

March 2018

# Quarterly Gas Review

## Analysis of Prices and Recent Events

*In this first of a new series of Quarterly Gas Reviews, Thierry Bros provides his insights and analysis on recent regional and global pricing issues while also commenting on relevant questions concerning policy and market-related matters. The report contains two major sections: an analysis of prices and recent events and a “Quarterly Focus” which provides an in-depth look at a specific topic of current relevance.*

### **Analysis of Prices and Recent Events**

We review global recent price trends, including the winter spike in global LNG prices caused by the surge in Chinese gas demand, and also introduce a new pricing metric, the spread between the theoretical price of US LNG and the actual Henry Hub price, and argue that this measure provides a good indication of “LNG tightness.” The higher the level the tighter the market, with LNG needing to be attracted to the gas markets in Asia or Europe, as evidenced in late 2017 and early 2018.

On a regional basis we discuss the impact of the weather bomb in the US, noting the arrival of a cargo of Russian LNG as one clear signal of the tightness of the global gas market. This was emphasized by high gas prices in Europe, where a number of supply and demand issues combined to exacerbate the impact of colder weather on the continent. In particular, we assess the changing gas relationship between the EU and Russia and the impact of likely further restrictions on Groningen output in the Netherlands.

### **Quarterly Focus: An analysis of spare capacity in the global gas market to 2021**

We argue that the globalisation of the gas market is leading to a situation where analysis of spare supply capacity is becoming as important a theme in the gas industry as it has been for some time in the oil market. We calculate that spare capacity was only 2.3% of global gas consumption in 2017 and was really only located in Russia, with Gazprom providing the extra gas that was needed to balance rising demand, with the implication that the market was indeed very tight.

Looking to the future we analyse the projects that are set to increase production between 2018 and 2021 in order to calculate the future supply upside, focussing on major projects. Our analysis suggests that spare capacity could have been adequate from 2016 to 2021 in a low demand growth scenario, but could be tight from 2017 onwards with high demand growth.

## Global Prices

### Record demand in China, the US, and the UK has pushed prices up this winter to close to 12\$/MBtu

For a quick overview of prices (all in \$/MBtu), we have focused on the three major indexes for gas demand:

- TTF Month Ahead (Netherlands) which reflects the hub pricing in Europe for both pipe gas and LNG;
- HH Month Ahead (US) which reflects pipe gas pricing in North America,
- ANEA Month Ahead which reflects the DES LNG spot pricing in Northeast Asia as assessed by Argus. As this contract rolls on the 16th of the month we have decided to provide a homogeneous picture by effectively rolling all 3 contracts on the 16th.

However, as the gas market is getting more global thanks to LNG becoming a more fungible market, we are also introducing a new metric derived from the FOB price from the US Gulf of Mexico<sup>1</sup>. With two liquefaction plants now on line and more to come this is a theoretical estimate which provides an idea of what is happening worldwide. But, in a gas market that is becoming more and more commoditized, this could become a traded product, in which case the global LNG index would show the value of LNG optionality, which can be transported to any regasification plants. We have therefore decided to report the spread between this assessment and the HH (USGC FOB LNG – HH): a low spread would suggest a close alignment of worldwide prices (due to higher US prices or increased global competition) while a high spread would suggest that LNG needs to be attracted to demand centres in Asia, Europe, Latin America or Middle East. A prolonged high spread could also be indicative of the need to invest in new liquefaction capacities. Hence we have labelled this spread ‘LNG tightness’. US LNG only became available in February 2016, hence the graph dates from June 2016.

The USGC FOB LNG – HH shows the sensitivity of the LNG market: it slackens in the summer when Northern Hemisphere gas demand falls, but gets tighter during the winter as demand increases.

Chinese winter gas demand caused Asian LNG spot prices to spike in January 2018. Whilst global LNG supplies grew by 9.2 per cent in 2017 compared to 2016, Chinese LNG demand recorded a massive 42 per cent growth<sup>2</sup> year-on-year. With ANEA peaking at close to 12\$/MBtu, demand might be expected to be affected, as indicated by the IEA’s World Economic Outlook<sup>3</sup>. To become the primary fossil fuel of choice, gas needs to avoid the usual boom and bust commodity cycle. During its full year 2017 presentation on 1 February, Shell’s CEO dismissed the prospect of an LNG “glut” as “conspicuously absent”, highlighting the booming demand in Asia which is attracting cargoes from as far north as Norway to South Korea. Our USGC FOB LNG – HH spread, which peaked at 6\$/Mbtu, confirms his analysis. With the end of winter and some nuclear capacity restarting in Japan, LNG DES ANEA started to drop as demand fell back and this trend could continue during the summer months as supply should theoretically increase as Yamal and Cove Point production is ramped up, although there are still some uncertainties following PNG’s closure due to an earthquake.

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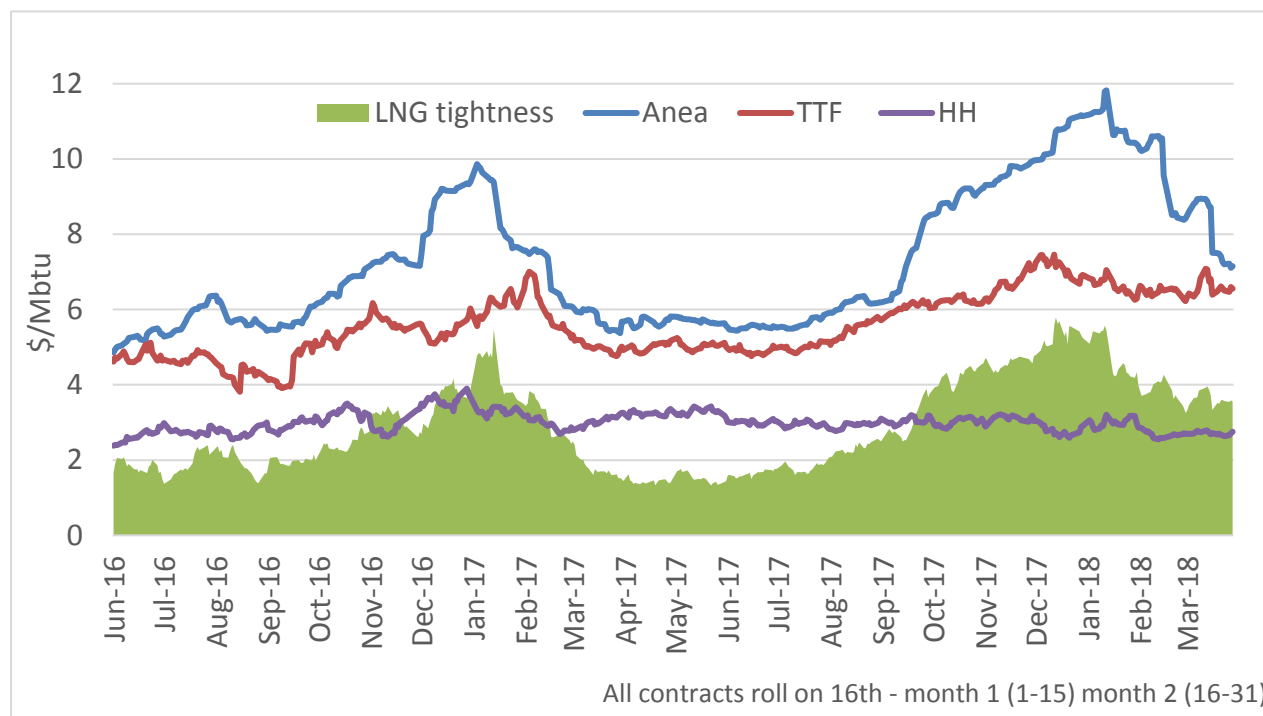
<sup>1</sup> Price assessments are based on two elements — a survey of market participants’ view of prevailing prices and indicative bids and offers; and an average of confirmed trades that meet the defined specifications. The final price determined for the day is an average of the survey result and the trade value. In the absence of any relevant traded volumes, Argus will take the average of the indicative bids and offers available from its market survey in order to establish a mid-point price.

<sup>2</sup> According to JODI gas data

<sup>3</sup> In “What’s the price for gas demand to grow?” p. 342, the IEA shows that in three OECD markets “demand decreased when prices were above 8\$/MBtu” and reaches the conclusion that “the gas industry needs to work hard on cost control to minimize the risk of losing out to other fuels and technologies”.



