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Argus White Paper:

Summer 2019 outlook — Power sector may struggle to absorb LNG

Strong LNG flows to Europe and high storage inventories following a mild winter have weighed on European summer hub prices. This has made gas more competitive in Europe's power sector.

But the likely step-up in power sector gas demand this summer may not fully cover the expected rise in LNG supply relative to recent years.

This could leave Europe's pipeline gas suppliers having to cut deliveries this summer compared with recent years to avoid hub prices tumbling.

Europe's power sector may struggle to absorb LNG

Europe's power sector may struggle to absorb rising LNG supply this summer, particularly in the April-May shoulder season. There is likely to be insufficient scope in Europe's largest fuel-switchable power markets for gas to displace coal and offset an expected rise in Europe's LNG receipts.

Even if all output from plants burning hard coal in the UK, Germany, the Netherlands, Spain, Italy and France in April-May were displaced by output from combined-cycle gas turbines (CCGTs), this would do little to offset the expected increase in LNG sendout compared with recent years.

CCGTs replacing all hard coal-fired output in these countries would result in a rise in power sector gas demand to around 2.24 TWh/d in April-May from the three-year average for the period of 1.76 TWh/d — a 480 GWh/d increase. This assumes the average fleet efficiency of CCGTs in each country.

This calculation excludes the possibility of gas displacing lignite from the generation mix, although gas for delivery in the second quarter has moved into competition in the power sector with lignite-fired plants. Fully displacing base-load lignite-fired generation could create at most an extra 611 GWh/d of gas demand in April-May, compared with the three-year average.

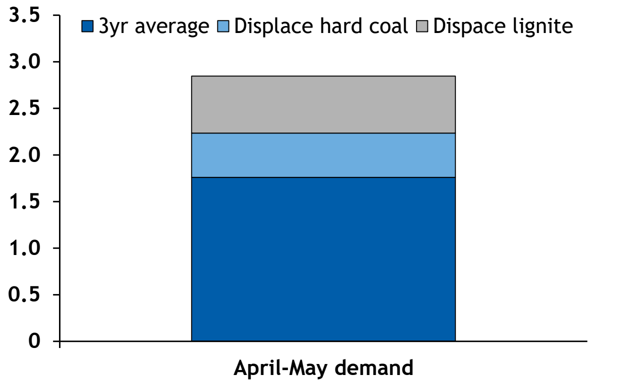
Full displacement of hard coal is unlikely given that constraints in local transmission capacity may not allow certain plants to be taken off line. And European coal prices have softened in recent weeks, slowing the fuel's displacement from the generation mix. Long-term power hedges locking in coal-fired generation may also limit the switch to gas.

The potential 1.09 TWh/d increase in power sector gas demand from the average — assuming gas displaces hard coal and lignite — would not fully cover the increase in LNG sendout if sendout holds flat to the first quarter in April-May. Sendout was 2.69 TWh/d on 1 January-15 March. The same volume in April-May would mark a rise of 1.2 TWh/d from the three-year average for the period of 1.49 TWh/d.

And LNG sendout may increase from the first-quarter average. LNG deliveries to northwest Europe typically accelerate in April-May compared with the first quarter, coinciding with the slowdown in northeast Asian demand between peak heating and cooling seasons.

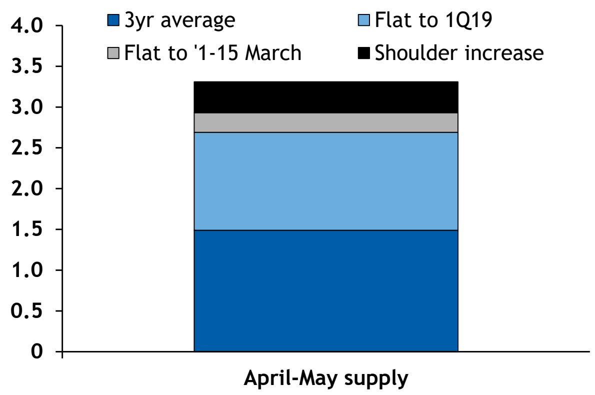
In the past couple of years, aggregate European sendout has stepped up substantially in April-May from the first quarter,

