Argus *Global LNG*

LNG markets, projects and infrastructure

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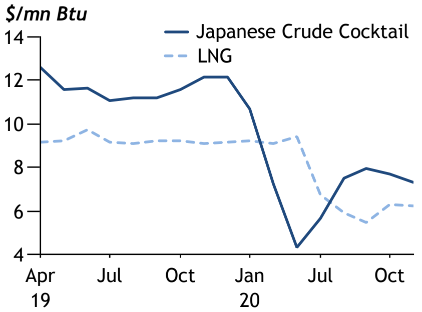
EDITORIAL: Traditional wisdom on price linkage is increasingly being challenged by developments

Japanese LNG vs crude



Key price points		*$/mn*
	Nov	**Dec**
Zeebrugge gas month-ahead	4.93	4.82
US Nymex month 1	2.77	2.92
US LNG import price	na	na
Japanese Crude Cocktail	7.69	na
Japanese LNG import price	6.21	7.56

— Markets and data pp17-31

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LNG smashes oil parity

If further evidence of the decoupling of LNG and oil prices were needed, the last 12 months provided plenty of it. When crude demand and prices collapsed last spring as the Covid-19 pandemic swept through many of the world's advanced economies, gas demand remained resilient, as locked-down populations continued to heat and light their homes. And when gas demand rose towards the end of 2020, the ensuing price rally far outpaced the crude market's more modest recovery back in the summer.

Of course, all of this is relative. Gas prices were low as 2020 began, as a succession of mild winters exacerbated a structural oversupply resulting from overenthusiastic investments made years previously in new LNG export capacity. The usual summer dip in prices took global gas prices to their lowest in many years.

But this makes the spike in prices with which 2021 began all the more remarkable. With cold weather blanketing the northern hemisphere and Japanese utilities caught off guard by a combination of nuclear restrictions and low LNG stocks, LNG prices reached unprecedented highs. The *Argus* northeast Asia (ANEA) des price peaked at $39.72/mn Btu on 13 January, almost double the highest price *Argus* had ever recorded previously — before swiftly declining in the second half of that month to more familiar, albeit still high, levels.

This peak was a staggering 70.6pc of the Brent crude price, eclipsing a previous high of 20.8pc of Brent set in January 2015. As one barrel of oil contains about 5.8mn Btu, traditional wisdom has it that LNG prices are capped at about 17.2pc of Brent — so-called "oil parity". Beyond that level, it would cost less to burn fuel oil to generate electricity.

But this traditional wisdom is antiquated. Oil-fired power plants account for just 4pc of total installed capacity across Asia-Pacific. And in Japan — the only Asian country in which oil-fired power plants still account for a double-digit (13pc) share of the generation fleet — fuel oil contributed for little more than 1pc of the country's total power output in the year to September 2020, down from 2pc a year earlier and a three-year average of 3.1pc.

And as curbs on climate-changing emissions tighten across the region, it is increasingly unlikely that these oil-fired plants will be used for much apart from emergency back-up.

Of course, oil's influence over the gas market persists in the form of indexation in long-term contracts. But this oil linkage provided perverse price signals to the market last year, with crude-indexed prices higher when demand was at its nadir and lower when demand spiked. Producers' margins were slashed, and the fourth-quarter rally in spot LNG prices did little to bolster oil-indexed revenues.

This is why the US' emergence as one of the world's largest LNG producers, and by far its most flexible, is so important. The world gas market needs its own price to signal to the market when to invest, and when not to, if it is to escape the extremities of the business cycle seen over the past decade.

And however much it may discomfit northeast Asian importers, the market needs price volatility, too — because only this will signal to the market that it needs to invest more in the flexibility that will help smooth price cycles and soften the market's peaks and troughs.

US

Four of the country's liquefaction facilities increased loadings, with three setting new records, writes Samuel Good

LNG exports			*mn t*
Project	**Jan 21**	**Jan 20**	**Dec 20**
Cameron	1.24	0.67	1.20
Corpus Christi	1.24	0.96	1.13
Cove Point	0.44	0.46	0.37
Elba Island	0.00	0.13	0.19
Freeport	1.32	0.89	1.29
Sabine Pass	2.32	2.52	2.37
Total	**6.56**	**5.63**	**6.56**

LNG export flows		*Cargoes*
Route	**Jan 21**	**Jan 20**
Via Panama Canal	21	29
Via Suez Canal	31	4
Via Cape of Good Hope	3	3
Delivered to Atlantic market	32	40
Total	**87**	**76**

Exports hold quick in January

Combined loadings at the US' six operational liquefaction projects in January were significantly higher than a year earlier, but broadly in line with December despite record-high prices and a new facility ramping up output.

The six projects together exported about 6.56mn t in January, judging by vessel size, up from 5.63mn t a year earlier, when the country's overall export capacity was smaller. The total new liquefaction capacity that came on line in 2020 was 28mn t/yr — including the third train of the Corpus Christi facility in Texas, which is still in commissioning phase — bringing the US' total liquefaction capacity to 80.1mn t/yr.

Yet the country's exports last month remained broadly unchanged from December 2020, despite the production ramp-up at Corpus Christi's third train and record-high Asian prices incentivising producers to test liquefaction capacities. Four of the US' liquefaction facilities increased loadings from a month earlier, with three facilities setting new monthly records.

Both the 15mn t/yr Freeport and the same-sized Cameron projects set records in January, having gradually ramped up production over the past year with the addition of new trains. Loadings at Freeport appeared to test the terminal's peak capacity, while Cameron output remained slightly below nameplate capacity. And exports from the 15mn t/yr Corpus Christi terminal totalled 1.24mn t in January — up from 989,000t in November and close to the facility's nameplate capacity, which was increased in early December with the start-up of the third liquefaction train. Exports from the 5.75mn t/yr Cove Point terminal also rose on the month, although it remained marginally lower than in January 2020.

Combined US exports failed to set a new record last month because two facilities exported less LNG in January than in December. Loadings at the 25mn t/yr Sabine Pass terminal fell slightly on the month, with repeated closures of the Sabine-Neches waterway because of fog likely disrupting loading schedules at the terminal, although January loadings remained close to the facility's nameplate liquefaction capacity.

And the 4mn t/yr Elba Island terminal did not produce any cargoes in January, after loading about 189,000t in December. Shell holds all the offtake from the facility, but may have opted to source volumes closer to demand markets, given the tight shipping market ahead of January.

Asian demand draws US LNG out of the Atlantic

A large share of US cargoes left the Atlantic basin as cargoes scrambled to reach Asian markets, where prices skyrocketed in the first half of January, largely outstripping a much more moderate increase in European prices.

Of the 87 cargoes loaded in January, at least 57 are scheduled for delivery to markets outside the Atlantic basin. And a further five — which are sailing towards the Suez Canal or the Cape of Good Hope without a declared destination — could also leave the basin for delivery to south or northeast Asia.

This suggests that only 26-32 of the 87 January cargoes could be delivered to Atlantic basin markets. And this number would be higher were it not for at least two diversions of carriers that had been en route to Pacific markets before being diverted to Europe as the inter-basin arbitrage collapsed in mid-January. Only 36 of the 76 loadings in January 2020 left the Atlantic basin.

Congestion at the Panama Canal through much of this winter is likely to have prompted charterers to seek out alternative routes to northeast Asia, with the Suez Canal emerging as the preferred option. Panama transits fell on the year to 21 from 29, while transits through Suez rose to 31 from four a year earlier.

QATAR

A dearth of prompt LNG available to the spot market limited vessel availability, driving up spot prices, writes Ellie Holbrook

Exports reach one-year high in January

LNG loadings at Qatar's 77mn t/yr Ras Laffan liquefaction complex dipped in January compared with a year earlier, but were still at their quickest for 12 months.

Exports hit 7.17mn t last month, against 7.20mn t a year earlier, data from oil and gas analytics company Vortexa show. Shipments continued to quicken after falling to 5.82mn t in November — the lowest monthly volume in at least three years — when two liquefaction trains were off line for maintenance (*see chart*).

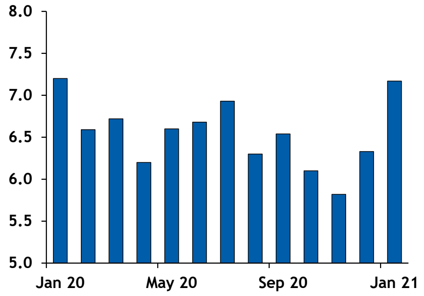
About 91pc of last month's exports were destined for Asia-Pacific, up from 76.4pc a year earlier and 88.4pc in December.

Flows were quickest to South Korea, accounting for 21.4pc of January exports, up from 14.1pc a year earlier and 13.8pc in December. Exports to China edged lower on the month and accounted for just 18.4pc, up from 14.1pc a year earlier but down from 20.4pc in December. Japan is set to receive just 826,000t, or 11pc of January loadings, down from 1.03mn t a year earlier and 1.19mn t in December.

The quicker Qatari exports to the region came amid a sharp increase in demand last month that pushed the price of spot LNG delivered to northeast Asia to a record high in January. A dearth of prompt LNG available to the spot market limited vessel availability, amid lower-than-expected temperatures and strong consumer demand, driving spot prices beyond the previous record set in 2014.

Most of Qatar's output is sold under long-term contracts, but state-owned QP, which owns 65pc of Qatargas, set up a trading arm in November that might have allowed the firm to sell more LNG on the spot market. And Qatar's location closer to northeast Asia than to US export facilities may have reduced its exposure to the recent rally in spot charter rates.

LNG exports *mn t*



European slowdown

Europe's imports of Qatari volumes slowed in January, with the region accounting for 9pc of shipments, down from 23.6pc a year earlier and 10.4pc in December.

Italy, Spain and Portugal were the only European countries set to receive Qatari cargoes loaded in January. Italian utility Edison and Spain's Endesa and Naturgy have long-term contracts with Qatar. By contrast, northwest European markets typically receive Qatari LNG under flexible supply agreements, which allows Qatar to deliver to some terminals in the region if more profitable destinations cannot be secured.

The UK has received no Qatari LNG volumes since October, despite having received the largest share of Qatar's European deliveries in January 2020, at 8.2pc. And Qatar supplied about 79pc of all UK LNG imports in April-October. Qatargas has a flexible marketing agreement with the operator of the UK's 15.6mn t/yr South Hook import facility.

Qatar sets 7mn t/yr 2030 carbon capture target

Qatar's state-owned QP has set itself a target of reducing greenhouse gas emissions, with plans to capture and store more than 7mn t/yr of CO_2 from its operations by 2030. QP says it wants to reduce the emissions intensity of its LNG facilities by 25pc, of its upstream facilities by at least 15pc and cut flaring by more than 75pc. QP's sustainability strategy sets a target to eliminate routine flaring by 2030 and limit methane emissions by setting a methane intensity target of 0.2pc across all facilities by 2025. Qatar awarded on 8 February a $13bn contract to a joint venture between Japan's Chiyoda and France's Technip FMC to expand its liquefaction capacity to 110mn t/yr by 2025.

EGYPT

Damietta to bolster LNG output

The facility's restart may enable the country's LNG production to continue its ramp-up of recent weeks, writes Antonio Peciccia

Egyptian LNG production could rise in the coming months with the restart of Damietta and higher LNG prices incentivising stronger output at Idku.

The 5mn t/yr Damietta terminal is set to produce a test cargo in mid-February as it restarts LNG production after being idled since January 2014, which Spain's Union Fenosa Gas has tendered to the market. UFG — a 50:50 joint venture between Italy's Eni and Spain's Naturgy — has agreed to sell its 80pc stake in Damietta's terminal operator, Segas, to Eni and Egyptian state-owned gas distributor Egas, but must produce a test cargo to confirm the plant still works before the sale is finalised. The deal, agreed last year, is expected to be completed by the end of March, with the terminal resuming regular exports this summer. In December, the European Commission approved Eni's acquisition of UFG assets, saying that it could not result in new overlaps between the firms' activities because it consists of a change from joint to sole control of these assets.

Damietta's restart may enable Egyptian LNG production to continue its ramp-up of recent weeks. The country's 7.2mn t/yr Idku terminal, its sole operational facility at present, exported seven cargoes in January containing a total of 482,300t, up from just 141,700t a year earlier and 317,600t in December. The volume exported last month was the highest since December 2019, when 585,700t was loaded on to nine vessels at Idku.

Forward prices in destination markets remain well above Egyptian production costs, providing an incentive for Idku loadings to stay high

Forward prices in destination markets remain well above Egyptian production costs, providing an incentive for Idku loadings to remain high in the coming months. Second-quarter prices at the Dutch TTF gas hub are \$5.70-5.90/mn Btu at present, up from \$2.50-3.00/mn Btu a year ago, which could provide sufficient returns for Egyptian cargoes. Egas pays \$4.50-5.50/'000ft^3 (\$3.81-4.66/mn Btu) for gas produced by Egypt's most expensive upstream projects. Eni received an average price of \$5.11/'000ft^3 (\$4.33/mn Btu) for its Egyptian production in 2019, up from \$4.85/'000ft^3 (\$4.11/mn Btu) a year earlier. Egas agreed to sell cargoes on a spot basis only if bids were above \$5/mn Btu in its latest spot tenders in 2019. And the 2020 fall in crude prices may have reduced the cost of production from the Zohr field, which is tied to crude prices, albeit with a floor and a ceiling.

Playing catch-up

Idku resumed production in October after remaining largely idled last summer, when global LNG prices fell below the cost of Egyptian production. Egyptian gas output fell to 164mn m^3/d in January-October 2020, the most recent official figures, from 185mn m^3/d a year earlier, mostly on lower export demand. Egypt also started receiving pipeline imports from Israel in January last year.

The terminal's output is split equally between Shell and Total, with Egas marketing on a spot basis volumes turned down by the two long-term offtakers. Last year, the two firms agreed to lift only 20 cargoes — their minimum take-or-pay commitment — leaving Egas to market up to 80 spot cargoes. The terminal eventually exported 19 cargoes over the whole of 2020, down from 54 a year earlier, suggesting at least one cargo may have been deferred to this year.

The sharp increase in northeast Asian prices at the turn of the year provided an incentive to ramp up loadings in January, but it was unclear how many of these cargoes may have been marketed by Egas. Egyptian oil minister Tarek El Molla says Idku loadings have already been booked until the end of March, but he did not specify whether these were for spot buyers or long-term customers.

Egas issued a number of spot tenders throughout 2019, but many of these tenders were not or only partially awarded, with the firm later suggesting that it would only sell spot volumes bilaterally.

AUSTRALIA

LNG producers push for investment decisions in 2021

Gas backfill projects for the Darwin and North West Shelf LNG plants are most likely to get the green light after Covid-19-related delays, writes Kevin Morrison

Australian LNG producers hope to reach final investment decisions (FIDs) in 2021 that were deferred under pressure from the Covid-19-related slump last year — particularly if a rally in Asian spot LNG prices to record highs last month prompts more buyers to enter long-term contracts.

The two developments expected to be approved are the Barossa gas backfill project for the 3.7mn t/yr Darwin LNG in the Northern Territory, operated by domestic upstream firm Santos, and the Scarborough gas project in the Carnarvon basin off Western Australia. The latter will be used partly as backfill for the 16.3mn t/yr North West Shelf (NWS), operated by domestic firm Woodside Petroleum, and a second train of 5mn t/yr at Pluto LNG, also operated by Woodside.

Barossa is expected to be first to reach an FID, after signing a 1.5mn t/yr sales and purchase agreement (SPA) with Japanese trading house Mitsubishi in December. This represents 80pc of Santos' 50pc equity interest in the project. Barossa's other stakeholders are LNG buyers that expected to take their share of sales from the venture, meaning no other SPAs are needed to get the project off the ground.

Santos signalled last month that it is ready to spend on Darwin LNG after deferring an FID on Barossa twice last year. It has announced a $235mn infill drilling programme at the Timor Sea's mature Bayu-Undan field, which feeds Darwin but eventually will be replaced by Barossa.

Woodside has earmarked Scarborough for approval towards the end of this year. It would supply up to 8mn t/yr at peak output, mainly as feedstock for the second train planned at Pluto LNG. The rest will be split between backfill for Pluto's existing 4.3mn t/yr train, and the NWS venture, with the projects to be connected by a 3.3km pipeline to allow gas flows to switch between them.

