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September 2023

Argus White Paper:

Winter 2023-24 European gas market preview

Europe must be prepared to outbid Asia for LNG to meet any supply challenges this winter. But it also needs to be prepared for another summer glut if the winter is mild. Either way, volatility is guaranteed

Europe braced for LNG tug-of-war

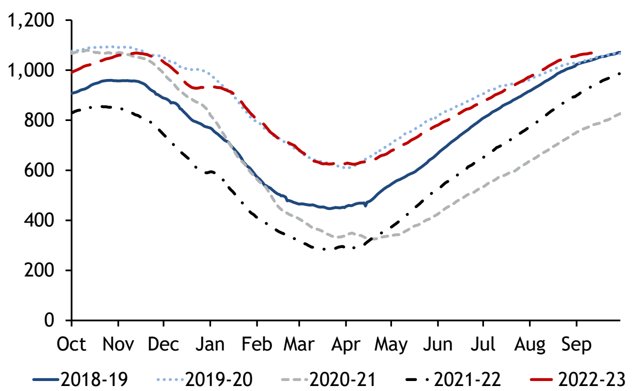
If Europe needs extra gas supply this winter compared with the last one to deal with cold snaps or unplanned supply disruptions, then it will have to turn to LNG and underground storage. Norway's gas production is poised to edge down because of the long-term decline of maturing fields, while the end of extraction from the Netherlands' Groningen field and the long-term decline of maturing fields should reduce production in northwest Europe as well. Infrastructure constraints limit southern Europe's ability to take more pipeline gas from Algeria. And Russian flows to Europe cannot rise by much from winter 2022-23 while only two transit routes remain open.

Colder weather than in the exceptionally mild winter 2022-23 would boost Europe's space heating demand, even assuming consumer demand restraint in the face of high energy bills continues. Higher household demand in a normal winter would more than offset a likely fall in Europe's power-sector gas use thanks to greater availability of French EdF's nuclear power fleet. And there is potential for extra industrial gas demand this winter provided wholesale prices remain lower, although an expected economic slowdown, lower energy costs abroad and some permanent demand loss will limit any increase.

But while European gas buyers used to be able to request more Russian pipeline gas committed under flexible long-term contracts to meet winter demand peaks, LNG answers the call of whichever market offers higher returns. This leaves open the possibility of a bidding war between Europe and Asia for marginal supply.

Conversely, Europe may again have to deal with an abundance of supply in summer 2024, as it did in summer 2023, if the northern hemisphere has another mild winter. LNG demand in northeast Asia looks likely to remain weak this winter, while the world will need to soak up an extra roughly 11.8mn t of LNG production relative to a year earlier. And the El Nino weather phenomenon hints at a higher-than-normal likelihood of weak heating demand across northeast Asia. There is already a strong price incentive for European firms to preserve underground storage inventories in October-December. Sustained strong LNG imports would limit the need for storage withdrawals in January-March as well, curbing summer restocking needs (*see underground inventories graph*).

European underground inventories TWh



European gas contracts for delivery in October and November have already opened up large discounts to later-dated contracts, thanks to full storage and weak consumption. This price environment should encourage a commercially driven turndown at the Norwegian Troll and Oseberg swing fields, strong injections into Ukraine's underground storage and the continued build-up of a vast amount of LNG at sea to act as floating storage, balancing Europe's gas market until heating demand emerges.

The risks are finely balanced for winter 2024-25, too. On the one hand, the expiry of the existing Russia-Ukraine transit agreement at the end of 2024 increases the likelihood of Russian gas transit through Ukraine coming to an end. And a healthier macroeconomic environment could lift gas demand globally. On the other hand, the world's liquefaction capacity will pick up strongly from late 2024, bringing even more supply to the market.

Weather could boost LDZ demand

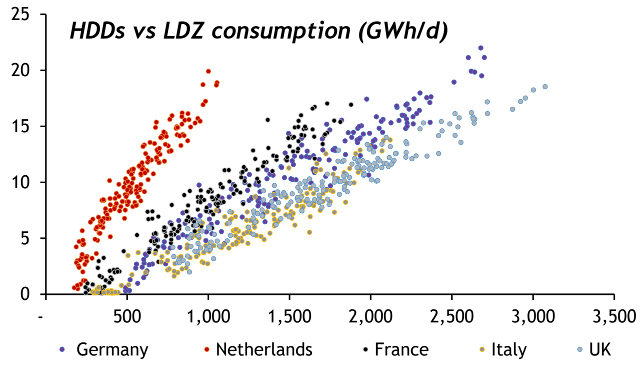
Europe's local distribution zone (LDZ) demand could step up if the weather is colder than in the exceptionally mild winter 2022-23 and the correlation between weather and consumption holds the same.

LDZ demand in northwest Europe — Germany, the Netherlands, France, Italy and the UK — averaged 5.86 TWh/d last winter, the lowest for the period since at least winter 2017-18. Average wind-adjusted and population-weighted heating degree days (HDDs) were the lowest since winter 2013-14 in four of those countries, with the exception of the UK, where last winter was still the second mildest since 2013-14 (*see LDZ graph*).

Assuming this relationship holds, LDZ demand could be roughly unchanged across the five countries only in a mild weather scenario, with HDDs in line with the mildest winter in each country since 2013-14. In a normal winter — in line with average HDDs since 2013-14 — LDZ demand would reach 6.22 TWh/d. Weather conditions in line with the coldest winter since 2013-14 would bring LDZ consumption to 6.69 TWh/d (*see LDZ table*). But demand could be even stronger if the correlation between weather and LDZ gas use realigns with the average observed across the five previous winters.

Potential winter 2023-24 LDZ consumption			*TWh/d*
Scenarios	**Mild**	**Normal**	**Cold**
If weather/demand correlation is in line with 2022-23			
Germany	1.46	1.55	1.66
Netherlands	0.52	0.56	0.60
France	0.98	1.05	1.11
Italy	1.19	1.30	1.41
UK	1.68	1.77	1.92
Total	**5.83**	**6.22**	**6.69**
If weather/demand correlation is in line with to 2017-18 to 2021-22 average			
Germany	1.56	1.65	1.76
Netherlands	0.66	0.70	0.74
France	1.13	1.20	1.27
Italy	1.33	1.45	1.57
UK	1.93	2.02	2.16
Total	**6.61**	**7.02**	**7.50**

LDZ demand v HDD



Rebound effect

A return to a pre-2022 correlation between gas demand and weather may be unlikely in the short term, but lower gas prices could provide scope for a rebound in household gas demand under similar weather conditions.

Gas prices for households are likely to be lower than a year earlier across the countries in question, which could reduce the incentive to curb gas use. UK unit price caps for households will be 23pc lower in the fourth quarter than in the same period of 2022. In Germany, a "price brake" that limits household costs to €0.12/kWh is likely to be in effect for the whole winter, while it was only in place for half of last winter. And wholesale prices may even be low enough to put market prices for consumers below the price brake.

Some businesses could be encouraged to increase their consumption this winter, as they will have rolled off high-priced but short-duration contracts signed out of necessity during a period of extremely high wholesale prices in summer 2022. On the other hand, the proportion of businesses still on cheaper fixed-price contracts that were entered into before wholesale prices rose in mid-2021 will be smaller this winter than last winter.

A structural shift?

