fully complete by early-2024, Adnoc has yet to decide on whether to switch out Murban volumes. The operative word of the project is flexibility, and differentials between the two grades do not currently point to significant revenue gains being on offer. Iman Nasseri, Middle East Managing Director at energy consultancy FGE, agrees, noting that "how they run Ruwais depends on the Murban/Upper Zakum differential, which currently is not so encouraging."

Light crudes such as Murban produce higher yields of light distillates such as naphtha and gasoline when refined, but margins for such products are currently in the doldrums, greatly reducing the pricing premium of these light crudes. Murban OSPs are set by trading on IFAD, with Adnoc then setting the prices for its other crude grades as differentials to Murban.

Upper Zakum has been priced close to parity with Murban since June, where typically it is priced at a discount of $1-2/B or more (see chart 2). Given the additional costs of transferring Upper Zakum to Ruwais by tanker against Murban's pipeline links, the current economic case for switching out Murban is far from clear and until that changes Adnoc may simply use its newfound flexibility to retain the status quo.

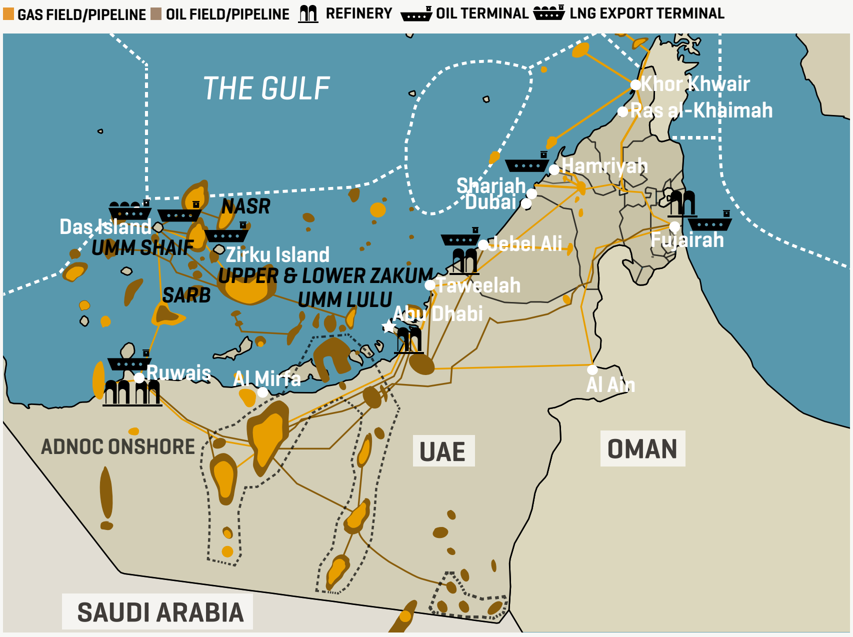
As light/medium differentials have weakened, IFAD Murban front month prices have dropped close to parity with regional medium-sour benchmark DME Oman in recent days. The M1 (front month v front month) differential has slumped this month, and on 15 November, IFAD Murban settled at a discount to DME Oman of $0.04/B (see chart 3). Likewise, IFAD Murban's premium to ICE Dubai futures has also slumped in recent days.

"The market for January-loading Murban has been weakening, tracking the slide in gasoil cracks in Asia," says Ahmed Mehdi, analyst at Renaissance Energy Advisors (REA). "Earlier this month, Totsa- an equity holder of Murban - declared the grade in the Dubai window, the first time since Q2 this year."

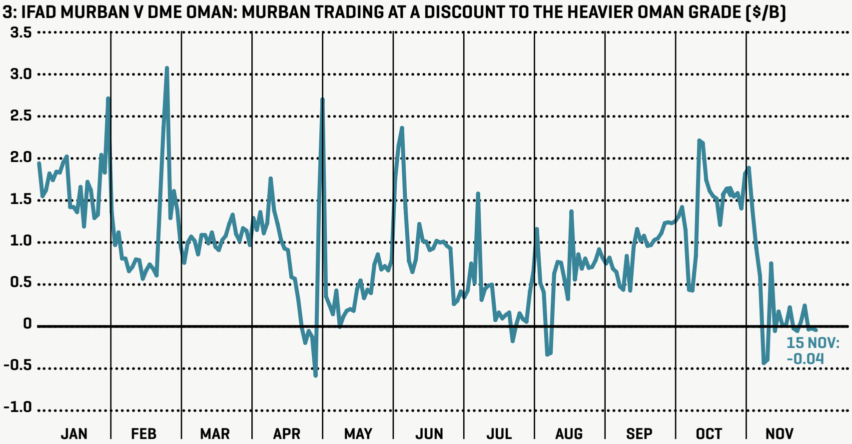
UPPER ZAKUM: BIG IN CHINA

Upper Zakum exports from Zirku Island have been averaging 939,000 b/d in 2023 according to Kpler: if maintained for the remainder of the year this will be

ADNOC KEY OIL AND GAS INFRASTRUCTURE



3: IFAD MURBAN V DME OMAN: MURBAN TRADING AT A DISCOUNT TO THE HEAVIER OMAN GRADE ($/B)



SOURCE: DME, ICE, MEES.

an annual record. Production is all from the Upper Zakum field, which is developed by Adnoc (60%), ExxonMobil (28%) and Inpex (12%). Production capacity at the concession is around 1mn b/d.