Woodside is adamant that it makes more commercial sense to develop Scarborough as feedstock primarily for a second Pluto train — even though it warns that half of NWS could be idled by 2028 if no new gas sources are developed to feed the plant — given the added cost of reconfiguring the NWS trains to receive Scarborough gas, which is drier than the facility's current feedstock.

Australian firms want to see sustained LNG price support before committing funds to developing gas fields or bringing forward deferred investment plans

Tight spot

The surge in LNG spot prices this year resulted partly from shutdowns at Chevron's 15.6mn t/yr Gorgon LNG and Shell's 3.6mn t/yr Prelude floating LNG venture, both off Western Australia. Shell resumed Prelude production last month, but Gorgon's first train is still off line for repairs to propane heat exchangers. Rapidly rising northeast Asian demand will require buyers in the region to source more volumes from outside the basin if Australian export capacity additions are slow, but Australian firms want to see sustained LNG price support before committing funds to developing gas fields or bringing forward deferred LNG investment plans.

And foreign stakeholders are looking to Australia's LNG sector for potential divestment opportunities. Shell in December raised $2.5bn with the sale of a 26.25pc interest in the LNG storage tanks, jetties and operations infrastructure at the 8.5mn t/yr Queensland Curtis LNG facility in Queensland state to US-based investor Global Infrastructure Partners. Shell will keep the remaining 73.75pc.

Australia forecasts its LNG exports to rise to 88mn t/yr in 2030 from 77mn t/yr in 2020, although it sees shipments dropping briefly in 2025 because of falling NWS output before rebounding later this decade, a Department of Industry, Science, Energy and Resources report says. NWS output is projected to fall in 2025 before recovering in 2028, as the Browse basin provides a large source of backfill. Darwin LNG will be off line in 2023-24 once Bayu-Undan is depleted, then return in 2025 with new feedstock from Barossa. Pluto's second train will be on stream in 2026.

PAPUA NEW GUINEA

Oil Search sees lower PNG LNG output in 2021

Maintenance works at the site are likely to weigh on overall production this year, writes Kevin Morrison

LNG output from the 6.9mn t/yr PNG LNG venture in Papua New Guinea (PNG) is expected to drop this year from the record 8.8mn t produced in 2020, with the facility expected to undertake maintenance at trains one and two this year.

The work on train one was deferred since last year, says Australian independent Oil Search, which owns 29pc of the venture. A major maintenance shutdown at the operated facilities, which occurs every four years, is also planned to coincide with the PNG LNG [maintenance] programmes to minimise impact on production. Oil Search's production guidance for 2021 is 25.5mn-28.5mn bl of oil equivalent (boe) or 69,900-78,000 boe/d. This range provides a small probability that 2021 output may still be above last year's levels, when it stood at 28.39mn boe, or 77,500 boe/d.

The ExxonMobil-operated PNG LNG venture produced at a rate of 8.7mn t/yr in October-December, down from an annualised rate of 8.9mn t in the July-September quarter. Output in 2020 exceeded the previous record of 8.5mn t in 2019.

"Despite the material challenges of 2020, PNG LNG continued to outperform in the fourth quarter, ending the year with its highest-ever production of 8.8mn t/yr," Oil Search chief executive Keiran Wulff says. The PNG LNG venture has produced above nameplate capacity each full calendar year since starting shipments in 2014 and produced exactly 6.9mn t in excess of nameplate capacity throughout 2015-20 — or the equivalent of one extra year of production.

A total of 29 LNG cargoes were delivered to customers in October-December, compared with 31 cargoes in July-September, comprising 26 cargoes sold under contract, including five under mid-term sales and purchase agreements and three on the spot market, the firm says. But two cargoes were on the water as of 31 December, the same as at the end of September.

The firm's capital expenditure is expected to remain unchanged this year. The PNG LNG Angore gas field development is scheduled to restart in 2021 after being deferred last year, when Oil Search had slashed spending in response to a sharp drop in oil and gas prices last March on concerns about the Covid-19 pandemic's impact on demand, it says. Oil Search laid out $425.4mn in calendar 2020, or less than half of the $870.7mn it spent in 2019.

The challenging market conditions also prompted Oil Search to halt exploration activities in PNG in October-December. It is reviewing its exploration portfolio in PNG and plans no exploration or appraisal drilling in PNG in 2021, it says.

AUSTRALIA

Wheatstone LNG operates below capacity

A shutdown last month has slowed production but it is expected to rebound in coming weeks, writes Eleanor Holbrook

Australia's 8.9mn t/yr Wheatstone LNG export facility is operating below capacity after a gas processing unit at the facility was shut in early December following the discovery of a fault during a routine inspection.

Terminal operator Chevron says it expects no impact on output for the second quarter, suggesting production is expected to rebound in the coming weeks. The firm expects Wheatstone to operate at normal levels for the rest of the year, taking into account the facility's scheduled maintenance later this year.

Slower Wheatstone output adds to Chevron's issues at its other Australian unit, the 15.6mn t/yr Gorgon LNG facility, where the first liquefaction train remains off line. Chevron plans to halt operations at Gorgon's third train once the first unit resumes in March. Gorgon's second train was off line from late May to mid-November. The shutdowns at Gorgon capped Chevron's Australian LNG output at 80pc of capacity in 2020. But it was able to meet its long-term commitments without needing to "buy high and sell low" during the rally in LNG prices last quarter, it says.

RUSSIA

Novatek sees LNG supply shortfall by 2030

The company believes LNG's cost competitiveness will ensure supply growth even if demand is low, writes Elaine Atwood

A lack of new final investment decisions (FIDs) and mounting worldwide demand could lead to an LNG supply shortfall by the end of this decade, Russian firm Novatek has said.

LNG supply could fall short by about 150mn t/yr by the end of this decade without additional FIDs, an issue that "needs to be addressed", Novatek chief financial officer Mark Gyetvay said at the virtual European Gas Conference.

Novatek expects worldwide LNG demand to continue to grow even as countries decarbonise their energy systems. The idea that gas is "falling out of the equation is grossly overstated", Gyetvay said.

Gyetvay expects increased coal-to-gas switching in the power sector, hydrogen production and gas being used in tandem with intermittent renewables for power generation to boost gas demand in the coming years.

LNG's cost competitiveness will ensure supply growth even in a lower-demand scenario, as "the lowest-cost producers will prevail", Gyetvay said.

And the flexibility provided by LNG will continue to be useful over seasonal demand fluctuations, as demonstrated by the recent spike in northeast Asian demand, Gyetvay said.

The firm expects gas demand in Asia to grow "very strongly" despite China's net-zero emissions target for 2060, and anticipates that 80-85pc of its LNG output will be delivered to the region in the future.

But new FIDs will need to be made to meet the rising demand, Novatek said. While spot northeast Asian LNG prices spiked earlier this month, firms are unlikely to make FIDs based on "inflated prices", Gyvetvay said.

Novatek still expects to make an FID on the 5mn t/yr Obsky LNG terminal this year, having postponed it from last year.

Gyetvay foresees a move away from FIDs being secured by traditional long-term supply contracts towards a model involving equity sponsors, given the rising number of firms seeking to secure volumes on a short-term basis.

The company expects supply sold under long-term contracts to fall to almost 50pc by 2025, from 65-75pc five years ago.

RUSSIA

Yamal train 4 starts production

The facility is expected to load its first cargo 'within the next couple of months', writes Antonio Peciccia

The fourth liquefaction train at Russia's Yamal LNG project has begun production and is expected to load its first cargo by the end of March.

The 940,000 t/yr train has produced its "first drop of LNG" and is currently in the commissioning phase, project operator Novatek's chief financial officer, Mark Gyetvay, said at the virtual European gas conference. The facility is expected to load its first cargo "within the next couple of months", he said.

The facility was already expected to start exporting in the first quarter of this year, having been postponed twice from an original planned start-up by the end of 2019. The first three liquefaction trains at Yamal — each with a design capacity of 5.5mn t/yr — were completed ahead of schedule.

Novatek is "on the path to open the Northern Sea Route (NSR) for 12 months a year", Gyetvay said. Yamal cargoes have been able to increase their use of the NSR in recent months, with two more cargoes transiting the passage in January, following two deliveries through the NSR that took place in December, he said. The 172,600m^3 *Christophe de Margerie* and the identically sized *Nikolay Yevgenov* delivered cargoes to China's Rudong and South Korea's Pyeongtaek terminals, respectively, in late January, after about 20 days' sail through the NSR.

GLOBAL

Gas demand to rebound in 2021: IEA

The return to positive growth will likely come from greater demand from the Asia-Pacific and Central and South American markets, writes Samuel Good

Global gas demand is set to grow in 2021 by about 2.8pc, the International Energy Agency (IEA) says, following a fall in overall demand last year.

Global demand fell by around 2.5pc last year, the IEA says, but expected growth in 2021 suggests that overall demand could rally to be broadly on par with that of 2019.

The return to positive growth is expected to come primarily from greater demand from markets in the Asia-Pacific and Central and South American regions, with most other regions also expected to have higher demand, although North American gas demand is expected to slow slightly, as gas faces stiffer competition from renewable generation and lower coal prices in the US.

And the increase in combined demand is expected to be driven by quicker power sector gas demand, although this is set to come mainly from developing economies, particularly in Asia, rather than mature markets, the IEA says. Power sector gas demand was the most affected demand sector last year, the organisation says, despite fuel switching in European and North American sectors through much of that year.

European gas-fired generation is projected to fall by about 1pc, being displaced by greater renewable and nuclear output in the region, while recent rises in European gas prices imply that the fuel may also face competition in the thermal fuel mix.

And while gas demand in most large gas-consuming markets in Asia is set to increase in 2021, projected falls in Japanese power gas demand are set to cut the country's total gas demand this year, with expectations of quicker nuclear generation, the IEA says.

The industrial sector is also expected to be a primary buttress of 2021 demand growth, again driven by Asian markets as goods production grows and international trade flows step higher again.

The industrial sector is also expected to be a primary buttress of 2021 demand growth

But the recovery in global demand is "fragile", the IEA says, highlighting uncertainties surrounding delays to the resumption in industrial activity, scope for mild temperatures and fuel competition within power sectors.

US production down, Eurasian up

US gas production is projected to fall by about 2pc in 2021, having already slowed last year, as associated shale output and conventional field production in general falls, the IEA says.

Dry shale output could grow by about 2pc, but this is dependent on uncompleted wells in the Appalachian basin and insufficient to offset other decreases in production.

But Eurasian production could increase, the IEA says, as supply routes from Russia — such as the Power of Siberia and Yamal LNG project — and Azerbaijan, in the form of the Trans-Adriatic pipeline, deliver more gas to demand regions.

The IEA expects European production — excluding Norway — to continue its decline, with a projected decrease of 3.3pc this year. This will bolster the region's import demand, but most of it is expected to be met by an increase in pipeline supply.

Low demand and weak prices prompted Europe's major pipeline suppliers to curb production last year. Market prices offer no such incentive to producers to restrain production this year, as European contracts delivering in 2021 are at a premium to contracts delivering in future years.

Asian economies are expected to absorb much of this year's 3pc growth in global supply, a sizeable proportion of which will take the form of LNG.

JAPAN

Tokyo looks to Asia for extra LNG supply security

Joint stockpiling initiatives are being considered as a way of providing emergency back-up amid the risk of tightening LNG availability, writes Rieko Suda

Japan is considering working with other Asia-Pacific countries to build LNG stockpiles, after a spike in electricity demand and a fall in domestic inventories of the fuel raised concerns about supply security.

The country came close to suffering power blackouts last month as utilities struggled to meet a surge in heating demand, with temperatures falling to their lowest in years. LNG stocks were rapidly depleted amid a supply shortage in the region and shipping constraints exacerbated by congestions at the Panama Canal hampering deliveries from the Atlantic basin.

This raised alarm bells at economy, trade and industry ministry Meti, which saw its worst energy-security fears almost become reality. Last month the ministry began consultations on issues that affect electricity supply, including how generation fuels and power capacity are procured and adequate disclosure of relevant information and risk management.

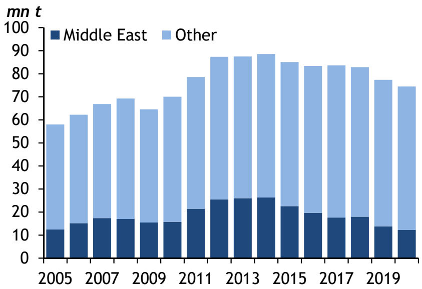
Meti in December had launched discussions with industry representatives and experts on how to address the risk of supply constraints and price volatility, as it revises its energy policies. For LNG, it is shifting its focus from supply diversification to opportunities to co-operate with Asia-Pacific countries on stockpiling.

Japan has sought to improve its energy security by diversifying its LNG import portfolio, with the Middle East accounting for only 16pc of its 2019 receipts, although it still relies on the region for 90pc of its crude supply. But it remains vulnerable to shortfalls as Japanese utilities typically target emergency LNG stocks sufficient to cover just 15-20 days worth of consumption, adding to the need for a back-up system to meet potential shortages.

Tokyo now wants to build on its ties with Asia-Pacific countries to develop emergency LNG stocks, while continuing efforts to develop and expand the region's LNG market. It has committed $20bn in state and private-sector funding to Asian LNG infrastructure and supply chain development since 2017. Japanese firms have invested in Asia-Pacific LNG infrastructure projects, particularly in southeast Asia, as they look to tap regional demand growth because of a weakening domestic market. Japan last year make a similar move in respect to crude supplies, co-operating with other Asia-Pacific countries on a joint crude stockpiling programme aimed at mitigating the risks of its heavy reliance on Middle East oil.

A marked slowdown in investments in new LNG production facilities in recent months has raised concerns that supply could become tighter in the next few years. And Japan's almost total dependence on thermal fuel imports is accentuating its vulnerability as it looks set to lose the bargaining power associated with being the world's largest LNG user as soon as next year, ceding the position to China. Japanese LNG imports peaked at 89mn t in 2014 but declined to 74mn t by last year — the lowest since 2010, just before the 2011 Fukushima-Daiichi nuclear accident prompted a surge in thermal power demand (*see chart*).

LNG imports



— Japanese finance ministry

Renewed emphasis

LNG is likely to retain a key role in Japan's power mix to balance the likelihood of growing grid instability as renewable output rises. Gas is also expected to be used to make "blue" hydrogen — where any CO_2 from the process is captured — as a step towards its full transition to "green" hydrogen, made using renewable power, in the run-up to the country's 2050 net-zero goal. Meti has provisionally proposed that renewables generate 50-60pc of Japan's power by 2050, with 30-40pc from nuclear and thermal fuels combined with carbon capture and 10pc from hydrogen. Renewables made up 18pc in April 2019-March 2020, thermal power 76pc and nuclear 6pc.

CHINA

The company is offering spare capacity at its six operational terminals for third-party access in 2021, writes Camille Klass

PipeChina shortlists firms for 2021 LNG import slots

Chinese state-controlled oil and gas pipeline firm PipeChina has shortlisted 54 firms that are seeking third-party access to spare import slots at six of its LNG regasification terminals in 2021.

The firm received submissions from 82 firms, following a call for applications at the end of last year. But it rejected applications from 28 firms after a review of their submissions and their credit and financial positions.

The 54 firms include state-controlled firms such as CNOOC, PetroChina parent CNPC, Sinopec, Sinochem, Huadian and Zhenhua; second-tier gas firms such as ENN, Guangdong Energy, Jovo, Beijing Gas, Towngas, GCL-Poly and Chinagas; and the Chinese units of international oil firms BP and Shell.

PipeChina announced in December that it was offering 6.4mn t/yr of spare capacity at its six operational terminals for third-party access in 2021. This volume is equivalent to 107 LNG cargoes, based on a 60,000t cargo size. The six terminals are the 2mn t/yr Yuedong, 4mn t/yr Diefu, 3mn t/yr Beihai, 2.2mn t/yr Tianjin floating storage and regasification unit (FSRU), 3mn t/yr Hainan and 600,000 t/yr Fangchenggang facilities.

Shortlisted firms were required to submit their confirmation of a draft terminal user agreement to PipeChina by the end of January, according to industry participants at some of the shortlisted firms. And the company was expected to award slots to successful firms by 12 February. A few industry participants at the shortlisted firms say they are reviewing the draft agreement because it includes a clause under which approved LNG importers are expected to agree to take future LNG cargoes from the term supply portfolios of CNOOC, PetroChina and Sinopec. This may be a challenge for gas buyers that were hoping to take advantage of potentially lower spot prices relative to term contract prices and not be burdened by an obligation to also take cargoes from the three state-owned firms, industry participants say. There is no clarity on the price of these long-term cargoes or the mechanism through which they are expected to buy the term cargoes, they say.