But customer behaviour changes may be structural and therefore long lasting, partly because of a shift away from domestic gas heating. This, coupled with the possibility of muted economic activity, could mean that the correlation between weather and demand holds similar to that observed last winter.

The ongoing roll-out of heat pumps across Europe could put a structural brake on gas consumption. About 3mn heat pumps were sold in Europe last year — almost double that of 2021. But the trend may have lost momentum in some countries, as rapidly falling gas prices from September 2022 reduced the price advantage of heat pumps. In Germany, applications for heat pump subsidies fell by half in the first six months of this year compared with the first half of 2022. France was the

European leader in heat pump sales last year, with more than 600,000 units sold, but the number of households connected to the gas network fell by only 91,000 over 2022. Many of the new units could be replacing existing units or go into newbuild properties. Only a quarter of newbuild homes in Germany were heated by gas in 2021, but replacements of existing units predominated, with gas boilers still accounting for 70pc of domestic heating devices sold. The roll-out of heat pumps will reduce gas demand, but so far its effect seems to be minor compared with that of weather and prices.

And slow economic growth, or even recession in some countries, could mute any rebound in gas demand from businesses. GDP could grow by just 1pc in France and 0.3pc in the UK this year, while it could contract by 0.3pc in Germany, according to the OECD's September outlook. But the OECD forecasts that GDP growth will pick up in 2024, to 1.1pc across the eurozone.

Nuclear to cut gas use

Power-sector gas demand could fall across major European countries this winter, as France's nuclear fleet is scheduled to return to nearly full strength.

Combined power-sector gas demand in Europe's six largest gas-consuming countries — Germany, the UK, Italy, the Netherlands, France and Spain — could fall year on year in the fourth quarter and into the first quarter (*see gas-fired generation graph*).

Europe's power demand could hold roughly stable from last winter, when it slumped from previous years following the introduction of a voluntary reduction target. This measure has been phased out for this winter, but energy efficiency gains and an economic slowdown might continue to curtail power demand. And the call on gas-fired plants may only be greater than in winter 2022-23 during heavy unplanned maintenance or a significant increase in the region's power demand.

Nuclear revival

The French nuclear fleet is on track to operate close to full capacity in the first half of this winter, eroding concerns of a repeat of last winter's curtailments. Only 11.1GW of France's nuclear generation capacity is scheduled to be off line in the fourth quarter and 9.8GW in the first quarter, according to system operator RTE's late-September schedule. Unavailability was 28GW in the fourth quarter and 20.7GW in the first quarter last winter.

This winter's nuclear power risk profile looks similar to that of winter 2021-22, RTE said in mid-summer. France's nuclear plants produced just over 42GW in winter 2021-22 and 35.1GW in winter 2022-23.

Stronger nuclear output in France would far outweigh the effect of Germany closing its nuclear fleet in April, which removed about 3GW of capacity.

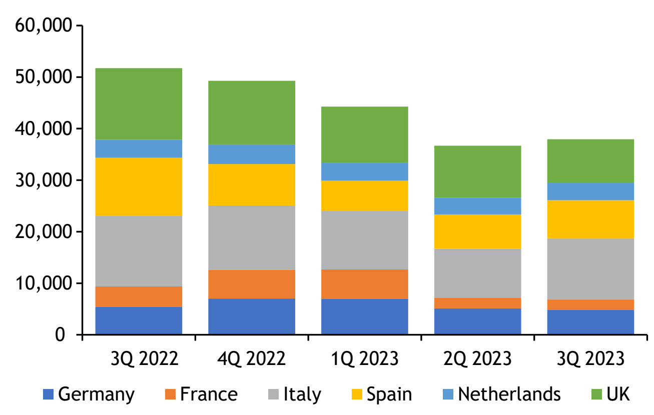
But nuclear unavailability could be revised at short notice, as happened last year, and any shortfall would raise the call on thermal generation.

Lots of renewables

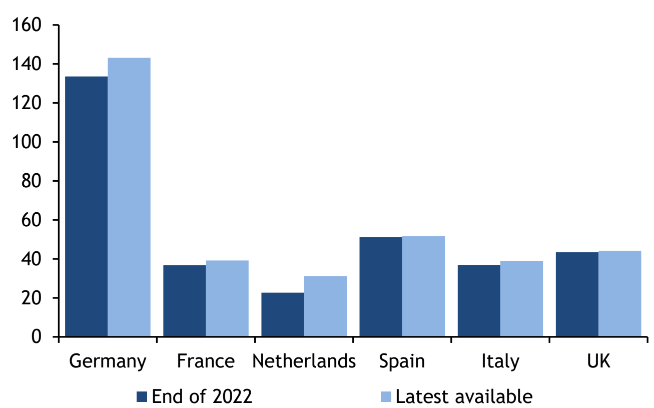
Renewable power generation is hard to predict given its intermittency, but a recent scale-up of the pace of installations will help to reduce thermal generation across Europe. Combined wind and solar power generation capacity across the six countries was about 348GW as of mid-2023 — about 7pc higher than at the end of 2022 (*see renewable capacity graph*).

Solar and wind generation already rose to a combined 61.5GW last winter from 57GW a year earlier. Assuming the same load factors as in winter 2022-23 but taking into account higher installed capacity, Europe could generate roughly 4.6GW of additional power from renewables this winter. This is a conservative estimate, given that wind speeds across Europe were below normal last winter.

Gas-fired power generation *MW*

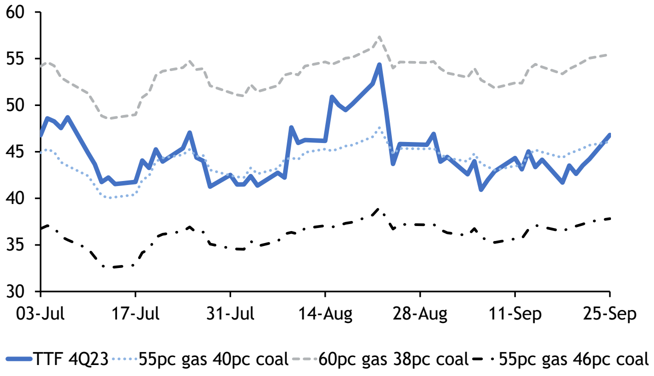


Installed renewable capacity *GW*



— **Germany July 2023 data, Netherlands June 2023 data, Italy May 2023 data, Spain/UK/France March 2023 data*

TTF 4Q23 vs fuel switch €/MWh



Meanwhile, hydropower reservoirs in Spain, France and Italy are much fuller than a year earlier. This provides operators with much more flexibility to raise hydropower generation this winter to reduce the call on thermal plants.

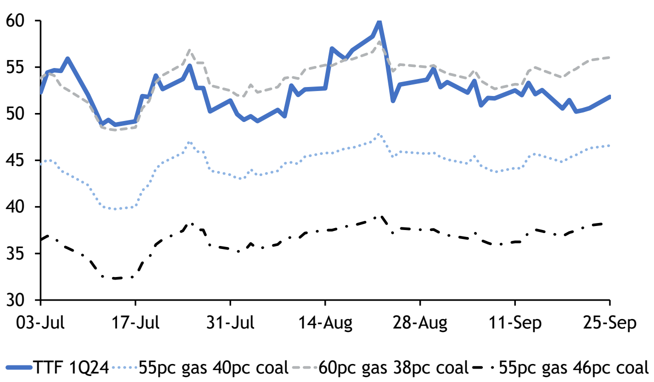
No clear path for fuel switching

Gas would be competitive with coal in the fourth quarter and largely uncompetitive in the first quarter based on late-September forward prices (*see fuel-switch graphs*). But the balance could quickly shift the other way depending on gas and coal market fundamentals. And high nuclear output could squeeze out gas and coal alike, particularly on windy and sunny days, reducing the significance of competition between the two fossil fuels.

