argusmedia.com

September 2021

Argus White Paper:

LNG winter 2021-22 outlook

Sea change

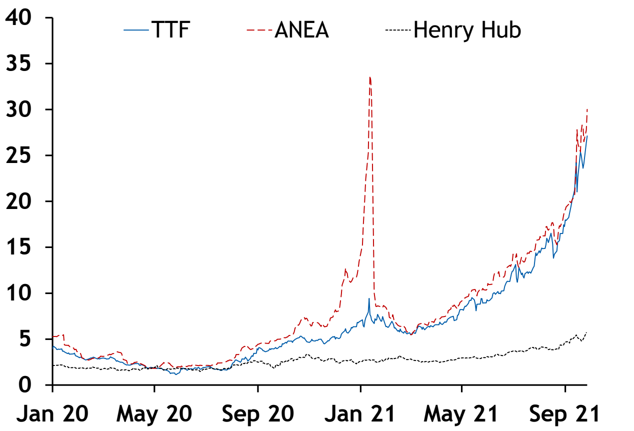
It would have been difficult to imagine a more radical reversal of the LNG market last year. In a pandemic-stricken 2020, global gas prices fell to historic lows to spur the massive supply-side response — producers curtailing output as customers cancelled cargoes and deferred contractual deliveries — needed to rebalance the LNG market.

The market has swung to the opposite extreme in 2021. With the global economy reopening, global gas prices have soared to unprecedented highs to spur the demand-side response needed to balance the market. For power generation, spot gas is more expensive than coal under any measure of comparison, and in some markets even uncompetitive with fuel oil. Gas-intensive industry is reeling, with some factories halting or curtailing production because of the high cost of supply. And in some markets, smaller retail suppliers have found their hedges inadequate and been forced into bankruptcy.

But the extent of a potential demand response could be limited. Some governments are intervening to ensure residential users are not left in the cold, and their industries keep running. In power generation, a switch away from gas may be confined to peak load, or capped by limited capacity using other fuels, as well as by environmental policies.

And there are downside risks. The price rally has been driven by strong restocking demand ahead of the winter, in an effort to avert a similar supply crunch to the one that marked the peak of the 2020-21 winter season. But more LNG supply will be available in the Asia-Pacific basin this year, where demand growth may also be capped by stronger nuclear generation availability in Japan and competition with pipeline supplies in China. This means a mild winter could quickly dampen northeast Asian LNG demand. But with low European underground stocks and early indications pointing to another cold winter, the LNG rally has continued.

Front-month gas prices $/mn Btu



Northeast Asian demand to edge higher this winter

Northeast Asian demand is expected to continue growing this winter, but probably at a slower pace than a year earlier, as stronger demand from China and Taiwan could be partly offset by lower Japanese and South Korean consumption.

Demand across the region may again be boosted by the emergence of a La Nina weather event, which typically brings a colder winter to northeast Asia and increases utilities' LNG demand for heating needs, spurring spot buying activity.

The US' National Oceanic and Atmospheric Administration (NOAA) has recently increased the probability of a La Nina weather event emerging in November-January to 79pc, having previously predicted a 70pc chance of a similar event occurring in those months. The Australian Bureau of Meteorology (BoM) also raised the probability of a La Nina event to 50pc, around double the normal likelihood, having previously maintained a neutral outlook. That said, the Japanese Meteorological Agency maintained a 70pc probability of neutral conditions remaining

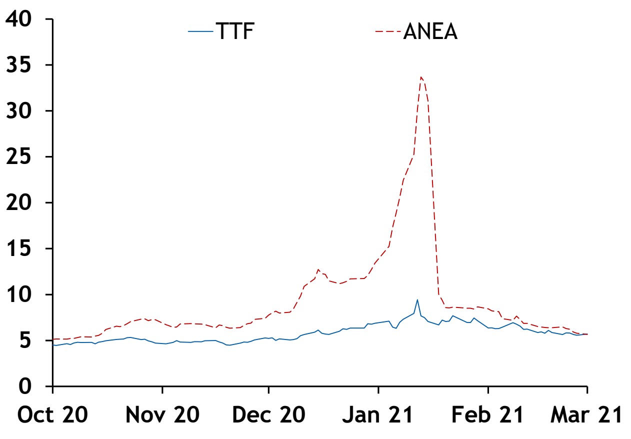
Copyright © 2021 Argus Media group - www.argusmedia.com - All rights reserved.
Trademark notice: ARGUS, the ARGUS logo, ARGUS MEDIA, ARGUS DIRECT, ARGUS OPEN MARKETS, AOM, FMB, DEWITT, JIM JORDAN & ASSOCIATES, JJ&A, FUNDALYTICS, METAL-PAGES, METALPRICES.COM, Argus publication titles and Argus index names are trademarks of Argus Media Limited.

until the onset of the boreal winter, although it still expects a 30-40pc probability of average temperatures being lower or in line with the 30-year average in December 2021-February 2022.

A La Nina event developed last winter, resulting in exceptionally cold weather across northeast Asia, which boosted heating demand and led to some countries — particularly Japan, which also had limited nuclear capacity available last winter — rapidly depleting stocks and rushing to secure spot supplies. A similar pattern is less likely this winter, given higher nuclear availability and a shift in buying patterns by many northeast Asian buyers, which have been stocking up on winter cargoes much earlier than usual to avoid a last-minute scramble for cargoes.

After spot LNG prices rose to all-time highs last winter *(see graph below)*, pressure from the respective governments this year has spurred buyers to ensure security of supply during the winter season.

Winter 2020-21 front-month gas prices *$/mn Btu*



At least six northeast Asian buyers issued strip tenders this year covering deliveries across the winter months, some as early as in February, reflecting a more conservative buying approach among buyers *(see table below)*.

Strip tenders by northeast Asian firms issued in summer 2021

Firm	Country	No. of cargoes	Delivery window	Closing date
CNOOC	China	10	May 2021 - Mar 2022	23 Feb 21
Unipec	China	45-60	Jun 2021 - Feb 2022	6 Apr 21
ENN	China	4-8	Jul 2021 - Feb 2022	14 Apr 21
CNOOC	China	10	Jul 2021 - Mar 2022	4 Jun 21
CPC	Taiwan	10	Oct - Dec 2021	28 Jun 21
Osaka Gas	Japan	6	Nov 2021 - Apr 2022	4 Aug 21
CPC	Taiwan	at least 10	Oct 2021 - Feb 2022	27 Aug 21
CPC	Taiwan	at least 7	Nov 2021 - Feb 2022	23 Sep 21
Unipec	China	at least 11	Nov 2021 - Mar 2022	24 Sep 21

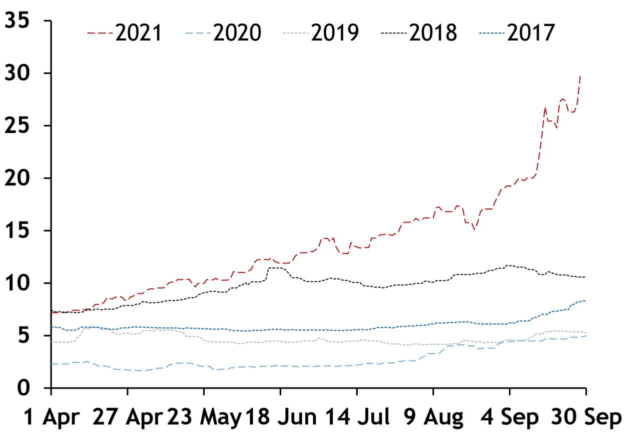
— *Argus*

A number of northeast Asian buyers, including a major Japanese importer, also secured the bulk of their winter requirements through bilateral discussions in the first half of the year. This was a shift from the previous year, when buyers generally waited for a clearer indication of weather conditions nearer to winter before committing to spot purchases.

