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EDITORIAL: Sanctions on Russia and concerns over US shale productivity may alter the outlook for a global upstream spending growth cycle

Capex conundrums

The economic and sanctions fallout of Russia's invasion of Ukraine continues to redraw the global energy map, not least as oil trade adjusts to the EU embargo on Russian seaborne crude imports put in place from 5 December. This seismic shift is already rebalancing the oil market roles of the world's three largest producers, the US, Russia and Saudi Arabia. UK bank Barclays' 2023 Global E&P Spending Survey forecasts a 13pc rise in global upstream capital expenditure (capex) this year, as the energy crisis exacerbated by the war underpins an upstream investment growth cycle it expects to last for at least the next three to five years. But diverging pressures on spending by the three leading producers point to a longer-term change in the balance of market power between them.

Total US crude exports averaged 3.6mn b/d in 2022, the highest on record since the US Congress first lifted decades-old restrictions on exporting crude in December 2015. They are poised to hit new record highs this year as US shale output expands and European countries seek to diversify their imports. And Russia, forced out of its formerly core market and heavily discounting supply to secure new buyers in the key Asia-Pacific markets of India and China, finds itself in intensifying competition with its fellow Opec+ leader Saudi Arabia.

The changing market roles of this oil triumvirate have defined key structural shifts in production policy and investment in recent years. The rise of US shale oil was critical in leading Saudi Arabia and Russia to form the Opec+ group in 2016. It was the brief Saudi-Russian war for market share at the onset of the Covid-induced oil demand slump in 2020 that finally hobbled US shale oil, and forced the creation of a far more effective Opec+ to manage the largest oil production cut in history. The uncertainty that now faces Russian oil production and exports, exacerbated by the G7's attempt to impose a price cap on Russian oil sales, appears to have done nothing to undermine the Opec+ ties between Riyadh and Moscow.

Overall US output in 2023 is forecast to surpass the record 12.32mn b/d posted in 2019, and Permian crude output may hit a record 5.6mn b/d this month. But Washington's call on US shale producers to increase investment to boost short-term supply is likely to keep falling on deaf ears. Barclays forecasts a conservative 17pc rise in US onshore capex this year, after a 44pc increase last year was largely swallowed up by cost inflation. Permian operators see that inflation as an added threat to their focus on maximising shareholder returns, and expect declining productivity in the basin to challenge long-term output growth.

Russian oil companies pledge to keep up capital spending, but short-term uncertainty over exports and production is likely to deepen in the longer term, as the loss of access to western technology makes Russia's upstream more capital intensive, and spending is diverted to build the infrastructure needed to tap new markets. Barclays and other capex forecasters assume an inevitable drop in Russia's upstream spending this year, while every other region sees spending rise.

But of the big three producers, only Saudi Arabia is forecast to increase investment this year by more than last, as it steps up drilling to expand crude capacity to 13mn b/d by 2027, alongside a huge gas investment drive. In an increasingly uncertain future for the world's leading oil producers, only Saudi Arabia appears able to commit to long-term outcomes.

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BRIEFING

US readies new focus on energy regulations

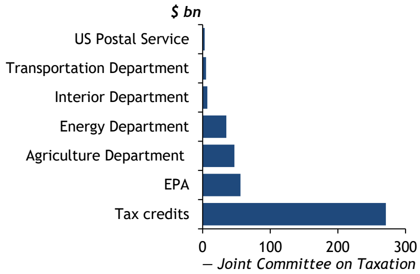
After legislating a shift in SPR policy last month, the administration is turning to regulation to advance this year's energy and climate goals, writes Chris Knight

US president Joe Biden will focus on climate regulations and doling out billions of dollars in new spending on clean energy this year, as the US Congress faces paralysis from internal divisions among Republicans.

The White House spent the last two years treading lightly on the regulatory front, given the risk that moving aggressively could cost Biden votes when Democrats held a razor-thin margin in Congress. But Democrats last year enacted their signature climate bill — the Inflation Reduction Act (IRA) — and see slim chances of advancing substantive legislation with Republicans now in control of the House of Representatives. Those political dynamics offer the Biden administration more leeway to advance regulations targeting climate change and energy, with a particular focus on completing work this year to offer enough time to fend off legal challenges before the 2024 elections.

The regulatory agenda includes a goal this year to complete inaugural methane emission limits for oil and gas facilities and to propose new climate regulations for power plants. The administration also intends to limit flaring by oil producers on federal land, propose new fuel economy standards and to more clearly consider climate change across the federal government.

IRA climate and energy funding



The White House could have even more influence over meeting its climate goals as it decides how the government will spend the $369bn in clean energy funding included in the IRA. The Environmental Protection Agency (EPA) under that law will decide how to award nearly $42bn on projects to reduce greenhouse gas emissions and conventional air pollution. The Treasury Department will write rules that will dictate which renewable energy projects, manufacturing investments, low-carbon fuels and electric vehicles should receive an estimated $271bn in tax credits over the next decade. And the Energy Department is set to award more than $16bn in new spending on clean hydrogen and carbon capture from an infrastructure law enacted in 2021.

Democrats have had their prior scepticism about the chances of negotiating major bipartisan legislation in the new Congress confirmed this week, as the new Republican majority in the House has been unable to unite to elect a speaker. This marks the first time in a century that a House speaker has not been elected on the first ballot, and could spell trouble for the Republicans' ability to pass legislation later this year to fund the government or raise an existing limit on US debt.

