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Argus White Paper:

Global LNG summer outlook

The Russia-Ukraine conflict has further stoked supply concerns in Europe, which had already been the key market driver in recent months. A milder winter coupled with slower Asian demand throughout most of the winter allowed a partial recovery in European stocks, but these remain lower than in most recent years. Global liquefaction capacity has increased by less than in previous years, but slower Latin American and Asian demand could leave more supply available to Europe. Asian buyers opting for strong summer restocking activity, as they happened in 2021, could bolster competition for spot LNG supplies, but Europe is advancing plans to increase its take of US exports

EU plans to replace Russian gas with LNG face headwinds

The EU's plans to reduce its dependency on Russian gas through LNG imports this year face numerous headwinds, with insufficient LNG import capacity and bottlenecks in the European grid posing the largest obstacles.

The US government and the EU announced plans to supply Europe with 15bn m³ of equivalent pipeline gas in the form of LNG, which would replace "the Russian LNG we have so far", European Commission president Ursula von der Leyen said. Russian LNG deliveries to Europe, excluding the UK, totalled 10.5mn t in 2021, equivalent to approximately 13.5bn m³ of gas, figures from oil analytics firm Vortexa show.

The EU had already pledged to reduce pipeline deliveries from Russia by over 100bn m³/yr by the end of this year, but stepping away from Russian pipeline supplies could prove more challenging. In the EU's plans, half the volume would have to be replaced with LNG deliveries. This would be equivalent to additional LNG imports of 38.8mn t/yr, which could test available regasification capacity within the region.

Aggregate LNG import capacity within the EU totals around 114.2mn t/yr. But this is not equally distributed in the region, with nearly 40pc located in the Iberian peninsula — which does not receive Russian pipeline imports and has limited interconnections with the rest of Europe. Excluding Spanish and Portuguese terminals, regasification capacity in the part of the EU that relies on Russian pipeline flows totals 64.35mn t/yr.

Not all this capacity would be available to accommodate additional imports, as part of it is used to receive deliveries under long-term contracts, which are already part of the region's supply mix. At least 10.3mn t/yr of capacity is tied to long-term contracts without destination flexibility, *Argus* estimates, reducing available capacity to around 54.05mn t/yr (*see table*). If 10.5mn t /yr of capacity is needed to replace Russian LNG, capacity available to LNG imports aimed at displacing Russian pipeline flows would be barely sufficient for the EU to meet its target.

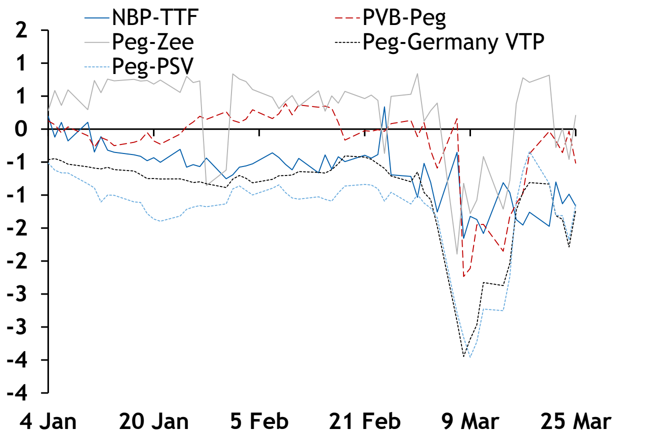
European* LNG des contracts *mn t/yr*

Supplying country	Supplying firm	Buyer	Duration	Volume
Algeria	Sonatrach	DEPA	na	na
Algeria	Sonatrach	Total	2021-23	2.0
Algeria	Sonatrach	Engie	na	1.5
Shell portfolio	Shell	Croatia	2021-27	0.2
Qatar	Qatargas	PGNiG	2015-34	1.1
Qatar	Qatargas	PGNiG	2018-34	0.9
Qatar	Qatargas	Edison	2009-34	4.6

**excluding contracts to Spain and Portugal*

Natural gas / LNG
illuminating the markets

Front-month differentials $/mn Btu



Recent shifts in regional price spreads within Europe could enable the continent to absorb more LNG (*see graph*). Near-curve prices at Spain's PVB gas hub have slipped to a discount to France's Peg market in recent weeks, providing an incentive for Spanish firms to bolster LNG deliveries while netting off their pipeline receipts from France, and also re-export regasified LNG through the Pirineos interconnection point.

This would require the utilisation rate of Spain's regasification capacity to increase sharply. The country took 15.2mn t of LNG in 2021, leaving 22.05mn t/yr of spare capacity. Netting off the 17.1bn m³ the country received from France last year would require additional LNG imports of 13.3mn t/yr. Further increases in LNG receipts would be capped by Spain's limited export capacity to France — which is around 19mn m³/d, or 5.4mn t/yr of LNG.

Even if Spanish capacity is fully utilised, the European gas grid — conceived to distribute flows from east to west — may struggle to dispatch volumes in the opposite direction. Near-curve contracts at France's Peg at a discount to Belgium's Zee and Germany's Trading Hub Europe (THE) may allow import flows from these countries to be backhauled, but physical export capacity is only available at the Alveringem interconnection point with Belgium — around 270 GWh/d, equivalent to 6.44mn t of LNG. Some flows could instead reach Italy through the Transitgas pipeline crossing Switzerland, but northbound deliveries at Wallbach — on the Swiss-German border — are limited by deodorisation capacity.

The EU may have scope to import more LNG through terminals in the UK, which has greater capacity to ship regasified LNG to the continent. But part of this capacity is typically used during the summer to bolster deliveries of Norwegian gas to the EU.

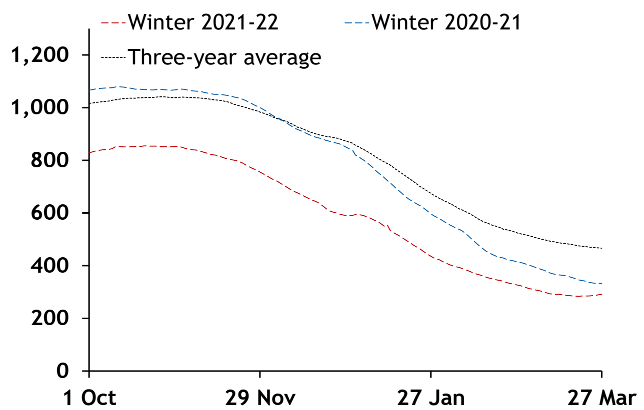
Storage injections to support European LNG demand

European injection demand could be higher than a year earlier and more than offset lower residential and industrial gas use this summer, despite a backwardation in hub prices providing no incentive for stockpiling beyond planned mandated thresholds.