The draft agreement may be a challenge for gas buyers that were hoping to take advantage of potentially lower spot prices relative to term contract prices

Firms that were interested in third-party access to PipeChina's terminals had to submit their applications to PipeChina by 25 December, detailing the number and delivery windows of import slots they were seeking this year, they say.

Priority treatment

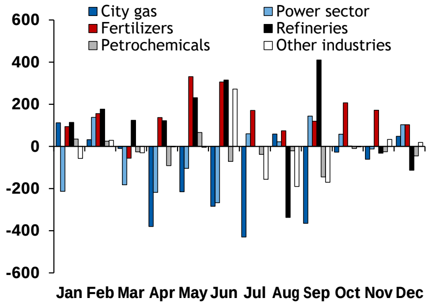
PipeChina will prioritise existing customers, those with legacy LNG term contacts and firms that have helped guarantee gas supply this winter and will apply for slots over the November 2021-February 2022 winter period in allocating slots. It will also give priority to firms with upstream portfolios and downstream consumers, with the ability to send out cargoes quickly. Legacy term contracts signed by previous operators of PipeChina's terminals — CNOOC, Sinopec and PetroChina — require the original annual delivery programme to take priority when PipeChina allocates capacity. Window slots are tighter in the winter, especially December when term supplies are needed to meet peak demand in the colder season.

PipeChina started operations on 1 October 2020 and owns nine LNG import terminals, following its latest acquisition of the 6mn t/yr Dalian LNG terminal in December from PetroChina unit Kunlun Energy. The firm acquired from CNOOC the 2.2mn t/yr Tianjin FSRU, the 2mn t/yr Yuedong and 4mn t/yr Diefu terminals in Guangdong, the 600,000 t/yr Fangchenggang facility in Guangxi and 3mn t/yr Yangpu terminal in Hainan, as well as two terminal projects under construction — the 3mn t/yr Zhangzhou project in Fujian and 5mn t/yr Longkou facility in Shandong. It also acquired the 6mn t/yr Beihai LNG terminal in Guangxi province from Sinopec. CNOOC, PetroChina and Sinopec all hold stakes in PipeChina.

INDIA

Fertilizer production was the main driver of the country's gas demand last year, writes Antonio Peciccia

Demand change, y-o-y *mn m³*



Gas demand rises in December

Indian gas demand increased in December compared with a year earlier, supported by stronger city gas and power sector demand that more than offset a slight reduction in industrial consumption.

Overall gas demand rose to 4.91bn m³ in December 2020 from 4.79bn m³ a year earlier, the most recent official figures show. The increase was mainly the result of stronger power sector gas burn, which rose by more than 12pc to 928mn m³ in December from 825mn m³ a year earlier.

The increase in power sector consumption, as well as from the city gas sector, was partly offset by weaker industrial demand, which edged lower despite gas consumption by fertilizer producers continuing to rise.

Fertilizer production was the main driver of the growth of Indian gas demand throughout last year. It accounted for an increase of 1.82bn m³ over the course of 2020, compared with that of 2019.

Demand from fertilizer producers and refineries offset lower consumption in all other sectors, with overall Indian demand for the full year of 2020 rising by less than 1pc from a year earlier, to 56.1bn m³.

But while demand from the city gas and power sectors decreased last year, regardless of the supply source, industrial consumers were able to take advantage of the lower LNG prices and switch to seaborne imports from domestically produced gas.

Most industrial sectors increased their LNG imports while reducing their use of domestic production — with the exception of refineries, which ramped up their use of domestic gas more sharply than their LNG imports.

Petrochemical producers reduced their reliance on LNG, although by a far lesser extent than the drop in their consumption of domestic gas.

Combined LNG deliveries to India rose by 10pc to 33.9bn m³ of pipeline gas equivalent in 2020 from 30.8bn m³ a year earlier.

INDIA

The charter will follow a 40-day off-hire period for 'minor modifications', writes Samuel Good

Jaigarh FSRU charter to start in March

Norwegian shipowner Hoegh LNG and India's H-Energy have finalised a charter agreement for a floating storage and regasification unit (FSRU) for the 6mn t/yr Jaigarh import terminal.

The charter, which is for the 170,000m³ *Hoegh Giant* unit, is scheduled to begin in March, Hoegh LNG says, and it will follow a 40-day off-hire period while some "minor modifications" are carried out on the FSRU at Keppel shipyard in Singapore.

The *Hoegh Giant* on 9 February discharged at India's Dabhol terminal a cargo that was loaded at Spain's Cartagena import facility last month, under a long-term charter with Spanish utility Naturgy.

A 40-day off-hire period starting from 9 February — presuming Naturgy's charter expires at that time — suggests that the FSRU's new charter for Jaigarh will not start until about 21 March.

This may mean that the terminal could come on line early in the second quarter of this year.

The Jaigarh project — which would be India's first FSRU-based import terminal — has faced repeated delays in recent years, as issues such as heavy rainfall during the monsoon season have affected construction.

But the construction work has since been completed, Hoegh LNG said in November last year.

SPAIN

Enagas to offer within-month LNG slots

The new system is hoped to resolve inflexibility issues in Spain's virtual LNG hub system, writes Silvia Fernandez Martinez

Spanish system operator Enagas will offer within-month capacity slots at the country's six LNG terminals, providing Spain with more flexibility to receive LNG deliveries on a prompt basis.

Enagas will introduce two types of within-month auctions, which revolve around demand in monthly capacity auctions.

If the capacity requested at monthly slot auctions is lower than or equal to that on offer, Enagas will notify market participants of the number of available within-month slots, if any, that can be requested shortly afterwards. In this case, within-month slots will be allocated on a first-come, first-served basis.

In the event of demand exceeding capacity on offer at the monthly capacity auction, any slots that later become available — for example, through cancellations — will be offered through a closed-envelope auction.

If demand exceeds available slots after the closed-envelope round, a second round will be held. If demand is below the slots on offer, any remaining slots again will be allocated on a first-come, first-served basis.

Slots cancelled during the delivery month can be re-offered in the within-month capacity process.

Any cancellation request received with fewer than 10 days' notice will be communicated to the regulator.

If a slot is cancelled for delivery in the following month or later, it will be re-offered at within-month or other auctions.

Better access to unloading capacity

Enagas' proposed within-month allocation process could resolve inflexibility issues in Spain's virtual LNG hub system, which was introduced in April last year.

Market participants had complained that a dearth of within-month slots offered by the system operator had hindered access to LNG unloading capacity, even when storage tanks were far from full.

LNG inventories averaged just 49pc of capacity in October-December, well down from 80pc a year earlier and 64pc on average in the past three years

Before April of last year, companies had been able to negotiate bilaterally with Enagas to acquire prompt slots when space permitted. Before the introduction of within-month slots, the new system had driven up the price of slots in the secondary market.

The lack of flexibility to incorporate more deliveries exacerbated the situation of low LNG stocks in early January, which played a role in the spike in PVB prompt prices.

A wide inter-basin arbitrage has pulled LNG supply away from Europe for most of this winter, tightening supply in the Spanish market and driving stocks lower.

LNG inventories averaged just 49pc of capacity in October-December, well down from 80pc a year earlier and 64pc on average in the past three years.

Below-average LNG stocks in early January coincided with a cold snap. And with Spain out of options to lift pipeline imports, given supply constraints in Algeria and limited connectivity with northwest Europe, PVB prices climbed to multi-year highs. The front-month contract even switched to a premium to northeast Asian prices.

The need for a more flexible system was evidenced last month when Enagas was forced to divert a vessel due at the Mugardos LNG plant to the Bilbao terminal, where regasification capacity is higher, after a cargo destined for Bilbao was cancelled on 4 January within less than the required 72 hours' notice.

Other deliveries scheduled for later that month had to be brought forward to meet strong conventional demand because of the difficulty of booking additional LNG deliveries.

BRAZIL

Hygo purchase transforms New Fortress

The acquisition gives the company a range of gas and power assets in the country, writes Elizabeth Johnson

New Fortress Energy's acquisition of Hygo Energy Transition has turned the US firm into a major investor in Brazil's burgeoning natural gas and power sector, building on its LNG presence in Central America and the Caribbean.

New Fortress will acquire Hygo from its owners, Norwegian firm Golar and US private equity fund Stonepeak, for about 31.4mn of New Fortress shares and $580mn in cash. Of this, 18.6mn shares and $50mn will go to Golar, while Stonepeak will receive 12.7mn shares and $530mn. The transaction has an equity value of $2.18bn. The purchase is being supported by New Fortress' parallel acquisition of Golar LNG Partners, which together with general partner Golar owns a fleet of LNG carriers and floating storage and regasification units (FSRUs), for $3.55/unit.

The deal comes four months after Hygo suspended an initial public offering (IPO) of shares following allegations against its former chief executive, Eduardo Antonello, under Brazil's far-reaching Lava Jato corruption probe relating to alleged wrongdoing while Antonello was working for Norwegian contractor Seadrill. Hygo had planned to raise $450mn through the IPO, significantly less than the value of the sale to New Fortress.

The acquisition provides New Fortress with a range of high-quality gas and power assets in Brazil, including a 50pc stake in local firm Celse — the owner of the 1.5GW Porto de Sergipe LNG-to-power complex in the northeast state of Sergipe. The plant is supplied by the 163,000m³ *Golar Nanook* FSRU, which has a 26-year contract with Celse.

Three additional vessels are expected to be deployed to Brazil under the deal, including the *Golar Mazo* LNG carrier, which has been slated for Suape port in Pernambuco. Two other LNG carriers, the *Golar Penguin* and *Golar Celsius*, will be converted to FSRUs and deployed in Brazil, New Fortress says.

New Fortress will also take over a 50pc stake in the 605MW Celba gas-fired plant in Para state, which was awarded 25-year power purchase agreements (PPAs) with nine power distributors in an October 2019 auction. Hygo's other assets include a 15mn m³/d LNG regasification terminal project in Santa Catarina state, which is awaiting final environmental approval to begin construction. Hygo is also building a 100,000 m³/d liquefaction plant at Uruguaiana in Rio Grande do Sul state, which will receive piped gas from Argentina.

New Fortress existing terminals

New Fortress acquired terminals

Purchasing power

In a further indication of New Fortress' ambitions, the company has also announced an initial agreement with leading Brazilian fuel distributor BR Distribuidora and power company CCETC to acquire generators Pecem Energia and Energetica Camacari Muricy 2, along with their 15-year PPAs. BR Distribuidora owns a 45pc stake in the former and 50pc in the latter, with CCETC thought to hold the remainder. New Fortress says it intends to meet the obligations of the PPAs by constructing a 288MW gas-fired power plant in Suape, which is scheduled to begin operating at the end of 2022. And the firm has reached a definitive deal with CH4 Energia to take over its project to install a regasification terminal and a 1.37GW LNG-to-power plant at Suape.

Hygo has an agreement with local firm Zeg to distribute bioLNG from a landfill site in Sao Paulo state. And it is finalising a tender to acquire 5mn m³/d of biogas, which will be transformed into bioLNG using small-scale liquefaction units.

New Fortress has been eyeing Brazil's LNG-to-power market for several years. The company in 2017 agreed with local firm Bolognesi Energia to acquire its 1.3GW Rio Grande gas-fired project and regasification terminal, but the deal fell through.

FREIGHT

Panama congestion may become structural

The sheer size of US production may have outgrown its ability to move across continents, writes Antonio Peciccia

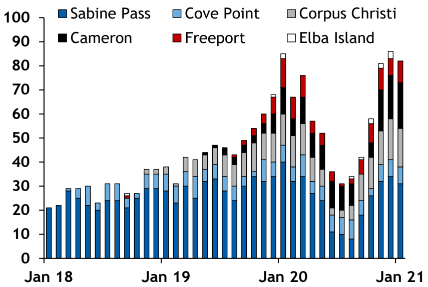
Congestion at the Panama Canal, which has been hampering recent US LNG deliveries to Asia, may be a recurring feature in the market in the coming years.

With the third train of the 15mn t/yr Corpus Christi facility still in the commissioning phase, the US is already producing about three LNG cargoes daily *(see graph)*. But only one LNG carrier a day can take the quickest route through the Panama Canal to typical global premium markets in northeast Asia. The Canal Authority normally allows no more than two LNG carriers a day to transit the waterway, either one in each direction or both heading to the Gulf of Mexico, although it has occasionally allowed extra crossings. When Asian prices are high enough to attract Atlantic basin cargoes, LNG tankers coming from the US may also have to compete with Trinidadian cargoes to secure the limited Panama slots on offer.

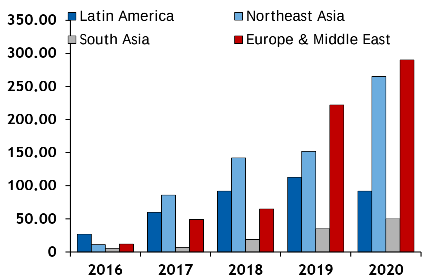
Asia taking a portion of US exports in line with the historical average would already be sufficient to create congestion at Panama. Since the US began exporting LNG, eastern Asia has received on average 35pc of total US production, against 30pc that instead found a buyer in Europe or the Middle East. But while eastern Asian markets absorbed the greatest share of US cargoes in 2017-18, a tighter arbitrage between the two main markets led to Europe taking a larger share in the past two years *(see graph)*. But LNG demand in the two regions is of a fundamentally different nature — with the largest Asian economies relying heavily on seaborne imports, while most European markets buy LNG only when prices are competitive with those of other supply sources.

The limited Panama capacity has already forced a large share of US cargoes to take a longer route to Asia in recent months, either through the Suez Canal or round the Cape of Good Hope. The US sent 265 cargoes to northeast and southeast Asia last year, but only 219 laden vessels from the US crossed Panama, suggesting at least 21pc of US flows to Asia had to take a longer and more expensive route. US deliveries to eastern Asia were 152 in 2019, accounting for 85pc of the 178 Panama crossings by US cargoes. But Asian demand for US cargoes was particularly strong in the fourth quarter of last year, which was likely to have exacerbated congestion and bolstered the use of alternative routes *(see graph).*

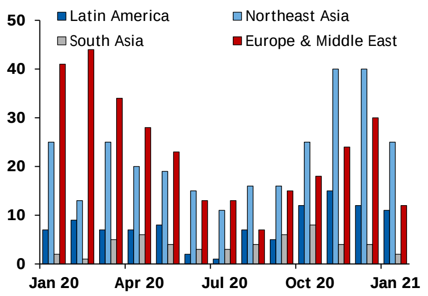
Total US exports ***Cargoes***



US exports by region ***Cargoes***



US exports, by destination ***Cargoes***



Asian demand

A sharp increase in northeast Asian demand, coupled with slower regional production, particularly from Australia, resulted in LNG prices reaching an all-time high in recent weeks. Regional demand continuing to rise at the pace seen in the past few years may increasingly require brisk imports from outside the basin. Northeast Asian demand grew at an average of nearly 7pc/yr over the past five years and the region in 2020 absorbed about 8.2mn t more than a year earlier.

The third 3.8mn t/yr train at the Tangguh facility in Indonesia, expected to start in September this year, is the only new liquefaction facility under construction in the Asia-Pacific basin at present. The addition of the 3.4mn t/yr Coral South FLNG in Mozambique may also be insufficient to dent the regional imbalance, suggesting Asian markets may continue to absorb the vast majority of Qatari supplies, while needing to open an ample premium to European markets to cover the additional costs of US deliveries through Suez or around the Cape of Good Hope.

The 5.4mn t/yr Papua LNG project and planned 2.7mn t/yr third liquefaction train of PNG LNG have yet to reach a final investment decision and are not expected to come on stream before 2024. The 13.1mn t/yr Mozambique LNG project, Mexico's 2.5mn t/yr Energia Costa Azul — which is located on the country's Pacific coast — and the first new train of Qatar's planned Ras Laffan expansion are not expected to be completed before 2024-25.