Biden says the speaker election stalemate is "a little embarrassing" and "not a good look" because it could raise questions about Washington's ability to get things done. While the impasse continues, Republicans cannot begin promised oversight work on issues such as climate policy and clean energy spending.

Regulators, mount up!

The EPA will be responsible for many of the climate-related regulations. It intends to roll out a plan in March to limit greenhouse gas emissions and conventional air pollutants from cars and trucks sold starting in model year 2027, according to a regulatory agenda the White House released this week. The following month, the EPA plans to release a proposed regulation to reduce CO_2 emissions from power plants, marking the first attempt to address the issue since the US Supreme Court weighed in on the agency's power plant climate authority last year.

In August, the EPA plans to finalise a rule that will require oil and gas facilities to cut methane emissions. And it is scheduled to begin to review — and potentially tighten — the stringency of national ambient air quality standards for ground-level ozone and particulate matter.

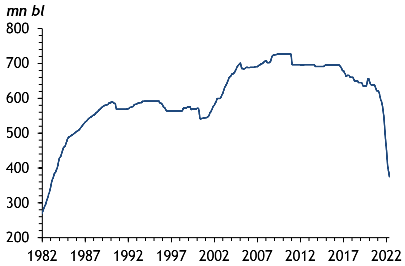
BRIEFING

At the Interior Department, the administration aims to finish by September new requirements for oil and gas facilities on federal land to reduce natural gas flaring. The White House is separately preparing to propose new standards for reviews under the National Environmental Policy Act, with a goal to incorporate a more exhaustive analysis of climate change in decisions such as whether to open more federal areas to oil and gas leasing.

Climate change is also set to be a focus at independent agencies led by Biden appointees. US financial regulator the SEC in April intends to finish requirements for publicly traded companies to disclose more information on climate-related risks. US energy regulator Ferc is trying to scrutinise climate change implications in the permitting of natural gas pipelines, although the agency's 2:2 split between Democrats and Republicans is likely to delay any changes.

Even regulations without an explicit climate focus are expected to have an effect on climate. The EPA is preparing concurrent work on regulations to require coal-fired power plants to reduce conventional air emissions, water pollution and combustion ash. Aligning those rules will require plant owners to decide whether to make all required upgrades at the same time.

US SPR inventory

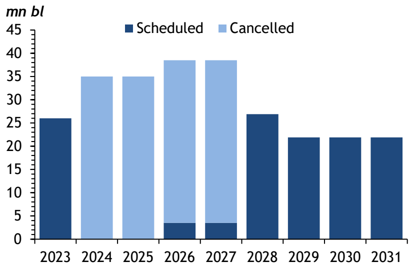


Being strategic

The Biden White House also intends to pursue a more flexible use of the Strategic Petroleum Reserve (SPR) to buy crude to refill the reserve when prices are near $70/bl, or potentially sell crude again if prices rise sharply, as it attempts to keep gasoline prices in check. The new policy, laid out by the administration, will kick off soon with a "pilot" purchase in February of up to 3mn bl of US produced crude that will be injected into the SPR's Big Hill storage site in Texas. The administration plans to buy more crude in the coming years to partly refill the SPR, which at 372mn bl is at over half capacity (*see graph*).

The plan to purchase crude to refill the SPR marks a shift from around a year ago, when Congress had committed through prior laws to sell more than 300mn bl of the 600mn bl of crude in the SPR at the time. That plan changed after Biden ordered the unprecedented emergency sale of 180mn bl of crude in response to the war in Ukraine. This proved a "good deal" for US taxpayers by bringing down fuel prices and selling crude at an average of $96/bl, administration officials say.

SPR mandatory sales by fiscal year



The White House's new plan aims to use the $17bn it earned from last year's sales to partially refill the SPR, while retaining the possibility of restarting emergency sales if required. A spending law passed at the end of 2022, while Democrats still held a majority in Congress, will support the policy. The law will divert some revenue from last year's emergency sales to cancel previous mandates to sell 140mn bl from the SPR in fiscal years 2024-27 (*see chart*). It would have made "no sense" to sell crude from the SPR at the same time it was being refilled, an energy department official told legislators last year. But a mandate requiring the US to sell an additional 26mn bl of SPR crude by 30 September is not affected by the law.

The pilot purchase of 3mn bl marks the first time the US will buy crude at a fixed price, rather than benchmark-based prices, an approach the administration says will give producers "assurances to make investments today". The White House plans to buy US produced crude when WTI prices are at or below $67-72/bl, either through immediate purchase or for future deliveries in 2024 and 2025.

Republicans criticised Biden's emergency crude sales as a political ploy to lower fuel prices before last year's mid-term elections. They plan to use their new majority in the House to pass a bill to block further drawdowns from the SPR, unless the White House offers a plan to increase oil and gas production on federal lands.

PRODUCTION POLICY

Opec+ staying vigilant as uncertainty persists

Uncertainty around both supply and demand is forcing the group to continue its 'wait-and-see' approach, writes Nader Itayim

The myriad uncertainties that made 2022 an extremely challenging year for oil markets look likely to continue to complicate the outlook for Opec+ in 2023.