Japan's power agency — the organisation for cross-regional co-ordination of transmission operators (Occto) — in April warned utilities to take sufficient precautions to ensure stable electricity supplies during the peak demand winter season. Utilities have been ramping up their LNG inventories since the end of May, in preparation for expected higher electricity demand for cooling and gains in gas-fired power burning.

Japanese LNG stocks stood at around 2.5mn t in mid-September, up by 25pc from 1.94mn t at the end of May and 54pc higher than a year earlier, when they totalled just 1.62mn t. Stockpiling demand, coupled with strong power sector gas burn amid higher-than-average summer temperatures across the region, have contributed to keep northeast Asian spot LNG prices on a steady upward climb since February, rising to multi-year seasonal highs *(see graph)*.

ANEA front half-month summer prices *$/mn Btu*



Japan's LNG demand likely to fall this winter

Japanese LNG demand may be lower than a year earlier this winter, as stronger nuclear availability is expected to more than offset the potential rise in power demand for heating.

Japan may face colder-than-usual weather in the upcoming winter, with the latest forecast by the Japanese meteorological agency — published on 24 September — showing a 30-40pc probability of average temperatures being lower or in line with the 30-year average in December 2021-February 2022. This implies electricity demand during the period is likely to be stronger than a year ago, when temperatures in most major cities were higher than the long-term average, although icy weather hit large parts of the country from mid-December 2020 to mid-January 2021.

Copyright © 2021 Argus Media group

But even if power demand is stronger than a year earlier throughout the winter, Japan is likely to use less LNG because of greater nuclear availability, reduced gas-fired generation capacity and increased renewables generation capacity. Spot LNG prices remaining above the oil-parity level may also increase the call on oil-fired plants to meet demand peaks (*see section on gas-to-oil switching)*.

Average nuclear capacity is scheduled at 7.88GW throughout October-March, up from just 3.34GW a year earlier. Assuming this capacity runs at an average 95pc utilisation rate, it could reduce LNG demand by approximately 2.24mn t over the six-month period, assuming it displaces gas-fired plants with an average 50pc efficiency rate, and power demand is in line with a year earlier (*see table below for breakdown by month*).

Japanese nuclear availability

	2021-22 *GW*	2020-21 *GW*	Potential reduction in LNG demand *'000t**
Total winter	7.88	3.34	2,358
October	8.80	2.53	554
November	8.24	1.86	546
December	8.44	2.84	495
January	8.71	3.49	461
February	7.70	4.14	284
March	5.39	5.19	18

**assumes no change in power demand, nuclear plants running at capacity and displacing gas-fired generation units with a 50pc efficiency rate*

— METI, Argus calculations

Japan will also have less gas-fired generation capacity in operation this winter, after five units with a combined capacity of 2.49GW were mothballed and four units totalling 2.4GW were scrapped earlier this year. The country will also have stronger solar capacity than a year earlier — at 12.6GW in April this year, up by 6pc from 11.8GW in December last year, according to the latest data from the trade and industry ministry (Meti).

Utilisation rate of Japan's LNG-fired plants averaged 48.9pc in the April 2020-March 2021 fiscal year, based on total LNG power output of 354.6TWh and an average output capacity of 82,851MW, according to Meti data.

Strong nuclear availability to weigh on S Korean demand

South Korean LNG demand may also be lower this winter, with more nuclear capacity available than a year earlier. But the country may have to rely more on LNG if the government imposes stricter restrictions on coal-fired generation.

The country imported 25.5mn t of LNG through October 2020-March 2021, up from 24.2mn t a year earlier. La Nina boosted heating demand last winter and the government suspended 9-16 coal-fired units each day during December-February and 19-28 coal-fired units in March, as part of its winter fine-dust management policy. It also imposed an 80pc output cap on the remaining capacity.

High spot LNG prices may lift wholesale gas monopoly Kogas' power sector gas tariff well above all fuel-switching levels, which could incentivise stronger use of available coal-fired capacity ahead of gas-fired plants.

An average of 20.4GW of nuclear capacity is scheduled to be available in South Korea across October to March next year. This is roughly similar to the 20.6GW scheduled to be operational last winter, but availability was reduced later in the winter as some maintenances were extended. Actual nuclear generation averaged 19.04GW in October 2020-March 2021.

South Korea nuclear availability

	2021-22 *GW*	2020-21 *GW†*	Potential reduction in LNG demand *'000t**
Total winter	20.45	19.04	802,478
October	18.58	18.10	46,638
November	19.26	19.51	-23,328
December	21.84	20.24	155,427
January	21.97	18.87	300,782
February	21.05	18.95	184,768
March	19.97	18.55	138,192

**assumes no change in power demand, nuclear plants running at capacity and displacing gas-fired generation units with a 50pc efficiency rate*
†actual generation

— Kepco, Argus calculations

Assuming power demand is broadly unchanged from a year earlier and available nuclear plants run close to capacity this winter, displacing solely gas-fired plants with an average 50pc efficiency rate, it may reduce the country's LNG demand by approximately 800,000t over the course of the winter.

That said, South Korea is expected to again impose capacity restrictions on its coal-fired generation fleet to reduce fine dust and other emissions, as it has done in recent years. But the government is yet to announce the exact limitations for this winter, although market participants expect restrictions to be broadly in line with a year earlier.

Chinese demand growth continues unabated

China's LNG appetite has increased significantly this year, with the new normal being "淡季不淡，旺季更旺" — meaning higher-than-expected demand during non-peak periods, and even stronger demand during peak periods.

This is mostly driven by their increased power needs, as the country continues to stimulate its economy after a tumultuous 2020 and resurgence of Covid infections in 2021. China's electricity consumption increased to 775.8TWh in July, up

Copyright © 2021 Argus Media group

by 12.8pc from the same month last year and 16.3pc higher than July 2019, according to energy regulator the NEA. Total consumption in January-July was 4,709TWh, up by 15.6pc from a year earlier.