IN BRIEF

NextDecade drops planned Galveston Bay LNG export terminal

US firm NextDecade has scrapped the planned 16.5mn t/yr Galveston Bay liquefaction facility in Texas as the intended site was deemed "not suitable for development of an LNG facility". The firm informed US energy regulator Ferc of its decision and will withdraw all Ferc pre-filing proceedings, it says. Galveston Bay, which was due to start operations in 2027, is the first large-scale US export facility to be scrapped in recent years. The firm's 27mn t/yr Rio Grande LNG facility is unaffected by the decision on Galveston Bay, it says. Rio Grande is expected to reach a final investment decision this year and start operations in 2023.

Jordan Cove loses bid for permit override

Canada-based Pembina, the developer of the proposed 7.8mn t/yr Jordan Cove LNG export terminal, has failed to persuade US energy regulator Ferc to authorise construction without an approved water permit from Oregon. Ferc voted unanimously against Pembina's claim that Oregon had "waived" its ability to deny that permit by exceeding a one-year deadline. The state's decision nearly two years ago to deny a required water permit to Jordan Cove LNG therefore remains in place, marking a setback for a project that has used its proximity to the Pacific Ocean as a selling point.

Eagle LNG signs preliminary terminal deal with Aruba

US firm Eagle LNG has signed a preliminary agreement with state-owned Refineria di Aruba (RdA) to install an LNG regasification terminal on the Dutch-controlled island. The timing of a final agreement and estimated investment have yet to be determined, but Eagle LNG says it aims to begin construction this summer. LNG will replace heavy fuel oil used for water treatment and power generation in Aruba, with the island also serving as a distribution and bunkering hub for the region, Eagle LNG says. RdA selected Eagle LNG and US consortium Quanten in December to develop the site of a former oil refinery dismantled in 2012. Quanten plans to build a more modern refinery as part of a comprehensive development plan for the island, which may help turn around Aruba's struggling economy at a time when tourism has collapsed because of the Covid-19 pandemic.

Argentina reopens terminal, frees up purchase plans

A federal judge in Argentina has ordered the reopening of the country's sole LNG import terminal after the government warned that failing to do so could jeopardise the procurement of wintertime gas supply. The ruling reversed a 16 October order that had suspended all operations at the Escobar facility, operated by Argentina's state-controlled YPF, as part of a preliminary injunction following the lawsuit of a nearby resident who warned of explosion risks. The analysis of potential dangers at the port must continue even after the closure is lifted, the judge said, ordering the energy secretariat to be involved in the process.

BP starts regasified supplies from Guangdong Dapeng

BP has begun supplying regasified LNG directly to Chinese customers from the 6.7mn t/yr Guangdong Dapeng LNG terminal in Shenzhen under the firm's new terminal use agreement. The company holds 600,000 t/yr of regasification capacity at Guangdong Dapeng and has agreed to supply Chinese independent firms ENN and Foran Energy with 300,000 t/yr each for two years, under two separate contracts signed in 2020. BP, which holds a 30pc stake in Guangdong Dapeng, is the first international company to supply directly to Chinese customers from the terminal.

IN BRIEF

Tokyo Gas wins Bangladesh engineering contract

Japan's largest gas retailer, Tokyo Gas, has secured a feasibility engineering contract from Bangladesh's state-owned Petrobangla to build an onshore LNG import terminal on Matarbari island in Bangladesh. Tokyo Gas Engineering Solutions, a wholly owned subsidiary of Tokyo Gas, and Japanese consultancy firm Nippon Koei were jointly awarded the contract for an undisclosed price. Tokyo Gas aims to expand its overseas business threefold by 2030 and aims to handle 20mn t of LNG domestically and internationally by that time.

German LNG developer extends market test

The developer of Germany's planned 8bn m^3/yr LNG import terminal at Stade has extended the deadline for its ongoing market test to 15 February following requests by interested parties, the operator says. Hanseatic Energy Hub (HEH) on 9 December launched the non-binding phase for the planned terminal's open season, which initially was scheduled to end on 1 February. HEH in early January applied to German energy regulator Bnetza for exemptions from third-party access requirements and tariff regulation. Developers of the other two German LNG terminals — the 7.6mn t/yr Wilhelmshaven and 6.2mn t/yr Brunsbuttel facilities — have also made requests for exemption, with Bnetza having approved the Brunsbuttel application in November.

Bulgartransgaz completes entry to Greek LNG project

Bulgarian system operator Bulgartransgaz has completed its purchase of a 20pc share in Gastrade, which owns the planned 4.2mn t/yr Alexandroupolis LNG terminal in Greece. The completion of the Interconnector Greece-Bulgaria pipeline will allow LNG delivered at Alexandroupolis to also reach Bulgaria, Serbia, Romania and North Macedonia, as well as markets further east, in Moldova and Ukraine. Gastrade expects to reach a final investment decision in March and bring the terminal on line by 2023.

Israel to bolster export capacity to Egypt

Israeli gas grid operator Israel Natural Gas Lines will build additional pipelines to bolster export capacity to Egypt, with partners in the Leviathan and Tamar projects providing the majority of funds. The works, which are expected to be completed by July 2022 and April 2023, respectively, will bolster export capacity from Israel's 623bn m^3 Leviathan and 285bn m^3 Tamar fields. Partners in the two projects have agreed to supply Egyptian firm Dolphinus Holdings with at least 44bn m^3 over eight years, but bottlenecks in the Israeli network prevented flows from reaching the contractual volume. Leviathan and Tamar partners will pay about 56pc of the project cost, estimated at 738mn new Israeli shekels ($227mn).

New carrier deliveries rise in January

A total of 10 newbuild LNG carriers were delivered in January, up from just one a year earlier and the highest in recent years. Quick January deliveries were buoyed by deferrals of the delivery of four of the 10 carriers expected in November-December. Covid-19 caused delays at shipyards throughout 2020, for both newbuilds and carriers already on the water that were scheduled to undergo dry-docking. Newbuild deliveries are set to slow for the rest of the first quarter, with five each scheduled for February and March, none of which were delayed from 2020. But while four of February's slated five newbuilds have at least started their gas trials — with three already completing them — Danish owner Celsius Shipping's *Hull 2313* has yet to start sea trials, suggesting its delivery could also be delayed.

MARKET OVERVIEW

Combined exports from Europe, Africa and the Americas rose to a record 10.1mn t in January

Global LNG exports edge higher in January

Global LNG production crept higher in January compared with December but was broadly unchanged from a year earlier, despite additional US liquefaction capacity.

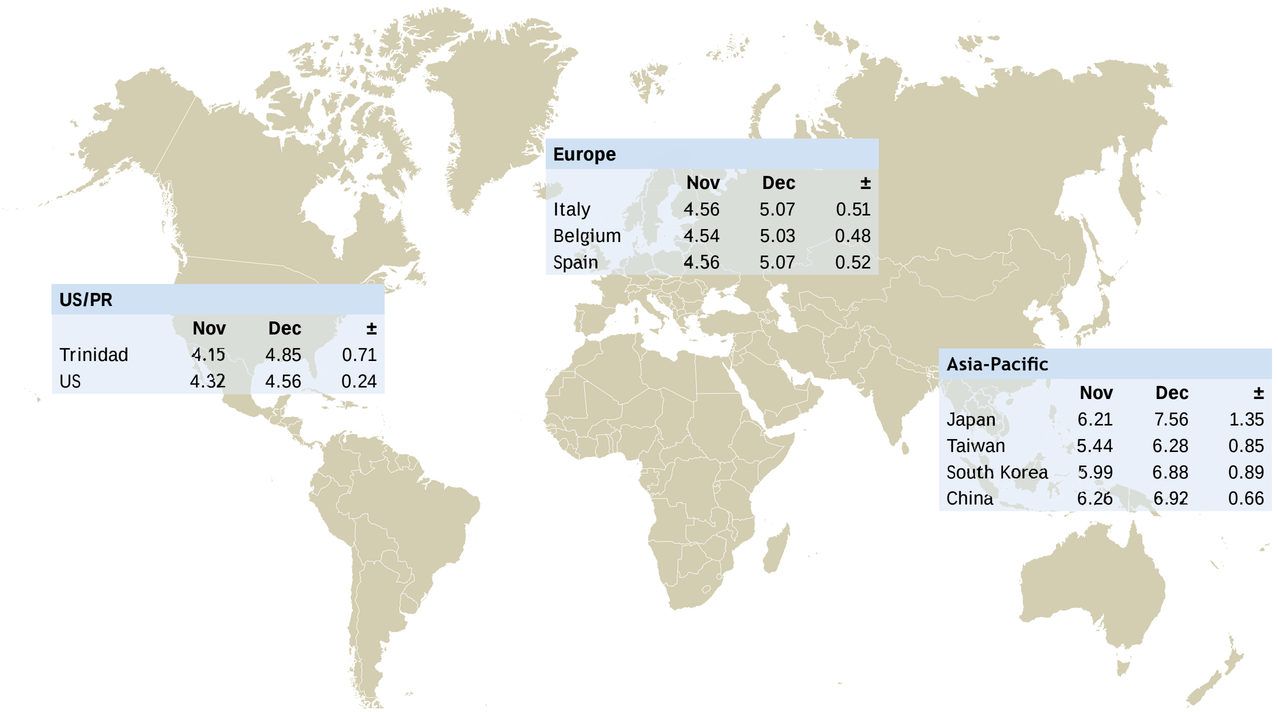
Worldwide aggregate LNG exports totalled 33.9mn t last month, up from 32.7mn t in December but unchanged from a year earlier and short of a previous record of 34.4mn t in December 2019, Vortexa data show. This was despite substantial additions to US liquefaction capacity, which rose to 80.1mn t/yr by the end of 2020 from 52.1mn t/yr a year earlier.

But there was a split between the Atlantic and Pacific basins. Stronger US production bolstered Atlantic basin supply compared with a year earlier, more than offsetting an outage at the 4.2mn t/yr Hammerfest facility in Norway and slower production from Trinidad's 14.8mn t/yr Atlantic LNG complex. Combined exports from Europe, Africa and the Americas rose to a record high 10.1mn t last month, from 9.7mn t a year earlier and 9.89mn t in December.

By contrast, LNG production in the Asia-Pacific basin fell short of previous year's levels, mostly as a result of slower Australian production. LNG exports from Asia, Oceania and the Middle East fell to 20.4mn t last month from 20.6mn t a year earlier, although it was stronger than the 19.3mn t in December. The 3.6mn t/yr Prelude facility in Australia halted production in February last year and only resumed loadings on 8 January, producing just two cargoes last month. And exports from the 15.6mn t/yr Gorgon facility fell to 968,000t last month from 1.4mn t a year earlier, with the facility's first train halting for repairs in early January.

The tighter balance between production in the two basins at a time when Asian demand surged contributed to Asian markets relying more on brisk inter-basin deliveries, which inflated the global price arbitrage and bolstered demand for LNG carriers, as a much larger number of ships were locked into longer journeys.

Global LNG prices at a glance *$/mn Btu*



Europe	Nov	Dec	±
Italy	4.56	5.07	0.51
Belgium	4.54	5.03	0.48
Spain	4.56	5.07	0.52

US/PR	Nov	Dec	±
Trinidad	4.15	4.85	0.71
US	4.32	4.56	0.24

Asia-Pacific	Nov	Dec	±
Japan	6.21	7.56	1.35
Taiwan	5.44	6.28	0.85
South Korea	5.99	6.88	0.89
China	6.26	6.92	0.66

MARKET OVERVIEW

LNG prices													$/mn Btu
Importer/source	**Dec 19**	**Jan 20**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Japan													
Abu Dhabi	8.78	8.11	8.35	8.95	5.97	10.43	6.15	4.03		6.00	8.93	5.20	11.18
Australia	9.43	9.26	9.09	9.28	9.37	10.03	9.57	7.72	6.20	5.56	5.65	6.56	7.14
Brunei	9.88	9.81	9.97	9.27	10.13	10.39	7.04	5.42	5.71	5.24	6.01	6.64	7.05
Indonesia	9.93	9.76	9.70	9.92	10.30	10.73	9.06	6.84	5.33	4.80	5.39	6.03	7.04
Malaysia	8.63	8.82	8.91	8.87	8.04	8.33	7.07	6.07	4.89	4.72	5.70	6.13	6.64
Nigeria	5.75	5.50	5.25	9.75	6.80	7.34	6.17	6.08		5.88	6.85	6.33	
Oman	8.67	9.24	8.98	9.98	9.71	9.41	9.40	9.12	4.96	6.83	7.18	5.99	7.63
Papua New Guinea	9.15	9.30	9.86	9.11	10.51	9.03	8.38	6.57	7.50	5.94	5.78	6.30	6.36
Peru		10.42			6.94		7.10		9.24	2.53	5.64		6.85
Qatar	9.59	9.43	9.64	9.57	9.82	9.77	8.88	6.30	4.82	4.29	5.09	6.13	6.76
Russia	9.07	8.76	9.07	9.41	7.97	9.75	7.92	7.04	4.98	5.46	5.98	6.31	7.11
US	8.86	8.45	8.71	8.65	8.98	8.49	8.70	9.27	9.34	8.08	7.56	6.92	8.15
Average	**9.24**	**9.11**	**9.17**	**9.25**	**9.09**	**9.39**		**6.77**	**5.90**	**5.47**	**6.29**	**6.21**	7.56
LNG Japan spot prices (contracted)	6.40	5.90	3.40	3.40	2.40								
LNG Japan spot prices (arrived)	6.70	6.00	5.50		3.00								
China													
Abu Dhabi		8.37	8.37	9.36	9.44				3.56				
Algeria	8.50					4.01				4.96			
Angola		6.94	6.94	6.17		2.37			7.88	2.93		7.23	7.24
Australia	8.27	8.23	8.23	7.85	8.27	7.42	6.77	7.30	5.17	4.84	5.25	5.82	6.85
Belgium							2.11						
Brunei	8.41	6.73	6.73	5.89	10.18	3.60	2.14	6.98				5.37	5.56
Cameroon	6.61						2.76	3.41	2.20		4.27	8.16	6.90
Equatorial Guinea	10.07	6.65	6.65			2.48							
France										4.30			
Indonesia	8.53	8.44	8.44	6.08	7.61	7.69	6.83	2.99	5.87	5.94	5.01	5.35	5.31
Malaysia	7.08	6.51	6.51	6.08	4.36	5.81	5.14	4.90	4.97	5.04	5.27	5.98	6.20
Netherlands	8.35	14.28	14.28									5.86	7.50
Nigeria	8.54	7.23	7.23	7.24	10.72	5.45	2.45	5.98	4.45	3.34	4.23	5.04	8.35
Oman	7.22	6.56	6.56	3.70	4.88	8.73	4.52		2.35	3.11	5.97	5.15	6.09
Papua New Guinea	9.54	9.56	9.56	9.58	8.93	7.15	6.99	7.18	5.38	5.51	4.60	5.53	6.30
Peru	6.44					6.50	8.41		4.15	6.34		6.37	7.85
Qatar	10.07		10.69	10.96	10.44	8.29	6.13	6.47	4.66	5.76	7.51	6.71	7.14
Russia	6.70	8.05	8.05	6.78	5.02	6.28	5.86	6.95	5.84	5.35	5.50	7.19	7.33
Singapore							8.40						
Trinidad	10.45	6.61	6.61										
US					3.58	6.94	5.54	5.82	7.07	4.83	6.06	7.91	7.59
unspecified	16.02	8.33	8.33										
Average	**8.49**	**8.38**	**8.38**	**7.82**	**7.66**	**6.90**	**5.60**	**6.56**	**5.20**	**5.02**	**5.93**	**6.26**	**6.71**
South Korea													
Abu Dhabi		5.41										6.61	6.55
Angola		7.75		4.46	3.13						4.55	6.98	6.13
Australia	8.13	8.95	8.15	8.99	8.58	7.45	9.49	6.30	5.72	4.88	5.26	6.08	7.35
Brunei				2.87	10.34	6.85		2.28		4.29			
Egypt	6.55	10.18											
Equatorial Guinea					10.44								
Indonesia	8.69	5.81	6.11	6.66	7.36	7.19			4.31	4.65	4.21	5.28	4.89
Malaysia	7.72	7.94	8.33	7.67	8.10	8.66	6.88	6.89	4.67	3.74	4.66	5.17	6.41
Nigeria	8.75					7.43	5.81	5.59				7.60	7.87
Oman	10.17	11.41	9.89	10.73	11.24	11.72	11.38	8.89	5.98	4.65	5.04	6.63	7.75
Papua New Guinea	5.39						70.15	8.70		9.47	4.50		6.70
Peru	9.80	9.62	9.93	9.56	10.74		6.69	6.74		4.05	7.30	7.59	7.86
Qatar	10.45	10.42	10.29	10.82	11.04	11.61	11.10	10.43	7.77	5.70	4.92	5.87	6.60
Russia	8.21	9.60	8.61	7.93	9.79	8.52		7.63	2.42	3.01	4.82	5.63	6.43
US	7.81	7.60	7.13	6.64	7.59	7.05	6.24	6.14	6.45	5.96	6.95	5.99	7.33
unspecified			4.61										
Average	**8.75**	**8.99**	**8.55**	**8.87**	**9.18**	**8.98**	**8.49**	**7.33**	**6.10**	**5.05**	**5.30**	**5.99**	**6.88**