**Figure 1: Worldwide gas prices and LNG tightness**



Source: Argus Media, thierrybros.com

In this section we will not focus on the spread between contracted gas and spot gas as this is generally only relevant at a dedicated regional level (if so it will be included in the following section). Additionally, pricing in Russia, another big area of demand, has not been taken into account, as it is unlikely that the Russian government would allow exports by European companies to be traded on the SPIMEX in St Petersburg. In order for this to be legally possible, Russia would need to cancel Gazprom's pipe export monopoly and revise export duties taxes. It is more likely that the Russian government would allow a few selected Russian companies to export pipe gas (as is the case in LNG). The SPIMEX price, if the exchange is a success, would be on average a netback to the TTF (taking into account the transport cost and export duty) as Nord Stream links these two markets. The push for SPIMEX comes from the need for Russia to have a domestic pricing reference (as HH achieved in the US prior to LNG exports). And as Russian LNG is not produced anywhere close to St Petersburg the SPIMEX should not impact global LNG prices even if it is successful. The UK NBP is also not under consideration as a recent OIES publication<sup>4</sup> has proved that TTF has overcome NBP at the EU level. Finally, as gas prices are becoming less and less linked to oil, in this section we will not be comparing gas prices vs Brent prices.

## Regional price activity

### US: Record day-ahead prices in New York at 140\$/Mbtu

Even though HH prices did not move much this winter, the intensely cold 'weather bomb' event in early January resulted in record levels of US gas demand and record wholesale gas prices. Day-ahead gas spot prices for 5 January 2018 reached 140.25\$/Mbtu in New York compared with 3-5\$/Mbtu average prices in

<sup>4</sup> "European traded gas hubs: an updated analysis on liquidity, maturity and barriers to market integration" published in May 2017 available at <https://www.oxfordenergy.org/publications/european-traded-gas-hubs-updated-analysis-liquidity-maturity-barriers-market-integration/>



the preceding six weeks. These prices exceeded January 2014 polar vortex prices by about 4-20\$/MBtu.<sup>5</sup> Despite the fact that the weather in January 2018 was a local problem, the interconnectivity of the markets meant that the solution was both local (higher prices) and global (rerouting of LNG cargoes<sup>6</sup>). Domestically produced LNG (from Sabine Pass in Louisiana) cannot go directly to the Everett regas plant because none of the world's LNG fleet meets the requirements of the US 1920 Jones Act, which mandates that vessels moving between US ports be built and registered in the country, and crewed by Americans. This is the reason that the first Russian Yamal LNG cargo, loaded in December 2017, arrived in Boston in January 2018.

### Europe: record demand due to less flexibility in power generation and cold spells

At the TTF, prices moved above 7\$/MBtu both in December 2017 and February 2018 as demand continued to grow while domestic supply was constrained. For the EU alone, we estimate that total imports from Russia were 165 bcm. Although it is too early to calculate year-on-year growth<sup>7</sup>, this is likely to be greater than the growth in Norwegian pipe exports (+ 8 per cent at 117.4 bcm) according to Gassco<sup>8</sup>, and also higher than expected total EU demand growth<sup>9</sup>. This means that Gazprom's market share should continue to grow from the 30 per cent recorded in 2017<sup>10</sup>, with an additional demand boost coming from the freezing Siberian weather which hit Europe in February and March. In addition, there has been a change in sentiment from the EU vis-à-vis gas which was first disclosed by Klaus-Dieter Borchardt, the director of the Internal Energy Market at DG ENER in an interview with the Florence School of Regulation<sup>11</sup> on 19 January 2018. He stated that as complete electrification will not work, gas should not just be seen as a bridge fuel for renewables, but that it has its own future in Europe. This explains why public funding for new gas interconnections has not been stopped: "Pipes and storage are the batteries of the new energy system", he stated, adding, "it is important to get this narrative across".

With EU gas demand in 2017 at 17 per cent above its record low witnessed back in 2014, there was a very significant change of tone in relation to EU-Russia gas relations at the European Gas Conference in Vienna at the end of January. At that meeting, both Gazprom and the EU Commission were extremely conciliatory about the EU-Russia gas relationship. Gazprom acknowledged that it wanted to play a bigger part in Europe and would abide by third package rules, while for its part, the EU Commission saw the mutual benefits of integrating EU and Russian gas markets to give welfare gains for both sides. But after the poisoning of a former Russian spy on the UK mainland, tensions are now rising between the EU and Russia and gas could become more politicized.

Additionally, on 1 February the Dutch energy regulator (State Supervision of Mines) recommended a significant cut in Groningen's production quota to 12.0 bcm/y as soon as possible (compared to 21.6 bcm/y currently), while Gasunie, the Dutch TSO, recommended to cut production to just 19.5-21.0 bcm for the current gas year. The Dutch economy minister ordered production to halt immediately at the Loppersum cluster (where production was 0.8 bcm last year) and declared that a 0.5-2.0 bcm cut in Groningen production this year would be possible. The operator NAM closed the Loppersum cluster the following day.

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<sup>5</sup> Full analysis available on Northeastern Winter Energy Alert at [https://www.eia.gov/special/alert/east\\_coast/](https://www.eia.gov/special/alert/east_coast/)

<sup>6</sup> According to monthly data available at <https://www.energy.gov/fe/listings/lng-reports>, in January 2018 (last month available) Everett regas terminal received on top of the usual long-term deliveries a spot cargo (compared to none in January 2017) at a landed price of 12.28\$/MBtu that was reloaded in the UK.

<sup>7</sup> Estonia (0.1 bcm consumption in 2016) and Latvia (1.3 bcm consumption in 2016) were not reported in Gazprom's Exports European sales in 2016. Gazprom's REMIT data only started in July 2016 and some of the exported gas could have been put in storage instead of being sold. According to Gazprom Export data at <http://www.gazpromexport.ru/en/statistics/> contracted exports to the EU were in 2017 156 bcm, up 3.2 per cent vs 2016.

<sup>8</sup> <https://www.gassco.no/en/media/news-archive/clear-record-set-for-norwegian-gas-exports/>

<sup>9</sup> Estimated at 4 per cent according to JODI first release as disclosed in NGW 22 Feb 2018 and at 6% according to the EU quarterly Report on European Gas Markets

<sup>10</sup> Estimates taking into account Gazprom exports data converted from Russian bcm into standard bcm and JODI demand estimates

<sup>11</sup> "All you need to know on the EU energy market in 2018-2019... in one interview!" available at <http://fsr.eui.eu/need-know-eu-energy-market-2018-2019-one-interview/>



The final decision for the current gas year quota will be taken soon and in June for gas production in the following year. Even if the minister says that a production cut to 12 bcm/y would endanger security of supply for L-gas<sup>12</sup>, track records show that before the next election in 2021, the quota would need to be at this level as residents now have the support of the State Supervision of Mines and no-one in the industry<sup>13</sup> or the government can afford to take the risk of further security concerns, even if there is a financial case to produce at higher levels. Meanwhile new tremors in February have put further stress on the Minister to reduce Groningen output still further.

Finally, the robustness of the European gas system was tested by the Siberian cold spell. With increased demand since 2014 following some coal-to-gas switching in power generation and lower domestic production, the overall acceptability of the system is being questioned by some customers. With coal exiting the electricity system, the system will have even less flexibility. Is Europe prepared to accept even higher volatility in the years to come or will politicians intervene to “fix” this problem?

Another issue to watch in the coming months is how Russian supply and transit contracts in Ukraine will evolve. Arbitration has settled past issues, but has created even more uncertainties going forward. The determination of Gazprom to terminate those contracts<sup>14</sup> shows the advantage of flexible LNG supplies, hence our USGC FOB LNG – HH spread reflecting the LNG tightness.

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<sup>12</sup> Groningen is a low calorific gas (L-gas) while most of the other fields in the world produce high calorific gas (H-gas).

<sup>13</sup> Both ExxonMobil and Shell (JV partners in NAM) did provide future worldwide production targets while flagging the Groningen seismic risk.

<sup>14</sup> As disclosed on Gazprom’s twitter account on 2 March 2018. For a detailed analysis please refer to After the Gazprom-Naftogaz arbitration: commerce still entangled in politics available at <https://www.oxfordenergy.org/publications/gazprom-naftogaz-arbitration-commerce-still-entangled-politics/>

## Quarterly Focus: Spare gas production capacity (2017-2021e)

*It is interesting in a world where the consensus was forecasting an LNG glut to see the first Yamal LNG cargo loaded in December 2017 arriving in Boston in January 2018<sup>15</sup>. It is therefore worth revisiting the concept of spare production capacity. Spare production capacity in Russia and high storage capacity in Europe are currently providing a global buffer to balance worldwide supply and demand. But for how long, given that Gazprom's increased production and overall growth in demand during 2017 means a decline in spare capacity?*

### Move to a quasi-global gas market

Prior to 2000, gas markets were national, with each consuming country responsible for planning its own supply. This was at a time when LNG was also a quasi-pipe business (the product being moved from a dedicated liquefaction facility to a dedicated regasification plant). Each country had its own strategy to mitigate any disruption (flexible long-term contracts, storage, interruptible contracts, etc.) and the concept of spare capacity was inappropriate.

