Argus *Global Gas Markets*

Gas and LNG markets, projects and infrastructure

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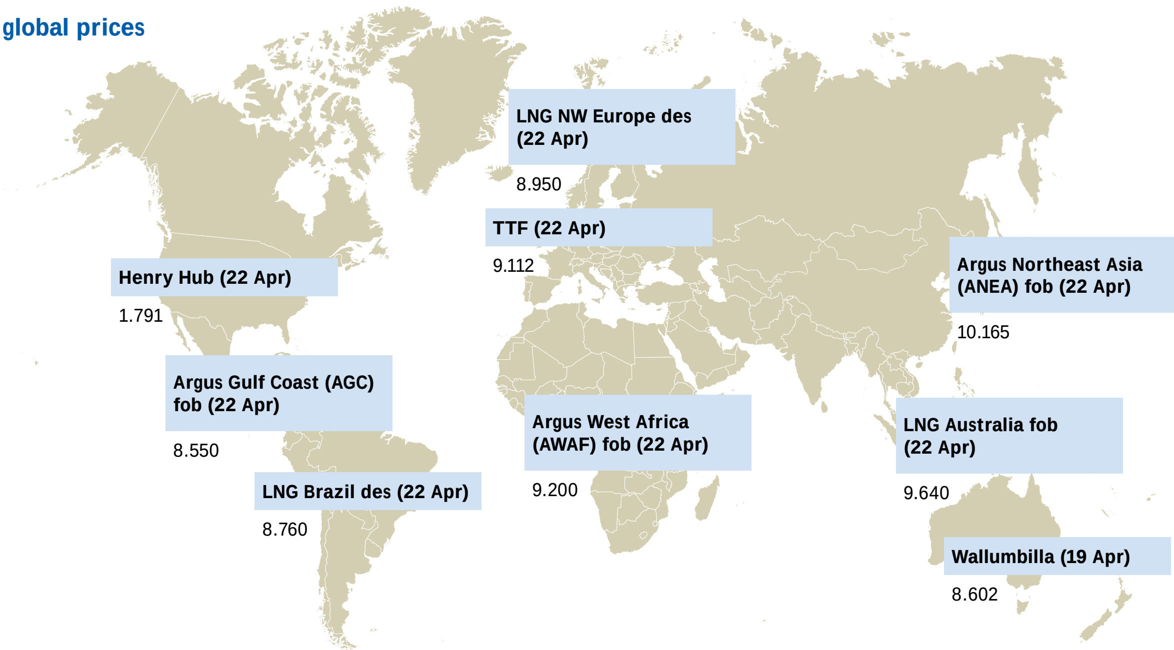
Key global prices *$/mn Btu*



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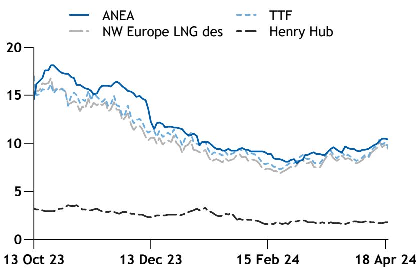

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EDITORIAL

And yet gas flows

Gas markets have been largely unaffected by escalating tensions in the Middle East

The global gas market's reaction to escalating tensions in the Middle East in recent weeks has been confined to minor and short-lived movements, despite the region being home to the world's second largest LNG exporter and some major regional suppliers.

Any risks of further escalation appear to have subsided in recent days. Even though tit-for-tat actions by Israel and Iran have edged closer to direct conflict than they had ever been, the limited extent of Israel's aerial assault on the central Iranian city of Isfahan late last week appeared designed to allow Iranian media to downplay it, as it effectively did. Even Iran's earlier attack on Israel had been highly choreographed and heavily telegraphed to key stakeholders beforehand. All in all, both parties appear keen to draw a line.

The market appear to have taken note of that. Besides, a closer look at the fundamentals shows the odds of rising tensions translating into an actual shift in the supply-demand gas and LNG balance are low. It would take a disruption to traffic through the Strait of Hormuz, through which all of Qatari LNG has to transit, for this to happen. But even in the event of further escalation, such an outcome is much further down the line.

Gas and LNG have continued to flow without major disruptions in recent months despite the ongoing Israel-Hamas conflict in Gaza and the attacks by Yemen's Houthi militants on ships transiting the Bab el-Mandeb strait.

After a temporary curtailment in October, Israeli exports to Egypt have rebounded to a record high in January. The bulk of such supplies flows through the East Mediterranean Gas pipeline, which runs offshore right in front of the Gaza strip and has already been subject to attacks in the aftermath of the Egyptian revolution a decade ago, when it used to supply Egyptian gas to Israel. With gas now flowing in the opposite direction, a disruption to supplies is unlikely to have much impact on the Israeli economy, but would be a lethal blow for Egypt, which is grappling with dwindling domestic gas production while also contending with the loss of much of its Suez Canal revenues.

The configuration of the global LNG market has allowed trade flows to readjust in response to the Houthi attacks in the Gulf of Aden

And the configuration of the global LNG market has allowed trade flows to readjust in response to the Houthi attacks in the Gulf of Aden. Ships transporting US LNG to Asia were using the Cape of Good Hope route extensively before such attacks began, and the bulk of Qatari cargoes were already heading eastwards. Disruptions were limited to some schedule adjustment for European long-term customers of Qatar, which had to wait a bit longer for their cargoes as flows redirected away from the Red Sea route. LNG deliveries through the Bab el-Mandeb strait have dropped to zero since February. Yet LNG is flowing and global gas prices have continued to decline.

Once again the greatest geopolitical risks for the gas market come from outside the Middle East. Perhaps astonishingly, Russian gas has continued to reach European customers even through war-torn Ukraine. But the expiry of the transit agreement that allows this is looming — and for now, none of the parties involved appear keen to facilitate an arrangement that would allow flows to continue.

Nevertheless, even though the financialisation of gas markets — with perhaps the help of some algorithmic trading — may have made them potentially more reactive to geopolitical tensions, the market has shown remarkable resilience.

Arguably, even the price increases of 2022 were testament that the system works as they stemmed from the sudden defection of Europe's largest supplier and the shortage that followed, and they provided the necessary price signals to stimulate new infrastructure development in LNG import capacity, pipeline interconnections and production.

EGYPT

Egypt swings to LNG imports

Dwindling output and higher domestic demand may boost imports this summer, write Antonio Peciccia and Matt Drinkwater

After completely pausing LNG exports throughout most of last summer, a further decline in upstream production may have turned Egypt into a swing market, switching from export to imports in the summer.

Last week, the country exported what is likely to be its last LNG cargo this summer. Days earlier, it had received its first LNG import since September 2018 at Jordan's 3.8mn t/yr Aqaba terminal. The two countries last year rekindled an arrangement that was already in force last decade that allowed Egypt to use Jordan's Aqaba terminal for LNG deliveries.

Egypt is also understood to have chartered the 170,000m³ *Hoegh Galleon* floating storage and regasification unit (FSRU) for 18 months. It is set to arrive in June and will probably be installed at the Red Sea port of Ain Sukhna, where a previous FSRU — the 170,000m³ *BW Singapore* — was moored until as recently as December.

While the vessel only left Egypt at the end of 2023, it was chartered by Italy's system operator, Snam, in June 2022, a time when FSRUs were in high demand as Europe scrambled to boost its LNG import capacity in the wake of Russia's invasion of Ukraine. The Aqaba terminal has been significantly underutilised in recent years as Jordan has been relying almost entirely on Israeli pipeline imports, but bottlenecks on the Fajr pipeline linking Jordan to Egypt are probably reducing the volume of additional supply capable of using this route, which may have informed Egypt's decision to secure its own import facility.

Total net pipeline flows into Egypt have not exceeded 26.6mn m³/d, well short of the 41mn m³/d of combined capacity theoretically available through the East Mediterranean Gas (EMG) and Fajr pipelines.

Egypt was an LNG exporter until falling domestic production in the wake of the 2011 revolution, coupled with rising domestic demand, forced it to turn to LNG imports in 2014. But a number of offshore gas discoveries were rapidly brought on line, including the giant 850bn m³ Zohr field, which started production in 2017. This enabled the country to halt LNG imports, release one of its two FSRUs and eventually resume regular LNG exports.

Combined Egyptian production has continued to fall sharply in recent months

But dwindling upstream output, along with steadily rising domestic demand, have progressively reduced the amount of surplus supply available for exports and eventually forced the country to switch back to importing LNG this summer. And while Egypt could be able to resume exports in the winter, the duration of the *Hoegh Galleon*'s charter suggest a similar seasonal shift may happen again next year.

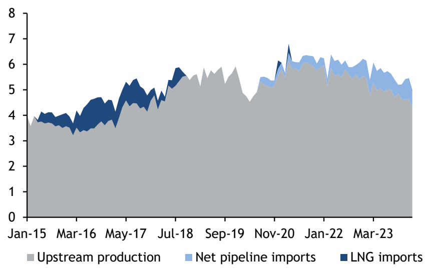
A Zohr point

Italian energy firm Eni, which operates Zohr, had expected the field's production to plateau for 6-7 years before any natural decline started. But after testing its technical capacity of 3.2bn ft³/d in its early production stages, the field has been suffering from water infiltration issues that have capped its output.

Eni's recent works on the field have included a "water shut-off programme for gas production optimisation", the firm says in a filing to the US security and exchange commission. But its total equity production from Egyptian fields has continued to fall in recent years — to 1.24bn ft³/d in 2023, from 1.34bn ft³/d a year earlier and 1.4bn ft³/d in 2021. Eni holds a 50pc stake in Zohr, alongside several other gas production assets in the country.

Combined Egyptian production has continued to fall sharply in recent months. It declined to 147.8mn m³/d in February, the most recent data from the Joint Organizations Data Initiative show, from 170.9mn m³/d a year earlier and the lowest

Egypt gas supply *bn m³*



EGYPT

for any month since December 2017. It also marked the ninth consecutive month of double-digit drop in output.

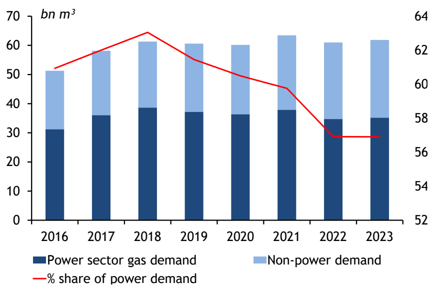
Egypt's petroleum ministry has set a target to add 1.5bn ft³/d of gas production from seven development projects and 20 development wells in the July 2024-June 2025 fiscal year. This would represent a sharp increase from the 165mn ft³ that has come on line so far in the 2023-24 fiscal year, according to the ministry. But even if this additional output materialises, it may be largely offset if production from existing fields continues to decline as rapidly as it has in recent months.

Egypt's petroleum ministry has set a target to add 1.5bn ft³/d of gas production from seven development projects and 20 development wells

The country's gas balance is alleviated by Israeli imports, which reached a record high of 29.5mn m³/d in January. Israeli flows totalled 8.6bn m³ in the whole of 2023, up from 6.3bn m³ a year earlier, but there is limited scope for them to increase further until additional transport capacity is commissioned. This should unlock a planned 1bn m³/yr rise in contractual deliveries to Egypt, and potentially leave space for further increases in supplies, as the production ramp-up from Energean's Karish field may have made more supply from the Chevron-operated 620bn m³ Leviathan field available for export.

But the Ashdod-Ashkelon pipeline offshore Israel, which is set to raise the EMG capacity from Israel to Egypt to about 6.7bn m³/yr from roughly 5bn m³/yr at present, has suffered several delays, and is not expected to be completed before next year. And the onshore Nitzana link, which would boost overall export capacity by 3bn-6bn m³/yr, is still in the design stage.

Egyptian gas demand ***bn m³***



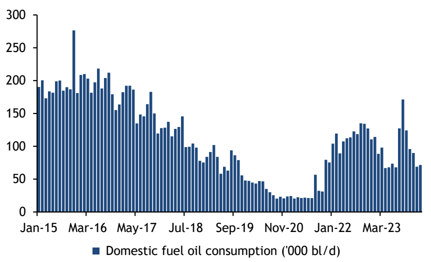
Demand will drive further shifts

The possibility of further shifts between exports and imports also hinges on the evolution of domestic demand, which rebounded on the year in 2023 but remained below the record high of 2021.

The possibility of further shifts between exports and imports also hinges on the evolution of domestic demand

Overall domestic consumption was 61.9bn m³ in 2023, up from 61bn m³ a year earlier but still short of the 63.5bn m³ recorded in 2021. The government has been striving to reduce power-sector gas demand in recent years, by introducing load-shedding measures aimed at containing power demand and bolstering the use of fuel oil for power generation. But non-power demand has continued to rise steadily in recent years, raising its share of overall consumption. Power-sector gas burn accounted for 57pc of total Egyptian gas use in 2023, having declined steadily from 63pc in 2018.

Egypt fuel oil consumption ***'000 b/d***



Egypt had already introduced measures to reduce power-sector gas use in late 2021, when gas became more expensive than crude oil on the international market on an energy-equivalent basis. This provided an incentive to use more fuel oil in the power sector and free more natural gas for LNG exports instead, a trend that continued in 2022, when the first energy-saving measures, including rolling blackouts, were also introduced. Domestic consumption of fuel oil jumped to 116,200 b/d in 2022 from 35,600 b/d a year earlier, and only edged lower to 98,800 b/d last year.

Last year Cairo extended these measures, and in July it also sought to reduce industrial demand, asking urea factories to cut output by 30pc in order to free up gas for power generation during the worst of last summer's heatwaves. Load-shedding measures have been reintroduced this month, with power supplies cut on a rolling basis for up to two hours at a time.

But in this year's lower gas price environment, Egypt may be able to afford to procure additional supply to keep the lights on. The country is already contending with the loss of much of its Suez Canal transit revenues, and so it has an incentive to minimise any measures that impinge on the tourism industry or that curtail manufacturing production.

EUROPE

Europe grapples with gas' role in power sector

Europe faces the tricky task of funding generation plants that use a fuel it is trying to replace, writes Evelyn Lee

The gas industry's long-standing argument that plans to boost the use of renewable generation sources will still require back-up from a fossil fuel is being put to the test in Europe, with several countries seeking to renew and expand their gas-fired generation fleets while striving to accelerate the build-up of renewables.

A faster deployment of renewables has been one of the cornerstones of Europe's strategy since the 2022 energy crisis. With the prospect of power storage technologies being deployed at scale still uncertain, the region may have little alternative but to continue relying on gas-fired plants as back-up in the medium term, possibly beyond 2030.

Italy, Germany and the UK, which have the largest gas-fired fleets by capacity in Europe, have expressed their intent to include gas-fired output in their future electricity mixes. Based on plans already approved, the three countries together account for more than half of the region's total new gas-fired capacity.

Most recently, the UK announced its intention to use gas-fired plants beyond 2030 — by extending the life of existing gas-fired plants, as well as building new facilities to replace retiring ones. "It is the insurance policy Britain needs to protect our energy security, while we deliver our net zero transition," prime minister Rishi Sunak says. Sunak did not provide more specific details, but energy minister Claire Coutinho previously said the UK would need to build a minimum of 5GW of new gas-fired capacity to partly offset the 15GW gas-fired capacity closures in the coming years. The UK has 34.5GW of operating gas-fired capacity at present, which is about 41.5pc of its total installed capacity. Gas-fired output accounted for 32.7pc of the UK's electricity mix last year, according to the National Grid data, followed by 30.8pc wind and 14.2pc nuclear outputs.

EU gas-fired plant projects	MW
Country	**Total**
Albania	500.0
Belgium	2,060.0
Bosnia & Herzegovina	715.0
Croatia	2,050.0
Czech Republic	1,145.0
France	446.0
Germany	10,582.0
Greece	4,022.0
Hungary	1,795.0
Ireland (Republic of Ireland)	592.0
Italy	7,284.0
North Macedonia	625.0
Poland	7,968.7
Romania	4,130.0
Serbia	1,315.0
Slovakia (Slovak Republic)	70.0
Slovenia	192.0
Spain	500.0
Turkey	2,327.0
UK	23,526.0

— Argus data and download

Similarly, Germany recently confirmed plans to build more gas-fired capacity, although Berlin appears to have partly pivoted away from a strategy centred on such plants being hydrogen-ready, instead introducing the possibility of using carbon capture and storage (CCS) in the power sector — a "pragmatic" and "responsible" decision as without CCS, Germany's climate targets will be "impossible to reach", economy and climate protection minister Robert Habeck says. The country closed its last nuclear plants in April 2023 and aims to fully suspend operations at coal-fired plants by 2030, but market participants worry that the timeline is too tight to build new dispatchable capacities.

Italy has authorised the construction of four 850MW gas-fired plants to be ready in 2024-26, along with a further 700MW of capacity from upgrades to existing facilities, as the country is on its track to phase out coal-fired power generation by the end of 2025 as planned. Italy, which has the biggest gas-fired fleet in Europe by capacity, was criticised by the European Commission in December 2023 that its draft updated energy plan "does not sufficiently elaborate" on how the climate targets will be met, and that an indicated expansion of gas networks in Sardinia contradicts the plan to reduce reliance on imported gas.

Projects could hinder investment

Considered against the energy transition goals, such plans could be seen as an unattractive proposition by prospective project developers.