MARKET OVERVIEW

LNG prices													***$/mn Btu***
Importer/source	**Dec 19**	**Jan 20**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Taiwan													
Abu Dhabi								3.30			4.62		4.91
Australia	7.03	8.41	8.39	8.17	8.66	6.25	5.71	6.57	5.12	5.15	5.78	5.88	6.68
Brunei					6.95					2.56			6.49
Egypt	7.87							2.09	2.43	2.88	4.41	6.01	7.07
Indonesia	5.39	10.11			6.64	3.06	2.14	3.88			3.12	6.01	
Malaysia	10.29	10.17	10.03	10.03			3.21	2.16		2.40		3.69	6.91
Nigeria													
Oman		5.53											
Papua New Guinea	10.46	10.32	10.21	6.47	10.54	7.37	10.61	9.25	9.18	5.12	4.68	5.32	6.92
Qatar	6.91	7.14	6.65	7.21	5.90	6.87	5.91	6.32	4.79	4.02	3.85	3.87	4.88
Russia	8.79	9.00	9.47	9.18	9.27	9.47	8.47	5.87	6.08	6.17	8.94	6.53	5.58
Trinidad						5.79					5.28	7.41	7.34
US	7.30	7.35	5.53	10.79	5.57		2.51	2.39			5.04	5.44	6.28
Average	**7.81**	**8.44**	**8.09**	**8.15**	**7.41**	**6.74**	**6.35**	**5.41**	**4.63**	**4.81**	**5.04**	**5.44**	6.28
Thailand													
Australia		8.03	7.98	7.99	8.49	8.75		7.28	5.58	4.14			5.24
Brunei			7.91										
Indonesia		7.81		8.27						4.35			
Malaysia	6.59	7.82		8.06	6.28	6.13	6.06	7.28		3.95	3.97	4.43	
Nigeria				8.05							3.77		5.35
Qatar	10.07	9.74	10.04	10.31	2.99	10.01	9.50	5.64	5.15	4.66	5.58	6.81	7.28
Trinidad	8.38										4.01	5.59	
US				2.80	8.85	8.78	6.81		5.56				5.82
unspecified	8.02			8.26								4.62	
Average	**8.44**	**8.96**	**8.52**	**7.86**					**5.32**	**4.28**	**4.33**	5.36	5.92
India													
Algeria					7.47			6.76	6.13				
Angola	7.17	7.06	5.01	4.82	2.78		4.80	3.99	6.72	3.48	5.25	4.24	
Australia			3.95	6.77		6.20			5.33	7.52	6.39		
Belgium							5.78			6.67	6.36	7.43	
Cameroon	4.78	8.01	6.82			2.89				2.21			
Egypt												9.16	
Equatorial Guinea		5.67	6.05	4.68			2.07				2.45		
France					4.88	8.17	4.14						
Netherlands								10.03					
Nigeria		6.67	7.20	5.01		5.81	6.53	5.29	4.82	5.16	5.14	6.36	
Oman			4.51	6.23	7.09	7.04	3.70		4.06	7.28	4.68	4.56	
Qatar	8.04	7.98	7.86	7.28	6.47	6.18	4.05	4.58	5.29	6.21	6.35	6.13	
Russia				3.34									
Trinidad	7.72			3.24			6.15	8.27	7.86	4.88			
UAE	6.29	13.70	4.56	4.51	3.66	3.19	3.68	2.29	5.37	3.94	5.13	5.18	
US	9.83	7.27	9.09		6.20	6.12	8.65	4.66	6.39	6.37	4.57	5.79	
unspecified	5.22												
Average	**7.67**	**7.67**	**6.12**	**5.10**	**5.61**	**5.29**	**5.15**	**5.42**	**5.77**	**5.37**	**5.15**	**6.11**	
Belgium													
Angola											2.02		
Qatar	4.53	3.76		3.57	2.31	1.65	1.41	1.25	1.42	2.04	3.77		
Russia	3.68	4.37	5.26	5.01	4.06	3.20	1.54	1.19	1.18	2.06			
Average		4.07	5.23	4.24	3.03	3.06	2.53	1.95	1.30			4.50	
Greece													
Algeria	7.97	7.93	8.42	8.81					2.46				
Nigeria						1.94		1.35					
Norway									1.98				
Qatar				2.95	2.77		1.42	1.35	1.82				
US			4.50	3.80	2.61	2.00	1.67	1.35	1.92	2.67	3.07	4.22	

MARKET OVERVIEW

LNG prices													*$/mn Btu*
Importer/source	**Dec 19**	**Jan 20**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Italy													
Algeria	13.40	13.45	13.30	7.53	8.27	3.60	4.44	4.33	4.44	4.50	7.25		
Norway													
Qatar	5.20	5.04	4.71	4.24	3.84	3.52	2.79	2.66	2.01	2.95	3.39		
Trinidad													
US	5.04	4.43	3.10	3.97	4.05	2.07	1.57	1.71	1.78	2.72			
Average	**6.34**	**5.96**	**5.68**	**4.83**	**4.50**	**4.86**	**3.52**	**4.53**	**3.72**	3.43	4.62		
Portugal													
Algeria											4.54	4.70	
Nigeria	6.11	6.45	6.32	6.75	5.98	5.68	5.44	4.70	5.44	4.29	4.15	4.45	
Norway				2.10	2.05								
Other	6.81	6.96	5.32	5.57									
Qatar	5.51			2.59		6.58		6.90	6.57	6.49		4.59	
US	5.88	5.93	6.35	6.75	3.65	1.86	1.50	6.28	6.51	6.42	4.90	4.17	
Spain													
Algeria	6.04	6.01	6.12	6.69	5.78	3.73	5.41	2.59	3.48	3.48	5.22	4.57	
Angola	4.72												
Equatorial Guinea							1.88	3.38	3.09	3.09	4.30	4.31	
Nigeria	5.38	6.40	4.73	4.55	3.89	2.90	3.30	3.12	3.58	3.58	3.82	4.26	
Norway		6.00						2.41	3.84	3.84			
Peru			6.12				3.14						
Qatar	6.02		3.77	5.31	4.85	3.29	2.14	2.28	3.28	3.28	4.06	4.24	
Russia	5.65	3.09	3.79	5.51	5.60	2.39	3.36	3.42	3.37	3.37	4.29	4.52	
Trinidad	4.91	4.87	2.70	5.74	3.45	3.98	4.80	3.20	3.95	3.95	4.20	3.88	
UK		3.91				1.17			3.63	3.63		4.54	
US	6.25	4.29	6.09	4.57	2.85	3.45	3.40	5.31	4.90	4.90	4.84	5.27	
Average	**6.10**	**5.66**	**4.71**	**5.08**	**5.40**	**4.40**	**4.72**	**3.24**	**3.21**	**3.60**	**4.91**	4.45	
UK													
Algeria		4.97										5.35	
Nigeria	4.48	5.13			2.54		1.05					3.70	
Norway	6.55	6.06						0.96			1.92		
Qatar	7.18	3.61	2.65	2.45	2.20	1.87	1.74	0.58	1.03	1.34	2.31	5.05	
Russia	4.66	6.00	3.45	4.02	4.34	2.23	2.02	0.32				5.14	
Trinidad	3.69	4.45	1.19	2.06	0.53	0.41					2.26		
US	4.94	4.70	3.23	4.23	2.65	2.06			1.23			5.05	
Average	**4.96**	**4.86**	**3.22**	**3.19**	**2.45**	**1.64**	**1.60**	**0.62**	**1.13**	**1.34**	**2.16**	4.86	
Brazil													
Nigeria					3.78								
Trinidad					3.03								
US	5.11	4.90	3.38	3.36	2.81	3.46	2.55					2.79	5.27
Average	**5.11**	**4.90**	**3.38**	**3.36**	**3.02**	**3.46**	**2.55**					2.79	4.76
US													
Cove Point													
Nigeria	6.57												
Trinidad	6.57												
Elba Island													
Trinidad													
Everett													
Trinidad	6.64	6.13	5.39	4.13									
US average		**6.13**	**5.39**	**4.13**									
Puerto Rico													
Average	**7.19**	**8.33**	**6.41**	**6.57**									

These numbers are derived from official sources and are subject to change without notice.

LNG MOVEMENTS

Import volumes												*'000t*
Importer/source	**Jan 20**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Japan												
Abu Dhabi	178.38	185.82	122.41	59.55	66.86	117.70	58.79		56.28	60.43	59.49	68.45
Australia	2,759.08	2,173.99	3,121.13	2,384.66	1,811.73	1,756.01	2,712.53	2,165.32	2,576.45	2,275.98	2,562.64	2,803.22
Brunei	458.50	453.41	393.10	268.46	132.67	578.42	200.61	253.92	327.20	322.44	253.70	319.25
Egypt												63.43
Indonesia	300.81	226.92	229.17	60.58	114.10	114.19	232.79	52.08	357.47	55.40	117.04	365.87
Malaysia	1,289.91	981.63	1,116.48	660.53	717.93	727.68	725.43	926.58	714.24	673.64	839.22	1,032.77
Nigeria	112.95	55.01	131.32	125.72	186.37	125.03	116.36		241.52	204.25	60.61	
Oman	191.62	251.59	119.31	304.84	189.27	187.44	183.89	181.74	261.42	191.13	127.72	259.74
Papua New Guinea	282.95	294.47	363.41	229.81	156.03	350.94	219.61	427.47	210.89	360.51	304.49	218.78
Peru	70.73	72.92		63.25	68.16			144.86	59.84	71.40		72.50
Qatar	923.54	876.61	695.70	296.96	403.61	765.74	728.44	822.00	627.39	937.40	626.88	1,030.17
Russia	541.10	597.14	522.49	392.78	323.62	265.95	390.67	594.96	652.18	528.98	580.28	750.26
US	403.04	472.58	394.24	349.06	409.31	206.59	466.63	271.13	419.13	198.61	457.25	674.14
Total	**7,512.61**	**6,642.07**	**7,208.76**	**5,196.20**	**4,579.66**	**5,198.69**	**6,035.74**	**5,840.06**	**6,504.01**	**5,880.17**	**6,018.89**	**7,658.58**
South Korea												
Abu Dhabi	58.71		840.76	596.23							58.70	58.22
Angola	69.72		67.01	62.77						65.78	62.30	58.40
Australia	784.46	838.86		550.29	721.69	491.30	479.30	330.65	850.23	694.18	886.70	551.09
Brunei			58.25	63.99	68.12		64.60		63.93			
Egypt	59.16											
Equatorial Guinea				62.48								
Indonesia	252.39	357.81	252.45	119.08	121.53	321.53	312.42	121.65	195.78	223.41	245.01	193.97
Malaysia	561.85	570.03	489.37	413.71	286.52	284.90	56.40	292.00	419.98	478.61	347.20	747.31
Nigeria					75.95						68.47	71.29
Oman	408.90	414.12	358.02	238.62	237.05	298.85	302.20	239.84	236.89	409.14		352.19
Papua New Guinea						70.15	8.70		75.17	74.25		65.89
Peru	215.02	291.11	217.55	70.70		139.88	71.49		208.87	213.51	59.46	138.32
Qatar	924.85	1,051.10	806.06	809.00	694.92	463.00	356.20	648.79	581.16	930.35	909.43	930.93
Russia	190.19	325.09	251.64	118.85	308.37		128.90	69.79	64.41	183.99	191.16	189.97
US	652.22	850.62	212.24	596.23	394.76	407.22	532.84	197.83	249.27	518.48	352.23	857.16
unspecified		64.17										
Total	**4,177.47**	**4,762.90**	**3,553.34**	**3,701.95**	**2,974.11**	**2,600.42**	**2,378.89**	**1,964.48**	**2,949.49**	**3,852.06**	**3,591.54**	**4,271.30**
China												
Abu Dhabi	29.48	29.48		121.87				58.36				61.74
Algeria					59.29				63.11			
Angola	33.63	33.63	52.42		68.53			75.05	69.76		67.96	128.98
Australia	2,477.83	2,477.83	1,912.44	2,798.05	2,382.47	2,253.46	2,430.64	2,505.97	2,309.03	2,325.42	2,755.33	2,500.91
Belgium						73.61						
Brunei	30.72	30.72	64.78	69.51	126.40	64.47	69.25				64.45	130.66
Cameroon						68.04	67.06	61.79		57.81	70.60	68.02
Egypt			0.02									64.31
Equatorial Guinea	32.26	32.26			74.31							
France									69.61			
Indonesia	424.32	424.32	336.72	497.57	274.36	988.13	114.78	580.06	548.47	308.76	366.20	271.48
Malaysia	446.55	446.55	454.10	379.36	431.65	561.53	655.59	697.31	545.26	524.34	419.40	556.67
Netherlands	0.22	0.22										70.21
Nigeria	201.53	201.53	276.06	10.02	224.32	141.77	353.50	318.71	330.71	198.55	61.01	138.38
Oman	159.73	159.73	62.14	55.94	129.29	63.52		62.32	119.38	8.70	120.68	128.00
Papua New Guinea	187.90	187.90	239.68	304.92	310.22	239.94	302.08	309.65	237.69	238.91	237.89	235.99
Peru	33.61	33.61	63.59	71.39	121.93	262.64		57.69	192.40		152.89	68.42
Qatar	909.74	909.74	520.35	300.55	360.06	266.92	698.56	544.47	570.46	390.85	1,266.77	1,429.00
Russia	430.24	430.24	210.58	269.27	330.21	395.88	201.51	545.48	412.73	684.44	543.78	661.26
Singapore						73.22						
Trinidad	131.60	131.60										
US				218.32	340.23	340.01	141.22	140.35	262.45	283.68	419.05	1,080.22
unspecified	1.32	1.32										
Total	**5,530.68**	**5,530.68**	**4,192.88**	**5,096.77**	**5,233.85**	**5,793.23**	**5,034.20**	**5,957.21**	**5,731.07**	**5,021.48**	**6,610.15**	**7,594.25**