Coal-fired generation still accounts for about 60pc of total output, and Chinese authorities have boosted support for domestic coal production to offset restrictions on Australian imports, which remain in place. But should domestic output fail to compensate for the drop in Australian receipts, the call on gas-fired plants could be even stronger.

Apparent gas demand — judging by official figures on domestic production, pipeline and LNG imports — totalled 181bn m³ in October 2020-March 2021, up from 161bn m³ a year earlier. Actual demand may have been around 9bn-10bn m³ stronger, assuming Chinese firms made extensive use of their underground stocks. A repetition of the 12pc increase recorded last winter — which was higher than the 5pc increase a year earlier, but still lower than the 16pc jump recorded in both 2017-18 and 2018-19 winters — would bring China's demand to 204bn m³ this winter. Chinese consumption could reach 365bn-370bn m³ in 2021, up by 11-13pc from the 328bn m³ recorded in 2020, the NEA forecasts.

Domestic production could cover around 104bn m³, assuming a 4pc increase in the first quarter compared with October-December, in line with recent years' average. China has already produced around 136bn m³ of domestic gas in January-August, on course to exceed the target 2021 output of 202bn m³ set by the country's main energy planning authority the NEA in April.

And China has continued to expand its underground gas storage capacity to smooth out chronic winter gas supply constraints experienced in recent years, although storage facilities still account for a fraction of the country's consumption. China's underground storage facilities are expected to provide 14.4bn m³ this year, up from 10.4bn m³ a year earlier, which may still account for just 7pc of winter demand, although this would be up from around 5pc a year earlier.

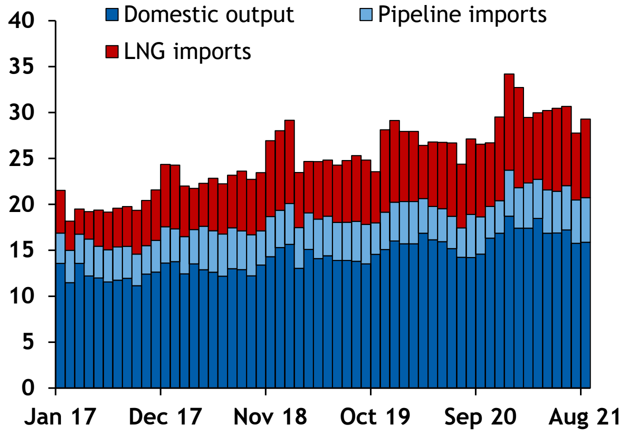
This would still leave around 85bn m³ of demand to be met by either pipeline or LNG imports, leaving China's LNG demand largely dependent on the extent of an expected ramp-up in pipeline supplies.

Power of Siberia to bolster pipeline imports

China is expected to continue boosting its pipeline receipts in the coming months, partly as a result of the gradual ramp-up in Russian flows through the Power of Siberia (PoS) pipeline.

Russia's Gazprom expects to increase its gas sales to the country to 8.5bn m³ in 2021 from 4.1bn m³ a year earlier, and this may increase further in 2022 as flows are meant to reach full capacity of 35bn m³/yr by 2025. But the exact contractual volume agreed for next year is unclear.

China gas supply *bn m³*



If Russia supplies around 5bn m³ in October-March — in line with the contractual volume for 2021 — and flows from central Asia and Myanmar are in line with last year, China may need to receive 45mn t this winter, which would test the country's aggregate regasification capacity. A 50pc rise in Russian flows in the first quarter — assuming the contractual volume is due to rise by 5bn m³ in 2022, as it did last year — could see the country's LNG demand fall to 44.4mn t, requiring LNG terminals to run at a 97pc utilisation rate this winter.

Gazprom sold 4.62bn m³ to China through PoS 1 in January-June, up from 1.57bn m³ a year earlier. The 449bn m³ Chayandinskoye gas field in Sakha Yakutia — the only field supplying PoS1 at present — produced 5.3bn m³ of gas in January-June, up from 1.7bn m³ a year earlier.

But Chinese firms have also a strong incentive to maximise pipeline deliveries from central Asia and Myanmar, as these are much cheaper than LNG. China paid an average $5.02/mn Btu for its pipeline imports in the first half of 2021, down from $5.26/mn Btu in the second half of last year and $6.21/mn Btu in January-June 2020.

China's pipeline imports rebounded to 27.7bn m³ in the first six months of 2021 from 23.7bn m³ a year earlier, reaching an all-time high in July. Excluding Russian flows, which accounted for about three-quarters of the increase the rebound was mostly the result of stronger flows from Uzbekistan and Turkmenistan, which more than offset the drop in imports from Kazakhstan. Imports from Myanmar were broadly unchanged despite being China's most expensive pipeline supplies.

Flows had fallen to 47.7bn m³ in 2020 from 50.1bn m³ a year earlier, despite the start of PoS flows in December 2019, as Chinese firms took advantage of lower LNG prices and the drop in crude prices, which translated into lower oil-linked prices later in the year and early 2021, to defer pipeline deliveries into later periods. Imports from central Asia and Myanmar rising in line

Copyright © 2021 Argus Media group

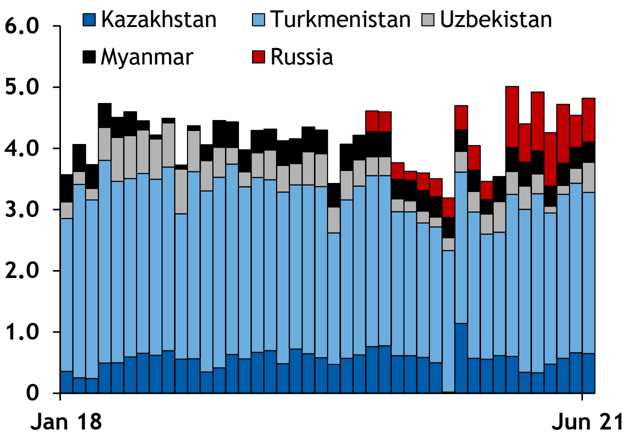
with the strongest flows recorded in recent years, coupled with stronger Russian flows in the first quarter, could reduce LNG demand to just 41mn t this winter — or about 89pc of combined regasification capacity.

Increase in LNG import capacity

China's aggregate regasification capacity rose further in recent months, with 7.3mn t/yr of additional capacity already completed and the 4.8mn t/yr second phase of the Tianjin terminal expected to be completed in November. This would bring the country's total import capacity to 93.3mn t/yr.

China has been pushing its LNG terminals beyond their nameplate capacity during the winter peak in December-January in recent years, while also maintaining a very high average winter utilisation rate — ranging between 89pc and 96pc over the past four winters. Assuming an average utilisation rate of 92pc over the winter, in line with the four year-average, China could import up to 42.9mn t in October-March, 3.9mn t more than a year earlier. A repeat of the 95pc utilisation rate seen over the previous winter would result in total receipts of 44.3mn t, up by 5.4mn t from a year earlier.