The Opec+ producer group opted at its last ministerial meeting in December to roll over the nominal 2mn b/d cut to production targets that ministers agreed at the previous meeting in October. Delegates argued it was more prudent to take a 'wait-and-see' approach to production policy until there was better visibility about the months ahead, given that the market was facing a host of uncertainties, not least around the EU's then-looming Russian crude import embargo.

Going into this year, the situation is no clearer, with geopolitical and economic uncertainties continuing to complicate any attempts by the producer group to plan for the coming months. On the supply side of the equation, there is no more important issue than Russia, and the impact that the EU embargo on the import of Russian seaborne crude — and another on products due to come into effect on 5 February — will ultimately have on supplies.

That Russian supplies will be impacted appears almost a foregone conclusion among market watchers, but they differ over the extent to which they think supplies could be disrupted. For its part, Moscow has said it may have to cut output by 500,000-700,000 b/d in "some moments" in early 2023 because of the embargoes and the G7-led price cap. But the projections of disruption grow from there, with Opec saying last month it expects Russian oil output to drop by 850,000 b/d to 10.1mn b/d in 2023, while the IEA sees a more dramatic 1.4mn b/d fall.

In December, the month in which the EU embargo on Russian crude began, crude exports from Russian ports, not including CPC Blend or Urals crude supplied by Kazakh firms, fell by 520,000 b/d to 2.61mn b/d, according to Vortexa.

This figure could feasibly rise in the first quarter of this year, particularly if Russian president Vladimir Putin makes good on his repeated threats to cut off any companies or traders that abide by the price cap. Such a move would not necessarily make economic sense, but some Opec+ delegates have warned that Moscow could retaliate by cutting supplies.

Opec+ Dec quotas			mn b/d
	Aug baseline	Cut	Target
Saudi Arabia	11.004	-0.526	10.478
Iraq	4.651	-0.220	4.431
Kuwait	2.811	-0.135	2.676
UAE	3.179	-0.160	3.019
Algeria	1.055	-0.048	1.007
Nigeria	1.826	-0.084	1.742
Angola	1.525	-0.070	1.455
Congo (Brazzaville)	0.325	-0.015	0.310
Gabon	0.186	-0.009	0.177
Equatorial Guinea	0.127	-0.006	0.121
Opec 10 total	**26.689**	**-1.273**	**25.416**
Russia	11.004	-0.526	10.478
Oman	0.881	-0.040	0.841
Azerbaijan	0.717	-0.033	0.684
Kazakhstan	1.706	-0.078	1.628
Malaysia	0.594	-0.027	0.567
Bahrain	0.205	-0.009	0.196
Brunei	0.102	-0.005	0.097
Sudan	0.075	-0.003	0.072
South Sudan	0.130	-0.006	0.124
Non-Opec 9 total	**15.412**	**-0.727**	**14.687**
Opec+ total	**42.101**	**-2.000**	**40.103**

Ground-zero-Covid

What impact these losses ultimately have on markets will depend in no small part on China and the speed at which its economy, and in turn oil demand, recovers after Beijing abruptly removed its zero-Covid policy last month. The lifting of lockdowns will no doubt drive a recovery in Chinese demand, but delegates highlight that the surge in infection rates that the country is now experiencing will almost certainly keep a lid on growth in the short term, possibly until the second half of 2023.

And beyond China, oil markets are still contending with the looming threat of recession in much of the western world, as inflationary concerns and continued tight monetary policies curb demand. "Advanced economies are heading into a recession, led by the euro area and the UK," British bank Barclays says in its first-quarter outlook, noting that the US economy "will also likely contract".

The producer group argues that the decision to cut production targets late last year has helped balance oil markets. Opec+ aims to be proactive and pre-emptive, as Saudi energy minister Prince Abdulaziz bin Salman says, but not reckless. In theory, the group's decision to keep production targets unchanged will hold until it next meets — which it is not due to do at a ministerial level until 4 June. But, with Saudi Arabia and Opec+ having already shown a willingness to meet and take decisions at short notice, there should be no doubt that the group will step in to adjust production should the need arise.

US

Top shale producer sounds alarm over Permian growth

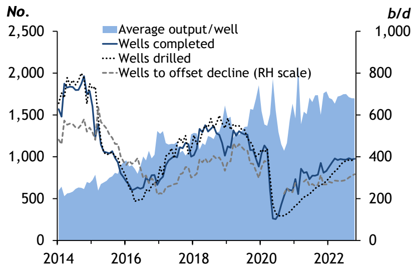
Declining well productivity, rising costs and the decision to prioritise investor returns are weighing on shale production growth, writes Stephen Cunningham

US shale oil output from the top-performing Permian basin risks coming up short as producers run out of their best well inventory.

Pioneer Natural Resources has scaled back its growth projection for overall Permian output to around 7mn b/d by 2030, down from 8mn b/d previously. Crude output from the basin in west Texas and eastern New Mexico is forecast to reach a record 5.6mn b/d this month, according to the US EIA. But gains have slowed in recent months as concerns have mounted over declining productivity, at the same time as labour shortages and cost pressures continue to be felt in the industry. Such pressures were in evidence in a recent survey of oil and gas executives by the Federal Reserve Bank of Dallas, which pointed to flagging optimism.