Fuel-switching dynamics were largely irrelevant last winter, as coal and gas each were priced in for base-load production for most of the season. Day-ahead operating margins for both fuels surpassed €100/MWh on various occasions.

If Europe has a surfeit of gas supply at times this winter — thanks to mild weather and full autumn storage — gas prices could drop through the bottom of the fuel-switching range. But even in this scenario, gas-fired generation would slip year on year after factoring in projected higher nuclear and renewables output.

TTF 1Q24 vs fuel switch €/MWh



EU industrial gas demand recovery to remain slow

The potential for Europe's industrial gas use to rebound this winter is capped by an expected economic slowdown, lower energy costs abroad and some potential structural demand destruction.

Industrial gas demand across the UK, France, Belgium, the Netherlands, Spain and Italy increased by roughly 7pc in August compared with a year earlier to a combined 1.12 TWh/d (*see industrial use graph*). But it was still far below 1.58 TWh/d in August 2021. Combined industrial consumption across these countries averaged 1.28 TWh/d in March-August, slightly down from 1.33 TWh/d a year earlier. Germany is excluded as there is no breakdown between power and industrial demand.

Unstable outlook across various sectors

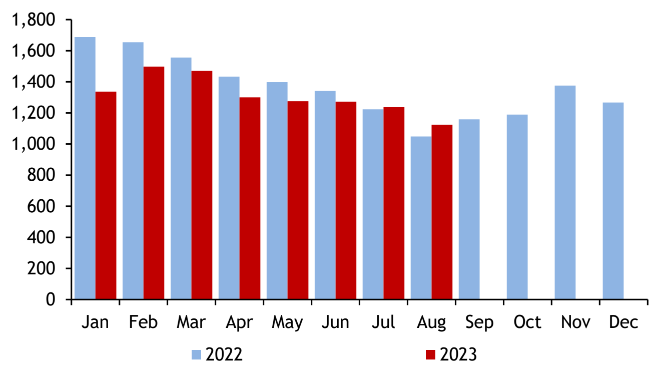
Production has been low across some key gas-intensive sectors this summer, despite a drop in gas and power prices, hinting at limited upside for this winter.

The production of ammonia — the key component in fertilisers and one of the most gas-intensive industries — has only partly recovered in recent months. *Argus* estimated European plant utilisation rates at 50-60pc of capacity in August, barely higher than a year earlier. Europe has an installed ammonia capacity of roughly 19.6mn t/yr, while plants tend to burn about 36mn Btu of gas to produce a tonne of ammonia. A 55pc utilisation rate implies gas consumption of roughly 9.5bn m^3/yr, against 17.3bn m^3/yr if sites operate at full capacity.

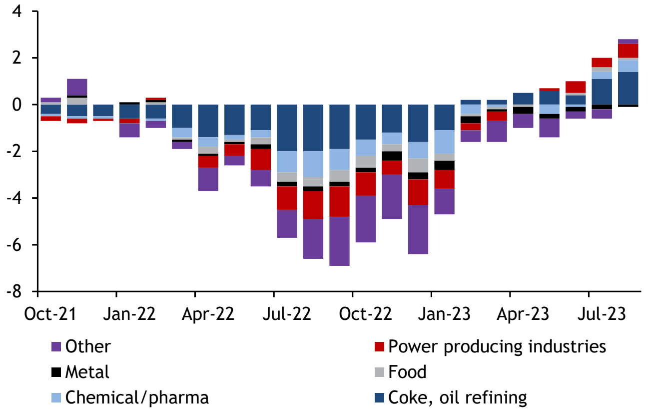
But the gas demand loss may be steeper than this estimation suggests, as some producers have opted to more fully use their most efficient plants and export some of this production to other parts of Europe, instead of producing ammonia locally in less efficient plants.

Imports of ammonia have been cheaper than domestic EU production for most of this year so far. And continued gas

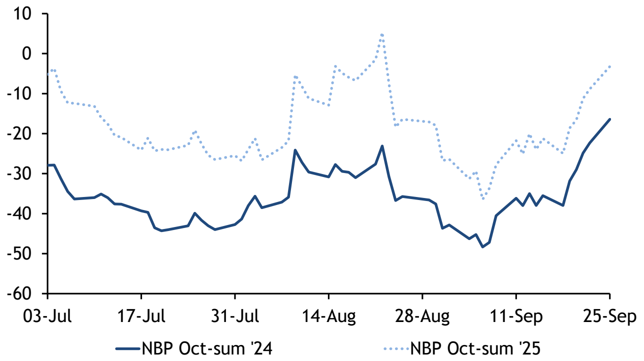
Combined industrial gas use GWh/d



Spanish industrial gas use, yr/yr change *GWh/d*



NBP price spreads *p/th*



price volatility has made producers wary of lifting output even import prices rise above domestic production costs.

Output in the chemicals sector as a whole so far this year has remained lower than a year earlier. Production in Germany, by far the bloc's largest producer, excluding pharmaceuticals, was down by 16.5pc on the year in January-June, national chemical industry association VCI said. VCI expects production to decline by 8pc this year as a whole.

Weak downstream demand and lower production costs abroad have weighed on output in the steel industry, too. EU steel production was down by 10.3pc in January-July from a year earlier and even further below historical averages.

The manufacture of refined petroleum products slipped in the second quarter to its lowest since the first quarter of 2021. That said, a rebound in gas use in refining has spurred higher overall Spanish industrial gas use in recent months (*see Spanish industrial use graph*).

The only increase in manufacturing output has been in motor vehicles, which was its highest in the second quarter since the third quarter of 2019 as chip shortages eased.

Norway's Equinor could restrain October production

Norway's state-controlled Equinor might turn down production from its flexible fields in October, which would help Europe's gas market to balance while storage is full and demand still low.

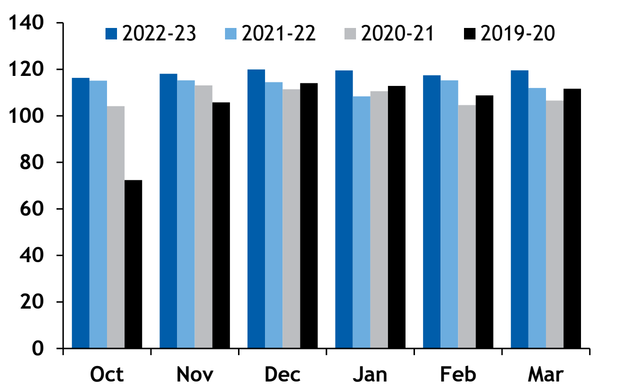
Most of Norway's seasonal swing comes from the Troll and Oseberg fields, which have flexible annual gas production permits. Equinor has a permit to produce 40.47bn m³ from Troll in October 2023-September 2024, up from 38.5bn m³ in October 2022-September 2023. Its quota for Oseberg of 7bn m³ is the same as for the 2022-23 gas year.