Volumes of Upper Zakum have increasingly been exported to China since 2020, with record volumes of 604,000 b/d so far this year equivalent to two thirds of the total. The biggest single destination according to Kpler data has been the 800,000 b/d Zhejiang Petroleum and Chemical (ZPC) refinery, which has been taking more than 100,000 b/d this year. But with Saudi Aramco this summer tying up an agreement to supply 480,000 b/d to ZPC (MEES, 28 July), volumes are set to be displaced.

In contrast to this, Murban is not especially popular with Chinese refiners. Any swapping out of Murban for Upper Zakum at Ruwais would therefore point to a reduction in Emirati crude exports to China.

Ultimately, if Adnoc is to truly capitalize on the flexibility afforded by the CFP then it makes sense to not have too high a proportion of output locked into term contracts. There is also the issue of the potential launch of an Upper Zakum futures contract on the IFAD exchange.

Originally planned to be launched in the middle of 2023 (MEES, 10 March), there is now little clarity on when, or if, it will go ahead amid speculation that Adnoc is concerned over the prospect of losing control of pricing the grade. If the contract is to ultimately go ahead, then a prerequisite for success would be strong liquidity and therefore not having too much tied up in term agreements.

The CFP means that domestic consumption, and therefore availability for export, of Adnoc's key grades could become increasingly uncertain as refinery throughputs are adjusted according to market dynamics. However, Adnoc's Fujairah Underground Storage project will enable the firm to smooth out the impact of this on export availability. The $1.2bn project for the development of three caverns each with capacity to hold 14mn barrels of crude (42mn barrels total), will enable Adnoc to maintain stable export availability for Upper Zakum and Murban regardless of domestic refinery requirements. MEES understands the construction work has essentially been completed and that the caverns will be ready to receive crude oil deliveries in the near future.

Saudi Seeks Prequalification For 3.7GW Of New Solar Projects

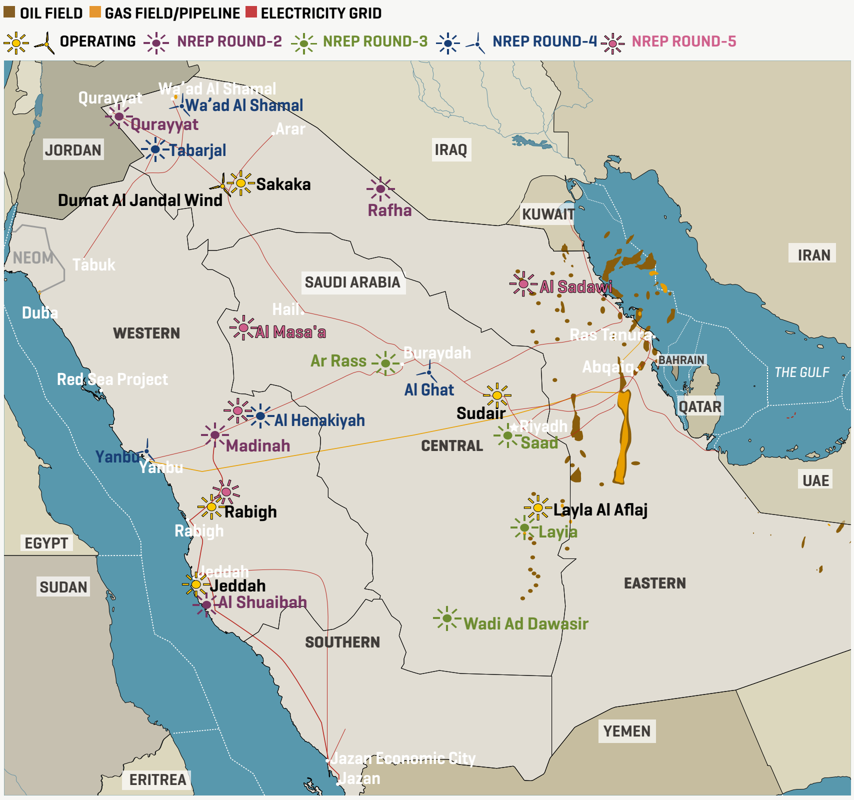
Saudi Arabia's ambitious 2030 renewables target requires an expanding pipeline of projects. Having signed contracts for solar projects under the fourth round of its renewables program, the kingdom has now opened the process for the fifth.

Saudi Arabia has kickstarted the fifth round of its National Renewable Energy Program (NREP), which will add 3.7GW of renewable power capacity. The process is being overseen by the Saudi Power Procurement Company (SPPC), which is responsible for the pre-development, tendering, and subsequent offtake of electricity from the projects. SPPC says that to-date, it has awarded more than 12.6GW of renewable energy capacity under NREP.

The kingdom has ambitious goals to displace liquids from its power generation sector, targeting a 50:50 mix of renewables and gas by 2030 and has made sizeable recent gains on both accounts. MEES understands that Saudi operational renewables capacity now stands at 2.8GW, which is equivalent to 3% of total installed capacity of around 91GW.

The 13 November announcement from SPPC that it has issued request for qualification (RFQ) for NREP Round 5 comes just a week after it signed power purchase agreements (PPA) for 1.5GW of solar power (MEES, 10 November). The strong pipeline of projects under development means that Saudi Arabia's renewable energy capacity should increase rapidly in the near-future.

SAUDI ARABIA RENEWABLE ENERGY PROJECTS



RENEWABLES ENTER ROUND 5

NREP Round 5 consists of four solar PV plants of varying scale. The largest is the 2GW Al Sadawi plant in Eastern province, which upon completion will join the under-development Ar Rass 2 facility as the largest solar plant in the kingdom. Al Sadawi is located in Saudi Arabia's north east and is around 100km from the Kuwait border (see map).