The oil industry has repeatedly rebuffed calls from the White House to ramp up output to bring down gasoline pump prices which surged after Russia invaded Ukraine. "They don't understand the inventory, they don't understand inflation", Pioneer Natural Resources chief executive Scott Sheffield said of President Joe Biden's administration at the Goldman Sachs Global Energy and Clean Technology Conference in Miami this week. John Hess, who heads rival producer Hess, said shale has lost its role as the swing producer, and the Opec+ producer group is back in the "driver's seat". Shale output could peak around 2025 or 2026, he predicted.

DPR-7 well completions and drilling



At the same time, the ratio of oil to gas in the Permian is likely to shift in favour of gas over the next decade, further straining limited takeaway capacity from the basin. "We're going to need a gas pipeline at least every 18 months to two years going forward," Sheffield predicted.

Coming out of the pandemic, publicly listed upstream shale producers have been wedded to a policy of strict capital discipline after past excesses cost them billions. As a result, the majority of their record profits from higher prices have been passed on to shareholders. That strategy is slowly helping the sector to regain confidence among investors, with its weighting in the S&P 500 benchmark stock index doubling to around 5pc since 2020. The goal is to get back to 10pc or even 15pc, Sheffield said.

But relations with the White House remain frayed, and Sheffield said he had yet to find an oil or gas chief executive who has spoken directly with President Biden. "It's the first US president that I know of that has not talked to anybody from our industry", Sheffield said. Looking ahead, he sees little chance the US will follow Europe in adopting a windfall tax on oil industry profits, given that the House of Representatives is in the hands of Republicans. The biggest risk would come if oil prices surged higher again, and that prompted renewed clamour in Washington for an export ban, Sheffield said.

Biden 'is the first US president that I know of that has not talked to anybody from our industry'

Labour pains

The oil and gas sector continued to grow in the fourth quarter, according to the latest Dallas Fed Energy Survey, but at the slowest pace in two years. The business activity index — the survey's broadest measure of conditions — fell to 30.3 from 46 in the third quarter. "Labour is an issue that is affecting our firm", one executive said. "The government can remove all regulations and timetables, and the amount of increase in activity would not be affected by more than 10pc."

Inflation and supply chain woes were cited as the main factors that could hold production back this year, but concerns over a "maturing asset base" followed closely behind. "Full field development and inventory degradation were buzzwords out of third-quarter 2022 earnings season, as the market worked to assess the longer term impacts from high-graded drilling programmes over the last few years", Canadian bank RBC analyst Scott Hanold says.

INDIA

Indian demand growth keeps Russian crude in focus

The pressing need to meet rising domestic demand suggests Russian crude will continue to flow to India, writes Pranav Joshi

Indian crude demand growth is likely to stay firm this year with the country continuing to import from Russia, despite western pressure to restrict Russian oil purchases and a planned move toward green energy in the long term.

India's imports of Russian crude rose to an all-time high in December at 1.19mn b/d, data from oil analytics firm Vortexa show, remaining above 1mn b/d for the seventh consecutive month, despite the G7 price cap on Russian supplies that came into force on 5 December. India was historically a marginal importer of Russian crude until last year, taking just 50,000 b/d in 2021. But Indian importers have taken advantage of heavily discounted Russian crude since the invasion of Ukraine in February, and the government says the country will continue to buy it to meet the energy needs of its almost 1.4bn population. Russia accounted for nearly 27pc of Indian crude imports in December, followed by Iraq at 17pc and Saudi Arabia at 15pc.

The OECD sees relatively high economic growth supporting Indian crude demand, forecasting the country's GDP to grow by 5.7pc in 2023-24 fiscal year ending 31 March, compared with a global average of 2.2pc. The government plans to move away from fossil fuels to renewable energy, but the development of nascent technologies such as green hydrogen is progressing slowly and the costs remain prohibitive. As a result, rising fuel demand in India necessitates a growing reliance on crude imports in the short term, especially as India is also struggling to meet its domestic production goals.

India produced around 590,000 b/d of crude in November, below its target of around 650,000 b/d and enough to meet only around 10pc of demand, oil ministry data show. Delhi slashed a windfall tax on domestic crude production in December, from 10,200 rupees/t ($16.82/bl) at the start of the month to just Rs1,700/t by 16 December, in a bid to incentivise domestic production after a fall in crude prices. But government ambitions to meet a quarter of India's crude demand with domestic production by 2030 look ever more unachievable, as demand of around 5mn b/d continues to rise, and successive attempts to attract more foreign upstream investment have consistently failed.

No worries

India needs to transition to clean energy "faster than anyone else", oil minister Hardeep Singh Puri says, but energy security priorities are likely to trump sustainability concerns, with geopolitical considerations unlikely to affect growing oil import dependence. Puri said in November that India is not worried about the G7 price cap, echoing foreign minister Subrahmanyam Jaishankar's assertion that India plans to continue buying Russian oil as it works to its advantage. The reluctance of western oil firms to buy Russian oil forced sellers to heavily discount their crude exports to attract other buyers, with India's exponential growth in Russian crude purchases putting it alongside China as Russia's biggest customers.

