MAY 2020

Quarterly Gas Review:
The impact of COVID-19 on global gas markets

Introduction

In this Quarterly Review we provide an initial assessment of the most important issue facing global energy markets in 2020, namely what will the impact of the COVID-19 pandemic and its economic consequences be? We have seen the dramatic effect that the lock-down of many global economies has had on the oil price as the transport sector, which contributes a majority of oil consumption, has effectively ground to a halt. When combined with a collapse in OPEC+ production restraint during March this led to a huge oversupply of crude oil which, for a short period, led to negative prices for the US benchmark WTI.

Our analysis focuses on the gas market and highlights a number of key differences with oil. Firstly, the gas market has been oversupplied for some time due to the emergence of new LNG supply over the past 18 months from projects which took investment decisions in the mid-2010s. This supply has entered the market at a time when global demand has failed to meet growth expectations, and so the COVID-19 pandemic has exacerbated a current problem rather than catalysed a crisis. The situation for suppliers was already bad in the gas market, and it has just been made significantly worse. One mitigating factor, however, is the second difference with oil, namely that gas demand is less focused on one sector and therefore the impact of the crisis is somewhat diversified. Furthermore, low gas prices have allowed gas to become even more competitive relative to its major competitor, coal, which has also offset some of the demand decline caused by the slump in the global economy. Despite all this, though, the gas sector faces a worrying time for the rest of 2020, especially over the summer months when a demand slump could cause a rapid filling of storage in Europe towards its capacity limits.

This Quarterly Review addresses these issues across a number of essays from our research fellows. Following the opening section where we review global gas prices over the past quarter, James Henderson analyses the link between global GDP growth and global gas demand and finds a close correlation in good and bad times, with worrying consequences for gas in 2020. Then Jack Sharples looks at the short-term impact of the crisis in the first four months of 2020 focusing on the balancing market for LNG – Europe. He highlights some key shifts in gas flows, some worrying demand trends and an emerging issue with storage. We then consider the regional impacts of COVID-19, looking at China (Michal Meidan), India (Anupama Sen), Europe (Anouk Honoré), Russia (Tatiana Mitrova) and the US (Mike Fulwood), with a number of differing themes emerging. Mike Fulwood then analyses the potential global supply-demand balance for 2020 based on the IMF forecast of a 3% decline in global GDP and finds that, even in the event of an optimistic V-shaped economic recovery, global gas supply in Q3 2020 will need to be restrained if a WTI-like gas storage crisis is to be averted. Finally, Jonathan Stern and Tatiana Mitrova consider the longer-term outlook for gas in a post-COVID-19 energy economy and find some glimmers of hope amid the overall threats to demand for hydrocarbons.

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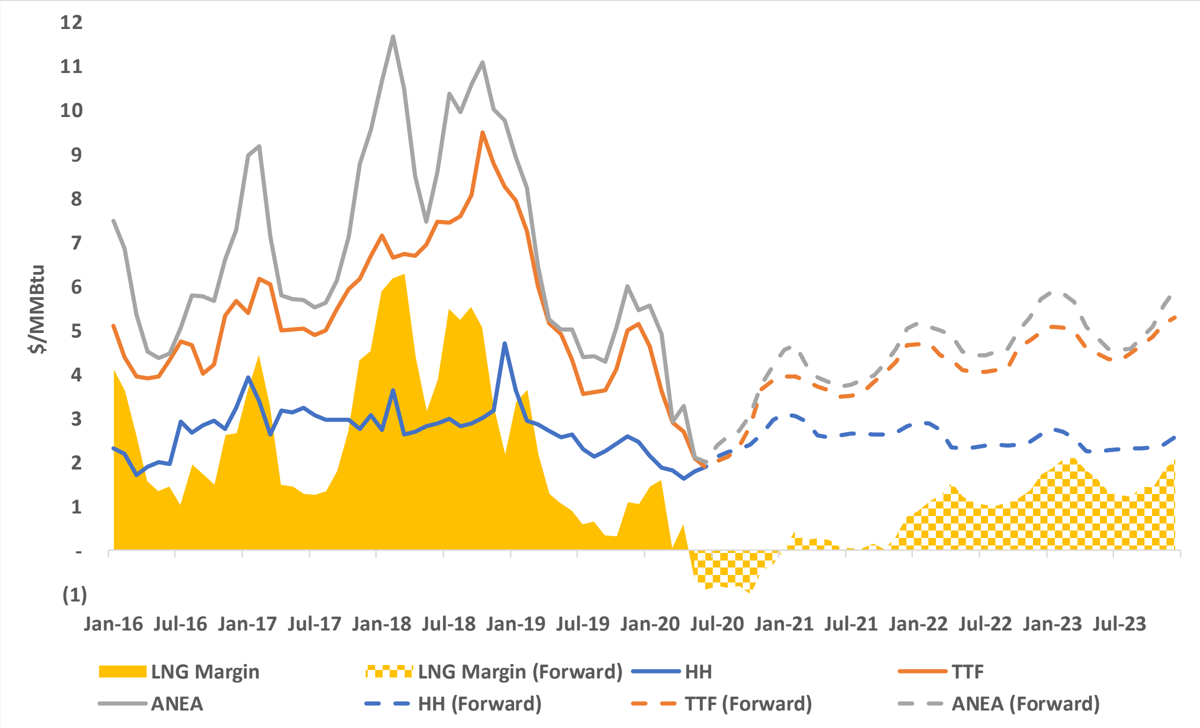
1. Pricing Analysis

Before we outline our thoughts on the impact of COVID-19 on the global gas market, it is worth briefly reviewing the five price-related charts that are the standard opening for our Quarterly Review as all demonstrate the impact of the continuing oversupply situation that was prevalent before the pandemic and is now being exacerbated by it even further.

1.1 LNG Tightness – cash margins have gone negative

Firstly we consider our 'LNG Tightness' analysis as an indicator of whether the gas market is providing any indication that new projects are required to balance the market or whether, alternatively, there is no need for new FIDs in an oversupplied global situation. 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 Gulf of Mexico based on the relevant transport costs. The LNG Tightness calculation is then shown on a historical basis and also based on futures prices, and provides an indication of whether developers in the US can expect to recover the cost of liquefaction on the Gulf Coast (which is generally estimated at around $3/MMBtu based on the traditional Cheniere contract). A margin above this level would provide an obvious incentive for new projects while a margin well below this would suggest an oversupplied market.

Figure 1.1: An assessment of 'LNG Tightness'



Source: OIES, based on data from Argus Media (Forward curve as of May 1st)

Given the current state of the global gas market, it should be no surprise that the indicator is not showing a need for new projects at present as the margin has shrunk dramatically over the past three months. It has now gone negative (based on futures prices) for the whole of the rest of 2020 and does not regain the $3 level that would catalyse new developments throughout the period to the end of 2023. This suggests that some LNG supply could actually be shut-in during the rest of 2020 (as will be discussed in our later analysis of COVID-19) and also that new FIDs are unlikely for some time, based on the price outlook. Of course, a number of caveats should be added. Various issues need to be taken into consideration when contemplating the shut-in of supply, for example offtakers of US LNG may continue to take deliveries for strategic or contractual reasons. Equally, FIDs for new projects are taken on the

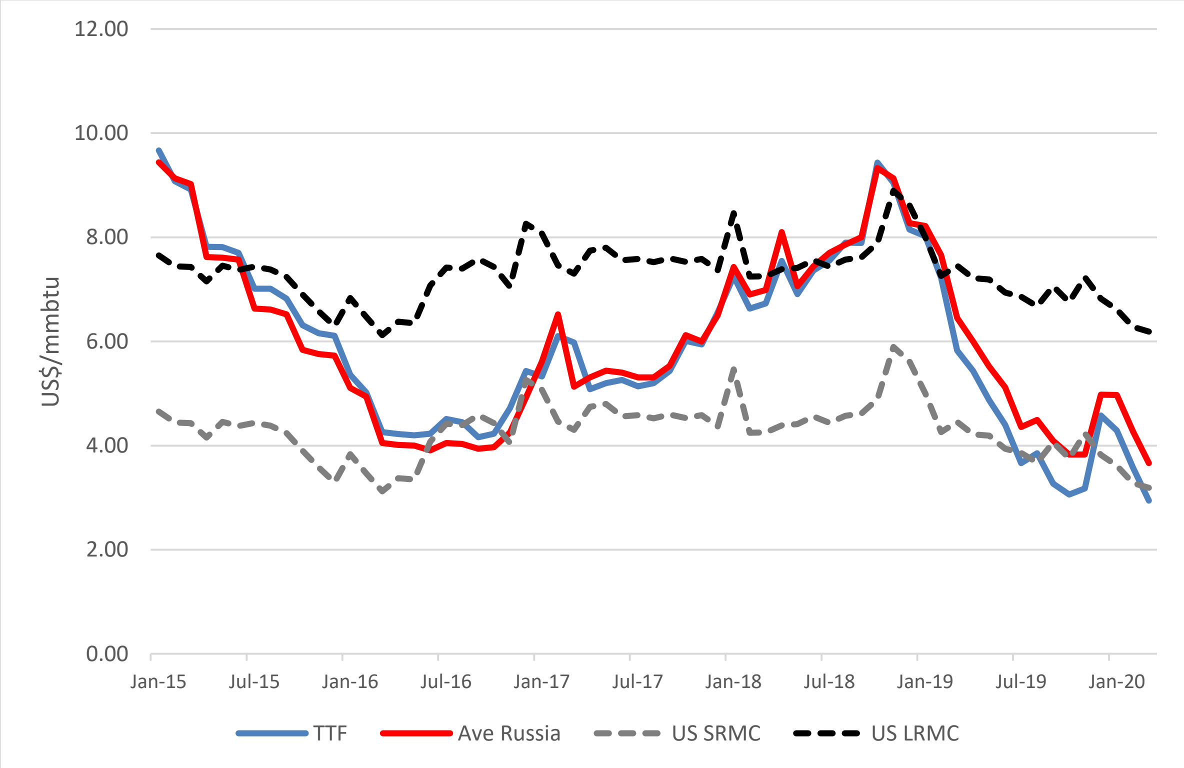
basis of forecasts of long-term LNG demand starting from the mid-2020s and stretching out over the following two to three decades. Nevertheless, the fact that the implied margin is so low at present is a clear signal that the market is very fully supplied and is likely to remain so for some time.

1.2 The Russian gas price and TTF versus US LNG in Europe

The difficulties for LNG suppliers can be illustrated by an examination of prices in Europe, the market of last resort for global LNG supplies, relative to the cost of US LNG. Figure 1.2 compares the average Russian export price with TTF and then compares both with the long- and short-run marginal cost of US LNG, based on the Cheniere formula.[1] It can give some indication of the level of competition in Europe between LNG and pipeline gas from Russia, Norway and other major importers.

As can be seen in Figure 1.2, for which the data was only available to March and therefore does not reflect the full impact of the COVID-19 lockdowns, the price of TTF, the most liquid European hub, has fallen below even the short-run marginal cost of US LNG, while the Russian gas price is heading in the same direction. This does not mean that no LNG can arrive in Europe – indeed volumes are high due to the fall in energy demand across the globe and the need for LNG producers to find a home for surplus supply. However, it does reiterate the point that the market is very competitive and that the price incentive to deliver higher cost LNG to Europe has all but disappeared.

Figure 1.2: Russian gas price and TTF versus US LNG in Europe



Source: OIES, with data from Argus Media

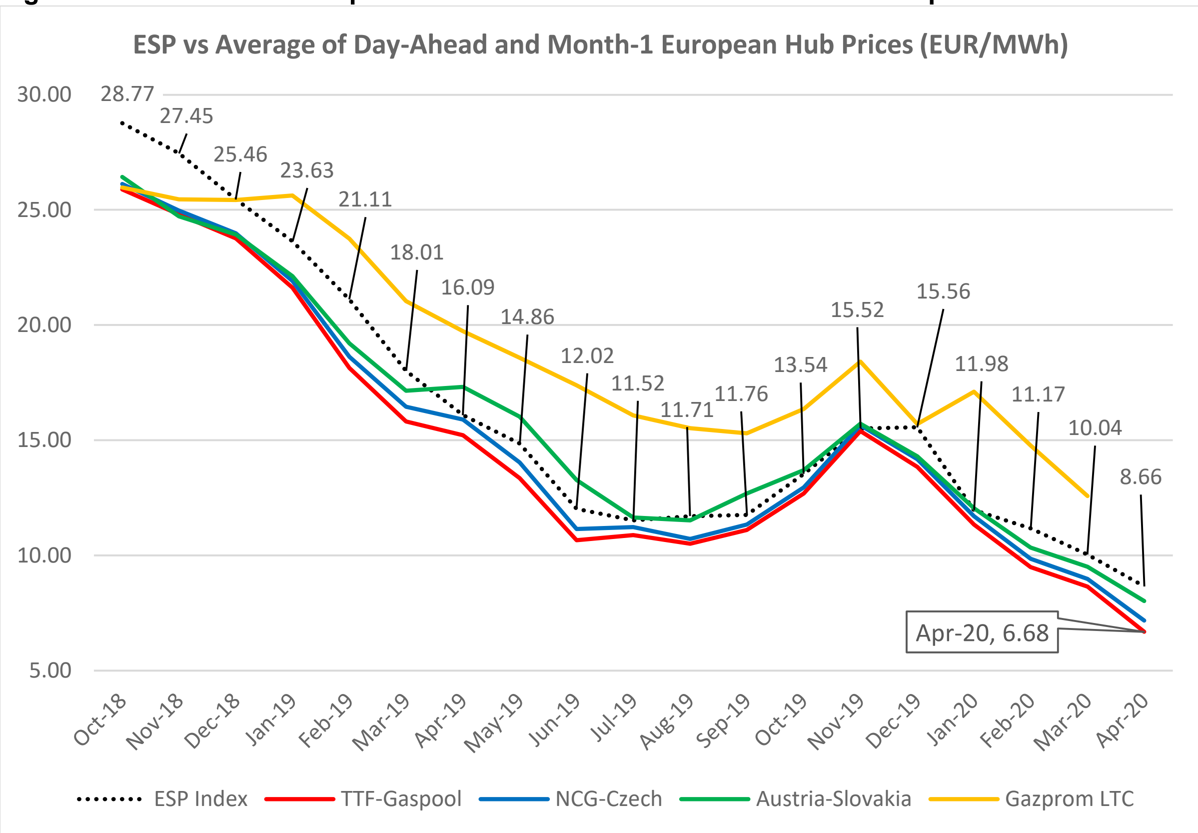
1.3 The price on Gazprom's Electronic Sales Platform

Another indicator of Gazprom's sales strategy in Europe can be found by examining the activity on the company's Electronic Sales Platform. The ESP, as it is known, has been used to sell extra Russian gas to fill pipeline export capacity and to top-up long-term contract sales. Indeed, for some time now the ESP Index (the average of ESP prices across a number of delivery points) has shown a price lower

[1] The Long Run Marginal Cost of US LNG (LRMC) is calculated as ((Henry Hub Price x 1.15) + $3 liquefaction tolling fee + $0.7 transport cost to Europe + $0.4 regasification cost in Europe). The Short Run Marginal Cost (SRMC) is the same calculation without the liquefaction fee.

than Gazprom's long-term contract (LTC) price, and this has continued in 2020. However, while January and February showed a dramatic increase in volumes of short-term gas on the Platform, indicating that Gazprom was offering very competitive gas to make up for a decline in long-term contract sales (as buyers had been nominating down to take-or-pay levels due to lower demand and the availability of cheap gas on European hubs), March has shown a significant change in strategy. Although the ESP price has remained very competitive, the majority of sales are now for month, quarter, season or even year ahead, indicating that Gazprom has no intention of actively engaging in a short-term price war but is now trying to lock in longer-term sales in a very difficult market. As a result, although Russian gas remains very price competitive and is certainly a threat to LNG arriving in Europe, it would at least seem that Gazprom is not keen to see the short-term price in Europe go any lower. Allegedly it has a target price of $100/Mcm, ($2.80/MMBtu or €8.61/MWh), which seems rather optimistic at present but may be reasonable once the European economy starts to become more active as lockdown restrictions are eased.

Figure 1.3: The Price at Gazprom's Electronic Sales Platform versus European Hubs



Source: GazpromExport, Argus Media, OIES

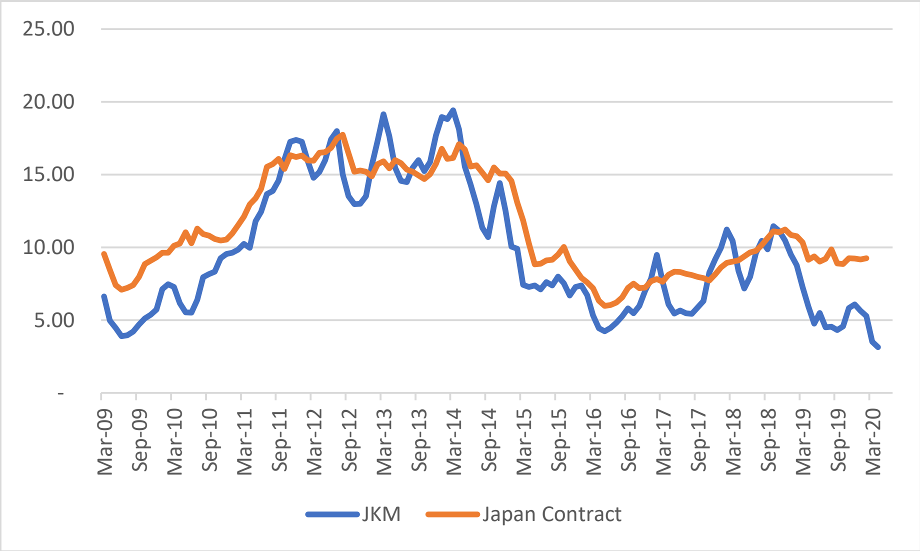
1.4 JKM spot price versus LNG contract price in Asia

The relationship between contract and spot prices in Asia is becoming increasingly interesting. As we have noted in various pieces of research, customers tend to demand change 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 from oil-linked pricing to hub-based prices, catalysed by new EU rules on market liberalisation. The trend away from oil-linked pricing in Asia has been much more gradual, and indeed some might argue that it has barely started, but as Figure 1.4 shows, a significant divergence between spot and contract prices has emerged in 2019 and has widened in 2020 to date, creating a significant incentive for customers to act.