Chinese pipeline imports *bn m³*



Additional LNG storage capacity at a number of terminals may also provide additional flexibility, with the country expected to have 11.1mn m³ of LNG storage capacity this winter.

Lower nuclear generation to bolster Taiwanese demand

Taiwan may need to rely more on LNG imports this winter following the early closure to one of its four nuclear units.

The first 985MW unit at Taiwan's Kuosheng nuclear plant was taken off line in early July, having initially been scheduled to go down in December, cutting nuclear output over the first half of this winter. Much of the shortfall is due to be met by the 550MW second gas-fired unit at the Chiahui independent power plant, which could add up to a further 260,000t of power sector gas demand this winter, based on a 60pc efficiency.

And while high LNG prices could incentivise generation firms to consider switching to coal-fired output, this could be curbed by any repeat of the environmental restrictions on coal-fired generation brought in by local government organisations in previous winters.

LNG prices above oil parity may see fuel-switching

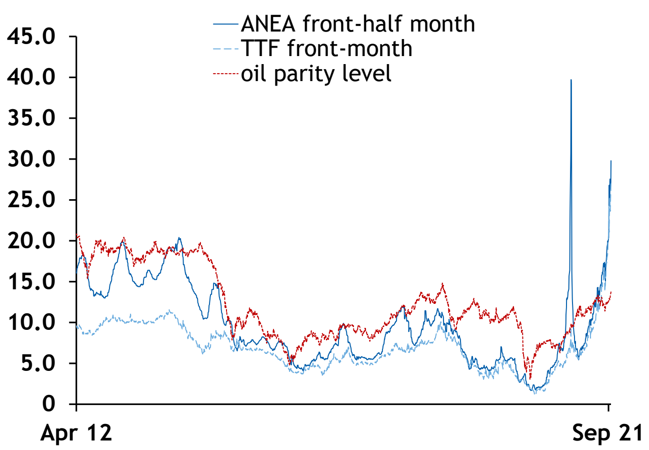
Gas and LNG prices have risen above oil in energy-equivalent terms for the longest period on record, which has already triggered a rebound in oil-fired generation in some Asian countries and may continue to do so this winter.

The *Argus* Northeast Asia (ANEA) front-half-month des price rose above oil parity — typically pegged at 17.2pc of Brent, based on a barrel of crude oil containing approximately 5.8mn Btu — at the end of June, and has remained consistently above that level through the following 62 trading days until 24 September. This is the longest period of LNG prices above oil parity since *Argus* began assessing ANEA prices in April 2012. The ANEA front-half-month price had previously remained above oil-parity for a maximum consecutive period of 37 days in January-February 2014, and a total of 55 days intermittently between November 2013 and February 2014.

European prices have been tracking Asian markets higher in recent months. The TTF front-month contract also rose above oil-parity in late July, for the first time in more than a decade, and has remained consistently above that level for the following 44 trading days. It had previously risen above this level for a total of 64 days, intermittently, between October 2008 and February 2009.

At these levels, both Asian and European utilities would find it more profitable to burn not only coal, but also fuel oil ahead of gas, even though governments may find the option undesirable because of environmental concerns. Furthermore, while many countries retain substantial coal-fired generation

ANEA, TTF above oil-parity *$/mn Btu*



Copyright © 2021 Argus Media group

capacity, plants using fuel oil for power generation have been largely decommissioned, leaving just a handful of facilities still technically in operation solely for security of supply.

Japan is the only Asian country with substantial oil-fired generation capacity, totalling around 31.6GW. Yet Japan has made increasingly less use of this capacity, with oil-fired generation falling to 11.9TWh in 2020 from 16.8TWh a year earlier and having declined steadily from a recent high of 33.3TWh in 2017. But oil-fired generation rebounded last winter as Japanese utilities faced significant LNG shortages, reaching 9.46TWh in October 2020-March 2021, up by 48pc from 6.39TWh a year earlier and almost in line with the 9.87TWh generated in October 2018-March 2019.

A more prolonged period of LNG prices above oil parity may further increase the call on oil-fired plants this winter. If Japanese oil-fired generation rises in line with the 20.2TWh recorded as recently as in the 2017-18 winter, this could displace around 1.4mn t of LNG demand throughout the six-month period. That said, the differential between spot gas and oil prices is unlikely to trigger a substantial use of oil-fired capacity for base-load generation, as Japanese long-term LNG import prices are structurally competitive with oil.

Only a handful of other countries in Asia may have significant scope for LNG-to-oil switching. Oil-fired generation in South Korea rose to 1.09TWh in January-July from just 380GWh a year earlier, but still has ample scope to increase further with an average load factor across the oil-fired fleet rising to 12pc in July, the highest since the 14pc recorded in January. Similarly, Taiwanese oil-fired generation stepped up to 1.49TWh from 881GWh, with average utilisation rate of oil-fired capacity rising steadily through April-July, but still at just 11pc in July. But similarly to Japan, oil may only be competitive with gas as a peak-load generation fuel, while long-term LNG prices remain economic for power sector firms.

Both Pakistan and Bangladesh have been making greater use of their oil-fired generation capacity in recent months, but stronger electricity demand has meant the increase in oil-fired generation has not halted growth in LNG demand.

Bangladesh has 6.85GW of oil-fired capacity and has been using it more extensively so far this year. The country generated 10.2TWh in March-August compared with 6.59TWh a year earlier, suggesting an average load factor of about 34pc. The utilisation rate was strongest so far this year at 42pc in August. But higher electricity demand has also ensured substantial growth in gas-fired generation, which rose to 24.7TWh in March-August this year, up from 21.1TWh a year earlier. LNG deliveries totalled 2.66mn t over the same period, up from 1.96mn t a year earlier, analytics firm Vortexa data show.

Similarly, oil-fired generation in Pakistan more than doubled in the first six months of 2021 compared with a year earlier, to 3.38TWh from 1.69TWh. But the country also had to ramp up use of regasified LNG, as well as coal and nuclear, to meet stronger electricity demand and offset a drop in hydroelectric generation. Power consumption rose by 12pc in the first half of this year compared with a year earlier. The utilisation rate of Pakistan's oil-fired fleet rose sharply to 25pc in June from 16pc a month earlier and just 3pc in April, still leaving ample scope for further ramp-up in oil-fired generation this winter.

Europe has 15,872MW of oil-fired generation capacity, more than half of which is concentrated in just four countries — France, Germany, Sweden and Turkey. Italy accounts for 10pc of Europe's total oil-fired capacity, but its use is mostly confined to emergency measure in case of a major disruption to gas supplies.

