May 2021

Quarterly Gas Review: Short and Medium Term Outlook for Gas Markets

Introduction

In this latest OIES Gas Quarterly we focus on the short-term activity in global gas markets, and this will be a recurrent theme in our Quarterly from now on. We start by reviewing a volatile period for gas markets over the first quarter of 2021, when a combination of cold weather, supply disruptions and a rebound in energy demand as the impact of the COVID-19 pandemic started to ease in a number of regions led to a dramatic tightening of the gas supply-demand balance at the turn of the year. Prices remain significantly above both 2020 and five-year average levels, and in the first section of the report we reflect on the implications for the LNG margin in the US Gulf and for Russia's export strategy, as well as looking at the interaction between the LNG spot and long-term contract price in Asia.

In the second section of the report, we take a more detailed look at the relationship between the gas price and the level of storage in Europe. We note the historical correlation between the year-on-year change in the TTF price and the change in storage utilisation, and while being cautious about defining a causal relationship, we assert that some interesting conclusions can be drawn about the implications for the futures curve. In the case of summer 2021 the current forward price would imply storage levels returning to their long-term average rather than the very high rates seen in 2019 and 2020, but this in turn has implications for the global LNG market as it implies lower LNG imports to Europe. Our analysis looks at the potential for further LNG shut-ins this summer, as supply continues to increase, and examines the various factors that could alleviate this risk while also identifying the key signposts that will give an indication of the direction of travel.

In future reports we will be broadening our analysis of the key drivers of short-term gas market activity to include carbon prices, inter-fuel competition and the impact of decarbonisation strategies, and we would welcome interaction on these important topics. If you would like to discuss any of these issues further then please contact Mike Fulwood (mike.fulwood@oxfordenergy.org) or Jack Sharples (jack.sharples@oxfordenergy.org).

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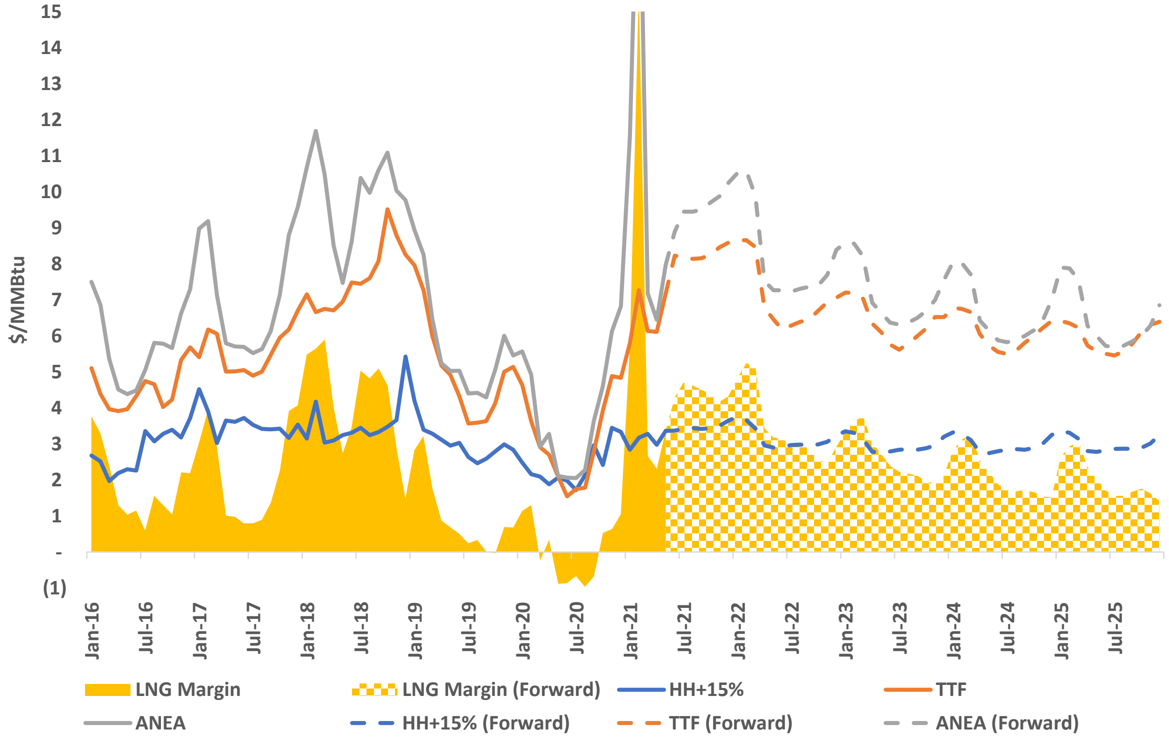
1. Price analysis

In this first section of the quarterly, we include below our regular review of some key pricing trends for global LNG, Europe and Asia.

1.1 LNG tightness

Firstly, we consider our "LNG Tightness" analysis as an indicator of how profitable existing export projects are and whether there is a need for new FIDs to meet demand in the global market. The graph below is based on data from Argus Media and shows the prices for TTF in the Netherlands, the ANEA spot price in Asia and the Henry Hub price in the US. It then calculates the highest netback from Europe or Asia to the US Gulf Coast plants based on the respective shipping costs. Deducting Henry Hub plus 15 per cent from the highest netback gives the LNG Margin, which provides an indication of whether developers in the US can expect to recover the fixed cost of liquefaction. A margin in excess of 3 USD/MMBtu (the fixed liquefaction cost in the traditional Cheniere contract) – as it was in 2018 - would provide an obvious incentive for new projects while a margin well below this suggests a more oversupplied market.

Figure 1.1: An assessment of "LNG Tightness"



Source: OIES, based on data from Argus Media. Forward curve at April 30

For the majority of 2020, when the COVID-19 pandemic caused lockdowns in Asia and Europe leading to economic decline and a fall in energy demand, the margin was negative, implying that US LNG exports were losing money on a cash basis. This led to between 150 and 200 cargoes being shut in, which started to impact the market during the summer months. However, since then the picture has changed dramatically. Initially the impact of the pandemic started to ease, and economic recovery brought higher demand and increased prices, pushing the margin back into positive territory in Q3, albeit only to a level that covered cash rather than full costs. At the end of 2020 and in early 2021, the very cold weather and a dramatic rise in prices in Asia (see Figure 1.1) pushed the margin briefly to an extremely high level. The price spike in Asia was discussed in a recent OIES Comment.[1] This analysis is updated in a later section.

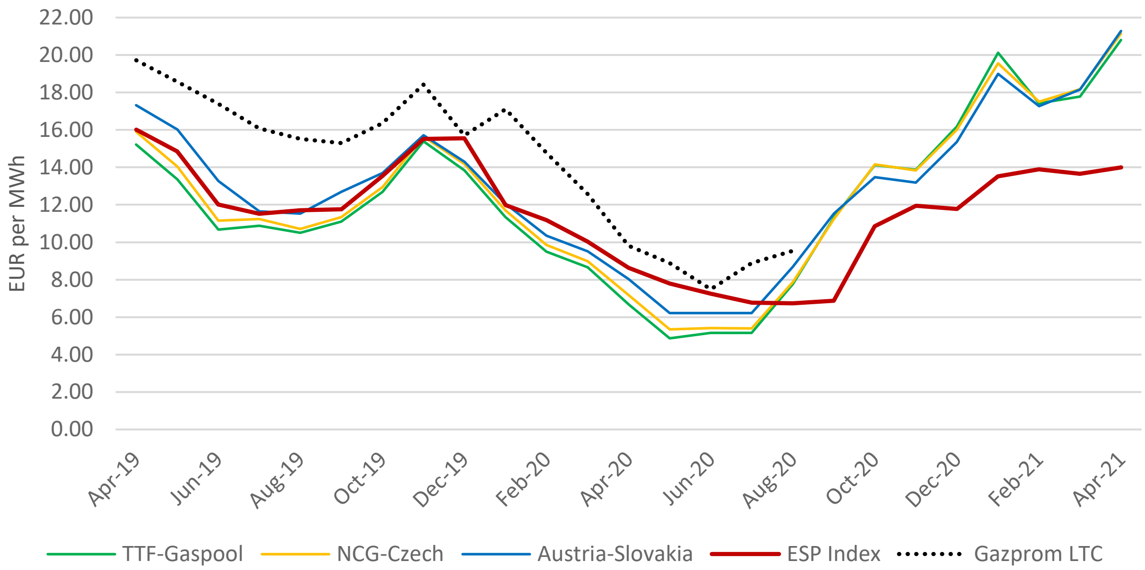
However, this was very much a short-term phenomenon, driven by the cold weather catching Asian buyers unaware, and the price was for a limited number of cargoes so not necessarily representative of even near-term fundamentals. As winter ended prices fell back, but remain at much higher levels than seen in 2020 – according to the futures markets. With the forward curve for both TTF and Asian spot prices being in the range of 8-9 USD/MMBtu even for Q3, the US LNG margin is over 4 USD/MMBtu for much of the rest of this year, which is more than covering the full cost (including the liquefaction fee) in both Europe and Asia. The forward curve suggests that the margin will remain positive over the next few years, albeit at lower levels than in 2021. Whether this is likely to be realised both for 2021 and beyond will be discussed later.