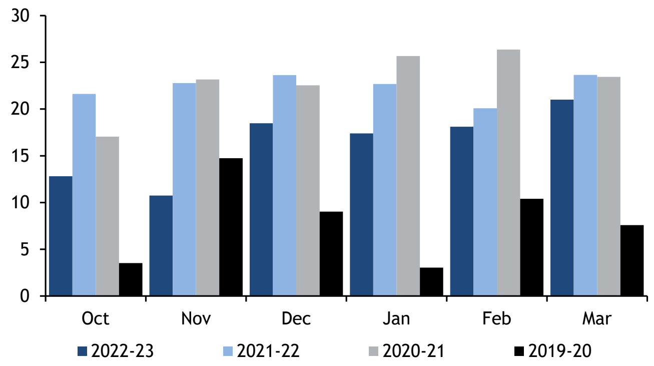
The October contracts at the UK NBP and Dutch TTF hold large discounts to all further-dated contracts up to summer 2027 (*see price graph*). This steep price contango offers an incentive for Equinor to reduce October production and possibly defer output into future gas years. Such a large time spread also makes it profitable for firms to delay LNG deliveries through slow sailing and the use of carriers as floating storage. And the price contango makes continued deliveries to Ukraine's underground storage attractive. A combination of all three should allow Europe to balance, while its other options for absorbing gas are limited — storage facilities will be brimming in October, while heating demand will stay low barring unseasonable cold.

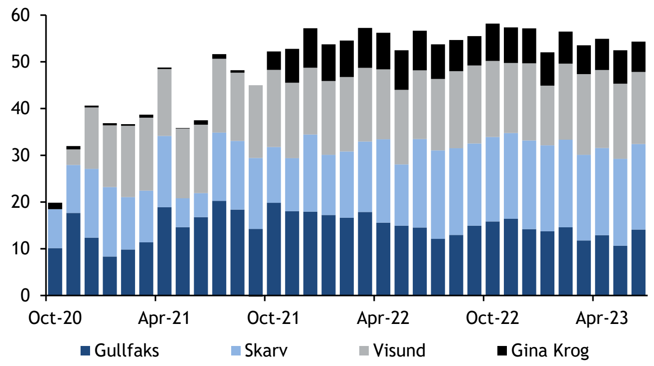
These price signals are no guarantee that Equinor will turn down production. Troll has operated close to available capacity in the 2022-23 gas year, despite prompt prices well below forward markets for extended periods. But Troll's summer 2024 production schedule — still subject to revisions — is significantly lighter than a year earlier, suggesting ample room for an October turndown even though Equinor has a higher production permit for 2023-24 than for 2022-23.

Norwegian production could be roughly 328mn m³/d in October if the Troll restraint is in line with October 2020, or as low as 290mn m³/d if the cuts are in line with October 2019 (*see Troll graph*).

Troll winter production *mn m³/d*







Equinor already cut Oseberg output in October-November last year, and could do so again this year, leaving production roughly unchanged on the year. Oseberg produced only 11.8mn m³/d in October-November 2022 and 18.7mn m³/d in December 2022-March 2023 (*see Oseberg graph*).

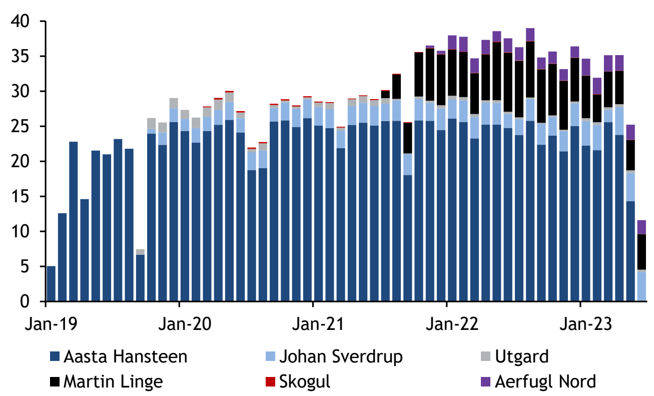
Maturing areas offset newer fields

Norway's winter production potential is slightly lower this winter than the one before, as the long-term decline of maturing areas is poised to outweigh additions from newer fields.

Norway could produce up to 348mn m³/d this winter in a scenario with no production restraint, excluding output from the Snohvit field which exclusively serves the Hammerfest LNG plant. This would be down from 352mn m³/d a year earlier.

Output from fields commissioned or restarted since December 2018 could rise by nearly 6mn m³/d year on year this winter, helped by the recent start-up of the Dvalin field, the restart of Njord and phase two of the oil-heavy Johan Sverdrup field (*see newer fields graph*). Production from fields at which gas reinjections have halted — Visund, Gina Krog, Gullfaks and Skarv — could be steady year on year (*see reinjection graph*).

Blowdown has begun at Skarv, and Aker BP told *Argus* that will not be reversed. Blowdown happens when most of a field's oil has already been recovered and involves a shift to gas production instead of gas reinjections.



Equinor declined to comment on its plans for the Visund, Gina Krog and Gullfaks fields, at which it paused reinjections from about autumn 2021 when it became more profitable to sell gas than oil. The TTF front-month has fallen back below North Sea Dated on an energy-equivalent basis since about April, but producers have so far shown no sign of shifting back to gas reinjections.

Additional gas from recently commissioned fields will be balanced out by the long-term decline of maturing areas. Production from all remaining non-flexible Norwegian fields has declined by 7pc/yr in the past six winters. A stable decline this winter would cut output by just over 9mn m³/d.

UK, Dutch production may keep falling

Production in the UK and the Netherlands looks poised to continue falling this winter, despite governments' resolve to reverse the long-term decline.

Production from the UK offshore was 100.7mn m³/d in October 2022-March 2023, down from an average of 103.9mn m³/d across the three previous winters. It could be about 97.8mn m³/d this winter, factoring in additions from fields that are already producing or are scheduled to come on stream this year (*see UK, Dutch table p7*). This estimate assumes stable output from all UK fields brought on line since December 2016, including Culzean, the UK's largest gas-producing field that came on stream in July 2019. Production from older fields could continue to decline at its average rate of 9pc over the past four winters.

The addition of new fields should partly limit the decline in other areas. UK-based private-equity backed firm Neptune Energy completed drilling of two wells at the UK Seagull oil and gas project in the second quarter and expects production to begin in September. And Shell resumed operations at the Pierce field in April after an upgrade to allow production of associated gas.

Dutch and UK winter gas production			*mn m³/d*
Winter	Dutch small fields	Groningen	UK
2019-20	41.1	29.6	108.8
2020-21	40.2	25.2	99.7
2021-22	35.5	12.4	103.2
2022-23	29.2	11.2	100.7
2023-24 projection	26.2	0.0	97.8

— NLOG, NSTA, Argus

Dutch production will drop this winter as output from the giant low-calorie Groningen field halts on 1 October. Groningen will play a back-up role in the 2023-24 gas year, with no production planned. But the Netherlands will retain the option of extracting gas "to a limited extent" from Groningen in the 2023-24 gas year. The field can be readied for production "in very exceptional circumstances", if severe cold is predicted, the Dutch economy ministry says. Production has already been limited to 2.8bn m³ this gas year (*see Groningen graph*).