Generation plants that are only meant to be used occasionally as a back-up for renewables may not be able to guarantee investment returns, and may even become stranded assets before firms have been able to fully recoup their investments. The European Bank for Reconstruction and Development (EBRD) does not plan to completely ban gas investments in the near future, chief economist Beata Javorcik says, although she warns EBRD funding for such projects would be given

EUROPE

in "rare and exceptional cases" where projects can demonstrate a "strong ambition to accelerate the low-carbon transition".

The uncertain evolution in power-sector gas demand since 2022 further complicates the task. Combined power-sector gas burn in Belgium, France, Italy, Portugal, Spain and the UK fell to 1.56 TWh/d in 2023, from 2.04 TWh/d a year earlier, and further to 1.39 TWh/d in the first quarter of this year from 1.67 TWh/d in January-March 2023. But elsewhere in the region, ample scope for displacing coal-fired generation may still underpin growth in power-sector gas demand.

Investment plans in the energy sector across central and eastern Europe suggest displacing coal-fired generation would result in stronger power-sector gas burn

Fuel-switching potential in CEE countries

Investment plans in the energy sector across central and eastern Europe suggest displacing coal-fired generation would result in stronger power-sector gas burn.

US-based think-tank Atlantic Council has indicated of the region's 41 energy priority projects only one is committed to cross-border electricity interconnection and one to an offshore wind farm grid connection, while 20 are linked to gas infrastructure expansion. And UK-based think-tank Ember Climate has said the rush to replace Russian gas is boosting investment in gas import infrastructure in the region beyond demand levels, while "massive grid investment and modernisation are needed" to support renewables growth.

By contrast, CEE countries account for about 30pc of gas-fired power projects in Europe, concentrated mostly in Poland, which is still heavily reliant on coal. In 2023, coal-fired generation — including bituminous and lignite coals — still accounted for 63.8pc of the country's total power output, although this was down from 73.4pc a year earlier. The share of gas-fired output increased to 8.2pc from 5.6pc over the same period.

GERMANY

Industrial gas demand may have peaked

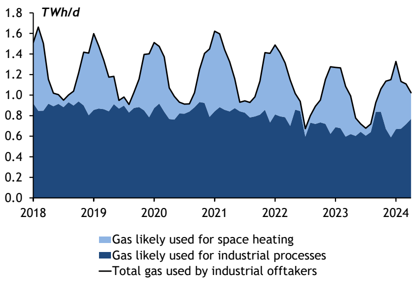
Structural changes in the country's industrial sectors since the energy crisis may have a permanent effect on gas consumption, writes Till Stehr

German industrial gas demand is showing signs of recovery, but market participants believe it may remain below pre-crisis levels permanently.

The German economy and climate ministry, BMWK, earlier this month said an "economic trend reversal" was visible from recent economic indicators. The latest available data released by the German statistical office Destatis show the country's industrial production rose for a second consecutive month in February. And while overall manufacturing output remained nearly 5pc lower than a year earlier, an index for the country's energy-intensive industries show a year-on-year uptick for the first time since February 2022.

Industrial gas demand appears to have moved in tandem with increased economic activity, posting a further uptick in March and the first half of April, according to *Argus* analysis. As German market area manager THE does not disaggregate industrial and power-sector gas demand, *Argus* assesses German industrial consumption based on power generation figures from German regulator Bnetza and assuming 36-40pc gas plant efficiencies, in line with fuel use figures from Destatis. Regular seasonal variations in the resulting figures suggest that part of the gas taken by industrial offtakers is used to heat their premises. In winter months, this may account for up to a third of industrial gas demand.

Industrial demand



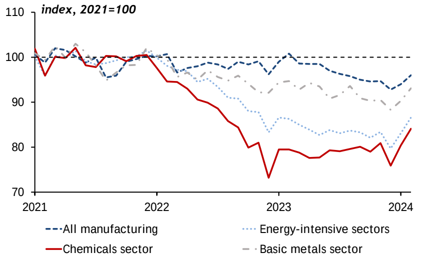
As the heating-related component of industrial gas offtake probably moves in parallel with swings in demand from households and small businesses, diverging trends between the two suggest a recovery in gas consumed in industrial processes. Industrial offtakers received about 1.1 TWh/d in March, 2pc more on the year, *Argus* estimates. By contrast, residential and commercial demand fell by about 20pc

GERMANY

in the same period. And while *Argus*-estimated industrial demand fell by 2pc on the year to 973 GWh/d on 1-15 April, residential and commercial demand fell by 40pc.

The recovery in industrial gas use stems largely from lower gas prices. European gas prices have fallen to nearly pre-crisis levels in the first quarter of this year, with the *Argus* TTF day-ahead index averaging €26.52/MWh in March, down from €44.50/MWh a year earlier. With natural gas prices regaining its competitiveness against alternative fuels such as LPG, some firms that had switched to using LPG as an energy source in industrial processes in the past two years have now switched back to natural gas. Lower prices also spurred higher utilisation rates at firms that use gas as a feedstock. Fertiliser producers Yara in March announced that, as a result of lower gas prices, it expected its European plants to run at or above 90pc of capacity in 2024, prioritising production at its most efficient plants in Sluiskil in the Netherlands and Brunsbuttel in Germany. Similarly, chemicals giant BASF in February said it would raise plant utilisation rates at its Ludwigshafen site, which could also lead to higher gas demand throughout this year.

Manufacturing output



— *Destatis*

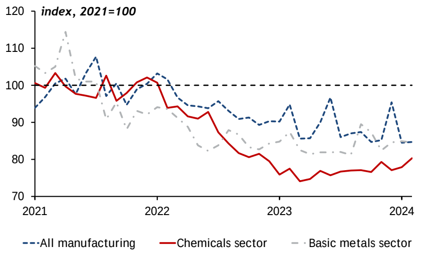
Gas may lose its ground

Despite the signs of recovery, the German industrial sector still faces a bleak outlook, according to industry federation BDI, which expects a 1.5pc drop in industrial production in 2024, the association's president, Siegfried Russwurm, says.

Even if prices have come down from the eye-watering levels of the past couple of years, they remain high by historical comparison. The *Argus* TTF day-ahead index was €17.68/MWh in March 2021. Even after adjusting for inflation, this was still roughly 20pc lower than in March this year. This has probably capped the increase in industrial gas use, which was about 15pc lower than the three-year average for the period in March and the first half of April.

And while lower gas prices provide scope for industrial demand to recover further in the short term, they may not be enough to bring industrial gas use back to pre-crisis levels. Many market participants believe the energy crisis may have triggered structural changes in Germany's industrial sectors. Some firms have opted to shut down part of their production capacity in Europe, saying energy prices in Europe are "structurally higher" than elsewhere. BASF already announced last year that it would permanently shut down some of its most-gas-intensive plants at its Ludwigshafen site. Similarly, BP in March announced that it would close a third of capacity at its Gelsenkirchen refinery, blaming high structural costs. German steel company Thyssenkrupp earlier this month joined the ranks of firms shutting down gas-intensive manufacturing activities, announcing its intention to cut steel production capacity at its Duisburg plant by about 20pc, or 2mn t/yr, because of "persistently challenging market conditions".

Destatis' new orders



— *Destatis*

Gas sellers have also sounded the alarm on industrials "jumping ship" from Germany. A combination of risk aversion, lack of planning security and an unfavourable price environment has prompted industrial firms to divert their investments away from Germany, Joerg Selbach-Roentgen, chief executive of trading firm MET Germany, tells *Argus*. While this may have been triggered by 2022 energy crisis, it is now driven by more long-term "strategic" considerations, he says.

Looking further ahead, energy transition goals may further weigh on industrial gas demand, both in Germany and Europe. Advancements in bioenergy and electrification may structurally reduce gas use in industrial processes. BASF on 17 April announced that it had started using two electrically-heated steam crackers in Ludwigshafen that previously existed only on pilot scale. The short-term economic drivers, coupled with long-term energy transition ambitions, may well mean gas' role in German industry has already peaked.

SOUTH KOREA

Elections cloud energy policy agenda

Government plans to revive nuclear in the power mix face an uphill battle, write Ronald Kim and Evelyn Lee

The opposition's landslide win in South Korea's parliamentary election could further hamper progress on the government's plans to expand nuclear power.

The largest opposition centre-left Democratic Party (DP) further tightened its grip on the country's national assembly by winning an absolute majority on 10 April, having secured 161 out of 300 seats, against 108 won by the ruling conservative People Power Party (PPP) of president Seok-Yeol Yoon. The PPP had hoped to secure a majority that would allow to push its legislative agenda, which has made little progress as the DP, together with other liberal parties, already held more than half of the seats before the election.

The government's energy policies, particularly its plan to boost the share of nuclear in the power generation mix, are among those that have been held back by the government's inability to get new laws approved by parliament. The DP and PPP have long disagreed over the role of nuclear. The DP and like-minded liberals have opposed president Yoon's decision to reverse the nuclear phase-out plan, a signature policy from his predecessor, Moon Jae-in of the DP. Yoon instead has pushed forward plans to further expand the country's nuclear fleet, by building more reactors and extending the lifespan of existing ones. But such plans hinged on the parliament's approval of a special law on radioactive waste management, which would provide a legal basis on which to build a permanent disposal facility before temporary storage facilities reach saturation level. The bill has struggled to make headway within the DP-controlled parliament and is even less likely to be approved in the changed political landscape.

South Korea's 10th power supply plan, published in 2022 and still in force, aims to boost the share of nuclear in the total power mix to 32.4pc by 2030, compared with 31pc in 2023, while the previous plan under former president Moon's administration targeted to reduce it to 25pc by 2030. The government was expected to publish an updated 11th long-term electricity plan before the election, but this has been delayed, and may be deemed to require adjustments, given that parliament needs to review it before it is finalised.

The Democratic Party could overturn the energy plan in three years, if it wins the next presidential election

Brighter outlook for gas under potential liberal comeback

The DP could overturn the energy plan in three years, if it wins the next presidential election. Gas may play a more central role in the power generation mix under a centre-left administration that seeks to reduce reliance on coal and nuclear, while significantly expanding renewable capacity.

In the latest parliamentary election manifesto, the DP proposed to retire all coal-fired plants by 2040, whereas there was no phase-out plan from the ruling PPP. The manifesto further said the DP would formulate a gradual fossil fuel exit strategy under the so-called "coal-fired generation phase-out law", while tripling the renewables capacity to a 40pc output share in the total electricity mix by 2035.

This implies South Korea would need more gas-fired units than the scheduled capacity under the conservative administration's energy plan if the DP wins the 2027 presidential election, as a means to providing transitional power supplies during the renewables rollout. The opposition party has not made specific pledges related to gas use, although the ninth energy plan under Moon's administration aimed to switch 24 coal-fired units to run on LNG, out of a total of 30 at that time. Under this plan, gas-fired output was to account for 23.3pc in 2030, compared with the current administration's 22.9pc target. Yoon's administration has been reluctant to approve new gas-fired projects since the release of the 10th plan. At least three applications for coal-to-gas fuel switching at combined-heat-and-power units in South Korea have been rejected by the energy ministry.

ARGENTINA

Milei has put gas and LNG exports firmly at the centre of his economic recovery plans, writes Lucien Chauvin

Argentina raises stakes on gas export plans

President Javier Milei's increasing focus on the gas and LNG sectors as a channel for economic reactivation became clear in the latest iteration of a massive omnibus bill he is fighting to push through congress.

LNG in particular gained more space in the newer version of the bill, which was presented to congress earlier this month. The original version, submitted last December, got caught up when lawmakers began voting down individual articles, so the government opted to withdraw it and restart the process. The government has also floated the idea of using executive orders for individual chapters, including those relating to energy, if congress fails to act by the end of May. In the new draft, Article 199 requires the energy secretariat to certify long-term gas reserves to ensure "firm and uninterruptable natural gas supply for LNG export projects". And LNG facilities will be granted 30-year contracts and allowed to export authorised volumes without "restrictions, reductions or redirection" of supply.

Vaca Muerta gas output, 2023		
Company	**Output (*mn m³/d*)**	**Wells drilled**
YPF	28.3	210
Tecpetrol	16.2	26
Total Austral	12.5	13
Pampa Energia	10.4	21
Pan American Energy	9.1	25
Pluspetrol	5.9	24
		— Energy Secretariat

Argentina has long sought to monetise its vast but underdeveloped gas reserves, particularly those in the giant Vaca Muerta shale formation, which holds an estimated 308 trillion ft³ of gas reserves, but only 4pc of its acreage has been developed so far, according to the US Energy Information Administration. The country has a second unconventional formation — Palermo Aike, which could hold more than 130 trillion ft³ in shale gas — and is home to the world's southernmost offshore production block, CMA-1, operated by TotalEnergies in partnership with Germany's Wintershall Dea and Argentina's Pan American Energy.

A preliminary deal to build a massive LNG export facility was signed by state-owned YPF and Malaysia's state-owned Petronas under the previous administration, which also sought to secure parliamentary approval for an LNG promotion bill aimed at unlocking the $60bn investment. But unlike Milei's bill, the previous government aimed to maintain some restrictions on LNG exports, such as an obligation that firms sell domestically at least a tenth of their production in June-August, Argentina's peak winter demand season.

Similarly, Milei has not scrapped his predecessor's plans to tie the recently commissioned 21mn m³/d President Nestor Kirchner pipeline, which links Vaca Muerta to Buenos Aires, to the existing northern gas pipeline, originally built to supply the capital, first with gas from the now-depleted northern fields and later with Bolivian imports. Argentina still receives 8mn m³/d from Bolivia under a long-term contract that expires in October, and already plans to use the pipeline in reverse flow to switch to exports as Bolivian production dwindles.

Milei's government aims to use the same scheme to tap the region's biggest market — Brazil

Milei eyes exports to Brazil

Milei's government has also embraced the previous administration's idea of using the same scheme to tap the region's biggest market, Brazil. The proposal involves using the pipeline that links Bolivia to Brazil, paying Bolivia a transport fee.

Bolivia instead has offered to buy Vaca Muerta gas and resell it to Brazil, sources at Argentina's energy secretariat say. But the government has rejected this idea and is looking at alternatives, including linking the northern pipeline directly to Brazil or extending the Argentina-Uruguay pipeline by another 350km to the border with Brazil. Argentina already exports gas to Uruguay, as well as Chile, but flows at present are minimal — 350,000 m³/d and 400,000 m³/d, respectively.

The other option would be exporting LNG to Brazil, if the planned liquefaction plant is built. But the project's first phase, which involves the installation of a 2mn t/yr floating LNG unit, would not start exporting before 2027. The government aims to reach 25mn-30mn t/yr of combined LNG export capacity, including both offshore and onshore facilities, by the early 2030s.

PANAMA

Panama Canal LNG transits may remain muted

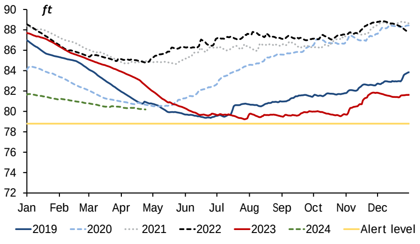
A planned rise in slot availability may not dent a long-term decline in LNG transits through the waterway, writes Martin Senior

The Panama Canal authority has started to unwind some of the transit restrictions it recently put in place to cope with low water levels, but LNG carriers' use of the waterway may remain muted in the medium term.

Subsequent transit restrictions imposed by Panama Canal's operator, ACP, in late 2023 have weighed heavily on the number of LNG carriers using the waterway in recent months. Only 16 LNG carriers transited the canal — either loaded or empty — in the first quarter of 2024, according to data from trade analytics platform Kpler. This is down from the 19 transits recorded in December 2023 alone, and the lowest quarterly transit rate since 2017. Standard-sized LNG tankers almost exclusively use the Neopanamax locks, with only three of the 326 LNG carriers to transit the canal from October 2022-September 2023 having used the smaller Panamax locks, according to ACP data. But ACP had reduced the number of daily Neopanamax slots to just six available for pre-booking, with an additional one auctioned daily, down from a total of 10 daily slots earlier in 2023.

Such restrictions were put in place because of a drought at Gatun lake, which sits above sea level between the Pacific and Atlantic locks and loses water every time a ship uses the locks. Rainfall in Panama is typically lower between January and May, but unusually low rainfall last year resulted in Gatun's water levels recovering much slower than usual in the second half of that year. This was caused by the El Nino weather phenomenon, according to ACP. Water levels may rise faster later in the year with a transition to a La Nina weather phenomenon, which typically brings more rainfall to Panama, considered more likely, according by the latest probabilistic forecast from the US National Oceanic and Atmospheric Administration's Climate Prediction Center. A projected increase in water levels at Gatun lake prompted ACP to announce plans to slightly increase slot availability to eight per day from June onwards, including the daily auctioned slot.

Gatun lake depth



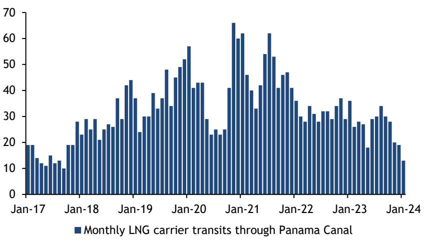
— ACP

Falling out of fashion?