A further question relates to whether a sustained margin in excess of 3 USD/MMBtu would raise the likelihood of a new round of FIDs since the economics of potential new projects would be enhanced. While it is true that the economics would look good, most new LNG developments will still require the backing of long-term contracts and it is not clear that the big Asian buyers are necessarily queuing up to enter into new contracts.

1.2 Gazprom's Electronic Sales Platform: prices and sales by delivery profile

As illustrated in Figure 1.2 (below), monthly average European hub prices rebounded in the second half of 2020, from a low of 5-6 EUR/MWh (1.75-2.00 USD/MMBtu) in May-July to a high of 18-20 EUR/MWh (6.30-7.00 USD/MMBtu) in the first quarter of 2021. Yet during that same period, Gazprom's sales via its Electronic Sales Platform (ESP) declined markedly (see Figure 1.3).

Figure 1.2: The price at Gazprom's Electronic Sales Platform versus European hubs



Source: Gazprom Export, Argus Media, OIES

Indeed, in Q1 2021 as a whole, Gazprom sold just 813 mmcm via the ESP, and less than 100 mmcm of that volume sold was for prompt or Balance of Month delivery. Rather, the vast majority sold in Q1 2021 was for delivery further into the future, namely summer 2021 (373 mmcm) and calendar year 2022 (345 mmcm), while just 8.5 mmcm was sold for delivery in 'winter 2021/22'.[2] For comparison, Gazprom's ESP sales in Q1 2020 were 9,074 mmcm, up from 1,953 mmcm in Q1 2019.

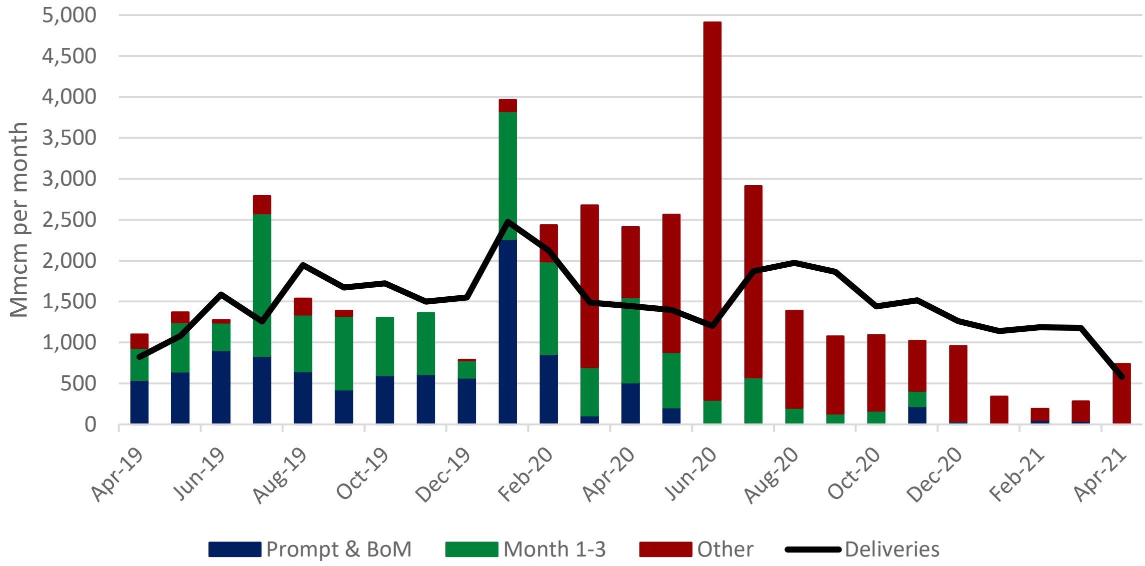
[1] Fulwood, Mike, 2021. Asia LNG Price Spike: Perfect Storm or Structural Failure? *OIES Comment*, 17 February. https://www.oxfordenergy.org/publications/asia-lng-price-spike-perfect-storm-or-structural-failure/

[2] As a reminder, volumes sold on the ESP are delivered on a flat profile across the duration of the delivery period.

Although sales volumes recovered in In April, to 739 mmcm, the entire amount sold was for delivery in 'summer 2022' or 'year 2022'. In the same month, the delivery of volumes sold on the ESP fell to 581 mmcm, which was the third-lowest full-month total since the ESP was launched in late September 2018. Indeed, it was the first time monthly deliveries of gas sold on the ESP had fallen below 1 bcm since April 2019. These April sales and delivery figures serve to further emphasise the limited supply of short-term Russian gas to Europe in the first four months of 2021.

In Q1 2021, the combination of cold weather across the northern hemisphere, LNG cargoes being drawn away from Europe to Asia, and European storage stocks being rapidly drawn down meant that commercially attractive windfall sales via the ESP were seemingly available to Gazprom. This begs the question: why did Gazprom's ESP sales in Q1 2021 fall so far below those of Q1 in 2019 and 2020, when the market conditions appeared to be so promising?

Figure 1.3: ESP sales by delivery profile (mmcm/month)



Source: Gazprom Export, Argus Media, OIES

The answer to this question is two-fold: The first part pertains to North-Western Europe, and the second part to Central Europe. In North-Western Europe, Gazprom simply did not have spare physical delivery capacity to offer additional prompt volumes via its ESP. Gazprom's physical exports to North-Western Europe via Nord Stream and the Yamal-Europe pipeline (via Belarus to Poland and Germany) had already been flowing at full capacity since early August 2020. When the weather-induced surge in European gas demand emerged in Q1 2021, there was no spare capacity to offer additional volumes to North-Western Europe. Even if Gazprom had wanted to use gas from its European storage stocks as a basis for ESP prompt sales at that time, it is highly likely that supplies from storage were being used to service demands from Gazprom's LTC counterparties, and were thus not available as a source for ESP sales.

In contrast, Gazprom's deliveries to Central Europe (specifically to Hungary, Slovakia, Austria, and Italy) were constrained not by physical pipeline capacity, but by its arrangements for transit via Ukraine. The transit contract signed in December 2019 saw Gazprom pre-book a flat daily rate of 178 mmcm/d transit capacity in 2020, and a lower rate of 110 mmcm/d from January 2021 to December 2024. Any quarterly, monthly or daily capacity bookings over and above these basic volumes are subject to higher tariffs. The extent to which Gazprom did (or did not) book such additional capacity via Ukraine during the winter of 2020/21 provides insights into Gazprom's commercial strategy.

In Q4 2020, Gazprom booked small amounts of additional monthly capacity. This raised the volume of capacity booked by Gazprom for entry into Ukraine at the Russian border to 183 mmcm/d (October), 188 mmcm/d (November), and 190 mmcm/d (December). Actual physical flows of Russian gas into Ukraine in Q4 2020 peaked at 185 mmcm/d in mid-December, as illustrated in Figure 1.4 (below).

For Q1 2021, when the contracted level of transit had fallen to 110 mmcm/d, Gazprom again booked additional monthly capacity: in January 2021, its total booked capacity was 151 mmcm/d, falling to 124 mmcm/d in February and March. In January and February, actual physical flows fell below these booked capacities, with flows into Ukraine from Russia totalling around 125 mmcm/d in January and around 120 mmcm/d in the first half of February. In the second half of February, flows dropped substantially, to a low of just below 70 mmcm/d, before recovering to around 125 mmcm/d in March.