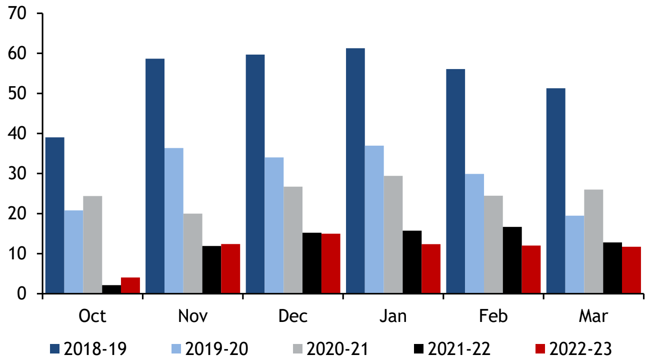
Output from the so-called small fields probably will continue to decline as the fields mature. The fields produced a combined 29.2mn m³/d last winter, down from a three-year average of 38.9mn m³/d. Production has declined at an average rate of 10.5pc across the past four winters. This suggests output from the small fields could slip to 26.2mn m³/d this winter.

Tyra to bolster supply?

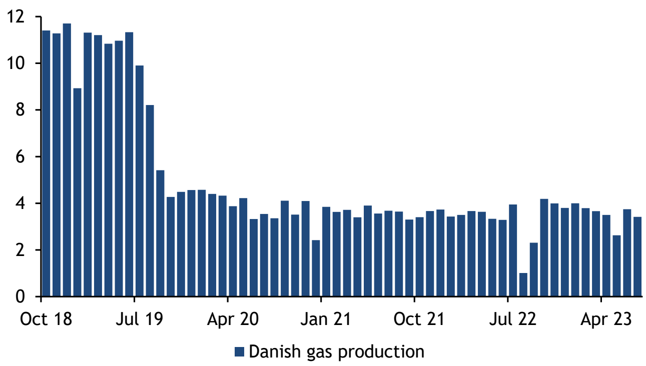
Danish production may step up this winter if the refurbished Tyra complex returns to operation, having gone off line in September 2019.

Combined Danish output fell sharply when Tyra, alongside six surrounding fields and a Norwegian field tied back to the Danish grid, was shut in 2019 (*see Danish output graph*). While the Tyra complex is shut, nearly all Danish output is sent into the Dutch grid through the Nogat pipeline under a temporary export solution. Production was 3.91mn m³/d last winter, broadly in line with the three-year average. Operator Bluenord

Groningen winter output *mn m³/d*



Danish gas production *mn m³/d*



gave a 50pc probability that the Tyra development will be open by December. It expects output from the field to reach 2.8bn m³/yr, which equates to 7.67mn m³/d.

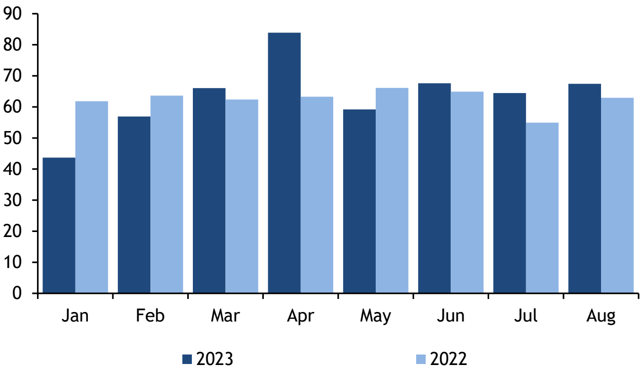
Limited scope for stronger Algerian exports to Europe

Infrastructure constraints and low demand could forestall any tangible increase in Algerian exports to Europe this winter, despite a continued rise in Algeria's upstream production.

The Italian government expects pipeline imports from Algeria to rise by 6bn m³ this year compared with 2021, and by 9bn m³ in 2024, according to a revised national energy and climate plan (NECP) it sent to Brussels in June. But flows are on course to fall well short of the expected increase. Deliveries at the Mazara entry point were 16.3bn m³ on 1 January-12 September (*see Algerian flows graph*). For aggregate Algerian pipeline receipts to total 27.1bn m³ — 6bn m³ more than in 2021 — flows would need to average 98mn m³/d on 13 September-31 December.

Pipeline deliveries to Italy have never reached that level in recent years, with maximum monthly flows of 83.9mn m³/d reached in April. Bottlenecks in the Italian grid have prevented the Transmed pipeline between Algeria and Italy from operating at full capacity. Algerian flows are generally capped at 80mn-85mn m³/d, with some fluctuations depending on demand, *Argus* estimates.

Algerian flows to Italy *mn m³/d*



Italian system operator Snam lists the pipeline's technical capacity as 108.7mn m³/d, but Tunisia typically absorbs about 11mn m³/d. Once Algerian gas reaches Italy, it blends with Libyan gas from the Gela entry point, where contracted capacity is about 13mn m³/d, and with domestically-produced gas from fields offshore Sicily. Some of this combined supply is absorbed by consumers in the southern regions of Sicily and Calabria, which used 16.8mn m³/d in 2021. Flows from Sicily mix with up to 30mn m³/d of imports from Azerbaijan and additional supply from Italian fields. But the amount of residual supply that is able to reach Italy's larger demand centres in the north is capped at 126mn m³/d by a bottleneck in central Italy, preventing the three southern pipelines from operating at full capacity simultaneously. Combined flows from Algeria, Libya and Azerbaijan exceeded 126mn m³/d on only one day last winter, with Italy receiving 91.2mn m³ from Algeria, 26.6mn m³ from Azerbaijan and 11.4mn m³ from Libya on 19 December.

Similarly, Algerian flows to Spain have limited scope to rise significantly, particularly as most of the capacity on the Medgaz pipeline is allocated to long-term contracts. Algeria's exports to Spain averaged 254 GWh/d last winter, compared with overall contracted volumes through Medgaz of about 305 GWh/d. Flows only exceeded 305 GWh/d — by no more than 7 GWh/d — on 32 days during the period.

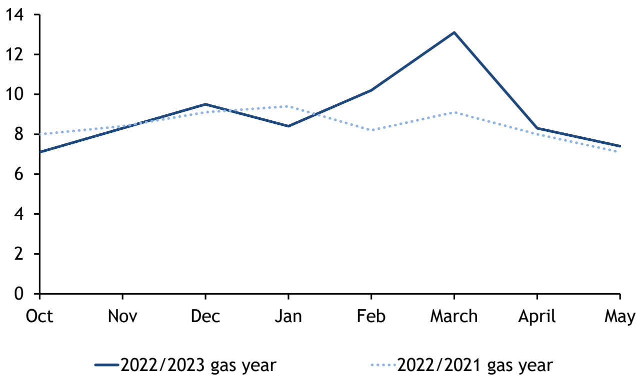
Contractual supplies vs physical flows

The increase in Algerian supply stated in Italy's NECP broadly matches the additional contractual volumes that Italy's Eni agreed with Algeria's state-owned Sonatrach in 2022, when the Algerian firm committed to add 3bn m³/yr from 2022-23, 6.2bn m³/yr from 2023-24 and 9bn m³/yr from 2024-25 to the existing long-term contract.