Oil-linked contracts at ample discount to spot

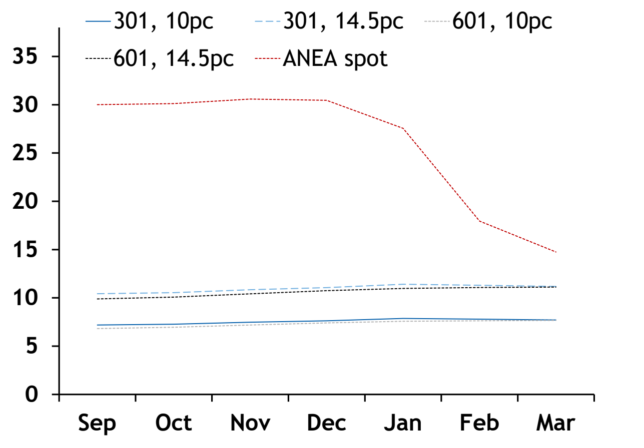
Oil-linked prices for both LNG and pipeline gas have been opening to wide discounts to spot prices in recent months, regardless of the indexation period or the Brent slope, as crude benchmarks did not track the recent rally in spot gas prices. Brent prices have been less volatile than gas futures in recent months, which has resulted in comparatively minor differences within months.

While this offers no incentive to defer deliveries to later periods, firms may have an incentive to maximise flows when the differential between contractual deliveries and spot prices is widest — December-January — to minimise spot purchases whenever possible. By contrast, in markets with substantial competition between LNG and oil-linked pipeline gas, pipeline flows are likely to be maximised when the discount to spot prices is widest. In the case of Europe, where the rally in TTF prices was led from the front of the curve, this would be earliest in the winter.

Global liquefaction capacity ramp-up slows

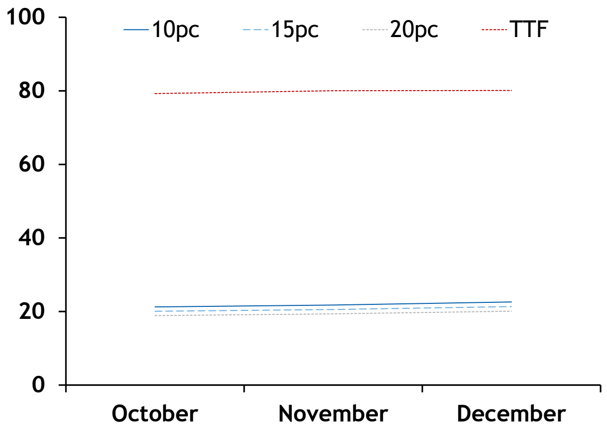
Global LNG supply is due to grow this winter compared with

ANEA spot vs oil-linked prices *$/mn Btu*



Copyright © 2021 Argus Media group

TTF vs oil-linked pipeline prices *€/MWh*



a year earlier, with more liquefaction capacity available and facilities widely expected to run at full capacity.

Global liquefaction capacity in operation at the start of the winter is due to total around 448mn t/yr, given the continued unavailability of Norway's 4.2mn t/yr Hammerfest and the first 3mn t/yr liquefaction train at Trinidad's Atlantic LNG. This would be up from 433mn t/yr at the start of last winter, when Hammerfest had already been taken off line following a fire in September, and the 3.6mn t/yr Prelude and the second 5.2mn t/yr liquefaction train at Gorgon in Australia were off line.

Liquefaction capacity remained broadly stable throughout last winter. Prelude only resumed loadings in February, while the first train at Gorgon went off line shortly after the restart of train 2. And the commissioning of the third 5mn t/yr train at the Corpus Christi facility in Texas was largely offset by the first train of the Atlantic LNG complex being put in an indefinite turnaround in late 2020 because of insufficient feedgas supplies.

The increase in available capacity compared with the start of last winter is partly the result of the two Australian facilities returning to full capacity, as well as the restart of Egypt's 5mn t/yr Damietta LNG terminal after being halted for nearly a decade. Apart from Corpus Christi train 3, which shipped its first cargo in December 2020, the only new facilities that started in recent months were Russia's 940,000 t/yr Yamal LNG train 4 and the 1.5mn t/yr Petronas Floating LNG (PFLNG) 2 in Malaysia.

That said, liquefaction capacity may increase further at some point this winter with the expected start-up of the 10mn t/yr Calcasieu Pass terminal and the sixth 5mn t/yr train at the Sabine Pass complex, both in the US.

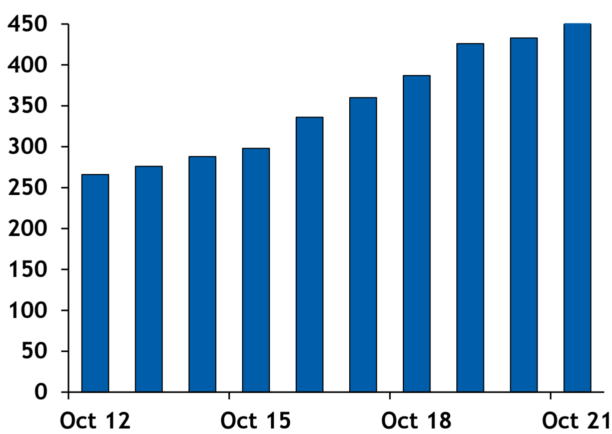
Liquefaction capacity growth mainly in Asia-Pacific

Despite most new facilities being located in the Atlantic basin, the increase in liquefaction capacity compared with a year earlier was mainly in the Asia-Pacific basin. Atlantic basin capacity rose to 178mn t/yr in October from 170mn t/yr a year earlier, while available production capacity in the Asia-Pacific basin rose to 267mn t/yr from 256mn t/yr.

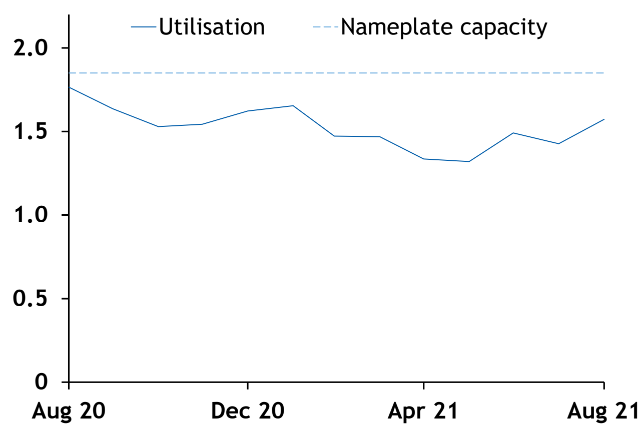
With global LNG prices hitting all-time highs in recent months, utilisation rates are likely to be as close to capacity as feedgas availability allows. Atlantic basin output could be around 76mn-78mn t in October-March, assuming output close to capacity at most west African facilities, the US and Russia's Yamal complex, and utilisation in line with recent trends elsewhere.