LNG MOVEMENTS

Import volumes												'000t
Importer/source	**Jan 20**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Taiwan												
Abu Dhabi							131.47			58.86		59.12
Australia	277.56	513.40	301.44	295.41	612.92	1,204.63	655.52	301.09	575.67	292.89	500.11	644.66
Brunei				125.47					65.61			
Egypt								62.16				63.10
Indonesia	58.92			60.23	167.42	56.63	56.62	177.54	113.14	173.95	111.28	60.08
Malaysia	122.34	178.85	113.50			63.10	122.95			63.12	111.28	
Nigeria							71.52	194.90			54.30	71.32
Oman	63.48											
Papua New Guinea	158.76	158.06	156.70	157.84	346.57	347.08	172.83	77.31	149.99	158.33	141.62	158.43
Peru	315.32	442.37	442.52	591.29		506.29	382.34	441.89	473.06	437.36	440.77	315.50
Qatar	128.46	193.01	259.90	257.97	260.00	258.00	263.67	265.62	203.01	69.06	129.74	193.13
Total	**1,194.98**	**1,668.13**	**1,347.63**	**1,680.72**	**3,166.57**	**3,628.18**	**3,221.20**	**1,520.51**	**1,650.67**	**1,310.67**	**1,634.44**	**1,749.73**
Thailand												
Australia	70.49	148.56	71.11	212.22	71.27		71.75	69.20	71.59			
Brunei		60.70										
Indonesia	63.03		73.95						71.88			
Malaysia	66.27		128.06	183.57	120.79	191.51	61.58		56.69	179.89	57.46	
Nigeria			67.94							60.32		57.91
Qatar	275.35	185.26	93.13	90.56	183.58	92.47	246.81	183.78	278.32	185.98	187.16	180.48
Trinidad										69.00	59.58	
US			62.77	142.46				57.57				68.97
unspecified			72.32								53.28	
Total	**475.15**	**394.52**	**569.28**	**628.81**	**445.77**	**495.06**	**591.04**	**310.55**	**478.48**	**495.19**	**357.48**	**372.42**
India												
Algeria				56.40			63.50	76.49				
Angola	262.71	263.07	263.07	198.65		264.28	252.54	139.68	200.86	200.40	204.24	
Australia		62.83	92.69		278.31			74.58	62.98	215.66		
Belgium						75.1			71.71	71.09	69.83	
Cameroon	62.15	143.27			66.35				70.63			
Equatorial Guinea	142.88	73.84	146.4			72.75				61.24		
France					68.12	70.61	67.69					
Nigeria	372.78	330.43	262.15		189.63	349.64	281.78	292.79	214.80	276.31	289.49	
Oman		138.66	139.66	75.93	140.34	77.24		144.60	66.81	273.86	135.27	
Qatar	964.05	1,144.90	982.04	456.52	569.86	894.23	1,004.35	817.29	847.23	981.78	611.76	
Russia			66.47									
Trinidad			72.55			72.26	71.71	145.18	139.34			
UAE	92.33	448.40	165.72	253.09	323.62	124.46	248.69	311.54	250.00	469.36	368.02	
US	143.75	66.25		204.69	420.30	147.02	199.30	209.04	207.83	69.87	351.12	
unspecified												
Total	**2,040.65**	**2,671.65**	**2,190.75**	**1,245.28**	**2,056.53**	**2,217.04**	**2,305.59**	**2,211.19**	**2,132.63**	**2,619.57**	**2,082.64**	
Belgium												
Norway							16.99			7.57		
Qatar	57.48		63.63	426.99	244.80	184.49	246.57	181.55	241.64	61.58		
Russia	12.90	300.45	285.15	362.87	129.86	156.28	6.71	2.69	5.42			
Total	**70.38**	**300.45**	**285.15**	**984.65**				**184.24**	**247.06**		61.41	
Greece												
Algeria	65.17	32.87	32.27					29.66				
Norway								61.24				
Qatar			39.42	55.49		91.14	28.23	124.07	503.46	577.51		
US		65.57	90.55	167.42	119.29	8.48		36.07	106.29	99.8	33.88	
Total	**65.17**	**98.44**	**162.24**					**251.04**	**106.29**	**99.80**	33.88	

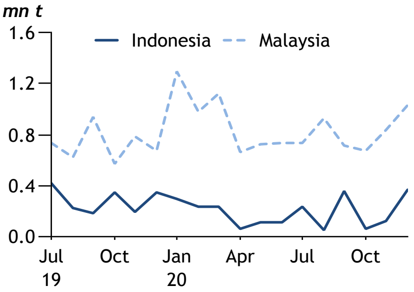
LNG MOVEMENTS

Import volumes												'000t
Importer/source	**Jan 20**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Italy												
Algeria	88.27	88.67	148.83	178.53	336.32	209.19	277.64	277.91	178.98	88.67		
Qatar	324.08	450.68	321.88	452.85	318.50	538.95	543.63	213.92				
Trinidad					57.58							
US	236.28	127.34	260.00	193.53	62.64	189.78	126.51	62.48	126.88			
Total	**648.63**	**807.00**	**791.77**	**916.63**	**876.28**	**1,077.82**	**1,090.73**	**625.21**	**872.54**	**782.28**		
Portugal												
Nigeria	180.47	225.00	224.65	241.53	171.55	197.15	181.76	167.14	233.94	228.75	158.88	
Norway			14.66	6.96								
Other	6.88		18.67									
Qatar			17.23		42.59	57.13	12.55	13.32	13.01		22.87	
US	131.72	106.97	73.42	52.46	15.01	9.91	48.06	45.28	44.34	85.54	43.25	
Total	**319.06**	**355.80**	**349.73**	**358.69**	**271.94**	**282.18**	**303.43**	376.51	377.02	378.42	291.15	
Spain												
Algeria	303.11	113.54	123.15	34.70	34.65	99.10	34.64	106.51	129.08	66.24	66.18	
Angola	69.66											
Equatorial Guinea		66.21	125.46				55.86	64.44	67.27	56.51	62.77	
Nigeria	134.13	65.49	189.73	243.27	432.31	122.89	174.54	248.53	249.65	175.78	191.09	
Norway		62.19			63.10	54.56		61.22	128.50			
Peru			56.86				66.32					
Qatar	253.27		155.98	60.00	60.00	313.83	474.38	336.68	207.36	119.00	59.02	
Russia												
Trinidad	363.06	308.92	88.88	116.02	194.22	124.46	66.04	200.42	89.80	48.46	111.58	
UK		58.75				61.85			67.57		69.08	
US	362.76	653.41	530.78	314.50	411.52	368.97	375.86	66.12	197.02	356.07	199.92	
Total	**1,708.15**	**1,277.62**	**1,356.36**					**1,227.34**	**1,474.04**	**1,105.12**	**1,048.88**	
UK												
Algeria	60.18										32.85	
Australia										433.32		
Nigeria	59.93										68.62	
Norway	61.59	184.50					56.15			56.15		
Qatar	657.75	181.36	754.87	1,027.06	1,027.11	961.99	595.43	296.24	701.95	433.32	90.58	
Trinidad	318.78	114.75	200.74	136.04	53.17					62.40		
US	504.39	399.58	467.58	543.68	124.38			54.68			323.35	
Total	**2,481.77**	**1,224.50**	**1,777.06**	**1,978.94**	**1,481.68**	**1,094.89**	**724.18**	**350.92**	**701.97**	**551.87**	**586.74**	
Brazil												
Nigeria				20.34								
Trinidad				116.90								
US	110.50	41.00	124.80	77.42	115.39	72.50					12.12	124.20
Total		**41.00**	124.80	214.60	167.71	72.50					12.12	192.82
US												
Cove Point												
Trinidad												
Nigeria												
Everett												
Trinidad	106.22	110.93	55.70									
Puerto Rico												
Norway			1.50									
Trinidad	31.50	86.70	30.30									
Total	**31.50**	**86.70**	**31.80**									

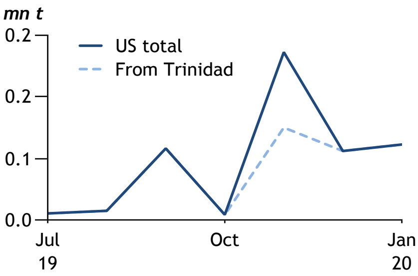
These numbers are derived from official sources and are subject to change without notice.

LNG MOVEMENTS

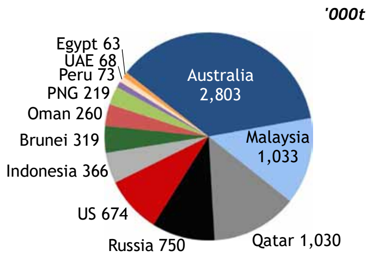
Japanese imports



US imports



Japan LNG import sources



Global deliveries fall in January

Global LNG deliveries fell in January despite a sharp increase in northeast Asian demand, with slow regional production requiring a substantial redirection of flows from the Atlantic basin.

Combined worldwide deliveries totalled 32.3mn t in January, down from 34.5mn t a year earlier and 33.6mn t in December, data from oil analytics firm Vortexa show, with a drop in European and south Asian receipts more than offsetting the rise in Chinese and Japanese imports.

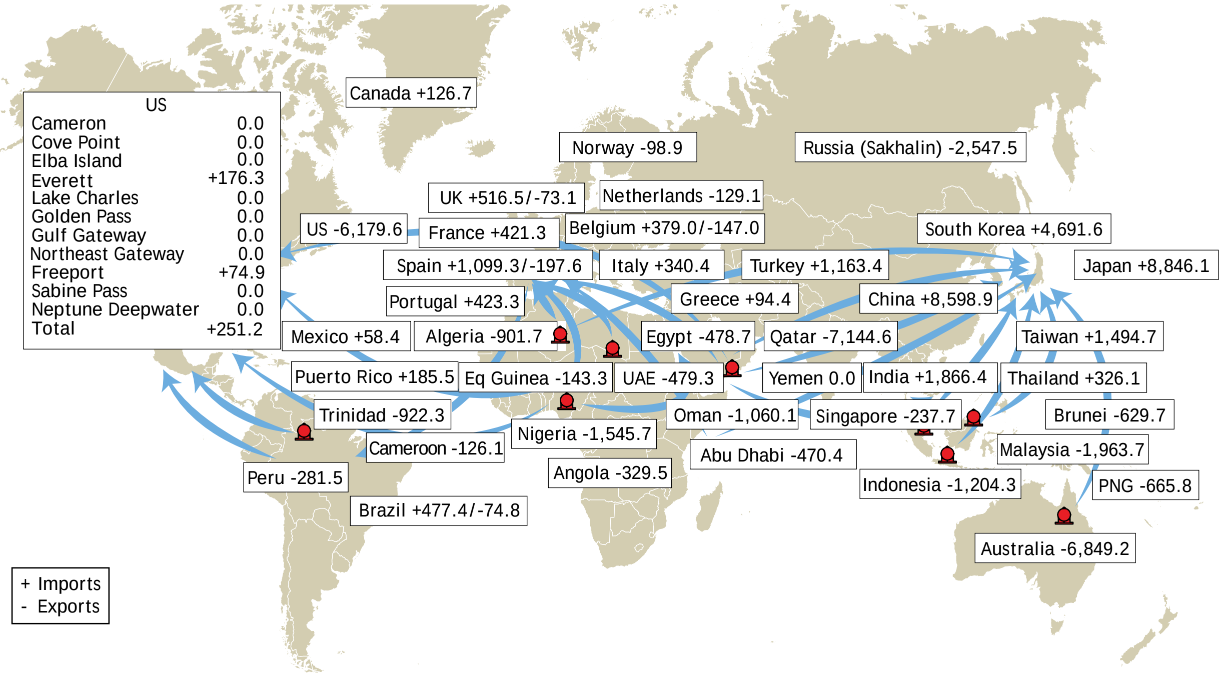
Northeast Asian imports rose to 22.9mn t from 20.2mn t a year earlier and 22.1mn t in December, driven by strong demand from the two largest importers. Chinese demand hit a record 8.6mn t, up by 38pc from 6.24mn t in January 2020, with recent additions to the country's regasification capacity providing scope for a large increase in receipts. And Japanese receipts rose to 8.44mn t from 7.84mn t, as cold weather bolstered heating demand and rapidly depleted the country's LNG stocks, which fell below 1mn t on 10 January. South Korean demand fell slightly short of its January 2020 levels, suggesting higher nuclear availability enabled the country to cope with stronger heating demand without the need to bolster gas-fired generation, despite the government's restrictions on coal-fired generation.

The sharp increase in Chinese and Japanese demand drew supply away from other markets, particularly as supply in the Asia-Pacific basin was not sufficient to meet the additional requirements. Total LNG loadings at facilities in the Asia-Pacific basin were lower than a year earlier in December and January, which likely forced China and Japan to source more cargoes from outside the basin. South Asian demand fell to 2.67mn t from 3.23mn t, driven mainly by slower deliveries to India. But most of the supply reaching northeast Asia appeared to have been redirected from European markets, with total deliveries to the region nearly halving to 4.58mn t last month from 8.92mn t a year earlier.

An increasing number of cargoes originally intended for delivery to Europe were cancelled throughout the fourth quarter of last year as northeast Asian prices continued to expand their premium to European hubs.

Latest estimated gas imports and exports

'000 t/month



EUROPE MARKET WRAP

Europe's LNG cancellations deepen in January

A surge in northeast Asian LNG prices in January drew Atlantic basin cargoes away from Europe, prompting extensive cancellations and contributing to an exceptionally strong call on Europe's conventional storage reserves.

A total of 5.24mn m³ was removed from the January schedules at French, Spanish, Croatian and Greek LNG terminals. France accounted for a 57pc share of the cancellations, with sendout slumping as a result, particularly in the second half of that month. And in Spain, system operator Enagas revised down deliveries by 1.59mn m³ from the opening schedule in late November to 2.34mn m³.

While UK terminals do not release monthly schedules, two cargoes were diverted away from the 14.8mn t/yr Isle of Grain mid-journey, having been rerouted to Portugal's 4mn t/yr Sines terminal.

Reloads were arranged at the Netherlands' 8.7mn t/yr Gate terminal, which received three cargoes and sent two re-exports to northeast Asia. Re-exports at Belgium's 7.2mn t/yr Zeebrugge terminal outnumbered deliveries last month.

With temperatures across northern Europe well below seasonal norms for much of last month, the region made a record draw on storage. The EU and UK together pulled 251TWh from inventories in January, topping the previous peak of nearly 250TWh in January 2017.

The exceptional call on storage led to a reconfiguration of prices along the forward curve at the Dutch TTF and UK NBP. Back in the summer, the prospect of a storage overhang being rolled from this winter into the winter 2021-22 market kept the TTF summer 2021 market at a discount to the summer 2022 contract. But as positions have been adjusted to take into account the call on storage, the summer 2021 market has moved to a premium to summer 2022 supply.

Argus European long-term contract prices *€/MWh*

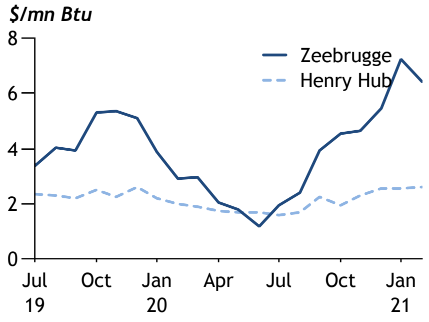
Delivery month	Apr 20	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21	Feb*	Mar*	Apr*
Oil index	24.39	22.53	20.20	18.09	16.29	14.69	13.67	13.81	14.54	15.21	15.62	16.14	16.76
+5pc discount	23.17	21.40	19.19	17.18	15.48	13.96	12.99	13.12	13.81	14.45	14.84	15.34	15.92
+7.5pc discount	22.56	20.84	18.68	16.73	15.07	13.59	12.65	12.77	13.45	14.07	14.45	14.93	15.50
+10pc discount	21.95	20.27	18.18	16.28	14.66	13.22	12.30	12.43	13.09	13.69	14.06	14.53	15.08
+12.5pc discount	21.34	19.71	17.67	15.82	14.26	12.86	11.96	12.08	12.72	13.31	13.67	14.13	14.66
+15pc discount	20.73	19.15	17.17	15.37	13.85	12.49	11.62	11.74	12.36	12.93	13.28	13.72	14.24
+20pc discount	19.51	18.02	16.16	14.47	13.04	11.76	10.94	11.05	11.63	12.17	12.50	12.92	13.41
TTF													
Oil index 90pc + 10pc TTF	22.78	20.93	18.66	16.81	15.20	14.03	13.44	13.84	14.48	15.31	16.01	16.43	16.78
Oil index 80pc + 20pc TTF	21.18	19.34	17.13	15.53	14.10	13.37	13.21	13.88	14.42	15.42	16.40	16.71	16.81
Oil index 70pc + 30pc TTF	19.57	17.74	15.59	14.25	13.00	12.70	12.98	13.91	14.36	15.52	16.79	16.99	16.84
Oil index 60pc + 40pc TTF	17.96	16.15	14.06	12.97	11.90	12.04	12.75	13.94	14.30	15.63	17.18	17.28	16.86
Oil index 50pc + 50pc TTF	16.36	14.55	12.52	11.69	10.80	11.37	12.52	13.98	14.24	15.73	17.57	17.56	16.89
NCG													
Oil index 90pc + 10pc NCG	22.82	20.97	18.70	16.81	15.20	14.03	13.43	13.84	14.46	15.28	15.94	16.37	16.82
Oil index 80pc + 20pc NCG	21.25	19.42	17.20	15.54	14.11	13.37	13.18	13.86	14.39	15.35	16.25	16.61	16.88
Oil index 70pc + 30pc NCG	19.69	17.87	15.70	14.27	13.02	12.70	12.93	13.89	14.31	15.42	16.57	16.84	16.94
Oil index 60pc + 40pc NCG	18.12	16.32	14.20	13.00	11.93	12.04	12.69	13.92	14.23	15.49	16.89	17.07	17.01
Oil index 50pc + 50pc NCG	16.55	14.77	12.70	11.73	10.84	11.37	12.44	13.95	14.16	15.56	17.20	17.30	17.07
VTP													
Oil index 90pc + 10pc VTP	22.87	21.05	18.78	16.87	15.30	14.13	13.45	13.79	14.42	15.22	15.88	16.32	
Oil index 80pc + 20pc VTP	21.35	19.58	17.36	15.66	14.31	13.57	13.24	13.77	14.29	15.23	16.15	16.49	
Oil index 70pc + 30pc VTP	19.83	18.10	15.94	14.45	13.32	13.01	13.02	13.76	14.17	15.24	16.41	16.66	
Oil index 60pc + 40pc VTP	18.31	16.63	14.52	13.24	12.33	12.44	12.81	13.74	14.05	15.26	16.67	16.84	
Oil index 50pc + 50pc VTP	16.79	15.16	13.10	12.03	11.34	11.88	12.59	13.72	13.93	15.27	16.93	17.01	

**provisional*

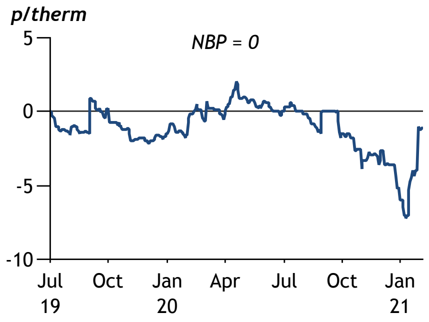
Please see the methodology for the Argus European Natural Gas Report at www.argusmedia.com/en/methodology

US MARKET WRAP

Henry Hub vs Zeebrugge



Zeebrugge front month vs NBP



US energy demand recovery years away: EIA

The US is unlikely to return to pre-pandemic energy consumption levels until 2029, under a new baseline scenario published by the US Energy Information Administration (EIA).