But there is potentially a mismatch between physical flows over a calendar year and deliveries under the contract, which includes a legacy component based on gas years — running from October to September — and the additional volumes agreed in 2022, which are instead meant to be delivered over storage years — from April to March. Moreover, an increase in contractual supply with one customer, albeit the largest one, may not necessarily translate into stronger aggregate flows to Italy, as it may reduce pipeline capacity available to other firms for spot deals. Sonatrach sold about 4bn m³ of spot gas last year, it says, without specifying the exact amounts purchased by Italy and Spain, or if the figure includes sales in the form of LNG.

But some firms may have opted to receive more Algerian supply in the form of LNG, although this is likely to be primarily the result of spot deals. Italy's NECP does not foresee an increase in Algerian LNG deliveries, but the number of cargoes from Algeria unloading at Italian ports has risen so far in 2023. The 2.7mn t/yr Panigaglia terminal received

Algerian gas production *bn m³*



31 cargoes from Algeria in January-August, against 35 in the whole of 2022 and already up from 25 in 2021. The 3.9mn t/yr OLT terminal received two ships from Algeria this summer, for the first time since 2021. And Algeria provided the first commercial cargo delivered to the recently-commissioned 3.9mn t/yr Piombino terminal.

Demand is key

There is scope for Algerian flows to increase if Italian consumption is higher than last year. Supply from Algeria to Italy was expected to increase in winter 2022-23, but flows were lower than a year earlier because mild weather weighed on heating demand. Entry flows at Mazara totalled 11.2bn m³ over the six-month period, down from 11.5bn m³ in winter 2021-22.

Limited injection demand and continued weak consumption means that Italy may have limited need to boost Algerian

Upstream production stays strong

Algerian exports this winter will depend on how the country's upstream production performs.

Several new upstream projects came on stream in Algeria in late 2022, including the 2bn m³/yr South Berkine, 1.8bn m³/yr Tinhert 1 and 1.6bn m³/yr Hassi Guettara fields, as well as the initial phase of the Hassi R'Mel LD2 reservoir, which was first announced by Sonatrach in June 2022. These projects have supported Algeria's output, which totalled 72.4bn m³ in October 2022-May 2023, up by 5bn m³ from a year earlier (*see Algerian production graph*).

This winter may bring about a further increase in production. The Hassi Bahamou field has recently come on line with capacity of up to 2.2bn m³/yr, although Sonatrach expects output to average 1.64bn m³/yr. And Hassi R'Mel LD2 should reach production of 5.5bn m³/yr by the end of 2023, having started production at 1.4bn m³/yr. Three more fields — TFT Sud, Ahnet and In Amenas Periphery — could add 7.1bn m³/yr over 2023. And more than 3bn m³/yr of additional production capacity from three other projects could come on line in 2024.

flows before the end of October. But cold weather over the core heating season could push flows at Mazara higher than a year earlier.

But even if Italian demand is low, Italian firms may have an incentive to keep Algerian flows firm and reduce their storage withdrawals, or even to increase export flows to northwest Europe. The incentive for exports looks limited for the time being, given the *Argus* PSV winter 2022-23 contract's premium to the TTF, albeit a small one.

Turkish Stream to determine Europe's Russian gas use

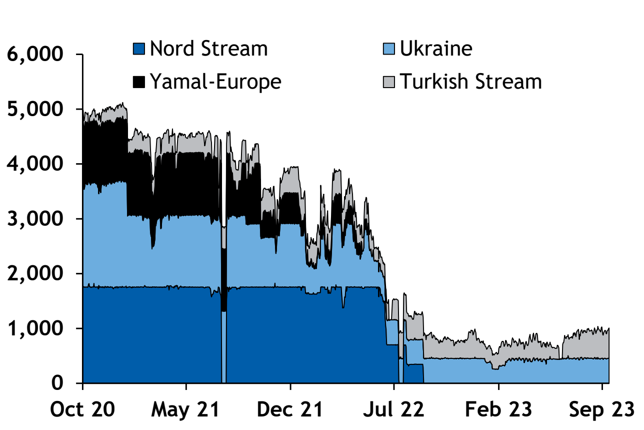
Russian deliveries to Europe cannot significantly exceed a year earlier because of transit route limitations.

The outlook for Russian supply this winter remains subject to high unpredictability, including the possibility of a dramatic disruption to flows through Ukraine. Russia's state-controlled Gazprom has previously hinted that Moscow may impose sanctions on Ukrainian state-owned Naftogaz, which would spell the end of Ukrainian transit.

Barring this extreme scenario, combined Russian flows through the Turkish Stream pipeline and across Ukraine could fluctuate between an average of 588 GWh/d and 969 GWh/d each month this winter. This assumption is based on the weakest and highest monthly Ukrainian flows since June last year and deliveries through Turkish Stream since October 2021, when it became possible to send this gas on to Hungary through Serbia.

After the closures of the Nord Stream and Yamal-Europe pipelines last summer, Russian gas is now flowing to Europe only through the Turkish Stream pipeline and across Ukraine. Combined Russian deliveries to Europe plummeted to 748 GWh/d in October 2022-March 2023, from 3.4 TWh/d in the same period a year earlier and 4.7 TWh/d in winter 2020-21 (*see Russian flows graph*).

Russian gas flows to Europe *GWh/d*



Ukraine transit in narrow range

Since Russian gas stopped flowing through the Sokhranivka point, Russian transit through Ukraine has slowed and held in a relatively tight range.

Russian gas flows through Ukraine at a single entry point, Sudzha, after Ukrainian system operator GTSOU on 10 May 2022 declared force majeure at the other shared point of Sokhranivka on the grounds that Russian troops had started to control the station. Gazprom has refused since then to redirect all transit shipments to Sudzha.

Entries into Ukraine from Russia averaged 420 GWh/d in October 2022-March 2023, well below 932 GWh/d a year earlier and 1.6 TWh/d in winter 2020-21.

Supply arriving through Ukraine is destined for Slovakia, Austria and Italy, while some of this gas also makes it to Hungary.

Turkish Stream flows vary more

Turkish Stream deliveries to southeast Europe have fluctuated more, and their pace this winter will largely depend on customers' demand.

Flows to Bulgaria through the onshore continuation of the Turkish Stream pipeline at the Strandzha 2-Malkoclar point slid to 327 GWh/d in October 2022-March 2023 from 408 GWh/d a year earlier, when some spells of cold weather had pushed up heating demand and consequently imports.

Russian deliveries through Turkish Stream have ranged since October 2021 from a low of 250 GWh/d in May this year to a high of 511 GWh/d in August, excluding June 2022 when maintenance cut flows. This monthly high is about 73 GWh/d below the Strandzha 2-Malkoclar point's nameplate capacity and existing bookings for October, according to data from transparency platform Entso-G. Booked capacity then falls to 511 GWh/d from 1 November and until the end of winter.

Hungary is one of the main Turkish Stream offtakers, but Russian gas could compete more with Azeri pipeline gas and LNG delivered to Greece and Turkey this year, as the country seeks to diversify its supply. Hungarian state-owned trading company MVM CEEnergy has concluded an agreement with Azerbaijan's Socar to import about 1TWh of gas by the end of this year.

And in the Greek market, Russian gas will need to compete with LNG receipts at Greece's Revithoussa facility. At the same time, the commissioning of a second LNG terminal in Alexandroupolis in January 2024 could allow for more seaborne supply to arrive in southeast Europe, further weighing on nominations for Russian gas, depending on price incentives at that time.