Next up will be the 1GW Al Masa'a facility in Hail province, to the west of Riyadh. As with Al Sadawi, the plant will be developed in an isolated area of the kingdom, and is not located near any existing renewable energy projects.

The other two components of NREP Round 5 are located near existing solar projects, and are smaller than Al Sadawi and Al Masa'a. The 400MW Al Henakiyah 2 plant in Medina province will be next to the planned 1.1GW Al Henakiyah plant, for which a consortium of Masdar, EDF Renewables and local firm Nesma Company signed a power purchase agreement (PPA) with SPPC last week. The consortium had submitted the lowest levelized cost of electricity (LCOE) of US¢1.68/kWh for the project (MEES, 8 September), which is due to be brought online in 2025.

Likewise, the 300MW Rabigh 2 solar plant in Medina province will be located near the existing 300MW Rabigh solar plant, which was connected to the grid in April. The now-operational Rabigh plant was developed by Japan's Marubeni and local partner Al Jomaih under a 2021 award as part of the second phase of the NREP (MEES, 28 April).

Despite opening Round 5, SPPC still has 1.8GW of wind-power projects from NREP Round 4 unawarded.

With SPPC having awarded more than 12.6GW of renewable energy capacity through NREP, capacity is set to grow sharply in the coming years. These projects are due online by end-2026 (MEES, 26 May), while the smaller NREP Round 5 projects could also conceivably be brought online by then.

This still leaves Saudi Arabia with a lot of work if it is to achieve its 2030 target of 58.7GW installed renewables – 42.7GW from solar and 16GW from wind. 70% of the total (41GW) is to be developed by sovereign wealth fund PIF's Badeel subsidiary alongside private sector champion Acwa Power through direct awards, with the remaining 30% (17.7GW) awarded through competitive licensing rounds.

Despite Acwa committing to a huge investment program through NREP's PIF-track, the firm continues to pick up awards through the tendering process and there is a good chance that it will be in the running for some of the Round 5 works. ◆◆

ExxonMobil Finalizes West Qurna-1 Exit As PetroChina Assumes Operatorship

ExxonMobil has finally reached the exit from Iraq after finalizing a deal to sell its remaining 22.7% stake at West Qurna-1 to Basrah Oil Company. PetroChina will take over as operator, refocusing attention on China's expanding footprint in Iraq.

It's a wrap for ExxonMobil's fourteen-year Iraq foray which began in 2009 when it signed a technical service contract (TSC) for the West Qurna-1 (WQ-1) oilfield in Basra province. A contentious two-year exit is now drawing to its conclusion (MEES, 23 April 2021), with the US giant finally inking a deal to sell its remaining 22.7% WQ-1 holding to state firm Basrah Oil Company (BOC).

An Exxon spokesperson confirms to MEES that "certain agreements" have been signed with BOC for the sale of the stake at the 500,000 b/d-capacity field. The transfer "is expected to occur by end of year," they add, with BOC to pay $350mn according to local media.

This follows a sign-off by Iraq's cabinet in early September on a final settlement "to resolve outstanding contentious issues arising from the service contract for the West-Qurna field." However, this settlement excluded tax disputes with the major (MEES, 8 September).

TAX DISPUTE: ARBITRATION

These issues remain unresolved, but in order not to delay its exit Exxon says that "As part of the settlement agreement, ExxonMobil Iraq Limited and the Government of Iraq agreed to refer a matter regarding US expatriate benefits to arbitration for final resolution."

Exxon in February managed to reduce its stake from the initial 32.7% with the sale of 10% to Indonesian state firm Pertamina (MEES, 17 February). Once the BOC deal concludes, WQ-1 shareholding will be PetroChina 32.7%, BOC 22.7%, Pertamina 20%, Japan's Itochu 19.6% and Iraq's state Oil Exploration Co. 5%. The partners have pledged to increase capacity to 800,000 b/d by 2028.

Exxon's time in Iraq has been tumultuous, with the firm angering Baghdad when it signed up to six blocks in the Kurdistan Region in 2011. That gamble ultimately failed, with Exxon quitting its last Kurdistan asset in 2022 without producing a barrel (MEES, 29 April 2022). Plans for a $53bn South Iraq Integrated Project (SIIP) entailing water injection, midstream and export infrastructure development, natural gas capture, and oil field development fell apart after years of on-off talks.

Even Exxon's departure has been acrimonious. In 2021, Exxon filed for arbitration at the Paris-based International Chamber of Commerce after Iraq blocked its decision to sell the WQ-1 stake to Chinese firms (MEES, 30 July 2021). Exxon later suspended the arbitration case to allow negotiations.

As with then, the decision to use arbitration for outstanding issues doesn't mean that a negotiated settlement cannot still be reached. The agreed $350mn value of the sale is thought to be based on an estimate of expected remuneration to Exxon between the sale completion and the end of the 20-year TSC in 2029. As this renumeration would be taxable at a statutory 35%, Baghdad's apparent calculus is that the sum paid should be reduced by 35% (around $122.5mn) to take this into account.

Exxon may see tax regimes differently, and the disagreement revolves around "US expatriate benefits" as highlighted in its statement. An informed source tells MEES that this is in reference to "about $100mn" in taxes on personnel not paid since 2010, which has been a "major sticking point," and that Exxon has no objections when it comes to taxing the BOC transaction. "I think by this point, they just want to be able to exit," they add.