Yet increased availability of Neopanamax slots may not be able to significantly spur market interest in using the waterway, as its slot-booking system remains unfavourable to LNG carriers and auctioned slots are not sought after by traders.

The Panama Canal is increasingly getting out of the picture for LNG, shipping registry Lloyd's Register's gas segment director, Panos Mitrou, said last year. The waterway has been largely ignored by many US offtakers as a viable trade route even when Neopanamax transits averaged 10 per day, as most US offtakers are not high enough on ACP's customer ranking to get slots. ACP's slot priority system favours container shipping firms, which use the canal more frequently, leaving fewer slots available for LNG transits. Of the six available pre-booked daily slots for the Neopanamax locks, only two are available for LNG carriers to bid for, from five available earlier in 2023, although container ships have priority over LNG carriers for all pre-booked slots.

Monthly LNG carrier transits



— *Kpler*

This has pushed LNG carriers to make greater use of the Cape of Good Hope or Suez Canal routes. Cheniere and Chevron — 127th and 15th on ACP's ranking, respectively — told *Argus* in July last year that neither firm uses the canal for LNG transit because of the waiting times for vessels without a pre-booked slot. Shell is 24th on the list, and the firm still ships most of its cargoes from Peru's 4.4mn t/yr Pampa Melchorita terminal to northwest Europe through Cape Horn, rather than take the much shorter journey through the Panama Canal. Using either the Cape of Good Hope or Suez route to reach Asian markets had probably become the norm for spot US deliveries, as the rapid growth in US liquefaction capacity already outstripped the availability of Panama transit slots for LNG carriers by

PANAMA

Sabine Pass to Asia*			*days*
Delivery terminal	**Via Panama**	**Via Cape of Good Hope**	**Days saved via Panama**
Tokyo	51	84	33
Incheon	57	83	26
Shenzen Taipei	59	74	15

*delivery times (round-trip)

2021, driving an increasing share of US cargoes either to seek a destination market within the Atlantic basin or take one of the longer routes to Asian markets.

And LNG carriers have shown a lack of interest in the daily auctioned slots that were introduced this year, from only occasional slots in the fourth quarter of last year. This is despite lower prices achieved at recent auctions, potentially making it cheaper to use the Panama route. Nine Neopanamax slots were auctioned on 14-18 April — none bought by LNG carriers — at a range of $256,000-701,000, well below the $3.975mn achieved for a single slot at an auction in November last year. The average premium to ship a 160,000m³ cargo by tri-fuel diesel-electric (TFDE) carrier from the US Gulf to Tokyo, Incheon and Shenzhen through the Cape of Good Hope over the Panama Canal was 32¢/mn Btu on 18 April. Assuming the average auction price from 14-18 April at $517,000 and a 160,000m³ cargo, it would cost 14¢/mn Btu to secure an auctioned slot, barely within the 16¢/mn Btu premium for one leg of the journey through the Cape of Good Hope.

With spot charter rates in contango until the fourth quarter, the incentive to buy auctioned slots may increase later in this year. But even when seeking auctioned slots makes sense economically, it may not make logistical sense, market participants say. Slots are typically auctioned seven days before the transit date, which may be too soon for some US Gulf offtakers, which usually fix cargoes further ahead of time. And with the risk of cancelled slots or volatile slot prices at the Panama Canal, trading firms can value the reduced risks that shipping a cargo through the Cape of Good Hope entails. Firms with smaller fleets may not be able to take advantage of the reduced sailing days on such a prompt basis, market participants say, meaning the opportunity cost is only applicable for firms with larger fleets. And with TFDE carriers facing a typical boil-off rate of up to 0.1pc/d, firms may be wary of approaching the canal without a pre-booked slot. Assuming a boil-off rate of 0.1pc/d, a cargo size of 160,000m³ and a round-voyage rate of $40,000/d, it would cost about 18¢/mn Btu for a 10-day wait offshore Panama.

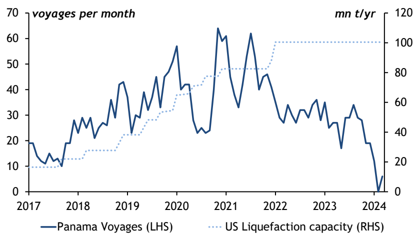
With spot charter rates in contango until the fourth quarter, the incentive to buy auctioned slots may increase later in this year

What next?

Going forward, a continued reconfiguration of the LNG supply-demand balance in the Atlantic and Pacific basins may further reduce the incentive for LNG trading companies to use the Panama Canal.

LNG trade flows through the canal have fallen sharply since 2022, after Europe's LNG demand surged in the wake of Russia's invasion of Ukraine and the subsequent drop in Russian gas supplies. But while Europe's LNG demand is set to stay higher than pre-2022 levels in the medium term, it has already slowed since mid-2023, and potential for further growth may be well short of the expected build-up in US exports. Production capacity from US Gulf coast facilities that have already reached a financial close is set to nearly double, to about 170mn t/yr, by the end of this decade. Notwithstanding other Atlantic basin supply, this is beyond Europe's record LNG imports of 127mn t/yr in 2022, according to data from oil analytics firm Vortexa.

Panama transits vs US liq. capacity



— Kpler, Argus

While the potential for LNG demand growth is much stronger in Asian markets, higher liquefaction capacity on the west coast of North America — such as Shell's 14mn t/yr LNG Canada project, which is set to begin operations by about the end of this year — as well as Qatar's 65mn t/yr expansion projects, could mean that much of this growth is met by supplies that do not require transit through the Panama Canal. But even if rising Atlantic basin output eventually results in more demand for Panama transits, the uncertain configuration of the global LNG market, which is often subject to swings in global price spreads, may provide little incentive for ACP to change its priority allocation system in favour of LNG tankers.

IN BRIEF

Dutch senate votes to shut Groningen gas field

The Dutch senate has approved a bill that will permanently halt production at the giant Groningen low-calorie gas field at the end of September. The plenary discussion took place on 14 April, and 12 of the 15 factions supported the bill. Those that opposed warned that there is no good alternative to Groningen and called the shutdown a "destruction of capital". Groningen production is being phased out because the field causes increased seismic activity. It was preliminarily shut on 1 October last year, and no production is planned for this gas year.

Austrian MEP asks EU to act on German gas storage levy

First vice-president of the European Parliament Othmar Karas and Austrian energy minister Leonore Gewessler have asked the European Commission to comment on Germany's gas storage levy within three weeks. Karas submitted an urgent parliamentary question on the matter on 16 April, referencing an attempt by central European countries to get the commission to act on the matter in February. Karas asked the commission to assess the incompatibility of the German storage levy, which is charged on all gas exiting the German grid, with "the principles of the internal market and EU law".

Ukraine delays gas market liberalisation

State-owned Naftogaz's public service obligation (PSO) to supply gas to Ukraine's residents, distribution system operators and electricity producers has been extended by the government. This obligation applies until 31 August. The government also extended a commitment from state-owned Ukrgazvydobuvannya and Chornomornaftogaz to sell their gas production at 7,240 hryvnia/'000m³, including value-added tax, to Naftogaz to meet its PSO needs.

Texas LNG delays FID, signs second agreement with EQT

US infrastructure developer Glenfarne has signed a non-binding agreement to provide 1.5mn t/yr of LNG to US firm EQT for 20 years from its planned 4mn t/yr Texas export terminal through a liquefaction tolling deal and also delayed its final investment decision (FID) on the project. This is the second preliminary deal that EQT has signed for Texas LNG tolling services, following a similar 15-year deal for 500,000 t/yr signed in January. This lifts total offtake signed under non-binding agreements to 2.5mn t/yr.

Mexico gas midstream growth to pull 1 Bcf/d from US

New LNG and natural gas pipeline infrastructure in Mexico is expected to push up US pipeline gas exports by 7.7pc through 2025, the US Energy Information Administration (EIA) said. "We expect US natural gas exports by pipeline to grow by almost 1 Bcf/d over the forecast period, mainly because of increased natural gas exports to Mexico," it said. US pipeline exports — to Mexico and Canada — will increase by 3.2pc to an average 9.24 Bcf/d this year and by 7.7pc to 9.64 Bcf/d in 2025 compared with this year, according to the EIA.

India's RIL, BP ramp up KG-D6 gas output in FY2023-24

Indian private-sector refiner Reliance Industries (RIL) and BP have raised gas output from "difficult fields" located in the Krishna-Godavari (KG) basin off India's east coast by 40pc on the year to 27.1mn m³/d during the April 2023-March 2024 financial year. The KG-D6 block, which includes the aforementioned difficult fields, is currently producing 30mn m³/d of natural gas, accounting for 30pc of India's overall gas production, and about 23,000 b/d of crude and condensate.

GLOBAL GAS MARKET OVERVIEW

Global LNG arbitrage edges wider

The differential between LNG delivered prices in Europe and Asia widened slightly at the start of this week compared with a fortnight earlier, after closing earlier this month, which may provide scope for some rebound in inter-basin LNG flows.

The *Argus* northeast Asia (ANEA) des price for deliveries in the second half of May increased its premium to the northwest European price for first half of May deliveries to $1.31/mn Btu on 22 April, from 75¢/mn Btu on 8 April and after dropping to just 2¢/mn Btu on 16 April.

If sustained, the differential may be sufficient to incentivise LNG cargoes loading in the Atlantic basin to head to Asian markets instead of Europe, particularly as charter rates for LNG carriers have edged lower in the past fortnight.

LNG charter rates have fallen in the past two weeks, even despite a rise in spot charter market activity, as high vessel availability continues to amply meet requirements. Downtime at the US' Freeport LNG terminal in particular buoyed the number of vessels on offer in the prompt market. Activity in the Atlantic market continues to outstrip that of the Pacific market, underpinning a small premium in west of Suez rates over east of Suez rates.

LNG prices in both northeast Asia and northwest Europe were higher on 22 April compared with two weeks earlier, having risen in mid-April before shedding some of these gains later in the month. Asian markets have seen a spate of spot trades in recent days, mostly pegged in the low $10s/mn Btu.

The earlier gains were driven by sharp increases in European downstream gas markets. TTF prompt prices have risen in the past two weeks on the back of cool weather and unplanned maintenance at Norwegian fields.

Below-average temperatures have pushed up demand in Europe, sending countries including the Netherlands and Germany back to net withdrawals.

And heightened geopolitical tensions may have played a role, with Russian attacks targeting Ukrainian storage sites on 11 April, although this is unlikely to have affected short-term market fundamentals.

As a result, European des prices also firmed, narrowing their discount to the corresponding European hubs. But both prices have fallen back since then, with European hubs outpacing the slide in Asian markets.

Margins for long-term offtakers of US LNG widened ahead of the 20 April deadline for confirming June-loading schedules. The *Argus* Gulf Coast spot fob price for June loadings rose to $8.90/mn Btu on 19 April from $7.75/mn Btu a fortnight earlier, while Henry Hub prices continued to ease on high stocks and slow demand as the market moves deeper into the spring shoulder season.

KEY PRICE MOVEMENTS

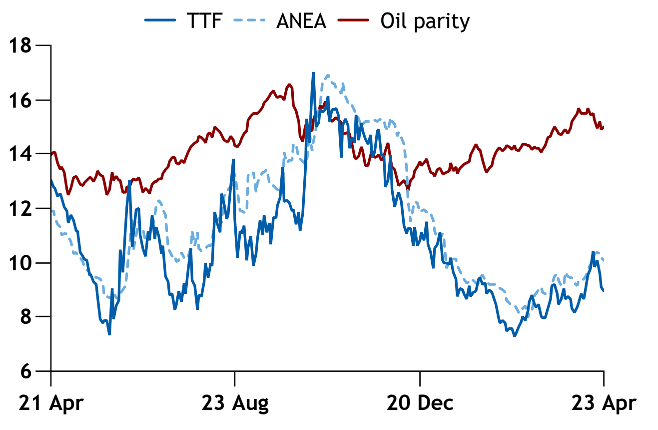
- The TTF May contract rose to $9.11/mn Btu on 22 April from $8.84/mn Btu a fortnight earlier, on cooler weather and unplanned maintenance at Norwegian fields

- European LNG prices firmed, narrowing their discount to corresponding hub prices and outpacing gains in northeast Asian markets

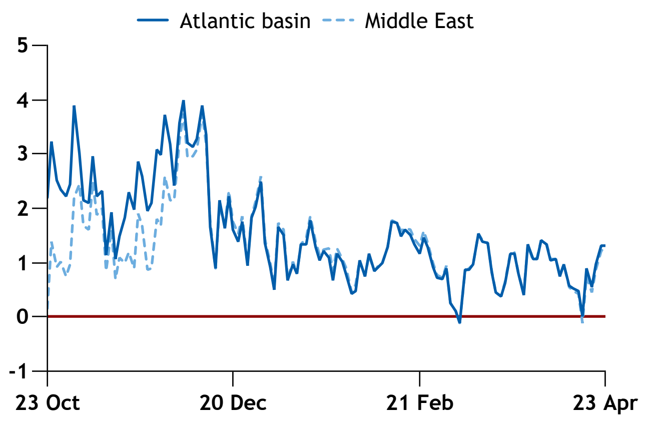
- Gas futures for May delivery at the Henry Hub settled on 23 April at $1.812/mmBtu, down by 3pc from two weeks earlier and about a fifth lower than a year earlier

- Charter rates for LNG carriers edged lower, with high vessel availability offsetting an increase in spot market activity

TTF, ANEA vs oil parity *$/mn Btu*

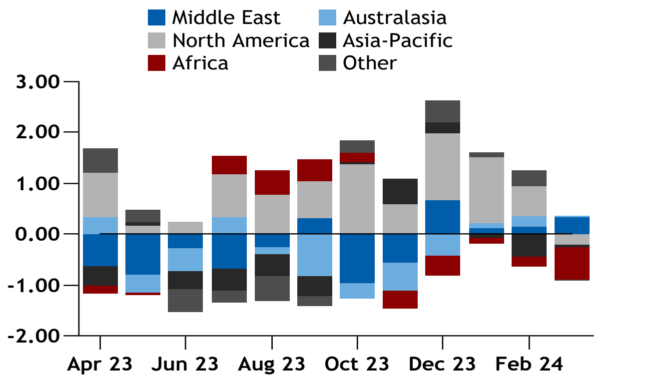


Global arbitrage *$/mn Btu*

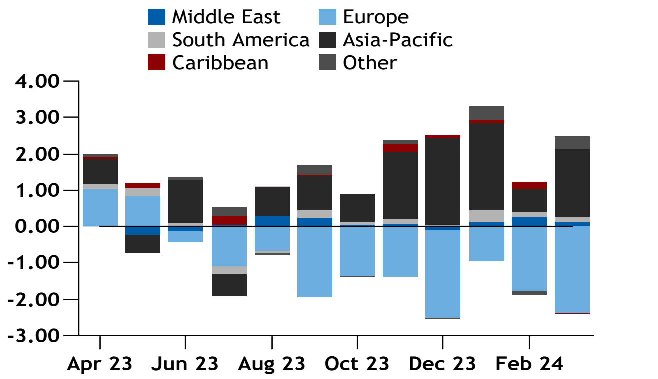


LNG TRADE FLOWS

LNG exports, y-o-y change *mn t*



LNG imports by region, y-o-y change *mn t*



Global LNG exports edge lower in March

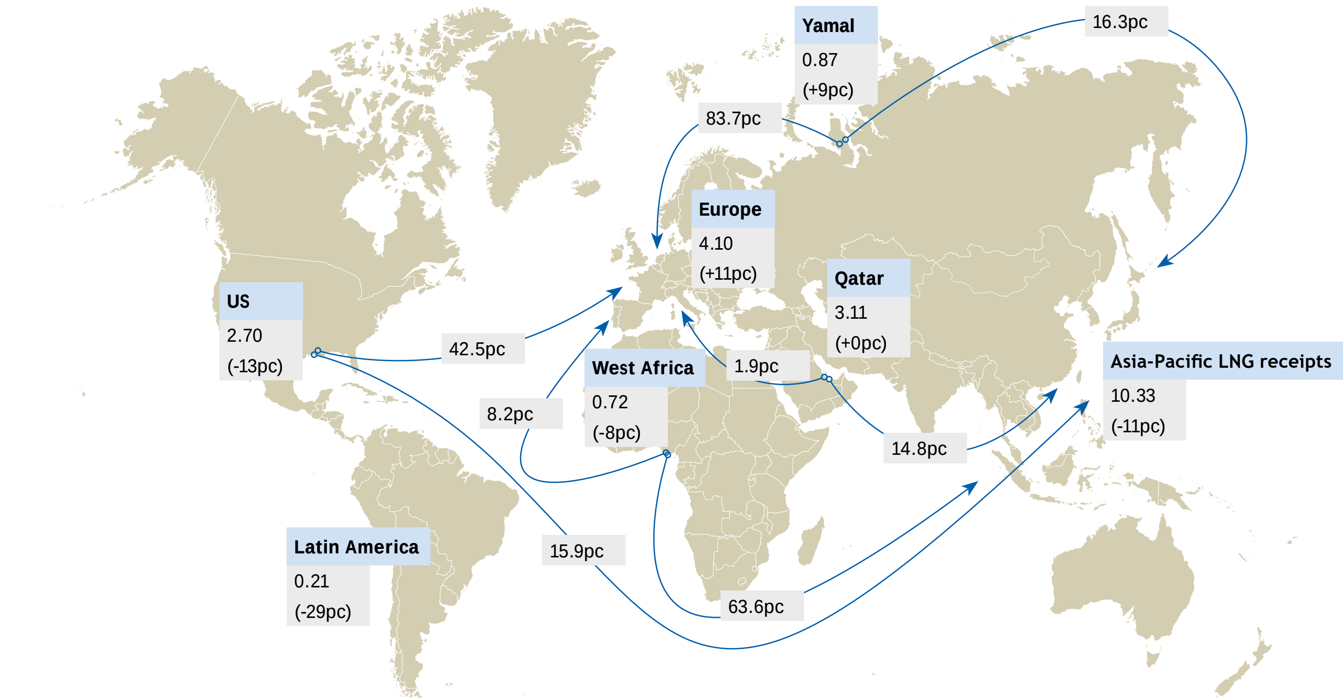
Global exports of LNG were lower than a year earlier in March as reduced output in Egypt and Nigeria outweighed increased production in the US.