A combination of milder weather and slower demand in Asia has allowed Europe to absorb brisk LNG deliveries in recent months, and the region's inventories to narrow the gap compared with recent years. Aggregate underground inventories within the European Union totalled 291TWh on 27 March, still around 42TWh short of a year earlier and 176TWh lower than the corresponding three-year average.

But the deficit compared with recent years has narrowed significantly since the start of 2022, when inventories were 226TWh lower than a year earlier and 265TWh below the three-year average (*see graph*).

EU underground gas inventories TWh



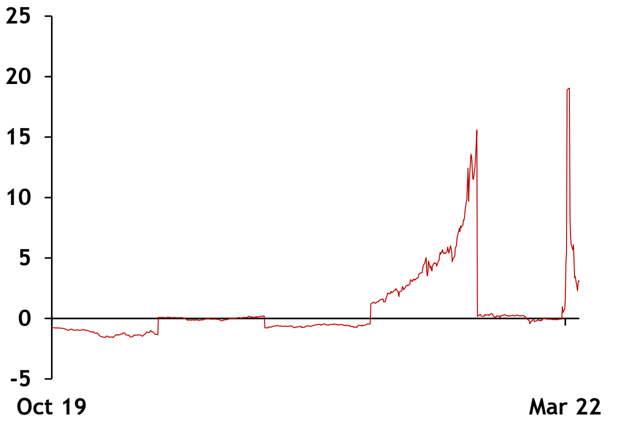
The European Commission has proposed a target to ensure EU storage sites are at least 80pc full by 1 November — or around 889TWh, based on aggregate capacity of 1.11PWh. This would require injections just short of 600TWh throughout April-October, which would be up from 513TWh injected throughout the same period a year earlier.

And should the additional 87TWh of injection demand be entirely met through LNG imports, the European stockbuild would result in additional LNG demand of 5.7mn t over the seven-month period. That said, there is still little clarity about how the proposed threshold will be implemented in individual countries.

Injection demand may be even stronger if storage facilities are filled up. For inventories to be on par with the highest recorded at the start of the winter in recent years — 1.09PWh on 1 November 2019 — Europe would need to inject 800TWh this summer, 287TWh (or 18.7mn t of LNG) more than a year earlier. Europe — including Turkey — received approximately 42.9mn t of LNG throughout April-October last year, shiptracking figures from Vortexa show.

But there may be no commercial incentive to do so, with European hub prices for winter deliveries remaining at a wide discount to the summer in recent weeks. The TTF summer 2022 contract stood $2.53/mn Btu above the TTF winter 2022-23 price on 28 March, even though it has been narrowing its premium from the record-high $19.04/mn Btu on 8 March (*see graph*).

TTF season 1-season 2 spread *$/mn Btu*



To incentivise firms to stockpile in April-September, summer prices typically need to retain a discount to winter prices wide enough to cover the cost of storage capacity. The lack of a commercial incentive to do so may lead European firms to defer injections until later in the summer, while awaiting more clarity on the proposed storage targets.

The stronger stockbuild could more than offset an expected drop in industrial gas use, which could fall by over 30TWh this summer, and a potential 50TWh reduction in residential demand, according to *Argus* analysis.

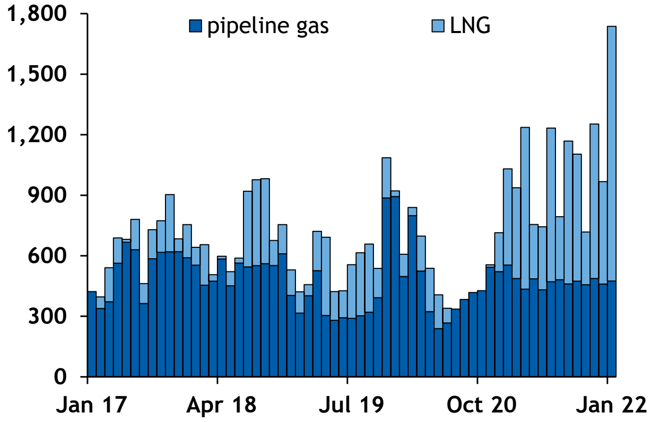
Stronger hydropower output to curb Brazil's LNG demand

Stronger hydroelectric generation is due to curb Brazil's aggregate LNG demand this summer, but more firms are seeking LNG supplies taking advantage of a recently liberalised gas market and increased import capacity.

Brazil is likely to remain dependent on LNG imports to meet its domestic demand this summer, but the record-high LNG imports seen in 2021 are not expected this year. The country received a record-high 6.26mn t of LNG in 2021, up from just 984,000t a year earlier and 2.13mn t in 2019, according to customs data. Pipeline gas imports also rose to 20mn m^3/d in 2021 from 18.5mn m^3/d a year earlier and 18.3mn m^3/d in 2019.

Last year's record gas demand mostly stemmed from a severe drought, which brought water reservoirs down to critical levels, and shaved hydropower generation down to around 45pc of the country's power demand. In normal conditions,

Brazil gas and LNG imports *'000t*



hydroelectric generations can account for more than 70pc of Brazilian power load.

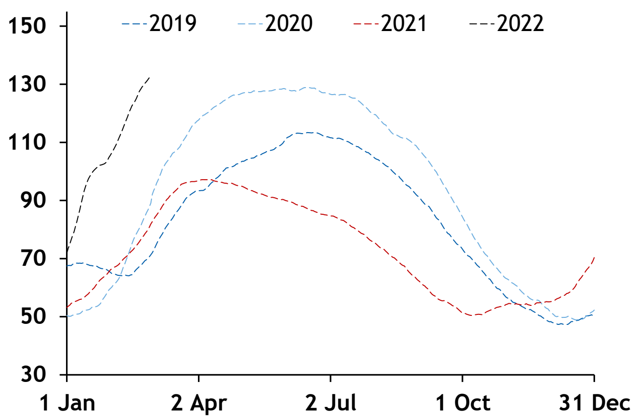
Lower hydroelectric output increased the call on thermal generation plants to meet demand. In November, at the peak of the dry season, power sector authorities were driven to dispatching all its thermal fleet, including LNG-fired units and even launching an emergency auction. Gas-fired power plant Uruguaiana, in Rio Grande do Sul state, secured supplies of regasified LNG delivered to Argentina's Escobar terminal, which sits close to the border with Brazil. The power plant could fit into the dispatch deck at R2,518/MWh ($145/mn Btu) in the last quarter of 2021, the highest cost on the deck.

The power sector monitoring committee at Brazil's energy and mines ministry has since introduced a price cap for power generation. This was initially set at R1,000/MWh ($57/mn Btu) in December, which was already low enough to leave out of the power dispatch deck most of diesel and fuel oil-fired plants. In January, this was slashed further to R600/MWh ($34.60/mn Btu).

