

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

Introduction

In this first OIES Gas Quarterly of 2021 we provide our usual review of global gas prices but more importantly highlight 10 key themes that we believe will be important in shaping the outlook for the global gas sector over the next 12 months.

We start, as usual, with a look at various price indicators which demonstrate what we believe are some key market trends, and some dramatic changes which have occurred since our October Quarterly. Every price indicator has been impacted by the dramatic jump in the spot prices in Asia, driven by the record-breaking cold snap that has hit the region. This has dragged LNG supply away from other markets, and a combination of higher demand, some global LNG supply problems and issues with shipping capacity (not helped by delays at the Panama Canal) have all combined to create a perfect storm for higher prices.

Looking beyond the winter months, though, Mike Fulwood sees a rebalancing of the global gas market in our first key theme, as he anticipates another summer of potential supply surplus. The main question surrounds the market in Europe, where the balance between pipeline and LNG supply, combined with the levels of storage utilisation, will be critical in determining whether futures prices, which see TTF at \$5-6/mmbtu this summer, are over-optimistic or not. A key indicator of the outcome will be the level of gas in storage in Europe throughout the year, but in particular at the end of this winter, and Jack Sharples analyses the history in 2019 and 2020 before looking at the prospects for this year in the second key theme. The essential question is whether the high stock levels seen during the past two years will return again in 2021.

Our third key theme discusses another continuing story – the construction of Nord Stream 2. Katja Yafimava assesses the likelihood of completion being achieved in 2021 and analyses the potential impact of US sanctions, which have played a key role in delaying the project to date. Her view is that the pipeline can be completed this year, but the possibility of further delay cannot be ruled out. For our fourth theme we remain in Europe, as Anouk Honore discusses the question of whether the trend in coal-plant closures will continue, or even accelerate, during the year. Clearly there is significant political pressure for coal consumption to be reduced in the region, and gas has benefitted from this and also from its price competitiveness in 2020. Although the current higher level of gas prices suggests that coal could see something of a comeback in 2021, Honore believes that this will be a short-lived revival and that the underlying trend is towards faster decline.

Theme five takes us to Asia and the outlook for gas in China. Michal Meidan paints a relatively positive picture, with continued policy support, regulatory changes and a more competitive market all boding well for the future of gas. Nevertheless, she also highlights the concern over security of energy supply that is always an important factor, and it will be critical to see whether the 14th Five-Year Plan, due for publication in March, makes any statements about the balance of pipeline and LNG imports. Theme six then takes us to South America, where Ieda Gomes highlights the potential for 2021 to be an important

year for the Brazilian gas sector. The availability of large associated gas reserves in the offshore pre-salt fields has catalysed a drive for deregulation of the gas market, and the expectation is that key legislation will be passed in 2021 to push this forward.

Our final four themes focus on decarbonisation, a vital topic for the gas sector and its future role in the global energy mix. In theme seven Martin Lambert looks at the increasing trend for global decarbonisation commitments and highlights the importance of COP-26 this year in Glasgow as a potential catalyst for further, more concrete, action. In theme eight Alex Barnes then looks at the regulatory progress being made in the EU and reviews the numerous new initiatives that could be taken forward in 2021 as the region continues to lead the way in encouraging, and enforcing, its commitment to decarbonisation. From a more global perspective, theme nine then reviews the growing trend for carbon-neutral LNG, with 2021 set to be an important year in building the definitions and terminology around this new gas offering and also creating the transparency that will be needed to establish credibility. Finally, in theme ten Marshall Hall looks at the critical topic of environmental policy in the US under the new administration of President Biden, in particular asking whether he may be keen to support the EU's new methane strategy.

As always, the contact details for each of the authors are included at the end of their articles, so if you would like to discuss any of the issues in more detail then please do get in touch with them, or with me, and we would be delighted to have a conversation with you.

Finally, we would like to offer all our readers best wishes for a healthy and prosperous 2021.

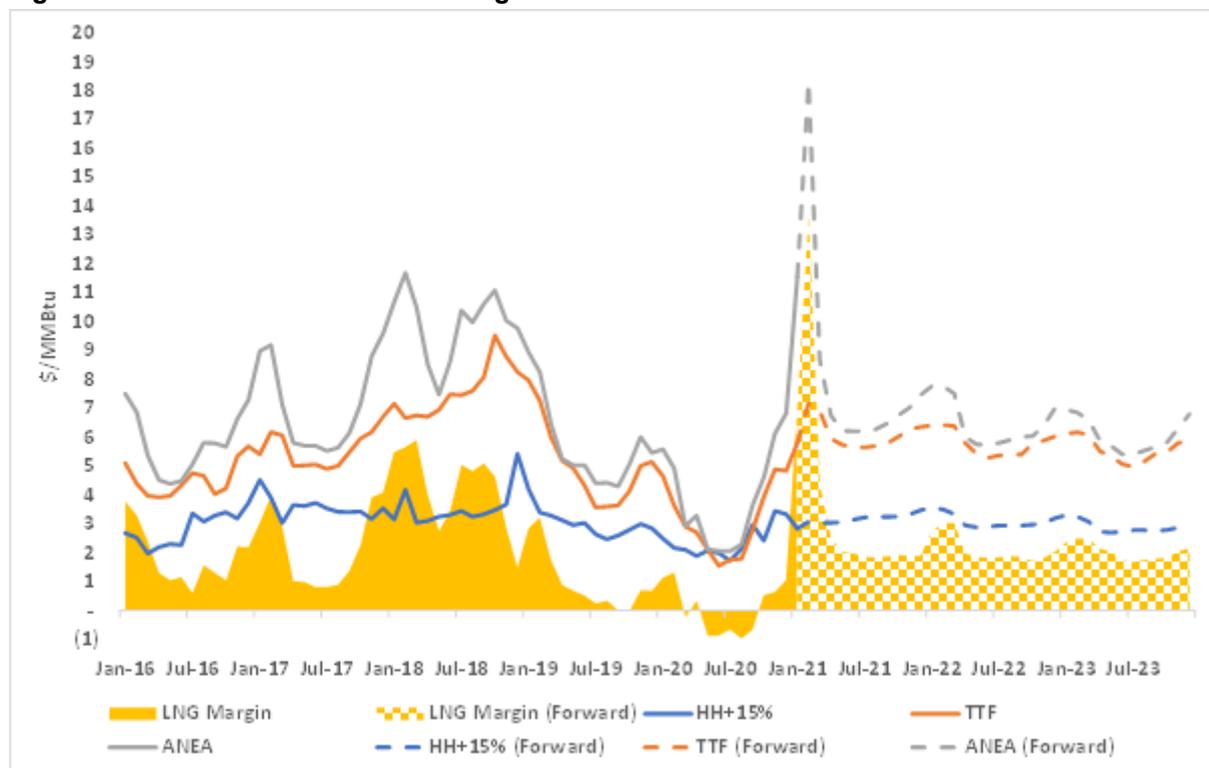
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1. Gas Price Analysis

1.1: LNG Tightness – cash margins have rebounded strongly

Firstly, we consider our “LNG Tightness” analysis as an indicator of how profitable existing export projects are and whether there is a need for new FIDs in an already oversupplied global market. The graph below is based on data from Argus Media and shows the prices for TTF in the Netherlands, the ANEA spot price in Asia and the Henry Hub price¹ in the US. It then calculates the highest netback from Europe or Asia to the US Gulf Coast plants based on the respective shipping costs. Deducting Henry Hub plus 15 per cent from the highest netback gives the LNG Margin, which provides an indication of whether developers in the US can expect to recover the fixed cost of liquefaction. A margin in excess of \$3/mmbtu (the fixed liquefaction cost in the traditional Cheniere contract) – as it was in 2018 - would provide an obvious incentive for new projects while a margin well below this suggests a more oversupplied market.

Figure 1.1: An Assessment of “LNG Tightness”²



Source: OIES, based on data from Argus Media

For the majority of 2020, when the COVID 19 pandemic caused lockdowns in Asia and Europe leading to economic decline and a fall in energy demand, the margin has been negative, implying that US LNG exports were losing money on a cash basis. This led to between 150 and 200 cargoes being shut in, which started to impact the market during the summer months. However, since then the picture has changed dramatically. Initially the impact of the pandemic started to ease, and economic recovery brought higher demand and increased prices, pushing the margin back into positive territory in Q3, albeit only to a level that covered cash rather than full costs. At the end of 2020, very cold weather and a dramatic rise in prices in Asia (see Figure 1.4) have pushed the margin to its highest level since US Gulf Coast LNG export plants started up in early 2016, at more than \$6/mmbtu. This is more than double

¹ 115 per cent of Henry Hub

² Forward curve as at January 15 2020

the level that would be needed to incentivise the development of new projects, and the futures curve suggests that the margin could even reach double figures in the short-term.

However, this is very much a short-term phenomenon, driven by the cold weather catching Asian buyers unaware. The medium-term outlook remains much more sober. As winter ends prices are expected to fall back, albeit to higher levels than seen in 2020 – according to the futures markets. The US LNG margin falls back to a level of around \$2-3 mmbtu by the end of Q1 2021, implying a much more nuanced outlook for new developments. It would seem that the market would support the development of lower cost projects which can develop liquefaction at the lower end of the \$2-3 range normally assumed. It will therefore be interesting to monitor whether developers can convince offtakers that the world really has changed, in order to support any additional US project FIDs in 2021, or whether it has just been a brief interlude in a continuing over-supplied LNG market.

1.2: Movements in European storage utilisation and gas prices

As another measure of the state of the gas market we have developed a methodology to compare the futures curve for TTF and the implications for storage levels in Europe. Figure 1.2 shows the historical correlation between the year-on-year change in storage utilisation and the year-on-year (YoY) change in the TTF gas price in Europe. As we identified in a recent paper³ there appears to be a relatively strong correlation between the two measures, and while any statistician knows that correlation does not imply causality it would seem that the two are both driven by the same supply and demand factors. As a result, if one can estimate the outcome for one of the measures, then one can make a reasonable prediction for the other.

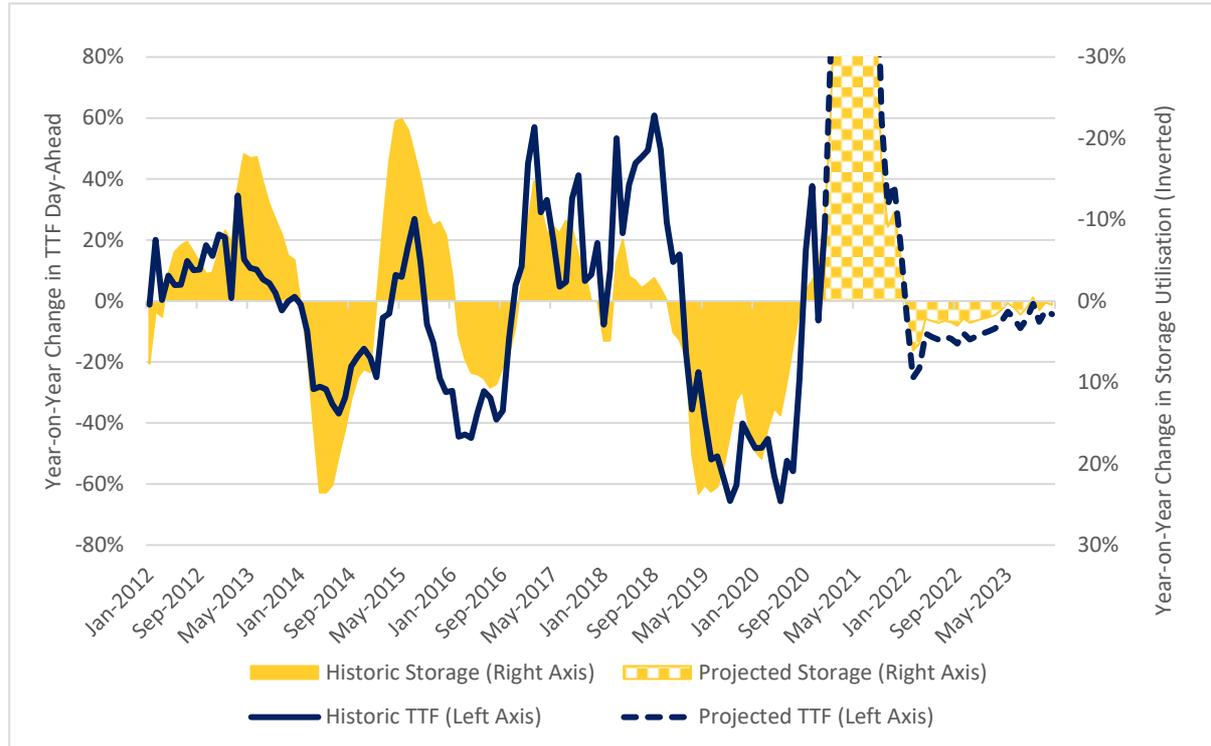
The outlook for storage utilisation is generally easier to predict than that for prices since changes in the former tend to move relatively slowly. However, we can reverse this as the futures curve provides a market-based outlook for prices from which one can infer an implied outcome for storage utilisation. One can then assess what the implications of this implied outcome are and therefore whether they are credible. By a process of reverse logic one can then provide an opinion on the underlying market conditions that must underpin the forward curve.