The utilisation rate at Nigeria's 22mn t/yr Bonny Island complex could edge closer to full capacity later in the winter, once upstream issues that have been weighing on LNG output are resolved *(see graph)*. And while feedgas flows to Egypt's Damietta terminal are consistent with the terminal's export capacity, utilisation rate at the country's second terminal is expected to remain low in the coming months. Utilisation of Algerian capacity has rarely exceeded 50pc in recent years, and output at Trinidad's Atlantic LNG train 2-4

Global liquefation capacity *mn t/yr*

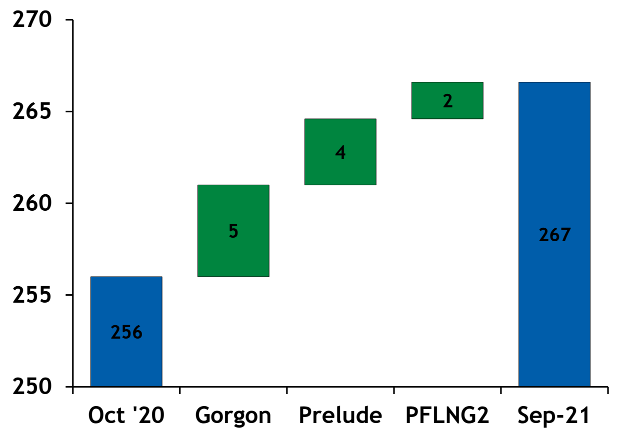


Nigeria utilisation *mn t*



Copyright © 2021 Argus Media group

Asia-Pacific liquefaction capacity *mn t/yr*

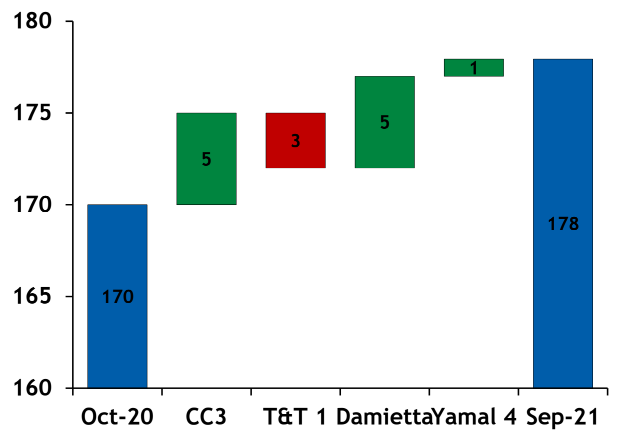


has been declining steadily throughout this year, slipping below 50pc in recent months before rebounding slightly in August.

Production in the Asia-Pacific basin could be around 117mn-120mn t in October-March, assuming most facilities run close to their respective capacities — including Peru's 4.4mn t/yr Pampa Melchorita liquefaction facility, which resumed loadings in September after halting in May. Planned maintenance at the 8.9mn t/yr Wheatstone, the 7.8mn t/yr Gladstone and the 9mn t/yr APLNG facilities in Australia are only expected to reduce output by a total of around 400,000t in the early part of the winter.

But production from Indonesia, Malaysia and Brunei is likely to remain below capacity. Indonesian output has remained around a third of nameplate capacity in recent months, with limited fluctuations, although it is expected to rebound next year. Malaysian output has also been declining in recent months, with utilisation rate only slightly above 50pc in August. Offtakers from Malaysia's 30mn t/yr Bintulu LNG complex have been informed of delays to their deliveries, because of production issues at the

Atlantic basin liquefaction capacity *mn t/yr*



7.7mn t/yr Malaysia LNG Tiga (MLNG 3) project. The 7.2mn t/yr Brunei LNG project has been running broadly steadily at around 80pc of its capacity in recent months.

Asia may need less Atlantic basin supply this winter

Some supplies regularly travel between basins. About 10-20pc of Qatari production typically heads to Europe, mostly under long-term contracts. Chinese state-owned firm CNPC typically brings to Asia its 3.3mn t/yr offtake from the Yamal LNG project, even when it requires transshipments at northwest European terminals. And the share of US production that can travel to Asia through the Panama Canal — around a third of total production at present — tends to do so.

Depending on the share of Qatari production heading to Europe, supply available to Asian buyers without the need for Atlantic basin deliveries through the Cape of Good Hope route could total around 125mn-129mn t this winter.

This could be sufficient to meet an increase in Asian demand of up to around 5pc — or 6mn t — this winter, compared with the 123mn t that markets east of Suez absorbed last winter, Vortexa shiptracking data show. By contrast, a repeat of the 12pc jump in demand seen last winter would bring total Asian deliveries to round 138mn t this winter, which would require up to 13mn t of Atlantic basin deliveries through the Cape of Good Hope. Asian markets received 29.2mn t from Atlantic basin suppliers last winter, about half of which was likely to have travelled through the Cape of Good Hope route.

But barring unforeseen events, a repeat of a similar jump in demand may be unlikely this winter. Additional demand from China and Taiwan may not exceed 7.5mn t over the winter, even assuming Chinese terminals run at full capacity and lower nuclear generation in Taiwan is entirely offset by stronger gas-fired generation, and this could be partly offset by lower Japanese and South Korean demand *(see northeast Asia section)*. Additional import capacity available in the Middle East — namely Kuwait's 22mn t/yr Al Zour terminal — are unlikely to absorb substantial volumes in the coming months, as the region's demand is typically strongest in the summer.

Europe may have to ramp up competition this winter

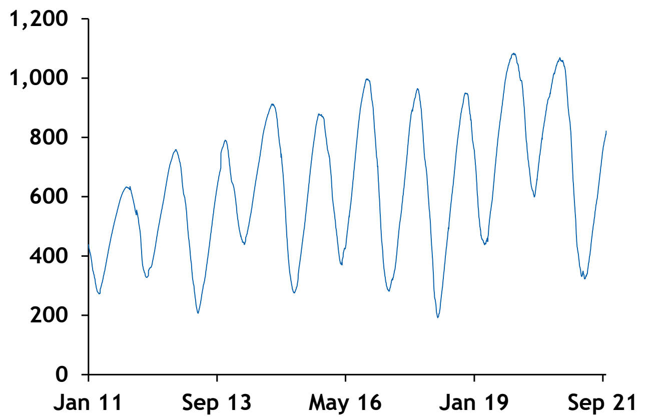
Europe may have to step up competition for LNG imports to preserve underground inventories for peak demand periods, as it approaches the winter with the lowest stocks in recent years and reduced flexibility in pipeline contracts.

Aggregate European inventories stood at 805TWh on 24 September, down from 1,053TWh a year earlier and the lowest for the date since 2013 *(see aggregate European stocks graph)*.