Power sector gas demand scenarios *TWh/d*

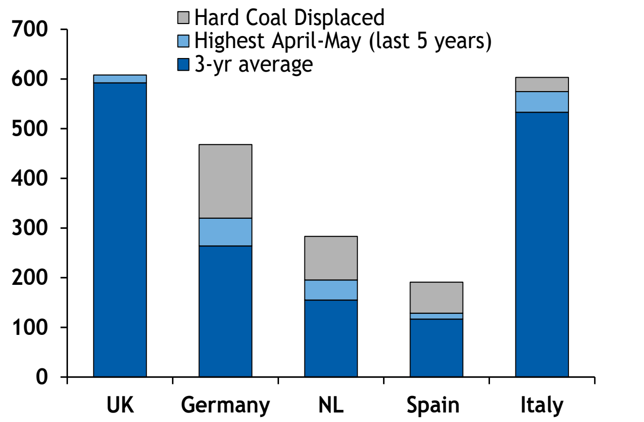


Natural Gas/LNG
illuminating the markets

April-May LNG supply scenarios *TWh/d*



Potential April-May CCGT gas demand *GWh/d*



led by northwest Europe. The increase was 25pc last year and 22pc a year earlier. A similar rise this year would take aggregate sendout to 3.32 TWh/d in April-May — up by 1.86 TWh/d from the average. Sendout had already quickened to 2.93 TWh/d on 1-15 March from earlier in the quarter, and exceeded 3 TWh/d on five days in the period.

Even if power sector gas demand in April-May rises into line with monthly highs for each country in the past five years, it would result in only an extra 1.35 TWh/d of demand against the three-year April-May average. And the monthly highs were all set in winter months when aggregate power consumption is typically higher than in April-May.

Where demand flexibility lies

The potential for gas to displace coal in the power sector is not evenly distributed in western Europe.

The UK's £18/t CO_2 (€21/t CO_2) carbon floor price has already favoured gas displacing coal from its generation mix in recent years. UK coal-fired output in April-May 2018 was just 512MW, while gas-fired output was 13GW. This means there is little scope for UK gas-fired generation to step higher than in recent years, assuming flat power demand and output from other sources.

Gas-fired generation at low enough prices to encourage power exports could offer some support to demand, but this would require NBP prompt prices to slip to a substantial discount to continental hubs to offset the additional costs of the UK carbon floor price. The new 1GW Nemo interconnector offers the potential for increased UK power exports this year, bringing the country's total export capacity to 4GW.

Spain and Italy have more scope for coal-to-gas switching in the power sector to absorb the increase in LNG sendout. There has been a substantial switch already in the first quarter.

But the rise in renewables output in both countries recently, as elsewhere in Europe, has eroded the share of power generation for thermal sources. The record monthly high for Spanish gas-fired output was 596 GWh/d in June 2008, but the highest in the past five years was just 330 GWh/d, in November 2011.

Spanish fuel switching would create 74 GWh/d of additional demand compared with the average.

Italy is likely to have strong gas-fired generation in the second quarter, as gas-fired costs move below coal-fired costs. Italian fuel switching would create 70 GWh/d of extra demand.

The Netherlands may have more potential for a rise in power sector gas consumption. The country's coal-fired generation data are not made available on European system operator association Entso-e's platform. But based on coal consumption by Dutch plants in April-May over the past three years, gas consumption could rise by around 128 GWh/d from the average.

The largest potential increase in power sector gas consumption is in Germany, where substantial coal-fired generation can still be displaced, at least in the short term. But fuel switching from hard coal to gas would add only 204 GWh/d of demand.

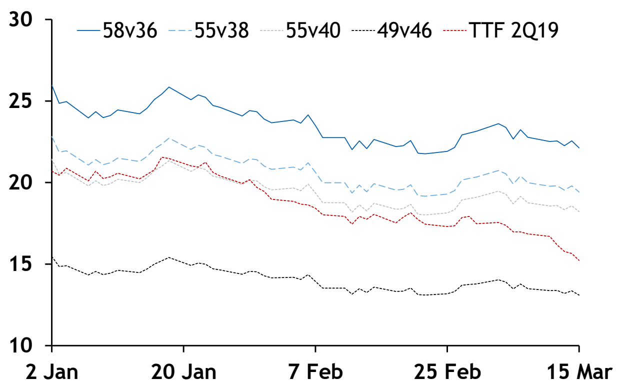
Other markets in the region have little scope for coal-to-gas switching. French fuel switching would add just 22 GWh/d of demand. And Belgium has fully phased out its coal-fired fleet, leaving no potential for fuel switching.

Dropping through fuel switching levels

Northwest European gas prices have dropped far through fuel switching levels in recent weeks, leaving only the least competitive CCGTs struggling to compete with the most efficient coal-fired units. Emissions adjusted spark spreads have largely moved to a premium to the equivalent dark spreads, assuming average gas-fired and coal-fired plant efficiencies.