Figure 1.2 plots the YoY change of the forward curve through to 2023 and also plots the implied change in storage utilisation (inverted) that should accompany this price movement based on the correlation inferred from the historical relationship. The forward curve is currently showing a sharp increase in the TTF price to just over \$6/mmbtu in Q2/Q3 2021, compared to \$2/mmbtu this year, with this higher level clearly influenced by the sharp rise in prices that we have seen at the end of Q4 2020 and the start of Q1 2021. The implication for storage levels in Europe is that they must be set to fall very significantly compared to 2020, and our calculations suggest that storage utilisation would need to be as much as 60-75 per cent lower in summer 2021 compared with this year to justify such a sharp year-on-year rise in the gas price. This would imply either that storage withdrawals during the winter 2020/21 will have to be much higher than during winter 2019/20 (in other words we really need a cold winter) or that summer injection levels in 2021 must be much lower than in 2020, with storage withdrawals possibly continuing well into the summer. Interestingly, storage levels in Europe have been falling quite rapidly over the past month as LNG supply has been dragged to Asia by high prices there (see Figure 1.4), but as of the time of writing remained higher than the 5-year average for this time of year. Should the cold weather in Asia and some parts of Europe continue for an extended period, then it is not impossible that storage levels could fall enough to justify the forward curve for TTF, but this would imply an exceptionally cold and long winter plus a dramatic improvement in the economic situation – and gas demand in Europe – if and when the impact of the pandemic starts to ease. Our view continues to be that, once the low winter temperatures in Asia have passed, the underlying oversupply situation in the LNG market is likely to become apparent once more, and especially in the summer months. At that time, it would seem that

³ Fulwood M. & Sharples J. (2020) "\$2 gas in Europe (Part III): Down, down, deeper and down", Oxford Energy Comment, Oxford Institute for Energy Studies

either supply will need to be shut-in again (although not to the level seen in 2020) or prices will be lower than the forward curve suggests in order for the market to balance.

Figure 1.2: YoY change in storage utilisation and TTF gas price⁴



Source: OIES, with data from Argus Media

Having said all this, a caveat that should be noted is that the forward curve rise in prices is well outside the observations that the correlation is based on, and it may not be appropriate to extrapolate outside this range. The year-on-year change in prices since 2012 has been in the range plus/minus 60 per cent, and the year-on-year change in storage utilisation in the range plus/minus 20 per cent. Any predictive power of the relationship established is only valid within the range of the historical observations and, even then, there will be a statistical error and range around the correlation. As a result, the exceptional nature of the trends in late 2020 and into 2021 means that any conclusions reached from Figure 1.2 must be seen as indicative rather than absolute, although the overall conclusion that stock levels in 2021 must be lower than 2020 to justify the forward curve remains valid.

1.3: The Price at Gazprom’s Electronic Sales Platform

One other source of flexibility in Europe is pipeline supply, and a key component of that is Russian gas exports. We therefore believe it is important to monitor key indicators of Gazprom’s sales strategy in Europe, one of which can be found by examining the activity on the company’s Electronic Sales Platform (ESP). The ESP is 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 than Gazprom’s 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 ESP, 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) the rest of the year has shown a marked change in strategy. We noted in the last two Quarterlies that the majority of sales are now for month, quarter, season or even year ahead, indicating that Gazprom has had no intention of actively engaging in a

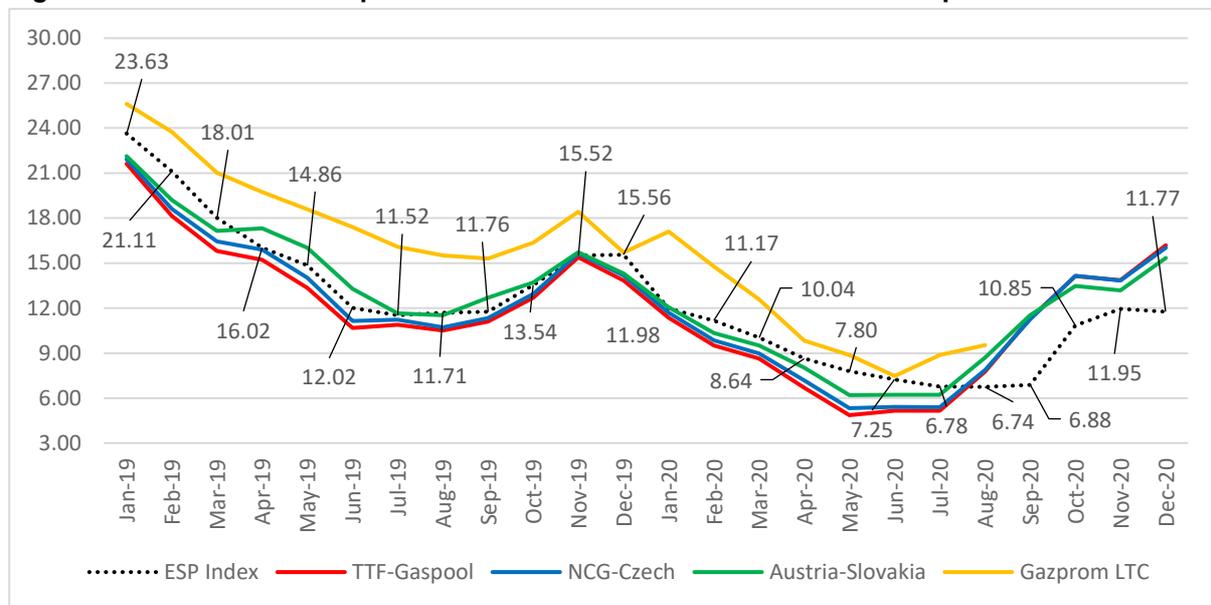
⁴ Forward curve as at October 14 2020

short-term price war but has been trying to lock in longer-term sales in a very difficult market. This trend has seemed to continue into Q4, with the majority of sales continuing to be for 3-months ahead or more.

This has a significant impact on the comparability of the ESP Index with day-ahead and front-month prices on European hubs. For example, 76 per cent of ESP sales in December 2020 were for delivery in Q2 or Q3 2021, while just 3.5 per cent of total sales were for prompt delivery. Given that the ESP index is the weighted average of all transactions concluded on the ESP, it is not surprising to see the ESP index (which currently reflects summer prices) at a discount to European hubs that are currently reflecting winter prices (Figure 1.3).

Therefore, rather than seeing the ESP Index at a discount to European hubs as evidence of Gazprom generating sales by offering supplies at a discount to European hubs, we interpret the lack of prompt ESP sales in Q2-Q4 2020 as evidence of Gazprom holding back from a supply-long market. With the TTF forward curve suggesting a potentially substantial year-on-year increase in monthly average prices throughout 2021, an increase in prompt ESP sales and a related convergence between the ESP Index and European hubs will indicate not only a tighter market, but also Gazprom's re-engagement with that market in terms of short-term sales. Hence, we shall continue to monitor both the ESP Index and ESP sales volumes closely.

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

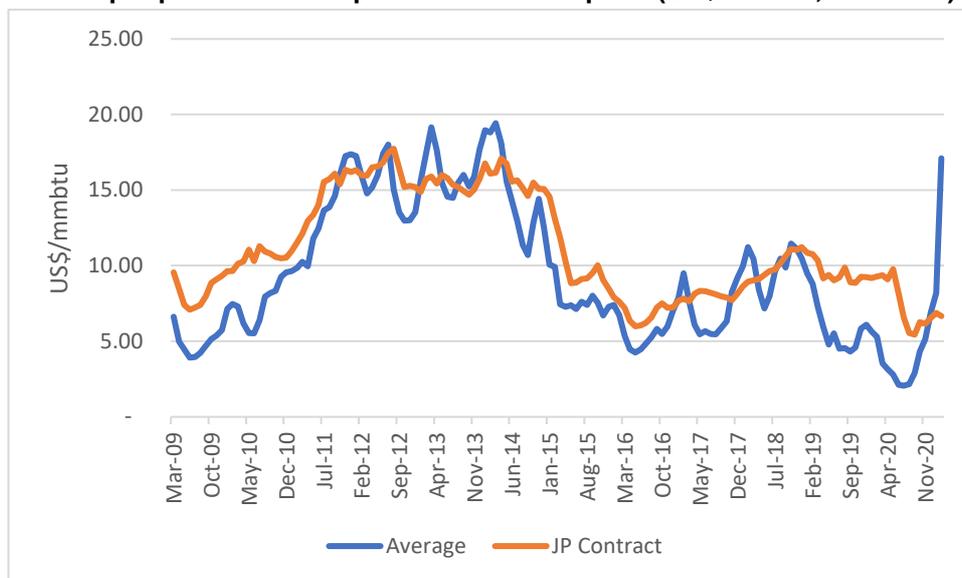
The relationship between contract and spot prices in Asia continues to be of significant interest. As we have noted at various times, customers tend to seek changes in the formation of prices when their impact causes them to suffer very substantial financial losses. This certainly occurred in Europe when spot and contract prices diverged and customers began to demand a move away from oil-linked pricing to hub-based prices, catalysed by new EU rules on market liberalisation. The trend away from oil-linked pricing in Asian contracts has been much more gradual, and indeed some might argue that it has barely started. Indeed, as Figure 1.4 shows, 2020 has been a year of wild fluctuations as, after a significant divergence between spot and contract prices emerged in 2019 and then widened in the first half of 2020, the final quarter of 2020 has seen a complete reversal of this trend due to an exceptionally cold spell in NE Asia.

We have noted previously that the low oil prices in the first half of 2020 were bound to feed through into the Japan Contract Price at some point, and as Figure 1.4 shows, this did happen as we entered Q3 while at the same time the spot market price rebounded slightly as economic conditions improved. As

a result, the two prices have converged for the first time since the end of 2018. In Q4, though, and especially into January 2021, the JKM price leapt to record levels due to a spell of very cold, and unexpected, weather, which caught importers in Asia by surprise. As electricity prices rose sharply so demand for LNG increased at a time when inventories were low and spot cargoes were not readily available. A variety of minor, but cumulatively significant, supply issues at a number of LNG plants combined with a squeeze on shipping capacity and delays at the Panama Canal have created a supply shortage that has caused the JKM spot price to burst through the \$30/mmbtu barrier on certain days. Meanwhile the contract price has continued to reflect lower oil prices earlier in 2020, meaning that for a short period at least the attractions of contract cargoes have increased dramatically. Indeed, the current spot price reflects a slope relative to the oil price of more than 50 per cent (with an oil price at \$56 per barrel), while the average slope for LNG contracts is around 14 per cent. We believe that this phenomenon is likely to be short-lived, and the JKM futures prices sees it fall back to around \$7-8/mmbtu by the spring, but it will be interesting to see how buyers react to the current anomaly and whether debates around oil-linked pricing are silenced for a while.

It should be noted that the prices in the graph below are monthly averages and reflect the price on delivery of a cargo. As a result, the current high JKM price is the February delivered price, and this is compared with the delivered contract price in Figure 1.4.

Figure 1.4: JKM spot price versus Japan LNG contract price (US\$/mmbtu, delivered)



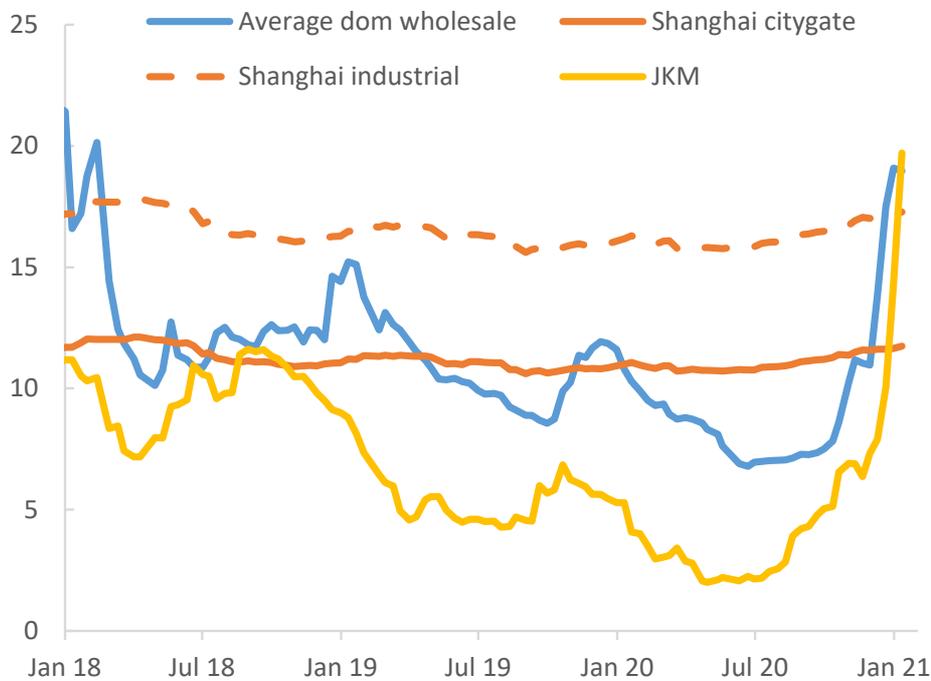
Source: Platts data, OIES analysis

1.5 Chinese domestic price versus LNG import price

An increasingly important indicator in Asia is the Chinese domestic gas price versus the LNG import price level, and we continue to monitor this on a quarterly basis. As with the other price graphs, this quarter (or the end of it) has brought a dramatic shift in the trends, but in the case of China this has had an interesting impact. For most of 2020 the market had expected that low spot JKM prices would filter through to domestic prices, leading to an uptick in China's gas demand. Indeed, as the chart below highlights, the average domestic wholesale price did trend in a downward direction but remained stubbornly above the level of the JKM price. Nevertheless, for the majority of the year the domestic wholesale price was more than \$4/mmbtu lower than its 2018-19 average, although this was partly due to the government's request that the majors reduce their sales prices and a mandate, back in February 2020, to cut city-gate prices. The trend started to shift at the start of the fourth quarter as low prices, Chinese government policy announcements and the start of winter began to push up demand, and with it the domestic price. Increasing demand for spot LNG also pushed up the JKM price and indeed the two started to converge, with the lowest differential since the middle of 2018.