The funds were set aside by the firm to prevent double taxation on its employees via the US tax code. Baghdad insists on accessing the funds. It's unclear if they were acquired through cost reimbursement or not. In recent years, Baghdad had begun a clamp-down on what it sees as costly IOC offshore offices, mostly based in Dubai, where staff associated with Iraq operations have been paid handsomely with few Iraqi tax liabilities.

PETROCHINA TAKEOVER: 1H 2024

Exxon confirms that PetroChina will become WQ-1's operator following its departure. This comes despite BOC CEO Bassim Abdulkareem saying in late-April that his firm would become operator.

Exxon says that it is "working with our co-venturers and contractors to ensure an orderly and safe transition to PetroChina, which is expected to be completed in the first half of 2024." The Chinese firm "will assume responsibility for overseeing daily operations, contracting activities and approvals," it adds.

BOC's Deputy CEO Hasan Mohammed tells Reuters that the decision to hand over to PetroChina was the "best option." This is a quiet U-turn: in late-2021 BOC publicly opposed a handover to a consortium led by US oilfield services company Halliburton, as favored by former Oil Minister Ihsan Ismaael, arguing that BOC would operate WQ-1 itself "in support of the national effort" (MEES, 10 December 2021).

IRAQ'S MAJOR SOUTHERN OIL FIELDS

GAS FIELD/PIPELINE · OIL FIELD/PIPELINE · GAS PLANT

NOT THE RIGHT SIGNAL?

Having lost western majors like Occidental and Shell, the latter selling its stake at WQ-1 and exiting Majnoon in 2018, Exxon's departure is a big blow for Iraq. Baghdad has at least managed to sign up TotalEnergies to a wide-ranging $27bn megaproject – with a large degree of overlap with Exxon's abortive SIIP – with both sides citing improved commercial terms (MEES, 14 July).

PetroChina's operatorship of WQ-1 again puts in focus the expanding footprint of Chinese companies, some of which are much smaller and less capable than PetroChina. The 2018 licensing round, ratified in February, saw awards to independent Chinese minnows like United Energy Group (UEG) and Geo-Jade (MEES, 24 February).

There might be more to come. Earlier this month, Shanghai-listed Zhongman Petroleum (ZPEC), which operates as a drilling contractor in Iraq, said it had been shortlisted by Oil Ministry's Petroleum Contracts and Licensing Directorate for the upcoming Fifth 'plus' annex and Sixth licensing rounds. With western majors showing little interest in Iraq, Chinese firms could be big players in the upcoming rounds. ◆◆

NEWS IN BRIEF

UAE INAUGURATES REGION'S LARGEST SOLAR PLANT

The 2GW Al Dhafra solar PV plant in Abu Dhabi was inaugurated on 16 November, just two weeks before the UAE hosts the Cop28 climate talks. Al Dhafra is the largest operational solar PV plant in the region, and brings total Emirati renewables capacity up to 5.91GW – level with Israel as the regional leader (see box p9) – with more under development.

Al Dhafra was developed by Abu Dhabi firms Taqa (40%) and Masdar (20%) alongside France's EDF Renewables (20%) and China's Jinko Power (20%). The plant already made a minor contribution to the grid in 2022, and this will have increased ahead of the inauguration (MEES, 17 February).

The Deputy Ruler of Abu Dhabi Sheikh Hazza Bin Zayed Al Nahyan, said of the inauguration that "As the UAE prepares to host Cop28, this pioneering project reflects the country's ongoing commitment to raising its share of clean energy."

US FLEET ARRIVES IN GULF

The United States Carrier Strike Group 2, led by the aircraft carrier USS Dwight D Eisenhower, arrived off the coast of Oman on 13 November. Originally deployed to join the USS Gerald Ford in the eastern Mediterranean in response to the Israel-Gaza war, it was redirected on 22 October to the Arabian Peninsula.

The vessels could be continuing to Bahrain where the US Fifth Fleet is based. By moving into the US Central Command (CENTCOM) area it is backing the first priority of the regional force's posture: deter Iran.

Armed groups in Syria and Iraq have conducted at least 55 attacks on US forces and installations in the region since October 7. In response CENTCOM forces have retaliated with three sets of airstrikes in Syria in the past three weeks.

The US directly blames Iran, calling the attacks "continued provocations by Iran's Islamic Revolutionary Guard Corps and their affiliated groups," a claim Iran denies. Yemen's Iran-linked Houthis and the US have also downed each other's drones in the Red Sea area, with the Houthis targeting Israel.

IRAQ RATIFIES TURKMEN GAS DEAL

Iraq on 14 November ratified a 10 June MoU (MEES, 25 August) signed between the country's Ministry of Electricity and Turkmenistan's state-owned Türkmengaz in another step towards importing gas from the Caspian nation via a swap deal with neighboring Iran. In an 8 November statement following a visit by Electricity Minister Ziad Fadhel to Ashgabat, the Turkmen Ministry of Foreign Affairs said that a protocol was also signed for a 9bcm/y (870mn cfd) five-year swap.

While Iraq will seek to portray this as reducing its dependence on Iranian gas, in reality the deal will entail Turkmenistan gas supplying northern Iran, freeing up an equivalent amount of Iranian gas to be piped to Iraq. Iran also supplies electricity to Iraq, and on 14 November the US renewed a 120-day waiver enabling Iraq to pay for this power.

IRAQ: NEW KHOR AL-ZUBAIR OIL BERTH

Iraq inaugurated a 340 meter-long oil products berth at Khor al-Zubair port on 13 November. The $100mn project was delivered in four years by Mitsubishi, and financed as part of a $376mn expansion package provided through loans from the Japan International Cooperation Agency (JICA).