The instance of arbitration cases has started to increase, albeit from a low base, and rumblings of discontent from those tied into higher-priced oil linked contracts has grown. Although COVID-19 issues

remain more important at present, there seems little doubt that if this trend persists we could see a real challenge to oil-linked pricing of LNG in Asia, with the JKM marker already becoming an increasingly liquid and important price benchmark. Of course, at a current oil price of around $20-30 per barrel the pressure may ease in Q4 when this lower level starts to impact long-term LNG contracts, but even then it will not completely solve the problem if spot gas prices remain at their current levels.

Figure 1.4: JKM spot price versus Japan LNG contract price ($/MMBtu)



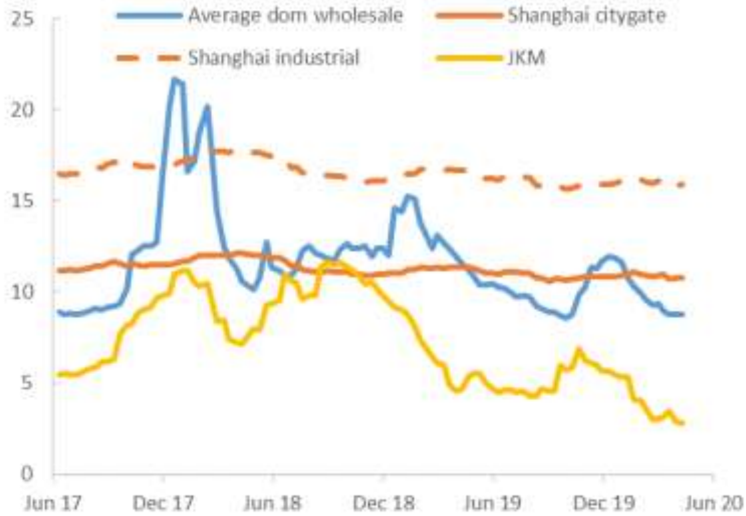
Source: Platts data, OIES analysis

1.5 Chinese domestic price versus LNG import price

An increasingly important indicator in Asia will be the Chinese domestic gas price versus the LNG import price level, and we are now monitoring this on a quarterly basis. The market continues to expect that low spot JKM prices will filter through to domestic prices, leading to an increase in China's gas demand. But as the chart below highlights, domestic city gate prices (taking Shanghai as an example) are disconnected from JKM (and from other international prices for that matter). Chinese domestic prices, which are assessed by the National Bureau of Statistics every 10 days, have been falling steadily over Q1 2020 (in no small part thanks to changes in the RMB/$ exchange rate) and are now roughly $3/MMBtu lower than their 2018-19 averages. However, they have not fallen as fast as JKM and at $8.70/MMBtu they still represent a hefty burden for industrial and commercial users. Going forward, the government has mandated cuts to city-gate prices, and with oil-linked contract prices also expected to decline in the second half of the year as the impact of lower oil prices kicks in, the differential to JKM should start to narrow.

As a result, the impetus for changing the domestic pricing mechanism is increasing. While the government is unlikely to liberalize prices altogether, it will want to see domestic prices reflect international movements more regularly. Yet, while Beijing wants lower prices to encourage end-user demand, it would also like to maintain sufficient incentives for the majors to keep producing domestic gas, suggesting that some level of administrative intervention will remain. Nevertheless, reform efforts do seem to be continuing, despite the overwhelming impact of the COVID-19 pandemic, and we will continue to monitor this price trend through 2020.

Figure 1.5: Chinese gas prices compared to JKM ($/MMBtu)



Source: NBS, SHPGX, Platts, OIES

2. The impact of COVID-19 on global gas markets

Executive Summary

The impact of the COVID-19 pandemic and its economic consequences on energy demand has shown marked differences by fuel. The immediate impact on oil has been dramatic due to the rapid decline of consumption in the transport sector as countries have implemented lock-down policies that have constrained movement of people and goods. The impact on gas has been less immediate, but our analysis suggests that a decline that is closely correlated with global GDP is inevitable over time. In line with the reference case forecast from the IMF we have assumed a 3% decline in global GDP in 2020 which then leads to a 3% decline in gas demand. However, the implied V-shaped economic recovery increasingly looks like an optimistic best-case outcome rather than a base case, and an obvious conclusion is that any worsening of the economic outlook will lead to a similar deterioration in gas demand. We note that the recent IEA report on the impact of COVID-19 sees a 6% decline in global GDP in 2020 and a 5% decline in gas demand.

In terms of the immediate impact of the crisis, in the period up to the end of April we find it particularly useful to look at the balancing market for global LNG, namely Europe. It is interesting to observe that LNG imports into Europe for the entire 4 months to date have been higher than the same period in 2019 due to an excess of global supply and lower than expected demand in Asia. In Q1 this caused a fall in pipeline imports but following the collapse in demand in April it has caused a surge in storage injection, with the result that capacity is now more than 60% full already. In 2019 it only reached this level at the start of June, and in 2017 and 2018 it was reached only at the end of July. The consequence is that if injection continues at normal rates storage could be completely full by early August, perhaps earlier.

In terms of the regional impact, experiences have been colored by the current role of gas in the energy balance and its competitive position relative to alternative fuels. In the US, for example, demand has been hit, but the low price relative to coal has meant that the impact has been offset somewhat in the power sector. Across the world, though, expectations for demand have declined, and although this does not always mean an absolute year-on-year fall in consumption compared with 2019 it does mean that in a world of increasing LNG supply the surplus of gas in 2020 is only set to grow. Resulting low prices will underpin demand in some countries, with India being a prime example of a country that has capacity to use more cheap gas in its power sector, but this will not be enough to offset the overall impact of lower economic activity. Meanwhile, gas demand growth in China will still be positive in 2020 but lower than expected.

In Europe, while the data for March showed a mixed impact on gas across individual countries, April has shown consistent and sharp decline in consumption. Demand in Germany has fallen by 9%, while the UK Spain, Italy and France have all seen year-on-year declines at around 20% or more. Signs of a relaxation of lockdown measures offer some hope for the rest of 2020, but even if a V-shaped recovery does take place we suggest that annual gas demand in Europe will be down by 6%, with the beneficial impact of low gas prices being offset by the increasing availability of renewables in the power sector. Meanwhile in Russia the impact of the virus seems to be increasing and the government is taking steps to protect its citizens by keeping regulated prices frozen and countenancing an increased level of non-payment. Even so, experience of previous crises suggests that gas demand, which accounts for over 50% of Russian energy supply, will at least fall in line with GDP, which the IMF expects to decline by 5.5% in 2020.

Taking these regional views into consideration, we have modelled one possible outcome for the global gas market, based on the IMF reference case mentioned above. We see a 3% decline in global gas demand in this relatively benign scenario but this still results in a level of surplus gas heading to the European market that could overwhelm storage during the summer months. We estimate that almost 50bcm of 'stranded' gas would need to be curtailed to provide any hope of balancing the market. Clearly, this is a world in which low prices are set to persist for some time and in which a storage crisis similar to that seen with West Texas Intermediate (WTI) oil in the US could emerge unless producers start to show significant restraint. Shut-ins appear inevitable, both for LNG and pipeline gas, with those suppliers (along the whole value chain) with the highest variable costs being the most likely to be forced into action.

In the short-term then, the outlook looks bleak unless the health and economic situations improve much faster than seems likely at present. For the longer term, though, the impact of the crisis on natural gas appears somewhat more benign. Low prices may not be sustainable for producers for long, but they can encourage a re-think about gas' role in the energy transition and could delay the most negative impacts. Indeed, in some countries there could be a significant boost to demand if current market forces combined with a rekindled desire for clean air catalyse an accelerated demise for coal. Low spot prices could also accelerate the transition away from oil-linked LNG contracts, which could further improve the competitive position for gas, especially in Asian countries which are expected to account for the majority of the increase in global demand. It will also be instructive to see whether this helps to ease the path for gas in energy transition policy-making even in a world in which governments are being encouraged to focus economic support on green investment. Our initial conclusion is that the strategic direction of the energy transition is unlikely to be altered, but its implementation may be delayed, providing the gas industry with a little additional breathing space to develop the decarbonisation strategy which we continue to believe will be vital for its long-term survival.

As far as the corporate landscape is concerned, the major energy companies had already been shifting their portfolios away from oil and towards gas, and although this process is likely to continue, it will be important to see whether a low price environment significantly undermines the appetite for new investment and whether banks and investors start to shift their priorities away from all hydrocarbons. This could create the potential for a price spike later in the decade if supply is insufficient to meet a rebound in demand, but we do not see this as an issue over the next five years unless a significant number of projects which have already taken investment decisions are deferred or cancelled due to the impact of the pandemic.

One further strategic observation is that, in a market where collapsing prices have reduced the differentials between regions to almost zero, the incentive for larger companies to continue with their portfolio approach to LNG may diminish as the returns from switching gas between markets decline. This could further undermine investment in new projects. A counter argument to this may be that the need for portfolio optimization and creative trading will become even more important during a period when margins are very tight, meaning that large players with multiple options may be able to survive the market downturn and benefit from the commercial problems of smaller companies. As a result, further consolidation in the gas sector may be an inevitable consequence.

A final conclusion is that it goes without saying that all these outcomes are highly dependent on the ultimate course of the health crisis and the timing and pace of any economic recovery. We can only hope that the human tragedy caused by COVID-19 can be alleviated as quickly as possible by the courageous work being done by health services all over the world and by the speedy development of a vaccine and/or effective anti-viral drugs. In the meantime, government action to mitigate the economic consequences and ultimately to return countries to growth will be critical, and energy consumption will clearly respond to this. As we describe, the gas sector will certainly be hit in the short-term, and indeed the outcome could be significantly worse than we describe as the IMF reference case assumption for global GDP which we have used looks increasingly over-optimistic. As a result, a significant demand crisis may emerge this summer, with the implication that storage in Europe could be full by mid-summer leading to a further slump in prices or a significant adjustment in production and exports by major suppliers. However, amid this gloom we do see the prospect of some more benign consequences over the medium term when economic growth returns and if gas is seen as having a positive role to play in sustaining some of the environmental benefits that have been witnessed over the past two months of lock-down.

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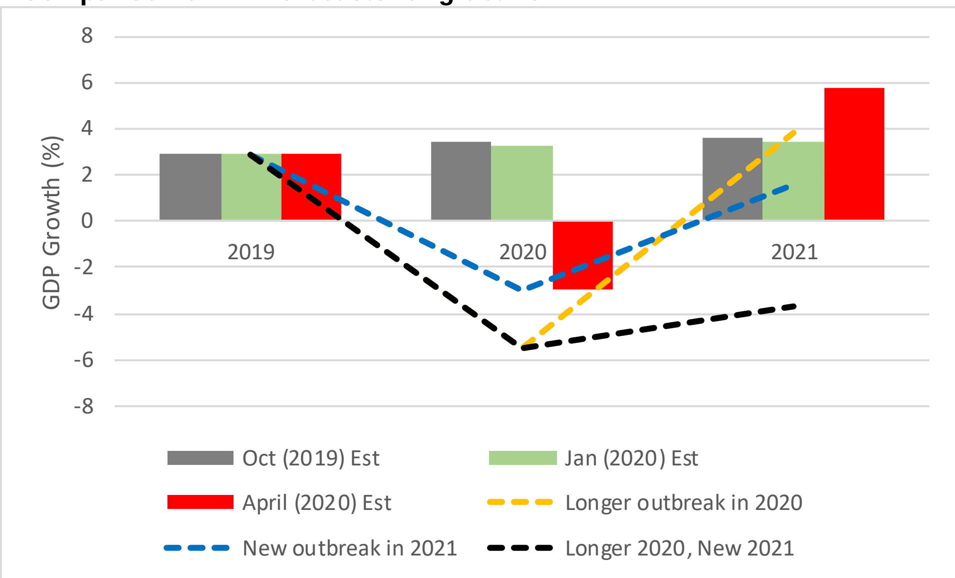
2.1 Global overview – gas markets and economic crises

Views on the economic impact of COVID-19

There seems to be little doubt that the COVID-19 pandemic will cause the greatest economic shock since the Great Depression almost 100 years ago as the lock-down implemented in many countries brings travel and business activity to a temporary halt. However, that is where the consensus among forecasters ends, due to the range of uncertainties around the length of the lock-down, the risk of a second wave of the pandemic, the impact of policies to safeguard businesses during the downturn and the medium term response of the private sector. One potentially worrying observation, though, is that most of the options being modelled by economists only show downside scenarios from their base case, suggesting that concerns over a worse-than-expected outlook abound.

A good starting place for an overview of the situation is the World Economic Outlook published by the International Monetary Fund (IMF), the latest version of which appeared in early April 2020.[2] The base case forecast outlined what would be best termed a 'classic V-shape' decline and recovery, based on the assumption that the maximum impact of COVID-19 will be felt in Q2 2020 and that the virus will then be largely contained and economic activity will be able to re-start, albeit gradually. The red bars in Figure 2.1 show the outcome of this analysis, which results in a decline in global GDP of -3.0 per cent in 2020 followed by a sharp rebound to growth of +5.8 per cent in 2021. This essentially implies an adjustment of -6.3 per cent in the IMF's forecast for 2020 compared to its estimate from January this year (the January estimate is shown in the green bars, and an estimate from October 2019 is shown in grey), underlining the dramatic change in circumstances in only three months.

Figure 2.1: Comparison of IMF forecasts for global GDP



Source: Data from IMF WEO, April 2020

However, as can be seen from the dotted lines in Figure 2.1, the IMF paints three alternative scenarios based on the predicted outcomes of the pandemic. In the first (the yellow line) the pandemic lasts for longer in 2020, implying an extended lockdown and a more dramatic impact on economic activity. This leads to a GDP decline of -5.8 per cent in 2020 and a rebound of +3.8 per cent in 2021, both well below the base case. It is interesting to note that in the case of an extended lockdown the OECD has offered a rule of thumb that each extra month equates to approximately 2 per cent removed from global GDP on an annual basis.[3] A second scenario (blue line) sees a new outbreak in 2021, which has no impact on the base case forecast for 2020 but reduces growth in 2021 to only +1.55 per cent. The third, and

[2] IMF World Economic Outlook, April 2020, at https://www.imf.org/en/Publications/WEO/Issues/2020/04/14/weo-april-2020
[3] OECD Interim Economic Outlook, 'Coronavirus: the world economy at risk' at https://www.oecd.org/economic-outlook/

most pessimistic scenario (black line), sees a combination of the first two outcomes, with an extended lockdown in 2020 and a second wave of the virus in 2021, leading to two years of global recession.

However, these alternative cases only paint half of the picture because another key dynamic is the policy response from governments, which can itself help or hinder economic recovery in any of the health-based outcomes painted by the IMF. Indeed, Oxford Economics have argued in recent papers that these responses will have a much more profound impact on the future of the global economy than the virus itself, and indeed have suggested that a V-shaped recovery is far from a certainty.[4] In fact their analysis shows that only around 60 per cent of GDP slumps caused by major crises have been followed by strong rebounds, and furthermore that the extent of the rebound is not strongly correlated to the size of the slump. As a result, government action is absolutely vital, with a clear divide being noted between 'governments that spend early and aggressively to counter an economic downturn and those that do not.' Also crucial is the ability to preserve industrial activity through the slump so that it is ready to re-start once the crisis is passed, with a particular focus on avoiding financial collapse due to excessive bankruptcies, loan defaults and commodity price slumps. It is interesting to note that Oxford Economics' downside scenario sees the potential for a global GDP decline of -8 per cent in 2020, much worse than the IMF, if the correct policies are not implemented.[5]

While this outlook appears remarkably gloomy, with only negative scenarios around the base case, some glimmers of hope have been identified. The consultants McKinsey & Co. have created a matrix of potential outcomes based on public health response and economic policies which identifies all the cases mentioned above but also sees variations in which the pandemic is effectively controlled and governments intervene in a strong and positive fashion.[6] This still leads to an economic decline in the short-term, although the magnitude is lower at -1.5 per cent for 2020, before a strong recovery in 2021. Nevertheless, even this research sees more negative than positive potential outcomes and also highlights a further risk, namely that the effect on emerging markets could ultimately be more painful than for developed markets that are currently feeling the worst of the impact.

This theme is picked up by other analysts who highlight that, although developed markets are likely to have a worse short-term outcome, the shock could be limited by aggressive intervention and by the relative strength of country balance sheets.[7] For emerging markets, the health crisis is taking longer to develop (possibly because of less extensive travel infrastructure) but could ultimately be more damaging and last longer because of poorer health facilities. In addition, the economic downturn could be exacerbated by a more limited ability to use significant state investment as a lever of economic growth and also due to the higher existing debt levels in many poorer nations.

Overall, then, while the economic outlook is obviously bad the key questions are how bad and for how long? The two key drivers behind the answers have different characteristics. On the one hand the spread of COVID-19 and the temporal extent of its impact are still relatively unknown and could cause further exogenous shocks. On the other, government responses are within our control, but uncertainty remains as to how forcefully and effectively they will be implemented. The outcome would appear to be a global GDP decline of between 3 and 8 per cent in 2020, with a potential return to growth in 2021, but the impact will be felt differently across countries and regions, with OECD markets suffering more in the short-term but with non-OECD markets likely to feel a more significant long-term effect.

What could this mean for the global gas market?