At the turn of the millennium, the BG group transformed LNG into a trading business with multiple delivery options, becoming the only pure LNG aggregator at that time. Combined with the efforts of the EU Commission to foster a single EU-28 market, connections began to be made between the major regional markets of Europe and Asia. This increased connectivity between markets was highlighted after the Fukushima disaster when 7 per cent of the global LNG supply was rerouted to Japan.

As LNG supply has grown, and with the advent of an increasing number of short-term trades (even given the relatively high cost of transportation), gas markets are becoming quasi-global. This means that a tightness in one specific market could have implications everywhere else, as seen post-Fukushima. This also means that most consumers cannot rely just on their own dedicated supply but must now consider the global supply-demand balance. Hence the concept of spare production capacity could soon become meaningful. The concept of oil spare capacity should therefore be revisited for the gas business. As in oil, spare capacity is just a metric, what also matters is who controls it (OPEC for oil) and for what purpose. Oil spare capacity is always measured ex-post and helps explain strategy and prices. It cannot be calculated ex-ante (or based on forecasts) due to the impossible task of not only assuming demand and supply growth but also geopolitical risk. It is also done on a daily basis as crude oil production is essentially flat all year round. Conversely, given gas demand is highly seasonal, our calculations of the spare capacity metric for gas are performed on a yearly basis. Which means that a yearly average which is too low could mean absolutely no spare capacity during peak periods.

### Significant reduction in spare capacity

In 2017, global spare gas capacity fell by 36 per cent, representing only 2.3 per cent of world consumption. Up until 2016, Gazprom had been one of the few companies investing and maintaining available spare capacity, with most, if not all, other listed companies focussing on producing at maximum capacity throughout the year. Due to increased regulated Russian prices and lower domestic demand post the 2009 economic crisis, in the years since 2012, independent gas producers have won significant market share from Gazprom and now account for around half of all gas sold on the domestic Russian market.<sup>16</sup> This automatically increased Gazprom's spare capacity: by taking the maximum daily production and comparing it to annual production, we estimate that Gazprom's spare capacity in 2016 was 140 bcm.

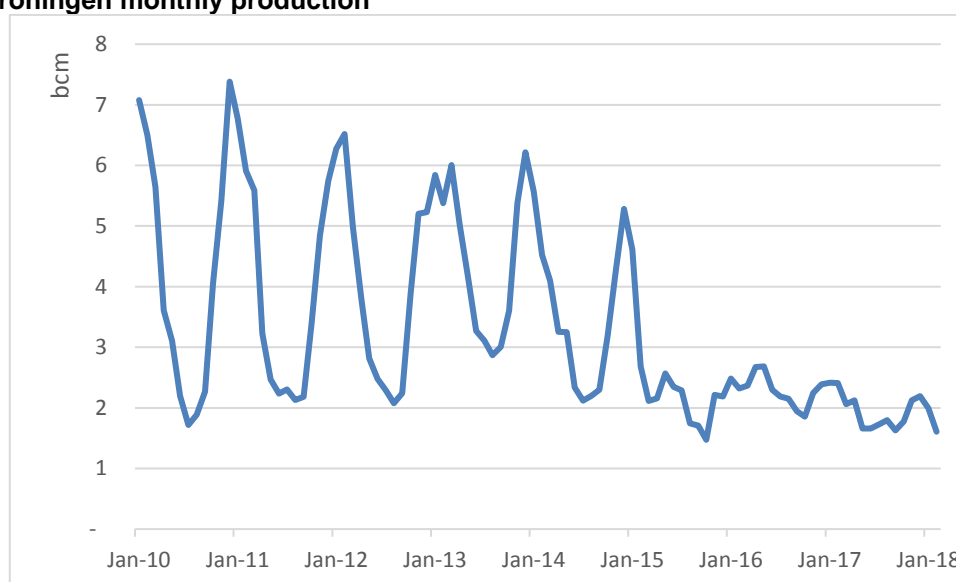
<sup>15</sup> The eighth delivered cargo also went to the US in February.

<sup>16</sup> Please refer to "The SPIMEX Gas Exchange: Russian Gas Trading Possibilities", OIES January 2018 for more detailed information, available at <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/01/The-SPIMEX-Gas-Exchange-Russian-Gas-Trading-Possibilities-NG-126.pdf>. This paper also argues that during the colder winter months most Russian producers have very little spare gas to sell on the exchange.



The most flexible field in Russia is Zapolyarnoye<sup>17</sup>, and it swung from 3 bcm of output in May to full capacity – almost 10 bcm – in December<sup>18</sup>. The only other field that had any spare capacity in Europe was Groningen in the Netherlands and this was used on a very seasonal basis. However, the seasonality of this field has been severely curtailed with the aim of reducing tremors and this has resulted in the Groningen field moving from being a swing producer to having quasi-flat yearly production with no spare capacity. Over the last six years, the previous 20 bcm of Groningen domestic supply seasonality has been provided by foreign suppliers (mainly Russia) and gas from storage. In addition to quota reductions at Groningen, the nearby Norg facility, with its 5 bcm L-cal storage capacity, needs to be watched to see if NAM can increase its capacity or if local population will try to withhold capacity here also.

**Figure 2: Groningen monthly production**



Source: NAM

The national oil companies of Algeria and Iran hold spare capacity in oil but do not hold any spare gas capacity. Faced with a lack of recent investments, supply has not kept up with increased domestic demand and foreign buyers have had to face gas curtailment in past winters<sup>19</sup>.

As for LNG, due to the high capex needed for liquefaction trains, producers are trying to achieve a high load factor<sup>20</sup>, hence why we have not yet had any spare liquefaction capacity.

Returning to Russia, Gazprom boosted its production in 2017, producing in excess of 470 bcm<sup>21</sup>, a 12 per cent increase compared to 2016. In absolute terms, this represented an increase of over 50 bcm from 2016 levels, leading to a theoretical spare production capacity of 90 bcm<sup>22</sup> (140 bcm in 2016 – 50 bcm = 90 bcm, based on Russian standards or 83 bcm using EU standards). This spare production capacity covers not only

<sup>17</sup> It is also the largest field by production capacity.

<sup>18</sup> "From Russia with loads of cheap gas", Natural Gas World – July 2017

<sup>19</sup> Turkey often faces gas shortages from Iran and in 2016/2017, Southern Europe suffered a shortfall of Algerian gas.

<sup>20</sup> The 2016 load factor was 78 per cent according to GIIGNL (264 mt was exported in 2016 compared to a 340 mtpa total nameplate liquefaction capacity)

<sup>21</sup> Russian standards bcm in <http://www.gazprom.com/press/news/miller-journal/2017/731937/> and 471 bcm in Gazprom Investor Day slide 19.

<sup>22</sup> This is also in line with Gazprom's maximum daily production level in 2017: 1.535 bcm



the European market (where demand was 429 bcm for the EU-28) but the total Europe and Eurasian market<sup>23</sup>, of around 1,030 bcm. This equates to 8 per cent spare capacity on a yearly average<sup>24</sup>. Given LNG reloads in Europe for the US, this spare capacity is in fact the only capacity available at a worldwide level, leading to a spare capacity of a mere 2.3 per cent<sup>25</sup>. In short, Gazprom is the only producer with any spare gas production capacity. The percentage of annual spare capacity in the gas market is strikingly similar to that which exists in the oil markets where there is 2 mb/d of global spare oil production capacity<sup>26</sup>, against consumption levels of 97 mb/d (2.1 per cent). By way of comparison, in his book 'Crude Volatility: The History and Future of Boom-Bust Oil Prices', Robert McNally mentions that just before the Achnacarry agreement in 1928 to restrain oil production growth, spare capacity was 37 per cent<sup>27</sup>. This illustrates how little spare capacity there is today compared to historically much higher numbers.

In the past, spare oil production capacity was carefully monitored as an indicator of the market's ability to respond to possible crises that had the potential to impact on oil supplies. From 2003 through to 2008, OPEC's total spare capacity remained below 2.5 md/d, which provided very little cushion for fluctuations in supply in the context of rapidly rising demand and decade long supply investment cycle. This metric is now no longer as relevant as shale oil has drastically reduced the timing of investment in supply from decades to months. On the other hand, the investment cycle in gas at a regional level can also be measured in months if we focus only on North America thanks to the development of shale gas but if we look at global spare gas capacity, we are once more looking at a longer lead time of years rather than months, because it is linked to giant conventional gas fields or liquefaction trains. This raises the question of whether the level of spare capacity in gas production could become more relevant than that of oil for global markets in the future.