The berth will allow both imports and exports, with 10,000-60,000DWT vessels able to dock. Iraq exports its high sulfur straight run fuel oil (SRFO) and naphtha on small vessels from Khor al-Zubair and Um Qasr South ports, which then load cargoes onto larger tankers within the country's territorial waters in the Gulf. The Khor al-Zubair lightering area is located west of the Basrah Oil Terminal. Last year, three VLCCs and an MR tanker were contracted from Safeen Group, the marine services arm of the Abu Dhabi Ports Group, to shuttle the cargos (MEES, 14 October 2022).

ISRAEL POWER PLANT SALE AGREED

At the second time of asking, Israel's state utility IEC has agreed to the IS9bn ($2.4bn) sale of the country's largest gas fired power plant, the 1.68GW Eshkol plant in Ashdod, to a private consortium led by Dalia Power. This follows the cancellation of an initial tender award in July after Dalia was unable to raise the IS12.4bn ($3.5bn) that it bid (MEES, 21 July).

This prompted IEC to relaunch the tender, which only garnered the solitary bid from Dalia. The Eshkol plant is the fourth power plant sold off by IEC as part of attempts to diversify the country's power suppliers. The sale of a fifth plant, the 428MW Reading in Tel Aviv, has been indefinitely delayed and is currently pending a government decision .

MAURITANIA: SHELL WELL FLOPS

Shell has plugged and abandoned its PannaCotta-1 deepwater exploration well on block C10 off Mauritania after drilling encountered only "traces of hydrocarbons," a Shell spokesperson tells MEES.

"We will now analyze the data gathered before deciding on next steps," they add. With Shell having declined to take up an option on a contract extension, the Noble Voyager drillship is now halfway across the Atlantic.

Spudded in September, the well 70km offshore in 600ms water depth marked Mauritania's first exploration well in four years (MEES, 22 September). Shell (50%op) is partnered by QatarEnergy (40%) and state firm SMH (10%). Having entered Mauritania when it signed up to explore C10 in 2018, Shell signed up for a second permit, C2, in February (MEES, 7 April).

CHINA: NEW OIL DEMAND RECORD

The IEA's latest monthly oil market report, released 14 November (see p7), revises up China's 2023 demand by 50,000 b/d to 16.44mn b/d and 2024 by 90,000 b/d for 17.08mn b/d, both new records. The IEA has Chinese oil demand hitting a fourth straight monthly record of 17.1mn b/d for September, in line with official Chinese stats that show record refinery runs of 15.53mn b/d for the month.

Latest official stats show runs easing to 15.10mn b/d for October. Whilst this represents a 43,000 b/d fall from September, it nevertheless leaves the last three months as the three highest on record. Runs are up 11% year-on-year at 14.91mn b/d for 10M 2023, demand up 12% at 16.33mn b/d and crude imports up 14% at 11.41mn b/d (MEES, 10 November), with all three metrics on track to smash previous annual records.

The record oil figures seemingly contradict other recent indicators showing a faltering Chinese economy with industrial output down again for October. The IEA cites China's booming petchems sector as the key source of demand growth.

Crude production was 4.09mn b/d for October, somewhat below the 4.19mn b/d 10M 2023 average. This is nevertheless up 2% year-on-year and on track for the highest annual figure since 2015.

October gas output of 19.0bcm was the highest figure since March for a 10M 2023 total of 189.5bcm, up 6% year-on-year. Implied gas demand (output plus imports) was 324.4bcm for 10M, up 8% year-on-year. As such both output and consumption are set to smash the previous annual record highs (of 218bcm and 368bcm respectively) set in 2022.

Gas imports were up 11% year-on-year at 98.63mn tons (135bcm) for 10M 2023 whilst those of LNG were up 12% at 56.9mn tons. However, the rise in both domestic output and direct overland pipeline imports from Russia has capped demand for LNG with volumes for this year set to come in well below the annual record of 79.9mn tons set in 2021 (MEES, 10 November).

CRUDE OFFICIAL SELLING PRICES ($/B)

	Oct23	Nov23	Dec23
KUWAIT			
to Asia (FOB, vs Oman/Dubai)			
Kuwait Export Blend (31°)	+3.05	+3.05	+2.85
vs Saudi Arab Medium	-0.40	-0.40	-0.50
Kuwait Super Light (48°)	+2.45	+2.95	+3.35
Khafji (28.5°)	+1.70	+1.70	+2.00
Hout (33°)	+3.52	+3.71	+3.66
Kuwait Export Blend to other destinations:			
to Med (FOB, vs Dated Brent)	+1.10	+2.50	+0.10
to N W Europe (FOB, vs Dated Brent)	+2.25	+3.25	+0.45
FOB Sidi Kerir (vs Dated Brent)	+1.40	+2.80	+0.40
to US (FOB, vs ASCI)	+8.15	+8.15	+8.15
delivered US Gulf (vs ASCI)	+9.45	+9.45	+9.45