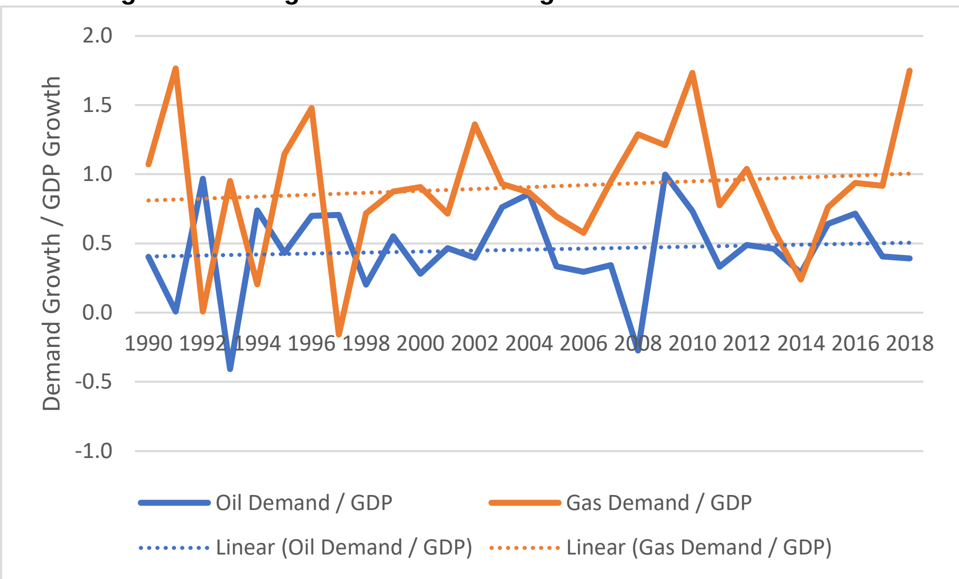
Energy demand growth is broadly related to economic activity and population growth, with the latter providing a more stable long-term trend while the former can obviously be much more volatile, as we are experiencing at present. In fact, when we look at the historic data for global total primary energy supply (TPES) and world GDP growth, in the period 1990-2018 the correlation between the two has been fairly tight, with an r^2 of 0.79 rising to 0.87 for the past decade.[8] During previous economic

[4] Oxford Economics (April 2020). 'After the pandemic: Medium-term growth uncertainties'
[5] Oxford Economics (April 2020). 'A downside scenario for the global economy'
[6] McKinsey & Co. (March 2020). 'Safeguarding our lives and our livelihoods: The imperative of our time'
[7] Morgan Stanley (April 2020). 'Global Macro Briefing: The Great Covid-19 Recession aka GCR'
[8] Global GDP growth data from World Bank database, global TPES from BP Statistical Review of World Energy 2019

downturns in 1998, 2001 and 2008/09 total energy demand has fallen in line with the slowdown in economic activity, and there is clearly no reason to believe that the same will not occur during 2020 – indeed we are already seeing significant evidence of this.

When considering the current impact of COVID-19 it would be logical to assume that the major decline would be seen in oil demand. Transport activity, which accounts for the majority of oil consumption, has fallen dramatically as almost all forms of travel have been severely impacted by the lockdowns imposed by governments to halt the spread of COVID-19. However, it is interesting to note that this is something of an anomaly when looking at the historic trends, which suggest that oil demand has moved up or down at around 50 per cent of the rate of GDP (see Figure 2.2). In fact, it is gas demand that is much more closely related to economic activity. Over the period 1998 to 2018 the average annual movement in gas demand over the entire period has been 91 per cent of the movement in GDP, compared to 46 per cent for oil, and as can be seen in Figure 2, this average has trended towards 100 per cent in the past decade.

Figure 2.2: Oil and gas demand growth versus GDP growth

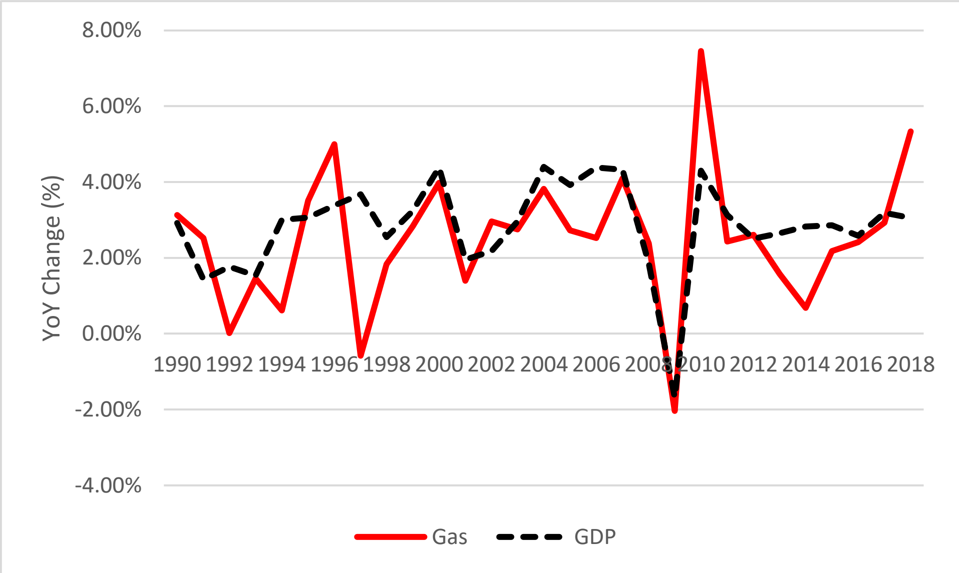


Source: Data from World Bank and BP Statistical Review of World Energy, analysis by OIES

Some of this difference may be explained by the fact that gas has been increasing its market share relative to other fossil fuels over the past two decades. Indeed, this might also explain why the correlation between the annual movements of GDP and gas demand is not as close, especially for the 1990s when the growth in gas's market share (especially in the power sector) was a major driving force.

Nevertheless, since 2000 the correlation between economic growth and gas demand growth has been increasingly tight, with an r^2 of 0.75 for the two decades since 2000 and of 0.81 for the period since 2009. Furthermore, it is interesting to note the very close link between the two in the most recent economic slumps in 2001 and 2008/09, when the declines almost mirrored each other (see Figure 2.3). While we cannot necessarily conclude that a 3-8 per cent decline in the global economy in 2020 will lead to a similar fall in gas demand, it would not be unreasonable to suggest that, although the fall in oil demand has been immediate and dramatic, a more gradual but nevertheless significant fall in gas demand would seem equally inevitable.

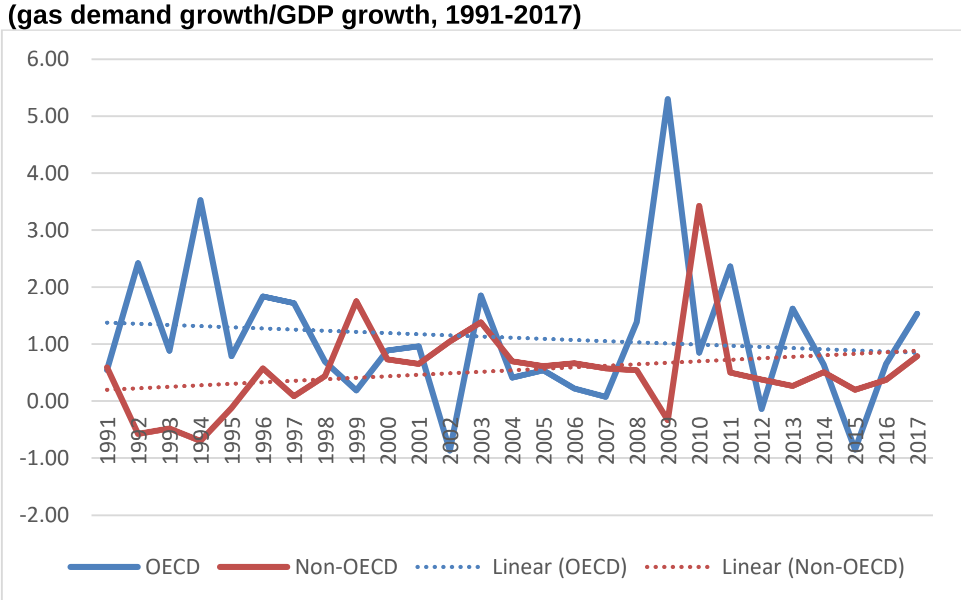
Figure 2.3: Global GDP growth compared with gas demand growth (1990-2018)



Source: Data from World Bank and BP Statistical Review of World Energy, analysis by OIES

There are a number of caveats around this overall analysis which should be acknowledged, however. The first, and perhaps most obvious, is the weather impact, which can clearly exaggerate any upswing or downturn. For example, the winter in the northern hemisphere in 2019/20 has been relatively warm, implying the likelihood of even lower gas demand, although this could clearly be reversed in winter 2020/21. The second is country and regional differences in the energy mix. Any country which uses gas as a major part of its fuel for power generation and industry (e.g. the UK) might expect a more significant decline in gas demand than a country where coal-to-gas switching is still continuing (e.g. the US in 2020). These differences will be discussed in the analysis of various regions in section 2.3.

Figure 2.4: Relationship between GDP growth and gas demand growth in OECD and non-OECD countries (gas demand growth/GDP growth, 1991-2017)



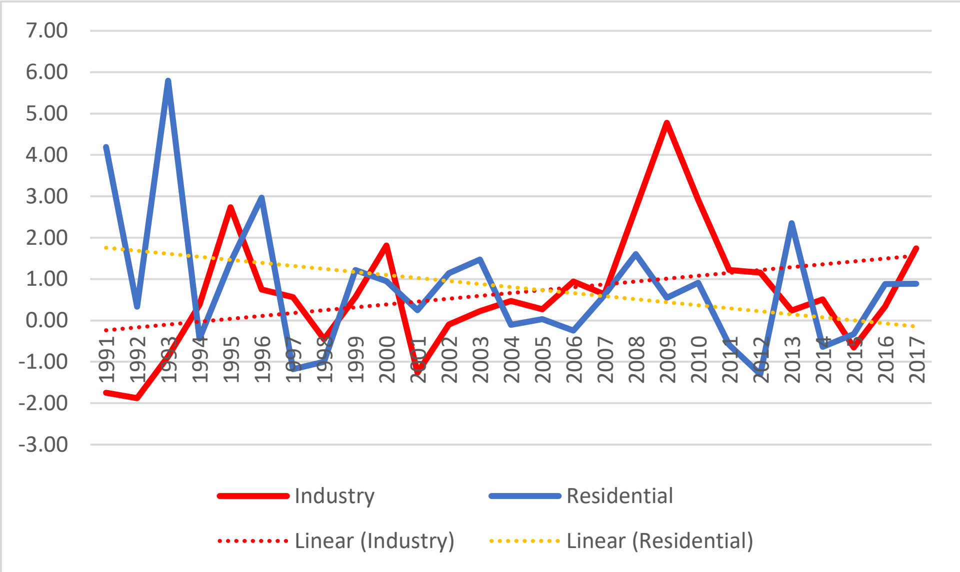
Source: Data from World Bank and BP Statistical Review of World Energy, analysis by OIES

However, even at a high level it is worth observing the different relationship between GDP growth and gas demand growth in OECD and non-OECD countries, which is shown above in Figure 2.4. Although the trend lines for both regions seem to be converging at a relationship of around 0.9 (gas demand

growth/GDP growth), the relationship between gas demand and GDP in each region is very different. The correlation between the two in the OECD has an r^2 of 0.62 over the past decade, for example, while for non-OECD the r^2 is -0.26, clearly underlining the variability of response across regions. This variation could be explained, for example, by different reactions to low prices, with demand in developing gas markets being particularly responsive to price movements.

The final area of difference is between sectors, and this again will differ by country. Figure 2.5 shows an analysis of the global use of gas in the industrial and residential sectors as an illustration. The relationship between industrial gas demand and GDP growth since 2000 has been very close, with the average growth of the former divided by the latter being 1.0, while the correlation has also been relatively tight with an r^2 of 0.72. By contrast the average movement of residential gas demand versus GDP growth has been a much lower 0.47 over the same period, with an r^2 of 0.17 – essentially very little correlation.

Figure 2.5: Relationship between GDP growth and gas demand growth in global power generation and industrial sectors (gas demand growth/GDP growth, 1991-2017)



Source: Data from World Bank and BP Statistical Review of World Energy, analysis by OIES

While the conclusion from this analysis might seem rather obvious – gas demand in industry is more correlated to economic activity than gas demand in households – it nevertheless underlines the contrast with oil demand (where use in one sector dominates demand) and also encourages a closer look at the sectoral breakdown of gas demand movements in an economic downturn.

Despite these caveats, though, the overall conclusion seems to be that we should not be complacent about the impact of an economic crisis on gas demand. The residential sector may provide something of a buffer and demand in the power sector may hold up in some countries if gas is not the main fuel of choice or if it is very competitive on price as, for example, is the current situation in the US, where low gas prices continue to encourage a switch away from coal use in the power sector. However, more broadly the examples of 1998, 2001 and 2008/09 suggest that gas demand will fall sharply in 2020 and will only rebound once the global economy starts to recover in a meaningful manner.

The next section examines the trends evident in the data from the first 4 months of 2020, while section 2.3 examines some of the regional differences that have been alluded to above. Section 2.4 then looks at the question of whether the gas market might experience a phenomenon similar to the oil market in April 2020, namely a storage crisis and a dramatic fall in prices, while section 2.5 considers potential medium- and longer-term consequences for the gas sector as a result of the pandemic.

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2.2 Supply to Europe and implications for storage

Introduction

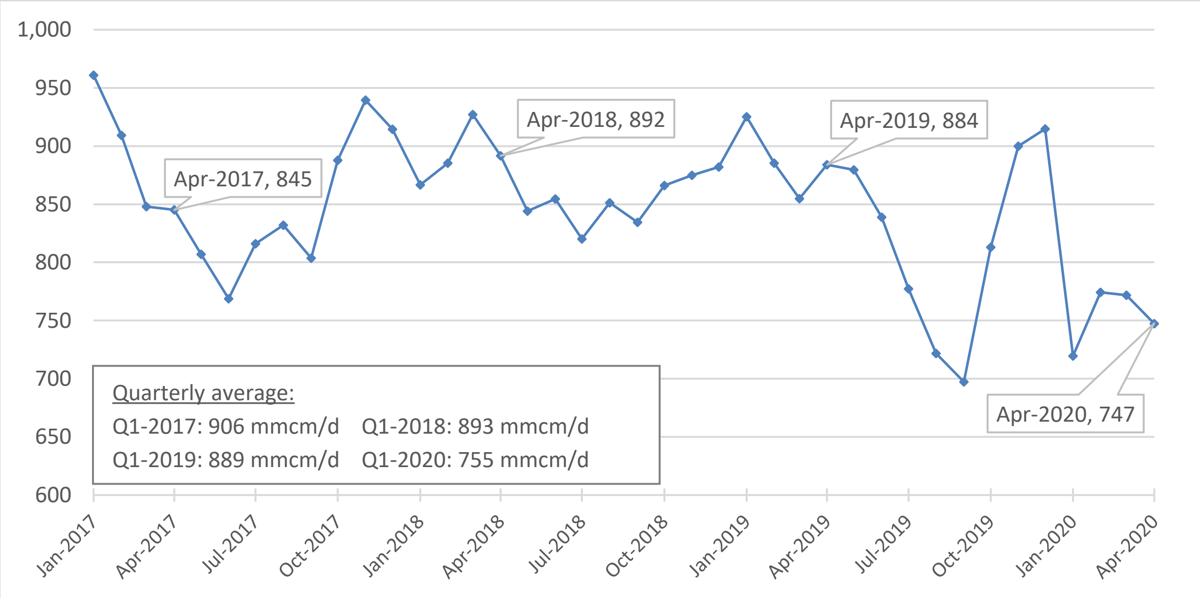
This analysis of the supply-side picture in Europe examines whether the COVID-19 lockdowns have had a significant impact on European gas supplies, in the form of pipeline imports, LNG imports, and net storage withdrawals, and therefore by implication on gas consumed by customers in Europe. The focus is on the most recent data for April 2020, with additional consideration being given to developments in Q1-2020 to provide context. Two points of analytical comparison are made: the year-on-year comparison with April 2019, and the short-term comparison with February 2020 (the last full 'pre-lockdown' month).

Pipeline gas supplies

In broad terms, 2020 began with a sharp decline in pipeline flows into Europe,[9] and those flows have yet to recover to the levels of recent years.[10] Monthly average flows between January and April 2020 have yet to surpass 775 MMcm/d, while monthly average flows for the whole of the period 2017-2019 only dipped below that level in June 2017 and August-September 2019.

In Q1 2020, pipeline flows were, on average, 134 MMcm/d lower than in Q1 2019. The largest year-on-year decline occurred in January 2020 (-206 MMcm/d, or -22 per cent), while the flows in February (-111 MMcm/d, or -13 per cent) and March (-83 MMcm/d, or -10 per cent) showed smaller year-on-year declines. However, a renewed decline emerged in April, when pipeline flows into Europe showed a year-on-year drop of 137 MMcm/d (-15 per cent).

Figure 2.6: Monthly average pipeline flows to Europe 2017-20 (MMcm/d)



Data source: ENTSOG Transparency Platform

The picture is one of a major year-on-year decline in January, an incomplete recovery in February and March, and a second substantial year-on-year decline in April. Russia accounted for 77 per cent (-103 MMcm/d) of the Q1 year-on-year decline, while flows from North Africa (-28 MMcm/d) and Norway (-3 MMcm/d) fell more modestly. In April 2020, Russia (-113 MMcm/d) accounted for 83 per cent of the

[9] Europe is defined here as the EU plus Switzerland and the Balkans, but minus Finland and the three Baltic states

[10] This flow data covers the following: 1) From Norway to the UK, France, Belgium, Netherlands, and Germany; 2) From Russia to Europe via Nord Stream, Belarus, Ukraine, and Turkey (at the Turkey-Bulgaria border); 3) From North Africa to Spain and Italy. Flows from Russia to the Baltic states, Finland, and Turkey (via Blue Stream, Turkish Stream, and the Trans-Balkan Pipeline) are excluded

total year-on-year decline, with the remainder of the fall largely borne by North Africa (-19 MMcm/d) as Norwegian flows declined on slightly year-on-year (-5 MMcm/d).

Detailed analysis of the data shows that Russian flows via Ukraine in Q1 2020 were down by 107 MMcm/d (-50 per cent), having fallen from 213 MMcm/d in Q1 2019 to 106 MMcm/d in Q1 2020. In April, Russian flows via Ukraine fell by 46 per cent (-115 MMcm/d) from 250 MMcm/d in April 2019 to 135 MMcm/d in April 2020. The year-on-year decline in Russian flows may be largely explained by the effects of the 'non-disruption' of Ukrainian transit, which has enabled Gazprom to draw on gas from stocks in Europe that were no longer needed as a hedge against a possible disruption, and to reduce its export flows via Ukraine accordingly. This was particularly felt in Q1, when storage facilities were being operated in 'net withdrawal' mode.