Combined LNG exports stood at 35.9mn t in March 2024, down from 36.1mn t a year earlier, according to data from analytics firm Kpler. The fall was driven mainly by lower Egyptian loadings, which fell sharply on the year from 610,000t to a single 70,000t cargo, their lowest monthly loadings for the 2023-24 winter. Exports were already curbed earlier in the season by downtime at the East Mediterranean Gas pipeline and Israel's Tamar field in early October, with Egypt having only resumed exports in late November.

Nigerian exports also dipped, to 1.06mn t from 1.32mn t a year earlier — a decline of nearly 20pc. March's loadings were also down compared with the 1.21mn t shipped in February 2024, itself a drop from the recent high of 1.47mn t in January. The country's 22mn t/yr Bonny terminal continues to receive variable amounts of feedgas because of ongoing issues with upstream production that forced terminal operator NLNG to declare a force majeure in October 2022.

US exports rose to 7.35mn t from 7.07mn t — the largest annual increase of any country, leaving the US to overtake Australia as the largest LNG exporter for the month. The increase resulted from the combined effect of elevated production at five of the country's seven LNG export terminals. The 12.4mn t/yr Calcasieu Pass facility in Louisiana posted a particularly large increase of 150,000t on the year.

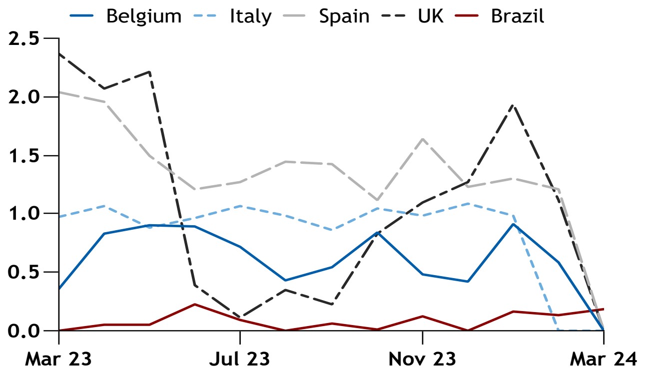
Latest estimated gas imports and exports *mn t*



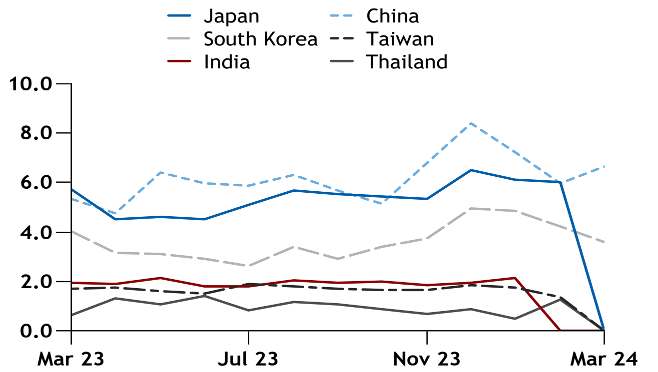
± change represents past two weeks vs previous two weeks

LNG TRADE FLOWS

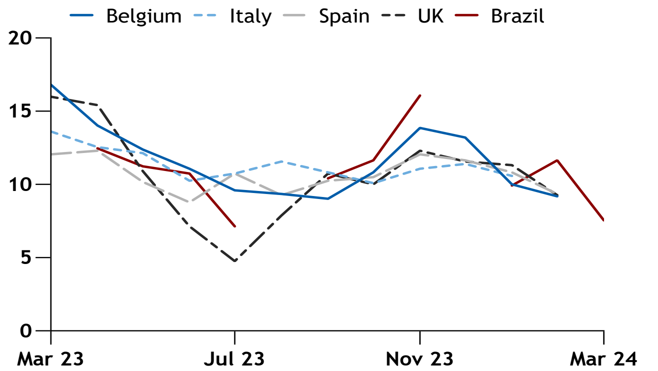
Atlantic basin LNG import volumes (customs data) *mn t*



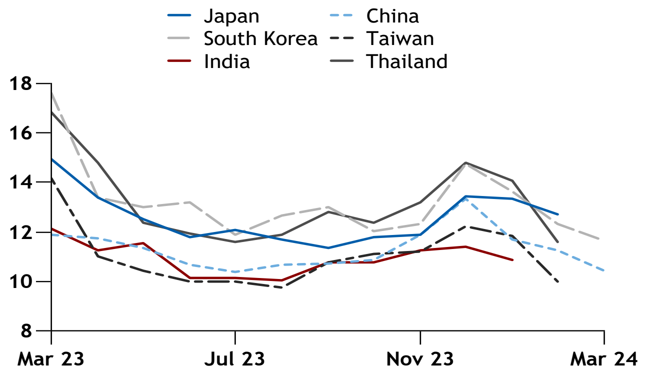
Asia-Pacific LNG import volumes (customs data) *mn t*



Atlantic basin LNG import prices (customs data) *$/mn Btu*



Asia-Pacific LNG import prices (customs data) *$/mn Btu*



Declared LNG import volumes *'000t*

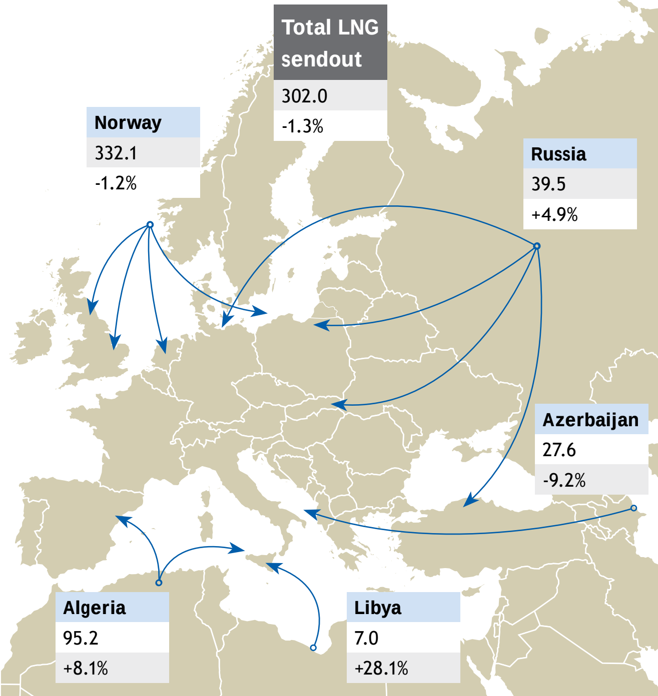
Importer	Oct	Nov	Dec	Jan	Feb	Mar
Northeast Asia						
China	5,169	6,801	8,401	7,248	5,951	6,648
Japan	5,413	5,330	6,496	6,109	6,025	0
South Korea	3,394	3,718	4,969	4,852	4,202	3,610
Taiwan	1,652	1,652	1,860	1,744	1,374	0
South and southeast Asia						
India	2,003	1,824	1,930	2,137	0	0
Pakistan	0	0	0	0	0	0
Bangladesh	0	0	0	0	0	0
Thailand	890	704	892	491	1,260	0
Europe						
UK	829	1,097	1,266	1,939	1,120	0
Netherlands	1,854	1,780	2,304	1,504	1,669	0
Belgium	840	486	422	907	583	0
Germany	448	297	488	480	424	0
Poland	0	0	0	0	0	0
Lithuania	0	0	0	0	0	0
France	0	0	0	0	0	0
Spain	1,113	1,636	1,226	1,299	1,206	0
Portugal	357	176	292	235	239	0
Italy	1,046	980	1,090	980	0	0
Croatia	130	133	187	126	125	0
Greece	204	35	102	48	268	0
Turkey	0	0	0	0	0	0
Latin America						
Brazil	9	120	0	165	133	189
Argentina	0	0	0	0	0	0
Chile	117	115	109	86	196	0

Declared LNG import prices *$/mn Btu*

Importer	Oct	Nov	Dec	Jan	Feb	Mar
Northeast Asia						
China	10.84	11.88	13.34	11.69	11.24	10.43
Japan	11.77	11.89	13.44	13.35	12.69	
South Korea	12.04	12.34	14.73	13.64	12.31	11.62
Taiwan	11.09	11.19	12.23	11.85	10.00	
South and southeast Asia						
India	10.77	11.24	11.40	10.87		
Pakistan						
Bangladesh						
Thailand	12.35	13.17	14.81	14.07	11.60	
Europe						
UK	9.97	12.29	11.56	11.32	9.22	
Netherlands	12.05	13.61	13.50	10.30	9.34	
Belgium	10.82	13.85	13.18	9.99	9.16	
Germany	10.18	17.66	12.21	14.17	13.29	
Poland						
Lithuania						
France						
Spain	10.46	12.02	11.60	10.83	9.31	
Portugal	9.82	9.21	9.28	7.87	8.67	
Italy	10.06	11.10	11.37	10.59		
Croatia	11.25	14.82	14.55	13.00	11.80	
Greece	8.95	11.78	15.88	21.01	10.33	
Turkey						
Latin America						
Brazil	11.65	16.06		9.89	11.64	7.55
Argentina						
Chile	6.33	7.87	7.06	7.16	7.69	

EUROPE

Supplies from key routes (month to date) *mn m³/d*



European stockbuild slows

The EU stockbuild has continued over the past two weeks, despite colder weather bolstering heating demand enough for net withdrawals on several days, but milder weather may allow firms to step up injections over the next fortnight.

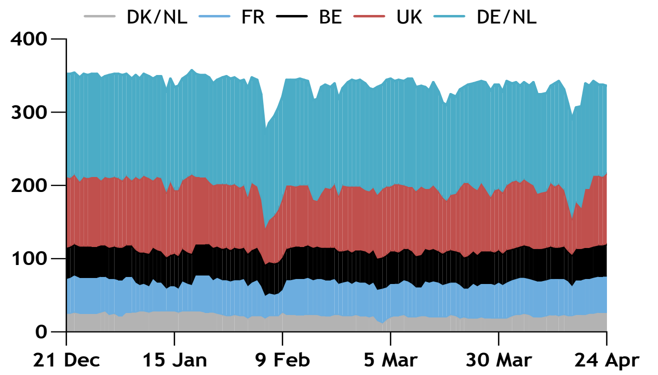
EU stocks were at more than 703TWh on the morning of 22 April, filling 62pc of capacity and up from about 680TWh two weeks earlier. Net injections averaged 1.59 TWh/d on 8-21 April, nearly three times faster than the roughly 550 GWh/d on 25 March-7 April.

But daily stockfill rates over the past two weeks reflect how quickly a cold spell sweeping Europe can tighten supply and limit the stockbuild. Generally mild weather leading up to mid-April enabled EU net injections to reach an eight-month high of 3.85TWh on 13 April, the quickest for any day since 4.13TWh on 13 August last year.

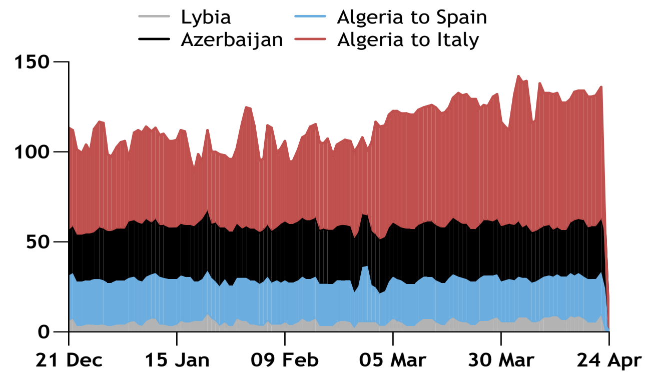
Shortly after this, as minimum temperatures fell, stock additions to the EU storage system slowed markedly and briefly switched back to net withdrawals. Just over 235 GWh/d of net supply exited EU storage sites on 18-19 April.

On the whole, milder conditions in recent days have eased heating demand across Europe, enabling EU-wide stocks to rise by about 610 GWh/d on 20-21 April. But persistent unseasonably cold conditions have driven a quickening

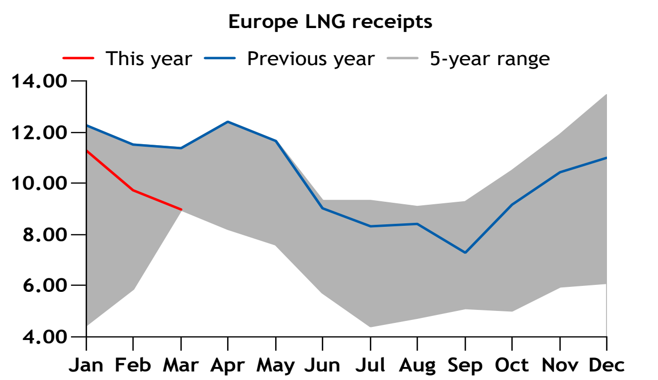
Norway pipeline supply to EU *mn m³/d*



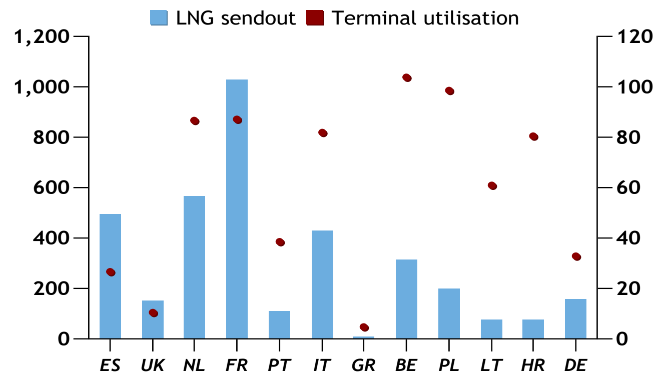
Supply to EU from southern routes *mn m³/d*



Europe LNG seasonality chart *mn t*

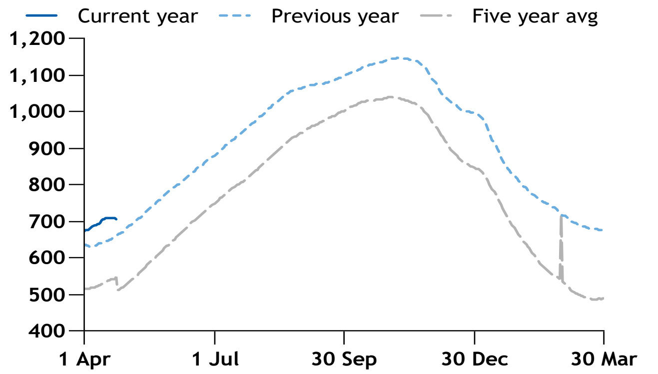


LNG sendout and terminal utilisation *GWh/d*

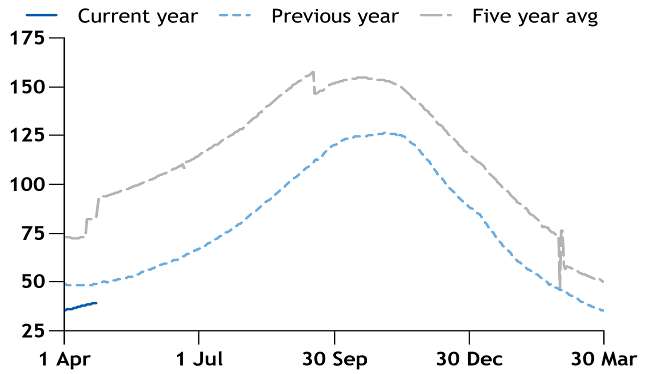


EUROPE

Total EU + UK gas stocks *TWh*



Ukraine stocks *TWh*



stockdraw in recent days in Germany, the EU country with the single-largest storage capacity of 246TWh.

German net withdrawals have quickened over the past week, rising to a six-week high of more than 860GWh on 22 April, up from about 260GWh on 16 April. This trend left the two-week average German stockbuild at just 37 GWh/d on 9-22 April, about half of the 71 GWh/d of net injections two weeks earlier.