The TTF second-quarter contract has in recent weeks dropped through several support levels at which gas would displace coal from the generation mix. The contract on 15

TTF 2Q19 vs gas-coal switching levels €/MWh



March put a 52pc-efficient gas-fired plant in competition with a 43pc-efficient coal-fired plant when adjusting for emissions.

The second-quarter price at which a 46pc-efficient coal-fired plant — such as those in the Netherlands — would be displaced by a 49pc-efficient gas-fired plant was €13.46/MWh on 14 March (*see graph*). The TTF second-quarter contract was €15.79/MWh on the same day. And the TTF second-quarter contract had already fallen that distance in less than a month.

Spanish gas-fired plants have similarly been much more competitive than coal-fired units. April clean spark spreads for a 55pc-efficient gas-fired plant widened their premium to clean dark spreads for a 38pc-efficient coal-fired unit to €10.80/MWh on 15 March — the highest since at least December 2014.

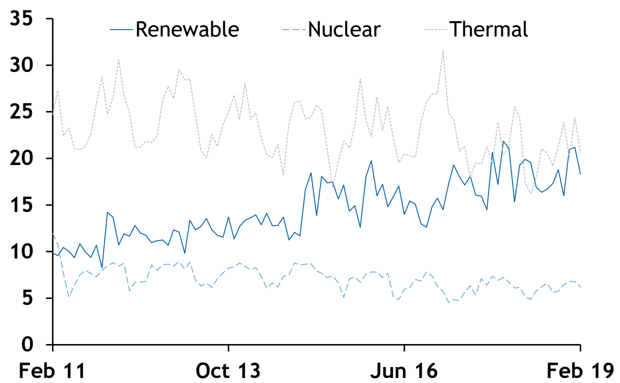
In Italy, breakeven costs for a 40pc-efficient coal-fired plant in the second quarter stood at €41.58/MWh on 13 March, based on API 2 coal swaps assessments and prompt EU emissions trading system (ETS) prices, while breakeven costs for a 55pc-efficient gas-fired plant were €41.18/MWh, based on PSV gas price assessments and prompt ETS prices. This was the first time a 40pc-efficient coal-fired plant had slipped behind a 55pc-efficient gas-fired unit in the generation mix for the next quarter.

Thermal displacement

Increased growth in renewable generation could further cut the call on thermal output, limiting a rise in power sector gas demand. Higher nuclear availability in France could do the same.

Increases in renewables output in recent years have substantially pared aggregate thermal output. And installed renewable capacity in western Europe, excluding the Nordic region, increased to 1.72TW last year from 1.52TW a year earlier. Solar output is typically strong in the second quarter, and April can be a windy month. Installed solar capacity rose by 61.9GW and wind capacity increased by 11.7GW in 2018.

German power output by source TWh



The load on installed renewable facilities this summer may not vary substantially from recent-year averages, with potential rises in output in some parts of Europe, but potential decreases in others.

Hydroelectric stocks are low in southern Europe compared with the averages for recent years. Spanish hydro stocks stood at 11.34TWh on 17 March, down from the three-year average for the day of 12.09TWh. But that average includes stocks of 10.2TWh at the same point in 2017. Italian hydroelectric stocks were down to 2.2TWh on 17 March, against a three-year average for the date of 2.5TWh.

Aggregate Nordic hydro stocks were 42TWh on 17 March. This was up from 40.8TWh a year earlier, but down from an average of 47.5TWh for the two previous years.

Hydroelectric generation may be strong in the Alps this summer. Swiss hydro stocks stood at 2.75TWh on 18 March, up substantially from the three-year average of 1.39TWh. And there is thick snow cover in the Alps, promising brisk run-of-river output around the start of the summer.

And Europe's nuclear availability may be greater this summer than in recent years. French nuclear availability — based on French state-controlled utility EdF's schedules, and still subject to considerable change — is expected to rise compared with a year earlier, with off line capacity averaging 13.4GW in April-May, compared with 18.7GW in the same period of 2018. Belgian nuclear availability remains constrained early in the summer.