All students know that low spare capacity limits OPEC's ability to respond to demand and price increases, while high spare capacity indicates a withholding of production presumably for price management purposes. The best paper on the advantage of holding spare capacity for Saudi Arabia (in oil) and Gazprom (in gas) is "Gazprom and the complexity of the EU gas market: A strategy to define",<sup>28</sup> where the authors conclude that those companies can successfully play on price uncertainty to their own advantage. The report states, 'Thanks to several comparative advantages, primarily the size of its reserves, the proximity of its current markets, its spare capacity, (...) Gazprom is in a position to deploy strategy designed to create uncertainty about the price of natural gas'.

### Low spare capacity is already creating volatility in key markets

With virtually no spare production capacity during the coldest months in the Northern Hemisphere and a mere 2.3 per cent of spare capacity worldwide, gas markets (which are becoming more interconnected) could also face increased volatility, as evidenced in January 2018 in the US North East area. The intensely cold weather event in early January resulted in record levels of US gas demand and record wholesale gas prices. To avoid a repeat of the 2014 price spike, the US could have invested in extra storage (as the industry was designed at a time of conventional production). But the price spike was so short-lived that this investment made no economic sense. It was a local problem and a local solution was found (higher prices in the region). The January 2018 cold bomb cyclone was similarly a local problem but this time, as markets are more interconnected, the solution was both local (higher prices) and global (rerouting of LNG cargos).

The following comment provided in 'Reflection on the Baumgarten Gas Explosion: Markets are Working'<sup>29</sup> turned out to be true only a day after publication. 'For US power, a record level of petroleum products was then needed to avoid electricity blackouts. High prices incentivized demand switching where it was still

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<sup>23</sup> 2016 data taken from the BP Statistical Review 2017

<sup>24</sup> And we can assume that there is virtually no spare capacity during the coldest three months of the year.

<sup>25</sup> As FY2017 worldwide demand is not yet available, we have assumed a 1.6 per cent growth from 2016. The exact percentage will be available in June 2018 after the publication of the BP Statistical Review.

<sup>26</sup> <https://www.eia.gov/finance/markets/crudeoil/supply-opec.php>

<sup>27</sup> After enormous investment, global shut-in production amounted to 60 per cent of production going into consumption (p. 87).

<sup>28</sup> By S. Boussena and C. Locatelli available at <https://hal.archives-ouvertes.fr/hal-01618494>

<sup>29</sup> <https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/01/Reflection-on-the-Baumgarten-Gas-Explosion-Comment.pdf>





possible in power generation. So, with the continued retirement of coal-fired plants, and the growing interdependency between gas and electricity in the US, the next Polar Vortex could prove to be more problematic: the past-embedded flexibility in power generation cannot be relied upon in the future.<sup>30</sup> So, with less flexibility<sup>30</sup> and more integrated markets, a shortfall could have a global impact. This time<sup>31</sup> European storage was able to mitigate the unexpected record demand in the US. The question going forward is for the industry to understand market signals to avoid both over-investment and delayed investment that entails the usual boom and bust commodity cycle. Another period where prices remain too high for too long could fast-track the move away from gas in favour of renewables that are getting cheaper (but remain intermittent).

Again, the cold spell in the UK, which led to an all-time record high NBP price (450 p/th on 2 March 2018), shows that with increased gas demand since 2014, continued lower EU production, and the closure of the Rough storage facility, the UK system now lacks the flexibility to cope with unexpected events. UK industrial consumers are also not willing to reduce their gas demand despite high prices in the market: investment in new supply and/or the creation of a degree of slack in the system must be made soon to avoid further peaks. Additionally, the UK has another major uncertainty which needs to be addressed first: what will the “broader energy framework”<sup>32</sup> look like after Brexit?

### Gas spare capacity needs to be carefully monitored

Back in 2011, higher wholesale gas prices post-Fukushima were witnessed both in Japan (to attract extra LNG) and in Europe. But at that time Gazprom’s spare capacity was high (around 140 bcm in Russian standards or 130 bcm in European standards) and the company’s strategy was to enjoy higher prices to maximise profits at the expense of slightly lower export volumes. So how much spare capacity is needed? As the January 2018 example shows it is not only production capacity but also storage that need to be looked into. Also, the Yamal LNG start up came at a perfect time just before gas demand recorded new higher levels in the US and the UK. Had this plant not come on-line, even higher world prices would have been needed to balance supply and demand.

While shale oil allows the US to be a price setter and respond to global price changes in months compared with years for all other conventional oil producers, this is not the case for US shale gas. Gas markets are still regional and only LNG has the ability to link them. This means that the lead time for global gas spare capacity evolution must still be measured in years and not months, as it takes years for new conventional pipe gas projects and liquefaction plants to move from FID to production. With Chinese gas demand booming again (causing LNG prices to spike), European demand also on the rise since 2014 and worldwide nuclear on a decommissioning trend<sup>33</sup>, how is gas spare capacity going to be affected in the coming years?

### What level of spare capacity should we expect by 2021e?

With very few FIDs<sup>34</sup> taken in 2017, it is interesting to see how the spare capacity could evolve in the period up to 2021e. We decided to try to improve on the analysis of oil ex-post spare capacity by estimating ex-ante future spare capacity in gas. We therefore need to compare expected gas demand growth with all major projects (LNG and pipe gas) that are under construction (FID taken but still not on-line). We focus only on major projects (more than 1 bcm/y capacity) and to simplify matters, neither the natural decline at existing fields nor enhanced gas recovery have been accounted for, except in the Netherlands and the UK (see later). The idea is to calculate what level of spare capacity we can expect in 2021e under different demand scenarios in order to see if we are likely to witness another boom and bust cycle. We also didn’t look into

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<sup>30</sup> Power markets are becoming more reliant on gas following the retirement of electricity generators using fuels other than gas.

<sup>31</sup> In 2014, the Everett regas terminal received 15 cargos under long term agreements and no extra short-term cargoes were needed <https://www.energy.gov/sites/prod/files/2015/11/f27/LNG%202014%20rev2.pdf>

<sup>32</sup> An idea mentioned by Prime Minister Theresa May in her 2 March speech

<sup>33</sup> According to Nuclear Monitor, instead of the 19 expected start-ups in 2017, there were only 4 start-ups and these were outnumbered by 5 permanent shut-downs (as a result, new nuclear capacity of 3.3 GW in 2017 was outweighed by lost capacity of 4.6 GW, a net loss of 1.3 GW). Article available at <http://energypost.eu/nuclear-power-in-crisis-welcome-to-the-era-of-nuclear-decommissioning/>

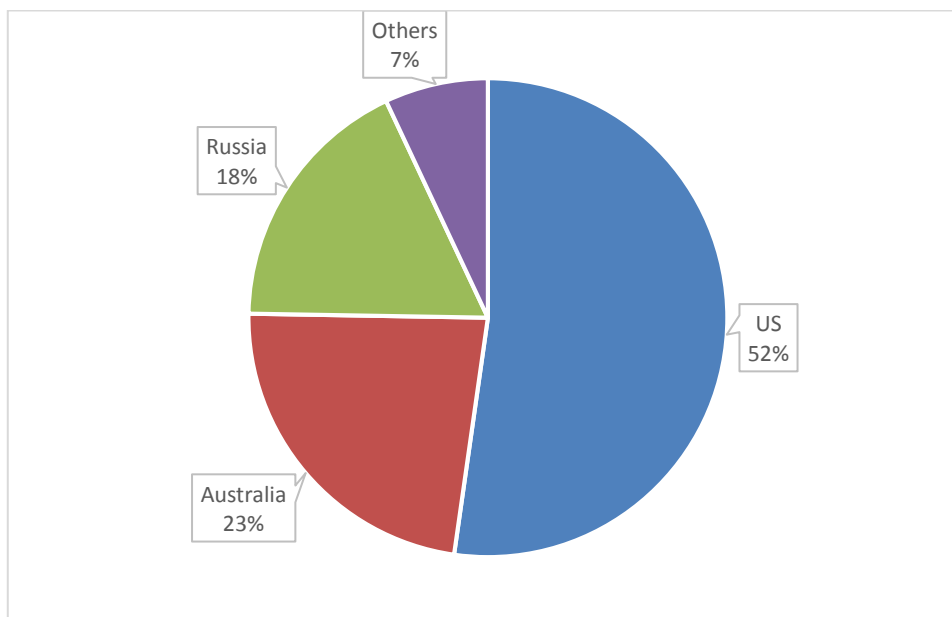
<sup>34</sup> Only Coral FLNG for LNG projects that will not be in production by 2021e.

any contractual agreements as we are more focused on the global supply-demand balance than on the specific dedicated supply per customer.