As has been seen in previous charts, the end of Q4 2020 and the start of 2021 have seen the market tighten dramatically with a record-breaking impact on prices. A strong rise in Asian gas demand, due to a colder than expected winter, have led to a surge in JKM spot prices in early January. Wholesale prices in China had already begun rising in November as domestic demand recovered, bolstered by the country's strong economic performance and by the central government's encouragement, back in October, to accelerate the coal to gas switch. The government had likely assumed that gas prices would remain subdued and that the creation of the midstream company, PipeChina, would help optimise supplies and prices. But by January 2021, prices reached highs last seen in the winter of 2017-2018, when the government-mandated coal-to-gas switch boosted demand, with supplies failing to keep up. This time, however, the shortage was likely exacerbated by poor coordination between PipeChina and the state-owned importers. PetroChina had reportedly booked less volumes on the pipeline network—looking to sell gas directly to end-users—with PipeChina and private importers reluctant to source expensive spot LNG when temperatures dropped. As temperatures rise again, domestic prices are likely to fall once more, bringing JKM values down with them. But the appetite for spot LNG may also weaken, with buyers contemplating oil-indexation instead.

Figure 1.5: Chinese gas prices compared to JKM (US\$/mmbtu)



Source: NBS, SHPGX, Platts, OIES

2. 10 Key Themes for 2021

2.1: Recovery from COVID-19 and Balancing the LNG Market in 2021

In our April 2020 Quarterly Gas Review,⁵ OIES projected a 3 per cent fall in global gas demand during 2020 over 2019, compared to a pre-COVID-19 rise of some 1 per cent. This was broadly based on the expected decline in global GDP of some 5.8 per cent, as projected by the IMF.⁶ The IEA also published their Global Energy Review in April 2020, where they projected a 5 per cent decline in global natural gas demand.

By October the IMF⁷ had revised the fall in global GDP to some 4.4 per cent and OIES had similarly revised its decline in global gas demand for 2020 to some 2.5 per cent. However even this decline now looks too pessimistic. Gas demand has been more resilient than previously expected in Europe and the US as well as in Asia, with China continuing to grow and little or no decline seen in other major LNG importers such as India, Japan, Korea and Taiwan. Gas demand in the power sector in particular has been more robust and demand in Asia was high in the last two months of 2020 as a result of the cold weather. The revised OIES estimate of global gas demand in 2020 is now only for a decline of between 1 - 1.5 per cent, significantly less than the 2.5 per cent decline recorded during the 2009 recession following the global financial crisis.

Back in April 2020, a rebound in global gas demand of some 3.5 per cent was projected for 2021, following the assumed 3 per cent decline in 2020. With demand in 2020 having declined by much less than previously expected, how might this impact the 2021 outlook?

Gas Demand in 2021

Most of the decline in gas demand in 2020 was in Latin America, Europe and the FSU. The rest of the world appears to have emerged largely unscathed, with growth in China, other Asian countries and the Middle East. Even in the US there appears to have been barely any fall in total demand. 2021 is starting with cold weather in North East Asia, which is already boosting demand for LNG with the market tightening considerably. If lockdowns in Europe, due to COVID-19, persist in the early part of this year then this could actually boost gas demand with a larger heating load for households more than offsetting reductions in demand in other sectors.

Outside any weather-related and COVID-19 effects, the growth in gas demand is likely to be driven by the Asian markets, especially China, and rebounds in Russia and other countries where demand was hit in 2020. In Europe, demand in 2020 appears to have fallen by less than 4 per cent, compared to an expected 6 - 7 per cent forecast in our April Quarterly Gas Review. In 2021 demand in Europe is expected to rebound, especially in Q1 if lockdowns remain in place, and in Q2 when demand was badly hit in 2020. It is possible that European demand could get back to 2019 levels, unless higher gas prices negatively impact demand in the power sector.

Overall, at a global level, gas demand may rise by 2.5 - 3 per cent in 2021, which is lower than expected back in April but that is only because 2020 demand has declined much less than previously anticipated.

LNG Supply in 2021

LNG export capacity will continue to rise through 2021, mostly reflecting projects which started in 2020 ramping up to full capacity, but also new projects starting up such as Corpus Christi Train 3 and Rotan FLNG in Malaysia. The rise in capacity from new projects is partly offset by problems at existing projects such as Hammerfest in Norway, Gorgon and Prelude FLNG in Australia.

⁵ OIES Quarterly Gas Review, April 2020 at <https://www.oxfordenergy.org/publications/quarterly-gas-review-issue-9/>

⁶ IMF World Economic Outlook, April 2020, at <https://www.imf.org/en/Publications/WEO/Issues/2020/04/14/weo-april-2020>

⁷ IMF World Economic Outlook, October 2020, at <https://www.imf.org/en/Publications/WEO/Issues/2020/09/30/world-economic-outlook-october-2020>

Average LNG export capacity in 2021 is expected to reach some 540 bcm, compared to 525 bcm in 2020 and 510 bcm in 2019.

LNG Imports in 2021

Initial data for 2020 suggests LNG imports increased by 13 bcm in 2020 – a rise of some 3 per cent. Asian imports were up by some 20 bcm partly offset by declines in Europe and North America. Imports into Europe were actually slightly up year-on-year through November but there was a big fall in December as LNG switched away from Europe to the increasingly cold Asian markets. Utilisation of available LNG export capacity fell from 93 per cent in 2019 to 92 per cent in 2020.

With gas demand rebounding in 2021, the prospects for the LNG market look positive at first glance. The Asian markets, led by China, look set to rise by over 20 bcm, with the rest of the world outside Europe being broadly flat. If LNG volumes into Europe remained at 2020 levels, then the global rise in LNG imports could be some 25 bcm, or a rise of 5 per cent. However, LNG imports into Europe will be under pressure from a partial rebound in pipeline imports and larger withdrawals from (or fewer injections into) storage. Our projections suggest that LNG imports into Europe could fall by some 13 bcm, limiting the global rise in LNG imports to some 10 bcm – a rise of only 2 per cent. With LNG export capacity continuing to rise, this suggests another summer of LNG cargoes being shut in.

Table 2.1 - Europe Balance⁸

BSCM	2018	2019	2020	2021
Demand	534.7	551.0	530.4	546.5
LNG Exports	5.8	6.4	4.1	2.0
Pipe Exports	13.0	15.6	12.1	2.9
Production	- 247.6	- 230.1	- 213.7	- 214.4
Import Gap	305.9	342.9	332.9	337.0
Pipe Imports	245.5	237.8	206.7	228.5
LNG Imports	69.3	116.0	113.0	100.3
Net Stock Withdrawal	- 5.4	- 20.0	14.2	8.2
Statistical Difference	- 3.4	9.1	0.9	-
Pipe Imports				
Algeria	33.5	21.9	21.0	19.8
Libya	4.5	5.7	4.4	4.2
Azerbaijan	7.5	9.5	11.6	14.6
Iran	7.9	7.7	4.3	8.0
Russia	192.2	192.9	165.3	181.8

Source: IEA, Platts LNG Service, OIES Estimates, Nexant World Gas Model

Balancing the LNG Market

Europe is again the key to balancing the LNG market. In 2019 Europe absorbed much of the rise in LNG imports, partly as demand increased and production declined but also by increasing the amount of gas in storage (up 20 bcm). The fall in gas demand in 2020 was balanced by a decline in production and a sharp fall in pipeline imports, offset by a net withdrawal from storage – mostly in the last two months as LNG was pulled towards Asia. In 2021, the import gap widens as demand rebounds and production stabilises (an increase in Norway offsets a decline in the Netherlands). Our modelling suggests that pipeline imports will partially bounce back, especially from Russia. With increased withdrawals from storage, this squeezes LNG imports.

⁸ EU27 plus UK, Norway, Switzerland, Serbia, Bosnia-Herzegovina, North Macedonia, Albania and Turkey

There would be more room for LNG imports in Europe if pipeline imports do not recover as much, which could happen if Gazprom does not succeed in utilising the Ukraine route as much as in 2020 – Nordstream 2 is not assumed to come on stream until the beginning of 2022. In addition, storage in Europe could again absorb LNG this summer – as in 2019 – but, as we have previously discussed,⁹ this may well require lower prices than the current forward curve for TTF (over \$5 per MMBtu for Q2 and Q3) suggests.

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2.2: European Gas Storage Levels

Gas storage as a market indicator

Gas storage enhances the ability of Europe¹⁰ to act as balancing element for the broader global gas market. In a supply-long context, storage allows the European market to receive far greater volumes than it could otherwise absorb through price-driven increases in consumption. Conversely, in a tight global market, slower summer injections or quicker winter withdrawals can curb European demand for imports and avoid related price volatility. Year-on-year changes in storage stocks are therefore an indicator of the current state of the market, with higher or lower stocks respectively indicative of a loose or tight market. As a result, European gas storage stock levels (both in terms of absolute volumes and relative to levels at the same point in recent years) and injection/withdrawal trends are a key factor in our short-term market outlook.

Recent history: storage fluctuations in 2019 and 2020

European gas storage capacity grew from 58 bcm in January 2011 to 95 bcm in January 2015. Since then, it has grown more slowly, reaching 104 bcm in January 2021. Therefore, analysis of comparable storage stocks is limited to the period since 2015, with the data illustrated in the graph below.

The years 2015 to 2018 were remarkably consistent in terms of volumes held in storage at the beginning and end of each calendar year: on 1 January, stocks ranged from 65.0 bcm to 71.1 bcm, and on 31 December stocks ranged from 65.5 bcm to 71.2 bcm. The net stock change between 1 January and 31 December in those years ranged from 0.7 bcm to 5.6 bcm. This smooth cycle suggests that variations in seasonal demand for storage withdrawals were balanced by summer injections and total stocks tended to end the year roughly back where they started.

By contrast, the past two years have seen dramatic fluctuations in stocks. In 2019, lower than average withdrawals in Q1 were followed by strong injections in Q2 and Q3, as Europe absorbed excess volumes from a supply-long global market. Then limited withdrawals in Q4 were at least partially motivated by hedging against a potential interruption in Russian gas transit via Ukraine. The resulting net stock change in 2019 amounted to an unprecedented increase of 20.4 bcm during the course of the calendar year. Not surprisingly, gas prices fell as a result.

Then, in 2020, storage withdrawals in Q1 were 9 per cent below the 2015-2019 average, thus retaining the storage ‘overhang’ until the end of winter. The consequence was record low prices in the second quarter of the year. Thereafter, though, summer injections in Q2 and Q3 were 25 per cent below the 2015-2019 average and winter withdrawals in Q4 were around 25 per cent above the 2015-2019 average, bringing total stocks on 31 December down to 77.3 bcm. This was well below the figure of 91.5 bcm for 31 December 2019, but still 7 per cent above the average for 2015-2019 (72.6 bcm). The net stock change during the calendar year 2020 was a reduction of 13.9 bcm and gas prices in Europe have continued their second half recovery as a result.

⁹ Fulwood, M. (2020). \$2 Gas in Europe: Groundhog Day? OIES Energy Comment, October. <https://www.oxfordenergy.org/publications/2-gas-in-europe-groundhog-day/>

¹⁰ The ‘European’ storage data discussed here covers the EU+UK (20 countries in total). It excludes Turkey, Ukraine, and other non-EU European countries

Furthermore, over the past two years the European storage system has arguably served its purpose very well in physical terms. In 2019, slower winter withdrawals in Q1 and Q4 and quicker summer injections in Q2 and Q3 enabled the European market to absorb volumes from the global market and hedge against a potential supply interruption. In 2020, slower summer injections in June-September and quicker winter withdrawals in Q4 helped rebalance the European market as gas demand proved more robust than expected despite the COVID-19 pandemic and the year-on-year contraction in global LNG supply between June and September.

The European gas storage outlook

The storage 'overhang' was still in place in January 2021, signifying that the market remains somewhat supply-long in the short-term compared to recent years. The extent to which that overhang is still in place at the end of Q1 will depend on both northern hemisphere seasonal demand, and the ongoing impact of the COVID-19 pandemic.