More LNG for Europe to shoulder

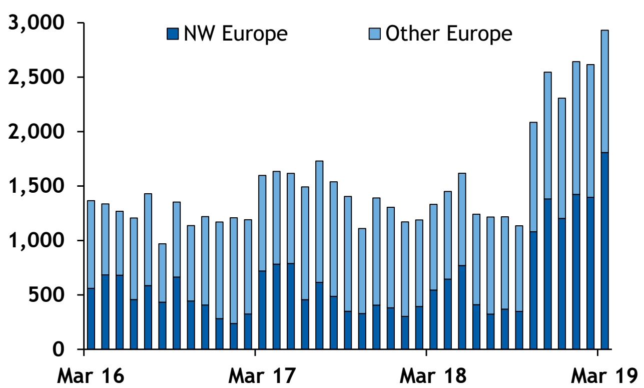
Growth in global liquefaction capacity will further boost supply this summer, while some summer LNG demand sinks of recent years are shallower this year, potentially leaving more cargoes for Europe.

Global liquefaction capacity has continued to expand, with 30.6mn t/yr added since the end of May 2018.

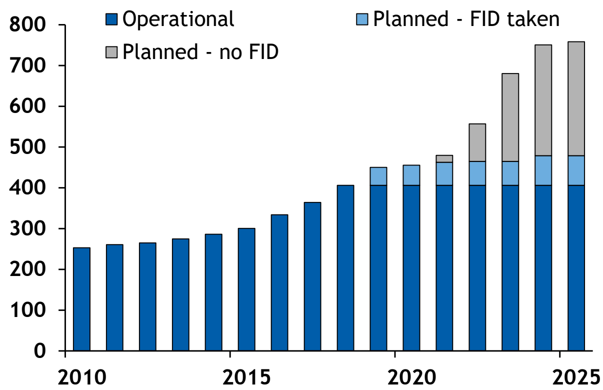
This includes 11mn t/yr from the second and third trains of Russia's Yamal LNG. Cargoes from the project have predominantly ended up in Europe over the winter. This was because of tight northeast Asian LNG market premiums to western European gas hubs and high freight costs, making European gas markets the highest netback option for Atlantic basin producers.

Ice cover on the Northern Sea Route (NSR) over winter also leads to more vessels having to pass through Europe for transshipment, given the lack of icebreakers to support delivery to northeast Asia. This increases freight costs for delivery to northeast Asia and makes the cargoes easily available to the European market if prompt and near-curve hub prices are high enough.

European LNG sendout *GWh/d*



Global liquefaction capacity *mn t*



US liquefaction capacity has grown substantially since last summer. It rose by around 15mn t/yr thanks to the start-up of the first train at Corpus Christi, the fifth train at Sabine Pass and the first train at Cameron LNG.

The share of US cargoes heading to Europe has risen substantially in recent months. And further US liquefaction additions are expected in the second quarter with the Elba Island project, Freeport train 1 and Cameron train 2.

Northeast Asian prices holding at a tight premium or even a discount to northwest European hubs in recent weeks will continue to drive the offloading of more Atlantic basin supply into Europe as the market of last resort. And maintenance scheduled for the shoulder period would need to be particularly heavy to offset the capacity additions.

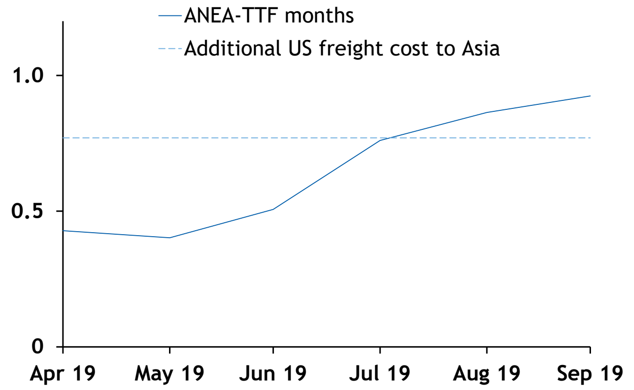
Swings in the supply-demand balance in some LNG importing countries could result in more cargoes arriving in Europe.

Egypt's demand has continued to grow, but its production has moved to a surplus to consumption, allowing it to switch back to being a net LNG exporter this year. State-owned Egas recently issued a tender for four LNG cargoes for loading in April-May. The start of Israeli gas exports to Egypt may further bolster supply available for export, although pipeline constraints may initially hamper these flows.

Reduced demand is also expected from Latin America this summer. Growing supply in Argentina, particularly from its Vaca Muerta shale gas formations, may result in less need for LNG during its austral winter. Argentinian state-controlled energy company Ieasa, formerly Enarsa, has been tendering for substantially less LNG supply in April-September than a year earlier.

Brazil is similarly growing its domestic output, although low hydroelectric reserves could support demand for gas-fired generation over the coming months.