### New LNG capacity

For LNG the exercise is quite simple. Of the three projects still in construction in Australia, only Wheatstone started operations in Q417. For simplicity we then take the combined Wheatstone, Ichthys, and Prelude liquefaction capacity (21.4 mtpa) as still to come on the market in our 2018-2021 timeframe. We use the same reasoning for Yamal (16.5 mtpa) which started in December 2017. For the US, we have Dominion Cove Point (5.3 mtpa), Freeport (13.8 mtpa), Cameron (13.5 mtpa), Elba Island (2.5 mtpa), Corpus Christy (9 mtpa) and Sabine Pass (4.5 mtpa for train 5). We then have to add Tangguh train 3 in Indonesia (3.8 mtpa) and floating liquefaction in Malaysia (1.5 mtpa) and Cameroon (1.2 mtpa). We do not take into account Woodfibre as the 2016 FID seems to be postponed or Coral FLNG in Mozambique (3.4 mtpa)<sup>35</sup> as both ENI and ExxonMobil have assumed 2022 as the start up. As for Qatar's new projects, they have not received any FID and will not be ready by then. Finally, in Papua New Guinea, even though PNG LNG is consistently operating above its nameplate capacity<sup>36</sup> we have not taken into account any extension as no FID has yet been taken<sup>37</sup>.

**Figure 3: LNG capacity expansion 2018-2021**



Source: thierrybros.com

### New pipe gas capacity

As the gas market is becoming more global, we have then to add major upstream investments for pipe gas. We haven't taken into account any pipeline projects in LNG producing countries such as the US, Australia, Trinidad and Tobago and Peru. In North America and Australia, LNG export growth (analyzed above) will represent the balance between supply and demand changes. Juniper (6.1 bcm/y) in Trinidad and Tobago which started production in August 2017 and is flagged for LNG<sup>38</sup> (10.5 mt produced in 2016 versus 15.3

<sup>35</sup> In its 2018 Analysts Meeting ExxonMobil assumes 2022 as the start-up of Coral FLNG.

<sup>36</sup> On the official company site <https://pnglng.com/> production of 7.9 mtpa is mentioned versus a GIIGNL 6.9 mtpa nameplate capacity. In its 2018 Analysts Meeting, ExxonMobil disclosed an 8.3 mtpa effective capacity.

<sup>37</sup> Three trains totaling 8 mtpa for \$13bn according to [http://www.oilsearch.com/data/assets/pdf\\_file/0020/17507/Oil-Search-Limited-2017-full-year-results-release-200218.pdf](http://www.oilsearch.com/data/assets/pdf_file/0020/17507/Oil-Search-Limited-2017-full-year-results-release-200218.pdf)

<sup>38</sup> <https://www.bp.com/en/global/corporate/investors/upstream-major-projects/major-projects-2017/juniper-trinidad-and-tobago.html>



mtpa capacity) and Sagari (2 bcm/y)<sup>39</sup> in Peru that started production in December 2017 to mainly feed Peru's LNG plant (4 mt produced in 2016 versus a 4.5 mtpa capacity) are not accounted for as these fields are only to mitigate poor load liquefaction plant.

Jangkrik<sup>40</sup> in Indonesia (6.2 bcm/y) which started in May 2017 supplies the local domestic market as well as the LNG export market. As 2.4 mtpa is already dedicated for LNG, we accounted for 2 bcm/y.

In Oman, on top of Rabab, Khazzan which started up last September has ramped up to 10 bcm/y, and is expected to increase to 15 bcm/y in the second phase of development allowing incremental LNG exports of 1.5 mtpa from Oman's LNG plants that are operating at the average load factor, showing again the interconnections between pipe gas and LNG. We therefore decided to account for 10 bcm/y of capacity for Oman.

Finally, projects such as Shell's Gbaran-Ubie Phase 2 in Nigeria that started production in August 2017 are not taken into account as the stated aim of that plant is, 'to ensure continued gas supply to the Nigeria LNG plant and a power plant at Gbarain'<sup>41</sup>; showing again the interconnection between upstream production and LNG plants. We have included Chevron's Sonam Field Development designed to supply 2 bcm/y to the domestic market which started production in H2 2017 and Shell Nigeria's Southern Swamp (1 bcm/y<sup>42</sup> out of the 40 kboed). State producer Nigerian National Petroleum Corporation (NNPC) has other upstream gas projects<sup>43</sup> that it says can be put into production by 2020 (amounting to around 30 bcm/y) as the country looks for a greater emphasis on gas. Unfortunately, with no FID in place and given the poor Nigerian track record for delivering on projects, we have not taken this potential production into account.

Gazprom's spare capacity is concentrated in the Bovanenkovskoye field which produced 82.8 bcm in 2017 but which has a planned capacity of 115 bcm/y (therefore spare capacity of around 32 bcm/y). Additionally, Achimov deposits produced 3.9 bcm in 2017 and are expected to produce 40 bcm/y long term. Gazprom's official presentation to analysts estimates production of 20 bcm in 2021e for Achimov (+16 bcm/y compared to 2017 levels). So Western customers can expect an additional 48 bcm/y (Russian standards or 45 bcm/y by European standards) from Gazprom. Far East investments have also been carried out to fill the 38 bcm/y Power of Siberia pipeline from 2019. But as the surge in production is going to last six years, we have used Gazprom estimated capacity for 2021<sup>44</sup> (13.8 bcm Russia or 12.8 bcm/y by European standards). Gazprom's strategy is to be flexible in production but it will not, as it did on the eve of the 2009 energy crisis, make massive investments in new fields. As Gazprom was the only holder of spare capacity in 2017, those 2018-2021 increased capacity levels will have to be added to our 2017 spare capacity (83 bcm).

Other major<sup>45</sup> upstream investments for pipe gas include the Zohr field in Egypt (initially 28 bcm/y, increased to 29 bcm/y following an announcement by ENI's CEO in February 2018), the Atoll Phase 1 (3.5 bcm/y in production since December 2017), the West Nile Delta, Giza/Fayoum (11 bcm/y) and West Delta Deep Marine (WDDM) 9B (3.6 bcm/y). Additionally, we have included the South Pars Phase 19 in Iran (20 bcm/y) and the Shah Deniz 2 (16 bcm/y) and Absheron Phase 1 (1.5 bcm/y) in Azerbaijan. There are some doubts, even if Shah Deniz 2 should begin flows to Turkey in mid-2018, about Azerbaijan's ability to meet both its

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<sup>39</sup> <https://www.repsol.energy/en/press-room/press-releases/2017/12/27/repsol-begins-gas-production-from-the-sagari-field-in-peru.cshhtml>

<sup>40</sup> <https://www.neptuneenergy.com/en/activities/partner-operated-fields-in-production/jangkrik-id>

<sup>41</sup> <https://www.shell.com/about-us/major-projects/nigeria-liquefied-natural-gas-supply-projects.html>

<sup>42</sup> <https://www.shell.com/about-us/major-projects/southern-swamp-associated-gas-solutions-project.html>

<sup>43</sup> NGW 9 March 2018 [https://www.naturalgasworld.com/nnpc-points-to-gas-supply-projects-59506?utm\\_medium=email&utm\\_campaign=Daily%20Natural%20Gas%20World%20-%20Latest%20News&utm\\_content=Daily%20Natural%20Gas%20World%20-%20Latest%20News+CID\\_123a335996aac8efa328155036131c0c&utm\\_source=Campaign%20Monitor&utm\\_term=Premium%20Nigeria%20Unveils%20Gas%20Field%20Projects%20But%20Funding%20is%20Unclear](https://www.naturalgasworld.com/nnpc-points-to-gas-supply-projects-59506?utm_medium=email&utm_campaign=Daily%20Natural%20Gas%20World%20-%20Latest%20News&utm_content=Daily%20Natural%20Gas%20World%20-%20Latest%20News+CID_123a335996aac8efa328155036131c0c&utm_source=Campaign%20Monitor&utm_term=Premium%20Nigeria%20Unveils%20Gas%20Field%20Projects%20But%20Funding%20is%20Unclear)

<sup>44</sup> Provided during the February 2018 Gazprom Investor Day

<sup>45</sup> CRD Red Emperor (0.6 bcm/y from 2019e) in Vietnam is under our 1 bcm/y limit.

growing domestic demand and its international obligations. But in our exercise, this doesn't matter as long as the estimated new capacity is put on line between now and 2021e.