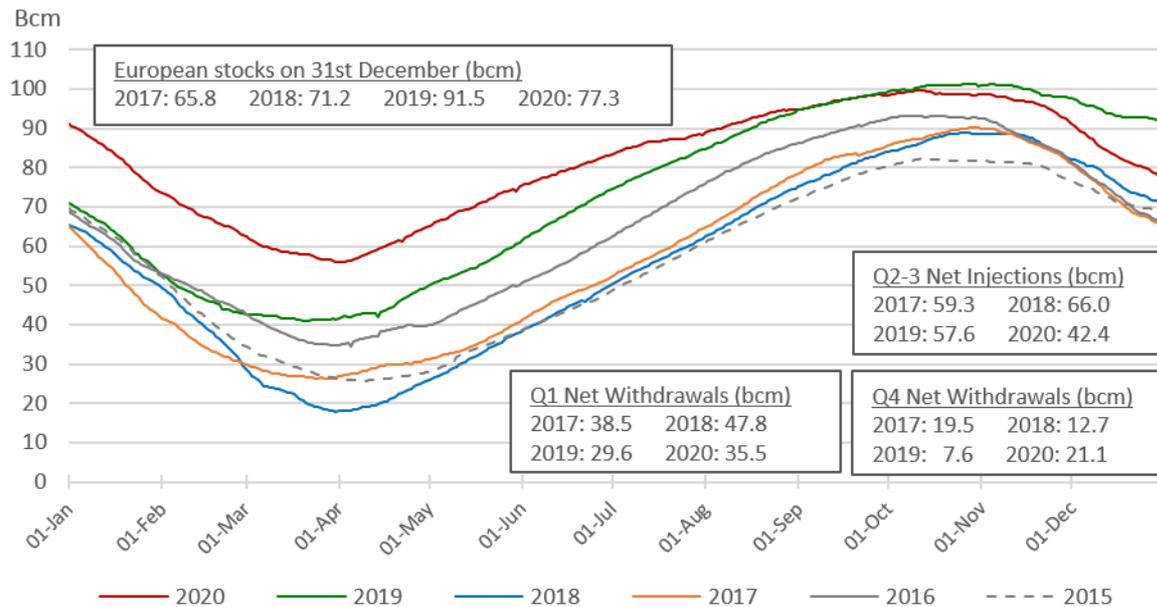
These factors will influence Asian LNG demand, which could draw cargoes away from Europe and stimulate further European storage withdrawals. That trend was already felt in December 2020: Asian LNG imports reached a record level of 34.4 bcm (4 bcm higher year-on-year), while European LNG imports fell to their lowest December level since 2017, having fallen by 4.6 bcm year-on-year. For context, global LNG exports in December 2020 were 0.4 bcm (1 per cent) lower year-on-year. This dynamic continued in the first half of January 2021, as discussed in section 1.1 above, and has been reflected in European hub prices, which rose to \$7 per MMBtu in the first two weeks of January 2021 - similar to levels seen in January 2019 and more than twice the average for January 2020.

The amount of gas held in European storage at the end of winter determines the volume of LNG that can be absorbed from the global market during the summer months. This, in turn, influences European summer gas prices. If storage withdrawals in Q1 2021 are similar to the Q1 average in 2015-2020 (37.8 bcm), Europe will end the winter with around 40 bcm in storage – the same as in 2019. This could allow Europe to absorb LNG as it did in 2019, thus reducing the potential need for export terminal shut-ins as seen in the US in summer 2020. By contrast, more limited withdrawals in Q1 (resulting in less summer injection capacity) could contribute to another period of '\$2 gas in Europe',¹¹ if another pandemic wave causes a repeat of the summer 2020 supply-demand balance – something that cannot be ruled out as the number of new COVID-19 cases continues to grow across many countries.

The key points to look out for regarding European gas storage are: 1) stock levels at the end of winter, as an indicator of European summer injection capacity; 2) the rate of summer injections, as an indicator of the European supply-demand balance; 3) the point at which peak stocks are reached before the market turns to withdrawals and volume in storage at that peak, as an indicator of whether the market is likely to be supply long or short through the winter. Over the past two years high stock levels at the end of winter, high injection levels in summer and a rapid increase towards full capacity have all been harbingers of lower gas prices to come. As a result, the level of European gas in storage provides an excellent market indicator and one which we will follow actively during the year to come.

¹¹ See the series of papers by Mike Fulwood on European gas prices at \$2.99 per MMBtu or lower in 2019-2020. See: <https://www.oxfordenergy.org/>

Figure 2.1: European storage stocks in 2015-2020 (bcm)



Data from Gas Infrastructure Europe Aggregated Storage Inventory (AGSI+)

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2.3: The Outlook for Nord Stream 2

Progress on Nord Stream 2 (NS2) – an offshore gas pipeline system, consisting of two parallel pipelines connecting Russia and Germany (Figure 2.2) – has been watched with interest throughout 2020, as Russia vowed to complete pipeline construction on its own, after Swiss Allseas pipe-laying vessels – which had built most of NS2 – suspended works on 20 December 2019 under a threat of US sanctions. On 11 December 2020, NS2 resumed construction, using a Russian vessel Fortuna, to build a 2.6 km section in the German EEZ in waters of less than 100 feet depth (and hence not subject to PEESA/PEESCA sanctions) and completed it on 28 December 2020.¹² Around 120 km remain to be built in the Danish and approximately 30 km in the German EEZ, potentially in waters more than 100 feet deep.¹³ NS2 was expected to resume construction in the Danish EEZ on 15 January 2021, also using Fortuna, thus suggesting that the vessel has already undergone all necessary verification activities and that NS2 has taken out insurance for pipe-laying works as required for the Danish permit.¹⁴ Another vessel could be added at a later stage as the permit allows for the usage of anchor-based vessels (like Fortuna) and vessels equipped with dynamic positioning systems (like Akademik Cherskiy), either separately or together.¹⁵ It is not clear at the time of writing whether Fortuna alone or together with another Russian vessel (Akademik Cherskiy and/or any other vessel that will not be deterred by US sanctions) are technically capable – with any upgrades that may have been made to any of them – of finalizing construction of the remaining section, and whether and to what extent the US sanctions (if imposed) could prevent them from achieving such capability.

¹² <https://uk.reuters.com/article/uk-usa-russia-nord-stream-construction/construction-of-nord-stream-2-pipeline-resumes-on-friday-idUKKBN28L1S8?il=0>, <https://uk.reuters.com/article/uk-russia-nordstream2-germany/nord-stream-2-completes-laying-pipes-in-german-waters-dpa-idUKKBN2921OH?il=0>

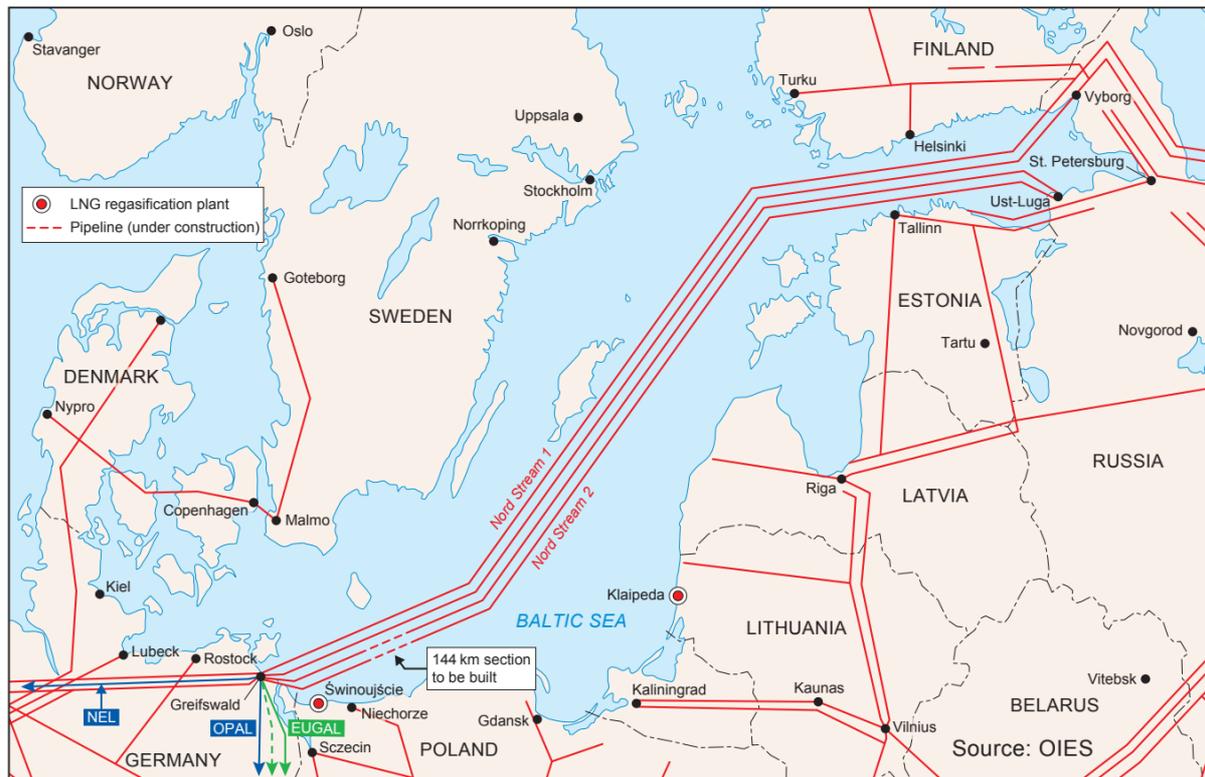
¹³ <https://www.bloomberg.com/news/articles/2020-12-29/russia-pushes-ahead-on-gas-link-to-europe-before-u-s-sanctions>

¹⁴ http://nautiskinformation.soefartsstyrelsen.dk/#/messages/table_under_NM-896-20.

¹⁵ It has also been reported that another vessel – Oceanic 5000 – could also be used for construction.

Several pieces of US sanctions legislation are already in place, such as the Countering American Adversaries Through Sanctions Act (CAATSA), adopted on 2 August 2017, the Protecting European Energy Security Act (PEESA/NDAA 2020), adopted on 20 December 2019, and most recently the Protecting European Energy Security Clarification Act (PEESCA/NDAA 2021), which having been initially vetoed by US president Trump, was adopted when the veto was overridden by the House on 29 December¹⁶ and by the Senate on 1 January 2021.¹⁷

Figure 2.2: Nord Stream 1 and Nord Stream 2 pipelines



Source: OIES

CAATSA has enabled the US President ‘in coordination with allies’ to impose sanctions on a person who knowingly, on or after 2 August 2017, ‘makes an investment [...] or sells, leases, or provides’ to Russia ‘goods, services, technology, information, or support’ of defined value ‘for the construction of Russian energy export pipelines’. The US State Department guidance, issued on 31 October 2017, specified that investments and loan agreements made prior to 2 August 2017 would not be subject to sanctions, thus suggesting that NS2 would be spared as its pipelaying vessels had been leased, pipes ordered, and financing agreed and partly executed prior to that date. The guidance was amended on 15 July 2020, by expanding the focus of implementation to include NS2 and deleting the sections saying that investments and loan agreements made prior to 2 August 2017 would not be subject to sanctions. Although the amended guidance confirmed that sanctions will not be imposed in respect of investment and other activities made prior to 15 July 2020, it also stated that ‘contracts and other agreements signed prior to 15 July 2020’ were not grandfathered. On the same date as the guidance was amended, the US Secretary of State, Mike Pompeo, stated that this was ‘a clear warning’ to companies involved in NS2 to ‘get out now, or risk the consequences’.¹⁸

PEESA/NDAA 2020 stipulates sanctions on persons which have knowingly ‘sold, leased, or provided’ vessels that are ‘engaged in pipe-laying at depths of 100 feet or more below sea level’, or ‘facilitated

¹⁶ <https://apnews.com/article/election-2020-donald-trump-media-social-media-elections-1f623a6e996dd56fdc238eb02b2d4f24>

¹⁷ https://www.rbc.ru/politics/01/01/2021/5fef72b89a794756cc397beb?from=from_main_1

¹⁸ <https://www.state.gov/secretary-michael-r-pompeo-at-a-press-availability-9/>

deceptive or structured transactions to provide' such vessels. Not later than 60 days after its enactment and every 90 days thereafter, a report must be prepared identifying the persons and the vessels, with the former not to be admitted to the US and their property blocked. In addition, OFAC guidance issued on 20 December 2019 left no room for interpretation favourable for NS2, stating that it must be ensured that such vessels cease construction-related activity 'immediately'. An additional State Department guidance issued in October 2020, has significantly expanded the scope of PEESA by stipulating that provision of the vessels 'may cover foreign firms or persons who provide certain services or goods that are necessary or essential to the provision or operation of a vessel' and that such activities 'may include, but are not limited to, providing services or facilities for upgrades or installation of equipment for those vessels, or funding for upgrades or installation of equipment for those vessels'.