Asia could draw US supply in 3Q19 *$/mn Btu*



And Mexico's imports of pipeline gas from the US are expected to displace at least some LNG arrivals. A total of six pipeline projects are scheduled to start delivering US gas to Mexico in April-August, although their commissioning has been long delayed.

China may still increase its LNG imports this summer compared with a year earlier, in line with continued growth in economic activity and stocking to avoid winter shortages as more heating is converted to run on gas. Little growth was expected in Chinese import capacity this year, but the spare import capacity last summer would allow for substantial growth in imports in April-September this year. Imports rising into line with installed capacity in April-September would equate to growth of 13mn t compared with last year. China's LNG imports grew by 6.9mn t last summer from a year earlier.

Barring China offsetting softer demand elsewhere and heavy maintenance at export facilities this summer, LNG flows to Europe are likely to be quick — at least before peak Asian cooling demand begins to make an impact towards the second half of the summer.

Aggregate European sendout for March is on track to be the highest for any month on record, given volumes shipped on 1-15 March. It was particularly strong in France, with regasification averaging 644 GWh/d on 1-15 March, up from the previous high of 588 GWh/d in February and before that 578 GWh/d in November 2010.

LNG supply could be drawn away later in the summer, with the *Argus* northeast Asian (ANEA) des market offering potentially higher netbacks for some Atlantic producers.

Europe's weak injection demand

European storage will start the summer with a large overhang, likely cutting aggregate injection demand. Mild weather and strong LNG imports have preserved inventories this winter and put sites on course to enter the summer with stocks at a multi-year high.

Combined German, French and Dutch stocks — excluding Norg — of 210TWh on 15 March were 88TWh above the three-year average for the date. The surplus was 141TWh to last year when a particularly cold snap in late February-early March helped rapidly deplete inventories in northwest Europe. An outage of the Forties Pipeline System in December 2017 had already accelerated the stockdraw as Europe sent more gas to the UK to offset the drop in supply.

And sites in northwest Europe have recently switched to net injections, which could result in the stock surplus climbing further by the start of April.

Assuming no increase in the 88TWh surplus in the second half of March would leave start-of-summer inventories at 197TWh. This would then leave April-September injection demand at 1 TWh/d, assuming stocks on 1 October are in line with the three-year average of 380TWh. This is well below the three-year average stockbuild for the period of 1.33 TWh/d.

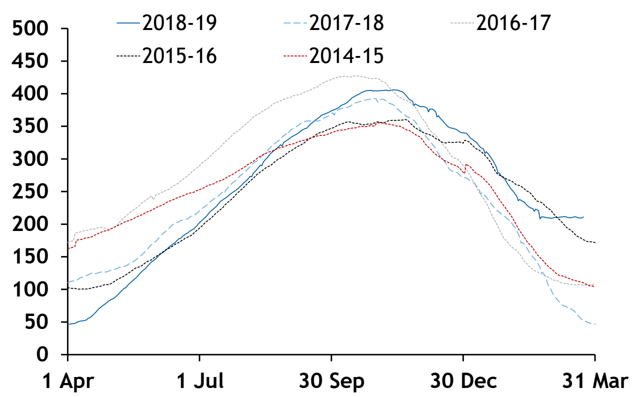
Second-quarter injections at sites in the region have always been weaker than third-quarter injections, at least since 2011 and irrespective of whether second-quarter prices were lower than those for third-quarter delivery. Second-quarter injections were just 8 GWh/d slower than third-quarter injections in 2011, but have been an average of 792 GWh/d slower in the past three years.

April-May injections may be just under 1 TWh/d, given that the second-quarter market discount to the third-quarter on 15 March was similar to the same point in 2011.

That said, taking inventories close to maximum capacity of 447TWh at the start of October would provide injection demand of 1.37 TWh/d, although this is still slower than injections of 1.51 TWh/d in April-September last year. But bookings have been strong at European storage auctions this quarter.

Aggregate demand in Europe could be weakened by a low call on heating early in the summer. The UK Met Office forecasts

European gas inventories *TWh*



higher-than-average temperatures in April-May. Lower temperatures early in the quarter can drive up residential consumption considerably.

Slow Algerian flows

Algerian flows to Europe have slowed considerably this winter, and it is unclear whether they will have to rise this summer for buyers to meet their contractual minimums or whether firms will roll over their take into future years, particularly given a significant number of contract expiries this year.

Aggregate flows to Italy and Spain averaged 779 GWh/d on 1 January-15 March, down from the three-year first-quarter average of 1.13 TWh/d.