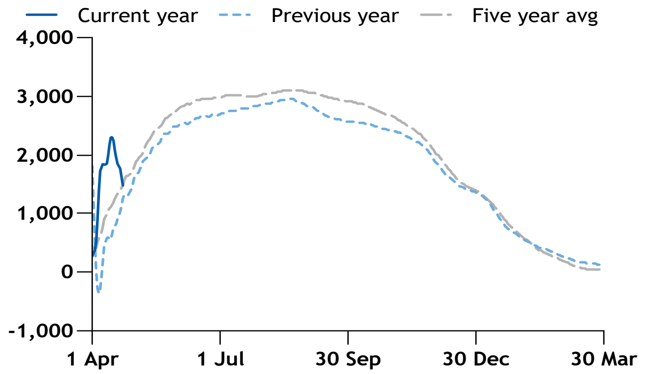
By contrast, in Italy — the EU country with the second-largest storage capacity — weather has been milder, and net injections have been uninterrupted since late March. In fact, the pace of the stockbuild has doubled in Italy over the past month, topping 530 GWh/d on 9-22 April, from about 225 two weeks earlier.

But warmer weather is forecast in Germany and other large gas-consuming EU member states in the next fortnight, which could weigh on heating demand, freeing up supply for faster injections.

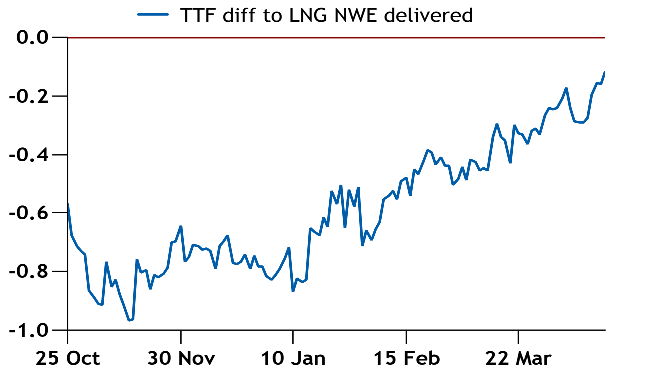
Average overnight lows in Berlin were forecast on 23 April to rise to about 11°C on 30 April-6 May, nearly 3°C above seasonal norms, from a below-average 3°C on 23-29 April and about 5°C over the two preceding weeks.

Further east, minimum temperatures in the Polish capital city of Warsaw were predicted to increase from an unseasonably low average of 4°C on 23-29 April, in line with the previous two weeks, to a higher-than-normal 10°C on 30 April-6 May.

EU + UK storage movements *GWh/d*



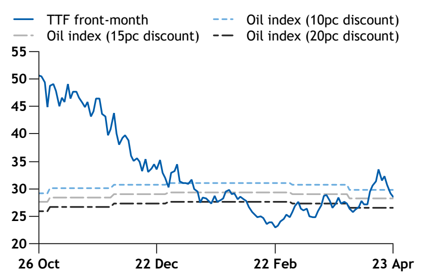
NW Europe LNG des-TTF spread *$/mn Btu*



Aggregate EU, UK and Ukraine inventories and storage movements *TWh*

Month	Initial stocks	% of capacity	Net withdrawals (injections)	1 year earlier	5-year average
Nov 23	1,268	86.3	1,748.4	1,175	1,367.5
Dec 23	1,202	81.7	3,918.6	1,140	1,370.9
Jan 24	1,080	73.5	6,672.5	1,022	1,374.5
Feb 24	861	58.6	2,956.9	878	1,378.5
Mar 24	761	51.7	1,615.4	740	1,383.6
Apr 24	709	48.5	-1,014.0	683	1,388.1

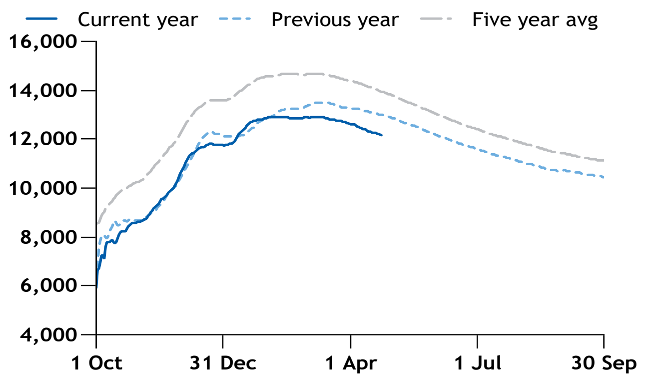
TTF vs oil-linked LT contracts *€/MWh*



EUROPE

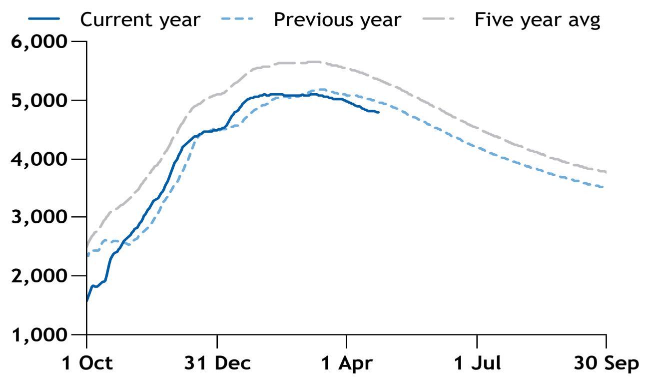
European demand by country, month to date										*GWh/d*
	Belgium	**France**	**Germany**	**Italy**	**Netherlands**	**Poland**	**Portugal**	**Spain**	**UK**	**Total**
Local distribution	217.9	549.8	807.4	579.4	357.9	365.7	58.7	na	1,259.5	**4,196.3**
Industrial	125.5	264.8	na	353.1	na	132.2	29.0	na	42.2	**946.7**
Power sector	52.1	7.3	na	400.1	na	na	4.7	140.8	218.1	**823.1**
Total consumption	**395.4**	**1,674.2**	**2,046.3**	**2,665.2**	**739.6**	**497.8**	**92.4**	**929.1**	**1,519.7**	**10,559.6**
±% year earlier	**-9.5**	**-16.1**	**-15.7**	**-15.1**	**-4.7**	**0.8**	**-16.7**	**-28.3**	**-16.3**	**-15.5**

Aggregate demand *GWh/d*



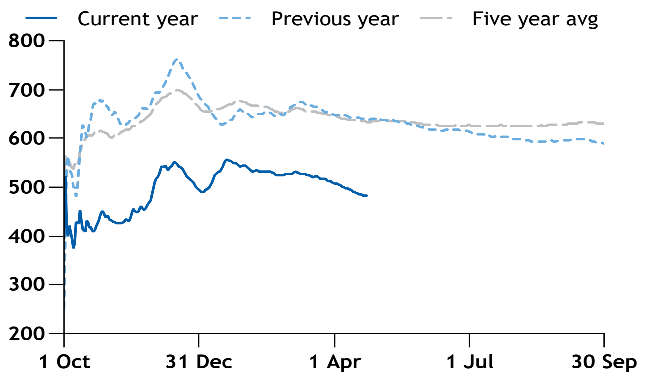
includes data on Spain, UK, Netherlands, France, Portugal, Italy, Poland, Germany, Romania, Hungary, Czech Republic, Belgium, Bulgaria, Croatia

LDZ demand *GWh/d*



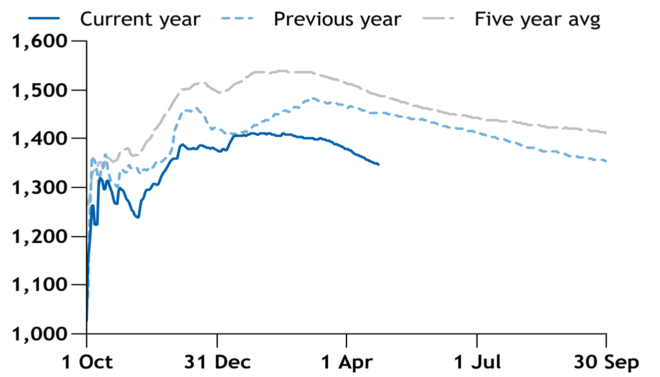
includes data on UK, Netherlands, France, Portugal, Italy, Poland, Germany, Romania, Belgium, Hungary

Power sector gas demand *GWh/d*



includes data on Spain, UK, France, Portugal, Italy, Belgium

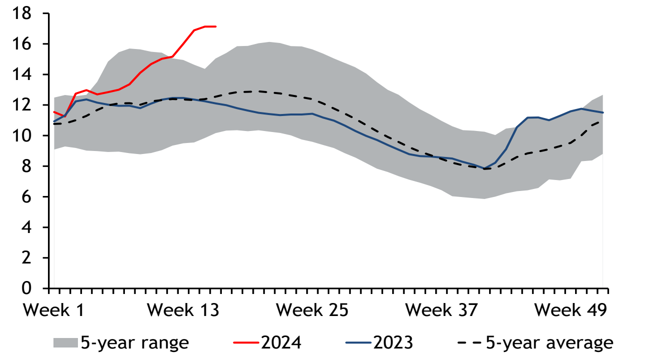
Industrial demand *GWh/d*



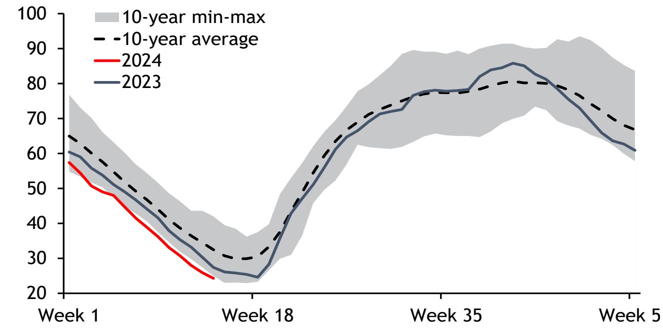
includes data on UK, France, Italy, Portugal, Belgium, Poland

Click here to download European gas demand data

Spanish hydroelectric stocks *TWh*



Nordic hydroelectric stocks *GWh*



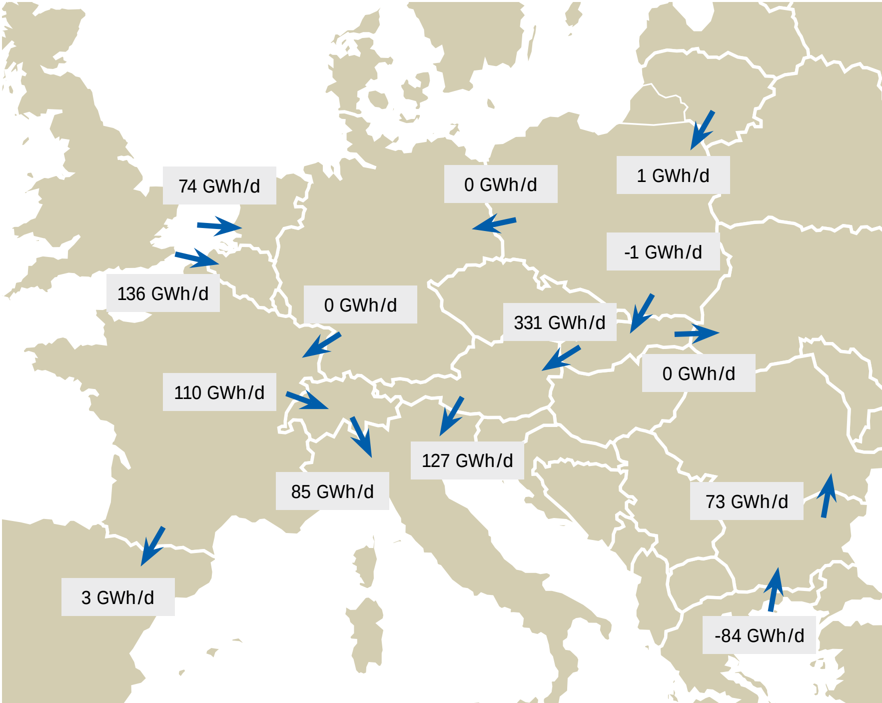
— Nord Pool

EUROPE

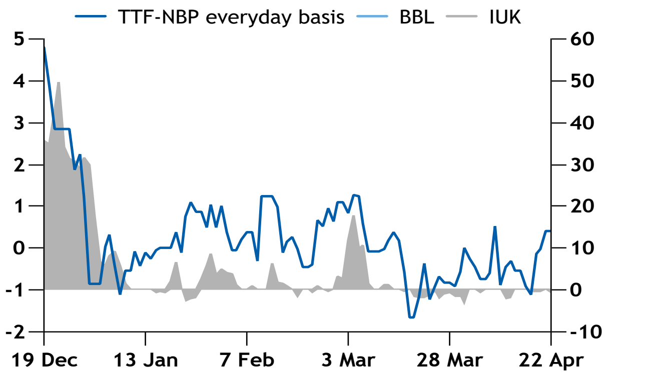
HIGHLIGHTS

- UK exports to the continent have slowed recently as unplanned maintenance on Norwegian fields limited gas supply while cool weather supported domestic demand.
- Maintenance at Oltingue has halted flows from France to Italy through Switzerland. Flows are to restart on 27 April, but some restrictions will remain until 4 May.
- Flows at Pirineos reversed in mid-April, and Spain has been exporting to France.
- The Finland-Estonia Balticonnector restarted commercial operations on 22 April after a rupture in October last year.

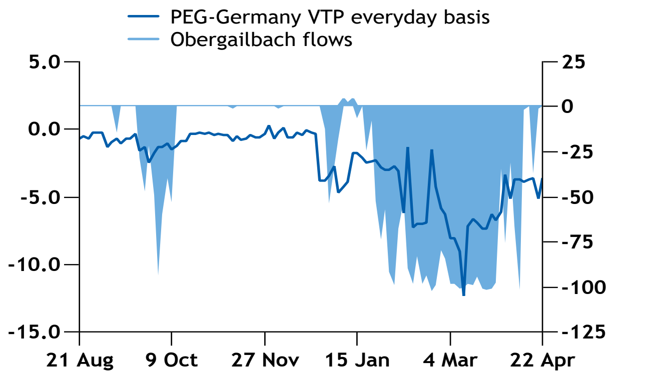
Cross-border flows



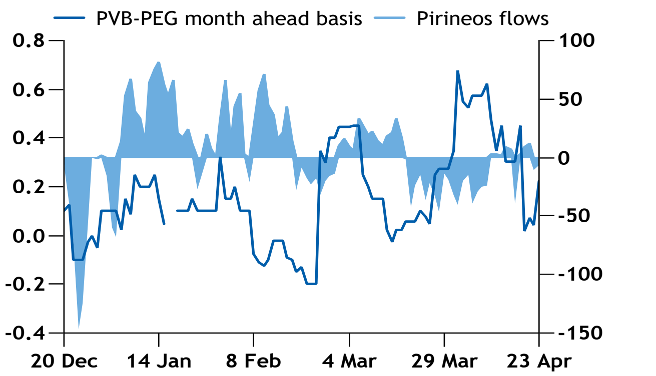
UK-EU gas flows *mn m³*



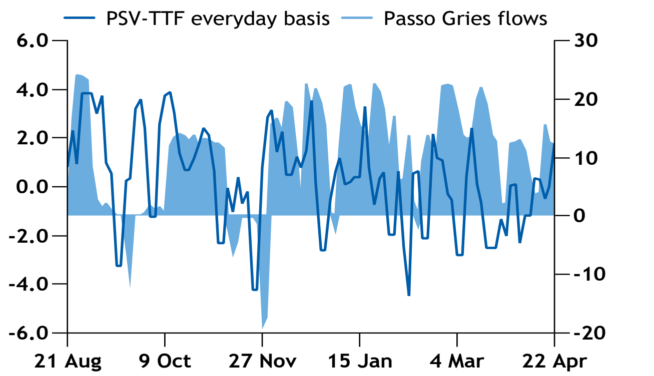
Germany-France gas flows *GWh/d*



France-Spain gas flows *GWh/d*

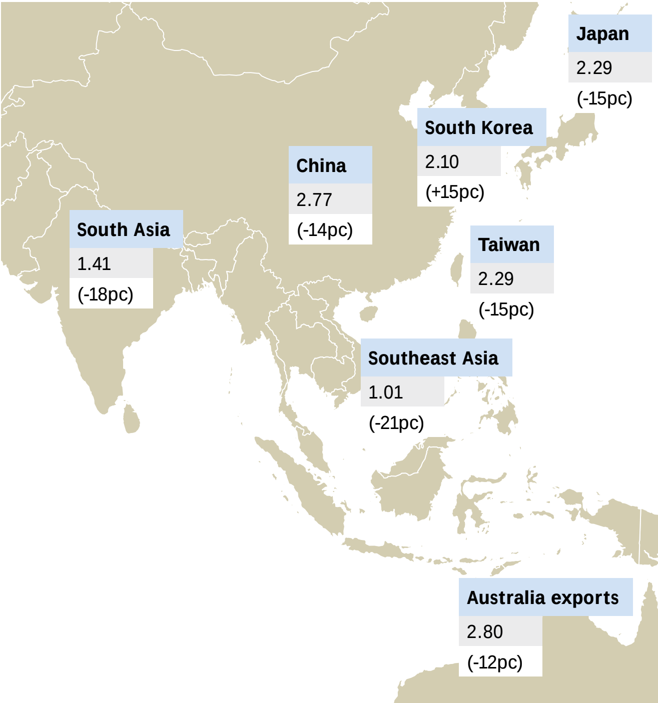


Switzerland-Italy gas flows *mn m³*



ASIA-PACIFIC

LNG deliveries to Asia-Pacific *mn t*



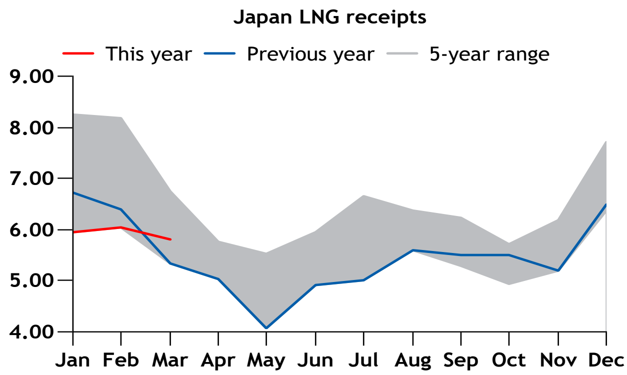
Japanese utilities add to LNG stocks

LNG stocks held by Japan's main power utilities rose during the week to 21 April, as mild weather weighed on power demand and cut gas-fired generation.