There could be an incentive for quick Russian imports through Turkish Stream at times when prompt European hub prices hold above the TTF front-month index, to which many of Gazprom's contracts are tied.

Ukraine may need to buy winter gas

Ukraine may need gas from the EU this winter, if domestic demand maintains modest year-on-year growth.

Ukraine's cabinet of ministers set a target for the country to have 14.7bn m³ of gas in storage ahead of this year's heating season. Inventories were already above this goal by late September, but some of the gas belongs to firms outside Ukraine that are using Ukrainian sites while EU storage is full and summer-winter price spreads are wide.

Naftogaz still hopes that it will not have to import gas this winter, commercial director Dmytro Abramovych said in late summer. But even a small increase in Ukrainian gas demand — which could be caused by cold weather, heavier reliance on gas for power generation or a partial economic recovery — may mean that Naftogaz or other Ukrainian firms will have to buy gas this winter.

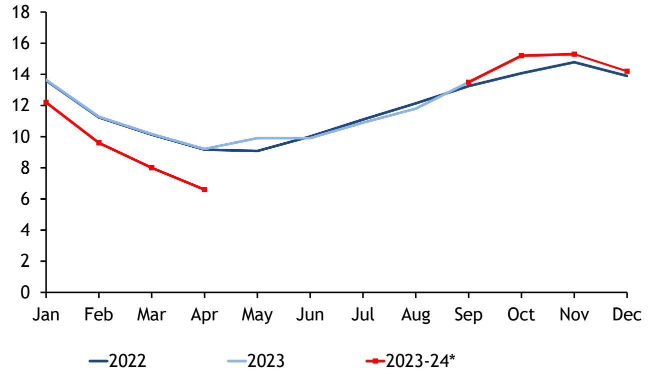
These purchases could come in the form of imports at EU border points, or by domestic companies buying some of the gas stored by EU firms in Ukraine to sell on the local market. Ukrainian winter imports from the EU might offset the flow of gas travelling westward back to the EU from Ukrainian storage sites. On the other hand, Ukrainian firms may need to deplete most of their inventories this winter if they make no gas purchases and need to cover an increase in demand.

Ukrainian stocks were on track to reach about 15.2bn m³ by the start of October, up from 13.9bn m³ a year earlier (*see Ukrainian stocks graph*).

Almost 2.8bn m³ of gas may be held under the customs-free warehouse regime by 1 October, assuming the proportion of gas imported for storage on customs-free terms is stable on the last days of September from earlier in the month. And 48pc of this might belong to foreign trading companies that have used short-haul tariffs with the intention of re-exporting the gas back to the EU.

The customs-free warehouse programme allows companies to keep gas in underground facilities for up to three years without paying taxes or customs duties as long as it is re-exported back to neighbouring markets. Firms have an opportunity to clear the supply held in storage sites under the regime to sell it on the local market, but they would then need to pay taxes and customs duties. The short-haul regime discounts cross-border gas transport capacity fees for firms that re-export gas back to the EU. Firms can sell this gas in Ukraine if they pay the standard entry tariffs for the daily product.

Ukrainian stocks *bn m³*



**Argus projection*

Unknown unknowns

Predicting likely Ukrainian winter gas demand is difficult, not least because of a lack of data transparency since the start of the Russian invasion. Assuming a 200mn m³/month increase in gas demand — in line with the June-July rise, which appeared to be driven by industry and the power sector — Ukrainian gas demand could be 17.8bn m³ in October 2023-March 2024. If production is roughly 9.2bn m³ — based on the June daily rate — then Ukrainian firms would need to draw down all their gas in storage in order to avoid imports. Available gas for withdrawal excludes the 4bn m³ of cushion gas needed to maintain enough pressure in facilities, and the almost 2.6bn m³ that might be held under the customs-free programme.

A cold winter with strong economic recovery and heavy reliance on gas for power generation could drive up gas demand much more than this conservative estimate suggests. But sustained mild weather, damage to infrastructure and economic stagnation might drive down consumption.

Balancing act

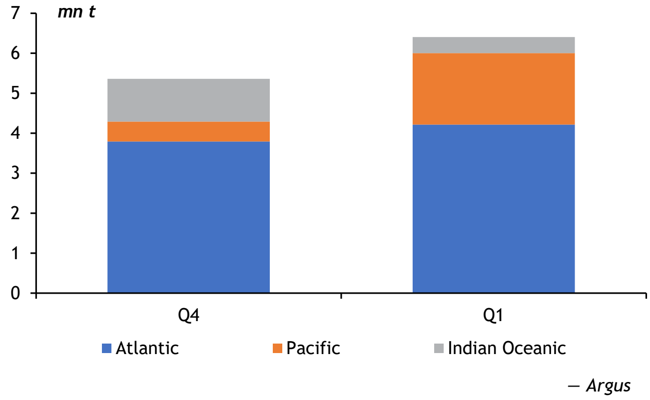
The way that Ukraine balances its gas supply and demand this winter will depend on whether it is the public or private sector that is in need of additional gas. If Naftogaz is short of gas to meet its public service obligation, it would be obliged to close the gap. The firm has to supply gas at a state-regulated price to the population, thermal power plants and entities that perform vital functions to ensure the state's defence capabilities. The state would have to compensate Naftogaz for losses related to this obligation.

But if commercial firms are short of gas, this could drive up domestic Ukrainian prices and potentially spur industrial gas demand reductions.

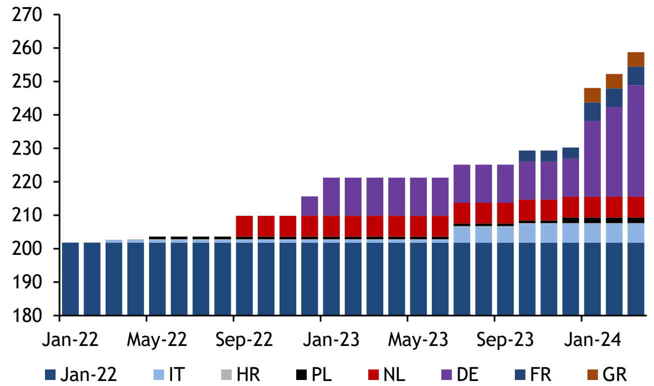
LNG supply growth to mitigate Europe's winter risks

Europe may take significantly more LNG this winter than the one before thanks to greater global LNG production, the build-out of the continent's LNG import capacity and limited demand growth in northeast Asia.

LNG supply increase YOY



Europe capacity additions *mn t/yr*

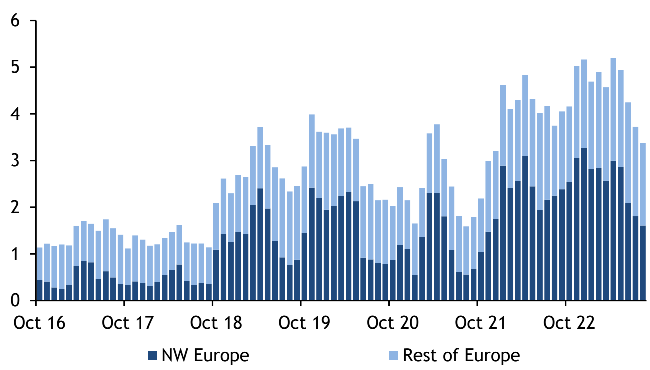


Global liquefaction capacity is poised to increase by about 11.8mn t to 213mn t in October 2023-March 2024, equating to nearly 1 TWh/d of additional LNG sendout. Of this, 8mn t will be in the Atlantic basin, driven primarily by greater availability of the 15mn t/yr Freeport facility in the US (*see liquefaction growth graph*).