All of Algerian state-controlled Sonatrach's remaining contracts with Italian firms are expected to expire this year, equivalent to 19bn m^3/yr of supply. It is unclear if at least one tranche of a supply agreement with Edison expired at the end of last year. There are also some Spanish contracts expiring around the end of the decade.

Oil-indexed prices are expected to be lower in the summer than in recent months, offering some incentive to turn up supply at that point. Italian firms may also have a greater discount on their oil-indexed prices for summer delivery. But given that hub and LNG prices for summer delivery are at strong discounts to oil-indexed prices, firms may instead seek to take make-up gas in future years.

Sonatrach has previously agreed supply cuts with European companies, reducing deliveries to Italy substantially in early 2013-early 2016. Sonatrach may have had an incentive to cut supplies during that time, given that Algeria's domestic consumption growth reduced available supply for export and the firm could likely achieve higher prices by selling gas as LNG to Asian markets.

Production growth in the past couple of years supported quick pipeline sales to Europe last year. But further increases in domestic consumption may again limit supply for export.

If European buyers of Algerian gas plan to meet their take-or-pay minimums this year, assuming their contractual commitments are unchanged from 2018, imports would have to accelerate substantially over the rest of the year. But Spain's provisional April plan has receipts at 284 GWh/d, which is down from the three-year monthly average of 478 GWh/d.

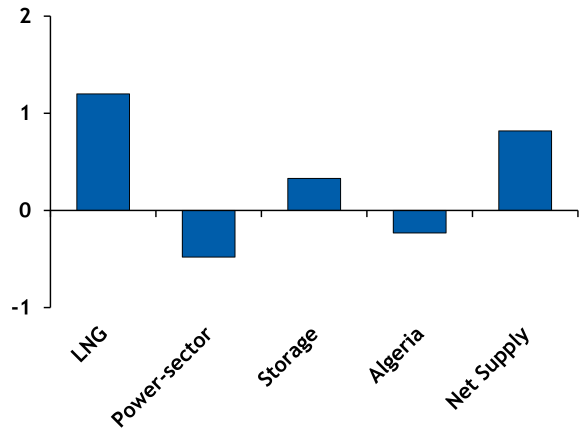
If Spanish receipts in April-May are in line with the April schedule and Italian receipts are in line with 1 January-15 March, this would put aggregate European pipeline supply from Algeria at 734 GWh/d, down from the three-year average of 966 GW/d.

Supply-side response may be required

This loosening of Europe's supply-demand balance has already weighed heavily on the front-summer market, and Europe's other pipeline suppliers may have to cut deliveries to prevent prices tumbling further.

The net effect of LNG sendout holding flat to the first quarter, hard coal being displaced by gas in the power sector in western Europe, weak injection demand and slow Algerian receipts moves Europe's supply-demand balance up by 820 GWh/d from the three-year average, assuming average pipeline receipts from other sources and consumption outside the power sector.

Change in Apr-May supply from 3yr average *TWh/d*



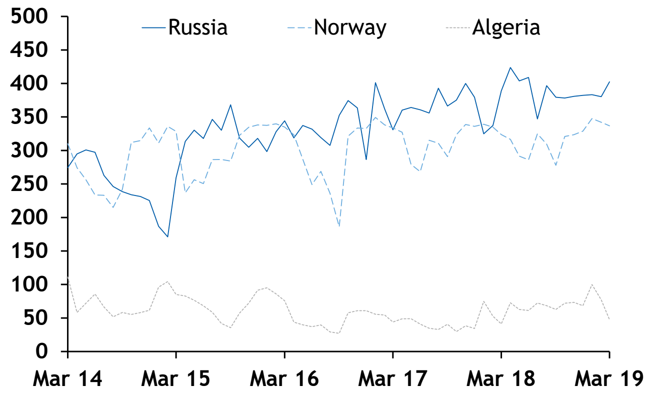
The TTF front-summer market had fallen to €15.40/MWh on 15 March from €20.58/MWh on 2 January, and was at a €1.80/MWh discount to the summer 2020 market. A comparable weakening of European summer prices against future summers in the past has resulted in Norwegian production being deferred. This was done by cutting output from the Troll swing field, buying gas at hubs and hedging sales for the following summer.

This last happened in 2016, when the TTF day-ahead market in July-September opened up a €2.26/MWh discount to the same delivery period a year later.