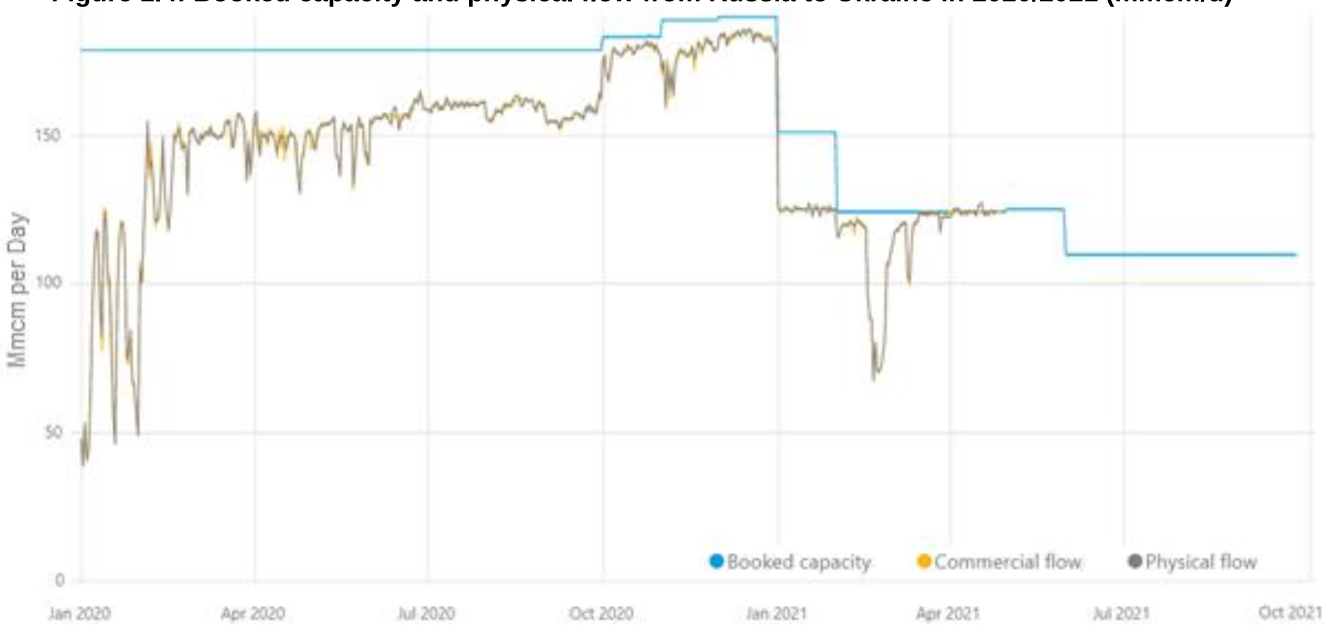
In April, booked capacity and physical flows were approximately 124 mmcm/d. In May, booked capacity is slightly higher (125 mmcm/d). As things currently stand, the booked transit capacity will drop back to the 'basic' long-term transit contract volume of 110 mmcm/d in June, July, and September, unless Gazprom books any additional for these months.

The key point here is that, although the Ukrainian system had spare physical capacity, Gazprom chose to book only very limited additional capacity of no more than 15 mmcm/d via Ukraine in both Q4 2020 and Q1 2021 (aside from January 2021, when it booked an additional 40 mmcm/d), despite the increase in both European demand and prices. Gazprom could have used such capacity to make additional prompt sales to Central Europe via the ESP, but it did not.

This was possibly because the combination of price levels in Central Europe, the higher rate of Ukrainian transit tariffs that apply to bookings over and above the long-term transit contract, and the availability of substantial gas storage stocks in Central Europe, meant that it was simply not commercially attractive to offer additional volumes for those markets via the ESP.

This dichotomy highlights an interesting aspect of the European gas market. While North-Western Europe (namely, the UK, France, Belgium, and the Netherlands) has access to LNG supplies, seasonal storage capacity relative to demand is limited. By contrast, Central Europe has very limited access to LNG supplies (namely via import terminals in Poland and Croatia), but larger storage facilities relative to demand. In North-Western Europe during the winter, as LNG cargoes were pulled away to Asia, there was a strong compensatory call on Russian pipeline supplies. Meanwhile, in Central Europe, storage withdrawals were sufficient that Gazprom was not motivated to make additional sales to the region via its ESP or to book additional transit capacity via Ukraine to deliver those volumes.

Figure 1.4: Booked capacity and physical flow from Russia to Ukraine in 2020/2021 (mmcm/d)



Source: GTSOU Transparency Platform

Looking ahead, a final point to add is the comparison between 2019, 2020, and 2021 in Gazprom's export capacity, as an indicator of how much capacity Gazprom has to rebound both its LTC and ESP sales in the current calendar year.

As the situation stands, Gazprom has 165 mmcm/d (57.8 bcma) of delivery capacity to Europe via Nord Stream,[3] 100 mmcm/d (36.5 bcma) delivery capacity via the Yamal-Europe pipeline (Belarus), and 16 mmcm/d (5.8 bcma) to Poland via Belarus at Wysokoje, giving a total of 281 mmcm/d (100.1 bcma) to North-Western Europe. Via Ukraine, Gazprom pre-booked 109.6 mmcm/d (40 bcma) for delivery to Poland, Slovakia, Hungary, Moldova, and Romania, and subsequently booked additional capacity sufficient to flow around 125 mmcm/d (the equivalent of 45.6 bcma) for most of the first four months of 2021. In the south, the combined capacity of the Blue Stream (16 bcma) and Turkish Stream (31.5 bcma) pipelines as they make landfall in Turkey is 130 mmcm/d (47.5 bcma). From Turkey, the onward capacity at the Turkey-Bulgaria border is 54 mmcm/d (19.7 bcma).

Therefore, Russia's total capacity for exports to Europe (including Turkey but excluding Finland and the Baltic states) is 187.5 bcma in the calendar year 2021. If Gazprom continues to book an extra 15 mmcm/d of capacity on the Ukrainian route, this would result in an extra 5 bcma of capacity. However, the potential could be much higher: for 2020/21, the Ukrainian TSO, GTSOU, reports technical exit capacity on its western border of 361.5 mmcm/d (132 bcma) to Poland, Slovakia, Hungary, and Romania.[4] This suggests that Ukraine has ample additional transit capacity available, if Gazprom is prepared to pay the higher tariffs. The uncertainty over exactly how much extra Ukrainian transit capacity Gazprom will book in 2021 therefore leaves open the question of how much overall capacity for gas deliveries to Europe will be available to Gazprom, which will in turn impact the total volume of actual deliveries and the extent to which Russian gas supplies to Europe 'bounce back' after their decline in 2020.

For comparison, the annual delivery capacity of Russian gas to Europe in 2020 was 212.5 bcm, given that Turkish Stream was launched in January 2020 and pre-booked transit capacity via Ukraine was 65 bcm. In 2019, Gazprom's European delivery capacity was effectively 238 bcma (that is, without Turkish Stream but with 132 bcma of transit capacity via Ukraine).

In terms of physical flows, Russian gas deliveries to Europe (including Turkey, excluding Finland and the Baltics) were 158 bcm in 2020, down from 193 bcm in 2019. Therefore, while Gazprom is likely to see a year-on-year rebound in 2021, reaching the level of 2019 will only be possible with the launch of new capacity (such as the completion of Nord Stream 2) or the continued booking of additional capacity (above the pre-booked 109.6 mmcm/d) via Ukraine.

To conclude, as the European market enters the summer season, if Gazprom's prompt and Balance of Month ESP sales remain limited while its physical exports remain at full capacity (that is, full physical capacity to NW Europe and booked capacity via Ukraine), they will be indicators that Gazprom's counterparties are continuing to maximise their LTC nominations in order to refill depleted storage stocks, and Gazprom itself is replenishing its own downstream storage stocks in Europe. It is therefore possible that, in this capacity-constrained context, Gazprom's prompt ESP sales will not rebound until either the call on Gazprom's delivery capacity declines, or additional export capacity comes on stream.