Russia has for decades been a key arms supplier to India, and despite US pressure over the Ukraine war, India maintained strong diplomatic ties with Russia throughout most of 2022, although prime minister Narendra Modi said in early December he would not be travelling to Moscow for an annual summit with Russian president Vladimir Putin, sending mixed signals on the state of their relations going into 2023. But having been in a strong, mutually beneficial partnership that withstood collective western pressure for a year, it is unlikely that this event will result in India reducing imports from Russia. Modi in September told Putin that "today's era is not of war", bringing cheer in western capitals, but availability of cheaper crude from Russia is likely to continue to override other considerations.

EU ENERGY CRISIS

ExxonMobil leads pushback against windfall taxes

The US major is contesting the levy, with many other companies echoing its claim that investment will be stifled, write James Keates, Laura Tovey-Fall and Antonio Peciccia

The oil industry is starting to challenge a temporary EU windfall tax on oil and gas company profits that was imposed at the height of the energy price crisis that followed Russia's invasion of Ukraine last year. ExxonMobil is taking legal action to try to block the levy, arguing that it will be "counterproductive".

ExxonMobil has filed a lawsuit at the General Court of the EU in Luxembourg, arguing that the European Council, the EU's executive branch, had no authority to impose the tax. The European Commission maintains that the measure is fully compliant with EU law, as it was approved under an EU treaty that allows qualified majority voting among member states in emergency situations.

ExxonMobil said it recognises the burden that high energy costs have placed on households and businesses in Europe, but it insists extra taxes are not the answer. The firm has estimated that windfall levies in Europe would cost it "upwards of $2bn" next year. ExxonMobil's profits in January-September trebled compared with a year earlier to $43bn. The company says it is only targeting "the counterproductive windfall profits tax" and not any other elements of the EU's package of measures to reduce energy prices. It says its future investment in the region will hinge on how globally competitive Europe will be.

Political pressure to impose additional taxes on energy companies has been mounting in Europe since a surge in oil and gas prices triggered by the war in Ukraine pushed company profits to eye-watering highs. UN secretary-general Antonio Guterres said in August that the scale of profits in the sector was "immoral". The UK last year imposed and then increased windfall taxes on oil and gas producers, leaving some operators rethinking investment plans for this year.

EU member states agreed in September to set a mandatory — albeit temporary — "solidarity contribution" on the profits of businesses active in the crude, gas, coal and refinery sectors as part of a package of emergency measures designed to help shield consumers from the effects of soaring energy prices. The levy is to be set at a minimum 33pc, calculated on taxable profits in the 2022-23 fiscal year that exceed the annual average since 2018 by more than 20pc. Member states were obliged to enact the measure before the end of 2022.

Official hostility

But countries have diverged in their approach. The Czech Republic and Romania have set the levy at as high as 60pc, prompting strong opposition by industry associations. Bucharest approved the measure on 28 December, with a payment deadline set for 25 June for this year's profits, and hopes to raise at least 3.9bn lei ($835mn) from the levy. Romanian oil and gas employers federation FPPG pointed at the government's approach as the "most hostile" within the EU, claiming that Romanian firms were already "overtaxed". FPPG suggested a lower rate of 33pc, to protect vulnerable consumers for a specific period but also "to limit the impact in discouraging local production and future investments".

Finland's proposed tax on excess power sector profits could curb investments in energy transition and secuity of supply when they are 'desperately' needed

Countries such as Germany and Finland have taken a more cautious approach, settling for the minimum 33pc, but have still drawn criticism from the energy industry. Finnish utility Fortum said in December that Finland's proposed tax on excess profits in the power sector could curb new investment in renewable energy, "at a time when Finland desperately needs new investments to proceed with green transition and improve security of supply".

And German industry association en2x criticised Berlin's proposal, saying the EU regulation only requires the levy to be in place for at least a year — Berlin plans to tax 2022 and 2023 profits. En2x also said 33pc is too high, because German taxes on corporate profits are already at the top end of the EU scale at around 31pc.

SOUTHEAST ASIA

Regional NOCs put energy security ahead of transition

Malaysia's Petronas is leading the way on low-carbon initiatives, but along with its peers still aims to boost hydrocarbon growth, writes Prethika Nair

Southeast Asian national oil companies (NOCs) are increasingly allocating portions of their capital expenditure (capex) towards decarbonisation efforts, but their focus still remains firmly on exploration and maintaining oil and gas output.

More NOCs in southeast Asia have set decarbonisation goals in line with their countries' net zero targets, and have accordingly allocated more of their capex towards lower-carbon solutions. Malaysian state-owned oil and gas firm Petronas has a net zero by 2050 target, and in line with this launched its clean solutions entity Gentari in 2022. Gentari aims to achieve 30-40GW of renewable power capacity, produce up to 1.2mn t/yr of clean hydrogen and achieve a 10pc share of the green mobility market, or 25,000 charging points across Asia-Pacific, by 2030.

These ambitious goals require significant investments. Petronas last month released its activity outlook for 2023-25. The firm did not provide a breakdown of its spending plans, but based on its activity outlook, RHB Investment Bank Research estimates Petronas' capex to be 45bn-50bn ringgit ($10.2bn-11.4bn) in 2023, with 20pc of this, or 9bn-10bn ringgit, expected to be allocated to clean energy solutions. But much of Petronas' expenditure is still likely to go towards keeping fossil fuels in the energy mix as the firm has been increasing its domestic oil and gas production, and intends to continue doing so for the next 5-10 years.