In Israel<sup>46</sup>, the Leviathan offshore field obtained an FID<sup>47</sup> in February 2017 with an expected 12 bcm/y for phase 1 from 2020e. For Algeria, we have included Reggane (2.9 bcm/y<sup>48</sup>) which started production in December 2017<sup>49</sup>, the much-delayed Timimoun<sup>50</sup> (1.8 bcm/y) field which started in February 2018, and Touat (4.5 bcm/y) where first gas is planned<sup>51</sup> for the second half of 2018 (even if some of this overall capacity could end up improving liquefaction load factors). For China and India, we added Changbei II tight gas (8.9 bcm/y) and the KGD6 R-series (c. 5 bcm/y).

### Scrutiny of company reports for the IOCs enable us to fine tune our analysis

- In its FY2017 presentation, **Shell** provides an extensive list of oil and gas projects with FID<sup>52</sup>, but separating out gas production is problematic.
- For **BP** we used their FY 2017 presentation<sup>53</sup> which highlights only the gas projects in operation and construction, and not those still at the appraisal/design stage.
- **ExxonMobil's** strategy is primarily geared to oil (deepwater drilling in Guyana, Brazil, Romania, and West Africa and unconventional production in the US), and then to LNG (PNG extensions and onshore Mozambique). However, as no FIDs have been taken on those liquefaction plants we cannot include them in our 2021e outlook even if ExxonMobil is using those capacities for its 2025 outlook<sup>54</sup>. ExxonMobil/XTO is planning to cut its US unconventional gas production at the expense of oil<sup>55</sup> in order to improve profitability. We used additional information from the investment program disclosed in the 2017 Investor Information Pack<sup>56</sup> and removed Natuna in Indonesia following the company's decision not to pursue the project<sup>57</sup> and Ca Voi Xanh in Vietnam as it is still in the exploration stages.
- **ConocoPhillips** in its Analyst and Investor Meeting in February, revealed that it is aiming towards a flat production case for the period 2018-2020<sup>58</sup> with growth only focused in the US (something we discounted as we focused on LNG plants in this part of the world, as explained earlier).

In Brazil, most of the growth is now coming from oil projects<sup>59</sup> hence why there is no increase in gas supply in our analysis for this country. We also decided not to take into account the incremental shale gas production

<sup>46</sup> We didn't take into account the FID taken on 22 March 2018 by Energean to develop Karish & Tanin (8 bcm/y) even if the contracted delivery date is Q1 2021 as it won't be fully operational in 2021

<sup>47</sup> <http://investors.nblenergy.com/releasedetail.cfm?ReleaseID=1014140>

<sup>48</sup> <https://www.repsol.energy/en/press-room/press-releases/2012/02/14/repsol-to-develop-reggane-north-gas-fields-in-algeria.chtml>

<sup>49</sup> Slide 7 of FY 2017 presentation

<sup>50</sup> We fully accounted Timimoun even if its gas will be exported via pipeline or LNG from Arzew.

<sup>51</sup> <https://www.neptuneenergy.com/en/activities/development-projects/touat-dz>

<sup>52</sup> Slide 33 [https://www.shell.com/investors/financial-reporting/quarterly-results/2017/q4-2017/\\_jcr\\_content/par/textimage\\_400875472.stream/1517492670313/19ed9f2d131d659401fcdafa4678c0d10fefeade7bf80f5fdf573e05f3dd0893/q4-2017-shell-results-webcast-slides.pdf](https://www.shell.com/investors/financial-reporting/quarterly-results/2017/q4-2017/_jcr_content/par/textimage_400875472.stream/1517492670313/19ed9f2d131d659401fcdafa4678c0d10fefeade7bf80f5fdf573e05f3dd0893/q4-2017-shell-results-webcast-slides.pdf)

<sup>53</sup> <https://www.bp.com/content/dam/bp/en/corporate/pdf/investors/bp-fourth-quarter-2017-results-presentation-slides-and-script.pdf>

<sup>54</sup> Slide 33 of the 2018 Analysts Meeting – ExxonMobil expects 13 mtpa from onshore Mozambique LNG from 2024.

<sup>55</sup> Slide 32 of the 2018 Analysts Meeting.

<sup>56</sup> Slide 37 of the 2018 Analysts Meeting

<sup>57</sup> <https://www.reuters.com/article/us-indonesia-gas-exxon-mobil/exxonmobil-says-will-drop-discussions-over-indonesias-east-natuna-gas-field-idUSKBN1A30JB>

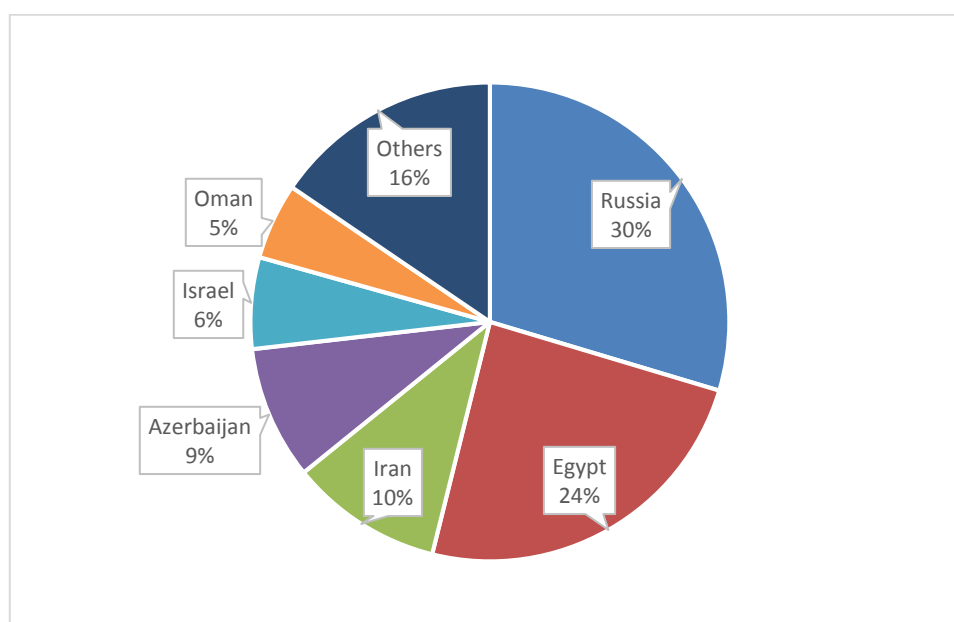
<sup>58</sup> Slides 25, 26, 27 and 28 in <https://static.conocophillips.com/files/resources/investor-update-feb2018-final.pdf>

<sup>59</sup> Slide 15 Petrobras 2018-2022 Business and Management Plan <http://www.petrobras.com.br/en/about-us/strategy/business-and-management-plan/>



in Argentina<sup>60</sup> where YPF hopes to increase overall gas production<sup>61</sup> despite failing to do so over the last two years. We have no Norwegian projects as the Norwegian Petroleum Directorate<sup>62</sup> is forecasting stable production in the country over the medium-term. Norway will continue to swing pipe exports to Europe to provide quasi-storage. We have also discounted any (political) declarations which are not financially backed, as is the case for Nigeria.

**Figure 4: Pipe gas capacity expansion 2018–2021**



Source: thierrybros.com

On a capacity basis, LNG makes up 39 per cent of the total for major FID projects that are planned to provide extra capacity between now and 2021e. This is in line with the fact that LNG should increase its current 10 per cent market share in gas supply<sup>63</sup> as its optionality is preferred by the industry compared to the inflexible pipe business. Both Shell and ExxonMobil are using the Wood Mackenzie view of a 4 per cent CAGR for LNG demand growth vs a 2 per cent CAGR for gas in general.

Globally, on a country-by-country basis, investment concentrated in Russia, the US, and Egypt accounts for nearly two-thirds of the total capacity expansion. It is also interesting to see that the US, even with Trump's plan for energy 'dominance', comes only second after Russia.