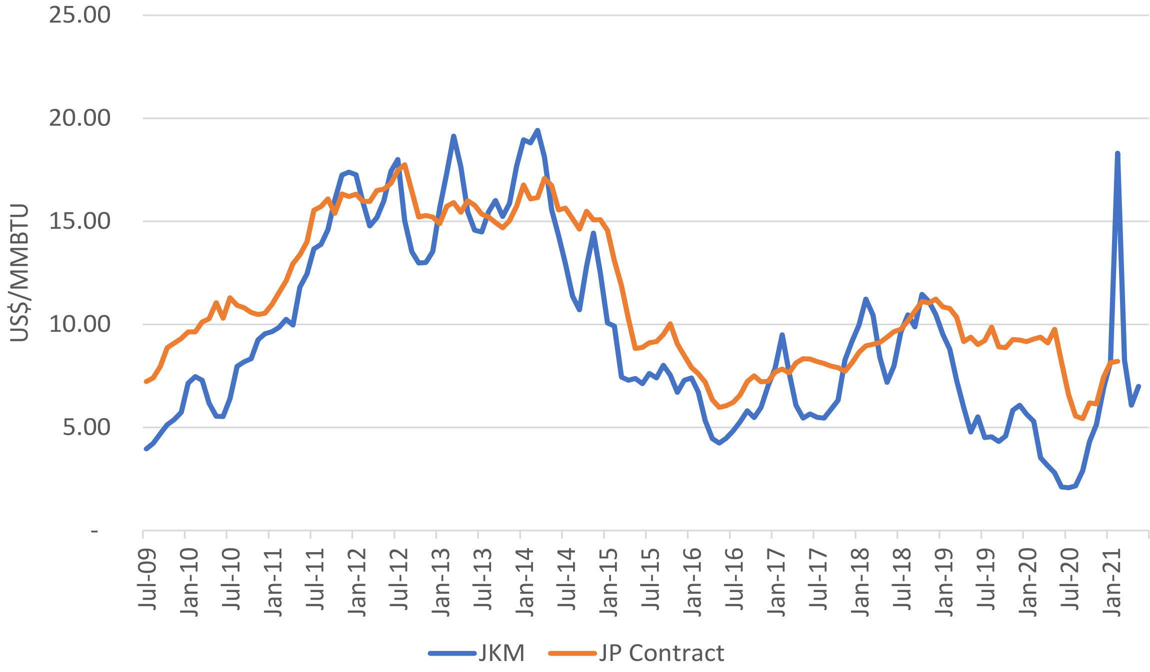
1.3 JKM spot price versus LNG contract price in Asia

The relationship between contract and spot prices in Asia continues to be of significant interest. As we have noted at various times, customers tend to seek changes in the formation of prices when their impact causes them to suffer very substantial financial losses. This certainly occurred in Europe when spot and contract prices diverged and customers began to demand a move away from oil-linked pricing to hub-based prices, catalysed by new EU rules on market liberalisation.

[3] Nord Stream is shut down for maintenance for two weeks every summer, and so only flows for around 350 days a year.

[4] GTSOU, 2021. *Capacity*. https://tsoua.com/en/possibilities-gts/capacity/; GTSOU, 2021. *Information about the capacity for entry/exit points to/out of GTS on interconnection points 2020-2021*. https://tsoua.com/en/transparency/available-capacities/

Figure 1.4: JKM spot price versus Japan LNG contract price



Source: Platts and Argus data, OIES analysis

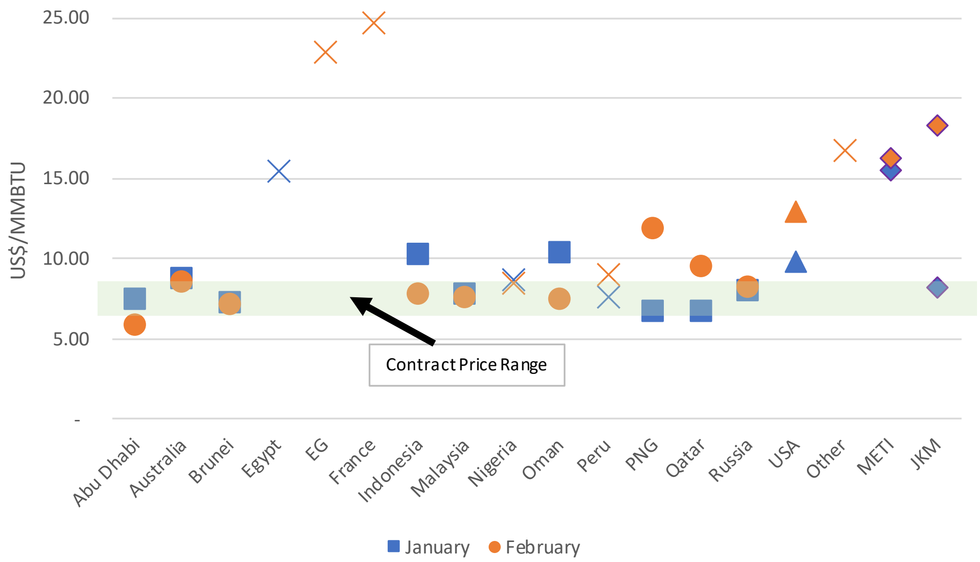
In early 2019, there was a decisive break between the oil-linked contract price and the JKM spot price, as Figure 1.4 shows. Contract prices came down in early 2020 as oil prices had fallen a few months before. The prices began to converge towards the end of last year before we saw the big jump in the JKM spot price in February. Two recent publications by OIES have analysed in some detail the jump in Asian spot prices as a result of the cold winter, supply issues and shipping constraints.[5]

The prices in the graph above are monthly averages and reflect the price on delivery of a cargo. As a result, the high JKM price is the February delivered price, which was determined on price assessments made between December 16 and January 15. The average contract price is itself an average of import prices into Japan from the countries with whom Japanese buyers have long term contracts. In January the average contract price was estimated at 8.14 USD/MMBtu and for February at 8.20 USD/MMBtu. Based on the relationship between JCC and the average contract LNG price, the January and February prices should have been closer to the 6.50 - 7.00 USD/MMBtu range, reflecting a JCC price of around USD 45/bbl a few months earlier. Prior to that an average LNG contract price calculated by lagged JCC prices was a very good fit for the average contract price calculated by reference to the main LNG suppliers with long term contracts. It is likely, therefore, that some of the cargoes coming from Japan's traditional suppliers in the first months of 2021 also included a number of higher-priced spot cargoes.

Figure 1.5 below shows prices in Japan for January and February. Where the prices from the traditional long-term contract suppliers are above the estimated range based on the lagged JCC price, it is likely that there were some much higher priced spot cargoes in the volumes supplied for January and February. In January, the average price of supplies from Australia, Indonesia, and Oman were above the estimated contract price range of 6.00-7.25 USD/MMBtu. The METI arrival spot price was 15.50 USD/MMBtu for January. In addition to around six spot cargoes from Egypt, Nigeria, and Peru, there will have been many cargoes from traditional long-term contract suppliers which were priced at spot around the 15.50 USD/MMBtu average, including some from the US.

[5] Fulwood, Mike, 2021. Asia LNG Price Spike: Perfect Storm or Structural Failure? *OIES Comment*, 17 February. https://www.oxfordenergy.org/publications/asia-lng-price-spike-perfect-storm-or-structural-failure/; Booth, Alex, 2021. LNG Winter 2020/2021 – a unique set of circumstances or a predictable inevitability? *OIES Insight № 88*, 22 April. https://www.oxfordenergy.org/publications/lng-winter-2020-2021-a-unique-set-of-circumstances-or-a-predictable-inevitability/

Figure 1.5: Average Japan prices by country of origin – January and February



Source: METI, Platts and Argus data, OIES analysis

Key: Spot LNG suppliers are X, LT contract suppliers blue square for January and orange circle for February, US LNG is triangle, METI arrival price and JKM are diamond shaped. LT contract price range calculated from lagged JCC.

In February, the average prices of supplies from Australia, PNG, and Qatar were above the estimated contract price range. US prices were also higher than the typical Henry Hub linked formula might suggest. The METI arrival spot price was 16.30 USD/MMBtu for February while JKM was assessed at 18.31 USD/MMBtu. There were some eleven spot cargoes from non-contract sources, with again many more spot cargoes from the traditional long-term contract suppliers plus the US.

The January and February prices from the long-term contract suppliers, therefore, were somewhat distorted by the inclusion of higher priced spot cargoes in the average. The much higher spot prices were picked up in February by all the benchmark assessments such as JKM, ANEA and METI, but it looks as though some of the very short-term spot cargoes delivered in January were not necessarily picked up in the JKM and ANEA delivered prices as the assessments had already been closed for the month.