Total energy consumption in the US last year fell by nearly 8pc from 2019, as measures to contain Covid-19 resulted in reductions in air travel, commuting and other economic activities. This energy demand shock is set to have a lasting impact, and the pace of economic recovery will determine when the US recovers to its pre-pandemic level of energy consumption, the EIA said. This milestone will occur as soon as 2024 under the agency's high economic growth scenario, or as late as 2050 under a scenario with lower-than-expected economic growth.

US electricity demand is expected to recover by 2025, the agency said. Renewable energy is expected to account for nearly 60pc of new generating capacity over the next three decades, doubling its market share by 2050. The share of the electricity market held by nuclear and coal are both expected to drop by half, while natural gas will be little changed at 36pc. Because of gains in energy efficiency and renewable energy, EIA expects energy-related carbon emissions in most scenarios will decline through 2035 and then start to increase.

US gas in underground storage *bn ft³*

Region	29-Jan	25-Dec	±	Year ago	Five-year av.	± % 5-yr ave
East	582	810	-228	609	562	3.6
Midwest	719	973	-254	735	670	7.3
Mountain	158	204	-46	138	140	12.9
Pacific	261	289	-28	210	218	19.7
South Central	970	1183	-213	956	901	7.7
Total	**2,690**	**3,459**	**-769**	**2,648**	**2,491**	**8.0**

Spot market natural gas prices (pipeline)

	Jan 20	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21
Europe *p/th*													
UK NBP, 1st month	28.76	22.25	21.61	14.94	11.57	13.36	13.78	22.16	30.25	39.88	39.62	47.36	59.08
UK NBP, 2nd month	28.04	21.77	21.30	15.89	12.28	14.12	15.87	24.67	36.18	42.07	40.79	48.18	54.42
UK NBP, 3rd month	27.42	22.40	21.74	17.13	14.02	16.82	19.94	33.12	39.73	43.24	41.04	44.67	47.36
ICE, 1st month	28.71	22.16	21.70	15.00	11.57	13.36	13.90	22.21	30.37	39.99	39.66	47.42	58.98
ICE, 2nd month	28.02	21.74	21.45	15.98	12.31	14.21	16.03	24.99	36.30	42.13	40.79	48.07	54.11
ICE, 3rd month	27.41	22.41	21.89	17.20	14.14	17.00	20.38	33.24	39.84	43.29	40.89	44.49	47.18
Europe *€/MWh*													
UK NBP, 1st month	11.03	8.96	8.28	6.21	4.69	5.16	5.28	8.12	11.27	14.29	13.90	16.44	20.50
UK NBP, 2nd month	10.94	9.02	8.24	6.52	4.87	5.41	5.91	9.40	13.04	14.91	13.99	16.70	19.62
UK NBP, 3rd month	11.01	9.20	8.46	6.81	5.41	6.34	7.43	12.16	14.37	14.41	14.05	16.38	18.31
ICE, 1st month	11.13	9.08	8.32	6.58	4.84	5.30	5.31	8.06	11.37	14.15	13.93	16.25	20.37
ICE, 2nd month	11.10	9.25	8.37	6.91	5.29	5.65	6.05	9.53	13.01	14.44	14.14	16.28	19.59
ICE, 3rd month	11.05	9.46	8.49	7.21	5.76	6.29	7.86	11.98	13.63	14.59	14.19	15.88	17.23
US *$/mn Btu*													
Henry Hub, 1st month	2.16	1.88	1.82	1.63	1.80	1.72	1.50	1.86	2.59	2.11	3.01	2.85	2.48
NY (Transco Zone 6)	2.10	1.88	1.49	1.54	1.39	1.47	1.70	1.55	1.26	1.32	1.52	2.82	3.12
Columbia TCO	1.74	1.66	1.47	1.56	1.53	1.42	1.56	1.69	1.41	1.55	1.67	2.21	2.43
SoCal border	2.18	1.87	1.54	1.42	1.68	1.62	1.79	3.37	2.30	2.79	2.97	3.31	2.85
Nymex, 1st month	2.31	2.06	1.86	1.74	1.74	1.82	1.71	1.76	2.26	2.29	2.77	2.92	2.62
Nymex, 2nd month	2.73	2.30	2.04	1.88	1.78	1.87	2.02	1.80	1.81	2.40	2.80	3.20	3.05

Please see the methodology for the Argus European Natural Gas report and the Argus Natural Gas Americas report at www.argusmedia.com/en/methodology

COMPETING FUELS

Crude													$/bl
	Jan 20	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21
Japanese Crude Cocktail	70.33	70.63	62.16	42.21	24.96	24.56	32.78	43.45	46.25	44.54	42.31	na	na
Tapis	71.42	62.67	35.38	17.91	26.40	40.78	45.62	46.30	39.48	39.15	42.54	50.88	55.98
Dubai (1st month) London close	63.68	54.22	32.86	21.18	31.18	40.67	43.19	43.94	41.23	40.58	43.51	49.75	54.84
North Sea dated	63.38	55.45	31.71	18.57	29.00	40.08	43.27	44.78	40.58	40.01	42.54	49.72	54.73
WTI (1st month)	57.52	50.53	29.89	16.52	28.57	38.30	40.76	42.36	39.60	39.53	41.10	47.05	52.10

Please see the methodology for the Argus Crude report at www.argusmedia.com/en/methodology

International fuel oil prices													$/t
	Jan 20	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21
HSFO 180 fob South Korea	341.30	307.13	210.63	159.25	180.61	245.25	260.81	278.85	262.38	272.42	287.95	312.02	337.24
HSFO 180 fob Singapore	330.30	296.13	199.63	148.25	169.61	234.25	249.81	267.85	251.38	261.42	276.95	301.02	326.24
LSWR fob Indonesia*	448.39	422.62	302.06	203.23	221.16	276.72	324.00	324.47	305.99	315.42	337.98	376.62	424.80
1pc fuel oil fob NWE	445.70	360.86	201.85	152.41	176.05	239.11	260.13	273.50	254.55	269.63	290.31	322.15	357.31
1pc fuel oil fob W Med	458.65	376.38	213.65	162.61	184.17	245.52	266.73	279.43	259.56	276.91	295.48	324.83	361.29
New York 1pc	464.20	373.70	211.20	164.93	173.38	231.17	262.21	287.36	274.24	282.37	300.48	333.64	361.22

**LSWR fob Indonesia changed to 0.45pc sulphur specification with price in $/t from 31 July. Prices before this date are for 0.35pc LSWR*

Please see the methodology for the Argus European Products, Argus Asia-Pacific Products and Argus US Products reports at www.argusmedia.com/en/methodology

International gasoil prices													$/t
	Jan 20	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21
C+F Japan	581.06	495.12	344.13	229.10	274.01	359.42	384.41	365.02	327.42	331.07	358.38	418.21	449.32
Fob South Korea	559.95	480.13	328.31	221.49	253.57	338.91	367.63	358.98	321.08	323.17	350.92	408.66	441.48
German heating oil	562.03	491.93	344.06	245.73	252.82	330.90	363.49	364.56	319.23	328.51	351.30	409.16	445.00
Heating oil fob W Med	551.59	482.06	329.67	199.28	226.86	325.86	360.92	359.21	314.72	325.89	349.52	408.94	441.49
No 2 oil New York	535.10	472.15	327.53	207.57	210.36	310.63	345.62	353.82	314.65	327.60	356.61	412.01	446.54

Please see the methodology for the Argus European Products, Argus Asia-Pacific Products and Argus US Products reports at www.argusmedia.com/en/methodology

International electricity prices													€/MWh
	Jan 20	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21
France month-ahead	40.02	32.75	23.84	17.82	22.96	31.38	33.81	39.54	45.20	47.01	42.55	57.40	62.74
Spain month-ahead	41.48	34.77	28.13	23.59	26.82	32.74	35.44	38.93	43.08	42.37	41.65	51.48	56.20
PJM West (off peak)($/MWh)	20.89	17.24	15.47	14.98	14.06	12.91	15.60	15.44	14.37	16.70	18.71	22.60	23.39
Entergy (off-peak)($/MWh)	16.69	17.82	15.62	14.89	14.48	12.99	14.51	16.55	14.85	19.45	21.52	21.53	21.93

Please see the methodology for the Argus European Electricity report at www.argusmedia.com/en/methodology

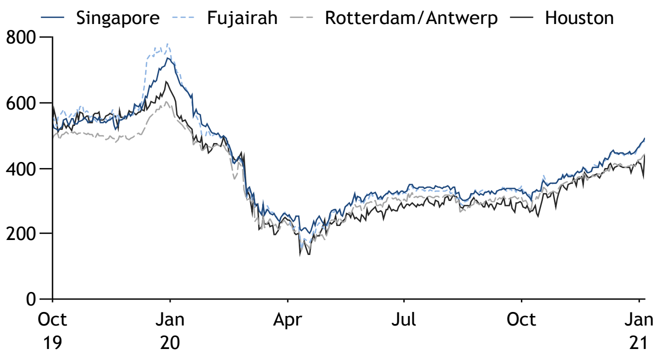
International coal prices													$/t
	Jan 20	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan 21
Japan	83.07	78.85	75.80	68.94	58.67	60.21	58.33	58.47	60.41	64.82	69.43	87.67	98.16
South Korea	75.60	74.77	72.61	66.75	58.49	59.69	57.97	57.97	58.91	62.38	65.30	82.22	94.82
Indonesia	68.78	69.09	67.88	63.24	56.10	55.15	53.44	53.06	52.88	56.79	58.90	74.73	86.99
ARA	50.19	48.27	48.16	42.98	38.67	46.00	49.85	49.02	53.01	56.22	54.13	66.72	67.49
Nymex spec Q1	51.50	51.00	46.45	46.20	43.50	38.00	39.00	41.44	43.95	46.65	48.93	#N/A	50.73

Please see the methodology for the Argus Coal Daily and Argus Coal Daily International reports at www.argusmedia.com/en/methodology

International shipping fuel prices						$/t
	Aug	Sep	Oct	Nov	Dec	Jan 21
Singapore 380cst	339.84	319.87	329.06	350.43	#N/A	438.89
Fujairah 380cst	330.63	315.70	331.26	352.45	#N/A	437.08
Rotterdam/Antwerp 380cst	294.76	293.52	285.64	304.50	363.73	399.84
Houston 380cst	311.69	291.47	303.35	326.71	366.99	401.34

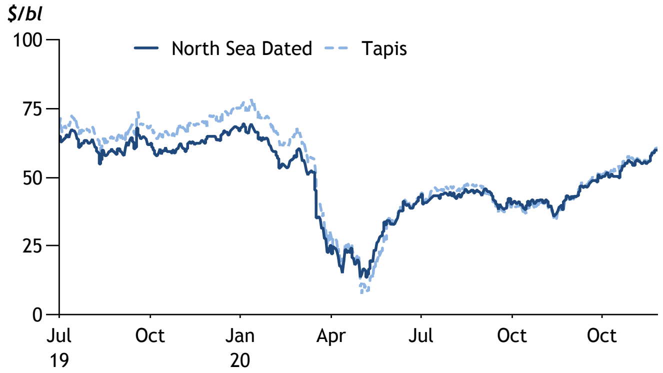
Please see the methodology for the Argus Marine Fuels report at www.argusmedia.com/en/methodology

Key shipping fuel prices **$/t**



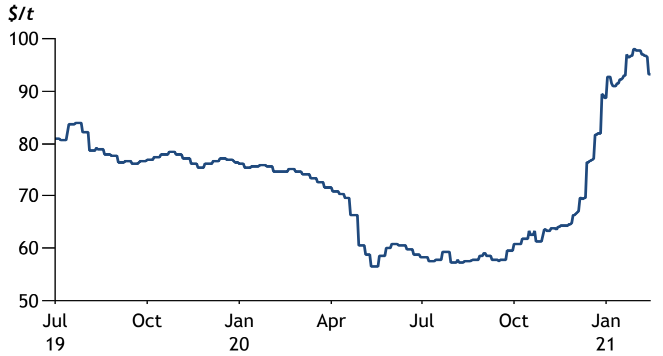
COMPETING FUELS

North Sea Dated vs Tapis

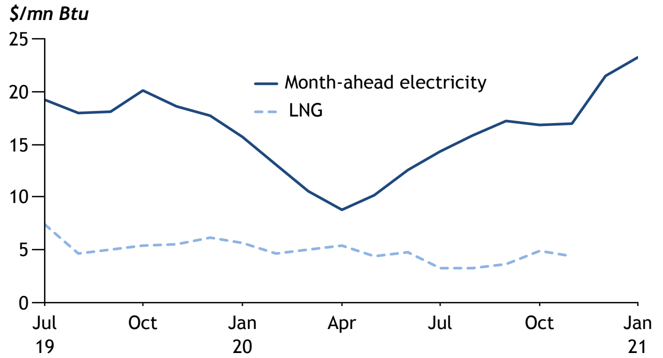


180cst fuel oil fob Singapore

Coal cif South Korea



Spain: Month-ahead electricity vs LNG



Crude prices push higher

Prices for Atlantic basin benchmark North Sea Dated and US marker WTI rose in January. Prices were supported by renewed Opec production caps, including Saudi Arabia's voluntary additional 1mn b/d cut. Russia and Kazakhstan were resistant to the caps, and production quotas for these two countries instead will rise by 75,000 b/d in February and March, while ceilings for all other members will remain flat. But price gains were capped by continued concerns regarding the impact that Covid-19 will have on demand throughout 2021. North Sea Dated rose by $5.07/bl across the month to end January at $55.05/bl.

Exports lift MGO, fuel oil margins

European products margins diverged in January. Eurobob oxy gasoline gained $2.44/bl to a $3.49/bl average premium to North Sea Dated, driven higher by a gasoline rally in the US. But fresh lockdowns across Europe pressured diesel cargoes 26¢/bl lower, to a $5.82/bl premium to Dated. Rising export demand saw very-low sulphur fuel oil margins gain 87¢/bl to a $6.89/bl premium to Ice Brent in January. A similar picture emerged in the marine gasoil (MGO) market, where outright prices on a fob ARA basis gained about 9pc on the month, to $447.91/t in January.

Coal prices firm on colder weather

European physical coal prices edged higher in January, supported by firm power demand and reduced spot availability for Russian coal. *Argus*' cif ARA NAR 6,000 kcal/kg coal assessment increased by $1.26/t on the month to $67.49/t. Low wind output and a cold snap drove European coal burn 3pc higher on the year in January, despite Covid-19-related lockdown restrictions, with cold weather and limited LNG supply maintaining high demand for the solid fuel in February. Strong demand for Russian coal from the cement industry in the wider Mediterranean region also supported prices in the European market.