PEESCA/NDAA 2021 has additionally stipulated sanctions not only for pipe-laying but also pipe-laying activity as well as sanctions for the provision of 'underwriting services or insurance or reinsurance', 'services or facilities for technology upgrades or installation of welding equipment for, or retrofitting or tethering' of the vessels, and 'services for the testing, inspection, or certification necessary or essential for the completion or operation' of NS2. PEESCA's all-encompassing nature suggests it aims at making completion of NS2 as difficult as possible, potentially sanctioning any (European or non-European) company involved. Nonetheless, PEESCA includes several clauses which provide the US President with a certain leeway over the imposition of sanctions. These clauses include the requirements that (a) consultation must be held with the governments of member countries of the EU as well as Norway, Switzerland, and the UK, prior to imposition of sanctions, (b) sanctions must not apply with respect to the EU, the government of Norway, Switzerland, the UK, or any member country of the EU, or any entity of the EU or the aforementioned governments that is 'not operating as a business enterprise', (c) a report must be produced not later than one year after the NDAA 2021 enactment, detailing the impact of the imposition of sanctions, and (d) the US President may waive the application of sanctions.

While it is understood that no sanctions have been imposed in relation to NS2 under CAATSA, PEESA or PEESCA to date, a mere threat of sanctions had already led the Swiss Allseas company to suspend pipe-laying work in December 2019, and a Norwegian DNL-GV company to cease delivery of services, such as verification activities linked to vessels with equipment serving the NS2 project in November 2020, as well as to 'stop all activities linked to pipeline system certification' in January 2021.¹⁹ Also in January 2021 a Swiss insurance company, Zurich Insurance Group, and a Danish engineering consulting company, Rambøll, have reportedly withdrawn from the project,²⁰

Nonetheless, a threat of sanctions has proved insufficient to persuade Gazprom's European partners and financial investors in NS2 – Uniper, Wintershall Dea, OMV, Shell, and Engie – to leave the project.

Whether or not the US will impose actual sanctions in respect of NS2 depends on many factors, most importantly on the ability and willingness of European countries to dissuade the US from doing so. The EU and Germany have been growing increasingly uneasy about US extraterritorial sanctions, with both the EU High Representative for foreign policy, Josep Borrell, and the German Chancellor, Angela Merkel, speaking strongly against sanctions, deeming them contrary to international law.²¹ The German local government of Mecklenburg-West Pomerania has proposed to set up a state-protected legal entity that would hold assets through a foundation and whose products and services would be used to finish NS2 construction, thus potentially protecting NS2 from sanctions, if it can be demonstrated that such an entity would not be operating as a business enterprise.²² An overwhelming majority of EU member

¹⁹ https://www.rbc.ru/business/02/01/2021/5ff096349a794791d357ed31?from=from_main_1

²⁰ <https://www.swissinfo.ch/eng/zurich-insurance-said-to-pull-out-of-nord-stream-2-project/46292008>, <https://politiken.dk/udland/art8060807/USAs-trusler-har-tvunget-danske-Rambøll-ud-af-Nord-Stream-2>

²¹ Statement by the High Representative/Vice President Josep Borrell on US sanctions, 17 July 2020, https://eeas.europa.eu/headquarters/headquarters-homepage/83105/statement-high-representativevice-president-josep-borrell-us-sanctions_en, 'Germany's Merkel says "right" to complete Nord Stream 2 gas pipeline', Platts, 2 July 2020, <https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/070220-germanys-merkel-says-right-to-complete-nord-stream-2-gas-pipeline>

²² <https://www.bloomberg.com/news/articles/2020-12-11/german-lawmakers-weigh-sanction-proof-structure-on-nord-stream-2>

states also oppose sanctions, as demonstrated by a call with the US State Department, organized by an EU delegation in the US, , during which 24 EU member states expressed their opposition to sanctions. Also, the EU has been analysing ways of increasing its resilience against extraterritorial sanctions, including the Blocking Statute.²³ It is possible that as a result of the consultation process, stipulated by PEESCA, the US may decide not to impose sanctions if it finds the European arguments sufficiently persuasive and the consequences of disregarding them sufficiently serious.

If imposed, sanctions could delay the completion of NS2 as they could have an impact on its ability to attract and modernise the pipe-laying vessel(s) – unless NS2 has already secured the vessel(s) that are technically capable of finalizing construction of the remaining section. Sanctions could also complicate verification activities linked to the vessel(s) and complicate vessel(s) (re)insurance – unless already accomplished – as well as complicate the certification of the pipeline itself. Although sanctions could create obstacles to NS2 completion these are not insurmountable and this author believes that it could be possible to finalize construction in summer 2021 and start gas flows over winter 2021-22, but a further delay cannot be ruled out.

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2.4: Europe - will 2021 be a catalyst for the ultimate phase-out of coal in Europe?

The role of coal in the electricity generation mix has been in structural decline in Europe for many years. An 18 per cent decline year-on-year in 2020²⁴ begs the question as to whether 2021 will see a continuation or even an acceleration of coal phase-out? The answer appears to be yes....and no.

Lower coal generation was partly explained by weak overall electricity demand (-4.5 per cent) due to mild temperatures in winter 2019-20, the economic impact of Covid-19 containment measures, and the high renewable availability (40 per cent of the mix). Lower nuclear generation (especially from the French fleet) helped absorb some of the lost demand but coal and gas, as the source of flexible, marginal generation in many power systems, were hit particularly hard.

Gas-fired generation came ahead in the merit order thanks to low natural gas prices (ample LNG supply and low gas use in power and industry) and to relatively high carbon prices (Figure 1). At a national level, the impact of coal-to-gas switching varied widely, but even in central and southeast Europe, coal and lignite generation declined due to fuel switching.

A combination of difficult market conditions and environmental policies resulted in many coal plants closing early. For instance, in June Spain closed seven of its fifteen remaining coal-fired stations, almost halving its coal capacity, after exemptions from the Industrial Emissions Directive expired and electricity companies decided not to invest to adapt the plants to the new standards. In the UK, two plants (over a third of its remaining coal-fired capacity) were shut in the first half of the year. Austria and Sweden phased out coal completely, years ahead of schedule. They became the second and third European countries (after Belgium in 2016) to eliminate coal from their electricity mix.

This structural trend is expected to continue in 2021. France, with a phase-out date by the end of 2022, is looking to complete its transition one year early. Portugal also announced the closure of its last coal plant two years ahead of schedule due to rising costs of coal production. The phase-out in Spain could also happen faster as four coal plants (half of the remaining units) have already filed for permission to shut down due to poor market conditions. In Germany, we will see the initial impact of the Coal Exit Law passed in 2020, which plans for about 1.2 GW of lignite plant and 5.5 GW of hard coal plants to be shut by the end of 2021 (almost 4.8 GW of hard coal plants were already retired from the wholesale market by 1 January 2021 after the first auction,²⁵ which included plants less than 5-6 years old with an efficiency of about 45 per cent). Three coal capacity closure auctions are planned in 2021 for the

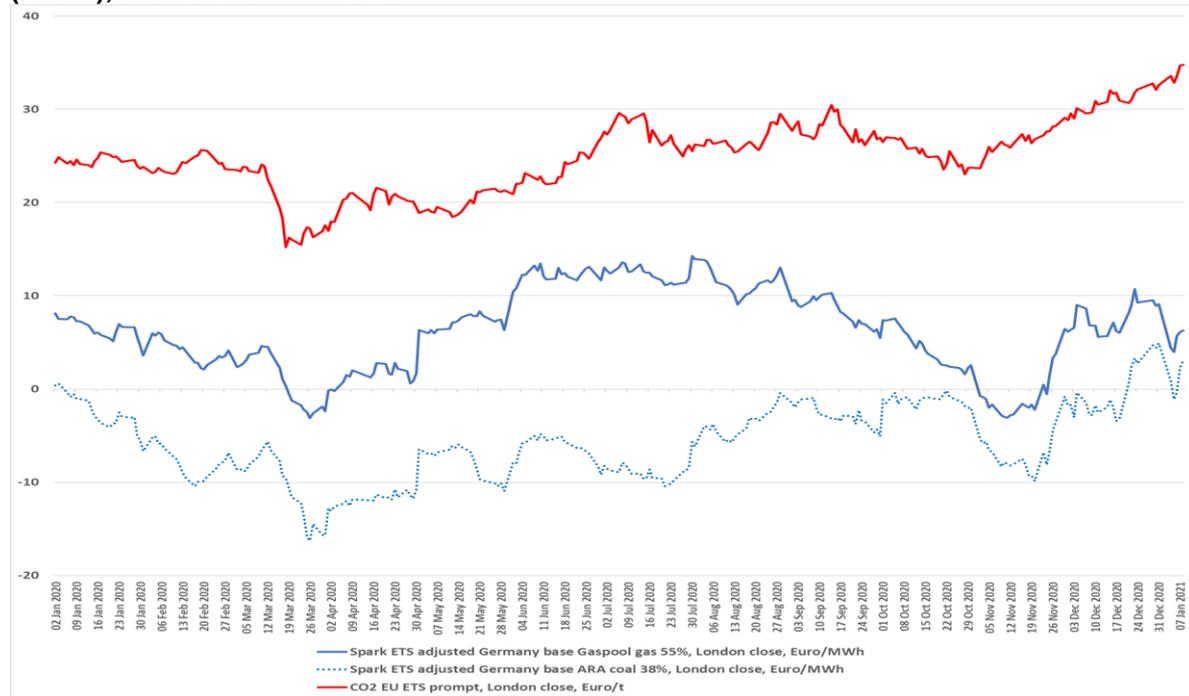
²³ For example, a detailed study has been prepared by the Directorate General on the external policies of the EU at the request of the Parliament's committee on international trade.

²⁴ Calculated from ENTSOE data

²⁵ <https://www.spglobal.com/platts/en/market-insights/latest-news/coal/120120-germany-awards-coal-closure-compensation-to-48-gw-to-shut-2021>

volumes necessary to reach the targets for 2021, 2022, and 2023. In addition, 50 per cent of the remaining nuclear capacity of 8.1 GW will also close in Germany by the end of 2021.

Figure 2.3: Clean spark and dark spreads in Germany (Euro/MWh) and CO2 EU ETS prices (Euro/t), 1/01/2020 to 8/01/2021



Source: Argus

However, Europe may witness a short-lived - and likely marginal - coal recovery in 2021. This is due to the combination of electricity demand growth and higher gas prices. The IEA expects a 2.3 per cent growth in power demand in Europe (still 2 per cent below 2019 levels) as economic activity recovers²⁶ and greater heating needs boost energy consumption (with some people working from home and some being in offices). Expected higher gas prices are driven by growing demand and a modest increase in production. However, it will still be hard for less-efficient coal plants to compete with gas for most of the year. In addition, the continued growth in renewables (over 40 GW of renewables are to be auctioned in 2021)²⁷ and the recovery in nuclear output (especially in France) will also limit any major growth in coal-based generation.

Other key points to look out for include the new emission limits from the BAT [Best Available techniques] conclusions that need to be enforced by mid-2021, which might trigger additional coal plant closures and further government policies required to achieve the new emissions reduction target of 55 per cent by 2030 (compared with 1990). The European Commission plans to unveil a formal legislative proposal for this around mid-2021. It will likely include additional measures for the EU ETS, which entered Phase 4 at the beginning of January. The linear reduction factor is likely to be further increased (in addition to other measures such as rules on free allocation of carbon allowances available to sectors at risk of carbon leakage, a review of the Market Stability Reserve, which keeps surplus allowances out of the market, and potentially the scope of the ETS which may be extended) leading to potentially higher carbon prices.

Finally, several elections are planned in 2021 across Europe but the most important one will be the German election in September, which will be the first election in which Angela Merkel is not running

²⁶ <https://webstore.iea.org/download/direct/4270>

²⁷ Platts Power in Europe, issue 838, January 11, 2021

since 2005. The climate debate, including potentially reopening the discussion about an earlier coal phase out, is expected to influence the elections.

All in all, the long-term decline of coal-fired generation in Europe may slow down in 2021 but the structural decline is expected to continue, and even possibly gain momentum, as new EU level targets for 2030 require faster decarbonization including in the power sector. The impact on gas-fired generation is likely to be marginal in 2021 unless power demand does not recover as expected. Another milestone to keep an eye on will be the UN Conference on Climate Change, COP 26, at which new commitments are likely to be made.

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2.5: The 14th Five Year Plan and China's golden age of gas

The Chinese government will unveil its 14th Five Year Plan (FYP), the policy blueprint for the next five years, in March 2021. While the March document will outline the overarching goals for the country's macroeconomic development - with specific sectoral goals for natural gas unveiled later on - a number of government statements are already offering insights into the priorities that will inform the supply and demand of natural gas over the coming years. Two main themes stand out as impactful for the gas market, pointing to ongoing demand growth, which initially are set to favour LNG, alongside structural changes to the domestic market. The first policy priority is accelerating the country's low carbon transition and the second is the need to beef up energy security.