SAUDI ARABIA KEY OIL DATA: SEPTEMBER SEES COUNTER-SEASONAL OIL BURN RISE

SELECTED DATA

	Sep23	vs Aug23	%	Aug23	Jul23	3Q23	vs 2Q23	%	vs 3Q22	%	2Q23	9M23	vs 9M22	%	9M22	2021	2022
Crude Output	**8,975**	+57	+0.6	**8,918**	**9,013**	**8,969**	-1157	-11.4	-2000	-18.2	**10,125**	**9,850**	-728	-6.9	**10,578**	**9,117**	**10,589**
Crude Stocks (mn bl)	**146.2**	-4.6	-3.1	**150.9**	**146.7**	**146.2**	-3.4	-2.3	+1.5	+1.0	**149.7**	**146.2**	+1.5	+1.0	**144.8**	**134.7**	**148.6**
crude stock change (mn bl)	-4.6	-8.8	-211.6	+4.2	-3.0	-3.4	-5.7	-251.6	-6.4	-217.7	+2.3	-2.3	-12.4	-123.1	+10.1	-5.4	+13.9
('000 b/d)	-154.7	-289	-215.4	+134.1	-95.5	-37.5	-62	-250.0	-69	-217.7	+25.0	-8.5	-46	-123.1	+37.0	-14.7	+38.1
Crude Supply to Market^	**9,226**	+386	+4.4	**8,840**	**9,164**	**9,076**	-1023	-10.1	-1860	-17.0	**10,100**	**9,879**	-661	-6.3	**10,540**	**9,132**	**10,549**
Crude Exports	**5,754**	+170	+3.0	**5,584**	**6,012**	**5,783**	-1233	-17.6	-1785	-23.6	**7,016**	**6,782**	-538	-7.3	**7,319**	**6,222**	**7,364**
% of crude output	64.1	+1.5		62.6	66.7	64.5	-4.8		-4.5		69.3	68.8	-0.3		69.2	68.2	69.5
Direct Burn Crude	**606**	-120	-16.5	**726**	**592**	**641**	+171	+36.5	+26	+4.2	**470**	**481**	-24	-4.7	**505**	**437**	**486**
% of crude output	6.8	-1.4		8.1	6.6	7.2	+2.5		+1.5		4.6	4.9	+0.1		4.8	4.8	4.6
Refinery Crude Intake	**2,866**	+336	+13.3	**2,530**	**2,559**	**2,652**	+38	+1.4	-101	-3.7	**2,614**	**2,617**	-100	-3.7	**2,717**	**2,474**	**2,701**
% of crude output	31.9	+3.6		28.4	28.4	29.6	+3.7		+4.5		25.8	26.6	+0.9		25.7	27.1	25.5
Run rate (% of capacity)	87.3	+10.2		77.0	77.9	80.7	+1.1		-3.1		79.6	79.7	-3.0		82.7	75.3	82.2
Refinery Output	**2,879**	+309	+12.0	**2,570**	**2,610**	**2,686**	+54	+2.1	-68	-2.5	**2,632**	**2,634**	-173	-6.1	**2,807**	**2,547**	**2,769**
LPG	31	-4	-11.4	35	26	31	+3	+9.5	-4	-11.5	28	28	-19	-40.5	47	39	46
Naphtha	7	-13	-65.0	20	25	17	+4	+33.3	-8	-32.5	13	29	-68	-70.1	97	174	88
Gasoline	702	+11	+1.6	691	663	685	+34	+5.3	+46	+7.1	651	642	+7	+1.2	634	544	631
Jet-Kero	174	+15	+9.4	159	190	174	+12	+7.4	+31	+21.3	162	162	+5	+2.9	158	126	153
Diesel/Gasoil	1,195	+17	+1.4	1,178	1,046	1,140	-3	-0.3	-69	-5.7	1,143	1,128	-69	-5.8	1,197	1,114	1,209
Fuel Oil	486	+28	+6.1	458	427	457	+19	+4.3	-7	-1.4	438	447	-47	-9.5	493	422	482
other products	284	+255	+879.3	29	233	182	-14	-7.3	-56	-23.6	196	200	+19	+10.5	181	128	161
Oil Product stocks (mn bl)	**89.1**	+5.1	+6.0	**84.1**	**90.0**	**89.1**	+3.8	+4.4	-2.9	-3.1	**85.4**	**89.1**	-2.9	-3.1	**92.0**	**98.8**	**86.9**
Total Oil Stocks (mn bl)	**235.4**	+0.4	+0.2	**235.0**	**236.8**	**235.4**	+0.3	+0.1	-1.4	-0.6	**235.1**	**235.4**	-1.4	-0.6	**236.8**	**233.4**	**235.5**
oil stock change (mn bl)	+0.4	+2.2	-124.3	-1.8	+1.7	+0.3	+0.4	-523.1	-1.8	-84.3	-0.1	-0.1	-3.4	-102.6	+3.3	-1.2	+2.0
('000 b/d)	+14.6	+72.7	-125.1	-58.1	+54.6	+3.6	+4.4	-518.5	-19.3	-84.3	-0.9	-0.3	-12.6	-102.6	+12.3	-3.3	+5.6
Refined Products Consumption	**2,168**	+120	+5.9	**2,048**	**1,995**	**2,070**	+85	+4.3	+61	+3.1	**1,985**	**1,977**	+115	+6.2	**1,862**	**1,729**	**1,886**
LPG*	51	-1	-1.9	52	50	51	-2	-3.8	+6	+12.5	53	54	+6	+11.8	48	47	50
Gasoline	517	+16	+3.2	501	488	502	-6	-1.2	-5	-0.9	508	505	+8	+1.6	497	480	500
Jet-Kero	96	-2	-2.0	98	111	102	+20	+25.0	+38	+59.7	81	99	+29	+40.8	70	47	72
Diesel/Gasoil	634	-5	-0.8	639	618	630	+42	+7.1	-2	-0.3	589	602	+36	+6.3	566	503	574
Fuel Oil	791	+122	+18.2	669	657	706	+18	+2.6	+33	+4.9	688	644	+44	+7.4	600	567	608
Total Oil Burn**	**1,397**	+2	+0.1	**1,395**	**1,249**	**1,347**	+189	+16.3	+58	+4.5	**1,158**	**1125**	+21	+1.9	**1104**	**1,004**	**1,093**
% of crude output	15.6	-0.1		15.6	13.9	15.0	+3.6	+31.3	+3.3	+27.8	11.4	11.4	+1.0		10.4	11.0	10.3
Refined Products Exports*	**1,309**	-17	-1.3	**1,326**	**1,144**	**1,260**	-163	-11.4	-166	-11.6	**1,422**	**1,363**	-134	-9.0	**1,497**	**1,343**	**1,470**
% oil exports	18.5	-0.7		19.2	16.0	17.9	+1.0		+2.0		16.9	16.7	-0.2		17.0	17.8	16.6
Naphtha	110	+8	+7.8	102	73	95	-6	-5.6	-41	-30.3	101	111	-33	-23.1	145	169	145
Gasoline	321	+42	+15.1	279	299	300	+7	+2.5	+32	+12.1	292	279	+8	+2.9	271	182	271
Jet-Kero	77	-57	-42.5	134	107	106	+36	+52.2	+6	+6.0	70	88	-12	-11.8	100	77	97
Diesel/Gasoil	542	-45	-7.7	587	405	511	-210	-29.1	-151	-22.8	722	618	-58	-8.6	676	682	671
Fuel Oil	193	+52	+36.9	141	165	166	+7	+4.4	-17	-9.1	159	190	-28	-12.9	218	156	204
Crude & Products Exports*	**7,063**	+153	+2.2	**6,910**	**7,156**	**7,043**	-1395	-16.5	-1951	-21.7	**8,438**	**8,145**	-672	-7.6	**8,816**	**7,565**	**8,833**
% of crude output	78.7	+1.2		77.5	79.4	78.5	-4.8	-5.8	-3.5	-4.2	83.3	82.7	-0.7		83.3	83.0	83.4
Oil Products Imports	**548**	+212	+63.1	**336**	**429**	**438**	-100	-18.5	+22	+5.4	**537**	**447**	+80	+21.7	**367**	**361**	**360**
Gasoline	100	+66	+194.1	34	57	64	-10	-14.0	-36	-36.3	74	78	-13	-14.3	91	83	92
Diesel/Gasoil	62	-11	-15.1	73	80	72	-98	-57.7	+5	+7.0	169	104	+27	+35.0	77	91	64
Fuel Oil	365	+145	+65.9	220	253	279	-1	-0.5	+44	+18.9	281	249	+64	+34.4	185	177	191
Total Net Crude & Products Exports*	**6,419**	-99	-1.5	**6,518**	**6,672**	**6,536**	-1,365	-17.3	-2,043	-23.8	**7,901**	**7,674**	-775	-9.2	**8,449**	**7,204**	**8,473**
NET PRODUCTS EXPORTS*	**761**	-229	-23.1	**990**	**715**	**822**	-63	-7.1	-188	-18.6	**885**	**916**	-214	-18.9	**1,130**	**982**	**1,110**
Naphtha	89	-4	-4.3	93	34	72	-19	-20.6	-57	-44.3	91	98	-37	-27.5	135	163	137
Gasoline	221	-24	-9.8	245	242	236	+18	+8.1	+69	+41.0	218	201	+21	+11.5	180	99	179
Jet-Kero	77	-57	-42.5	134	107	106	+40	+59.8	+12	+13.2	66	85	-10	-10.7	95	73	92
Diesel	480	-34	-6.6	514	325	440	-113	-20.4	-156	-26.1	552	514	-85	-14.3	599	592	607
Fuel Oil	-172	-93	+117.7	-79	-88	-113	+8	-6.9	-61	+117.3	-121	-59	-92	-279.4	33	-21	13
Net Products %	11.9	-3.3		15.2	10.7	12.6	+1.4		+0.8		11.2	13.1	-0.3		13.4	13.6	13.1