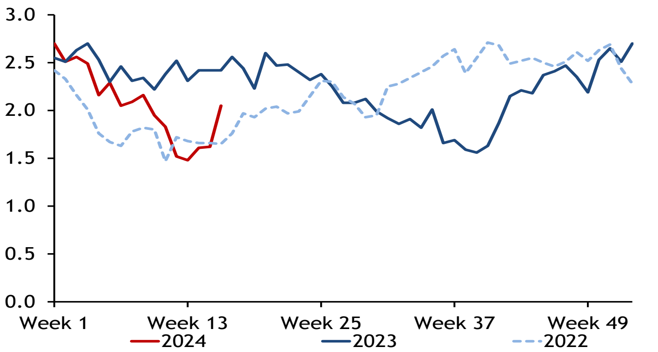
Firms had 2.05mn t of LNG stocks as of 21 April, up by 27pc from the previous week's revised 1.62mn t, according to a weekly survey by trade and industry ministry Meti. The latest figure exceeded 2.02mn t, the average level of end-of-April stocks over 2019-23, although this was 20pc lower than 2.56mn t on 23 April 2023. Power demand averaged 83GW across 15-21 April, down by 3pc from a week earlier, as average temperatures in Japan's 10 main cities rose by 2.1°C to 18°C. Operational gas-fired capacity rose to an average of 57.7GW during the week to 21 April, up by 204MW from a week earlier. But lower electricity demand curbed gas-fired output by 2.4GW to 24GW during the period.

Generation economics for gas-fired plants using spot LNG turned negative, as wholesale power prices fell with lower demand. Margins from a 58pc-efficient gas-fired unit averaged at a loss of ¥0.83/kWh ($5.35/MWh) on 15-21 April, down from the previous week's profit of ¥0.67/kWh, based on *Argus* Northeast Asia (ANEA) spot LNG prices. The 58pc spark spread using oil-priced LNG supplies remained negative, averaging a ¥3/kWh loss in the week to 21 April.

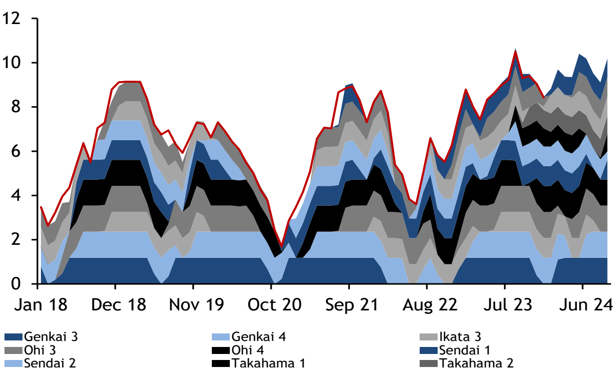
Japan seasonality chart *mn t*



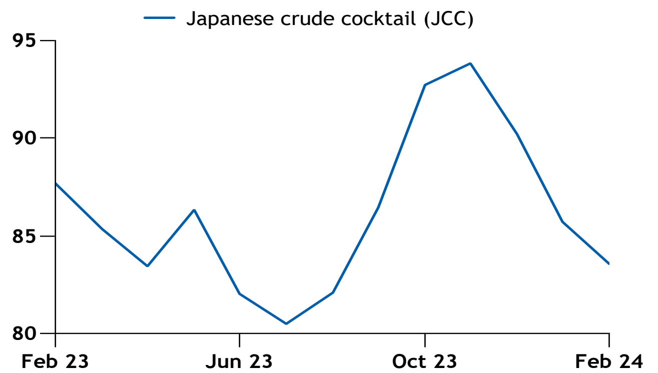
Japanese LNG stocks *mn t*



Japan nuclear availability *GW*

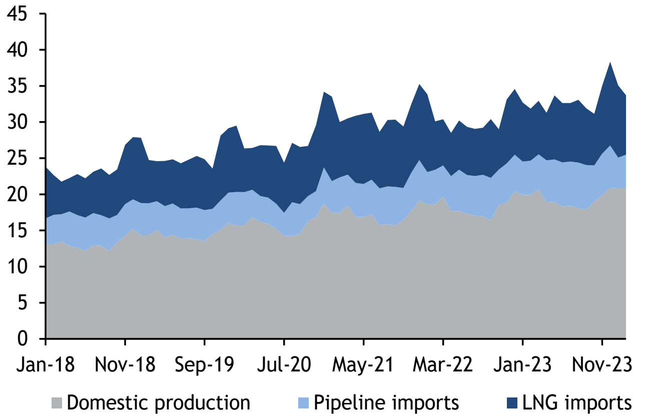


Japanese Crude Cocktail (JCC) *$/bl*



ASIA-PACIFIC

China supply balance *bn m³*



Click here to download data on Chinese domestic production, pipeline imports and LNG receipts

Chinese gas imports hit March record

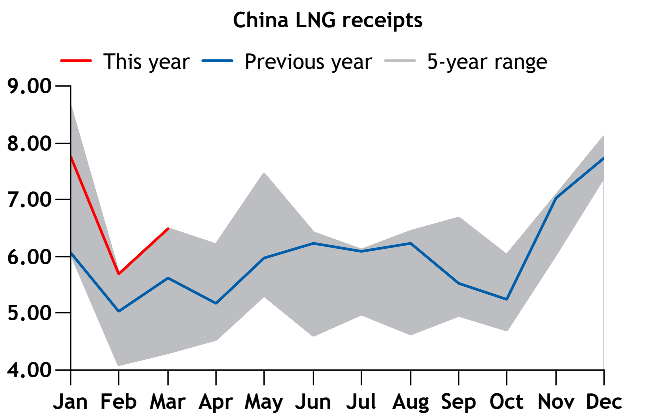
China's combined gas imports rose sharply on the year in March and were the highest for the month, with LNG receipts reaching a March record.

China imported 10.75mn t of combined LNG and gas in March, up from 8.87mn t a year earlier, Chinese customs data show. LNG deliveries rose to 6.65mn t from 5.36mn t over the same period, with pipeline gas imports also increasing sharply to 4.11mn t from 3.51mn t. Colder weather in northern China may have supported heating demand, with minimum temperatures in Beijing averaging 2.3°C in March, down from 3.7°C a year earlier.

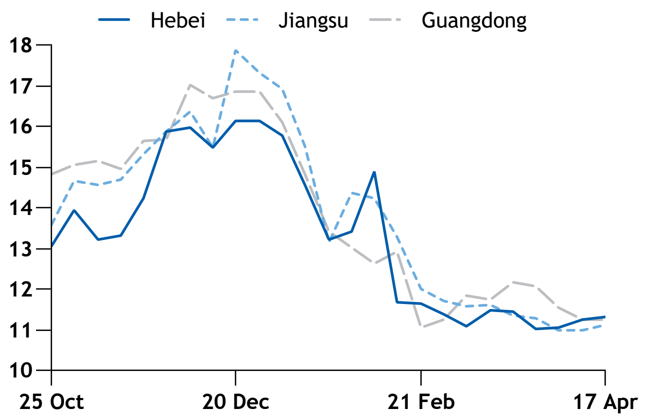
Lower spot LNG prices may also have spurred buying activity. The *Argus* northeast Asia des price for March averaged \$9.70/mn Btu from January to mid-February, lower than the \$19.22/mn Btu over the same period in 2023.

Stronger pipeline imports may have been driven by higher contractual deliveries of Russian gas. The 38bn m³/yr Power of Siberia pipeline is set to deliver 30bn m³/yr to China in 2024, an 8bn m³/yr increase from last year.

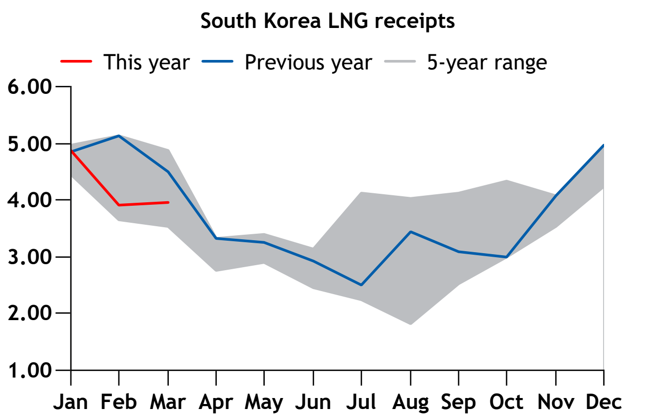
China LNG seasonality chart *mn t*



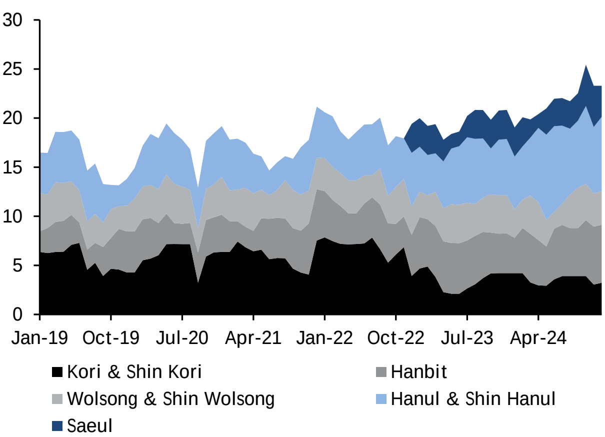
China domestic trucked LNG price *\$/mn Btu*



South Korea LNG seasonality chart *mn t*

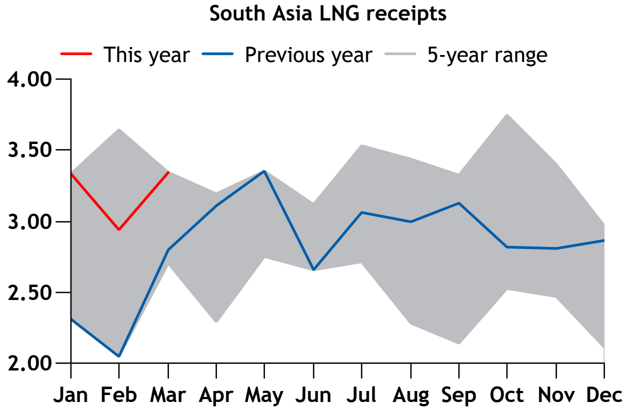


South Korea nuclear availability *GW*

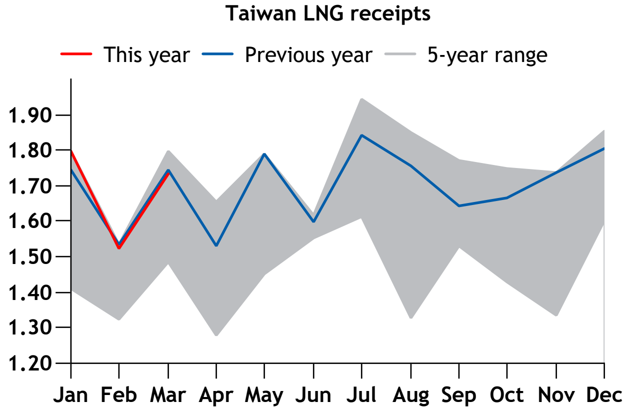


ASIA-PACIFIC

South Asia LNG seasonality chart *mn t*



Taiwan LNG seasonality chart *mn t*



India's LNG receipts slow in April

India's LNG receipts so far this month were 7pc lower than a year earlier despite expectations of stronger power-sector gas use this month.

The country received 1.83mn t on 1-23 April, down from 1.97mn t a year earlier, data from market analytics firm Kpler show. This is despite an expected surge in power demand and government directives which supported a greater share of gas-fired generation.

The Indian government had estimated peak power demand to reach 256.5GW in 2024 from a record 243GW in 2023 on the back of severe heatwaves during April-June. The power ministry had also issued an order, directing gas-based power plants to lift generation.

But LNG receipts rose sharply last month, totalling 2.26mn t, a 23pc increase from a year earlier, possibly as a result of firms stockpiling LNG ahead of the peak power-sector gas demand period.

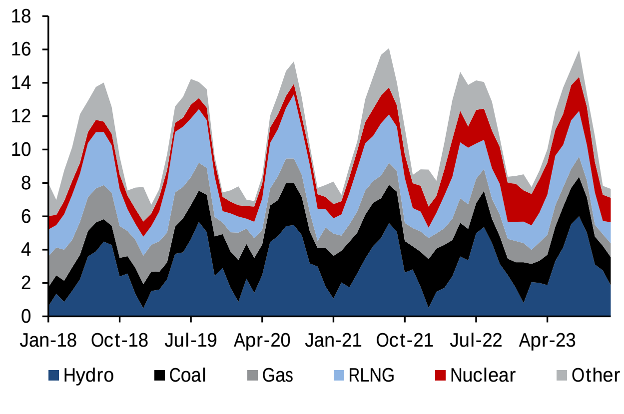
A significant portion of India's 25GW gas-fired generation capacity is underutilised, according to the power ministry. The government has asked all gas-based power plants to boost generation between 16 March and 30 June, which is seen as the "crunch period".

The ministry would temporarily permit these utilities to seek higher power tariffs from buyers and allow the plants to sell surplus electricity on the exchanges at market prices. Gas-fired plants account for about 5.8pc of overall generation capacity of 434.2GW.

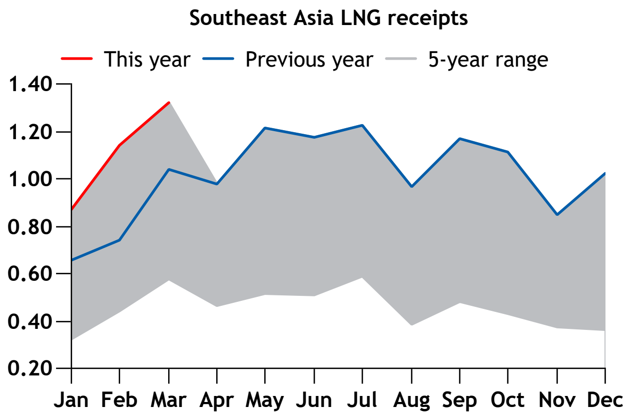
India's private-sector Torrent Power is set to supply electricity from its gas-fired power plant to a unit of state-owned NTPC to meet peak power demand during summer, which may boost the use of imported LNG.

But LNG prices remain a sticky issue for buyers, as Indian power utilities seek the fuel at a discount to make operations viable, market participants say.

Pakistan power mix *TWh*

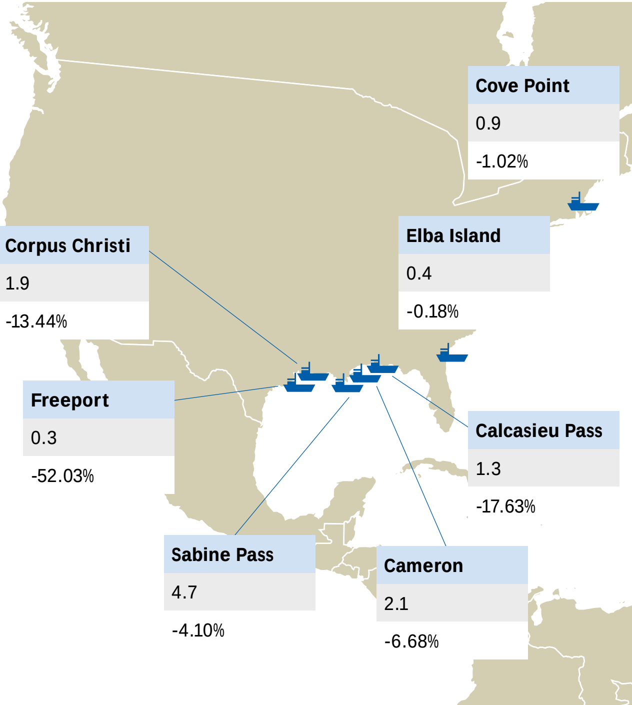


Southeast Asia LNG seasonality chart *mn t*



AMERICAS

Feedgas flows to US LNG terminals *trillion Btu/d*



US prices fall on robust gas inventories

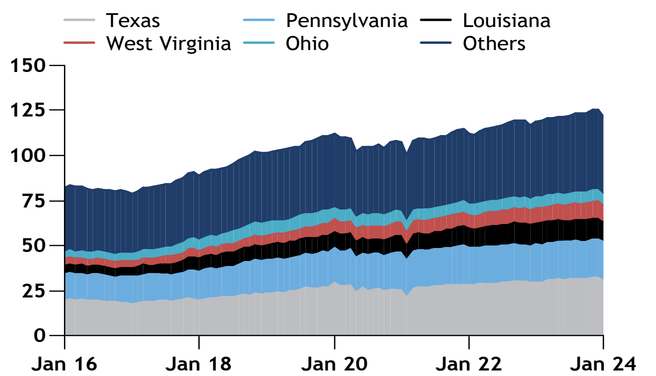
US gas futures fell over the past two weeks on high inventories, despite lingering cool weather and looming output cuts.