And the bulk of this additional LNG supply may be directed to Europe, given that northeast Asia's demand appears poised to hold broadly unchanged year on year. Japan and South Korea may each import fewer LNG cargoes than a year earlier, as higher scheduled nuclear power plant availability may weigh on gas demand from the power sector. And while a rebound in industrial activity could spur a limited recovery in China's spot LNG needs, higher domestic production will meet the bulk of the country's gas demand growth.

Europe would offer higher returns than northeast Asia for Atlantic basin LNG in the first half of winter judging by forward prices as of late September. While the TTF October and November contracts are priced far below the rest of the winter there is an incentive for LNG sellers to hold their cargoes at sea and deliver to Europe later rather than take the longer journey to northeast Asia.

Europe's LNG sendout *TWh/d*



Europe near-term FSRU additions *m³*

Terminal	Country	Start date	FSRU	Capacity
Le Havre	France	Sep 23	*Cape Ann*	145,000
Wilhelmshaven	Germany	Dec 23	*Excelsior*	138,000
Stade	Germany	Dec 23	*Transgas Power*	174,000
Alexandroupolis	Greece	Jan 23	*Alexandroupoli*	135,000
Deutsche Ostsee	Germany	Feb 23	*Transgas Force*	174,000
Vasilikos	Cyprus	1H-23	*Etyfa Prometheas*	136,600

Potential challenges

Assuming all incremental global LNG output is directed to European terminals, the increase in supply may be sufficient to balance Europe even if the weather is especially cold or there is a major disruption to supply.

The roughly 1 TWh/d of extra global LNG production that may be available for Europe would completely cover the year-on-year increase in LDZ demand in the cold weather scenario outlined above that assumes consumption correlates with weather in the same way as last winter. The extra LNG would balance Europe even in the event of no year-on-year change in gas demand from the power sector or industry.

And in a separate scenario in which demand is stable year on year but Russian pipeline flows to Europe halt from 1 October, an extra 1 TWh/d of LNG sendout could still fully plug the gap.

But Europe's access to lots of extra LNG this winter, just at the moment that it needs it, is by no means guaranteed. It will depend on the continent's ability to remain the world's premium LNG market. If cold weather drives a surge in demand in Europe and Asia at the same time, this could spark fierce competition for spot LNG – particularly if it happened near the tail end of the winter when Europe's stocks are already drawn down or at the same time as a disruption to a major supply source. Northeast Asian markets have limited underground storage capacity, making them more reliant on LNG to balance during high-demand periods.

Infrastructure can handle LNG import jump

Infrastructure limitations capped Europe's LNG import potential last winter, but there is scope for a large increase this winter.

Europe maximised its LNG imports for most of last winter, bringing several new import facilities on line and rerouting pipeline flows to facilitate west-to-east transit. European regasification was 4.7 TWh/d in October 2022-March 2023, including a daily high of 6.01TWh on 30 November (*see sendout graph p11*).

LNG facilities operated at about 62pc of capacity last winter. A repeat of this utilisation rate would equate to about 4.9 TWh/d of sendout this winter, with technical sendout capacity of just over 8 TWh/d.

Regasification hit a fresh monthly high of 5.19 TWh/d in April, while the Netherlands reached a monthly record two months later. Sendout in each country in line with its monthly record would equate to 6.05 TWh/d — just shy of the extra supply needed to cope with a colder than usual winter and no Russian gas in the scenarios outlined above.

And even more LNG import capacity is to come on line in the coming months. TotalEnergies' planned 3.3mn t/yr import terminal at France's Le Havre is scheduled for a late-September start-up. Two more floating storage and regasification units (FSRUs) are scheduled to start operations in Germany in December and one in February. And further FSRUs should begin operations in Greece in January and in Cyprus in the first half of 2024.

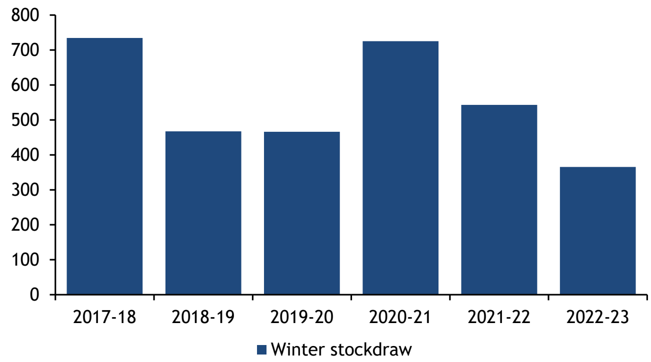
Europe may conserve its stocks

Europe will start October with underground gas inventories at their highest in recent years. This provides a large buffer to deal with any winter challenges. At the same time, it sets Europe up for another summer supply glut if the region gets through the winter without any deep cold snaps or unplanned supply cuts.

Assuming Europe's stocks enter October at 95pc of capacity, just above their late-September level, Europe could count on nearly 400TWh — or roughly 2.17 TWh/d — of additional withdrawals on top of winter 2022-23 levels while still leaving sites 30pc full by the end of March. A repeat of the largest ever winter stockdraw, in 2017-18, would leave storage sites 32pc full by the end of March (*see historical stockdraw graph*).

If European firms are forced to heavily deplete their inventories, it could be a challenge to top up storage next summer. If sites are 30pc full on 1 April, a stockbuild of over 700TWh would be needed to meet the EU's 90pc fill target. This would be over 220TWh higher than in summer 2023.

Historical winter stockdraw *TWh*



Conversely, if Europe has a normal or mild winter, then companies may be able to preserve the majority of their stocks, making it easier to prepare for winter 2024-25.

Companies will be incentivised to choose LNG sendout over underground storage withdrawals in early winter judging by late-September forward prices. All constituent months of the *Argus* TTF fourth-quarter 2023 contract were below the summer 2024 market as of late September, suggesting a strong incentive to keep gas in storage. At the same time, the wide TTF September-October spread encouraged the build-up of a large amount of floating LNG carriers by late summer. And the TTF October-November spread is wide enough to make floating storage economical further into the shoulder season.

The TTF first-quarter 2024 market's premium to the summer 2024 price as of late September suggested an incentive for storage withdrawals in the second half of winter. But if Europe's demand is weak through the heating season, this could push down prompt prices relative to forward markets at delivery, discouraging withdrawals. High availability of nuclear power plants, an economic slowdown hampering any rebound in industrial gas use and households managing their thermostats in response to high energy bills all point to historically weak European gas demand. The main risk factor for higher demand is sustained colder weather, particularly if combined with low wind power generation.

Another mild winter with weak northeast Asian LNG demand could again leave Europe with high stocks at the start of April next year. But stocks may not go much above the 54pc on 1 April this year. Companies holding capacity at aquifer storage sites in France and elsewhere need to cycle the majority of their stocks each year to maintain the structural integrity of the reservoirs. And firms would need to consider how much of a summer storage overhang they could manage, although the option of storing excess gas in Ukraine should remain available.

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