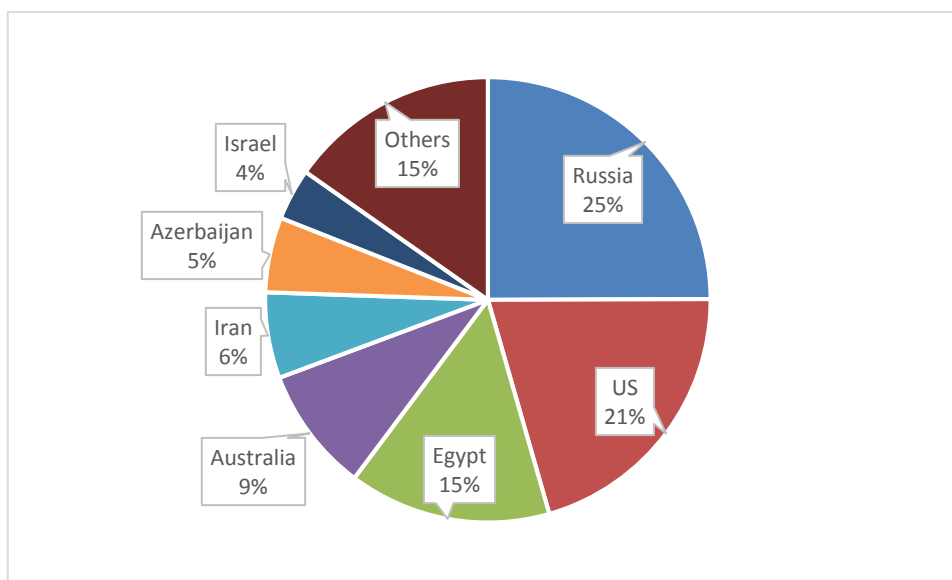
<sup>60</sup> Vaca Muerta is already in production and Argentinean gas could start to re-fill existing pipelines to Chile and Brazil from this year, at least during times of seasonal low domestic demand. But for Vaca Muerta to achieve its full 50 bcm/y potential, an estimated \$70bn is needed which has so far not been allocated. Hence why we have again assumed that the actual non-conventional growth in the country will only curb declining mature conventional production.

<sup>61</sup> 25 per cent between 2017 and 2022 as disclosed in slide 24 of the October 2017 investor day presentation: <http://www.ypf.com/english/investors/Lists/Presentaciones/YPF-Investors-Day.pdf>

<sup>62</sup> "The forecast for short- term gas sales shows that a stable high level with a minor increase over the next five years is expected", NPD January 2018 available at <http://www.npd.no/en/news/News/2018/The-Shelf-2017/1-Increasing-oil-and-gas-production-for-the-next-five-year-period/>

<sup>63</sup> BP Statistical Review 2017

**Figure 5: New total capacity to come online before 2021**



Source: thierrybros.com

For the UK, we used the Oil and Gas Authority's average scenario<sup>64</sup> which forecasts a drop in production of 7.1 bcm between 2017 and 2021e, and therefore haven't taken into account the different fields disclosed in industry presentations.

For Groningen, we have assumed that by 2021e, the Dutch energy regulator's (State Supervision of Mines) recommendation to significantly cut the production quota to 12 bcm/y will have been implemented as the government must prioritize security concerns of its citizens over the need to make money.

### Project lead times mean no supply upside by 2021e

Shell's realized gas price in Europe in the Q4 2017 surged to \$5.56/MBtu, its highest for two years, according to the company's Q4 earnings report. This could perhaps trigger new FID but as mentioned previously, this will not add any supply until after 2022e.

It is worth underlining the fact that the development of the Zohr field in Egypt is the quickest major gas projects ever to get to market. It was discovered by Eni in August 2015 and, following a fast-track development, it went into production in December 2017, two years and four months after discovery. Is this a new trend or an exception to the rule that major conventional gas projects take at least a decade between appraisal and first gas? In the same area of the East Mediterranean, neither Israel, Greece nor Cyprus have managed to do anything within the same time frame. This means that at best all new FID projects could be operational by the end of our timeframe as any new major conventional upstream or liquefaction plants not in construction now will not be operational by then. In short, we do not expect any upside on the supply side by 2021e.

Once Zohr reaches its full capacity, the Egyptian Damietta LNG plant (5.5 mtpa, which was stopped in 2013) and the Idku LNG plant (7.2 mtpa with limited amounts of exports since 2016 after a full closure in 2015) should come back from 2020e, showing the interlinking between LNG and upstream projects. This is why we have accounted for Zohr capacity in our analysis but not for the actual stranded LNG plants.

<sup>64</sup> <https://www.ogauthority.co.uk/media/3391/oga-production-projections-february-2017.pdf>

Finally, some of the gas projects in Asia to be sanctioned in the coming years will feed into the regional LNG plants, and allow them to maintain their commitments under long-term gas sales agreements. Again, this will not improve global spare capacity.

### Regulation/policy could further reduce expected extra supply

The potential supply disruptions at Groningen have already been documented. It is also worth looking at how another major area of supply could potentially be impacted by policy issues, specifically the recent imposition of gas export restrictions in Australia. In 2017, the Australian federal government announced a major new policy for gas security which requires gas producers to guarantee the availability of gas supplies during periods of peak electricity demand. The purpose of this 5-year Australian Domestic Gas Security Mechanism (ADGSM) is to ensure a secure supply of gas to meet the needs of Australian consumers, including households and industry, by requiring, if necessary, LNG exporters who are drawing gas in net terms from the domestic market to limit their exports or find offsetting sources of gas. The idea is to relax the domestic market (and hence reduce prices) and discourage exporters from buying from the traded market in direct competition with domestic consumers. The ADGSM creates two powers for the Minister: firstly, discretionary power to determine when a year will be a domestic shortfall year; and secondly, the power to grant permission to LNG exporters to export LNG in a domestic shortfall year.

As a result of the ADGSM, it is now highly probable that the Santos Gladstone LNG will never produce<sup>65</sup> at its nameplate capacity but see a poor load factor (around 5.5 mtpa or 70 per cent versus an industry average of 78 per cent, coupled with binding LNG sales agreements with Petronas and Kogas for 7 mtpa in aggregate) for the foreseeable future. Gladstone LNG could end up as a perfect example of what can go wrong: an increase in capex of more than 15 per cent between FID and final construction; a load factor way below competitors due to the use of harder to produce coal seam gas, and an unexpected government intervention.

This is why we have used the 2016 worldwide liquefaction load factor for all the LNG capacity coming on-line in 2018-2021e and not nameplate capacity. Therefore, instead of a global LNG nameplate capacity of 126 bcm/y, we have used 99 bcm/y. For pipe gas we have used the disclosed nameplate capacity. Using this method, we estimate that net extra supply between 2017 and 2021e amounts to 274 bcm.

### What about demand?

To avoid being over-optimistic, as the consensus was with the “LNG glut” that so far has not materialized, it is important to compare these major new supply projects with expected demand growth. To do this we could try to answer questions such as how fast will continental power generators switch away from coal, or how sustainable is China’s growth? Alternatively, we could assume a worldwide demand growth rate for 2018-2021<sup>66</sup>. According to the BP Statistical Review, gas demand grew by 1.5 per cent in 2016 versus 2015 (2016 was a leap year) but we expect economic activity to pick up in the next few years, hence our decision to take 1.6 per cent as a minimum<sup>67</sup> level. In this base case, total worldwide demand is expected to grow by 297 bcm between now and 2021e. This number is needed to calculate the world-wide percentage level of the spare capacity but not for our spare capacity in bcm as we have not taken the full supply growth. We need to exclude North America, Australia, Trinidad and Tobago, and Peru from the equation (as local demand in these countries will be met by incremental local projects). We then end up with an expected demand growth of 210 bcm for the world outside North America, Australia, Trinidad and Tobago and Peru.

<sup>65</sup> In 2017, GLNG produced 5.2 mtpa according to Santos’ Q4 Activities Report [https://www.santos.com/media/4302/2017\\_fourth\\_quarter\\_activities\\_report\\_final.pdf](https://www.santos.com/media/4302/2017_fourth_quarter_activities_report_final.pdf)

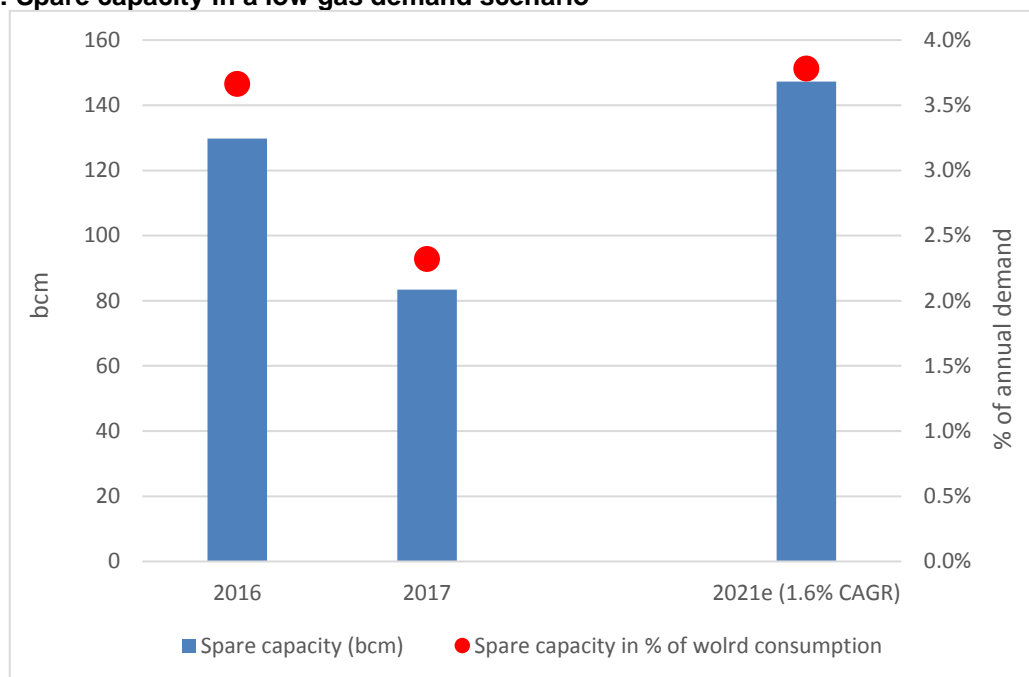
<sup>66</sup> Gazprom, the world leader in gas production, is taking 1.5 per cent CAGR for the period until 2035 (as disclosed in slide 7 of the 2018 Gazprom Investor Day in February 2018).