Following President Xi Jinping's pledge in September 2020, that the country will aim for carbon emissions to peak by 2030 and achieve carbon neutrality by 2060, the Chinese bureaucracy is now working to translate these ambitions into policy steps with the 14th FYP likely offering initial indications of how China aims to decarbonise its economy. Many feasibility studies on the pathways to carbon neutrality in 2060 suggest that for the coming decade, China's energy consumption and emissions will continue to grow, with natural gas and oil demand still rising. What is more, as the share of renewables in the power mix grows - likely more rapidly than expected before the 2060 pledge - the need for flexible power sources such as natural gas will also increase. And with greater urgency to phase out the use of coal in industrial, commercial and residential applications, the coal-to-gas switch will likely continue, supporting demand for natural gas.

CNPC, China's largest oil and gas company, expects natural gas consumption to reach around 420 bcm in 2025, slightly lower than our estimated 450 bcm of demand, and to reach 600 bcm by 2035 - against our 630-650 bcm forecast for that year. Still, the outlook remains one of ongoing growth in gas use, albeit at slower rates than over the past decade. It remains to be seen whether the 14th FYP will introduce a target for the share of gas in the energy mix for 2025, as it did for the 13th FYP. For the 2016-2020 period, the government aimed for natural gas to account for 10 per cent of the energy mix but this was later revised down to 8 per cent, a goal that has been met. At the same time, the government's outlook for domestic production in the 13th FYP - seeking to reach 200 bcm of domestic output including 30 bcm of shale - has not been met, suggesting that the government could issue vaguer goals for the next plan.

While the low carbon transition points to ongoing increases in gas use and to a growing role for gas in power, other government priorities suggest some structural changes in the market, including a stronger position for independent buyers. These changes, in the near term, could support LNG at the expense of pipelines. Government documents and statements issued at the end of 2020 highlight the importance of supply security, but the government's view on the paths to achieving reliable supplies has evolved. Traditionally, supply security policies focused on limiting import dependency by stressing both overland and seaborne import routes while maintaining strong domestic production. Even as these remain the premise of supply security, policy makers are emphasising supply diversification (including diversity of *suppliers*), the need to develop adequate infrastructure and storage capacity as well as price reforms in a bid to add flexibility to the system. To that end, the creation of PipeChina, the state-owned midstream pipeline company will, over time, support third-party access and help the optimisation of gas

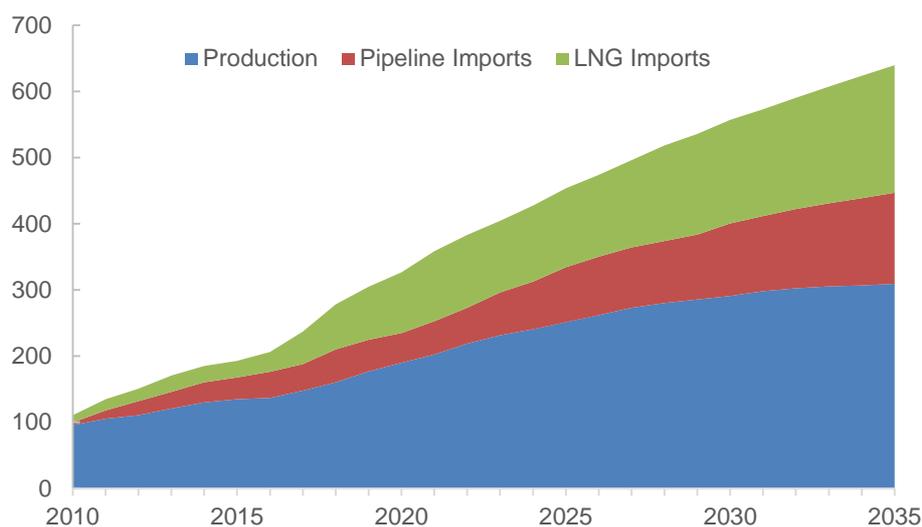
imports into China, especially if price reforms continue and new exchanges support the domestic price discovery process.

Since the transfer of assets from the state-owned majors to PipeChina in October 2020, PipeChina's operations have been fraught with disaster, starting with a fire at the Beihai LNG terminal and severe winter shortages that the state-owned majors have reportedly blamed on PipeChina's inexperience. However, the new midstream operator has also enabled third-party access, with Chinese independent Jovo energy receiving an LNG cargo through PipeChina's Hainan terminal. PipeChina has also launched a platform through which all third parties can register as certified shippers and apply for pipeline transmission and LNG import capacity, with 1,000 companies reportedly applying by end-October 2020. In December 2020, it also released details of 6.4 Mt of spare import capacity at six regas terminals for 2021.

Going forward, as the operating and regulatory guidelines are clarified, third-party access to the midstream network will increase and given the addition of new import terminals, incremental LNG flows are likely to outpace additional pipeline arrivals. Already in 2020, the longer lag between oil and piped gas favoured contract LNG, but the wide discount of spot LNG values to oil-indexed prices spurred buyers with sufficient capacity to switch between the sources. As a result, China's LNG imports in 2020 exceeded 90 bcm, increasing year-on-year by a strong 14 per cent, even as pipeline flows fell by an estimated 5 per cent year-on-year. Going forward, with 8 Mtpa of new LNG import capacity starting up in late 2020, and at least 10 Mtpa of delayed terminals from 2020 set to come online in 2021, LNG flows will rise strongly. In 2021, we expect LNG imports to increase by a strong 14-15 bcm from 2020 levels.

Yet this will not be the case indefinitely. The government will want to balance the risks associated with seaborne imports with pipelines, as the Power of Siberia from Russia is expected to double flows to 10 bcm in 2021 and gradually increase to 38 bcm by 2025. Moreover, the state-owned majors, who will face stiffer competition in the LNG market, have already stated their intention to focus on domestic supplies of both conventional and unconventional gas. In 2020, domestic output rose by close to 15 bcm from 2020 levels (or 8 per cent), and we expect similar growth rates in 2021. The 14th FYP may not mandate output goals or a specific share for pipeline supplies in the import mix, but its emphasis on supply security will indicate to state-owned companies that a balance between supply sources must be struck.

Figure 2.4: China's gas balances, bcm



Source: NBS, Customs, OIES

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2.6: Liberalisation of the Brazilian gas market: challenges and opportunities

Over the last 30 years there has been an ongoing discussion in Brazil on how to increase the share of natural gas in the energy mix. This discussion has been guided by the need to improve air quality in large cities, increase the productivity of key industry sectors, and reduce dependence on bottled LPG, widely consumed by households. Additionally, starting in the early 2000's, there has been an increased requirement for gas-fired power plants, as an insurance against the seasonality of the large and dominant hydro power supply.

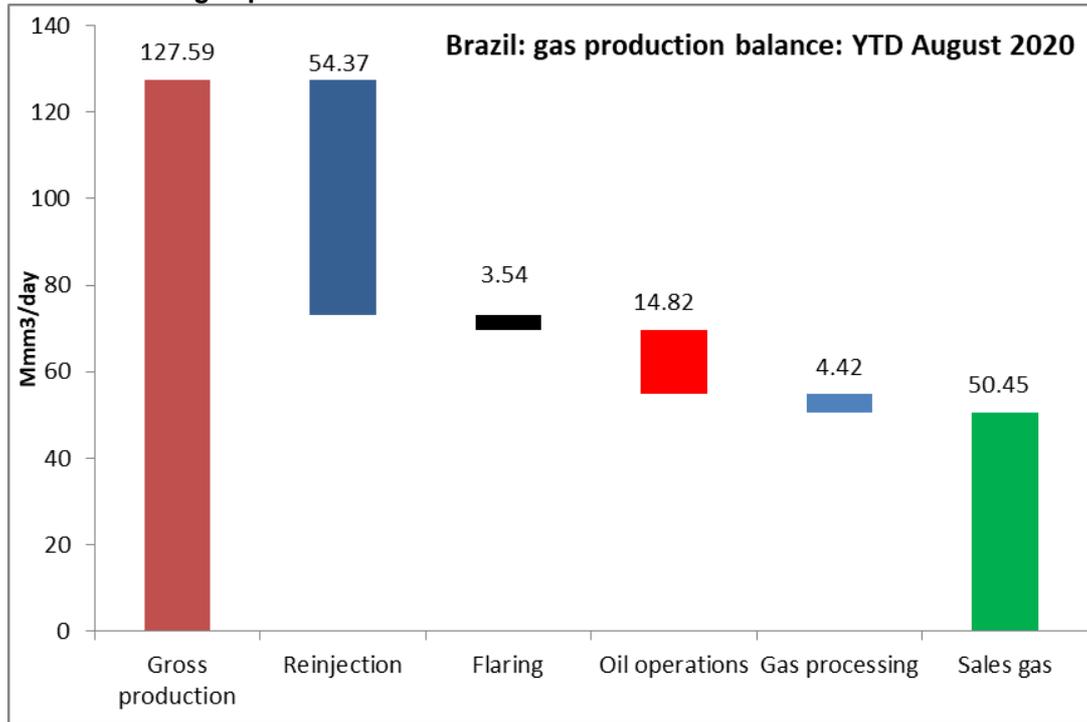
Brazil has not been endowed with large gas reserves and therefore the country has had to rely to a large extent on imports from Bolivia, with a 3000 km pipeline commissioned in 1999, followed by three LNG terminals in 2009-2014, all controlled by the incumbent national oil and gas company Petrobras.

The dominance of Petrobras in the supply of natural gas and its main competitor fuels – fuel oil, diesel and LPG - has been a considerable obstacle to the implementation of competition in the supply of natural gas. A Gas Law, enacted in 2009 (Law 11907), had little impact in promoting competition because it did not tackle third party access to essential facilities and did not address the incumbent issue. On the distribution side, the federal states have control of local distribution, and most of them have granted 30-50 years exclusive concession rights to state-controlled companies, with only a few of them allowing for large consumers to choose their gas suppliers. The industrial sector accounts for half of the consumption of gas, and consumers associations complain that a combination of high wholesale gas prices, Petrobras-controlled city gate prices, distribution margins and taxes, weigh heavily on profit margins and are an impediment to increasing demand.

In the power sector, another important potential area of demand, gas-fired power plants are not baseload and are used as back-up to hydro power and increasing renewable installed capacity, mostly wind and solar. Nevertheless, annual power auctions, underpinned by 25-year PPAs and guaranteed fixed revenues, have encouraged the implementation of thermal power plants, but with a maximum dispatch inflexibility of 50 per cent. These provisions have allowed for the development of three new LNG-to-power projects, and currently around 5000 MW are in operation / construction / development, all financed by private investors.

However, the situation was significantly altered by the discovery of large and highly productive offshore pre-salt fields in the late 2000's which have enabled the production of high-quality oil and large quantities of associated natural gas. As of August 2020, Brazil's domestic gas production had increased to an average of 127.59 MMm³/day (96.24 MMm³/day in 2015), with 43 per cent (54.37 MMm³/day) being reinjected. This amount of reinjection, almost three times the volumes imported from Bolivia, is caused by a combination of factors: limited upstream pipeline infrastructure, high CO₂ content in some fields, and lack of a large and firm demand source to underpin the investment needed to bring associated gas to shore.

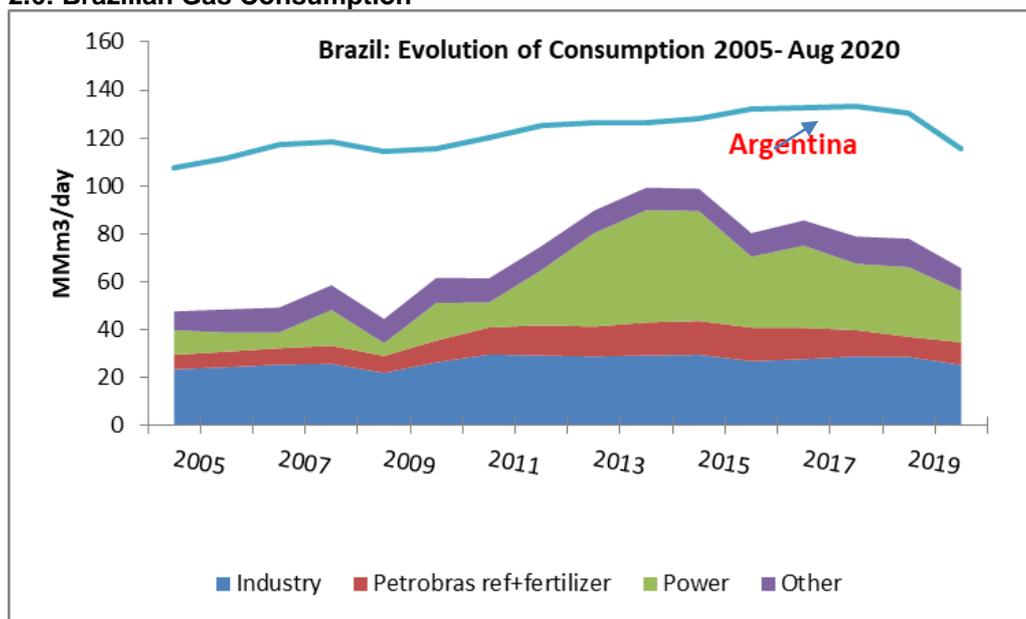
Figure 2.5: Brazil's gas production balance



Source: Ministry of Mines and Energy – Brazil (2020)

In addition, gas consumption has been falling since 2015, due to lower power dispatch and an economic downturn. Despite an economy much larger than Argentina, Brazil's gas consumption is half that of its neighbour.