2. European storage, gas prices and the LNG market

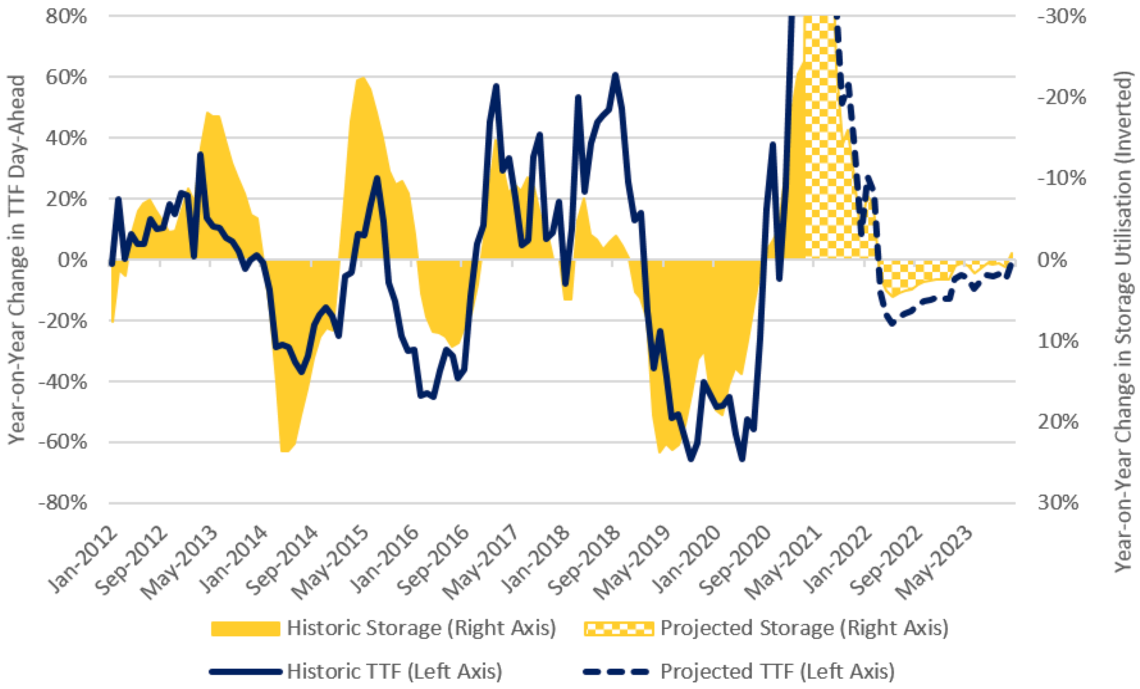
2.1 Storage utilisation and prices

In recent months, we have tracked the correlation between the year-on-year percentage change in monthly average TTF day-ahead prices (EUR/MWh) and the year-on-year percentage change in monthly average European storage stocks as a percentage of European storage capacity. We refer to the latter as the 'storage utilisation rate'. As can be seen in Figure 2.1 (below), while there was a general correlative pattern from January 2012 onwards, this correlation has been particularly close since May 2016, with the exception of the period from April 2018 to February 2019.

It has been our contention that, while correlation does not necessarily imply direct causation, the two dynamics (hub prices and storage utilisation rates) appear to be influenced by the same market forces. Put simply, when the market is supply-long and prices are low, storage stocks are more likely to be accumulated, and thus the storage utilisation rate rises. Conversely, in a tight market, when prices are higher, stocks are less likely to be accumulated and the storage utilisation is accordingly lower.

There are two seasonal factors that may explain this trend. Firstly, in the summer, higher prices reduce the likelihood of a profitable seasonal spread, and so reduce the motivation to inject gas into storage. The flip side of this coin is that low summer prices make a profitable seasonal spread more likely, and so encourage injections. Secondly, in the winter, higher prices indicate higher demand, leading to more gas being withdrawn from storage and the ratio of stocks to capacity being accordingly lower.

Figure 2.1: YoY change in storage utilisation and monthly average TTF day-ahead gas price

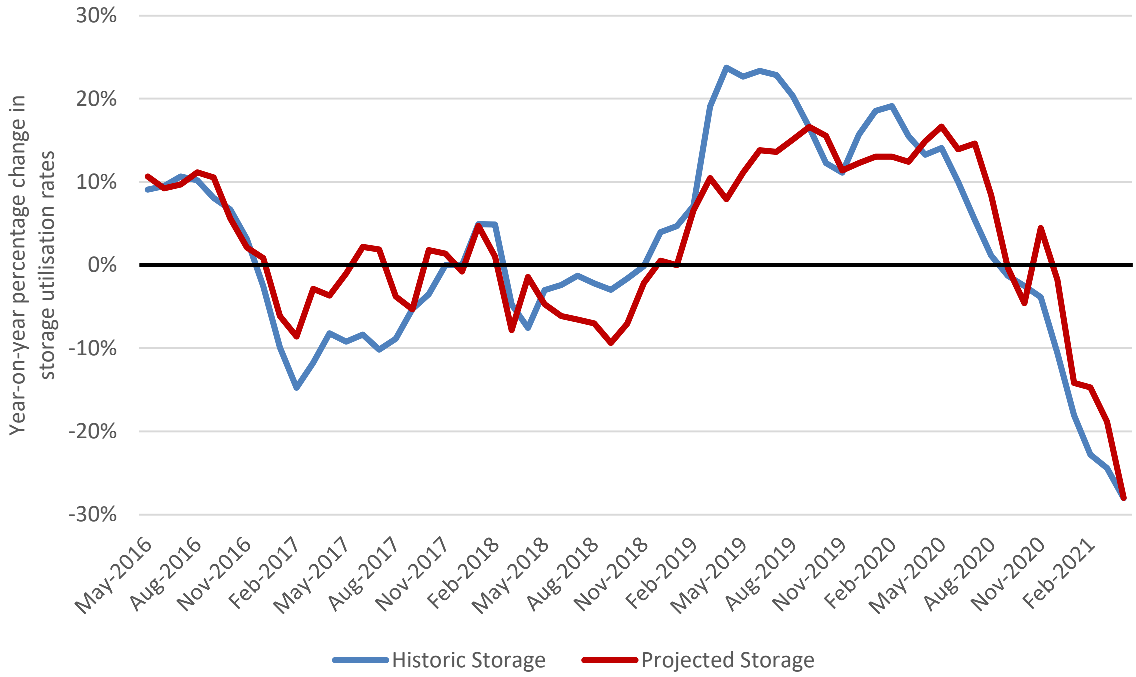


Source: OIES, with data from Argus Media. The r-squared for this dataset (Jan 2012 to April 2021) is 0.51.

The first quarter of 2021 posed a new challenge to this relationship. Between January 2012 and December 2020, the year-on-year percentage change in monthly average TTF day-ahead prices was never greater than +61 per cent, and never lower than -66 per cent. By contrast, in January 2021, the monthly average TTF day-ahead price was 84 per cent higher than in January 2020, while the relative figures for February and March 2021 were 87 per cent and 107 per cent higher, respectively. In April, the monthly average TTF day-ahead price (20.92 EUR/MWh) was 224 per cent higher than in April 2020 (6.47 EUR/MWh). In short, during the period covered by the available data (that is, since January 2012), the year-on-year percentage change in European hub gas prices has never been so dramatic as in the past four months.

If the correlative relationship between prices and storage utilisation were to hold true, this would imply an equally dramatic reduction in European storage stocks relative to storage capacity (namely a reduction in the storage utilisation rate) proportionate to the rise in monthly average day-ahead hub prices. As Figure 2.2 illustrates, this is precisely what happened in Q1 2021. The actual decline in storage utilisation rates correlated closely with the decline in storage utilisation that would have been predicted, based on the rise in hub prices. In order to refine the analysis, the regression analysis was re-run using only data for the past five years (since May 2016), and the results are illustrated below.

Figure 2.2: Year-on-year changes in actual storage utilisation and predicted storage utilisation rates - The latter based on year-on-year changes in monthly average day-ahead TTF prices



Source: OIES, with data from Argus Media (prices) and Gas Infrastructure Europe (Aggregated Storage Inventory). The r-squared for this dataset (May 2016 to April 2021) is 0.75.

A greater challenge to this correlative relationship emerged with both the dramatic year-on-year change in monthly average TTF day-ahead prices in April 2021, and the TTF forward curve as it stood on 29 April 2021.[6] As Figure 2.1 (above) illustrates, the forward curve implies that the year-on-year percentage change in TTF prices will not turn negative until March/April 2022. In other words, the market currently expects that TTF prices will be higher than the year before for the next twelve months.

Given the historically low European hub prices seen in the summer and autumn of 2020, this is not surprising. Furthermore, while the surge in hub prices in Q1 2021 was impressive relative to the preceding months, monthly average TTF day-ahead prices in Q1 2021 (between 17.40-20.40 EUR/MWh – roughly 6-7 USD per MMBtu) were very much in the range of monthly average prices in Q1 over the preceding decade (16-26 EUR/MWh, or 5.50-9.00 USD per MMBtu).[7]

More spectacularly, the forward curve implies year-on-year percentage changes in TTF prices of between 200 and 360 per cent in May, June, and July 2021. In absolute terms, the forward curve for TTF prices in Q2 and Q3 2021 shows prices of around 22 EUR/MWh (7.30-7.50 USD per MMBtu), compared to prices of 4-5 EUR/MWh (1.40-1.75 USD per MMBtu) in Q2 2020, and 7.80 EUR/MWh (2.70 USD/MMBtu) in Q3 2020. Therefore, it is not only the case that the forward curve implies the highest summer prices since summer 2018, but also that the basis for year-on-year comparison (the prices of summer 2020) is so low.