Heavy rainfall in most Brazilian regions since the start of 2022 has replenished hydroelectric stocks. In late February, power grid operator ONS announced that water reservoir levels were back to 60.9pc, allowing them to reduce the cap to R375,66/MWh ($21.70/mn Btu), which is due to remain valid until further notice. This would require gas-fired plants to secure feedgas supplies below $10.80/mn Btu to make a profit, assuming a 50pc efficiency rate.

Brazil's rainy season typically runs until early April, when new policies about the topic may be rediscussed. But stocks have already exceeded previous years' peaks, reaching 133TWh on 28 February, up from 82TWh a year earlier and the 2021 peak of around 97TWh in early April. The additional reservoirs compared with last year's peak could be enough to displace around 4.7mn t of LNG demand, assuming hydroelectric generation displaces gas-fired plants with an average 50pc

Brazil hydroelectric stocks *TWh*



efficiency rate. That said, hydroelectric stocks have typically peaked later in the year in the past — at 129TWh in mid-June 2020 and 113TWh a year earlier.

Increased availability of gas produced domestically may also weigh on LNG demand. The planned start-up of the Route 3 pipeline is expected to bring to the market up to 9mn m³/d of gas from offshore pre-salt fields by mid-2022, before gradually increasing to full capacity of 21mn m³/d next year.

More Brazilian buyers seek LNG purchases

That said, the liberalisation of Brazil's gas market — following the new gas law approved in April 2021 — coupled with additional import capacity may open new regional markets within the country.

Two new terminals — in Sergipe and in Rio de Janeiro — have started operations in 2021, and US firm Excelerate took over Petrobras' Bahia terminal in December. With a new gas market in the making, more firms are looking closely at the global LNG market and considering long-term supply agreements.

Argentina's LNG imports to edge higher in 2022

Argentina seeking an earlier start of LNG imports at its Escobar terminal as well as a larger import facility to be installed at Bahia Blanca suggest the country's LNG demand may increase further this year.

The country, which typically only imports LNG to complement domestic production during the austral winter, was set to start deliveries already in March — earlier than in any previous year since 2017, which was before Argentina released its Bahia Blanca floating storage and regasification unit (FSRU), with rising domestic production at the time suggesting the country would be able to reduce its dependence on LNG imports. State-controlled firm YPF issued a tender in January on behalf of fellow state-owned energy firm Ieasa, for a mid-March delivery to the 3.7mn t/yr Escobar terminal. The tender was heard to be awarded at around $27/mn Btu.

Argentina has also sought an earlier restart of operations at Bahia Blanca import terminal, where it likely plans stronger deliveries this year. In January Ieasa sought to charter an FSRU for use at the terminal over 18 May-31 August — a slightly longer period than last year, when the 150,900m³ Exemplar FSRU operated at Bahia Blanca throughout June-August. Ieasa has also requested that the FSRU is able to deliver around 1.6bn m³ of gas, equivalent to around 1.24mn t of LNG, and more than the 831,000t the Exemplar received last year, based on tender results disclosed by Ieasa.

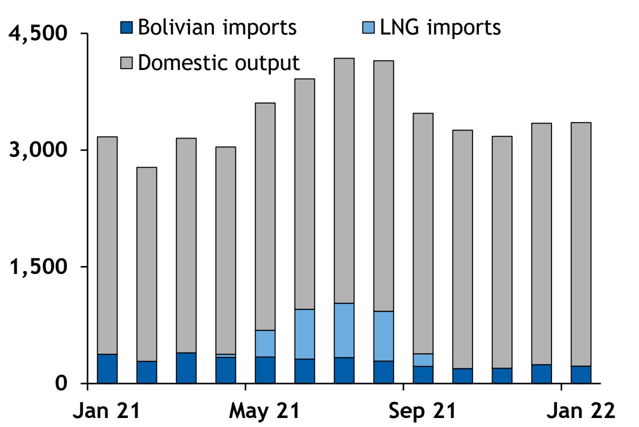
Argentina's LNG demand may also be supported if Bolivian pipeline flows remain weak in the coming months. Bolivian flows to Argentina totalled 3.53mn t in 2021, down from 4.15mn t a year earlier and 3.85mn t in 2019, customs data show.

Declining upstream production in Bolivia may have weighed on the country's ability to maintain strong exports, with output at 45mn m³/d in 2021, up from 43mn m³/d a year earlier, when production dropped to a record low at the start of the Covid-19 pandemic, and 51mn m³/d average across 2017-19, official data show.

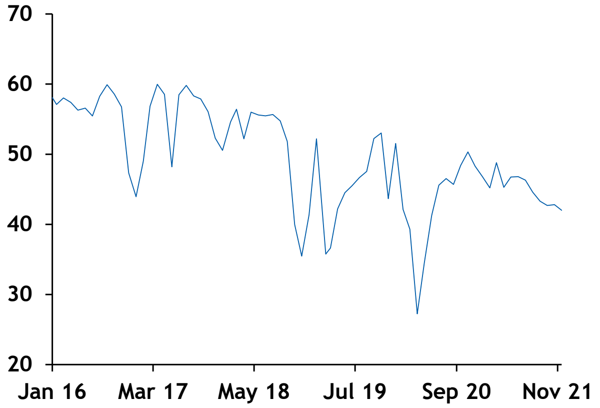
That said, Argentina's LNG demand may largely depend on the country's upstream production in the coming months. Output rose slightly over last year's austral winter — averaging 128mn m³/d across May-August, up from 125mn m³/d a year earlier. The 2021 high of 133mn m³/d in August was the strongest output since October 2019. It later declined to 129mn m³/d in September-December, likely as a result of the seasonal drop in demand, but remained higher than the 118mn m³/d produced in September-December 2020, although still below the 133mn m³/d over the same period in 2019. The latest official data show January output at 130mn m³/d, up from 116mn m³/d a year earlier.

That said, government subsidy programmes intended to boost production have attracted limited market interest in recent months, which may reduce scope for a sustained rebound in upstream output to continue throughout 2022. In the latest

Argentina supply balance *'000t*



Bolivia upstream output *mn m³/d*



auction for state-subsidised domestic supplies for power generation through May this year until the end of 2024, Argentina awarded only 3mn m³/d of supply, having intended to purchase up to 5.5mn m³/d. The additional subsidised production would come on top of supply secured through previous auctions, which did result in higher production.

Asian buyers mull strategies for summer 2022

Asian buyers are likely to again opt for early restocking well ahead of the winter, but many are striving to adapt their purchasing strategies — seeking to reduce their exposure to a volatile spot market through new term contracts, time swaps and smaller tenders.