Figure 2.6: Brazilian Gas Consumption



Source: Ministry of Mines and Energy – Brazil (2020)

In 2016 the federal government devised a new initiative (Gas for Growth) to revitalise and liberalise the gas market in Brazil, re-baptised as the 'New Gas Market' in 2019. The programme was based on a

three-pronged approach: i) reduce Petrobras' dominant position, by directing it to provide third-party access to infrastructure and sell its participation in gas pipelines and distribution companies; ii) amend the tax regime regulating interstate sales of natural gas to base it on contracts, rather than physical flows; and iii) reform the 2009 Gas Law, allowing for negotiated access to essential facilities, moving from concession to authorization for the construction of transmission pipelines, the unbundling of pipeline infrastructure ownership and enhancing regulation for free consumers.

As a result, Petrobras has sold two of its largest pipeline systems to international investors, and is finalizing plans to sell its stake in the Bolivia-Brazil pipeline. It is also selling its controlling stake in the largest gas marketer in Brazil, Gaspetro, which is responsible for supplying most of the gas sold to gas distribution companies.

The Gas Bill was overwhelmingly voted for by the lower Chamber of Deputies in September 2020 but faced considerable opposition with regard to the unbundling provisions. Some sectors of the industry also wanted to enshrine in law the obligation to have baseload gas power plants in the interior of Brazil, with connecting pipelines funded by the government. In December 2020 the Senate added a few amendments in this regard, forcing the Bill to be sent back to the Chamber of Deputies. If the Chamber rejects these amendments, then the new Law can be enacted in the first half of 2021.

In conclusion, the success or otherwise of the Gas Bill is poised to impact on the growth of gas demand in Brazil, with the potential to create another 24 MMm³/day of industrial demand by 2029 and another wave of private investment in M&A, new pipelines and other LNG business models. If there is more incentive to divert associated gas from reinjection into demand centres, this is also likely to impact the dynamics of gas imported from Bolivia into Brazil. As such, 2021 could be a very important year for the Brazilian gas sector and we will be watching progress carefully.

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2.7: OIES Key Themes 2021: Will COP26 catalyse significant global decarbonisation commitments?

Twelve months ago, in the OIES Key Themes for 2020, we asked, “will there be signs of decarbonisation spreading outside Europe?” Up to that point, serious interest in decarbonisation as a key policy driver was largely confined to Europe (and mainly Western Europe). We noted, in January 2020, though, that there were “growing signs that decarbonisation, including decarbonisation of gas, is starting to gain traction outside Europe”.

We could not have predicted at that time the significant impact that Covid-19 was going to have on the entire global economy during 2020. Five years after the Paris COP21 meeting in December 2015, the COP26 meeting to review progress and increase individual country ambitions had to be postponed to November 2021. Despite, or maybe to some extent because of, the pandemic we believe that global policy statements regarding decarbonisation have exceeded our expectations at the start of the year. The following are significant developments:

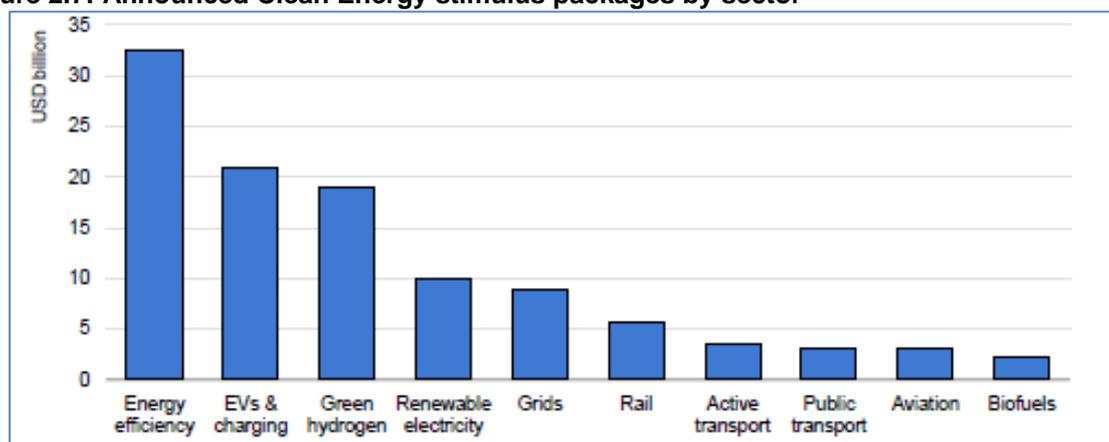
- **China:** In September 2020, President Xi Jinping announced that China intends to peak emissions by 2030 and aim to achieve carbon neutrality before 2060. This announcement was unexpected and is thought significant, although further details are likely to emerge following finalisation of the 14th Five Year Plan during 2021
- **USA:** As announced by President Trump in 2017, the US withdrew from the Paris agreement on 4 November 2020. President-Elect Joe Biden has committed to re-join the agreement on the first day of his presidency in January 2021, and has also made a commitment to achieve net zero emissions by 2050
- **Japan:** Prime Minister Suga announced in October 2020 that the country would aim for net zero GHG emissions by 2050, including a ‘fundamental shift’ in its coal policy (although details are still to be firmed up)

- **South Korea:** Two days after Japan’s commitment, President Moon Jae-in announced that South Korea would commit to achieving carbon neutrality by 2050, including by replacing coal-fired generation with renewables
- **EU-27:** Having already made the high-level net-zero pledge in 2019, the EU strengthened its position in October 2020 by making the target legally binding and then in December 2020 EU leaders agreed a 55 per cent reduction in carbon emissions (from 1990 levels) by 2030 (although this did require commitments by richer countries to support some Eastern European countries, notably Poland, Hungary, and the Czech Republic).
- **UK:** Having been the first major economy to make a net-zero pledge in 2019, 2020 saw some more details emerge and the publication of a ‘Ten Point Plan’ in November 2020. Perhaps the most world-leading pledge was to commit £1bn to support carbon capture and storage, although details of how these funds would be allocated are still to be confirmed. It was also overshadowed by....
- **Norway:** ... where the government committed in December 2020 to contribute \$1.63 billion to allow the Northern Lights CCS project to proceed.

The last of these is perhaps unique in being a commitment to a specific project which will now begin construction. A key question for 2021, in the run up to COP 26 in November, will be the extent to which the high-level political ambitions outlined above will start to be translated into project investment decisions which can start to deliver significant progress towards making those ambitions a reality.

The IEA expects that global renewable electricity capacity additions will be around 10 per cent higher in 2021 than in 2020 at around 220GW, with half of that new capacity being in solar PV.²⁸ For the gas industry, a key question will be whether decarbonisation of gas can start to accelerate to make up some of the ground which has been lost to renewable electricity. Some comfort can be drawn from the IEA analysis of global plans for clean energy stimulus packages, where a significant share is focused on green hydrogen (see Figure 2.7).²⁹ As part of the EU Hydrogen Strategy published in July 2020, there is a target for 6GW of green hydrogen capacity to be onstream in Europe by 2024, which will necessitate rapid progress on large scale (100MW or greater) projects during 2021.

Figure 2.7: Announced Clean Energy stimulus packages by sector



Source: IEA

Similarly, in both the Stated Policies and Sustainable Development Scenarios, the IEA expects to see significant growth in biomethane as early as 2025, with growth continuing thereafter.³⁰

²⁸ IEA, Renewables-2020, p 29.

²⁹ Ibid, p 143

³⁰ IEA, Outlook for biogas and biomethane, 2020, p 58

During 2021, OIES together with the IGU and other partners will be collecting data on the status of renewable gas projects globally, and will publish an analysis to assess whether project progress is consistent with the bold decarbonisation ambitions which have been spreading globally in recent months. More generally, OIES will continue to track progress towards decarbonisation of the global energy system. At this stage, we expect the key countries/regions of interest for significant decarbonisation steps during 2021 could be:

- China as the 14th Five Year Plan is finalised;
- USA as the Biden administration puts more detail around its decarbonisation pledges;
- Europe as some of the aspirational statements to date evolve into concrete policy measures.

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2.8: The Prospects for Decarbonisation Legislation in the EU

2021 will be a busy year for the proposal and development of legislation relating to the decarbonisation of gas, with a series of proposals for legislation due from the Commission. However, it will be a complex process because a number of the initiatives that are expected would be major undertakings in their own right - for example, the revision of the EU Emissions Trading System or revised state aid rules. As a result, it will be difficult to develop a coherent framework for decarbonisation because it is spread across a number of different proposals and different directorates. Firstly, there is the scale, scope, and novelty of what is being attempted – namely the decarbonisation of the entire economy - and the market failures associated with greenhouse gas emissions will require considerable government intervention. Secondly the rules can be complex which makes it difficult to keep track of all the interdependencies. Thirdly the normal legislative process means that there will have to be compromises between conflicting interests. Different groups have very different views as to the best way to achieve decarbonisation. Furthermore, what may make sense within one initiative may have different consequences when interacting with another piece of legislation. With this in mind it is worthwhile to know what is coming down the track.

The first and most important piece of legislation is the **European Climate Law**³¹ which will amend Regulation EU 2018/1999 to make the targets of net zero in 2050 and a reduction of 55 per cent in emissions by 2030 legally binding. The EU Parliament voted in favour of the new 2030 targets in October 2020, and the EU Council representing Member States also approved the targets in their December 2020 meeting, clearing the way for agreement of the legislation this year.

By the end of Q2 2021 the Commission will come forward with proposals for the **revision of the EU Emissions Trading System**.³² Currently this covers sectors responsible for 55 per cent of EU emissions, such as industry. Reform could include extending the scheme to sectors not covered and the removal of free allowances for sectors at risk of carbon leakage in combination with a Carbon Border Adjustment Mechanism (see below). Revenues from the ETS are also used to fund decarbonisation projects via the ETS Innovation Fund and increasing the price of carbon is seen as key to incentivising decarbonisation. The Commission has also proposed the idea of Carbon Contracts for Difference as a means of supporting low carbon or renewable hydrogen production. Sectors not covered by the ETS are subject to Member States' commitments under the **Effort Sharing Regulation**,³³ with revision proposals also due in Q2. Member States have different emissions reduction targets which combined meet the overall EU target.

Also, in Q2 the commission will come forward with proposals for a **Carbon Border Adjustment Mechanism (CBAM)**.³⁴ The idea is that imports from countries which have less stringent emissions targets than the EU will be taxed so that EU production of such goods competes on a level playing field.

³¹ European Commission: [European Climate Law](#).

³² European Commission: [Climate change – updating the EU emissions trading system](#).

³³ European Commission: [National emissions reduction targets \(Effort Sharing Regulation\) – review based on 2030 climate target plan](#).

³⁴ European Commission: [EU Green Deal \(carbon border adjustment mechanism\)](#).

It would thereby prevent ‘carbon leakage’ where EU production either moves abroad or closes, and the EU relies on imports instead. Currently sectors at risk of carbon leakage receive free ETS allowances. However, if a CBAM was introduced, any carbon tax on imports would also need to be applied to EU goods to comply with World Trade Organisation rules. The EU would also need a methodology to determine the carbon footprint of imports produced by different firms in different countries.

Revision of the **Energy Tax Directive**,³⁵ aimed at aligning taxation of energy products with EU energy and climate policies is also due in Q2. This could, for example, impact the taxation of electricity used for electrolysis, which would affect the competitiveness of ‘green’ hydrogen.

There is potential linkage between CBAM and **proposals to implement the Commission’s Methane Emissions reduction strategy**,³⁶ also due in Q2. Although most methane emissions relating to natural gas occur in production and transport outside of the EU, the EU has said that it will use its position as the world’s largest importer of fossil fuels to promote methane reductions by its global partners. It has also said that it will introduce legislative measures if partners do not take steps to reduce methane emissions. Much will depend on the design of such measures, but it is possible that they could be combined with a CBAM. A key element of the strategy is improving the measurement, reporting and verification of methane emissions. Even if such information is not used as part of efforts to target natural gas imports, it could have relevance to hydrogen production from natural gas.

This is because of the Commission’s commitment to introduce a comprehensive terminology and European wide criteria for the certification of renewable and low carbon hydrogen. The vehicle for this will likely be a **revised Renewable Energy Directive**,³⁷ updating the current version known as RED II, and due in Q2. RED II already contains provisions for Guarantees of Origin for hydrogen, as well as for other renewables, and efforts are underway to include carbon footprint information. A revised RED II could also contain demand side measures such as quotas.

Proposals for the **revision of the Third Energy Package for gas**,³⁸ are due in Q4. The aim is to update this to regulate competitive decarbonised gas markets and thereby to enable the deployment of hydrogen. This will be a major piece of work because of the highly prescriptive nature of the current gas regulatory framework, and the issues involved such as tariffs, investment in or repurposing of networks, interoperability between hydrogen and natural gas, and third-party access.