The company is still "focused on pursuing sustainable value-driven production growth [and] monetising oil and gas resources", it said. Petronas recorded 10 hydrocarbon discoveries in Malaysia in 2022 following increased exploration activity. It plans to drill 96 wells in 2023 under its development, appraisal and exploration drilling programme. Petronas could be looking to "extend the life of the wells in order to leverage on current high oil prices", RHB said.

Thai state-controlled oil firm PTTEP last month revealed that its 2023 budget has been set at $5.48bn, which includes $3.15bn of capex. But out of this, only $53mn, or a mere 1.7pc, is being set aside for decarbonisation initiatives. In comparison, $2.66bn, or 84pc, is being allocated for raising production by accelerating exploration, and by developing and increasing output at existing projects. The firm has also allocated $193mn of capex for geological studies and exploration drilling, as well as appraisals of wells in Thailand, Malaysia and Oman.

Fossil backbone

NOCs in southeast Asia are keen to maintain energy security while incorporating lower carbon solutions and renewables into existing operations to reduce or offset emissions. PTTEP has set aside $4.8bn for 2023-27 to expand its business in the research and development of power and renewables, carbon capture and storage (CCS), carbon capture and utilisation (CCU) and hydrogen.

Pertamina will continue 'to invest in fossil fuels and petrochemicals... to ensure that the energy transition will not interfere with energy security'

Petronas is also involved in many CCS initiatives, such as with South Korea's SK Energy and Dutch bulk liquid and gas storage firm Vopak. Petronas also expects its Kasawari CCS project to reduce CO_2 emissions from flaring by 3.3mn t/yr of CO_2 equivalent, making it "one of the largest CCS projects in the world".

Indonesian state-controlled Pertamina is also attempting to reduce its CO_2 emissions through CCS initiatives. The firm has indicated that it will increase the share of its revenue spent on its "green business" from 5pc in 2022 to 13pc in 2030, without providing specific figures. But Pertamina also stated that its upstream unit Pertamina Hulu Energi "carried out a massive and aggressive operations strategy through several exploratory drills" in 2022, which resulted in additional oil and gas resources. Similar to its regional peers, Pertamina will continue "to invest in fossil fuels and petrochemicals as the current business' backbone, to ensure that the energy transition will not interfere with energy security", the company says.

NORTH AFRICA

Algeria steps up gas export ambitions

The country's plans to sell more gas to Europe face production and pipeline constraints, write Antonio Peciccia, Jeff Kuntz and Alexandra Vladimirova

The disruption to Russian pipeline natural gas exports to Europe following Russia's invasion of Ukraine has spurred the region's other gas suppliers to step up their export ambitions in the hope of filling the shortfall. Algeria aims to nearly double the gas production it has earmarked for export as soon as this year, but its plans may take much longer than that to materialise.

"We currently produce nearly 102bn m^3 of gas, half of which is consumed locally," Algerian president Abdelmadjid Tebboune said last month. "I hope that in 2023, we will reach production of 100bn m^3 of gas intended exclusively for export." Algeria exported 51.2bn m^3 of gas in November 2021-October 2022, including 37.3bn m^3 by pipeline and 13.9bn m^3 as LNG, the most recent figures made available by the Joint Organisations Data Initiative show. The Algerian government has given scant details about how it aims to achieve this surge in exports, but the scale of the targeted increase suggests plans may involve a combination of production increases and demand reductions.

'We produce nearly 102bn m^3, half of which is consumed locally. I hope that in 2023, we will reach production of 100bn m^3 intended exclusively for export'

The target may be ambitious, to say the least. Algerian production rose to 102.8bn m^3 in 2021, 21pc higher than a year earlier, but output in the previous two years fell below 90bn m^3 from the 2016-18 average of 93.9bn m^3, probably because of reduced export demand. And production of 81.5bn m^3 in January-October puts output for last year on course to fall short of the 2021 figure, although stronger demand in the last two months of 2022 is likely to have supported production.

Scope for domestic demand reductions to release substantial volumes for export may be limited. Algerian gas consumption rose at an average rate of 6pc/yr in 2017-20, before edging lower in 2021, when it fell to 44.8bn m^3 from 45.6bn m^3. Consumption of 35.6bn m^3 in the first 10 months of 2022 puts demand on track to fall further for the full year, although it is typically stronger in winter.

Algerian state-owned Sonatrach has agreed to provide additional supply to Italian energy firm Eni, which is one of the largest recipients of Algerian gas. But supplies are due to increase by only 3bn m^3 for 2022 and 6.2bn m^3 in 2023, compared with 2021 levels.

In any event, Algeria would not be able to immediately double gas exports as it lacks sufficient export capacity, even taking into account an unlikely resumption of flows through the 12bn m^3/yr Maghreb-Europe gas pipeline, which used to carry Algerian gas through Morocco to Spain until flows halted in November 2021, several months after Algeria cut diplomatic ties with Morocco. Since then, pipeline supply to Spain has been flowing only through the 10.5bn m^3/yr Medgaz pipeline, while Italy has been receiving the bulk of Algerian pipeline flows through the 30bn m^3/yr Transmed line. Running the 21mn t/yr Arzew and 4.5mn t/yr Skikda LNG facilities at maximum utilisation would add 33bn m^3/yr to Algeria's export capacity, but utilisation rates at the terminals have been well below capacity in recent years.