Norwegian state-controlled Equinor cut aggregate production and Norway's deliveries to Europe fell to 230mn m^3/d (2.43 TWh/d) in July-August from 285mn m^3/d a year earlier. Production was then turned up substantially in the same period in 2017 to 306mn m^3/d.

And Equinor deferred production in 2014, when the TTF day-ahead market in July-September averaged a €5.31/MWh discount to the third-quarter 2015 market. This deeper discount in contracts for delivery in 2014 relative to 2015 also provided the incentive for a large fall in supply from Russia in 2014 and early 2015. Deliveries from Russia fell quickly over the course

Western Europe's main pipeline supply *mn m³/d*



of 2014 as hub prices tumbled from the front of the curve and deliveries hit their lowest in February 2015.

Russian deliveries in winter 2014-15 averaged 218mn m³/d, down from 313mn m³/d a year earlier. State-controlled Gazprom did not meet nominations for deliveries to some clients in central and eastern Europe, and paid compensation in lieu.

The summer market this year is weakest in the second quarter, with contracts for delivery in April-June trading at a €2.15/MWh discount to the second-quarter 2020 market on 15 March — a similar spread to the Equinor deferral in 2016. Equinor has hinted that production from Troll this gas year is unlikely to exceed its 36bn m³ cap.

Gazprom has said that it plans to maintain flat or increase sales to Europe, excluding the Baltic states, and Turkey in the coming years compared with its record sales of 201bn m³ last year.

Gazprom may need to support its cash flow given that its largest ever investment is planned for this year at 1.4 trillion roubles ($21.5bn), up from Rbs1.28 trillion in 2018. This is in part to finance large infrastructure projects such as the controversial 55bn m³/yr Nord Stream 2 pipeline and the 31.5bn m³/yr Turkish Stream pipeline, as well as completion of the 38bn m³/yr Power of Siberia pipeline to China.

Gazprom has been making substantial sales through its online platform for delivery this summer, which could offset firms seeking to turn down their take under long-term contracts.

LNG shut in?

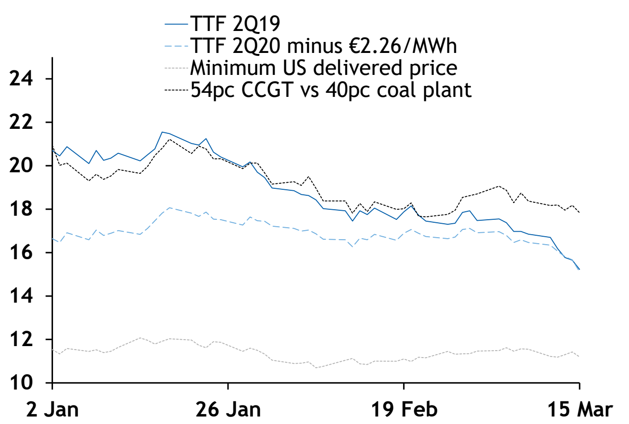
European hub prices could fall far enough this summer to discourage LNG production at some liquefaction facilities, unless supply cuts are implemented from the region's pipeline gas producers.

Annual maintenance concentrated into the period of lowest European hub prices could help tighten the market. Liquefaction plants that have been operating for a sufficiently long time to have amortised their costs could also curb output, particularly if there is comparatively low gas reserve replacement upstream of the facilities, such as in Indonesia. And liquefaction plants in regions with a domestic gas market, such as the US Gulf coast and Queensland in Australia, could pare production further and sell to the local market.

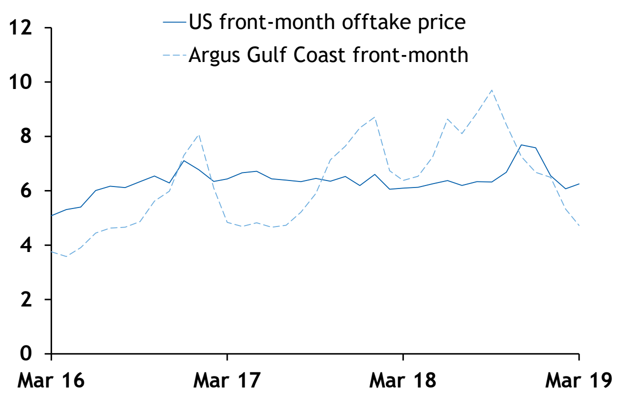
For US exporters in particular, the free-on-board (fob) value of cargoes has dropped substantially in recent months, tracking falls in delivery markets. It was already insufficient to cover liquefaction fees for most offtakers from US facilities of around $2.25-3.50/mn Btu, under the first contracts with US exporter Cheniere.