Demand, low wind boost gas generation

Gas-fired generation in central-western Europe and the UK rose from a month and a year earlier in January amid strong demand and low wind output. Combined gas burn in Germany, Belgium, the Netherlands, France and the UK rose to 37.0GW last month from 35.1GW in December, its highest since at least 2018. Conversely, total onshore wind output in the same area fell to 21.2GW from 21.9GW in December and 27.7GW in January 2020. Cold weather boosted demand, with UK and French grid operators issuing margin notices because of tightness in the electricity system.

SHIPPING

Spot charter rates fall back from mid-January highs

Spot LNG charter rates declined throughout the second half of January after rising to record highs earlier that month, as demand for tonnage slid amid an easing of tight vessel availability.

Rates for tri-fuel diesel-electric (TFDE) carriers fixed west of Suez were at \$120,000/d on 1 February, down from \$156,000/d on 4 January and a mid-month high of \$255,000/d on 8-14 January. The corresponding east of Suez TFDE rate also rose sharply through early January before falling back in the second half of that month, although it remained at an ample premium to Atlantic rates.

LNG production in the Asia-Pacific basin failed to keep up in recent weeks with rapidly rising demand from the world's two largest markets, China and Japan, and this pushed LNG delivered prices in the region to unprecedented highs and required brisk deliveries from outside the basin. This boosted tonnage demand for long-range deliveries, leading to exceptionally tight vessel availability, particularly in the Atlantic basin, with some offtakers struggling to secure carriers to load their cargoes, regardless of the cost.

But as Asian prices fell in the second half of January, demand for tonnage in the Atlantic also eased. Some Atlantic basin cargoes were redirected towards Europe, leaving a number of charterers with surplus shipping capacity that was offered for sub-charters on a spot basis. Firms willing to reduce offers to secure employment for these vessels accelerated the decline in charter rates.

Netbacks for 138,000m³ tanker Jan

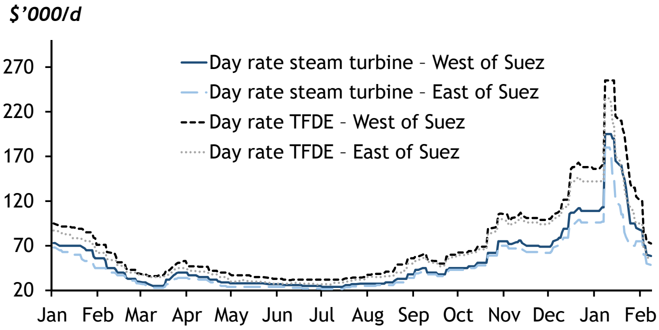
	Sailing days, one-way	Bunker fuel \$	Manning \$	Insurance \$	Repairs & maintenance \$	Stores and lubes \$	Capital costs \$	Total shipping and storage \$	Gas delivered, minus boil-off '000m³	Delivered value of cargo \$	Transport and regas costs \$/mn Btu	Delivered price \$/mn Btu	Reporting month	Netback \$/mn Btu
Qatar-Japan	14	1,477,680	129,115	72,261	10,602	24,955	803,786	2,518,399	125,320	18,468,231	0.94	6.76	Dec 20	5.82
Qatar-S Korea	15	1,551,338	134,946	75,524	11,081	26,082	840,086	2,639,057	125,174	18,010,039	0.99	6.60	Dec 20	5.61
Qatar-Spain	11	1,183,048	105,791	59,207	8,687	20,447	658,586	2,035,766	125,906	11,637,780	0.76	4.24	Nov 20	3.48
Abu Dhabi-Japan	14	1,477,680	129,115	72,261	10,602	24,955	803,786	2,518,399	125,320	30,543,614	0.94	11.18	Dec 20	10.24
Qatar-Belgium	3	355,966	40,817	22,844	3,352	7,889	254,100	684,968	127,539	10,481,883	0.25	3.77	Oct 20	3.52
Algeria-S Korea	20	2,072,752	179,095	100,233	14,706	34,615	1,114,929	3,516,329	124,065	22,772,875	1.32	8.42	May 17	7.10
Algeria-Spain	1	87,072	19,159	10,723	1,573	3,703	119,271	241,502	128,083	12,760,357	0.09	4.57	Nov 20	4.48
Algeria-US	11	1,131,622	103,292	57,809	8,482	19,964	643,029	1,964,197	125,969	11,341,509	0.73	4.13	Mar 20	3.40
Australia-Japan	8	853,046	78,302	43,823	6,430	15,134	487,457	1,484,192	126,597	19,705,065	0.55	7.14	Dec 20	6.59
Australia-S Korea	8	917,531	83,300	46,620	6,840	16,100	518,571	1,588,963	126,471	20,264,508	0.59	7.35	Dec 20	6.76
Brunei-Japan	5	530,621	53,312	29,837	4,378	10,304	331,886	960,337	127,225	19,553,160	0.35	7.05	Dec 20	6.70
Brunei-S Korea	6	616,601	59,976	33,566	4,925	11,592	373,371	1,100,031	127,057	11,882,650	0.40	4.29	Sep 20	3.89
Indonesia-Japan	7	777,813	72,471	40,559	5,951	14,007	451,157	1,361,959	126,743	19,451,563	0.50	7.04	Dec 20	6.54
Indonesia-S Korea	7	745,571	69,972	39,161	5,746	13,524	435,600	1,309,573	126,806	13,517,792	0.48	4.89	Dec 20	4.41
Malaysia-S Korea	5	509,125	51,646	28,904	4,241	9,982	321,514	925,413	127,267	17,783,970	0.34	6.41	Dec 20	6.07
Nigeria-Spain	8	873,070	82,467	46,154	6,772	15,939	513,386	1,537,787	126,492	11,747,087	0.57	4.26	Nov 20	3.69
Oman-Japan	13	1,372,454	120,785	67,599	9,918	23,345	751,929	2,346,030	125,530	20,879,865	0.87	7.63	Dec 20	6.76
Oman-S Korea	12	1,319,842	116,620	65,268	9,576	22,540	726,000	2,259,846	125,634	21,225,928	0.84	7.75	Dec 20	6.91
Oman-Spain	12	1,298,796	114,954	64,336	9,439	22,218	715,629	2,225,372	125,676	12,191,851	0.83	4.45	Nov 20	3.62
Oman-US	9	983,120	89,964	50,350	7,387	17,388	560,057	1,708,266	126,304	11,371,652	0.63	4.13	Mar 20	3.50
Trinidad-US	5	490,234	52,479	29,371	4,309	10,143	326,700	913,236	127,246	11,456,430	0.34	4.13	Mar 20	3.79
USGC-Japan	20	2,028,912	179,095	100,233	14,706	34,615	1,114,929	3,472,489	124,065	22,042,629	1.31	8.15	Dec 20	6.84
Algeria-UK	4	418,019	45,815	25,641	3,762	8,855	285,214	787,306	127,413	14,860,178	0.29	5.35	Nov 20	5.06
Nigeria-India	15	1,555,648	137,445	76,923	11,286	26,565	855,643	2,663,510	125,111	17,346,425	0.99	6.36	Nov 20	5.37
Qatar-India	3	320,198	37,485	20,979	3,078	7,245	233,357	622,343	127,622	17,054,672	0.23	6.13	Nov 20	5.90

SHIPPING

LNG vessel fleet, May					
		Age of fleet			Total cap.
Owner	No	Av	Min	Max	m³
Teekay	29	8	1	27	4,602,900
Maran Gas Maritime	26	4	1	7	4,370,925
Nakilat	25	11	10	12	6,055,700
GasLog	24	7	1	14	3,870,600
MISC	22	19	11	39	3,098,900
Mol	17	5	1	16	2,901,447
BW	16	11	1	17	2,467,100
BGT Ltd	13	11	4	18	2,029,000
Dynagas	12	7	1	13	1,771,970
Knutsen OAS	12	9	1	16	1,957,600
NYK	12	10	1	14	1,894,600
BP	10	6	1	13	1,662,800
Golar LNG	10	7	5	17	1,594,000
J4 Consortium	10	22	16	24	1,374,100
SK Shipping	10	14	1	26	1,525,900
Golar LNG Partners	9	20	6	43	1,281,003
Hoegh	9	5	1	14	1,508,332
Hyundai LNG Shipping	9	17	3	26	1,288,200
Excelerate Energy	8	12	6	15	1,191,000
National Gas Shipping Co	8	25	23	26	1,082,300
NYK, K Line, Mol, Iino, Mitsui, Nakilat	8	12	12	12	1,704,200
Sovcomflot	7	4	2	6	1,198,000
Chevron	6	5	3	6	960,000
Flex LNG	6	2	1	2	1,041,600
Korea Line	6	12	3	20	921,400
Maran Gas Maritime, Nakilat	6	12	2	15	902,000
Shell	6	15	10	18	886,200
Brunei Gas Carriers	5	9	5	18	740,600
China LNG Ship Mgmt	5	11	11	12	736,800
China Shipping Group	5	3	2	3	870,500
K Line	5	8	2	13	804,300
Nakilat, Teekay	5	12	12	14	1,020,600
Petronas	5	3	2	4	751,000
Teekay, Marubeni	5	11	10	12	830,900
TMS Cardiff Gas	5	8	6	16	788,100
Commerz Real, Nakilat, Pronav	4	13	12	13	840,800
Hanjin Shipping Co	4	22	20	25	544,400
Mitsui, NYK, Teekay	4	9	8	9	641,200
Mol, China LNG	4	5	4	5	684,223
Mol, NYK, K Line, SCI, Nakilat, Petronet	4	12	4	16	604,200
Nakilat, OSC	4	13	12	13	864,800
North West Shelf Venture	4	29	26	31	507,400
OSC, Mol	4	16	14	19	579,500
Sinokor Merchant Marine	4	21	16	31	543,900
Teekay, China LNG Shipping	4	1	1	1	688,000
Tepco, NYK, Mitsubishi	4	13	11	17	568,800
BW, Pavilion LNG	3	4	1	5	497,400
Golar Power	3	5	2	7	490,000
Hyproc	3	8	3	16	490,900
K Line, PT Meratus	3	12	11	12	464,800
Mitsui, Sonangol, Sojlitz	3	9	9	9	480,000
Mol, Kepco	3	7	4	12	467,900
Mol, NYK	3	11	10	12	440,600
Mol, NYK, K Line	3	27	15	36	399,200
Shell, Gaslog	3	13	13	14	435,000
Stena Bulk	3	11	9	14	491,700
Thenamaris	3	6	5	7	480,000
Others	81	11	1	43	11,909,500
Total	534	3	1	43	85,798,800

Key ship deliveries 2021-25		
Owner	No of vessels	Delivery period
Sovcomflot	19	2021-2025
N.Y.K. Line	9	2021-2022
Maran Gas Maritime	8	2021-2022
Knutsen OAS Shipping	7	2022-2024
Capital Gas	6	2021-2023
Minerva Marine	5	2021-2022
BW LNG	4	2021-2022
TMS Cardiff Gas	4	2021
Panama LNG	4	2022-2023
Dynagas	4	2021-2022
CSSC Shpg Leasing	4	2021-2022
Korea Lines	4	2022-2023
MOL	3	2021
K Line	3	2021-2022
Alpha Gas	3	2021
Cosco Shipping Energy Transportation	3	2022-2023
Mitsui OSK Lines	3	2023
Flex LNG	3	2021
Gaslog LNG Services	3	2021
Celsius Shipping	3	2021
Oceonix	2	2023
Jovo Group	2	2021-2022
JP Morgan	2	2022
Others	44	2021-24

LNG vessel day rates



SPARK SPREADS

International spark spreads							**$/MWh**
			Spark spreads at varying conversion rates				
Jan 21	**Fuel**	**Electricity**	**30pc**	**34pc**	**38pc**	**49.13pc**	**55pc**
Japan							
LNG	25.70	53.56	-32.03	-22.03	-14.08	1.24	6.83
Coal, cif Japan	14.07	53.56	6.72	12.19	16.54	24.93	27.98
HSFO 180, cif Japan	27.76	53.56	-38.88	-28.08	-19.49	-2.94	3.09
South Korea							
LNG	23.39	45.08	-32.81	-23.71	-16.47	-2.53	2.55
Coal, cif Korea	13.59	45.08	-0.17	5.12	9.32	17.43	20.38
HSFO 180, fob Korea	28.17	45.08	-48.72	-37.76	-29.04	-12.25	-6.13
Belgium							
LNG	15.30	62.74	11.80	17.75	22.48	31.60	34.93
Zeebrugge pipeline natural gas	19.96	62.74	-3.72	4.05	10.22	22.12	26.46
Coal	9.67	62.74	30.54	34.30	37.29	43.06	45.16
Fuel oil 1pc fob NWE	29.84	62.74	-36.64	-25.03	-15.80	2.00	8.48
France							
LNG	15.71	69.92	17.62	23.73	28.59	37.95	41.36
Pipeline natural gas, Russia	55.32	69.92	-114.29	-92.77	-75.65	-42.67	-30.66
Coal	9.67	69.92	37.72	41.48	44.47	50.24	52.34
Fuel oil 1pc fob w Med	30.18	69.92	-30.57	-18.83	-9.49	8.50	15.05
Italy							
LNG	15.71	70.85	18.54	24.65	29.51	38.88	42.29
Pipeline natural gas, Russia	52.39	70.85	-103.62	-83.24	-67.03	-35.79	-24.41
Coal	9.67	70.85	38.64	42.40	45.40	51.16	53.26
Fuel oil 1pc fob w Med	30.18	70.85	-29.64	-17.90	-8.57	9.43	15.98
Spain							
LNG	15.18	62.64	12.07	17.98	22.68	31.73	35.03
Pipeline natural gas, Algeria	62.25	62.64	-144.67	-120.45	-101.19	-64.08	-50.55
Coal	9.67	62.64	30.43	34.19	37.18	42.95	45.05
Fuel oil 1pc fob w Med	30.18	62.64	-37.86	-26.12	-16.78	1.21	7.77
US Gulf coast							
LNG	14.09	21.93	-24.99	-19.51	-15.15	-6.75	-3.69
Natural gas, Henry Hub Nymex	8.98	21.93	-7.96	-4.47	-1.69	3.66	5.61
Coal Central Appalachia	7.27	21.93	-2.28	0.55	2.80	7.13	8.71
HSFO 3pc fob USGC	25.86	21.93	-64.18	-54.12	-46.12	-30.71	-25.09
US Northeast							
LNG	14.09	30.31	-16.61	-11.13	-6.77	1.63	4.69
Natural gas, Transco Z6 NY	10.61	30.31	-5.01	-0.89	2.39	8.72	11.02
Coal Central Appalachia	7.27	30.31	6.10	8.93	11.18	15.51	17.09
HSFO 3pc fob NYH	27.41	30.31	-60.95	-50.29	-41.81	-25.47	-19.52

Please see the methodology for the Argus Coal Daily and Argus Coal Daily International reports; Argus European Products, Argus Asia-Pacific Products and Argus US Products reports; and the Argus European Natural Gas report and the Argus Natural Gas Americas report at www.argusmedia.com/en/methodology

Conversion factors (left-hand column units are multiplied by the factor shown to convert to units in the top row)								
Equals	**Million British thermal units**	**Barrels of oil equivalent**	**Tonnes of oil equivalent**	**Cubic feet (ft^3) gas**	**Cubic metres (m^3) gas**	**m^3 LNG**	**Tonnes LNG (specific gravity 0.425)**	**Tonnes LNG (specific gravity 0.475)**
1 million *Btu* (1mn *Btu*)	1	0.172	0.0235	1000	28.3	0.0459	0.0195	0.0218
1 barrel of oil equivalent (boe)	5.8	1	0.136	5800	164.2	0.266	0.113	0.126
1 tonne of oil equivalent (toe)	42.5	7.33	1	42.5	1200	1.95	0.828	0.925
1 ft^3 gas	0.001	0.000172	0.0000235	1	0.0283	0.0000458	0.0000195	0.0000218
1 m^3 gas	0.0353	0.0061	0.00083	35.3	1	0.00162	0.000688	0.000769
1 m^3 LNG	21.8	3.76	0.513	21,824	618	1	0.425	0.475
1 tonne LNG (specific gravity 0.425)	51.3	8.85	1.207	51,350	1,450	2.353	1	
1 tonne LNG (specific gravity 0.475)	45.9	7.91	1.081	45,950	1,300	2.105		1

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