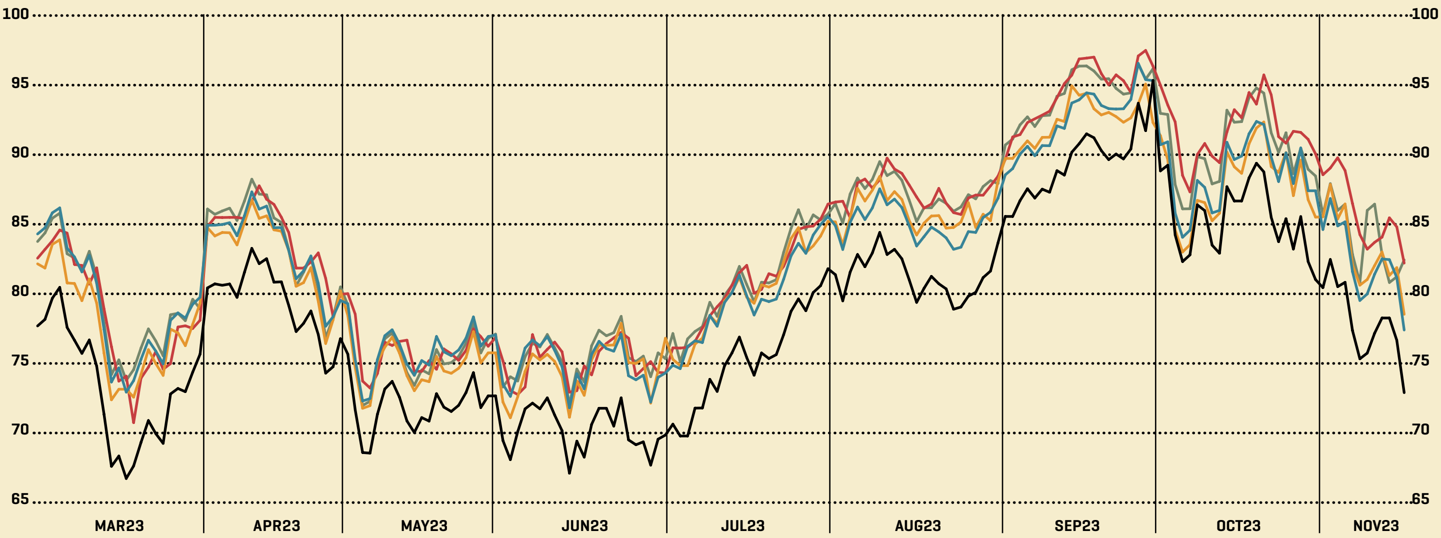
*REFINED PRODUCTS ONLY. EXCLUDES FIELD LPG (AROUND 850,000 B/D OUTPUT), OTHER NGLs AND CONDENSATE. **PRESUMES ALL DOMESTICALLY-CONSUMED FUEL OIL IS BURNT IN POWER PLANTS. ^JODI CRUDE IMPORTS INCLUDE SMALL VOLUMES EXPORTED ON BEHALF OF BAHRAIN SINCE JULY. SEE ANALYSIS P2. SOURCE: JODI, MEES.