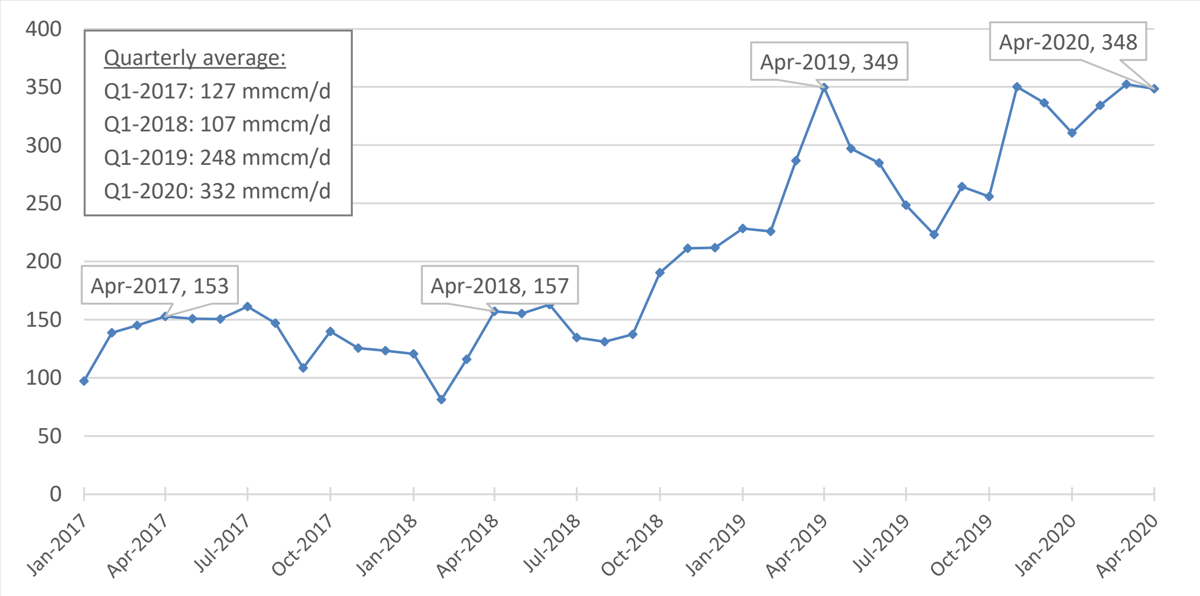
Compared to February 2020, total pipeline flows in April 2020 were 27 MMcm/d lower (-3.5 per cent). While Russian flows increased by 15 MMcm/d, North African flows declined by 9 MMcm/d and Norwegian flows dropped by 33 MMcm/d. In February (the last 'pre-lockdown' month), pipeline flows were lower than usual due to competition from LNG cargoes and higher storage withdrawals. In April, storage had switched to net injections, and yet pipeline flows were even lower than in February. As discussed below, LNG supplies increased slightly between February and April 2020, meaning that pipeline flows suffered from both competition from LNG and a dramatic decline in demand.

LNG supplies

While LNG supplies to Europe remained within an approximate range of 80 to 160 MMcm/d between January 2017 and September 2018, those volumes have since grown substantially. In Q1 2020, total LNG supplies to Europe were 84 MMcm/d (+34 per cent) higher than in Q1 2019. This undoubtedly contributed to the lower pipeline imports in Q1.

In April 2020, LNG supplies were just 1 MMcm/d (-0.3 per cent) lower than the average for April 2019, and almost double the monthly averages for April 2017 and 2018. Notably, European LNG imports in April 2020 (349 MMcm/d) were 14 MMcm/d (+4 per cent) higher than in February 2020 (334 MMcm/d). This increase was not driven by higher demand for LNG in Europe, but rather by a lack of demand in the rest of the world and LNG looking for a home in the market of last resort. In any case, that slight increase in LNG supply failed to offset the 27 MMcm/d decline in pipeline supplies to Europe between February and April 2020.

Figure 2.7: LNG supplies to Europe 2017-20 (monthly average MMcm/d)



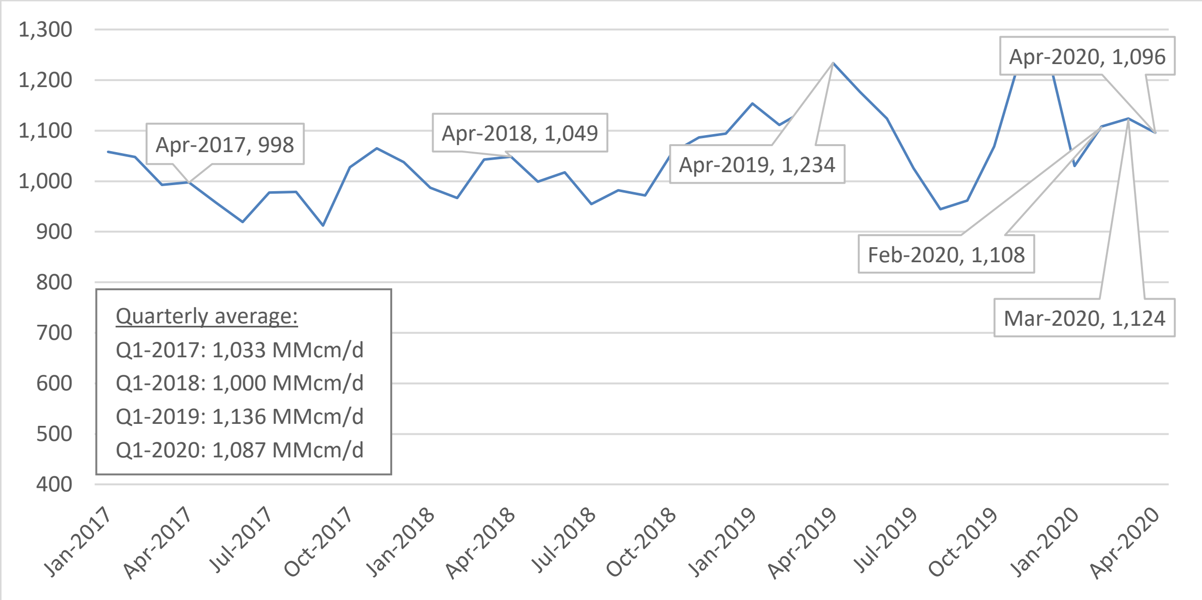
Source: Data from Platts LNG

Pipeline and LNG supplies combined

Given the flows discussed above, it can be concluded that combined pipeline and LNG flows into Europe in Q1 2020 (1,087 MMcm/d) were 49 MMcm/d (-4 per cent) lower than in Q1 2019 (1,136 MMcm/d) – a decline that was largely caused by the non-disruption of Russian gas transit via Ukraine and related higher storage withdrawals, with the greatest impact occurring in January 2020.

In April 2020, combined pipeline and LNG flows were down by 138 MMcm/d year-on-year (-11 per cent). However, it should also be noted that such supplies were 4.5 per cent higher than in April 2018 (+47 MMcm/d), and 10 per cent higher than in April 2017 (+98 MMcm/d). Compared to February 2020, combined pipeline and LNG flows were down by 12.5 MMcm/d - a modest decline of 1.4 per cent.

Figure 2.8: Combined pipeline and LNG supplies to Europe 2017-20 (monthly average MMcm/d)



Source: Data from ENTSOG Transparency Platform and Platts LNG

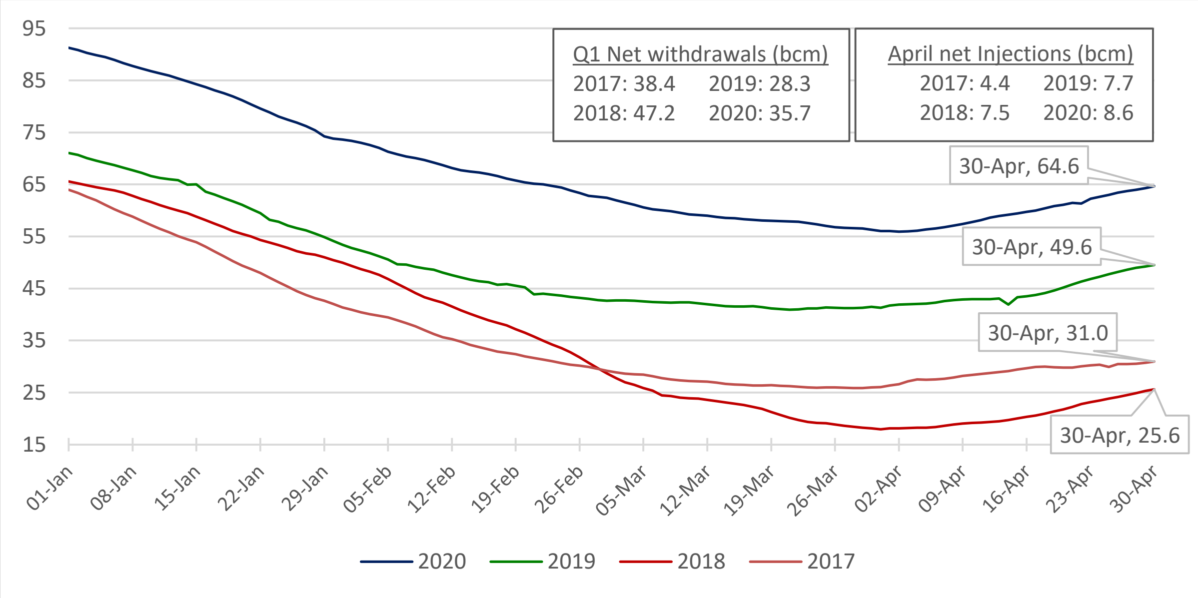
Storage

European storage peaked at a record 101.4 Bcm on 27 October 2019 and remained high to reach an end-of-year record of 91.5 Bcm – 20 Bcm higher than at the end of 2018. Storage withdrawals in Q1 2020 were 25 per cent higher than in Q1 2019 (+78 MMcm/d, up from 314MMcm/d in Q1 2019 to 392MMcm/d in Q1 2020) despite broadly similar weather conditions. However, this still left stocks at the end of Q1 at a record level of 56 Bcm, leaving just 47.5 Bcm of storage capacity available for filling during the forthcoming summer.

Most importantly, though, net storage injections averaged 287 mmcm/d in April 2020. In April 2019, net storage injections averaged 257 MMcm/d, similar to April 2018 (248 MMcm/d) and substantially higher than April 2017 (147 MMcm/d). Therefore, storage injections in April 2020 were substantially higher (+11%) year-on-year. For the month-by-month comparison, in January 2020 net monthly storage withdrawals averaged 574 MMcm/d, with lower figures for February (388 MMcm/d) and March (217 MMcm/d).

The combination of higher opening stock levels, higher year-on-year storage withdrawals in Q1, and quicker-than-average stock replenishment in April means that the European market faces the rest of the summer with stocks already at 62.5 per cent of storage capacity – a record for the end of April. In previous years' stocks did not reach 62.5 per cent of storage capacity until 6 June 2019, 5 August 2018, and 31 July 2017.

Figure 2.9: European gas in storage 2017-20 (Bcm)



Data source: Gas Infrastructure Europe (AGSI Platform)

Total supplies to the European market and implications for demand levels

By subtracting storage injections from (or adding storage withdrawals to) 'domestic' European production plus pipeline and LNG imports to the European market, it is possible to calculate how much gas was available to final consumers.

In Q1 2020, higher LNG imports (+84 MMcm/d) and higher storage withdrawals (+78 MMcm/d) were not sufficient to offset the decline in production (-37 MMcm/d) and lower pipeline imports (-134 MMcm/d). Total supply dropped by 8 MMcm/d (0.4 per cent), from 1,735 MMcm/d in Q1 2019 to 1,727 MMcm/d in Q1 2020.

In April 2020, production was 33 MMcm/d lower than in April 2019, pipeline imports were 137 MMcm/d lower, LNG imports were virtually unchanged (-1 MMcm/d), and storage injections were 29 MMcm/d higher. Therefore, total supply fell from 1,224 MMcm/d in April 2019 to 1,024 MMcm/d in April 2020 – a decline of 200 MMcm/d (16 per cent).

These figures are highlighted in Figure 2.6 (pipeline imports), Figure 2.7 (LNG imports), and Figure 2.9 (storage stocks) above. Below, Figure 2.10 shows the production/import/storage balance for January to April 2019, Figure 2.11 shows the balance for January to April 2020, and Figure 2.12 shows the year-on-year changes between 2019 and 2020.

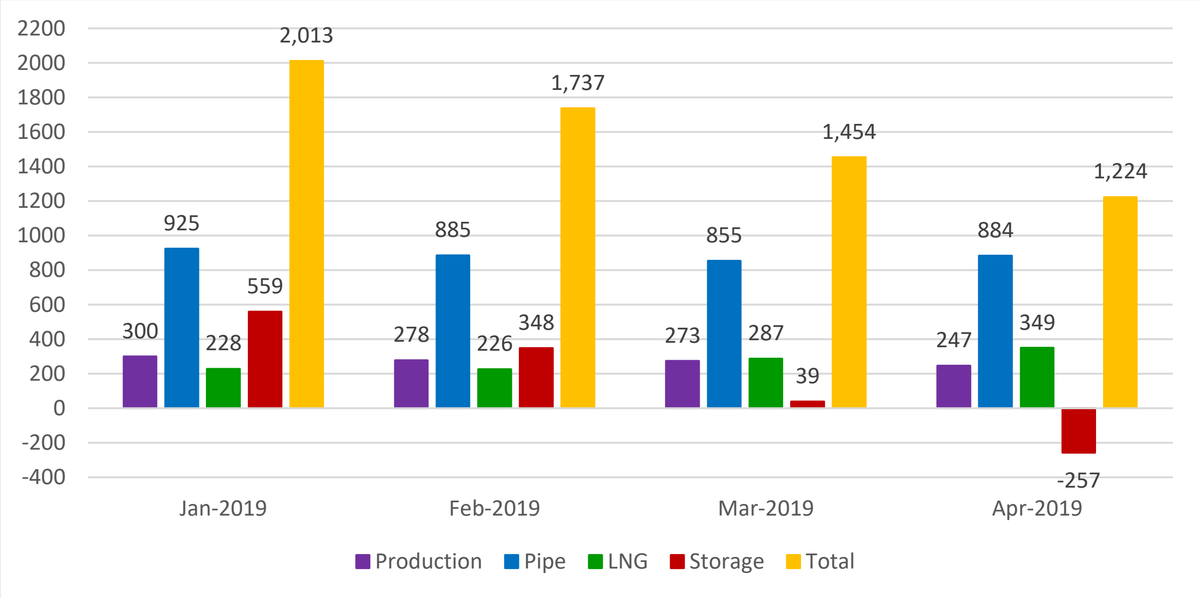
The figures for Q1 2020 suggest that, prior to the impact of COVID-19 from mid-March, European gas demand was relatively similar to that in Q1 2019. The major difference was in how that demand was met. In particular, Russian pipeline flows to Europe via Ukraine declined and related storage withdrawals increased, larger volumes of LNG flowed to Europe from an oversupplied global market, and European production declined (mostly in the Netherlands and to a lesser extent in the UK and Denmark).[11]

The figures for April 2020 compared to April 2019 are indicative of a substantial decline in demand leading to oversupply. That implied decline in demand is consistent with the analysis of European demand in section 2.3 of this paper, and with the scenario for European demand in Q2 2020 highlighted

[11] Production data from the ENTSOG Transparency Platform and JODI Gas Database are used for the UK, Netherlands, Romania, Germany, Poland, Italy, Ireland, Hungary, Croatia, Austria, Czechia, and France. These countries accounted for 99.9 per cent of EU gas production in 2019.

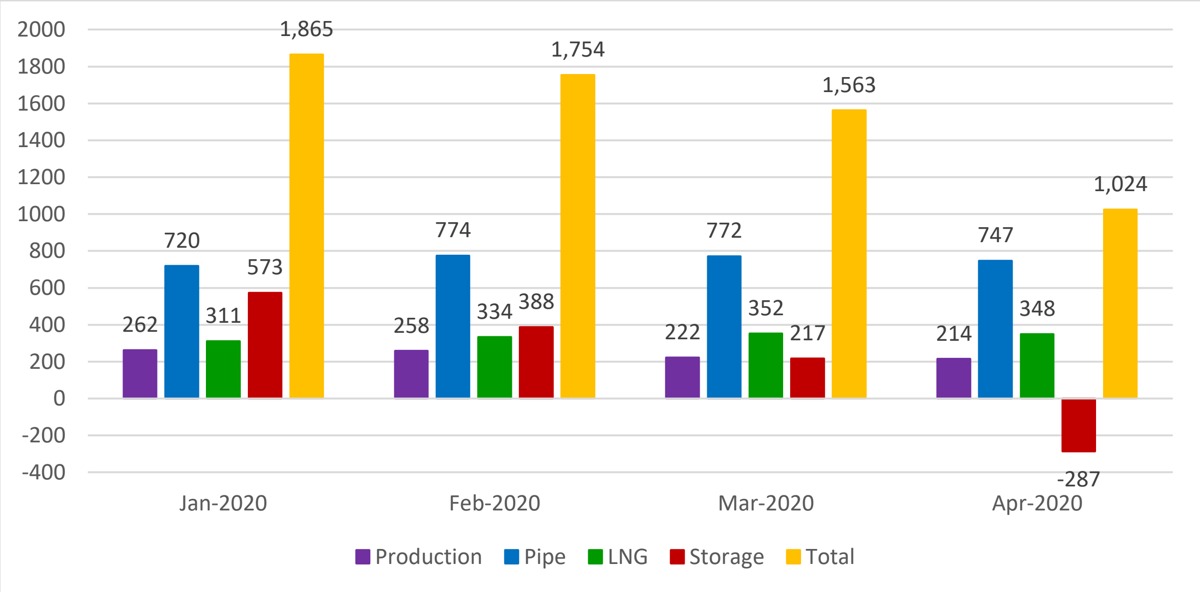
in section 2.4. The oversupply in April 2020 would have been even greater if production had not declined year-on-year. Although storage injections increased year-on-year to absorb some of that oversupply, the main competition was between pipeline and LNG imports. As Figure 2.12 (below) shows, it was the pipeline suppliers that were impacted by the decline in European gas demand, as LNG import volumes remained almost unchanged.