Spot prices well above the cost of term supplies under oil-linked formulas throughout last year spurred Northeast Asian buyers to sign at least 22 term contracts in 2021 alone, the highest contracting activity seen in recent years. Chinese firms accounted for the bulk of these deals, with as many as 14 buyers signing a total of 20 deals last year.

Many new contracts are slated to start from 2023 onwards. But at least five contracts totalling around 11.45mn t/yr were

Asian firms' term contracts starting in 2022 *mn t/yr*

Buyer	Seller	Export terminal	Expected start	Volume
CNOOC	Venture Global	Calcasieu Pass	2022*	1.50
CNOOC	QatarEnergy	Ras Laffan	2022*	3.50
CNOOC	Petronas	na	2022*	2.20
Sinopec	QatarEnergy	Ras Laffan	01-01-22	2.00
CPC	QatarEnergy	Ras Laffan	01-01-22	1.25
Shell (for delivery to China)	QatarEnergy	Ras Laffan	01-01-22	1.00
Sinochem	Cheniere	portfolio	07-01-22	0.90
ENN	Cheniere	portfolio	07-01-22	0.90
Total volume				**13.25**

**start date not officially unconfirmed*

expected to start in January this year, followed by two more 900,000 t/yr contracts in July 2022 *(see table)*.

Assuming buyers take 10-20pc less during summer months, this could reduce northeast Asian spot demand by 5.1mn-5.7mn t in April-September.

That said, some deals may not immediately reach the full contractual volume, with market participants suggesting that arrangements regarding delivery windows and frequency may remain a "work in progress" in the initial period.

Most buyers are likely to continue purchasing cargoes well in advance this summer, as they did in 2021, in a bid to avoid a repetition of the supply crunch they experienced in winter 2020-21, when they found themselves caught short amid an unexpectedly cold winter *(see table)*.

Spot winter 2021-22 tenders by northeast Asian buyers

Firm	Country	Closing date	Delivery period	No. of cargoes
CNOOC	China	02-23-21	May 2021-Mar 2022	10
Unipec	China	04-06-21	Jun 2021-Feb 2022	45-60
ENN	China	04-14-21	Jul 2021-Feb 2022	4-8
CNOOC	China	06-04-21	Jul 2021-Mar 2022	10
CPC	Taiwan	06-28-21	Oct-Dec 2021	10
Osaka Gas	Japan	08-04-21	Nov 2021-Apr 2022	6
CPC	Taiwan	08-27-21	Oct 2021-Feb 2022	at least 10
CPC	Taiwan	09-23-21	Nov 2021-Feb 2022	at least 7
Unipec	China	09-24-21	Nov 2021-Mar 2022	at least 11
Total				**113-132**

—Argus

Expectations of tight supplies and risks stemming from the conflict in Ukraine are likely to make this strategy a keeper even beyond 2022, with buying activity already proving strong in the first months of 2022 *(see table)*.

Asian buyers' spot tenders for 2022

Firm	Country	Delivery period	Closing Date	No. of cargoes
Inpex	Japan	27-31 Mar	02-22-22	1
PTT	Thailand	Apr	02-22-22	Unspecified
Kogas	South Korea	Mar	02-20-22	Unspecified
RPGCL	Bangladesh	12-13 Mar	02-20-22	1
Pakistan LNG	Pakistan	2-3/10-11 Mar	02-22-22	2
GSPC	India	1-15 Mar	02-18-22	1
CPC	Taiwan	Apr	02-15-22	2
PTT	Thailand	Apr	02-17-22	Unspecified
Kogas	South Korea	20 Feb-10 Mar	02-16-22	Unspecified
Gail (swap)	India	Apr-Sep	02-16-22	6

South Korea's main importer Kogas has issued several tenders in recent weeks, seeking spot cargoes for prompt delivery. This may also suggest a shift in the firm's purchasing strategy, with repeated tenders for small batches of cargoes likely allowing Kogas to mitigate risks, market participants said.

Similarly, Thailand's state-owned PTT has been active in purchasing spot cargoes since late 2021, possibly as negotiations with a few suppliers to secure term cargoes have failed so far, market participants said. Dwindling output from the Erawan gas field, one of the country's two biggest offshore blocks, may have further compelled PTT to seek spot cargoes to make up for the shortfall.

Japanese LNG buyers have also sought to shore up supplies through time swap instead of bolstering spot purchases, but with so far limited success — which could result in the country having already higher than anticipated summer supplies.

At least three Japanese utilities have procured prompt cargoes through time swaps in the last three months. But the inflexibility of term contracts, with some still including destination restriction clauses, and the difficulty to determine the prompt-summer price spread amid recent volatility resulted in failure to secure such arrangements in most cases, market participants said.

That said, Japanese buyers may need to secure more spot cargoes this summer in the event of a ban on LNG supplies from Russia. Japan has joined G7 countries on a number of sanctions targeting Russia, but these have so far stayed clear of the energy sector. But some LNG buyers have already been considering alternatives to Russian LNG, including the possibility of swapping cargoes with Chinese buyers.

At least eight Japanese firms have term offtake from the 9.6mn t/yr Sakhalin LNG export terminal, for a total of around 5mn t/yr *(see table)*.

Japanese term offtakers from Sakhalin LNG			*mn t/yr*
Buyer	**FOB/DES**	**Duration**	**Volume**
Jera	FOB	2009-29	1.50
Jera	DES	2011-26	0.50
Hiroshima Gas	FOB	2008-28	0.21
Osaka Gas	FOB	2008-31	0.20
Saibu Gas	DES	2014-27	0.07
Toho Gas	DES	2009-33	0.50
Tokyo Gas	FOB	2009-31	1.10
Kyushu Gas	DES	2009-31	0.50
Tohoku Electric	FOB	2010-30	0.42
Total			**5.0**

Many Japanese buyers also purchase spot supplies from the plant. Some Singaporean banks have also stopped issuing standby letters of credit for purchasing spot cargoes from Sakhalin, market participants said.

Chinese gas demand growth to slow this summer

China expects demand to rise further this year, albeit at a slower pace than in 2021 — as continued economic growth and a government-driven coal-to-gas switching policy offset the impact of China's zero-Covid policy, price-driven fuel substitution and lower export orders slowing manufacturing activity.