Algeria would not be able to immediately double gas exports as it lacks sufficient export capacity

Pipeline plans, still in the pipeline

Algeria's ambitions to boost exports to Europe may be dependent on building new routes to market. Italy could become a hub for distributing Algerian gas to other countries, Tebboune said. But to further increase gas imports from its southern entry points, Italy needs to build an additional pipeline that would bolster its south-north transport capacity, which is not expected to be ready before 2027. Algerian energy minister Mohamed Arkab says the country is ready to relaunch the Galsi pipeline project, which would link Algeria to northern Italy through Sardinia, bypassing the grid bottleneck in mainland Italy. But the project, originally proposed in 2002, failed to progress and was dropped from the EU's list of Projects of Common Interest in 2017.

IN BRIEF

Moscow to release more details of price cap response in January

Russia will release details this month of how it plans to monitor and implement its ban on oil exports to companies that adhere to the G7-led price cap. President Vladimir Putin signed a decree on 27 December banning oil exports to companies that agree to the price cap terms, but left it to the government to work out how the decree will be enforced. The government is working to devise "the mechanism of monitoring and implementation of the decree", deputy prime minister Alexander Novak says, as quoted by state news agency Tass. The restrictions on selling oil to price cap participants take effect on 1 February, remaining until at least 1 July.

Vitol sells stake in Russia's Vostok Oil

Trading company Vitol has sold its interest in Russian state-run Rosneft's Vostok Oil onshore project in the Arctic. The firm has divested its 5pc stake, which it held through a consortium with Singapore-based Mercantile and Maritime Energy, to Dubai-based Fossil Trading FZCO — the parent of Geneva-based Energopole, which was previously Rosneft's trading arm. Vitol has been trying to exit the project since Russia invaded Ukraine. Deals involving Russian energy assets held by companies from "unfriendly" states are banned until the end of 2023. But President Vladimir Putin gave the go-ahead for deals involving Vostok Oil last month.

Lula names state senator Prates as Petrobras head

Brazilian president Luiz Inacio Lula da Silva has appointed Rio Grande do Norte state senator Jean Paul Prates as the new chief executive of state-controlled oil firm Petrobras. Prates has positioned himself against Petrobras' privatisation and has questioned the company's fuel pricing policy. The firm should invest more in renewables and refining, he says. Increasing the share of renewables in Brazil's energy mix is one of the aims of the energy transition secretariat created by new mines and energy minister Alexandre Silveira. The secretariat will promote the integration of new technologies such as energy storage and low-carbon hydrogen, while natural gas and biomass will play important roles in Brazil's energy transition.

RWE, Equinor tie-up on Norway-Germany H2 supply chains

Germany's RWE and Norwegian Equinor have formed a partnership to produce hydrogen in Norway and develop hydrogen-ready power plants in Germany. The companies plan to produce blue hydrogen from Norwegian gas, capturing up to 95pc of the CO_2 emissions for sequestration offshore. Over time, they plan to scale up production of renewable hydrogen from offshore wind projects in Germany and Norway to "complement and eventually replace" blue hydrogen. They also plan to develop over 3GW of hydrogen-ready gas-fired power plants in Germany by 2030. Germany had been reluctant to make blue hydrogen a key component of its energy transition strategy, but has softened its stance over the past year as it battles with energy security issues caused by the sharp cut in Russian gas supply to Europe.

Adnoc earmarks $15bn for decarbonisation

Abu Dhabi's Adnoc plans to allocate $15bn towards decarbonisation projects, including carbon capture and storage, in pursuit of its 2030 emission targets. The projects include investments in clean power, carbon capture, utilisation and storage (CCUS), electrification and new measures for zero gas flaring. Adnoc expects to expand its carbon capture capacity to 5mn t/yr by 2030. Its new low-carbon energy portfolio would be expanded through its stake in clean energy firm Masdar. Adnoc is preparing to invest heavily in carbon capture technologies at its Habshan gas processing facility, similar to those employed at its Al-Reyadah CCUS facility.

MARKET OVERVIEW

Chinese Covid rates stoke demand concerns

Crude prices dropped as China's Covid problems suggested a potential weakening of demand early this year

Oil prices fell as China's efforts to deal with surging Covid-19 infection rates sparked fresh alarm over an economic slowdown.

Atlantic basin marker North Sea Dated fell by $3.29/bl to $77.11/bl in the two weeks to 5 January, while US light sweet WTI was down by $3.82/bl to $73.67/bl. Mideast Gulf sour benchmark Dubai fell by $2.78/bl to $75.20/bl.

China's struggles to combat Covid-19 have added to worries about the outlook for oil demand. But higher products export quotas issued by Beijing in a first batch for this year could encourage Chinese refiners to raise throughputs. Spot Angolan crude prices firmed on the prospect of a Chinese demand recovery, as well as a slimmer February loading programme. Most Angolan grades rose by 20¢/bl, while Dalia gained $1.40/bl, against North Sea Dated.