Figure 2.10: Pipeline, LNG, and storage supplies in Jan-Apr 2019 (MMcm/d)



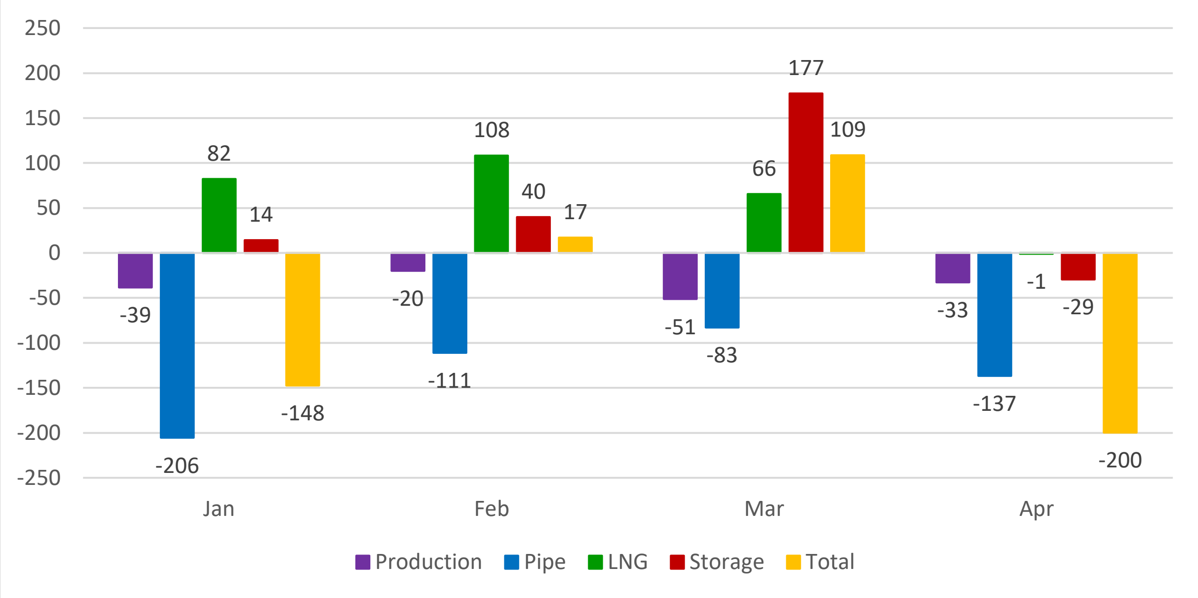
Data source: ENTSOG Transparency Platform, Platts LNG, and Gas Storage Europe

Figure 2.11: Pipeline, LNG, and storage supplies in Jan-Apr 2020 (MMcm/d)



Data source: ENTSOG Transparency Platform, Platts LNG, and Gas Storage Europe

Figure 2.12: Year-on-year change in production, pipeline, LNG, and storage supplies in 2019-2020 (MMcm/d)



Data source: ENTSOG Transparency Platform, Platts LNG, and Gas Storage Europe

Given the context of a pre-existing year-on-year decline caused by warmer temperatures, it is useful to test the extent of the impact of the COVID-19 lockdowns in April relative to February - the last fully 'pre-lockdown' month.

In February 2020, total supplies to the European market averaged 1,754 MMcm/d, falling by 730 MMcm/d to 1,024 MMcm/d in April – a decline of 42 per cent. Production (-8 MMcm/d) and LNG imports (-4 MMcm/d) fell slightly between February and April, while pipeline imports fell by a greater amount (-25 MMcm/d). However, it was storage that supplied a swing of 675 MMcm/d, from net withdrawals of 388 MMcm/d to net injections of 287 MMcm/d.

Given that a major determinant in the decline in gas demand between February and April of any given year is the impact of weather-related demand, it is instructive to note that between February and April 2019, the equivalent decline in total supply was 513 MMcm/d (-30 per cent). This leads to the conclusion that the impact of COVID-19 exacerbated the regular seasonal decline in gas demand between February and April by an additional 217 MMcm/d – a figure broadly in line with the year-on-year decline in total supply of 200 MMcm/d between April 2019 and April 2020.

Conclusion

In a supply-long global gas market, the dramatic decline in volumes being delivered to the European market is undoubtedly being driven by demand-side factors, namely warmer weather and latterly the reduction in economic activity caused by the lockdowns associated with the COVID-19 public health crisis. The year-on-year comparison for April shows increased storage injections partially compensating for much lower demand in a market that remained oversupplied despite the substantial decline in pipeline supplies, a decline in European production, and almost no change in LNG supplies, leading to an overall decline in gas supplied to the market of around 16 per cent.

Before the impact of COVID-19 was felt, the major development in Q1 2020 was the substantial year-on-year decline in pipeline imports and increase in both LNG imports and storage withdrawals, as the market adjusted to the 'non-crisis' in Ukrainian transit. The impact of COVID-19 in April has been to keep pipeline imports down and ramp up storage injections as the market attempts to stay in balance. The decline in day-ahead TTF prices to below $2 per MMBtu in the second half of April suggests that market is struggling to cope with the excess supply.

Comparing April 2020 to the immediate ‘pre-lockdown’ period, the picture is one of storage providing the swing as production, pipeline imports, and LNG imports only fell very slightly between February and April. The role of storage in absorbing excess supply in an oversupplied market will remain key, given the likely market conditions of continued suppressed demand and plentiful supply throughout the summer of 2020. The ability of storage facilities to absorb excess supply will decrease considerably throughout Q2 as capacity is filled from its already-high levels. In May-July 2019, net storage injections averaged 382 MMcm/d. With 38.9 Bcm of total European storage capacity currently remaining unfilled, storage injections at a similar rate would see European storage completely full by early August, that is, long before the end of Q3.

The main conclusion to be drawn is that if demand remains depressed as storage reaches full capacity, the competition between pipeline and LNG supplies will intensify with the result being severe downward pressure on prices. Therefore, the risk of the European gas market repeating the American oil experience of supply overwhelming demand in the context of limited storage, resulting in the collapse of prices from already low levels, will most likely occur in Q3 2020.

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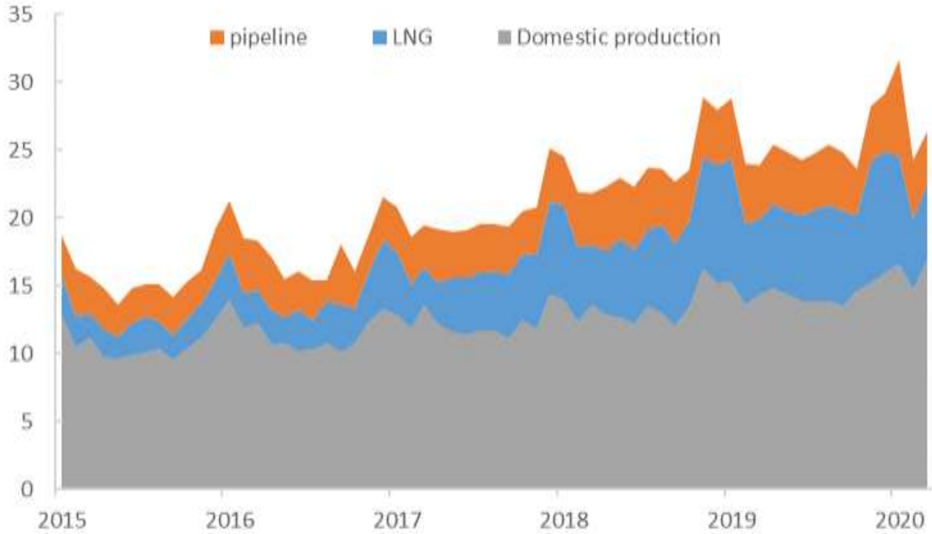
2.3 Regional perspectives on COVID-19's impact on gas demand

China

China's efforts to contain the spread of the coronavirus (COVID-19) led to a sharp drop in economic activity in Q1 2020, with official GDP contracting by an unprecedented 6.8 per cent year on year and 9.8 per cent quarter on quarter. Yet despite the bleak macroeconomic data, China's implied gas demand (domestic supply and net imports) seemed to reach 68 Bcm in Q1 2020, a year on year increase of 8 per cent, as evidenced by a strong rise in domestic production (12 per cent year on year), combined with a more modest 1 Bcm (3 per cent) increase in imports.

Figure 2.13: China's gas supply, Bcm

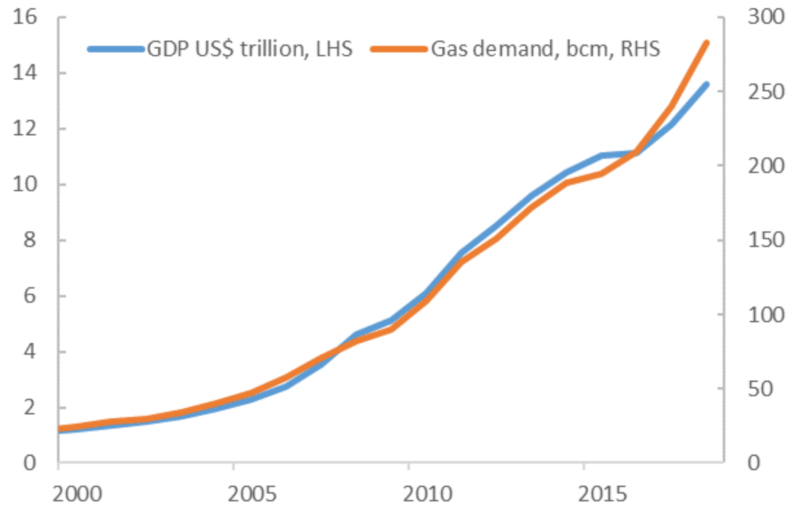


Source: NBS, China Customs, OIES

However, the official data would appear to be telling a misleading story as the opacity surrounding storage levels is likely masking the full extent of what is, in reality, a significant demand hit. The Chinese majors' decision to declare force majeure on some of their LNG cargoes in February and March, combined with injections into storage in mid-March, suggest that China's (limited) storage capacity is now close to full. Moreover, given that historically, China's GDP and gas demand have been tightly correlated, the sharp drop in economic activity should be reflected in gas consumption. It is true that the last time China's GDP contracted was in 1976, amidst the turmoil of the Cultural Revolution, when China's gas consumption was only 11 Bcm. Nevertheless, GDP and gas demand growth rates have correlated closely throughout the 2000s (see Figure 2), decoupling in 2017 as the policy-driven coal to gas switch led gas demand to rise faster.

China's gas demand in Q1 2020 was, therefore, weaker than official data suggests. According to industry estimates, commercial demand took the biggest hit, falling by a third year on year, followed by a strong 20 per cent contraction in transport use. But given their limited share of total gas demand, the two sectors combined have likely accounted for only 3 Bcm of lost demand in Q1 2020. Industrial use, the biggest consumer of gas in China, dropped by close to 20 per cent, leading to a steeper 4-5 Bcm of demand loss. Gas use in power is also estimated to have contracted but given the limited share of gas in power, this likely accounts for an additional 1-2 Bcm of lost demand over the quarter. Overall, China's economic inactivity took a toll of around 8-10 Bcm, partly offset by 2-3 Bcm of incremental residential demand. This 8 per cent year on year decline would also suggest that the correlation with GDP still holds true.

Figure 2.14: China's GDP ($ billion), gas demand



Source: BP, World Bank, OIES

So, as China's economy gradually recovers, gas demand should rise correspondingly. But China's GDP growth for the year is unlikely to be anywhere near the 5-6 per cent assumed in early 2020, and a V-shaped recovery is looking extremely unlikely in light of China's ongoing efforts to prevent another wave of infection. Returning to work is proving slower than many had expected as industry finances have taken a hit and the looming global recession will weigh on China's manufacturing industry. But even the IMF's expected 1 per cent GDP growth for China this year could translate to 3-4 per cent rise in gas demand growth (or around 15 Bcm year on year). Even though low oil and gas prices are unlikely to shut-in domestic production—due to the supply security imperative—they could constrain pipeline flows from Central Asia and support LNG imports. Low prices will also boost demand. Already in February, Beijing cut city-gate prices which will help commercial and industrial consumers.

At the same time, the government is pursuing its liberalisation plans, allowing new entrants into the market which are looking to capitalise on cheap spot cargoes. With oil-indexed contracts likely to deliver low term prices later in the year, LNG is becoming increasingly competitive in power production and could also displace diesel in transport. Finally, the government's recent push to expand natural gas storage capacity, as part of its infrastructure stimulus, could support LNG arrivals at the margins in 2020 and 2021. While China's LNG imports are unlikely to top last year's 9 Bcm increment, lower prices and government support suggest China may be a lone bright spot in an otherwise dire market.

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India

As this issue went to press, India's six-week lockdown, imposed on 25 March, was extended to 17 May.

Prior to the crisis, in the first two months of Q1 2020, Indian gas buyers responded resoundingly to falling global gas prices. LNG imports rose year on year by 25 per cent in January, and a record 68 per cent in February – with import dependency rising to 60 per cent of consumption. A sectoral breakdown for January-February shows that the majority of demand came from the power sector, in which LNG consumption doubled in February (year on year), followed closely by refineries and petrochemicals

(37%), city gas (34%), and fertilisers (20%). These sectors bought distressed LNG cargoes at prices around \$2.77/MMBtu (following *force majeure* notices from Chinese buyers).[12]

The impact of the lockdown was partially reflected in provisional data for March: LNG imports were down by around 20 per cent from their February high (yet up by 26 per cent on March 2019). Total gas demand fell by 9 per cent in March over February but was up by 16 per cent on March 2019. With the domestic gas price trending down since 2014 (from \$5.05/MMBtu then, to \$2.39/MMBtu in 2020), and the 'ceiling' price, introduced in 2016 for deep-water fields[13] failing to revive upstream activity, production also fell year on year by around 11 per cent during Q1 2020, driven by private sector production declines.

Economic activity since the lockdown has slowed down significantly across all sectors, barring essential goods and services. Restrictions were partially lifted on 20 April for areas not experiencing serious outbreaks – aimed mainly at restarting agriculture ahead of the harvesting season, and largely excluding industrial and urban financial centres. The lockdown was then partially eased yet again on 3 May for areas of the country that remained infection-free, based on a 'traffic signal' system dividing the country into green, orange and red zones. However, a resurgence of infection in any of these areas could see restrictions re-imposed, and the economic fallout of COVID-19 could include a supply-side shock, followed by a second-round demand-side shock from falling consumption.

The IMF projects India's GDP growth at 1.9 per cent for 2020, picking up to 7.4 per cent in 2021 – that is, a short shock followed by a sharp recovery. The Confederation of Indian Industry[14] highlights the possibility of a longer recovery, with the length of lockdown and quantum of government stimulus to industry shaping the outcome. It projects a base GDP growth forecast of 0.6 per cent with an upside of 1.5 per cent (similar to the IMF), and downside risk of –0.9 per cent in 2020.

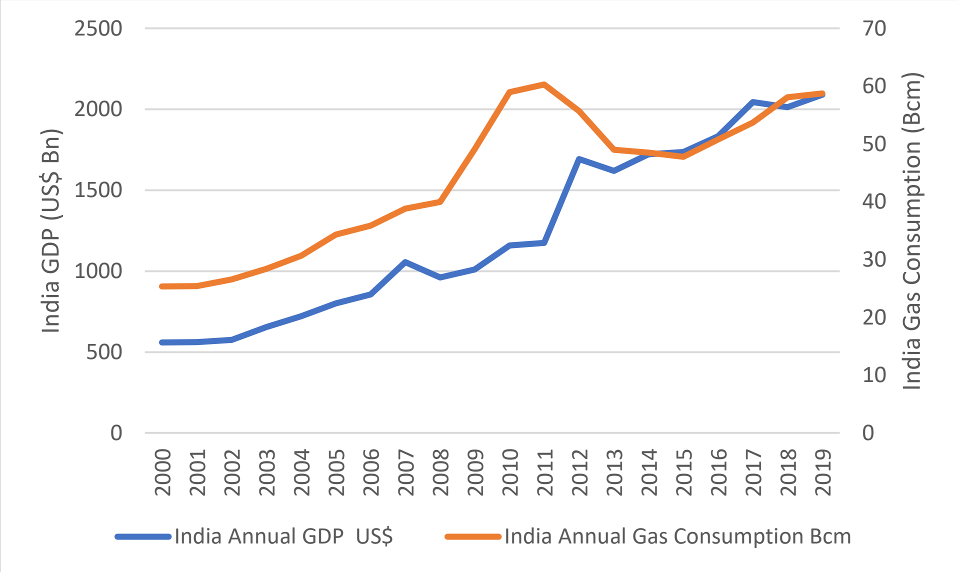
The data suggests that Indian gas consumption and GDP have been correlated since the early 2010s. But it also shows that gas demand in the fertiliser sector has tended to be relatively price-inelastic, whereas demand in power, city gas and refineries/petrochemicals is relatively elastic. Preliminary data for March shows that electricity demand in the week following the lockdown declined by 28 per cent[15], and petroleum product consumption (refineries and petrochemicals) declined by 18 per cent in March 2020.

The situation is fluid, but assuming that complete lockdown continues for three months, followed by a gradual resumption in economic activity supported by a stimulus, and a persistently low gas price, a COVID-19 sectoral demand scenario for 2020 over a base case of 63.25 Bcm could look something like the following: first, assuming that gas demand in *power generation* doubled in Q1 at sub-\$5 gas prices, and that perhaps 80 per cent of stranded gas fired capacity could be revived at current Plant Load Factors - but adjusting for a 30 per cent decline (extrapolated from March data) in power demand, gas demand in power would increase by 20 per cent over the year as a whole.

Second, assuming that the lockdown results in a complete cessation of industrial activity for three months, followed by a gradual resumption of 50 per cent of activity in Q3; this could result in a decline in gas demand in *industry* of 37.5 per cent for 2020 as a whole. Third, we could assume that CNG demand in *transport*, which collapsed when the lockdown was imposed, does not recover, as local travel restrictions on public transport continue through 2020. Fourth, we could assume that gas demand in the *commercial sector* halves as restrictions continue through 2020. Fifth, we could assume that higher household demand for gas for at least two quarters boosts gas demand by 50 per cent.

[12] City gas, refineries and petrochemicals posted double-digit year/year growth in January
[13] Pegged to the import prices of naphtha, coal and LNG, this stood at \$5.61/MMBtu in April 2020
[14] See https://www.ciicovid19update.in/ for updates on COVID-19 impact in India
[15] See https://www.ceew.in/ for discussion of energy economy in India

Figure 2.15: India GDP and gas consumption



Source: Ministry of Finance (2020); PPAC (2020); BP Statistical Review (2019)[16]

Finally, in the *non-energy use (feedstock)* sector, a variety of factors are at play. The 20 per cent growth for fertilisers in March could be extrapolated to the entire year; meanwhile the 18 per cent March demand drop in refineries could run through to June but would be offset to some extent by a 6 per cent estimated higher household LPG demand. Meanwhile the 18 per cent drop in March for petrochemicals could also be extrapolated through to June, while other feedstock use, such as for sponge iron and steel, could see a lower decline, but with recovery constrained by the pace of the global economic recovery.

In such a scenario, gas demand for 2020 could drop to 54.7 Bcm or 13.6 per cent (8.6 Bcm) lower than the base case. It should be noted that this potential scenario is based on a combination of preliminary data and anecdotal evidence available at the time of writing – a prolonging (or shortening) of the lockdown, and magnitude of stimulus could significantly alter the outlook.