Offtakers may choose not to load cargoes if the price they can achieve in delivered markets minus freight and logistics costs falls below the price of feedgas into Cheniere facilities of 115pc of the Henry Hub settlement for the month of loading. They may choose in this instance to just pay the liquefaction fee to Cheniere, which some consider to be a sunk cost.

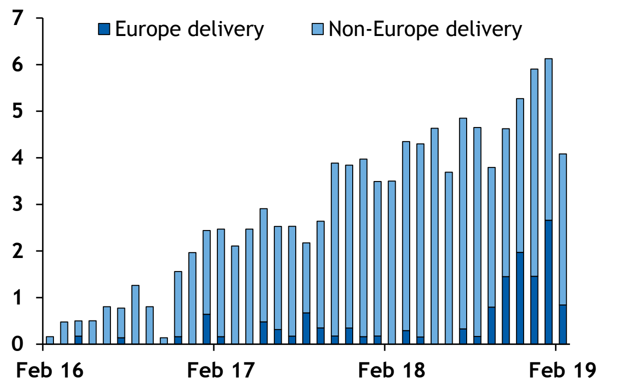
TTF support levels *€/MWh*



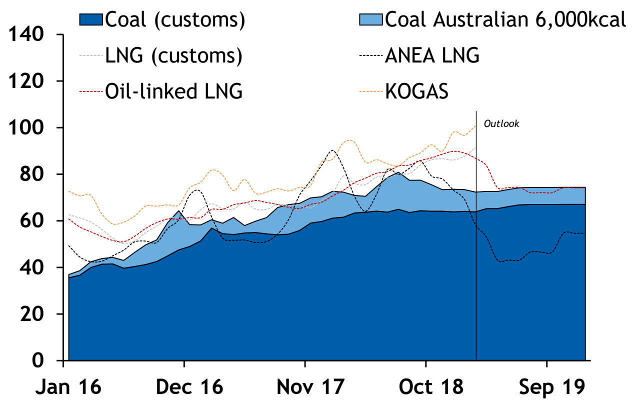
US fob market below full offtake costs *$/mn Btu*



US LNG exports *m³ of LNG*



Theoretical South Korean generation costs *$/MWh*



Subject to Cheniere's hedging strategy for its gas purchases, the firm could choose not to buy gas for liquefaction for LNG exports above its contractual commitments to offtakers and its supply commitments to its own portfolio of buyers.

Europe has served as the market of last resort for US LNG exports in recent months, with an increased share of deliveries heading to European terminals. Hub prices for the second quarter were still some way above the potential delivery price for US exports, assuming 115pc of Henry Hub plus short-term shipping and logistics costs to Europe.

But the gap has been closing and the TTF second-quarter market would only have to drop to below €11.20/MWh from €15.22/MWh to no longer cover short-term costs, based on prices on 15 March.

Support level outside Europe

Europe has typically been seen as the market where the global gas trade balances, owing to its demand-side flexibility from the power sector and storage. But with these demand sinks offering less support this year, some traders have been looking to potential support levels elsewhere.

TTF prices falling below $6/mn Btu (€18/MWh) have previously triggered an Asian demand response, Shell Energy executive vice-president Steve Hill said in February. But insufficient flexibility to switch away from long-term supply and higher nuclear availability in South Korea and Japan may be limiting rises in LNG demand in these markets amid lower prices.

Tax reforms in South Korea that come into effect on 1 April are designed to favour gas for power generation ahead of coal, but may not result in substantial fuel-switching. The price that state-controlled LNG importer Kogas was charging utilities for gas supply disconnected substantially above spot LNG prices in January-February and tracked closer to oil-indexed costs.

If Kogas is able to make more spot purchases later this year — and if this is reflected in the prices that utilities pay — gas-fired generation would be substantially cheaper than coal-fired output. But this depends on the flexibility of Kogas' long-term contracts and whether aggregate demand is higher than contractual commitments.

Nuclear availability in South Korea has continued to strengthen in recent months and helped curb winter thermal power demand. Higher nuclear output this summer could continue to pare the call on gas-fired output even if gas moves ahead of coal in the generation merit order.

More information

- All prices included in the white paper are based on Argus assessments unless otherwise stated
- Fundamentals data used in the charts are available to our subscribers, and can be downloaded through our Argus Direct platform
- More information on the topics discussed and other relevant issues is available through subscription to the following services: **Argus European Natural Gas**, **Argus LNG Daily** and **Argus European Electricity**

For more information:

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