When the year-on-year percentage changes in prices generated by the forward curve are applied to the established relationship between prices and storage, the forecast for the near-term decline in storage utilisation rates in May, June, and July (between -40 and -70 per cent) would cause storage stocks to fall to unrealistic levels. Indeed, since January 2012, the greatest year-on-year changes in monthly average storage utilisation rates have been plus/minus 28 per cent. Therefore, for the period

[6] CME Group, 2021. *Dutch TTF Natural Gas Calendar Month Futures – Settlements: Thursday 29 April (Final)*. https://www.cmegroup.com/trading/energy/natural-gas/dutch-ttf-natural-gas-calendar-month_quotes_settlements_futures.html
[7] The exceptionally high prices of Q1 2013 and the exceptionally low prices of Q1 2016 and 2020 lie outside this range.

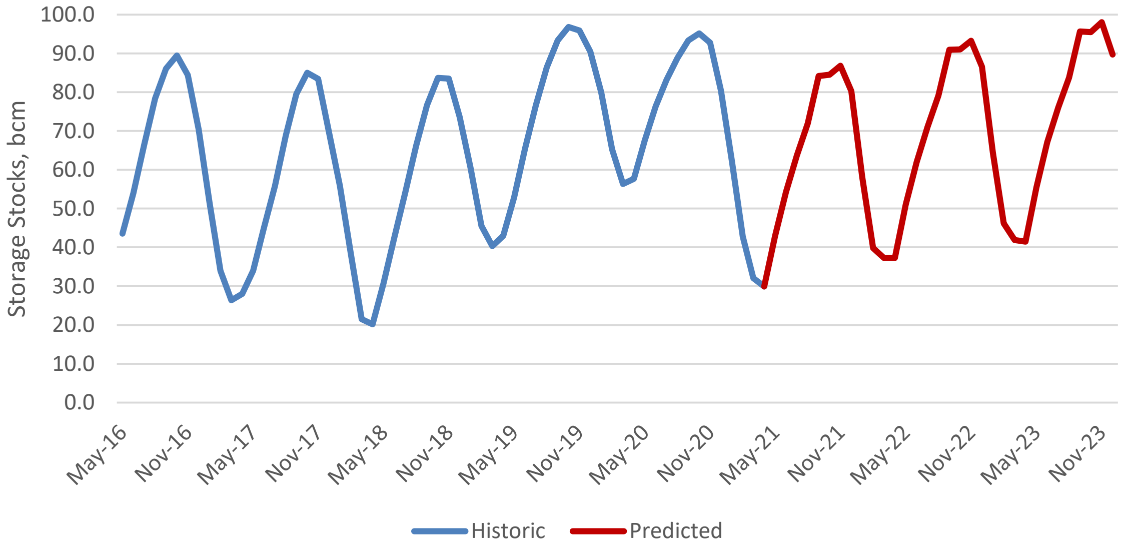
May to July 2021 only, we took the decision to cap the predicted year-on-year change in storage utilisation rates at plus/minus 28 per cent (the actual figure for April 2021).

In effect, the forecast year-on-year change in TTF prices for May-July 2021 is so great as to fall outside the range of prices tested by the historical dataset for year-on-year changes in prices and storage utilisation rates. In statistical terms, it is not appropriate to project a relationship going forward when the parameters are outside the historic boundaries.

When the forecast year-on-year changes in storage utilisation rates (based on the TTF forward curve) are translated into actual storage volumes (expressed in bcm), the result is expressed in Figure 2.3 (below). For the period May 2016 to April 2021, the graph shows historic storage stocks (blue) and from May 2021 onwards, the predicted storage stocks are based on the TTF forward curve (red).

As the graph shows, the predicted storage stocks based on the current TTF forward curve could result in start-of-winter stocks of 85 bcm in October 2021 – very similar to October 2017 and October 2018. Further into the future, the predicted stocks for October 2022 (91 bcm) and October 2023 (96 bcm), reach levels similar to those see in October 2019 and October 2020. This would imply European storage injections of approximately 55 bcm in summer 2021.

Figure 2.3: Historical European gas storage stocks for the past five years (May 2016 to April 2021) and forecast storage stocks (May 2021 to December 2023)



Source: Data from Argus (TTF historical prices), CME (TTF forward curve), Gas Infrastructure Europe (historical storage stocks), and OIES (forecast storage stocks)

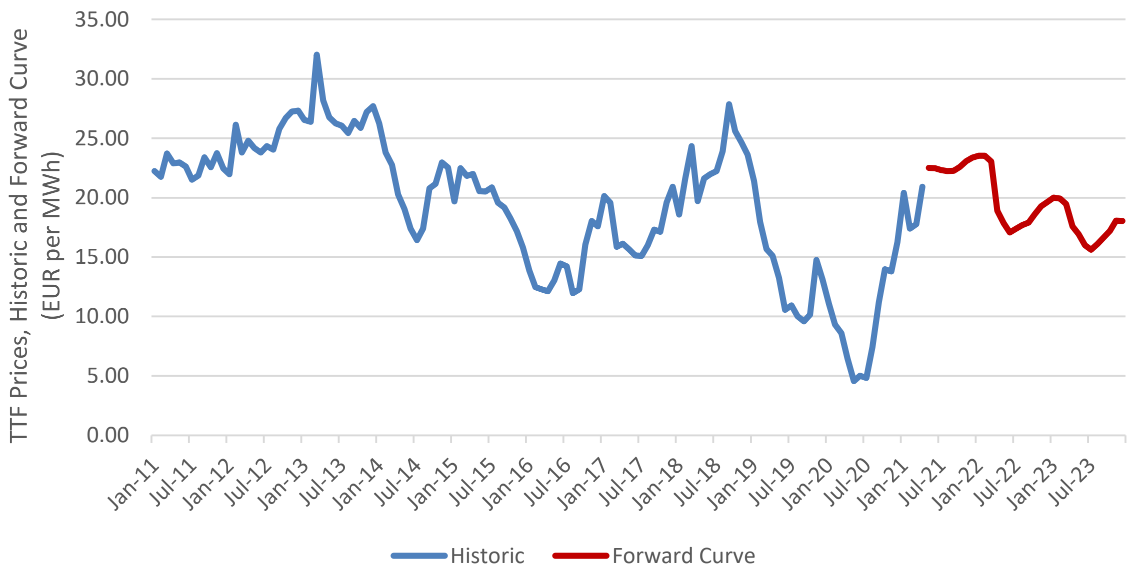
Comparing this forecast to recent years, summer injections of 55 bcm in 2021 would be higher than the average for 2013-2016 (49 bcm), and marginally lower than those seen in the summers of 2017 (59 bcm) and 2019 (57 bcm). Such injections in summer 2021 would be substantially lower than those seen in summer 2018 (64 bcm), which was the last time European storage was replenished after a dramatic draw-down in late winter 2017/18. The key difference between the summer injection seasons of 2018 and 2021 is that in 2018, a substantial seasonal spread existed along the forward curve, to motivate injections. By contrast, in 2021, the forward curve exhibits very little spread between summer and the following winter. The last time injections were substantially below 50 bcm was in the summer of 2020, when injections of 38 bcm were limited by an overhang of gas in storage at the end of winter 2019/20 and storage facilities reaching full capacity by late summer. Looking further forward beyond 2021, the predictions based on the TTF forward curve are for injections of 54 bcm in both summer 2022 and summer 2023.

Therefore, the fact that the analysis generates substantial predicted storage injections despite the narrow summer-winter spread implied by the TTF forward curve, which amounts to little more than 1.30 EUR/MWh (0.50 USD/MMBtu) between August 2021 and January 2022, deserves further scrutiny.

A comparison of historical TTF day-ahead prices and the TTF forward curve sheds light on this conundrum. The current forward curve, which shows a price of about 22 EUR/MWh (7.90 USD per MMBtu) for summer 2021, puts the European market back at summer pricing levels last seen in 2018. While a certain percentage of storage stocks 'at the top of the tank' may be motivated by summer-winter spreads, it seems that a substantial proportion of European storage injections are made even if the spreads are narrow, given the need of wholesale traders and suppliers to ensure that they can meet their commitments to final consumers during the winter months. This could support European hub prices this summer.