Also due in Q4 will be proposals for the **revision of Energy and Environmental State Aid guidelines**.³⁹ This will be crucial to ensuring that the necessary government support for decarbonisation and hydrogen projects is compatible with state aid rules. State aid will also be influenced by the **Taxonomy Regulation**⁴⁰ which establishes a framework to facilitate sustainable investment. The rules for this are being finalised in early 2021.⁴¹

The consultation process for many of the proposals has already started. However, it will take time for the Commission to develop full legislative proposals, and then for these to be agreed with the Parliament and Member States, with a further lead time before the measures come into force. The direction is clear – both the Council and the Parliament support both the stricter 2030 targets and the 2050 net zero target. The timing and the exact form of the future legislation is less certain.

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³⁵ European Commission: [EU Green Deal – Revision of the Energy Taxation Directive](#).

³⁶ European Commission: [EU strategy to reduce methane emissions](#).

³⁷ European Commission: [EU renewable energy rules - review](#).

³⁸ European Commission: [Commission Work Programme 2021. Annex](#).

³⁹ European Commission: [State aid for environmental protection and energy – revised guidelines](#).

⁴⁰ European Commission: [EU taxonomy for sustainable activities](#).

⁴¹ European Commission: [Sustainable finance – EU classification system for green investments](#).

2.9: Carbon neutral LNG cargoes: the need for measurement and verification

Since mid-2019 there have been a reported seven 'carbon neutral' LNG cargoes sold in Asia. These are LNG cargoes where the greenhouse gas (GHG) emissions associated with the production and delivery of the cargo have had their emissions offset through the purchase of carbon credits (supported by reforestation, afforestation or other renewable projects).⁴² These cargoes have attracted considerable interest from the LNG industry, but also challenges from some commentators as to the accuracy and consistency of the carbon measurement and offsetting methodology.

The GHG emissions associated with an LNG cargo include those from upstream gas production, the pipeline from the wellhead to the liquefaction plant, the liquefaction process and shipping to market. The downstream emissions from the cargo include regasification and combustion by the end user(s). To obtain a complete GHG estimate, it is essential to measure the carbon and methane emissions from a cargo. In his November 2020 paper,⁴³ Jonathan Stern set out the three main categories of methane emissions: venting, flaring and fugitive.

Of the seven cargoes, some sellers reportedly included emissions offsetting for all parts of the chain, whilst others only included some elements, but all cargoes were referred to as 'carbon neutral' LNG. A major problem is that there is no clarity as to which emissions (total GHG or just carbon) are included in a 'carbon neutral LNG' cargo, and how these and the corresponding offsets are measured. Some argue that the term 'carbon neutral' is being increasingly used in the LNG industry as a marketing ploy rather than a technical definition.

Energy transition will require considerable reductions in GHG emissions from all sectors of the energy sector. This is particularly the case for countries in the European Union (EU) which individually, and as a Union, have set climate neutrality (net zero) targets. The EU, as well as the key LNG buying countries of Japan and South Korea, has set a 2050 target, while in October China announced a target date of 2060.

In order to achieve these targets, a first step must be to know the volume of emissions. It is, therefore, key that a transparent methodology for measuring and reporting GHG emissions is developed with independent verification. In its Methane Strategy⁴⁴ published in October 2020 (as part of its Green Deal legislation), the European Commission goes further and includes compulsory measurement, reporting, and verification (MRV) for all energy-related methane emissions, obligations to improve leak detection and repair (LDAR) from all fossil gas infrastructure, and elimination of routine venting and flaring in the energy sector covering the full supply chain up to the point of production. The Commission is also clear that, 'In order to incentivise accurate MRV on fossil gas (including imports), the Commission will propose to use a default value for volumes that do not have adequate MRV systems in place'. The LNG industry must therefore develop the necessary measurement and reporting systems for GHG for each cargo. There has been some discussion in industry forums about using generic GHG emissions figures in the absence of detailed data, arguing this would be a first stage towards more accurate measurement. It is unlikely this will be acceptable to policymakers and environmental stakeholders.

In April 2020, Pavilion Energy issued an LNG purchase tender for up to 2 million tonnes of LNG over a five-year period, with supply to commence in 2023. This tender included a requirement on LNG sellers to collaborate with Pavilion Energy on the development of a quantification and reporting methodology for the GHG content of deliveries. In November 2020 Pavilion Energy and QP Trading (QPT) signed a ten-year LNG sales and purchase agreement for the supply of up to 1.8 million tonnes of LNG per year to Singapore from 2023. Critically each LNG cargo delivered under this agreement will be accompanied by a statement of its GHG emissions measured from well to discharge port.⁴⁵ The GHG measurement methodology will be developed by Pavilion Energy and QPT during 2021 with the intention that it will

⁴² Stern, J. (2020). 'Methane Emissions from Natural Gas and LNG Imports: an increasingly urgent issue for the future of gas in Europe', Oxford: OIES, NG165, 24.

⁴³ Stern 2020, NG165, 4

⁴⁴ https://ec.europa.eu/energy/sites/ener/files/eu_methane_strategy.pdf

⁴⁵ <https://www.pavilionenergy.com/en/media/pavilion-energy-and-qatar-petroleum-sign-strategic-lng-supply-agreement-for-singapore>

create a standardised methodology to quantify and report GHG (carbon and methane) emissions. Pavilion Energy has said that it intends to make public this methodology.

As a result of this important development in the LNG industry the OIES Natural Gas Programme plans to monitor two key measures of progress during 2021. Firstly, we will keep track of the number of publicly reported carbon neutral cargoes traded, and will also monitor the definitions of carbon neutrality in each one. It will be instructive to see whether a common definition starts to emerge as an industry standard or whether an ad hoc, and therefore less helpful, approach is adopted.

Secondly, and perhaps more importantly, we will also monitor progress towards a transparent and independently verifiable measurement system for GHG emissions from LNG cargoes by Pavilion Energy and other companies and industry organisations. The Pavilion tender offers hope that a specific methodology could start to be developed, but it will be important to assess whether it can form the basis of an industry standard or whether it will be a one-off outcome. We would argue that until an industry standard can be agreed that will satisfy consumers and policy-makers alike it will be difficult for the LNG industry to truly enhance its environmental credibility.

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2.10: What should we expect from Biden's energy and climate policy?

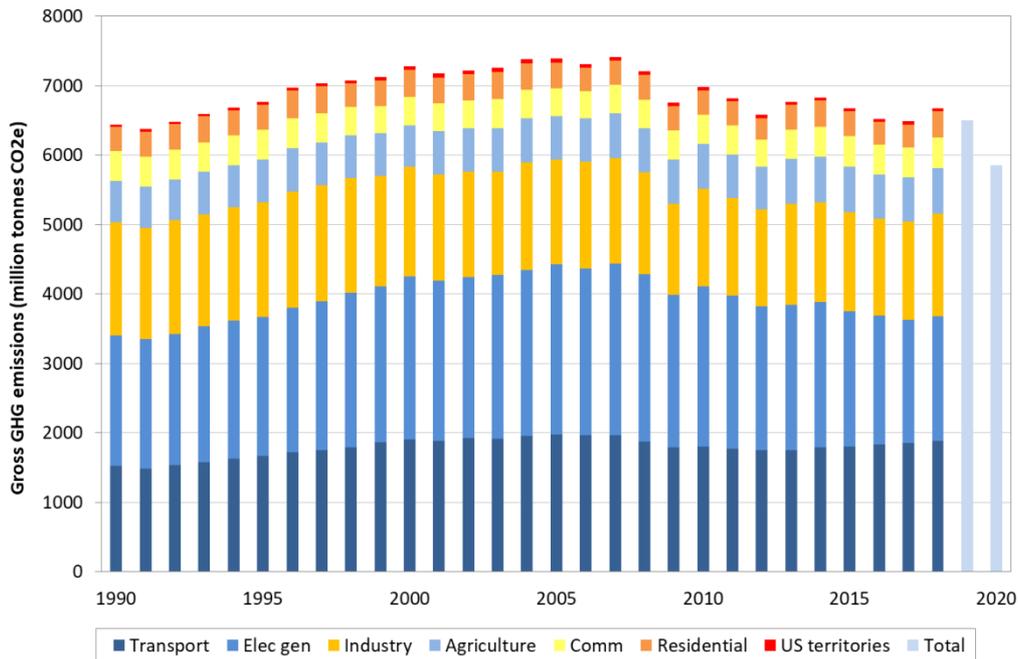
After the polemics of the Presidential and Congressional elections in November and the drama and violence of the transition period, the Biden administration in the US will soon set about the more prosaic task of policy formulation, detailed executive rule-making and the tabling of legislative proposals. In energy and climate, the contrast with the stated policies of the Trump era will be stark. In some quarters, expectations are high that the Biden presidency will deliver major changes in US energy and climate policies with far-reaching consequences for domestic production, the use of energy and GHG emissions, and even usher in a new era of US leadership on environmental issues. However, even with a narrow Democratic majority in the Senate, in a deeply divided country, the domestic political and potential legal obstacles to durable change at federal and state level promise to be considerable. Abroad, the US has much to do to re-establish trust and credibility on energy and climate, as on trade and security. The history of domestic US action on energy and climate, from Clinton to Obama, has taught us to expect only moderate, hard-fought, gradual change in domestic energy markets and frequent setbacks, not overnight change or radical reform.

In the first 100 days, President Biden is expected to set out his plans to deliver the main elements of his intended \$2 trillion energy plan, reinforcing the COVID-19 recovery stimulus package, and to launch the process of restoring the rules on environmental matters which were relaxed or revoked by President Trump. On some environmental rules, such as those regarding domestic oil and gas drilling and coal power plants, Biden may not simply restore the 'status quo ante' but introduce more stringent federal rules. Within 12-18 months, the content of his energy and climate plans to promote renewables generation, lower-carbon transportation and low-carbon infrastructure investment should be clear. On energy and climate, as much as any policy area, Biden will face opposition not only from much of the Republican minority in Congress but also from some 'progressive' elements of the Democratic majority and from individual states. Biden's success should perhaps be measured less by the emission reduction he achieves in his four years and more by whether he can build a bipartisan consensus which can survive his presidency.

Biden is committed to quickly re-joining the Paris Agreement and to improving the reputation of the US as a policy laggard on climate change. The submission of the US Nationally Determined Contribution (NDC), setting out GHG emission reduction targets for 2025 and 2030 from a 2005 baseline, will provide the first indication of the milestones towards the key stated aims of decarbonising the power sector by 2035 and achieving a 'net zero' economy by 2050, going beyond Obama's aim of an 80 per cent reduction. Power generation was responsible for more than 1.8 Gt CO₂e of total US GHG emissions of 6.7 Gt CO₂e in 2019, down from 2.47 Gt in 2007 as natural gas and renewables gradually displaced coal-fired generation. US steam coal use in 2020 was lower than at any time since the mid-1970s. The

extension of federal tax credits, carbon pricing, and financial support to new low-carbon technology will be essential to achieving the 2035 target, and as a result there may not be many more years of growth of unabated gas-fired generation if both federal and state authorities actively pursue the target as a precursor to EV expansion in transport, the biggest GHG-emitting sector (see chart below).

Figure 2.8: US Gross Greenhouse Gas Emissions 1990-2020



Source: EPA, Inventory of US GHG Emissions and Sinks 1990-2018

Climate change policy adds a new dimension to the already fraught area of international trade and investment protection. Nowhere is this more evident than in the US where climate policy is overshadowed by 'great power competition' with China. Biden is unlikely to relax entirely the hard-line stance adopted by Trump towards China on trade since he wants to prevent China gaining any unfair advantage in international trade if the US adopts its own net zero target. Fear of carbon leakage and a risk of renewed job losses to China promises to become an additional, complicating dimension in US-China relations. If a degree of mutual trust between the two superpowers cannot be re-established and maintained, a key question will be whether Biden will revert to a Trump-style unilateral sanctions-based approach or explore a multi-lateral approach with the EU and other climate-conscious Asian countries to introduce carbon border adjustment mechanisms which include Chinese exports. The COP26 process may provide the first clues of the new US-China relationship under Biden.

There are two areas of international climate change policy which Biden may choose to emphasise in 2021 to restore US climate credibility: methane emissions and climate finance. As the world's largest oil and gas producer, the new US administration will be aware of the scope to improve the reporting and abatement of methane emissions in the oil and gas chain. US methane emissions were 634 mt CO_{2e} in 2018, or almost 10 per cent of total GHG emissions; almost 30 per cent of *reported* methane emissions come from the oil and gas chain – the real figure is probably much higher. After the US has set out its own proposed regulation of domestic flaring, venting, and methane emissions from upstream operations, especially from fracking, it will be interesting to see whether it seeks to include methane on the agenda of COP26 and to support the EU's ambitious Methane Strategy. More stringent controls on methane emissions may be the price the US upstream industry will have to pay for continued access to all export markets. The other area in which the US federal government, backed by its major banks and financial institutions, could play a decisive role is in the development of climate finance to support international decarbonisation investment and in improving financial disclosure of climate-related



financial risks. In other words, if Biden can garner domestic political support and international allies through a commitment to fund emission reduction in developing countries, his influence may possibly extend beyond direct emission abatement to corporate financing, environmental disclosure and the trading of financial instruments. None of this will be simple or easy but at least the US under Biden will regain a seat at the international table and have a respected team in climate negotiations.

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