Strong Asian demand throughout most of the past winter drew supply away from Europe, forcing the region to rely much

Copyright © 2021 Argus Media group

Aggregate European gas inventories TWh



more on withdrawals from underground storage inventories. This left inventories much more depleted at the end of the winter than in recent years, and the deficit with previous years widened further as cold weather persisting into the early summer resulted in a late start of the stockbuild. Injections, which typically slow towards the end of the summer as facilities approach capacity, have picked up in recent weeks *(see graph).*

There may be scope for the injection cycle to extend further into the winter this year, with ample capacity still available at European sites. Aggregate European gas storage inventories could peak at around 850TWh if injections continue at the same pace as in the first three weeks of September until 10 October — when storage volumes peaked last year. This would be 217TWh lower than October 2020 peak of 1,069TWh.

But with the TTF October contract at a $1.45/mn Btu premium to March and slightly above the February contract on 27 September, there is limited incentive to continue injecting next month, with the exception of markets such as Italy, where regulation means the stockbuild continues until 31 October.

Firms may be instead facing a hard choice of whether to front-load withdrawals in the fourth quarter or preserve stocks until later in the winter in spite of price signals, with no historical precedent to examine in search of some guidance about traders' potential attitude. This is the first time the TTF fourth-quarter contract goes into delivery at a premium to the first-quarter price since *Argus* began assessing these contracts in 2004. Should this boost the stockdraw above the three-year October-December average of 2.5 TWh/d, inventories could start 2022 below 560TWh, which would be the lowest since 2012, further boosting the region's LNG first-quarter demand.

A cold winter could therefore test the flexibility European storage typically provides. European stocks fell to a low in the last winter of 331TWh on 25 March 2021, suggesting a maximum stockdraw of 738TWh during a winter that was, by historical standards, particularly cold. If stocks peak this October at around 850TWh, a repeat of last winter's stockdraw could drive inventories down to a low of around 113TWh — well below any single day in at least the preceding two decades. Aggregate inventories reached their lowest in the past two decades on 31 March 2018, after a particularly cold winter pulled down stocks to 192TWh.

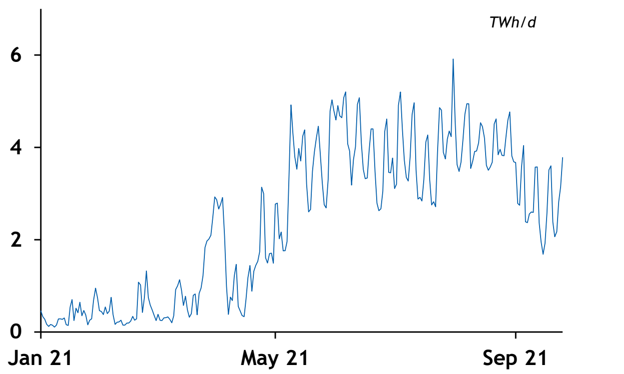
LNG demand could be particularly strong in those markets with limited underground storage capacity, such as the UK. The NBP 4Q21 and 1Q22 contracts stood at a much wider premium to corresponding contracts at continental hubs than in recent years.

European regasification capacity this winter will also be higher than a year earlier, with the start-up of Croatia's 2.05mn t/yr Krk facility in early January this year, and the planned stage-one expansion at Poland's 3.9mn t/yr Swinoujscie import facility to add 1.8mn t/yr of regasification capacity by 1 January 2022 *(see Europe LNG import capacity chart).*

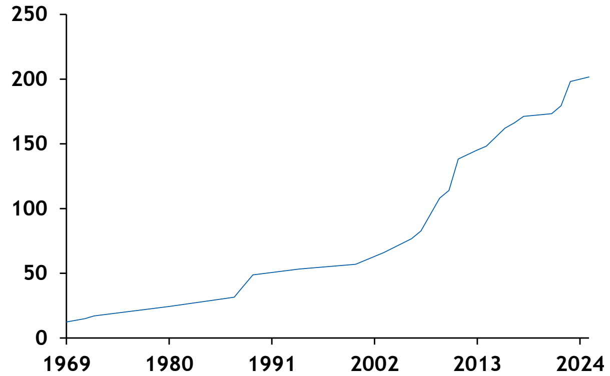
Alternatives in the pipeline

If Europe needs to be more competitive for LNG, it is also because it may have already used some of the flexibility provided by pipeline supplies. Markets that receive oil-indexed gas supply — such as Italy, Spain and Turkey — had an incentive to front-load deliveries earlier this year, after the steady recovery in crude oil prices since November 2020 resulted in a contango structure for oil-indexed gas prices.

Aggregate European injections TWh/d



European import capacity



Copyright © 2021 Argus Media group

Because the rally in spot gas prices in recent months has far outstripped further gains in crude futures, these contracts have been bolstering their competitiveness against European hubs, but buyers may have limited contractual flexibility left to receive more volumes under these contractual terms.

Algerian flows to Spain, Portugal and Italy, as well as Russian supplies to Turkey, have been very quick so far this year. These countries may need to reduce their take in order to adhere to yearly contractual volumes, possibly absorbing more LNG to meet heating demand, until they enter into the new contractual year. For Italian importers, this may happen as early as next month, as most of the Algerian contractual supply is based on the gas year. Italy has also begun to receive spot pipeline volumes from Algeria, although these are said to be more expensive than contractual volumes.

Spain's long-term contracts with Algeria are mostly based on the calendar year, which reduces scope for Spanish importers to increase deliveries until later this year. Spain already took 10.3bn m³ of Algerian gas on 1 January-24 September, up from 4.8bn m³ a year earlier and the three-year average of 8bn m³.

Spain and Portugal may also face a more serious curtailment to their Algerian pipeline supply if the concession to operate the Maghreb-Europe gas (GME) pipeline — which delivers Algerian gas from the giant Hassi R'Mel field through Morocco to the Spanish port of Tarifa — is not extended ahead of its scheduled expiration on 31 October. A potential halt to flows through the line may only be partly offset by a capacity hike on the Medgaz pipeline, which is due to increase to 10bn m³/yr from 8bn m³/yr in the fourth quarter.

Algeria's state-owned Sonatrach has also signalled it could seek replace some of its pipeline volumes with LNG loadings for delivery to the Iberian peninsula, but such plans may require the company to book substantial regasification capacity at Spanish terminals, where scheduled deliveries for the coming months are already brisk. That said, Spain has recently increased the number of unloading and regasification slots available to buyers over the winter.

Turkey has had to lift spot LNG purchases in recent weeks — with three large tenders issued by Botas over the past two months — after boosting pipeline deliveries in the first half of the year, particularly from Russia. Pipeline flows were 24.2bn m³ in January-June, nearly double the 12.2bn m³ Turkey received a year earlier, despite Azeri flows nearly halving from April as one of the two long-term contracts with Socar expired.