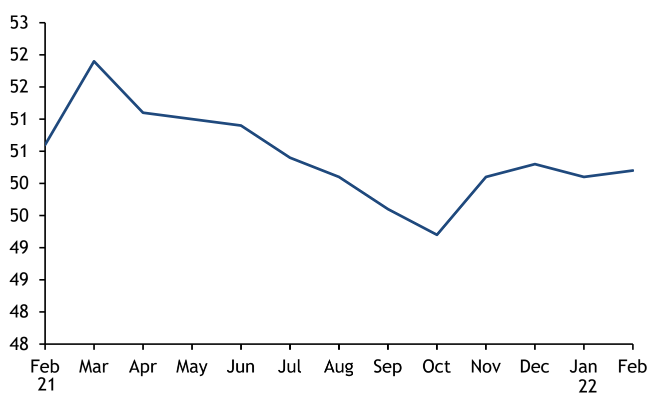
Aggregate Chinese gas demand could reach around 407bn m³ in 2022, up by approximately 9pc compared with a year earlier, according to the research branch of state-owned firm CNPC. This would represent a slower growth from a year earlier, when consumption totalled 373.8bn m³ — 12.9pc higher than in 2020.

Continued economic growth and a further government push to foster industrial gas use could underpin the increase. China's official Purchasing Managers' Index (PMI) stood at 50.2pc in February, indicating a further expansion despite the typical slowdown during the lunar new year holiday. The index has remained mostly above 50pc throughout the past year, only falling below that level in September-October.

China's main economic planning agency NDRC last month published plans to further bolster coal-to-gas switching in the industrial sector this year, specifically targeting the building materials manufacturing sector — including flat glass, construction and sanitary ceramics industries.

About 38-41pc of the expected increase in gas demand may be met by stronger domestic production, which is forecast to rise by 13bn-14bn m³ in 2022, the CNPC Research Institute estimates. An additional 5bn m³ of Russian gas is expected to reach China through the Power of Siberia 1 pipeline, which is contracted to deliver 15bn m³ this year.

China's Purchasing Manager Index (PMI) %



China would still need additional LNG imports of 14.2bn-15.2bn m³ (11mn-11.8mn t of LNG) this year, assuming pipeline receipts from sources other than Russia are broadly in line with a year earlier. This would be short of the additional 12.6mn t China received in 2021, although still higher than in previous years.

Limited demand seasonality

Apparent gas demand during summer months has accounted for approximately 48pc of the total over the past five years — with only minor fluctuations — as power sector gas demand coupled with storage injections have largely balanced the traditional peak in winter heating demand.

Power demand is typically stronger during the summer, accounting for an average 51.3pc of yearly generation over the past three years, with China's expanding storage capacity also contributing to reduce its demand seasonality. At the start of 2022, CNPC had 11 facilities in service with a combined nameplate capacity of 19.3bn m³, but their actual usable capacity is estimated at 13.9bn m³, up from 12.4bn m³ a year earlier. The firm said it accounted for 82pc of total storage capacity in the country, suggesting this could be around 16.95bn m³.

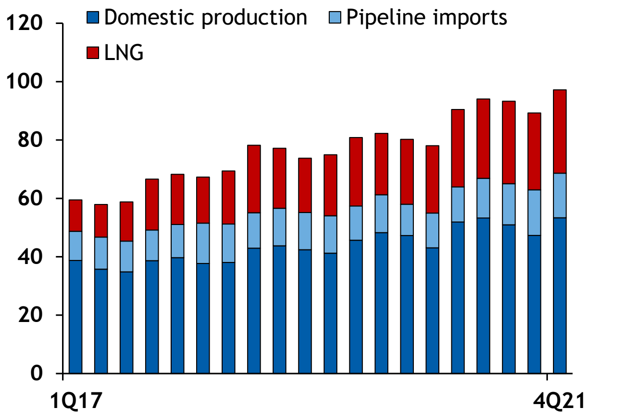
Assuming the summer-winter demand share is in line with the five-year average, China may need approximately 195bn m³ over April-September. By contrast, China's LNG imports have become more evenly distributed between summer and winter, with April-September receipts accounting for 49.5pc of the total in 2021 — compared with 48.8pc in 2020, 47.3pc in 2019 and 45.7pc in 2018. If summer receipts account for a similar share of the total as in 2021, additional LNG demand may be around 5.7mn t this summer.

This would exceed the additional term supplies starting this year, suggesting spot LNG demand may be stronger than a year earlier this summer. New term contracts totalling 6.15mn t/yr started in January, with two more deals totalling 1.8mn t/yr due to start in July.

China has already sufficient import capacity to support the increase in deliveries this summer, despite limited additions in recent months. The country has 22 terminals with a combined receiving capacity of over 100mn t/yr, and 11.7mn m³ of LNG storage capacity. Seven new terminals and one expansion project are meant to be commissioned in 2022, but only the 3mn t/yr CNOOC Jiangsu Binhai terminal is expected this summer.

But Chinese firms may have an incentive to maximise pipeline receipts early in the summer, as the recent rally in oil prices is likely to increase the cost of oil-linked supplies later in the year, which could sap the country's spot demand in the first half of the summer.

China's gas supply mix *bn m³*



Limited scope for stronger summer Japan demand

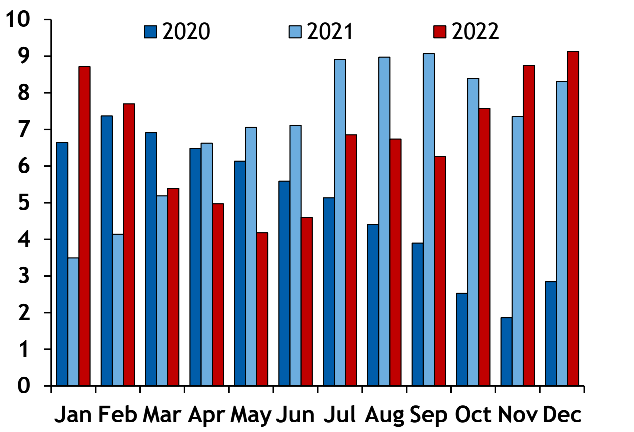
An expanded fleet of coal-fired generation plants may offset most of the expected drop in Japan's nuclear output this summer, as LNG prices remain uncompetitive with coal and oil in the country's generation mix.

Eight out of 10 operating reactors in Japan are scheduled to carry out maintenance this year, reducing nuclear capacity available for commercial use by around 2.36GW in April-September compared with a year earlier, based on data from utilities and the Japan Electric Power Exchange (Jepx). Japanese nuclear plants are required to conduct a turnaround every 13 months.

The largest shortfall in nuclear generation is expected in May, traditionally a shoulder season characterised by lower power demand, when capacity available is scheduled to be 41pc lower. But availability is due to remain much lower than a year earlier in the third quarter *(see graph)*.

Assuming the reduction in nuclear output is entirely offset by gas-fired plants running at an average 50pc efficiency rate,

Japanese nuclear availability *GW*



Japan would need to import around 1.33mn t of LNG more than a year earlier across the six-month period — or approximately three standard-sized cargoes a month. The country took 33.5mn t in April-September 2021.