It follows that if the forward curve were to shift and open up greater seasonal spreads, Europe could see greater volumes of storage injections during the summer. This, in turn, could bring European storage stocks at the start of winter back to the levels seen in October 2019 and 2020, with implications for the global LNG market. This is discussed in the next section.

Figure 2.4: Historic TTF Day-Ahead Prices and TTF Forward Curve



Source: Data from Argus (TTF historical prices) and CME (TTF forward curve)

To conclude, the dynamics of historical prices and storage utilisation, and the forecasts for storage based on the TTF forward curve, would seem to suggest that the distinct period from mid-2019 to late 2020 (influenced by a supply-long global LNG market in 2019 and the COVID-19 pandemic in 2020) could be drawing to a close. The structural build-up of large storage stocks that was carried over from one winter to another has potentially unwound, and the market as a whole could be reverting back to pricing levels of 15-23 EUR/MWh (5-8 USD per MMBtu) seen between March 2014 and August 2018.

Looking specifically at the summer of 2021, much remains uncertain. As mentioned above, if the growth in Asian LNG demand in summer 2021 is not as strong as currently forecast, and the European market begins to absorb more LNG, the result will be lower prices and higher rates of storage injection, which could once again bring Europe's start-of-winter stocks back to 100 bcm, as seen in the past two winters. These influential factors are discussed below.

2.2. Implications for the LNG market

The previous section noted that European summer storage injections could be around 55 bcm to be consistent with the TTF forward curve. It was noted that this leaves storage stocks below the levels seen in 2019 and 2020. The amount of gas injected has significant implications for the LNG market. The table below looks at the European[8] summer supply-demand balance.

Table 2.1: Europe Summer (Q2/Q3) Supply – Demand Balance

BCM	2018	2019	2020	2021 Range	
Production	117.7	107.3	100.5	100.0	100.0
Pipe Imports (Net)	111.8	104.2	88.8	105.0	100.0
LNG Imports	30.4	55.8	53.9	55.0	65.0
Total Supply	*259.9*	*267.3*	*243.2*	*260.0*	*265.0*
Consumption	191.0	206.8	196.1	205.0	205.0
LNG Exports	3.2	3.2	2.5	-	-
Storage Injection	66.0	57.9	42.6	55.0	60.0
Total Requirement	*260.1*	*267.9*	*241.2*	*260.0*	*265.0*
Statistical Difference	*-0.2*	*-0.6*	*2.0*	-	-

Source: Data from IEA, ENTSOG, Platts LNG Service and OIES Estimates

Gas production has been declining rapidly, principally driven by the sharp fall in Groningen production, although this is now slowing. With Norwegian production picking up, the level of total European production in summer 2021 could be similar to last year.

Net pipeline imports (gross imports less exports, mainly to Ukraine) were down sharply last year, especially from Russia. Imports from Russia in 2021 are running at slightly higher levels than last year and, even with the reduced capacity bookings on the Ukraine route, a recovery in the summer is expected, but not back to 2019 levels. However, volumes on Turkish Stream are increasing now the connection from Turkey to Serbia is operating (via the existing connection to Bulgaria and in addition to the flows to Greece via Bulgaria), effectively diverting volumes which previously went via Ukraine. Looking forward, the onward connection from Serbia to Hungary (due in October 2021) will stimulate further flows via Turkish Stream. Finally, volumes from Azerbaijan are rising with the completion of the Trans-Adriatic Pipeline (TAP) into Italy.

Gazprom recently stated[9] that exports to Europe, excluding the Baltic states, could be between flat or up 5 per cent on last year. The high end of the range for pipeline imports in Table 2.1 above would imply a rise of 5 per cent or more from Gazprom while the lower end of the range would suggest no change or a smaller rise. The rise in volumes from Azerbaijan, Iran, and possibly Algeria has also contributed to the rise in overall pipeline imports compared to 2020.

If consumption is assumed to rise back to 2019 levels – which were higher than 2018 as a result of the coal-to-gas switching in power – then with 55 bcm of storage injection there is room for 55 bcm of LNG imports, similar to 2019 and 2020 levels. As a reminder, European LNG import volumes were very high in April and May 2020, before falling sharply for the rest of the summer. LNG imports could be significantly higher if pipeline imports were lower – for example if Russian volumes were lower – and if more gas was injected into storage. In April, there was very little net injection into storage, so a 55 bcm injection in the summer from May to October, would require injections to average at least 9 bcm a month – most likely less in May and September-October, and closer to 10-12 bcm in the June to August period.

Figure 2.5 shows the monthly historic and projected LNG imports compared to export capacity.

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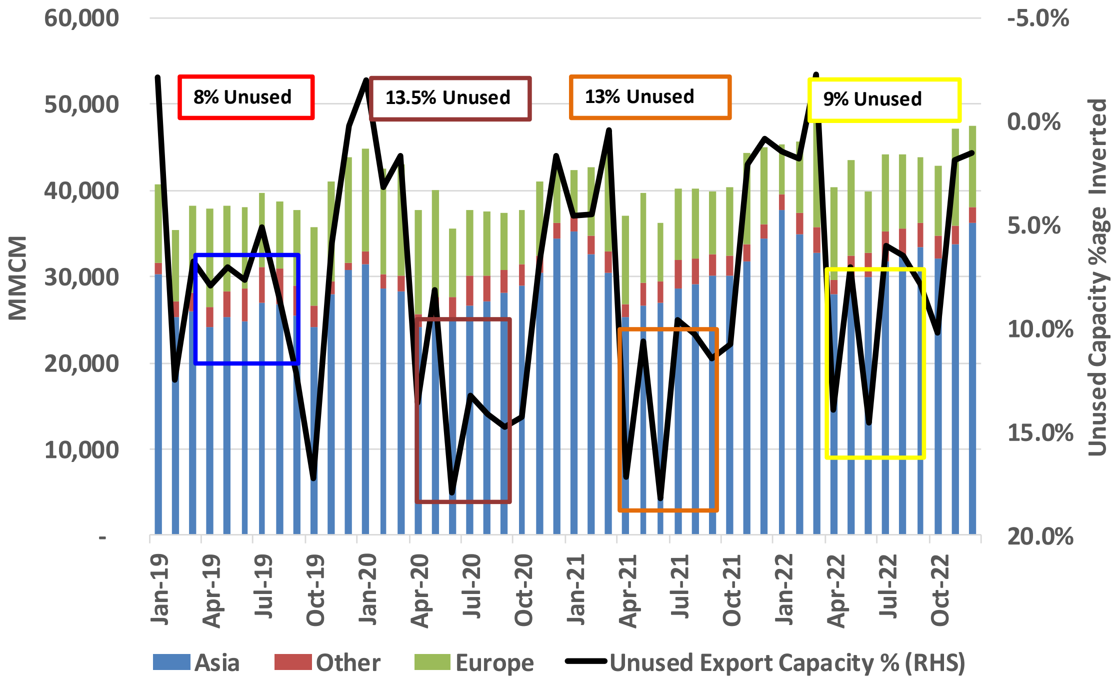
[8] Europe includes the EU plus UK, Switzerland, the Balkan countries, and Turkey.

[9] Argus Media, April 29 2021

Figure 2.5: Monthly LNG Imports



Source: Platts LNG Service, Nexant World Gas Model, OIES estimates

LNG imports are seasonal with higher volumes in the northern hemisphere winter months, so more unused capacity is usual in the summer. Asia is the key demand centre for LNG and the underlying assumption in the figure above is for a 7 per cent increase year on year (a rise of around 11 bcm) driven by higher volumes in China and all other Asian countries, including India, except for Japan, Korea, Taiwan, where volumes are slightly lower. Other markets have slightly lower volumes and European LNG imports are at 55 bcm – marginally lower than in 2020.