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Europe

On 13 March, the World Health Organization (WHO) declared Europe to be the epicentre of the new coronavirus epidemic. Across the region, countries were closing their borders and introducing increasingly strict restrictions on movement to stop the virus spreading. Italy was the first in the world to issue a nationwide lockdown on 11 March, but within a week, many other European countries had taken similar decisions.

Containment policies have been almost exclusively national and not uniform across Europe with various degrees of restriction, geographical coverage and starting dates, but they have all come at huge economic and social cost. First signs were felt in the service sector (closed restaurants, empty shops and office buildings) and soon after in the manufacturing sector (reduced industrial production). Unprecedented damage to business activity also led to reduced energy demand. In the power sector, demand was down by 4.4 per cent in March compared to the same period in 2019 (ENTSO-E data), and by 11.2 per cent in April. Renewable generation was up during both periods, squeezing fossil fuel

[16] GDP numbers in the graph should be taken as illustrative, as there was a recent rebasing of the national accounts series.

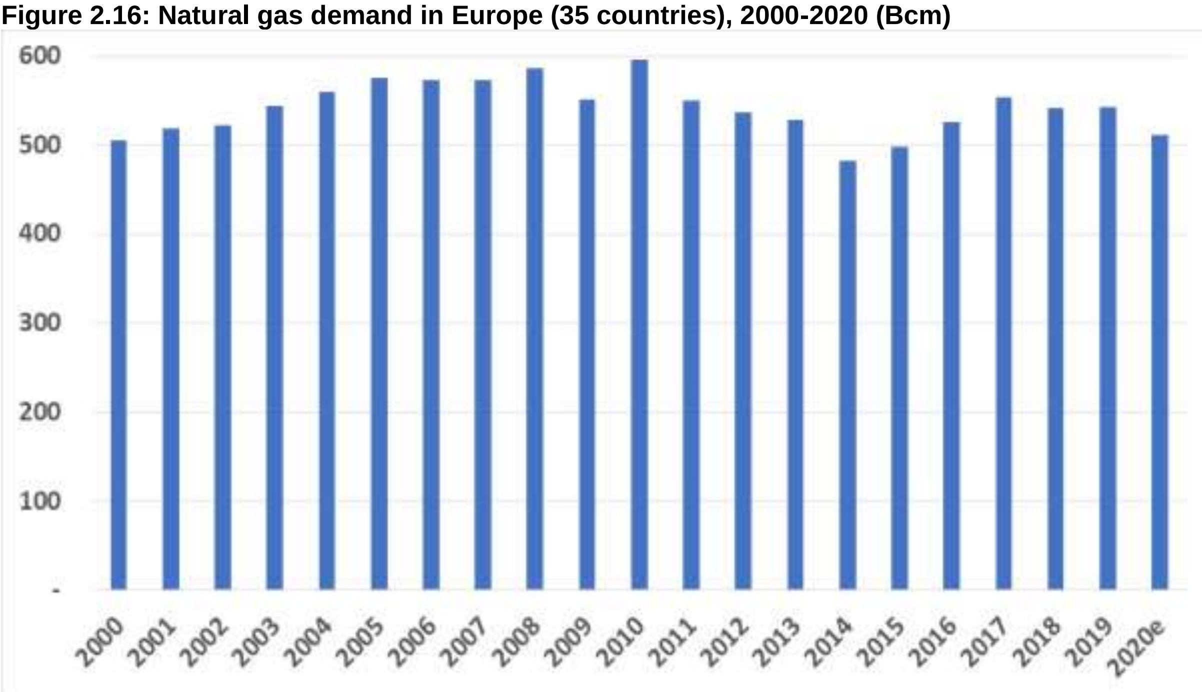
generation, especially coal, which was down by 17 per cent and then 35 per cent but also natural gas generation which declined by 5 per cent and 24 per cent.

Data for natural gas demand in March and April is still preliminary but it seems that lockdowns have caused major reductions in overall gas consumption. March figures show inconsistent impact, up in some countries compared to the same period in 2019 (Germany, UK, France) and down in others (Italy, Spain) as containment measures and lockdown starting dates differ. In April, demand for gas collapsed compared to the year before (-9 per cent in Germany, -19 per cent in the UK, -23 per cent in Spain and Italy and -35 per cent in France, based on preliminary TSO data). This was essentially driven by the consequences of the corona crisis leading to lower gas use for power generation and by a fall in industrial gas consumption, as well as by the mild temperatures that have kept residential gas demand low.

What can be expected for the rest of the year? Much will depend on the speed of a return to more normal levels of economic activity. In its April 2020 outlook, the IMF expected the European economy to suffer a 7.1 per cent contraction this year, before a rebound to 4.8 per cent growth in 2021. Of course, much sharper and/or longer decline can also be envisaged depending on how long containment measures last and on how strict they are. The good news is that, at the time of writing (24 April), there were signs that the virus infection rates had begun to fall and several countries were starting to relax lockdown measures, including Germany, Italy, Spain, Poland, Austria, the Czech Republic and Denmark.

The impact on individual economies remains uncertain. This will be predicated on a combination of a good policy response with strong support for the economy, as seen in Germany for instance, and a medical response in the form of a vaccine and/or treatment to avoid new waves of infection and further lockdowns. The EU and national governments have been spending more money more quickly than during the financial crisis a decade ago, but more will be needed, especially in the hardest hit countries.

Figure 2.16: Natural gas demand in Europe (35 countries), 2000-2020 (Bcm)



Source: 2000-2019: IEA and Eurostat data, 2020 estimate: author

As for gas demand, utilities and industries will be able to continue to take advantage of record low prices when the economy eventually starts to recover. Calls for prioritising economic activity over green packages for 2020 are also growing louder. In the power market, while renewables availability remains high, gas generation is benefiting from better economics than coal (mid-April, clean spark spreads were

> €10/MWh above clean dark spreads - Argus data for 55 per cent efficiency gas plants and 38 per cent coal). If some coal plants were to shut down earlier than planned due to bad economics and low power demand, this may favour some recovery in gas demand, while cold weather at the end of 2020 would also increase gas demand for heating, especially if a large number of people were to continue to work from home.

Figure 2.16 above shows a possible decline of about 6 per cent in European demand (35 countries) in 2020 based on a V shape recovery in 2020/2021 with a relaxation of confinement measures from May/June across Europe, strong financial stimulus, low coal in the generation mix and an average winter at the end of the year. In this scenario, gas consumption would go down to about 511 Bcm (32 Bcm less than in 2019), which would still be above the low levels seen in 2014 and 2015. The biggest declines are expected in the countries hardest hit by the coronavirus as they take longer to recover, namely Italy, Spain, France and, to a lesser extent, the UK.

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Russia

The Russian domestic gas market has not yet been severely affected by COVID-19 as the spread of the virus is lagging behind the main European economies by approximately two to three weeks. A bigger impact has, so far, been caused by the weather, which in Q1 2020 was the warmest in at least a decade, leading to lower than expected domestic gas demand. In March, for example, five temperature records were broken. As a result, with many regions of the country only going into lockdown in late March, this natural phenomenon has blurred the picture, preventing an accurate analysis of the direct effect of the epidemic on demand.

Nevertheless, some demand reaction is inevitable: despite all the quarantine measures, by mid-April Russia ranked 10th in the world in terms of the number of cases (just behind China), and, according to IMF projections, it is likely to see GDP decline by 5.5 per cent in 2020 (although there are other much lower estimates).

Some preliminary thoughts are possible, though. Firstly, gas demand for the power sector will almost certainly be affected. Although it is still early to make an accurate assessment, due to the late quarantine, in the first week of April the average decrease in electricity consumption was 6-7 per cent (according to state-owned utility UES) and in the second week of April it was 3.2 per cent. According to some sources, the maximum decrease occurred in the first days of April in the European part of Russia (ECO Center, Volga UES, UES South) with a fall of up to 15-19 per cent, but by mid-April this had reduced to a fall of 3-7 per cent. Meanwhile by mid-April the power systems in the Urals, Siberia, and the Far East had not yet shown significant changes in consumption. Nevertheless, given that gas generation accounts for the majority of electricity production in the western part of Russia, the quarantine regime will inevitably affect national gas consumption.

Meanwhile an increase in demand for thermal energy due to people staying at home is unlikely to happen because, unlike Europe, the Russian housing stock consists mainly of apartment buildings that receive heat from centralized sources. Such a system is poorly adapted to regulate heat energy consumption based on the wishes of the residents of a particular apartment - therefore, an ‘empty’ apartment consumes as much heat as one that is ‘overpopulated’.

Demand from the largest export-oriented manufacturing companies (such as steel-makers and fertilizer producers), which provide the bulk of gas consumption in the industrial sector, has not declined so far, as the rouble devaluation has meant that their export volumes have not been affected yet. Nevertheless, the global economic slowdown and gaps appearing in economic supply chains might soon lead to a reduction in their gas needs.

Given the early stage of developments in Russia, it is interesting to use the examples of previous crises in 2009 and 2014 to help generate a view on the outlook for Russian domestic gas demand. At those

times, with similar falls in GDP to that forecast by the IMF for 2020 (-8 per cent and -5 per cent respectively) Russian domestic gas demand fell by -5.5 per cent and -6 per cent. Weather impacts could be different, of course, and the outlook for 2020 GDP could change for the worse, but nevertheless the comparison is useful. We would suggest that, based on this historical evidence, it is reasonable to expect that gas demand for power generation could reduce by a maximum of 5-6 per cent while industrial consumption could fall by 8 per cent, but the residential sector with its centralized heating would most likely not see any change.

Furthermore, domestic gas prices have not reacted to the crisis. The majority of volumes are supplied under long-term contracts which are linked to the regulated price, while the Gas Exchange price has only seen a 1 per cent fall in April due to very limited trading volumes. Given the current state rhetoric, it is reasonable to expect that prices will remain frozen (in rouble terms) until the end of the crisis. However, there is one large problem looming, as the level of non-payment will almost certainly increase dramatically due to a lack of liquidity (especially when it comes to small and medium enterprises) and government instructions to energy suppliers that they should not put pressure on consumers.

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US

The US Energy Information Administration (EIA) published their Short-Term Energy Outlook (STEO)[17] on 7 April which took account of the initial phases of COVID-19 on the US energy markets. The STEO suggested US GDP would fall by 3.2 per cent year on year in Q2/Q3 2020 with the total for 2020 being a 2 per cent decline on 2019, with manufacturing output 4.3 per cent down year on year and the summer Q2/Q3 period down 4.7 per cent.

In contrast, the Q2/Q3 changes in gas demand for 2020 over 2019 were estimated as follows: residential +4.9 per cent; commercial +0.7 per cent; industrial -0.8 per cent, and power +2.2 per cent. Compared with other projections across the global economy, the EIA STEO looks very optimistic, with only a small impact seen on GDP and with the gas demand outlook remaining positive. A number of US banks were reportedly looking at a 15 per cent year on year Q2/Q3 fall in GDP, with a 5.5 per cent fall for the whole of 2020 compared with 2019. The IMF's latest World Economic Outlook[18] (WEO) projected, in their base case, a 6 per cent fall in US GDP this year, a reversal of 8 per cent compared with their forecast before COVID-19 struck. In our comments in this paper we also use the IMF WEO as a base for assessing the gas demand outlook and, if the major effects are assumed to occur in Q2/Q3, then the bulk of the GDP impact on gas demand will be in the summer months.

Gas demand outlook by sector

Residential

Residential demand is likely to be quite a bit higher with more people at home, although gas consumption in households is relatively low in the summer. The air conditioning load would increase but that would be reflected in electricity demand. An increase in residential gas consumption in Q2/Q3 of between 12 and 15 per cent is possible. However, Q2/Q3 residential consumption is less than 25 per cent of total for the year, so that would translate to around a 3 per cent increase for 2020 as a whole.

Commercial

With shops, restaurants, cafes and offices closing, commercial demand will be significantly hit. With GDP possibly 15 per cent or more down in the summer compared to last year, commercial gas demand in the private sector could be down a lot more than this, although most federal and state operations are likely to continue, limiting the fall in energy consumption. Nevertheless, a fall in gas demand of over 15 per cent could be assumed for commercial consumption in total during the summer, but as Q2/Q3

[17] https://www.eia.gov/outlooks/steo/
[18] https://www.imf.org/en/Publications/WEO/Issues/2020/04/14/weo-april-2020

commercial consumption is just over 30 per cent of the total for the year this would translate into an annual 5 per cent decline for 2020 as a whole.

Industrial

Some industrial sectors may be badly affected with factories having to shut and supply chains from other countries being disrupted. Overall industrial production could fall by 20 per cent. However, gas demand in industry is heavily concentrated in chemicals, petrochemicals and iron and steel and, if other process industries are included, this accounts for around half of industrial gas demand. While these industries may be somewhat impacted, they are much less likely to shut down. A reduction in industrial gas demand of between 10 and 15 per cent year on year may be a reasonable assumption for Q2/Q3. Industrial gas demand is more evenly spread through the year with some 45 per cent in the summer months, so for the whole of 2020 that translates into a 5 per cent decline.

Power

Gas demand in power may be one of the few relatively bright spots. The EIA has assumed that the coal industry would take the vast majority, and perhaps all, of the 3 per cent decline in electricity demand they have forecast, but on the basis of the much bigger fall in GDP estimated by the IMF electricity demand could be some 10 per cent or more lower. Coal is unlikely to take the entire fall and there may be some impact on gas despite it being very competitive against coal. A fall in gas demand in power of 5 to 6 per cent may be a reasonable estimate for Q2/Q3. Unlike other sectors, gas demand for power is higher in the summer, some 55% of the total for a year. That gives a decline for the whole of 2020 of 3 per cent.

Total gas demand impact in the US

Adding these changes together produces a tentative estimate that total gas demand in 2020 could be some 3 per cent lower than it otherwise would have been – this is less than half the drop in US GDP between IMF's January and April WEO estimates. However, the decline in gas demand in Q2 and Q3, when we assume the major impact will be felt, could be over 6 per cent, with power and residential compensating somewhat for the other sectors.

The US projection is highly uncertain, however, due to the radically different approaches to dealing with COVID-19 between states and also with the Federal Government's roller coaster approach. If a significant proportion of the country comes out of lockdown relatively quickly, this could limit the fall in gas demand, partly in Q2 but more likely in Q3 although in this case, there must be a high risk of the virus recurring leading to the possibility of further significant disruption later in the year.

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2.4 A major gas supply overhang – who will blink first?

Health Warning: *This is NOT a forecast but an analysis designed to assess the impact of a significant decline in demand on the global gas market, based on the assumption that COVID-19 is a six month 'hit' on demand, with a return to 'normal' after that, and to discuss when the excess supply may overwhelm global and European markets. If the impact on gas demand is longer than six months, which other analyses, such as the IEA, are projecting, then the outlook would be much worse for the global gas market.*

How big is the supply overhang?

Even before the dramatic impact of COVID-19 and the consequential lockdowns leading to drastic declines in economic activity, the global gas market was already looking at a significant supply overhang in 2020. With a mild northern hemisphere winter and a new Ukraine transit deal with Russia being agreed (leading to higher than normal gas storage levels), European gas prices were already heading into the $2 per MMBtu range, as had been discussed in recent OIES Energy Comments.[19]

The gas supply overhang had already manifested itself in late 2018 and into 2019. This was reflected in a collapse in spot gas prices in both Europe and Asia. Both TTF and JKM fell by $5 per MMBtu between 2018 Q4 and 2019 Q4. The average price for TTF in 2019 was $5.06/MMBtu, against $7.61 in 2018 and the average price for JKM in 2019 was $5.97, against $9.85 in 2018. The TTF price in Q3 2019 had already fallen to an average of $3.60 per MMBtu showing how weak the market was before winter 2019/20, before the impact of COVID-19.

However, how can we know how large the global gas supply overhang was or will be? After all, first year economics will tell you that supply must equal demand all the time.[20] A possible proxy for the supply overhang, however, could come from the European gas market and LNG trade. Unlike almost all other markets which import LNG, Europe has the ability to absorb LNG, if supply is plentiful, and allow LNG to be diverted to higher value markets when supply is tight. This reflects the fact that Europe has indigenous production, imports pipeline gas from multiple suppliers, plenty of gas storage and, for the most part, is a fully liquid trading market.[21] In almost all other LNG importing markets, especially in Asia, the level of LNG imports is fundamentally driven by the level of gas demand, with little or no choice of switching to or from different gas supply sources, other than, possibly, China.[22]

The main pipeline gas supplier to the European market is Gazprom, and Russia has surplus production capacity[23] which can be ramped up or down. In terms of supplying Europe, at the moment a key constraint is pipeline capacity and, if this is fully utilised, then there is no real excess supply available for the European market. OIES estimates that there was very little unutilised capacity on the main Russian routes[24] into Europe in 2019 – less than 5 per cent of total available capacity – indicating pipeline capacity was, effectively, fully utilised.

[19] Fulwood, M. (2019). Could we see $2 gas in Europe in 2020? OIES Energy Comment, October https://www.oxfordenergy.org/publications/could-we-see-2-gas-in-europe-in-2020/?v=79cba1185463, and Fulwood, M. (2020). $2 gas in Europe is here: who will blink first? OIES Energy Comment, March https://www.oxfordenergy.org/publications/2-gas-in-europe-is-here-who-will-blink-first/?v=79cba1185463

[20] But not what price will clear the market

[21] This is especially so in respect of Northwest Europe – UK, France, Benelux and Germany – which is a fully liquid trading market with abundant regasification capacity

[22] This refers to switching between different sources of supply and is not related to switching because of price which is possible in a number of markets such as India

[23] Alexey Miller announced that Gazprom's production capacity for 2020 was 545 Bcm compared to 2019 production of 500 Bcm (Russian Bcms)
Interfax Russian and CIS Oil and Gas Weekly, 26 March-1 April 2020 p9

[24] Nordstream into Germany, Belarus into Poland, Blue Stream into Turkey, Ukraine into Slovakia

For the LNG market, OIES considers available export capacity rather than nameplate.[25] In 2019 available capacity was some 510 Bcm and total LNG imports were 465 Bcm[26]. This is a utilisation level of 91.4 per cent. It is rare for the utilisation of available capacity to be over 93 per cent[27], since there is also likely to be some spare capacity, LNG in the carrier's tanks which boils off and/or is used as fuel and doesn't get delivered, as well as scheduling and loading issues. The volume of 'excess' supply or 'stranded' gas, therefore, was some 8 Bcm. Given that it was argued that there was a severe supply overhang in 2019, this does not sound that much – around 1.5 per cent. Ordinarily this would be true, but Europe effectively absorbed much of the supply surge, not by consuming it, but by putting it into storage. Gas in storage in Europe rose by 20 Bcm between the end of 2018 and the end of 2019, driven not only by the LNG supply surge, but also by uncertainties over Russia and Ukraine's contract negotiations for transit in 2020 and beyond, which might be considered as 'hidden stranded' supply. Taking into account the very low level of unused pipeline capacity from Russia (2 Bcm), the measured 'stranded' supply for LNG and the 'hidden stranded' supply which went into European storage, then the total supply overhang was around 30 Bcm.