But gas-fired plants using spot LNG are unlikely to be called first to meet the shortfall in nuclear generation. The dark spread for a 40pc-efficient coal-fired plant was last assessed at ¥25.08/kWh for August in the Tokyo area on 25 March, based on *Argus* spot coal, freight and power assessments. This was slightly higher than the spark spread of ¥24.13/kWh for a 58pc-efficient plant supplied with oil-linked LNG. But the spark spread was just ¥7.87/kWh if the same plant were using spot LNG.

Instead, Japan could rely on stronger coal-fired output, tapping an expanded fleet of coal-fired units. Five new plants with a combined capacity of 3,870MW are due to begin operations during the April 2022-March 2023 fiscal year — including two units totalling 2,070MW that are expected to start in time for the summer months. This would be on top of two units — totalling 1,193MW — installed in the second half of 2021-22.

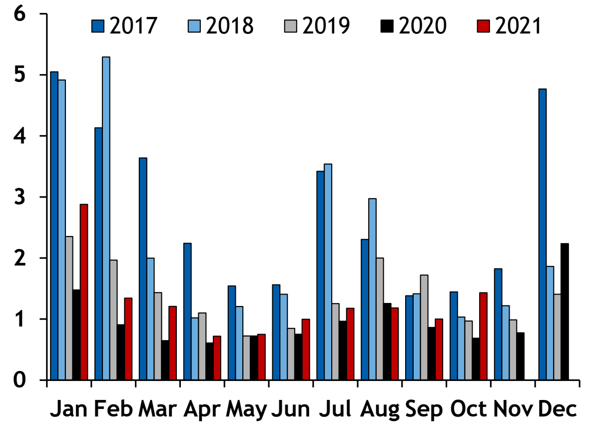
Additional coal-fired capacity of 3,263MW would far outstrip planned outages averaging 898MW in July-September, according to *Argus*' calculation based on Jepx data, and could be sufficient to entirely offset lower nuclear generation if it runs at full capacity. But this scenario may be dependent on how quickly the 16 March earthquake-hit coal-fired units will be restored. It is still unclear when three coal-fired units, with a combined capacity of 1,224MW, will be brought back on line.

By contrast, Japan's gas-fired generation fleet is due to shrink this summer. Four gas-fired units with a combined capacity of 2,513MW are expected to start in 2022-23, including two units totalling 1,219MW in time for the summer months. But this would not be enough to offset planned outages at other facilities, which are scheduled to average 1,307MW in July-September, *Argus* estimates.

LNG prices remaining above oil parity may also continue to incentivise stronger oil-fired generation, as they did in recent months *(see graph)*.

That said, a relatively tight power supply expected this summer could prompt importers to rebuild LNG stocks early in the season, as they did last year in a bid to avoid a repetition of the severe power shortage Japan faced in January 2021. LNG inventories held by Japan's main power utilities, excluding stocks owned by other power producers, stood at 1.68mn t as of 20 March, according to Japanese trade and industry ministry Meti's weekly survey — down from 2.41mn t at the end of March 2021 and the four-year average of 2.19mn t for the same period.

Japanese oil-fired generation *TWh*



The government has repeatedly called for preventative actions ahead of peak demand periods, urging firms to ensure stable LNG imports and monitoring inventories. And power demand is forecast to be higher this summer, as economic activity continues to recover after Covid-19. Peak power demand in the country's nine service areas, excluding Okinawa, is forecast to reach 171GW if temperatures match the highest recorded in the past decade, according to Meti's latest outlook — well above last summer's peak demand of 127GW.

Economic recovery may also boost industrial demand, which accounted for around 60pc of total city gas sales in 2021. Japan supplied 8bn mn^3 of city gas in July-September last year, which required 5.8mn t of LNG, Meti figures show.

Nuclear, coal to squeeze South Korean LNG demand

Stronger nuclear generation and greater potential for gas-to-coal switching are likely to weigh on South Korea's LNG demand this summer.

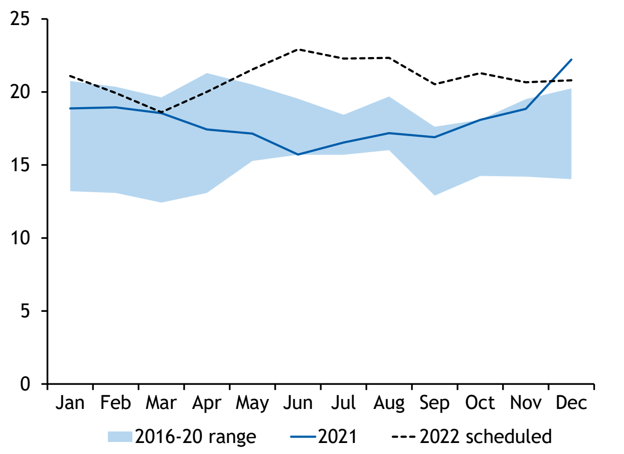
South Korea's power demand has grown steadily over the past two years, exceeding earlier projections. The pandemic reduced power demand to 552.1TWh in 2020 from 563TWh a year earlier, but this was still higher than a government's forecast of 516.7TWh. In 2021, actual power generation totalled 576.3TWh, surpassing Seoul's expectation of 544.6TWh.

Assuming electricity demand is again 7-8pc higher than expected, in line with the past two years, power generation could total 585.4TWh in 2022. This would leave power demand over the second quarter of 2022 at 62.6GW, and 67.5GW in the third quarter, *Argus* estimates, judging by seasonal demand trends over the past decade.

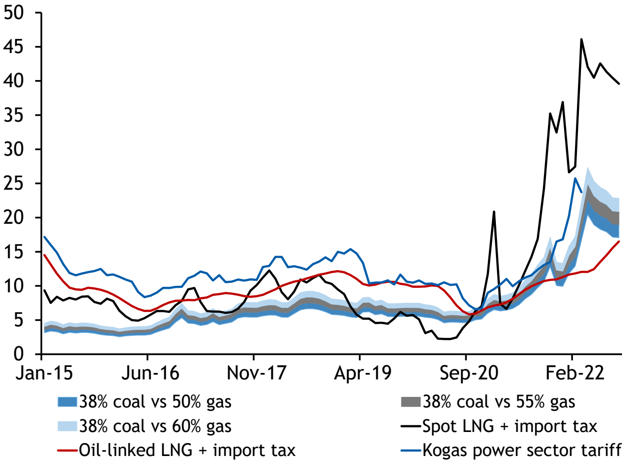
Firmer nuclear availability to pare thermal generation

The country's nuclear availability is scheduled to average 21.6GW during April-September, compared with an actual output of 16.8GW a year earlier *(see chart)*.