Prices faced downward pressure as the market moved deeper into April, the first month of the spring shoulder season. Lingering cold in early April curbed injections but did little to dent the storage overhang, after stocks ended March at the highest end-of-winter level in eight years.

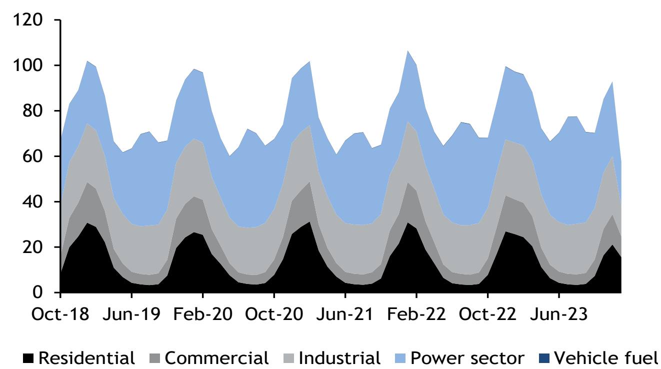
US stocks have increased by 74bn ft³ (2.1bn m³) during the two weeks ending on 12 April, 13pc below the five-year-average build of 85bn ft³, the most recent data from the US Energy Information Administration (EIA) show. Total inventories as of 12 April were 2.333 trillion ft³ — 36pc higher than the five-year average and up by 22pc on the year. The EIA expects stocks to top 4.1 trillion ft³ ahead of next winter, a record high and 10pc above the five-year average. But injections were forecast to lag average levels as producers pare output because of low gas prices.

The US natural gas rig count fell in the week ending on 19 April as producers reined in drilling on a dim demand outlook for the coming months. US operators had 106 working gas rigs, down by three rigs from a week earlier and 53 rigs lower than the same week a year earlier, according to oil field services provider Baker Hughes.

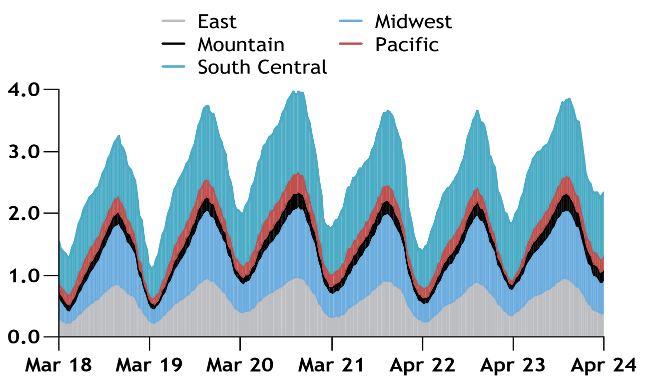
US production *bn ft³/d*



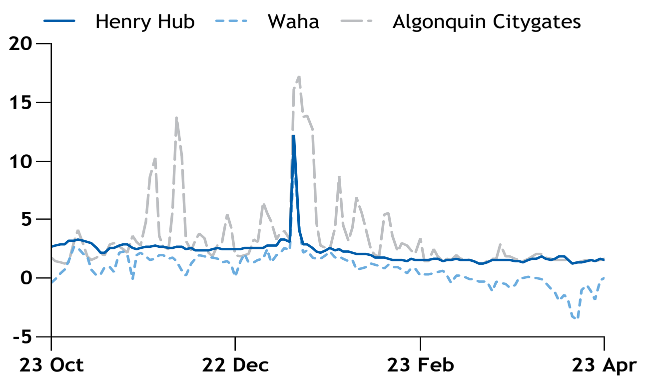
US demand *bn ft³/d*



US stocks *trillion ft³*



US domestic gas prices *$/mn Btu*



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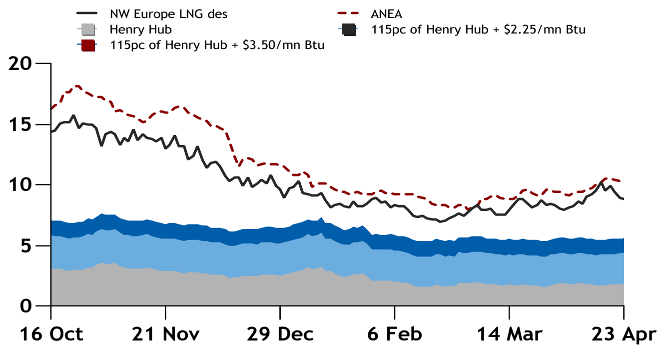
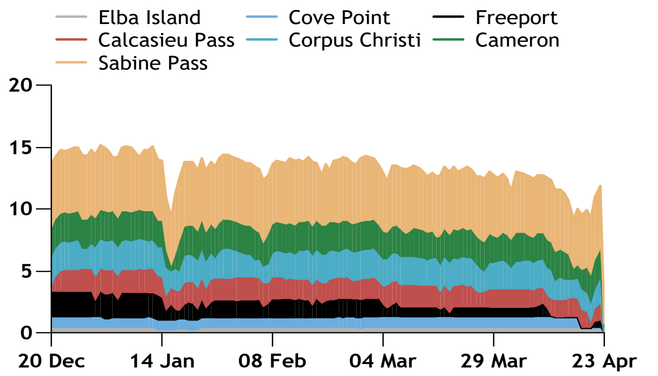
US storage movements, stocks							*bn ft³*
Region	**12 Apr**	**5 Apr**	**Implied flow**	**Year ago (7 Apr)**	**% change**	**Five-year average (19-24)**	**% change**
East	379	362	17	345	9.9	303	25.1
Midwest	528	512	16	427	23.7	375	40.8
Mountain	167	165	2	80	108.8	90	85.6
Pacific	230	229	1	74	210.8	156	47.4
South Central	1,029	1,014	15	929	10.8	765	34.5
Total	**2,333**	**2,283**	**50**	**1,855**	**25.8**	**1,688**	**38.2**

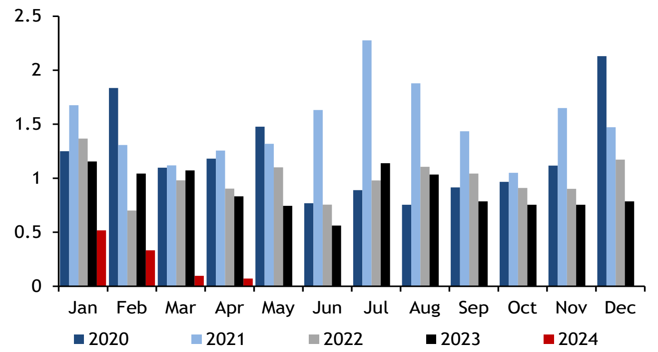
US long-term fob vs Europe, Asia spot des prices *$/mn Btu*



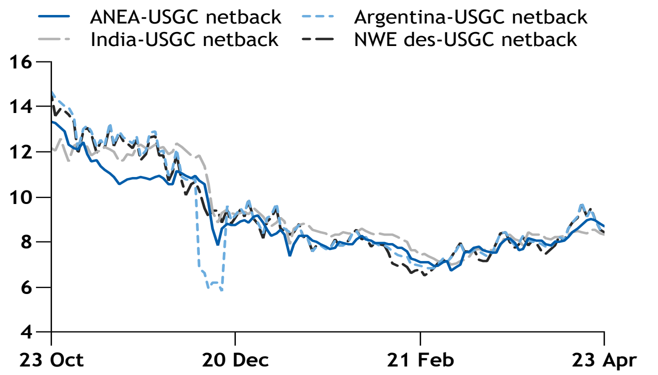
Feedgas flows to LNG plants *trillion Btu*



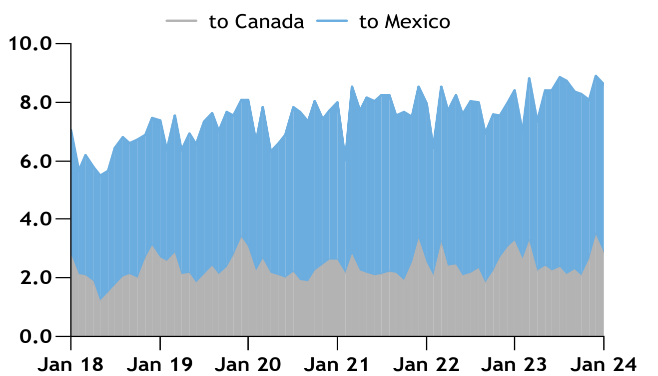
LNG deliveries via Panama Canal *mn t*



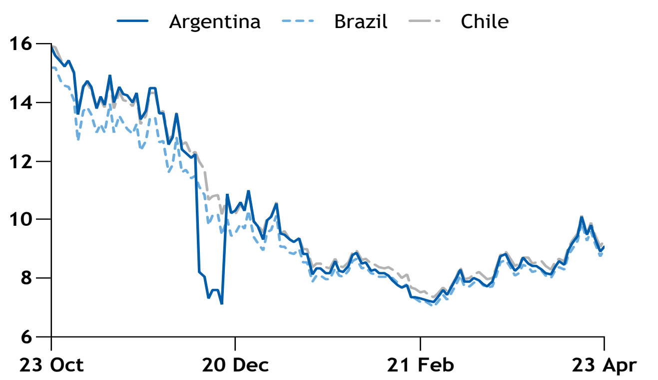
Netbacks to US Gulf coast *$/mn Btu*



US pipeline flows to Mexico *bn ft³/d*



LNG delivered to South America *$/mn Btu*



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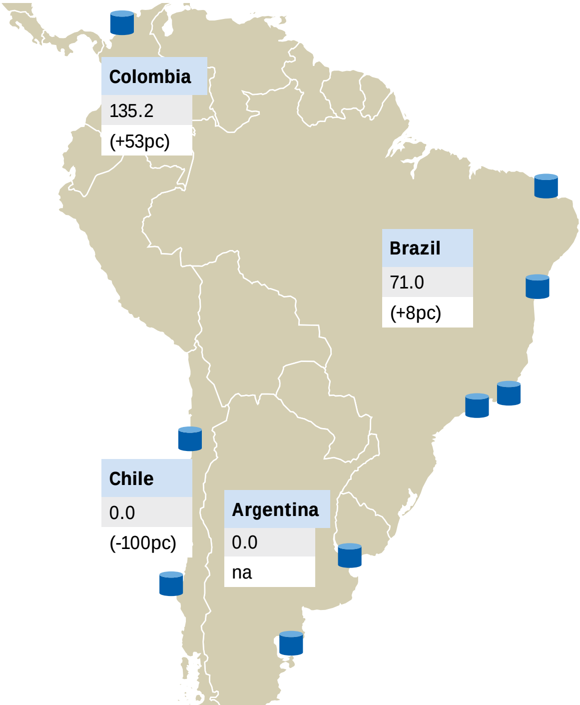
South America LNG receipts *'000t*



Brazil gas output up by 16pc since 2021

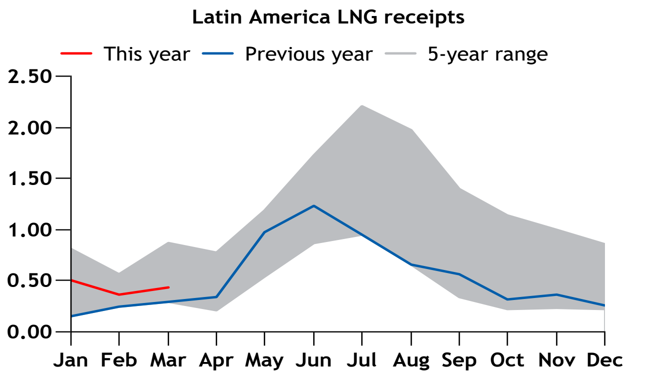
Brazil's natural gas output has grown by nearly 16pc since the new gas market law took effect in April 2021, according to hydrocarbons regulator ANP data.

Gross production has risen to 113.5mn m³/d from 144 wells in February, compared with 92.2mn m³/d from 122 wells in April 2021. Despite the higher gas production, the amount of supply made available to the market has remained broadly unchanged at just above 50mn m³/d, as most of the extra production is from pre-salt fields that reinject gas to optimise crude recovery.

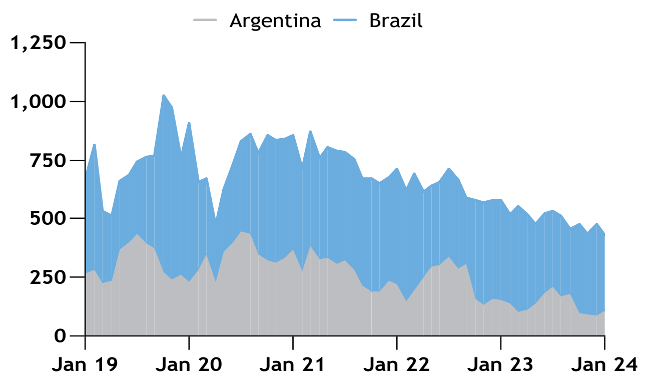
The 18mn m³/d Rota 3 pipeline is expected to enable stronger production from offshore fields, but its completion has suffered numerous delays. It is now scheduled to begin operating in the second half of this year, pending the completion of onshore treatment facilities.

Petrobras continues to dominate the Brazilian market, despite a noticeable decline in its market share. The firm still accounts for two-thirds of the country's total production with 99mn m³/d in February this year, despite this being down from 75pc in April 2021 and as much as 90pc in December 2010. Shell has remained the second-largest producer in Brazil, with a 11-12pc share of total output (16mn-17mn m³/d).

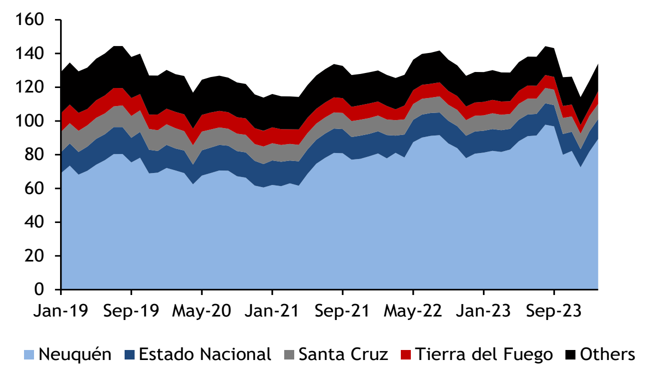
Latin America LNG seasonality chart *mn t*



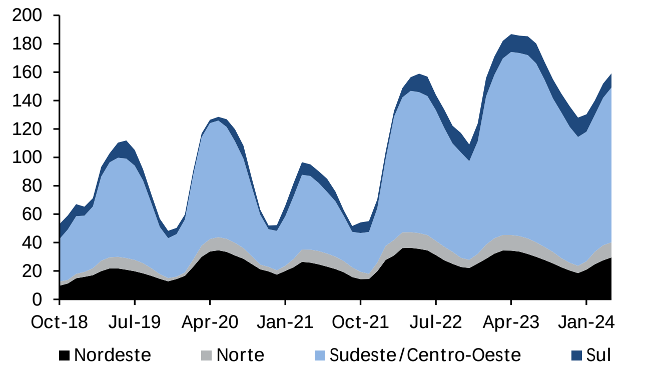
Bolivian flows to Argentina, Brazil *mn t*



Argentina upstream production *mn m³/d*

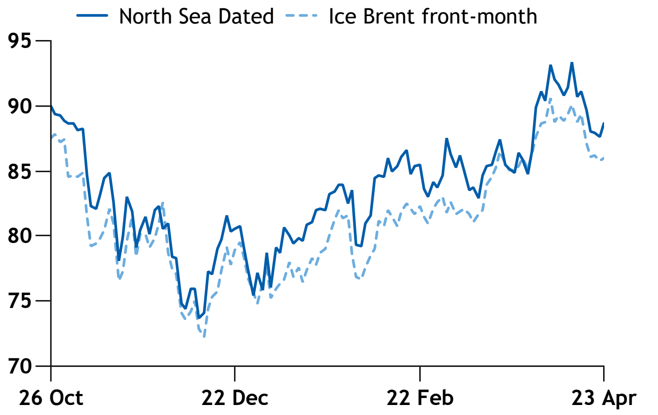


Brazil hydro stocks *TWh*

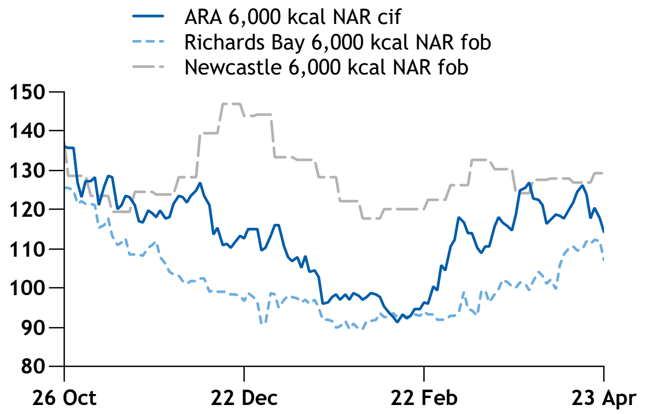


RELATED MARKETS

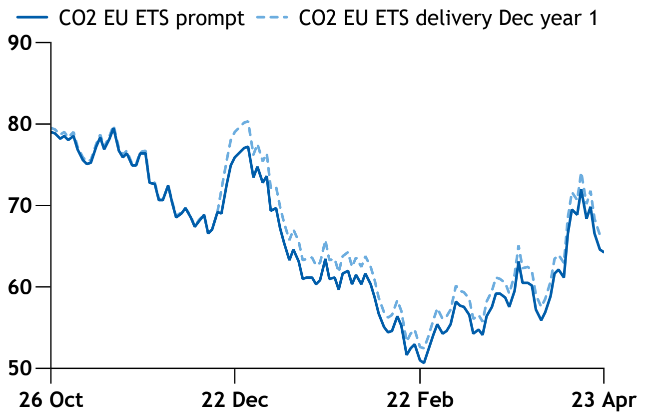
Crude prices *$/bl*



Coal prices *$/t*



EU ETS *€/t*



Crude prices slide

Global crude prices eased as Middle East tensions appeared to de-escalate. Atlantic basin benchmark North Sea Dated shed $4.42/bl to $87.58/bl on 22 April. WTI also weakened by $1.09/bl to $82.85/bl across the same timeframe. But demand for European crudes firmed over the past fortnight as seasonal refinery maintenance eased in the May-loading trade cycle. European staple medium sour Norwegian Johan Sverdrup and Iraqi medium sour Basrah Medium each strengthened because of increased demand as the bitumen season began. Demand for sweet crudes firmed on both sides of the Atlantic as the US increased demand for gasoline-rich grades ahead of the summer driving season. US Gulf and west coast demand for Guyanese Unity Gold firmed the grade's price in Europe, which in turn supported the prices of Es Sider, Saharan Blend and other European light sweets.