Russian flows to Turkey soared to 14.4bn m³ in the first half of the year, from 4.68bn m³ a year earlier and almost matching the 16.2bn m³ Gazprom delivered to Turkey over the whole of 2020. Botas had already received the full contractual volume through the Turkish Stream pipeline by mid-June and has been taking some make-up volumes in the following weeks, while Gazprom in July cut deliveries to a number of Turkish private-sector firms over a dispute over arbitration-related payments. That said, earlier this month Botas began to receive Azeri flows under a new three-year, 6bn m³/yr supply deal indexed to the Italian PSV gas hub, which allowed its largest storage site to resume injections after switching to withdrawals for most of July and August.

Nord Stream 2 may not offer additional supply

The expected start-up of Russia's 55bn m³/yr Nord Stream 2 pipeline may only result in a redirection of flows that would have alternatively travelled through Poland or Ukraine if the pipeline comes on stream this winter, as Russia may have limited excess supply available to boost exports. Gazprom last month confirmed its export forecast to Europe, and clarified it does not expect higher sales if Nord Stream 2 is commissioned this year. The firm had previous said it could be able to deliver 5.6bn m³ through Nord Stream 2 already this year, but these volumes – if indeed delivered — would probably have been redirected from other routes. That said, Russian producer Rosneft could provide additional supply to Europe, if allowed to do so. In any event, there are still a number of regulatory hurdles and the pipeline, despite being completed earlier this month, is unlikely to deliver any gas this winter.

While Gazprom has been meeting its contractual obligations in recent months, it has opted not to boost deliveries beyond those levels, prioritising instead the need to refill much-depleted domestic storage facilities. This, coupled with underinvestment upstream, is likely to have left Gazprom with little extra gas to sell to Europe, although the move has been widely interpreted as politically motivated.

But European receipts from Russia this winter could be supported as the producer's domestic market transitions out of its own injection cycle. And Gazprom has said it can "sharply increase" supply volumes throughout the year, with nearly 150bn m³ of surplus production capacity available for peak volumes, although it provided little detail about this.

Panama limits to support tonnage demand

US LNG loadings are expected to far outstrip transit capacity at the Panama Canal this winter, which would significantly lift tonnage demand providing that Asian prices hold an ample premium over Europe prices. But if Asian demand slows on a mild winter, the redirection of flows to Europe could significantly curb demand and spur subchartering activity.

The Panama Canal offers two pre-bookable transit slots for LNG carriers on any given day — one each way or two northbound (Pacific-Atlantic) — and although the canal may accommodate some additional transits, these are at the discretion of the Panama Canal Authority and can often entail significant delays. In the case

Copyright © 2021 Argus Media group

of these delays, the number of sailing days for US-northeast Asia through Panama can approach the number required for US-northeast Asia through the Cape of Good Hope route.

This suggests that a maximum of 28-31 southbound transits — for laden carriers heading to Asia from the US — can be booked ahead of the transit day each month this winter, depending on the month in question.

But aggregate US loadings, judging by online liquefaction capacity, are due to outstrip this by more than three times. The US' six operational export projects, operating at peak capacity, could produce around 92-95 cargoes a month at the start of winter, which could increase to around 99 cargoes a month by the end of the season if the Calcasieu Pass and Sabine Pass terminals start operations as scheduled.

This would leave around 50pc of US loadings this winter open for delivery to northeast and southeast Asia through the Cape of Good Hope or Suez Canal, or to Europe, given that south Asian, South American and Middle Eastern markets have historically taken a combined total of 10-15pc of US loadings in past winters.

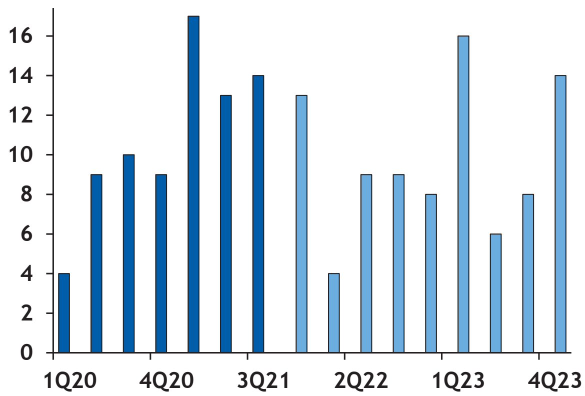
Delivery to northeast Asian markets from the US through the Cape requires a round trip of around 80 days. To send 50pc of total US winter loadings through this route, a minimum of around 120-130 vessels would be required to maintain loadings — around 20pc of the global LNG fleet. By contrast, a mild winter may result in Asian prices holding a premium to European markets only wide enough to draw volumes that can travel through Panama, which could in turn weigh heavily on tonnage demand.

Delivery from the US to Europe requires a round trip of just 26 days, meaning that if this 50pc of aggregate US winter production is diverted to European markets instead, the number of required vessels would fall to around 40-43.

Fluctuations in the price differential between Europe and Asia could therefore result in a swing of up to 80-85 vessels — equivalent to around 15pc of the global LNG fleet. An especially mild winter leading to further redirection of flows to Europe could remove demand for a further 40-45 vessels — given that flows through Panama equate to around a third of US production, requiring around 85-90 vessels over the winter.

The impact of any waning of Asian demand may mean that some firms seek to sublet tonnage as they attempt to optimise by diverting volumes into Europe instead. But some firms — typically the oil majors and large trading firms, as well as some major Asian buyers — may be less exposed to such fluctuations, as they rank higher in the Panama Canal customers ranking system, which makes it easier for these firms to secure slots.

Newbuild deliveries *no. of vessels*



Tight spot vessel availability opens scope for volatility

Spot vessel availability this winter is expected to be particularly low because many firms have opted to charter vessels on a term basis for at least the whole winter. Demand for term charter contracts has often outstripped activity in the spot charter market over the summer. High newbuild deliveries over the past year have boosted tonnage availability for the coming winter, with 27 new carriers due to have joined the market by the end of September since April, adding to a further 26 carriers that were delivered last winter. This contrasts with more limited growth in global liquefaction capacity over the past month.

The additional 18mn t/yr of liquefaction capacity available at the start of this winter compared with a year earlier would require around 112 loadings, assuming an average cargo size of 160,000m³. But only 25 vessels would be required to deliver these loadings in a year, even assuming all cargoes require a return trip of 80 days.

But newbuild deliveries are due to slow over the coming winter, with only 13 carriers scheduled to join the global fleet in the fourth quarter and just four in the following quarter — all in March. The additional 15mn t/yr expected in the coming months would require 18 more vessels, based on a similar assumption, suggesting the additional length in the shipping market may be partly reabsorbed towards the end of the winter if both Sabine Pass train 6 and Calcasieu Pass start operations as scheduled.

For more information:

contact@argusmedia.com +44 20 7780 4200 www.argusmedia.com @argusmedia

Copyright © 2021 Argus Media group