A smaller loading programme for February Norwegian sour Johan Sverdrup supported the grade. Johan Sverdrup and fellow North Sea sour crudes Grane and Flotta Gold firmed by $2.00-2.50/bl against North Sea Dated, but remained at a discount to the benchmark. The arbitrage to move European cargoes to Asia-Pacific became more workable, with Ice Brent holding a smaller premium to Dubai. The February Brent-Dubai exchange of futures for swaps (EFS) — the premium of Ice Brent to Dubai swaps and an indicator of the eastward arbitrage — fell to $4.66-4.85/bl in the last week of December, the narrowest in three months. The open arbitrage to the east, and stronger naphtha margins, may have supported a demand surge for Caspian light sour CPC Blend in the last week of December.

Increased eastward flows of Atlantic basin crude could limit Asian refiners' need for Mideast Gulf grades. Slow demand from China, and continued exports of Russian crude to India and China, put downward pressure on Mideast Gulf crude values, pulling the front-month February premium to third-month April Dubai down to $1.17/bl on average in December, the shallowest backwardation since May 2021. This led Saudi Aramco to cut its February Asia-Pacific formula price for Arab Light crude to the lowest since November 2021.

China's crude import demand may rise following the issuance of higher products export quotas. But the higher quotas are weighing on Asia-Pacific gasoil margins. Jet fuel margins in Asia-Pacific also weakened as regional Covid measures for Chinese travellers are likely to curb a rebound in Asian travel demand.

Diesel margins in Europe made gains, with cargoes going into storage to prepare for expected supply tightness when the EU bans Russian diesel imports from 5 February. The stockpiling pushed independent inventories of diesel and gasoil in the Amsterdam-Rotterdam-Antwerp hub to the highest in nearly 15 months. Unless demand collapses, Europe will have to replace a significant quantity of Russian diesel from February, either through higher refinery runs, which will be profitable only if diesel prices rise, or by paying up for imports from Asian refiners. Either way, diesel supplies are likely to become more expensive in the short term.

European gasoline margins were supported by a rise in US demand as US refinery outages caused by winter storms prompted buyers to turn to European supplies. Gasoline prices on the US Gulf coast rose to a seven-week high at the end of last year as the winter freeze halted some refineries in Texas and Louisiana.

In the running

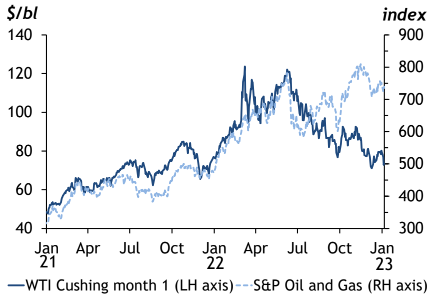
Plentiful crude supplies and slow demand have kept a lid on prices. But crude prices could rise if refiners boost runs to meet a diesel supply shortfall when EU sanctions on Russian product imports are imposed in February. The outlook for Chinese oil demand remains a key uncertainty. Prices could bounce back if Chinese demand recovers sufficiently to curb the country's products exports.

Key oil prices			$/bl
		5 Jan	± 22 Dec
North Sea Dated		77.11	-3.29
WTI Cushing	Feb	73.67	-3.82
Oman	Mar	75.18	-3.91
Dubai	Mar	75.20	-2.78
Tapis		84.56	-3.29
ASCI	Feb	68.75	na
Netbacks*		5 Jan	± 22 Dec
NW Europe - Brent		98.02	+2.52
US Gulf - WTI		114.66	+9.89
Singapore - Oman		70.84	+0.84

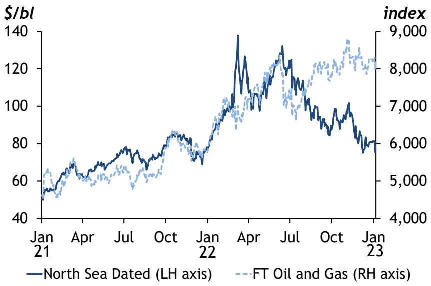
**complex yield for NWE and US, simple yield for Singapore*

SHARE PRICES AND ENERGY INDEXES

S&P Oil and Gas Index, WTI Cushing



FT Oil and Gas Index, North Sea Dated



World energy share indexes				5 Jan
	Index	±	52-week	
	5 Jan	22 Dec	High	Low
Americas				
S&P Energy	661	13	725	451
S&P Oil & Gas	740	15	814	504
S&P Equipment & Services	324	8	348	209
TSE Oil & Gas	2,724	-50	3,346	2,395
Europe				
FT Oil & Gas	8,096	-136	8,799	6,132
Russia				
RTS Oil & Gas	152	-5	257	89
Micex Oil & Gas	5,650	+88	9,473	3,962
Asia-Pacific				
TOPIX Oil & Coal	1,035	-13	1,365	1,001

Company share prices			5 Jan
	5 Jan	22 Dec	±%
BP	£4.72	£4.78	-1.29
Chevron	$175.24	$172.08	+1.84
ConocoPhillips	$116.77	$112.90	+3.43
Eni	€13.61	€13.38	+1.73
ExxonMobil	$109.21	$105.88	+3.15
Repsol	€14.77	€14.77	-0.03
Shell	£23.11	£23.52	-1.74
Equinor	NKr319.60	NKr365.40	-12.53
TotalEnergies	€57.94	€59.00	-1.80
Pioneer Natural Resources (*see p5*)	$227.13	$220.15	+3.17
Petrobras (*see p10*)	R27.08	R27.17	-0.33

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