South Korea's nuclear generation GW



S Korea's gas prices vs fuel-switching threshold GW



Assuming reactors run at flat year-on-year load factors and the increase in nuclear output entirely displaces gas-fired generation plants with an average 50pc efficiency rate, this alone could result in South Korean LNG demand being slashed by some 3.12mn t over the six-month period — or around seven cargoes per month.

The expected increase in nuclear output would be partly the result of the planned start-up of the long-delayed 1.4GW Shin-Hanul 1 unit, which is scheduled for April, having been delayed from August last year. Barring further delays, South Korea's nuclear generation could average 22.3GW and 22.2GW during the second and third quarters this year, from 16.8GW and 16.9GW a year earlier, respectively.

This would leave some 33.8GW and 39.2GW for combined thermal generation during the two summer quarters, down from 38GW and 45.5GW a year earlier, respectively — assuming renewable generation is broadly flat on the year.

That said, even if the start date at the Shin-Hanul reactor gets delayed again, nuclear availability is still scheduled to rise by 3.9GW during April-September, which would imply 3.8GW less room for thermal generation over the same period on average.

Scope for gas-to-coal switching continues

Firmer nuclear output would likely weigh more on gas-fired generation than on coal-fired plants, as these offer better returns to utilities because of lower coal prices.

Both oil-linked and spot LNG forward prices for delivery into northeast Asia are set to hold well above all the key fuel-switching bands over summer months, with the South Korea-delivered forward coal curve in a steeper backwardation than corresponding LNG prices *(see chart)*.

In February, a 58pc-efficient gas-fired unit running on Kogas' supply was around $73.79/MWh costlier than an average-efficiency coal-fired plant, based on *Argus*' NAR 5,800 kcal/kg cfr South Korea assessment.

The government's efforts to facilitate coal-to-gas fuel-switching — by implementing environmental dispatch or reflecting marginal carbon cost when determining merit order — have also yielded small results so far, with carbon prices holding too low to make coal uncompetitive against gas. South Korea introduced the environmental dispatch on 1 January this year, which lifted coal's system marginal price (SMP) to 135.5 won/kWh in January from 125.8 won/kWh a month earlier, data provided by Korea Power Exchange (KPX) show. By comparison, gas' SMP increased to 206.2 won/kWh from 193.8 won/kWh.

As a result, the government may consider reintroducing a voluntary cap on Kepco's coal-fired power plants for April-November, but utilities may struggle to cope with restrictions similar to last year.

Even assuming that gas accounts for a similar share of thermal generation as in the past two years, gas-fired generation would still fall to 14.8GW in April-June and 15.7GW in July-August — down from 17.9GW and 19GW, respectively. This would result in LNG demand falling by around 885,000t and 952,000t over the same periods.

New president to revive nuclear industry

South Korea's energy policies may face an upturn over the summer as Yoon Seok Yeol, the conservative opposition People Power Party's presidential candidate, was elected on 9 March.

The new president has previously pledged to revive South Korea's nuclear industry and bring an end to incumbent Moon Jae-In's nuclear phase-out policy. Yoon had criticised president Moon for increasing reliance on "expensive" LNG generation to reduce nuclear output.

Fertilizers, city gas could support Indian demand

Stronger demand from government-subsidised sectors such as fertilizers producers and city gas distributors may provide some support to India's spot LNG demand this summer, which has remained subdued in recent months.

Indian buyers have largely stayed clear of the spot market in recent months, as LNG prices climbed to levels they consider unsustainable, while stronger domestic production has allowed the country to reduce its reliance on imported LNG. Output rose by 20pc to 31.1bn m³ in April 2021-February 2022 from 26bn m³ a year earlier, according to the oil ministry, mainly because of the production ramp-up at Reliance Industries and BP's deep-sea development in the Krishna Godavari basin. India's dependence on imported LNG declined to 49.1pc during the same period from 54.5pc a year earlier.

Barring a sharp increase in downstream demand, India is likely to continue relying predominantly on domestic production and term LNG supplies indexed to crude prices, which make up 85pc of the country's LNG imports, as most downstream users have been priced out of spot LNG supplies. Before the outbreak of the Ukraine conflict, the country's state-controlled importer Petronet had expected LNG rates to settle below $20/mn Btu this summer, but industry officials have warned spot prices may remain consistently over $30/mn Btu in the coming months. The *Argus*-assessed India front-half month des price hit a record-high of $47.24/mn Btu on 7 March, before reversing most of its recent gains later in the month. It was last assessed at $34.98/mn Btu on 18 March.

India's LNG imports fell by 3pc to 29.3bn m³ of equivalent pipeline gas in April 2021-February 2022, compared with a year earlier.

Fertilizer producers and, to a lesser extent city gas distributors, are shielded from global LNG prices. Fertilizers producers are able to pass on higher gas costs to consumers because the government offers subsidies to urea makers. Similarly, city gas distributors receive supplies at a cheaper rate than imported LNG, but are not able to entirely pass on price increases to their customers. The two sectors together made up over half of India's total gas use and 49pc of imported LNG in April-January.

India's fertilizers production is also set to expand in the coming months. The government has set up new ammonia urea plants at five fertilizer plants — Sindri, Barauni, Gorakhpur, Talcher and Ramagundam. These are expected to require about 5mn-6mn m³/d of feedgas supplies — including 2.2mn m³/d to the Ramagundam plant, starting from April, and 1.5mn m³/d for private-sector Matix Fertilizers' Durgapur facility, equivalent to approximately two standard-sized LNG cargoes/month. Gail plans to bring more of its US contracted supply to India to meet the increased domestic demand from this summer, although this will still be predominantly through cargo swaps.

Rapidly expanding city gas networks may also support gas demand. India had 3,771 compressed natural gas (CNG) stations at the end of 2021, the most recent figures available show, up by 43pc from 2,629 a year earlier. Similarly, domestic connections to the distribution grid rose by 20pc to 8.7mn from 7.25mn. A rebound in economic activity — after Covid-19 cases trickled to less than 10,000 a day, prompting state governments to lift all restrictions — could also contribute to higher gas demand.

Global LNG output growth to slow this summer

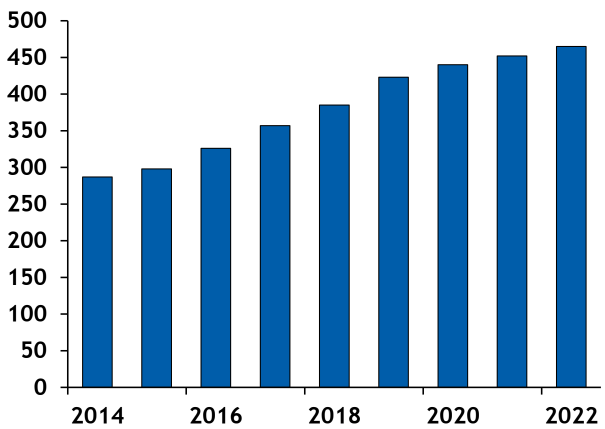
Global LNG supply is set to be higher than a year earlier this summer, mostly because of capacity additions in the US, although the build-up in liquefaction capacity has slowed from previous years.