European coal prices mixed

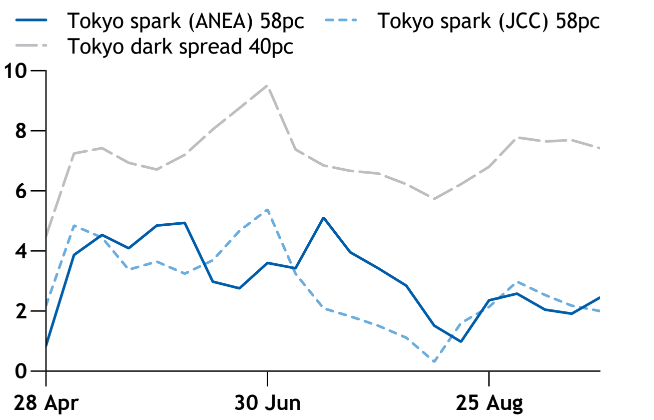
European cif ARA coal prices saw mixed directions over the past two weeks, rising to a near-four-month high before falling back as the market overall remains well supplied and coal dispatch low in Europe. Cif Amsterdam-Rotterdam-Antwerp (ARA) NAR 6,000 kcal/kg coal prices hit $126.19/t on 16 April, just shy of the four-month high of $126.83/t seen at the end of March. Prices then eased to $114.25/t at the start of this week. Market participants had expected the downward correction as fundamentals remain weak, with the earlier spike driven by a shortage of specific benchmark-grade coals rather than any broad supply squeeze. Stockpiles in the ARA region have dropped slightly but remain high. Demand from Asian markets remained subdued, with sufficient stocks and comparatively cheaper domestic supply in China. Negotiations between Japanese buyers and Austrialian producers for annual coal supplies were still ongoing.

ETS prices rise

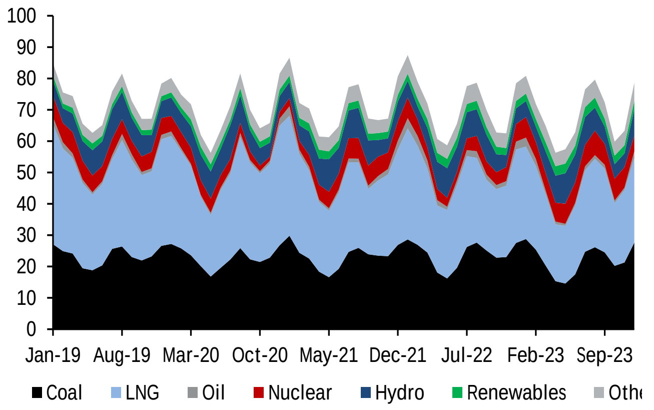
EU emissions trading system (ETS) allowances rose to their highest levels since early January in week 16. Allowances for December 2024 delivery — the benchmark contract — closed at above the €70/t of CO_2 equivalent mark (CO_2e) over the first four sessions of the period, compared with a low of €62.87/t CO_2e in week 15. EU ETS prices largely took direction from stronger moves in the wider energy complex, particularly European gas and power markets, in the context of escalating geopolitical tensions. But EU ETS prices also retreated with those markets as the situation appeared to de-escalate, and December 2024 closed at below €70/t CO2e again in the final session of week 16, before falling further to €66.35/t CO_2e on 22 April.

GLOBAL GENERATION ECONOMICS

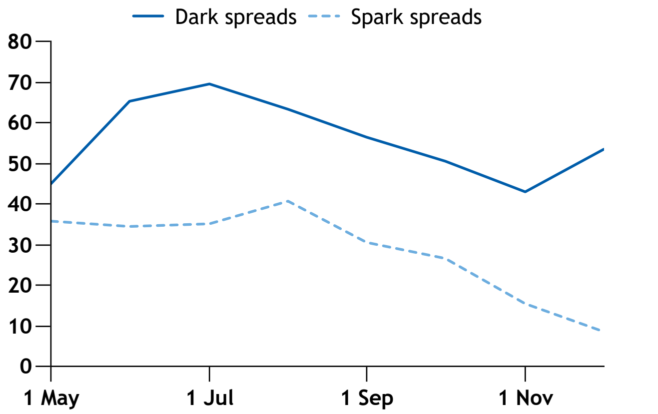
Japan fuel switching *¥/kWh*



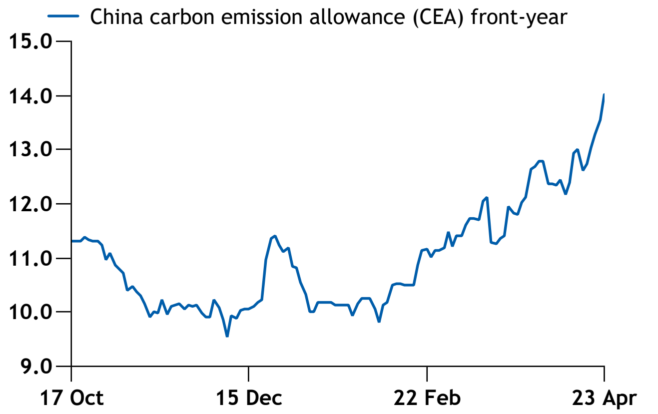
Japan power generation mix *GW*



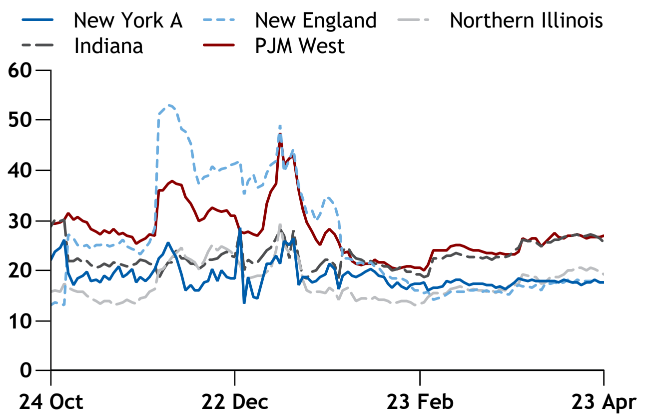
South Korea fuel switching *$/MWh*



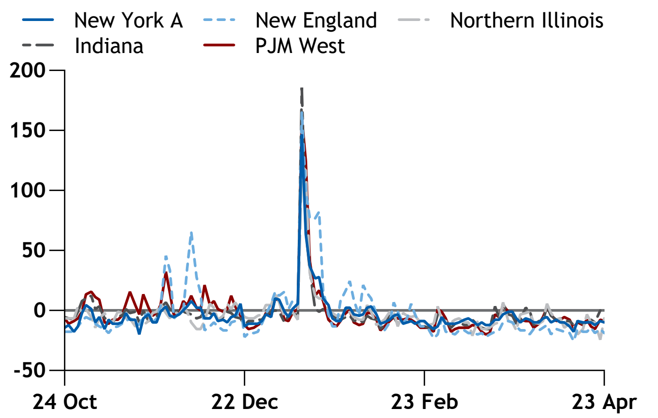
China carbon emission allowances *$/t*



US spark spreads *$/MWh*

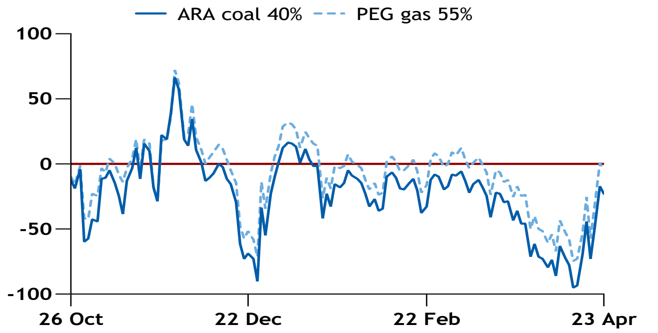


US dark spreads *$/MWh*

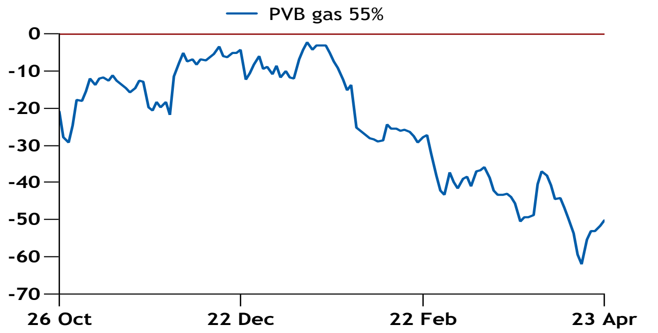


GLOBAL GENERATION ECONOMICS

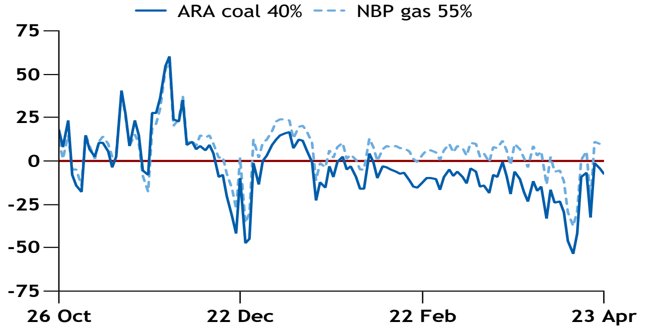
France ETS-adjusted spark spreads *€/MWh*



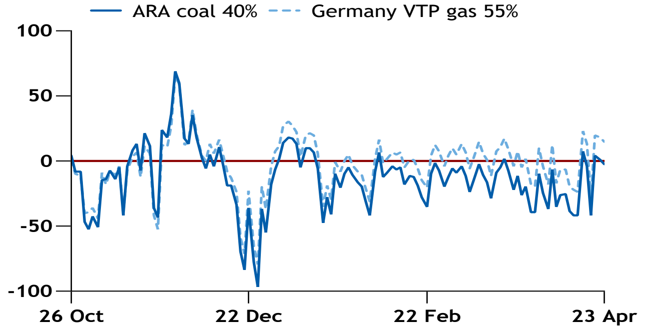
Spanish ETS-adjusted spark spreads *€/MWh*



UK sparks vs darks *£/MWh*

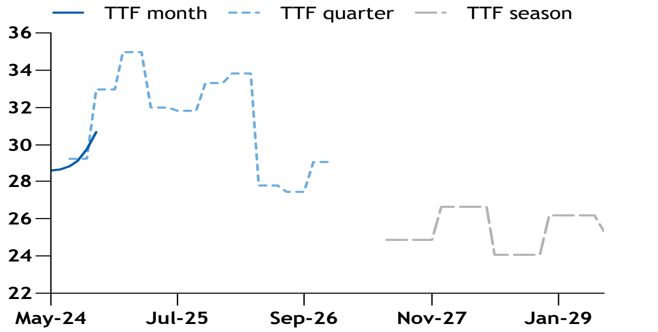


Germany sparks vs darks *€/MWh*

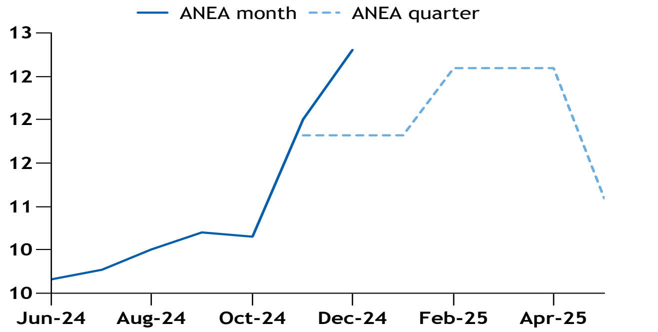


FORWARD CURVES

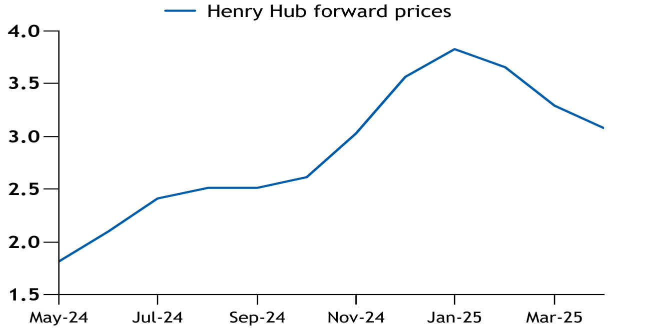
TTF forward curve *€/MWh*



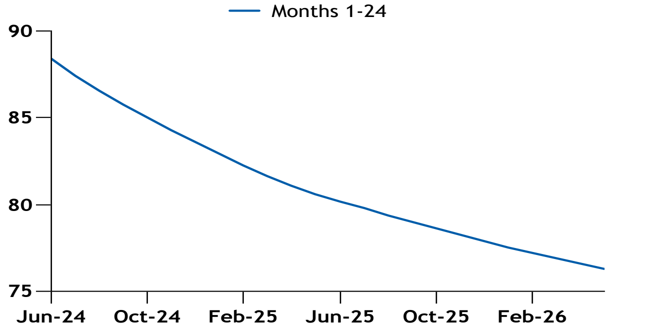
ANEA forward curve *$/mn Btu*



Henry Hub forward curve *$/mn Btu*

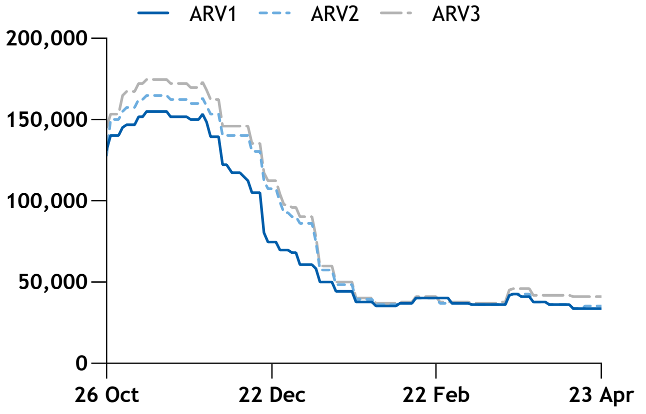


Ice Brent forward curve *$/bl*

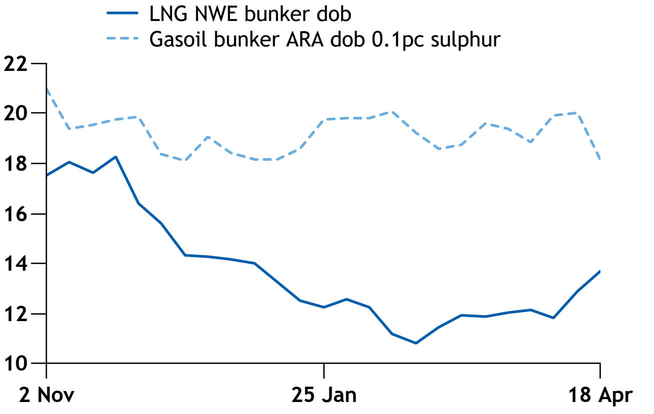


FREIGHT AND LNG AS MARINE FUEL

Argus Round Voyage (ARV) rates $/d



Marine fuels competition $/mn Btu



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