2020: Pre COVID-19

In the absence of the COVID-19 virus and also with the fall in oil prices as OPEC+ failed to agree on production quotas, the OIES projection[28] - Reference case – can be summarised as follows:

- Global gas consumption was expected to rise by 1.5 per cent over 2019 – some 50 Bcm – almost wholly in China, Middle East and Japan, Korea and Taiwan. Production increases were mainly seen in Australia (LNG exports) and Middle East. US consumption was projected to decline slightly, with production increasing to meet rising LNG exports.
- LNG export capacity was forecast to rise by 50 Bcm, with LNG imports rising by 48 Bcm, leading to little change in export capacity utilisation and in 'stranded' gas. The rise in LNG imports was all in Asia, driven by a strong recovery in China plus smaller increases elsewhere. European imports were projected to decline marginally from the very high 2019 levels. The global increase in LNG imports would be largely supplied from the US.
- Europe consumption was expected to rise marginally and production was down some 10 Bcm. Pipeline imports were forecast to be up slightly but LNG imports declined a little from the high 2019 level. The market was seen to be finely balanced, however, with storage largely filling again by October, and just about able to absorb most of the LNG supply coming to Europe, together with the pipeline imports.
- Prices were expected to be around $1 lower in 2020 than 2019 for both TTF and JKM, averaging in the low $4 for TTF and the middle $4 for JKM. TTF was expected to be below $3 for much of summer 2020, especially in Q3.
- The total supply overhang or 'stranded' gas in 2020 was projected at around 25 Bcm for both unused pipeline capacity from Russia and the global LNG market, higher than the measured 'stranded' supply of some 10 Bcm.

2020: Post COVID-19

Based loosely on the global GDP projections discussed in Section 1, OIES has made broad estimates of the likely reductions in gas demand for the main regions involved in international gas trade – North America, Europe and Asia[29] – with generic assumptions for the rest of the world. The estimate of the

[25] Available capacity adjusts nameplate capacity for regular maintenance, unscheduled maintenance, technical and operational issues, feed gas problems and, on the other side, the ability of a number of plants to produce above nameplate capacity
[26] Source Platts LNG Service
[27] 2006 was the last year utilisation was above 93% - calculation from Nexant World Gas Model
[28] Scenario outputs from the Nexant World Gas Model, with OIES assumptions
[29] These 3 regions account for 75% of global gas demand, 95% of LNG imports and 80% of inter-regional pipeline flows

decline in demand is predicated on a six-month hit to demand – in Q2 and Q3 for most countries[30]. After this decline, demand everywhere is assumed to revert to normal.

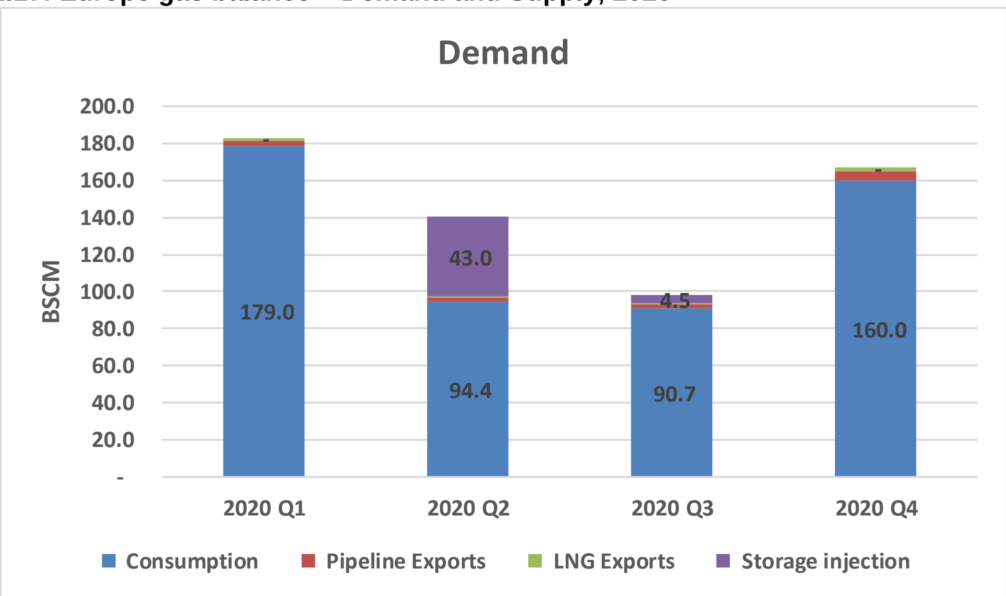
Global consumption is projected to be 115 Bcm lower in 2020 than in 2019 – a fall of almost 3 per cent and over 4 per cent below the Reference case. The largest volume declines are in North America, Europe, and Russia. Consumption in China is up by just under 5 per cent in 2020 but that is some 5 per cent less than the pre-COVID-19 case. Consumption in all other regions is either flat or declining in 2020 over 2019. There are significant production declines in Russia, Europe, North America, Caspian region and the ASEAN countries.

In terms of international gas trade and the linkage between regional markets, it is LNG which is key. With LNG supply still growing rapidly, total global LNG trade still grows by 5 per cent year on year (around 25 Bcm), but this is less than the 8 per cent growth projected in the Reference case.

For many regions the COVID-19 case has similar or lower imports than in the Reference case – for North America and ASEAN there is absolutely no difference. LNG imports to China still grow but by less than in the Reference case. Imports into Japan, Korea and Taiwan remain similar to 2019 levels rather than growing as previously projected. In Europe, LNG imports, rather than declining slightly as in the Reference case, actually increase in the COVID-19 case by some 5 Bcm (10 Bcm higher than the Reference case). This is evidence of the supply push effect, with as much LNG as possible going to the only market which can absorb it.

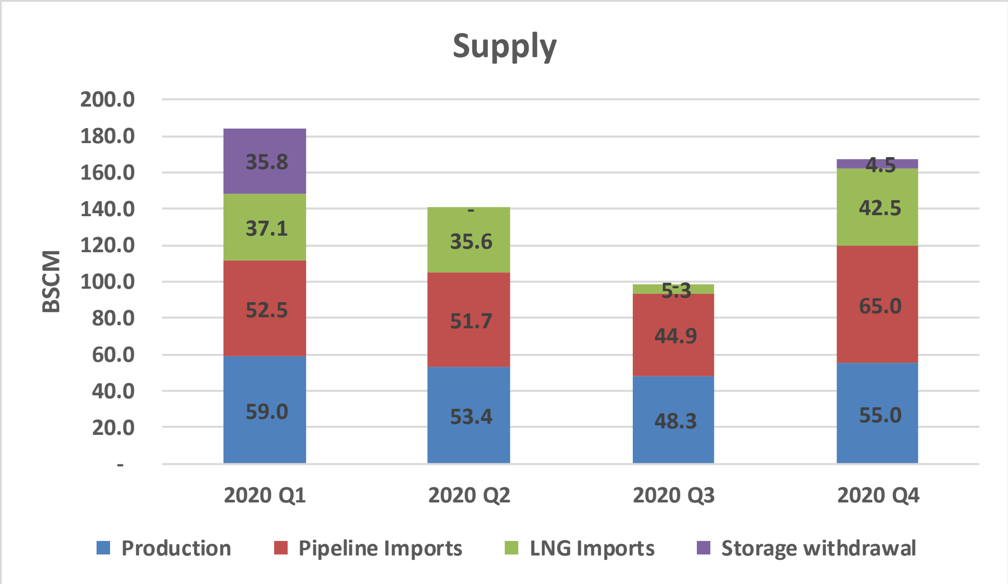
As in 2019, Europe is the key market in terms of its ability to absorb LNG, but this is particularly dependent on the space available in European storage. It was noted in Section 2.2 that the volume of gas in storage at the end of March was at historically high levels, with only 47.5 Bcm of space to fill in the summer months before the colder winter weather arrives[31]. This lower level of available storage in Europe means that the region will be unable to absorb in full the excess LNG from the rest of the world (see European Gas Balance below in Figure 2.17). As a result, the growth of global LNG imports in the COVID-19 case is around 15 Bcm lower than in the Reference case because there is nowhere for this extra LNG to go.

Figure 2.17: Europe gas balance – Demand and Supply, 2020



[30] For China mostly Q1 and Q2

[31] Ukraine has offered some 10 Bcm of storage capacity to European companies which could alleviate some of the constraints if this was taken up



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

Consumption in Europe falls sharply in Q2, to well below normal seasonal levels, declining by some 16 Bcm year on year (15 per cent lower) – half the full decline for the whole of 2020. However, storage can fill rapidly so much of the LNG can be absorbed. It is in Q3 that supply overwhelms demand, as storage is completely full. Consumption is down 7 Bcm (7.5 per cent lower) but with almost no storage space left, only 5Bcm of LNG imports can be accommodated.[32] On the assumption that everything is 'back to normal' by Q4, consumption rises sharply and LNG imports also increase.

As shown in Table 2.1, both indigenous production and pipeline imports are also down significantly year on year. LNG imports for 2020 as a whole are higher than in 2019, and as noted above, higher than in the Reference case. Norwegian production and pipeline imports from Russia are reduced to accommodate it. There appears to be some evidence for this as Norway has announced cuts in oil production[33] which will impact associated gas, although not necessarily non-associated gas. Gazprom also stated recently[34] that exports to Europe were expected to slump by over 16 percent in 2020, which is around a 30 bcm fall for the whole year, which is consistent with the fall in pipeline imports shown in the table below for the first three quarters of this year (assuming the rest of the Gazprom decline is then in Q4)[35]. Prices are already heading below $2 in Europe (and in Asia) for this summer and any slight change in demand, indigenous production and/or pipeline imports, especially in Q3, could make the prospects for LNG even bleaker.

[32] It has been reported that possibly 25 LNG cargoes (around 2.3 Bcm of delivered gas) from the US will not be lifted for June, which is consistent with the sharp drop in LNG imports in Q3, since they will not be delivered until July https://www.argusmedia.com/en/news/2100349-up-to-25-us-lng-cargoes-may-be-cancelled
[33] https://www.npd.no/en/facts/news/general-news/2020/cutting-oil-production/
[34] Argus *European Natural Gas* April 29 2020
[35] In addition the Iran to Turkey pipeline is out of action for the whole of Q2 as a result of an explosion

Table 2.1 Europe balance year on year change

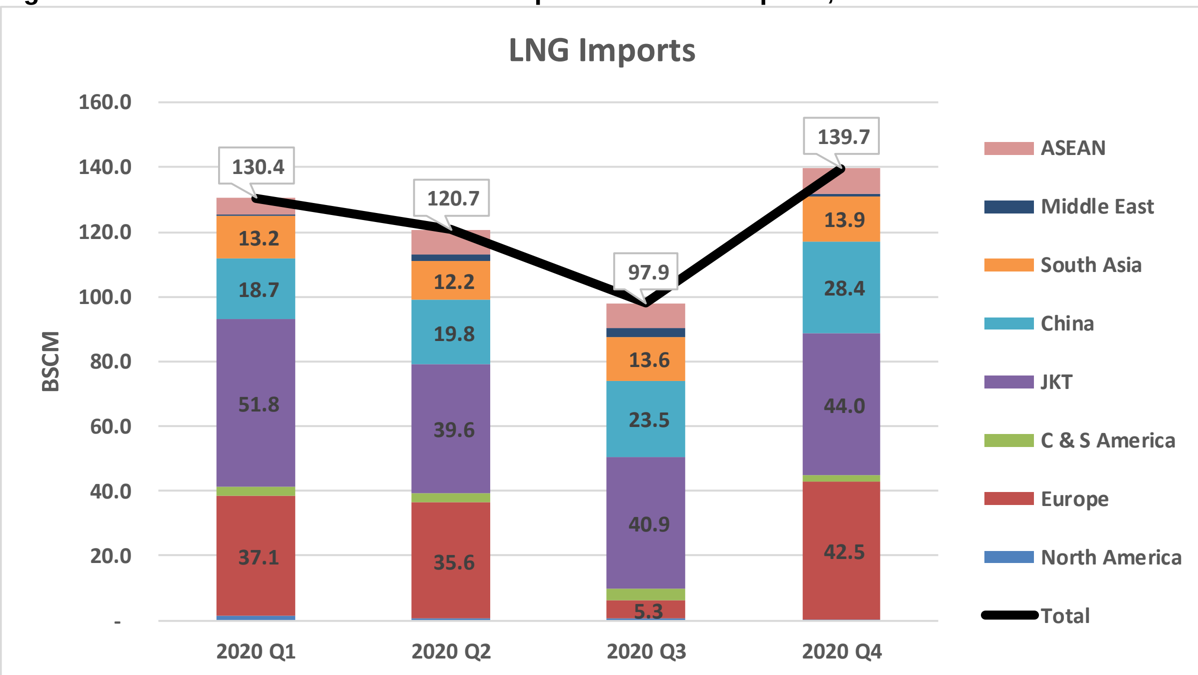
CHANGE OVER 2019					
BCM	2020 Q1	2020 Q2	2020 Q3	2020 Q4	2020
Production	-5.4	-3.9	-1.7	-3.5	-14.4
Pipeline Imports	-8.4	-8.1	-9.5	2.3	-23.8
LNG Imports	9.7	4.9	-19.7	9.6	4.5
Storage withdrawal	5.9	-	-	-3.5	2.4
Total Supply	1.9	-7.1	-31.0	4.9	-31.3
Consumption	-6.6	-15.6	-6.7	-0.9	-29.7
Pipeline Exports	0.6	-1.7	-3.3	1.6	-2.8
LNG Exports	0.1	-1.3	-1.1	0.2	-2.1
Storage injection	-	10.0	-20.4	-	-10.4
Total Requirement	-5.9	-8.6	-31.5	0.9	-45.0
Statistical Difference	7.7	1.5	0.5	4.0	13.7

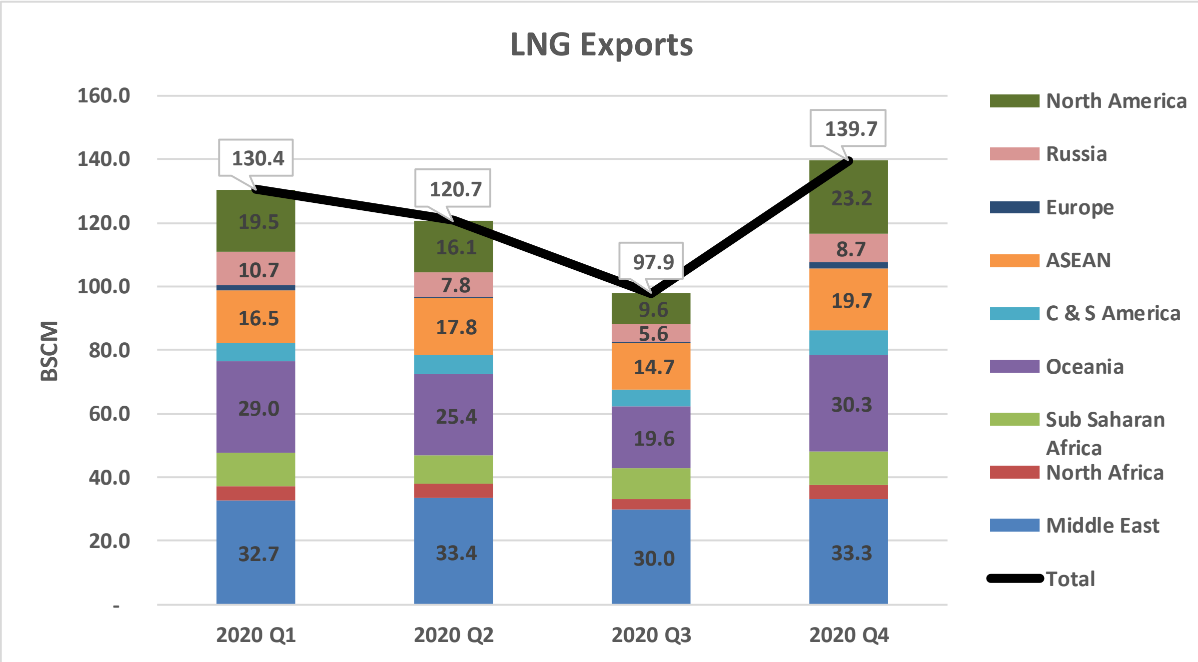
Source: OIES estimates, IEA data, Platts LNG Service and Nexant World Gas Model

What does this imply for the global LNG market? Figure 2.18 shows the supply and demand balance for the global LNG market. Total LNG trade was at record levels in Q1 2020 and, while a decline in Q2 is expected with weaker demand, the Q2 total of 120 Bcm is still 7 Bcm higher than in Q2 2019. The ability of Europe to absorb the LNG and a small recovery in China is sufficient to offset weakness elsewhere, especially in Japan, Korea and Taiwan. It is in Q3 2020 when the LNG market takes the biggest hit, to under 100 bcm, compared to 116 bcm in 2019, despite China and other regions taking more volumes – Europe simply has no more storage space left.

In respect of exporters, the US, Russia and Australia are most affected, but all suppliers can expect to see lower volumes – apart from Qatar which emerges largely unscathed. However, US LNG exports still increase by over 20 Bcm compared to 2019 – a rise of just under 50 per cent.

Figure 2.18: Global LNG balance – LNG Imports and LNG Exports, 2020





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

The amount of 'stranded' gas in 2019 was 10 Bcm – measured in relation to Russian gas coming into Europe and the global LNG balance – if the 'hidden stranded' gas which ended up in European storage is ignored. Even in the Reference case, with more LNG supply, largely from the US, coming onstream, 'stranded' gas was expected to rise to 25 Bcm. In the COVID-19 case this rises to 48 Bcm. Compared to 2019, sixty percent of the 38 Bcm rise in 'stranded' gas comes from LNG and the remainder largely from Russia holding gas flows back. In addition, Norwegian production may also ease back somewhat, compared to the Reference case.[36]

Even if this LNG and pipeline gas is held off the market, prices would still be much lower than in the Reference case with TTF averaging slightly below $3 for 2020 and JKM in the low $3 range. These prices are broadly consistent with the actuals through April and the forward curves for TTF and JKM.