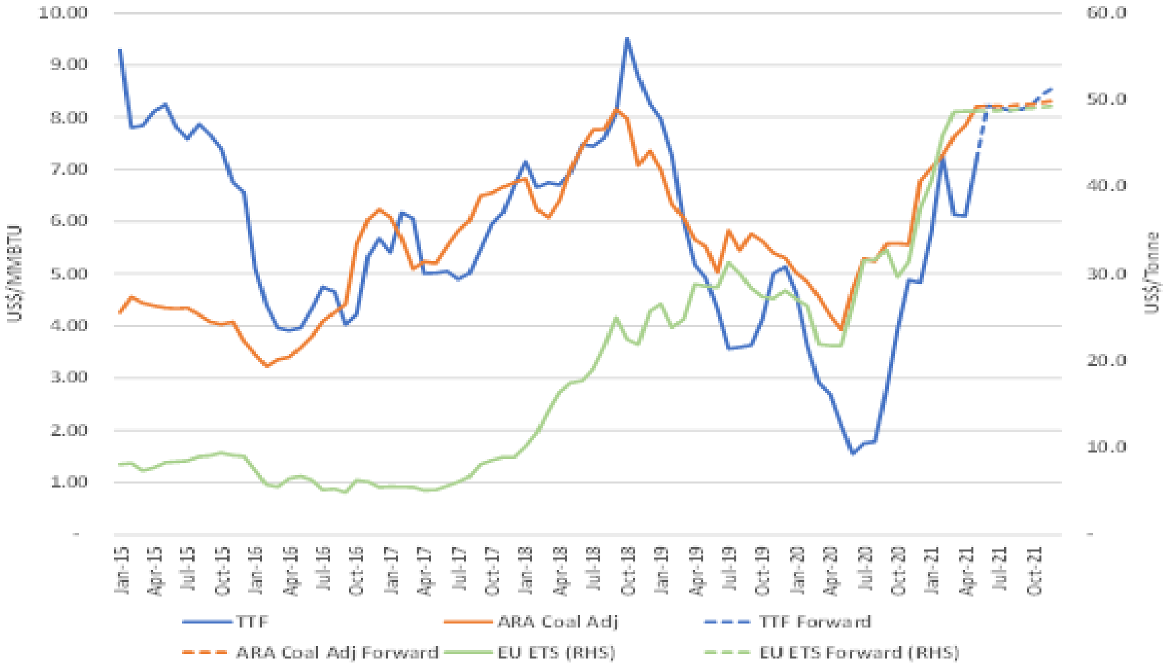
This leaves the level of unused export capacity at a similar percentage to 2020, when the market saw shut-ins of significant volumes of LNG, especially from the US. Clearly higher demand from Asia or even other markets could soak up some of the excess capacity but more LNG could also go into Europe to fill up storage. If an extra 10 bcm were imported into Europe – around 100-120 cargoes, as shown in the upper range of Table 2.1 – then the unused capacity percentage would be at a similar level to 2019. In 2022, rising demand, especially in Asia, reduces the level of unused capacity.

As noted in Section 2.1, a storage injection of 55 bcm is consistent with the current forward curve for TTF of around 22 EUR/MWh (around 7.50-8.00 USD/MMBtu). This level of storage injection would take the total in storage in mid-October to around 85 bcm, which is similar to the 5-year average of storage stocks between 2014 and 2018. In order to incentivise storage injection above these levels – especially in Q3 – we would need much lower TTF prices to create a wide enough summer – winter spread; the current Q3 2021 to Q1 2022 spread is only 1 EUR/MWh (0.30 to 0.40 USD/MMBtu). The current forward curve is consistent with 2018 prices, when summer injections were around 65 bcm, above our projection for this summer. However, in 2018/19 the forward curve spread was three to four times wider than the current spread.

The implications of European summer storage injections of 55 bcm, from Table 2.1, is that some available supply needs to be shut in. Based on the marginal cost of supply, it is LNG which takes the hit, as pipeline imports into Europe rebound – some increase from Russia is expected, but not back to 2019 levels, with additional increases from Azerbaijan, Iran, and Algeria. In order to avoid LNG shut-ins this summer, either:

- European storage needs to fill more than might be expected, based on the current TTF forward curve, suggesting lower summer TTF prices to create the incentive, especially in Q3
- Europe production and/or pipe imports must be lower, creating more room for LNG to meet demand; or
- Demand for LNG outside Europe, especially in Asia, must be higher.

Figure 2.6: TTF and Rotterdam Coal Prices (adjusted for carbon price) and ETS Prices



Source: Argus Media, ICE

The other key issue relates to European demand. Table 2.1 (above) assumes a return to 2019 levels, when there was significant coal-to-gas switching, reflecting much lower TTF prices than the adjusted coal price[10] in Europe. Coal-to-gas switching continued in 2020 as the TTF price remained well below adjusted coal prices. However, the forward curve shows a significant rise in TTF prices this summer compared to last year. But EU ETS prices are also well above last year's levels, and the adjusted Rotterdam coal prices are on a par with the TTF price, looking forward. Effectively the rise in the EU ETS price has compensated for the much larger rise in TTF prices relative to coal. Whether the competitiveness of gas relative to (carbon and efficiency-adjusted) coal in power generation can be maintained this summer is finely balanced. If gas becomes more expensive than coal, and consequently, the share of gas in power generation is not maintained, then lower European gas demand would increase the pressure to reduce imports and/or increase storage injection, leading to downward pressure on gas prices that could then re-establish the competitiveness of gas relative to coal in power generation.

In respect of monitoring the progress in the market, the key metrics to follow would be:

- Is injection into European storage running above 11 bcm a month from May onwards, which could lead to Europe LNG imports averaging above 8.5 bcm (6.25 mt) a month? This would imply lower prices in Europe.

[10] ARA coal price adjusted for the relatively higher carbon costs of coal and the relative efficiency of gas power plants to coal power plants.

- Are Asian LNG imports above or below our projected rate of some 26 bcm (19 mt) a month from April rising to 30 bcm (22 mt) a month by September? A higher number would imply stronger prices in Europe and vice versa.
- Will ‘Other’ LNG imports (outside Europe and Asia), average 2.5 bcm (1.8 mt) a month or be higher? If they are higher then again this could put upward pressure on prices in Europe.

The global gas market can balance at the current forward curve levels, with higher Asian and Other LNG imports noted in the bullet points above. In the absence of this, Europe would need to absorb more LNG this summer than the ‘expected’ 8.5 bcm per month. Lower pipeline imports and/or European production could accommodate this with the market clearing again at the forward curve, but if storage injections are running at much higher rates to repeat the filling of storage in 2019 and 2020, then the market might be expected to clear at lower prices than the current forward curve, especially in Q3.

3. Conclusions

After a summer of historically low prices, LNG shut-ins, and the refilling again of European storage facilities, Q4 2020 saw a return to market conditions similar to those in late 2019, which was itself a supply-long year. In that context, the sudden cold spell of weather that occurred across the northern hemisphere in Q1 2021, with its domino-like effect across North-East Asia, Europe, and the US, appears to have caught those markets somewhat off-guard, perhaps lulled into a false sense of security by a couple of consecutive mild winters and a general feeling of oversupply on the global market.

The impact of that cold weather was to generate a surge in demand that triggered price spikes in North-East Asia that pulled LNG cargoes away from Europe, as Europe itself drew heavily on its own storage stocks. In effect, European storage balanced the global LNG market. Despite the high spot prices paid for some LNG cargoes, as noted earlier, market participants were perhaps fortunate to enter the winter with very high storage stocks in Europe and a continuing oversupply on the global LNG market. The latter is set to ease in the next two years as overall demand rises and fewer new export projects come on stream. Furthermore, the ability to meet the demand surge in three different regions was enhanced by the fact that those demand surges occurred at slightly different times. If both European storage stocks and the general level of supply relative to demand on the global LNG market had been lower, and/or the particularly cold snaps of weather had occurred simultaneously in Europe, North-East Asia, and the US, the picture may well have been rather more dramatic.

Looking forward, the TTF forward curve, and Asian prices as well, may well be incorporating a ‘fear’ premium based on the events of the winter just gone when Asian buyers were caught out by the very cold weather. In the absence of sufficiently strong Asian LNG demand in 2021 and/or a failure of the rebound in European pipeline imports to materialise, it seems rather more likely that prices during the summer will fall below those of the forward curve. This would prompt both greater injections into European storage and the stimulation of greater LNG imports into the most price-sensitive markets (with the caveat being the influence of COVID-19 on domestic demand, as currently seen in India), which could reduce the likelihood of LNG shut-ins this summer.

All we can say for certain is that the key metrics that we shall be following in the coming months – European and Asian gas prices, European storage injections, and Asian LNG imports – will unfold in parallel, and will influence one another as they do so. By the time our next Quarterly is published, the general trend in each of these metrics will be clearer, and they will provide an indication of where the market is likely to be heading going into the winter. After the rollercoaster ride of the past twelve months, there will be many market participants more than happy to settle for a ‘regular supply-long summer’.