Liquefaction capacity in operation worldwide should be 465mn t/yr at the start of April, up from 450mn t/yr a year earlier. But the 15mn t/yr increase was lower than in the preceding 12 months, when new facilities totalling 18mn t/yr were commissioned.

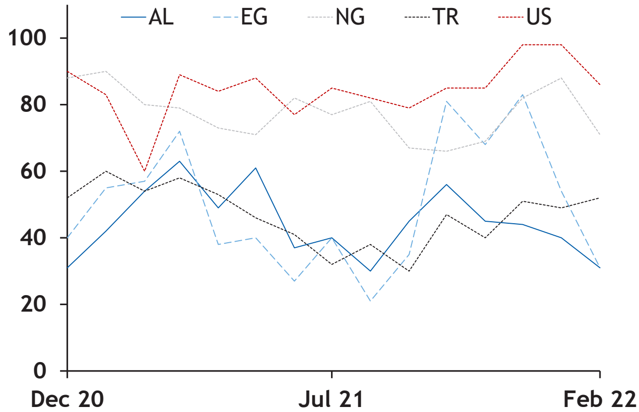
The increase stemmed entirely from new US facilities. The sixth 5.5mn t/yr train at the Sabine Pass complex shipped its first cargo in December and began commercial service in February. The US' 11mn t/yr Calcasieu Pass LNG facility exported its first cargo in March, but only five out of its nine liquefaction blocks, with a combined capacity of approximately 7.5mn t/yr, have already received regulatory approval to start exporting.

Atlantic basin capacity is set to be around 196mn t/yr at the start of April, up from 182mn t/yr a year earlier, and may increase further later in the summer if more Calcasieu Pass trains are commissioned and with the planned restart of Norway's 4.2mn t/yr Hammerfest liquefaction terminal

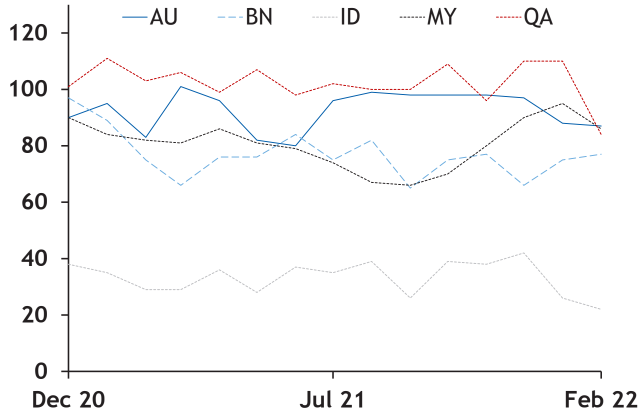
Global liquefaction capacity growth *mn t*



Atlantic liquefaction capacity utilisation %



Pacific liquefaction capacity utilisation %



— which is expected in mid-May, after repeated delays. By contrast, operational capacity in the Asia-Pacific basin is set to hold at around 269mn t/yr at the start of April, little changed from a year earlier.

High prices incentivise strong utilisation rates

With high global gas and LNG prices incentivising producers to maximise exports, utilisation rates should be close to capacity at most facilities, except where feedgas availability is constrained or technical problems cap output.

Atlantic basin output could be 75mn-78mn t in April-September, depending on the ramp-up at Hammerfest and Calcasieu Pass and assuming utilisation rates elsewhere are in line with the past six months — with the exception of Egypt's 5mn t/yr Damietta terminal, which is expected to operate at 70pc of capacity this year, up from 50pc in 2021, with stronger Israeli pipeline flows bolstering feedgas availability later this summer.

Output could be even higher if stronger feedgas availability allows Nigeria's 22mn t/yr Bonny Island complex and Trinidad's 14.8mn t/yr Atlantic LNG facilities to ramp up.

Australia to support Asia-Pacific output

Asia-Pacific basin output could reach 115mn-120mn t in April-September, assuming facilities run in line with recent trends.

Maintenance at Australian terminals is expected to reduce output by around 2.26mn t this summer — a smaller reduction than a year earlier, when maintenance curtailed Australian output by some 3mn t *(see table)*.

Indonesia has continued to export at around 35pc of its capacity in recent months, with strong domestic demand and upstream problems at the Merakes field limiting feedgas availability. The launch of the third train at Indonesia's Tangguh LNG project, previously expected in 2021, has been pushed back to December 2022.

Malaysia's 30mn t/yr Bintulu LNG plant is also faces disruption because of problems at the Pegaga gas field.

Asia to rely less on Atlantic supply this summer

Not all Asia-Pacific output stays within the basin, as Qatar typically delivers 10-20pc of its exports to Europe, mainly under long-term contracts. But this could be more than offset by the share of US production heading to Asia through the Panama Canal, as well as Russian deliveries from the 17.4mn t/yr Yamal export plant along the Northern Sea Route (NSR).

Assuming US deliveries through Panama are in line with the waterway's capacity of around one cargo a day, and that Yamal deliveries through the NSR are similar to last summer, supply available to Asia-Pacific markets could reach 107mn-110mn t this summer without the need for Atlantic basin deliveries around the Cape of Good Hope.

This would be sufficient to meet an increase in Asian demand of up to 9pc compared with summer 2019 and 2020, when it stood at approximately 98mn t. But Asian demand in line with the 112mn t that the region received last summer would require up to 5mn t of additional supply from the Atlantic.

Planned Australian maintenance

Project	Start	End	Capacity impact *t/d*
Wheatstone	04 Apr 22	09 May 22	21,300
NWS	24 Apr 22	28 Apr 22	8,930
APLNG	26 Apr 22	29 Apr 22	6,160
NWS	29 Apr 22	21 May 22	8,930
QCLNG	16 Jun 22	17 Jul 22	8,730
Ichthys	01 Jul 22	05 Aug 22	24,370
APLNG	28 Jul 22	26 Aug 22	12,320
APLNG	04 Oct 22	12 Oct 22	6,160
QCLNG	18 Oct 22	14 Nov 22	8,730
QCLNG	20 May 23	22 May 23	8,730

— AEMO, Chevron, Inpex, Woodside

excludes Prelude and Darwin, which do not publicise maintenance plans

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