SELECTED DATA

BENCHMARK CRUDE PRICES ($/B)

	16Nov	6-10Nov	30Oct-3Nov	Oct23	Sep23	Aug23	Q3 2023	Q2 2023	Q1 2023	2023 (>16Nov)	2022	2021	2020
WTI	72.90	77.29	81.35	85.47	89.46	81.32	82.15	73.52	76.11	78.11	94.37	68.09	39.49
ICE Brent	77.42	81.55	86.25	88.70	92.59	85.10	85.92	77.73	82.16	82.63	99.02	70.97	43.21
ICE Murban	78.74	82.76	87.41	90.57	94.29	87.19	87.55	78.00	81.65	83.26	98.84	72.92	na
DME Oman	78.75	82.70	86.3	88.01	92.38	85.91	86.21	77.16	79.82	81.87	94.42	69.00	43.24
OPEC Basket	82.22	85.31	89.71	91.77	94.68	87.33	87.57	78.06	80.57	83.20	100.01	69.82	41.62
JCC	na	na	na	na	86.44	82.04	82.98	83.93	87.07	na	102.70	69.11	45.73

AVERAGE SETTLEMENT PRICES FOR PERIOD IN QUESTION.



ASIAN LNG PRICES: SPOT VALUES SPIKE THEN EASE AS DEMAND REMAINS SUBDUED

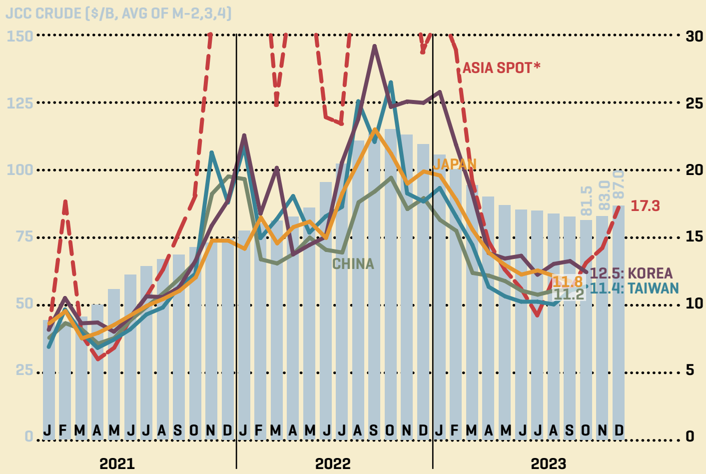
*Average spot LNG prices for East Asian delivery rose to a nine-month high of just over $17/mn BTU for December-delivery on the back of Middle East instability, according to an average of Reuters assessments. However, prices appear to have eased in recent days as the restart of Israel's Tamar gas field holds out the hope of a resumption of Egyptian LNG exports (see p8).

*Weighing on prices are weak underlying demand fundamentals. Of the two largest global importers, Chinese demand has been capped by a combination of weak industrial performance and growing overland imports from Russia and domestic output (see p18). Japan's demand for incremental gas (all of which comes from LNG) has been crimped by the restart of nuclear power plants (MEES, 10 November). Healthy inventories in both Japan and number three importer South Korea have also capped incremental demand.

*Latest data from Japanese state body Jogmec shows that the country's importers paid an average of $14.7/mn BTU for spot cargoes contracted in October – roughly analogous to November-arrival cargoes – up $2/mn BTU from the average price two months earlier.

*With spot buying subdued, the latest comprehensive import data, for October, shows little sign of rising prices: Taiwan's average October price of $11.4/mn BTU was up 30cts on September for a six-month high but Korea's $12.5/mn BTU was a three-month low (see chart).

ASIAN LNG PRICES: SPOT PRICES SPIKE FOR DECEMBER ($/MN BTU)



ALL PRICES ARE FOR MONTH OF DELIVERY. *AVERAGE OF REUTERS ASSESSMENTS. SOURCE: NATIONAL IMPORT STATISTICS, REUTERS, MEES.