Conclusions

Clearly there are major uncertainties in this analysis, not least on the level of gas demand around the world and how long it will be impacted by the reduced economic activity as a result of COVID-19. What can be said with reasonable certainty, however, is that there isn't likely to be anywhere near enough gas demand and gas storage to absorb the level of supply available in the market in 2020. Our model clears the market largely by holding back supply – LNG on a global level, pipeline imports into Europe from Russia (largely), and some Norwegian production. This relies on Russia reducing pipeline supplies to Europe in Q2 and Q3 at similar rates to its Q1 reduction. While Gazprom is expecting a decline in its exports, consistent with this analysis, the projected balance in the market is on a knife edge and marginal changes in supply and demand could put even more pressure on the LNG market.

Could gas prices in Europe, or even Asia, become negative at some stage this year, as WTI did in the US for the May settlement price[37] and Permian gas did for a period last year? This seems unlikely since US oil production was faced with a market that disappeared almost overnight as well as completely full storage so there was nowhere for it to go. Similarly, in the Permian basin last year, the rapid rise in oil

[36] The decline in Groningen production was already factored into both cases and there is no change in other countries
[37] The negative WTI for the May settlement price was mainly a technical price since it was the day before settlement and sellers had to close their positions or go to physical delivery with nowhere to put the oil

production led to rising associated gas which couldn't find a market because of the lack of takeaway pipeline capacity – again there was nowhere for the production to go.

In theory, a similar situation shouldn't occur in the global gas market as producers and off-takers of LNG can adjust their supply more easily. However, will producers (especially Gazprom) and off-takers hold back volumes as the market balance from our modelling suggests, or might they even be encouraged by governments to keep exports going in order to support jobs and production? If they fail to react in a timely manner to these pressures, especially in Europe in Q3, then prices could be at levels normally seen in Dollar General[38] stores! The question was asked in the title of this section – who will blink first? There are signs that Russia may have started to blink in the last month or two, and while other market players may not have joined them yet it would seem that their eyes are beginning to water!

Postscript – IEA Global Energy Review

On April 30th the IEA published their Global Energy Review on the impact of COVID-19 on the energy markets. They projected a 5% decline in global natural gas demand, based on a more significant 6% fall in global GDP in 2020 than the 3% we use in our modelling. However, they did note that a faster post-lockdown recovery in Europe and North America and shorter lockdowns in other regions would reduce the negative impacts on Asian manufacturing economies and gas exporting regions, leading natural gas consumption to decrease by about 2.7% instead of 5%. This is broadly consistent with our six-month hit to demand and back to "normal" thereafter, resulting in a 3% decline in global natural gas demand.

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[38] Chain of stores in the US where items are sold at slightly more or less than $1 – other brands are available such as Dollar Tree and Family Dollar, and even Poundland in the UK

2.5 The longer-term implications of COVID-19 for gas markets

When economies and markets experience shocks, they do not go back to their previous trajectories. Therefore, at times such as the current COVID-19 pandemic, forecasting based on extrapolation is not useful. Particularly problematic is that previous shocks (e.g. the 2008 financial crisis) were completely different in nature to the present situation which is a shock of a type never previously experienced. How the next few years will unfold will depend on the depth of the national and global recession and the speed or shape of the recovery – V, U, W or L. It will also depend strongly on the policies which governments choose to prioritise in relation to both economic recovery and decarbonisation. For this section we devised a set of questions about the potential longer-term[39] implications of COVID-19 for seven national and regional gas markets - Europe, US, China, India, Russia, Qatar and Australia - which we believe will have an important impact on gas and LNG supply, demand and trade. Our country and regional specialists have contributed answers to these questions which form the basis of this narrative, to which have been added some global perspectives. Because natural gas markets are still fragmented, national and regional implications of the crisis will be significantly different, but we have looked for common patterns and factors which may have global implications.

General Trends and Major Questions

1. Will the Pandemic Change Government Policy on Energy Security and Governance in Relation to Gas?

Policy on energy security and governance is often expressed in generalizations from government documents which may be several years old. But the crisis may require governments to intervene in order to protect industries and (in some cases) customers against what they see as much more immediate negative consequences.

For importing countries, very low prices (even lower than before the crisis began) are positive in terms of increasing the competitiveness of gas and reducing foreign exchange outflows. For India, low import prices are a particular benefit since energy security is very much about minimizing fiscal deficits. In China, low-cost gas imports are helping to accelerate market liberalization and filling storage. In both countries, but especially China where tensions with the US have prompted a greater focus on domestic production and clean coal, the crisis will highlight security of supply concerns around import dependence and how to maintain domestic production at a time of very low import prices (see Question 5). In Europe, domestic gas production has been in long term decline and current price levels will accelerate this trend, possibly even in Norway which has hitherto been the exception, but it is doubtful that government support will either be forthcoming or would have any major impact. Some countries will use the availability of very low-cost LNG to accelerate their drive to reduce dependence on Russian gas imports, for political and security reasons. For others, commercial issues will be the most important determinant of their supply choices.

Exporting countries are moving to protect their national and possibly even their privately-owned companies (see Question 6). The Russian government is supporting domestic gas demand growth – prices will be frozen to support industry and prevent protests and payment obligations for consumers have been relaxed – as a way of absorbing excess domestic production. Some European regulators have introduced similar measures to prevent utilities cutting off customers unable to pay for energy supplies. There is no change to the US Administration's energy dominance and self-sufficiency policy, but should a Democratic Administration be elected later this year, these policies could change. For Qatar, a protracted period of low prices could create incentives to increase regional exports, but this would require improved political relationships with neighbouring countries. In Australia, energy security has risen up the political and security agenda, with a focus on electricity networks following power shutdowns in some regions over the past several years. All of these potential policy changes seem likely to be positive for gas demand and trade, with the limiting factor being the capacity of governments to maintain those policies which create an additional short-term financial burden.

[39] We define the longer-term time horizon as the period up to 2025.

2. Will the current crisis lead to a prioritization or a weakening of decarbonization policy?

Countries and regions have very different policies towards decarbonization and there are very different views as to their likely reactions in the current crisis. The European Union Parliament and many member state governments have expressed continued commitment to the `Green Deal', `net zero' emissions by 2050 and raising emission reduction targets for 2030. But there are signs that Green Deal policies are encountering delays given the current imperative of supporting the economy in general, companies and employment. Greenhouse gas emissions are likely to fall significantly in 2020 due to the crisis, and this may relax pressure for a rapid phase-out of gas as it can be part of the economic recovery.

For China and India, the signs are unclear. Renewables are making progress, especially in China, but coal is also progressing and the past two years have been negative for decarbonization. In India renewable development will depend on continuing overseas investment, and the competitiveness of different energy sources will be more important than policy. Although an official national strategy for low-carbon development to 2050 should be submitted to the Russian government later this year, current drafts suggest it will have minimal impact, and the current economic and health crises will most likely further weaken any initiatives.

There will be no change in US policy under the current administration but should there be a change in government after the 2020 election then decarbonization policy could be significantly strengthened. Decarbonization is not a significant policy issue in the Gulf countries, and although renewable energy development is increasing (but from a low base in all countries other than UAE) the major impacts are likely to be seen post-2025. The Australian government has stated that it will not support climate policies that harm the economy or put jobs at risk - the economic risk of climate policy is a powerful narrative - but the recent bushfires have led to significant debate about climate policy.

A global impact of the crisis is the improvement of urban air quality which has brought health benefits which electorates – and therefore politicians – will be keen to retain. While this is more immediately related to transport (and therefore oil-related) emissions, it may have more general implications which could be positive for gas in the short term where there is potential for coal to gas switching.

3. Will Gas' Position in the Energy Transition Strengthen or Weaken?

Just as in relation to decarbonization, the outlook for individual countries and regions is very different in relation to the position of gas in energy balances, but in general the next few years could be positive for gas due to low prices and advantages over coal. In countries where decarbonization is a strong political and policy priority, the crisis may delay implementation for perhaps as much as several years. In countries where energy transition has never been considered important, it will slip further down government agendas, especially in the context of falling power and energy demand, meaning that although gas demand may also decline it may not fall to the extent of other fossil fuels. Indeed, very low pipeline gas and LNG import prices up to 2025 could be a major factor in cushioning the impact of the crisis on gas demand, counterbalancing gas to renewables switching. In contrast, the crisis could create major problems for coal as many mines around the world are not profitable, cannot reduce costs any further and, where coal-fired power plants are very old, closing them could make a significant contribution to air quality. Natural gas could benefit from earlier than anticipated coal retirements even with reduced electricity demand and increased renewable generation.

In Europe, prior to the current crisis natural gas was seen as being part of the transition by many governments but it was also thought that it would be progressively replaced by `green gas' (biogas, biomethane and hydrogen) as these technologies evolve and their costs fall. Governments could prioritise investments in green gas technologies as part of their recovery packages. They could also increase national carbon floor prices or taxes which consumers may not resist (or notice less) given the fall in fossil fuel prices. This could create momentum for the introduction of national, and eventually EU, border taxes on the greenhouse gas (carbon+methane) content of imports later in the decade. For gas imports with high methane emissions in the value chain (or which are unable to provide certified evidence of their emissions), this could be a significant problem.

Chinese government policy seems to be once again emphasizing coal and switching to gas has slowed. The crisis is unlikely to change this as the focus on domestic sources of energy is likely to increase. On the other hand, gas demand in India could accelerate because much gas-fired capacity is either idle or running at low load factors; and gas has become more competitive against naphtha in the fertilizer sector. In the US, the impact of the crisis in power generation has been greater for coal than for gas. More homeworking may support renewables but higher residential demand has reduced resale of power to the grid and therefore offset (some of) the decline in fossil fuels. There will be little domestic impact in Russia or Qatar but both will see reduced income from exports. In Australia, the domestic debate between coal and gas continues to rage but the latter's position is not likely to change. Gas will struggle to make headway in power generation in the 2020s due high domestic gas prices, and this is unlikely to change until coal-fired power stations close starting from the early 2030s.

4. Will COVID-19 lead to Changes in Consumer Behavior which could Impact Gas Demand?

The immediate impact of the crisis on gas demand cannot be compared to the situation for oil where the impact on all forms of transportation has led to projections of demand reduction in the tens of millions of barrels a day. Nevertheless, homeworking in Europe has already flattened daily power demand and adjusted the balance between morning to afternoon, and if physical return to offices remains restricted, winter residential demand could increase significantly. In Europe and the US, installation of greener heating and cooling devices (heat pumps, rooftop solar, home storage systems, micro-CHP, renewable hydrogen) and all forms of efficiency improvements are likely. Some of these will need financial support from government or regulators and if implemented on a large scale would probably require a longer timescale than five years. However, the potential reduction of time spent in the office is creating possibilities for moving out of big cities and (as long as high-speed broadband connections are available) into new developments which can incorporate low carbon distributed energy systems. In the short term, gas may benefit if there are connections to the network, but longer-term benefits will be for renewables. In Russia, gas demand may not be greatly impacted but non-payment is increasing, which will result in falling cash revenues for gas companies. In China, home working will mean marginally more gas use, but price competitiveness with coal will likely be more important. Indian government policy will favour home working to improve air quality and traffic congestion, but this will reduce gas demand in transportation. There is little discussion of these issues in Australia or the Gulf States.

5. What are the Implications for Producers and Investors in Relation to Pipeline gas and LNG Projects – could an investment standstill accelerate a new price cycle?

The fall in gas, but particularly in oil, prices and demand means that all producing companies will have less money to invest in new developments. For this reason, with the possible exception of Qatar, investments in gas production and new infrastructure projects will fall, possibly very substantially, as projects are deferred. LNG projects which are under construction may be delayed for both logistical and financial reasons, and FIDs for new projects will be stalled for several years.

Aside from investments by energy companies themselves, it is unclear whether banks, hedge and pension funds will still be interested, and have sufficient liquidity, to invest in gas projects. Their decision-making criteria in relation to risk and return may favour expansion, rather than greenfield, projects. But it is possible that price volatility and increased politicization may increase this risk profile to the point where the sector is no longer seen as an attractive future investment.

In April 2020, Australia reported $80bn of energy projects had been deferred although some of these may be more directly related to the oil price fall. Low prices could impact some Australian projects, principally those which need additional gas to maintain current export levels, consequently exports may decline modestly in the early 2020s. In Russia, the government may use (oil and) gas investment support as a driver of general economic recovery, and rouble devaluation will soften some of the financial impact. Pipeline gas projects under construction will be completed but the crisis could delay new Russian pipelines to China. In the US, investment in (oil and) gas will fall sharply but could quickly pick up again if prices recover. The current Administration may provide financial support for gas and LNG companies.

In China, domestic production is likely to remain a priority, but Chinese investors may review their global portfolios. In India, private sector production which has been in long-term decline at low prices is likely to collapse. NOC production will fall but not so dramatically, due to protection from government and revenue streams other than gas. 2020 prices have created even more bad news for European gas producers which were already under pressure following the 2018 price downturn. This will accelerate the decline of UK gas production. Norwegian gas production and exports will reduce somewhat due to oil production cuts (as part of the April 2020 OPEC+ agreement) and low prices will also delay new developments. But Norwegian long-term contract commitments have significantly reduced compared to previous levels, giving producers flexibility to adjust their exports to current demand and price levels. In the Mediterranean, gas developments which looked marginal even at pre-2019 price levels, will only progress if their destination can be regional countries (rather than European Union or global LNG markets). By contrast, Qatar will press ahead with its new LNG export projects although delays, principally for logistical reasons, are possible. Other Gulf countries will reduce gas investments except possibly those building LNG receiving terminals to take advantage of low prices.

The low-price gas environment, which started a year before the crisis, and pre-crisis was expected to last for several years, may be prolonged unless production and export control measures can be agreed (see Question 8). This raises the prospect of a gas `bust' creating a shortage and a new `boom' around 2025 (but possibly later) with much higher prices as the global supply/demand balance tightens and delays to projects mean insufficient new supply and export projects coming on stream. But any return to prices anywhere close to 2014-18 levels would substantially speed up Energy Transition developments away from gas.

6. Will the Crisis Change the Role, Importance and Strategies of IOCs and NOCs in the Gas Sector?

In terms of the future role and importance of IOCs and NOCs:

- In Russia, India and Qatar NOCs and national champions are likely to maintain and even increase their importance as private sector and foreign investors pull back and/or ask for tax concessions (which are unlikely to be forthcoming).
- In China, new domestic private and international companies are likely to be allowed to enter the gas sector and may choose to do so given that demand is continuing to increase.
- The US shale sector may undergo significant structural change with smaller players disappearing or being taken over by IOCs.

In relation to future strategies, the share of gas in the reserve portfolios of many NOCs and IOCs has increased over the past decade and both groups of companies may see future gas investments as less risky than oil (given the uncertain future of post-crisis oil demand). This can be represented as diversification until large scale investments in non-fossil energy sectors become realistic and attractive. But the portfolio player strategy of global LNG purchase and sale, which was highly successful in a market with significant regional price spreads, has far fewer advantages in a market where regional prices are uniform and low. Until it can be anticipated that prices will increase significantly and unless regional differentials then re-emerge, there will be very limited arbitrage gains from moving LNG around the world. The crisis could therefore slow down gas `globalization' and reduce the anticipated increase in international trade. Protection of national producers, and government attempts to use them to promote economic recovery, also suggests greater self-sufficiency and reduced international interactions.

7. Will the crisis cause a profound change in price mechanisms and contractual conditions?

In the major liberalized markets of Europe and North America, hub prices are well-established and no change is envisaged. In smaller southern and eastern European markets where prices are still mainly oil-linked, the move to market pricing is a matter of time and increased interconnections; the main remaining uncertainty on price transition is in Turkey. In Russia, regulated prices will remain for the domestic market.

In Asia, the transition from (crude) oil-linked pricing in LNG contracts to a different price formation mechanism, and from 25 year contracts with high take-or-pay to shorter term and spot contracts with more flexible offtake, is underway but by no means fully established. In China, these developments are part of an ongoing process towards spot prices – although whether JKM[40] or a domestic Chinese benchmark is yet to be determined – and more flexible contracts. Indian off-takers will continue their previous efforts to move towards spot prices, take-or-pay waivers and short-term contracts. Many long-term Asian LNG contracts expire in the next few years and extensions or renewals are likely to feature shorter durations, with much greater volume flexibility, spot price indexation and more frequent price reviews.

Exporters will also face difficult problems during this period with most Russian contracts in both Europe and Asia needing price revisions in order to protect market positions. US LNG exporters may have to offer non-Henry Hub related prices, if they are to retain their market, but this will be very difficult as existing contracts are believed not to include price reviews or reopeners. Australia will face similar demands for price reviews and greater flexibility but the very costly oil-indexed projects which came onstream in the 2010s are facing extremely difficult commercial problems even at current prices. Qatar has already accepted spot and hub pricing in Europe and countered this by vertical integration into import markets (via ownership of regasification terminals and marketing) and its cost structure means that although export revenues have been much reduced, it can cope with less difficulty than other LNG exporters. We may not see the same degree of litigation in relation to pricing in Asian long-term LNG contracts as happened in North America and Europe, although some US and possibly Australian contracts could be exceptions to this observation.

8. Will there be any appetite among gas producers for supply and price control mechanisms?

There has never been an organization of gas exporting countries similar to OPEC in the oil market, but the Gas Exporting Countries Forum (GECF) was created nearly 20 years ago as a meeting place for gas exporters. From a Russian perspective, negotiations among GECF member governments are becoming more likely. Europe, as the most competitive market where any pipeline or LNG exporter can sell gas at liquid hubs, is the `battleground' and where any agreement on supply and price control would focus. There is a real possibility that without such controls, or the imposition of additional sanctions to restrict Russian gas exports, European gas prices could turn negative in the second or third quarters of 2020 and possibly thereafter, depending on the loss of demand resulting from the crisis and the speed of recovery. Any such short-term agreement among producers would be informal and voluntary and would need to include (at least) Russia, Norway, Qatar and probably Algeria. There will be extreme caution surrounding any such arrangements because they might simply reduce the sales of participants, allowing other supplies - such as US LNG – to take their market share. But should any such arrangement be successful, it could be repeated over the next several years during periods when over-supply threatens to drive prices to (what are perceived to be) unacceptably low levels.

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[40] Platts Japan-Korea marker price.