<sup>67</sup> In 2015-2016 China’s gas demand growth was half the average for the decade CAGR but picked up in 2017. First estimates from IEA are even for a global gas demand growth of 3 per cent in 2017 vs 2016.

## Conclusion

Our calculations show that worldwide net spare capacity will reach 147 bcm by 2021e, representing 3.8 per cent of total demand (274 bcm new capacity minus 210 bcm additional demand in this specific area, added to existing spare capacity in 2017) in our minimum demand growth scenario.

**Figure 6: Spare capacity in a low gas demand scenario**



Source: thierrybros.com

As this looks higher than in 2016, we could conclude that 2017 was a tight year but that the medium-term future looks better. But these numbers are subject to some major unknowns. Spare capacity could be reduced in the following cases:

- Ukraine transit – We have assumed transit via Ukraine to continue but if Gazprom is successful in terminating the transit contract<sup>68</sup> and unsuccessful in building Nord Stream 2, that would result in around 50 bcm/y of spare capacity in Russia which could not be transported to the EU. This would bring effective spare capacity down by a commensurate 50 bcm/y, leading to very little growth in volume from the tight 2017 data (97 bcm or 2.5 per cent of demand).
- Demand estimates – If we take the Shell's<sup>69</sup> 2 per cent pa growth instead of our 1.6 per cent pa, then spare capacity shrinks back to 92 bcm (2.3 per cent of total demand). Given the 2006-2016 CAGR at 2.2 per cent, 2 per cent pa growth for the coming years does not look impossible.
  - China – The Chinese authorities have estimated gas demand to continue to grow by 8.5 per cent in 2018e versus 2017 (the same level of growth as in 2016-2017), way above the 7.7 per cent recorded in 2015-2016 but way below the 15 per cent CAGR for the 2005-2015 period. This shows the huge unknowns we face in a country that should soon become the third biggest gas consumer (after the US and EU and ahead of Russia).

<sup>68</sup> As disclosed on Gazprom's twitter account on 2 March 2018

<sup>69</sup> Shell 2018 LNG outlook disclosed on 26 February 2018.





- Coal to gas switching could reduce spare capacity – with an increase in EU ETS prices, coal switching could be fast tracked in Europe, which would reduce the overall flexibility of the system even further.
- Time to market could reduce spare capacity – We stick to what companies have disclosed as far as completion of projects is concerned, but the likelihood of slippage can be high as seen historically both in LNG and in pipe projects.
- Capacity – We have used 78 per cent and 100 per cent respectively for LNG and pipe gas. The LNG number could improve following the recent information disclosed by ENI CEO about the Zohr facility but could equally prove too high.

Or, conversely, supply could be improved in the following cases:

- China – To date, technical and water resource challenges, outdated equipment, inexperienced workers, complex geology, regulatory hurdles, transportation constraints, and competition with other fuels and conventional gas have all contributed to slowing the development of China's unconventional gas resources. Any technological breakthrough could boost the development of unconventional gas in China and this would then become a manufacturing process that Chinese industries master very well, although this seems very unlikely this side of 2021.

It should be acknowledged that this broad brush approach doesn't address some major unknowns, such as:

- Turkmenistan supply – It is always difficult to find reliable figures on Turkmenistan's gas industry<sup>70</sup>, although we know it exported 31 bcm in 2016<sup>71</sup>. The 4<sup>th</sup> (D) line (30 bcm/y) has been postponed and the lines A, B and C to China are not flowing at capacity (55 bcm/y)<sup>72</sup>. It could be possible that China will revert to boosting Turkmen upstream if it fails both to produce its own unconventional resources or fails to attract LNG. But with Turkmen already responsible for 40 per cent of total Chinese imports, it looks like China is now looking to diversify its gas of supply rather than importing additional Turkmen gas<sup>73</sup>.
- This yearly analysis doesn't take into account either seasonality or renewable intermittency.

Our analysis suggests that spare capacity could have been adequate from 2016 to 2021 in the low demand growth scenario, but could be tight from 2017 onwards with high demand growth.

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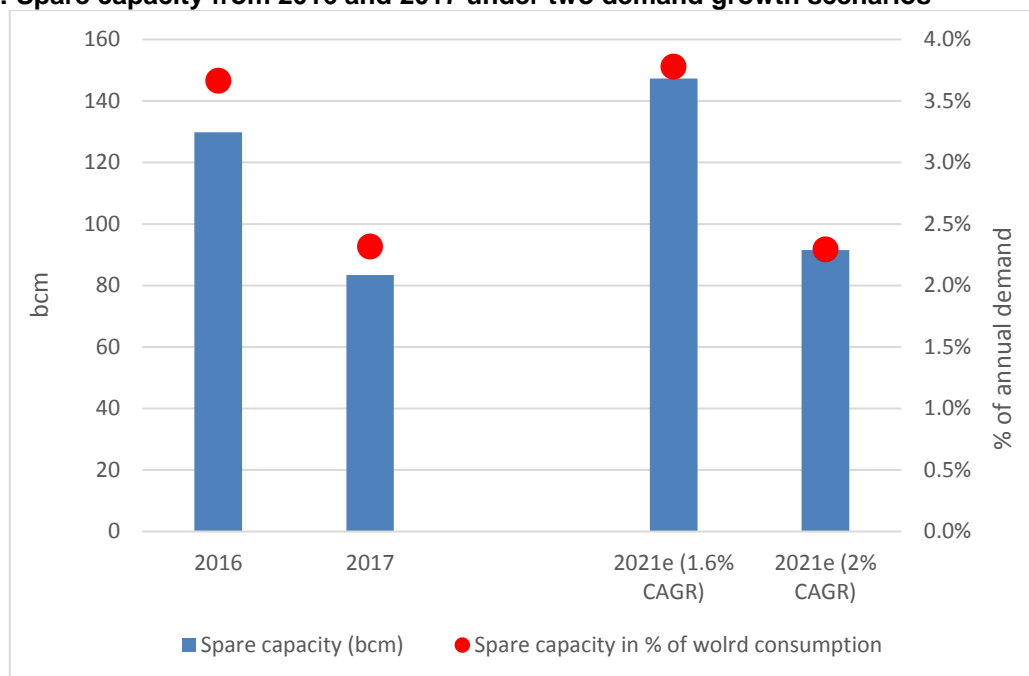
<sup>70</sup> Turkmenistan doesn't report on JODI gas database

<sup>71</sup> BP Statistical Review 2017 – Exports to China and Kazakhstan (up 2 bcm from 2016)

<sup>72</sup> [http://www.cnpc.com.cn/en/pipelineandstoragetank/column\\_content.shtml](http://www.cnpc.com.cn/en/pipelineandstoragetank/column_content.shtml)

<sup>73</sup> For the period Dec 2016-Nov 2017, looking at Chinese data on JODI, pipeline imports increased by 2 bcm, showing that China focused more on LNG than pipe in 2017 (+45 per cent).

**Figure 7: Spare capacity from 2016 and 2017 under two demand growth scenarios**



Source: thierrybros.com

This graph sums up the challenges for the gas industry. Back in 2016, when gas demand growth was low (1.5 per cent per annum) the industry could expect enough spare capacity to be available until 2021e and hence there was no need for new FIDs. On top of that, the future expected cap of Groningen production was not as small as it is now. Today, we have already experienced a tight market (in China in winter, in the US in January 2018, and in the UK in February 2018) and our simple analysis shows that it could stay tight until 2021e. The high supply growth that the consensus expects in 2018-2020 could further delay new FIDs leading to another boom and bust cycle as the industry will then not have enough time to put on-line the extra supply that is needed post 2021e.

With LNG now linking all regional gas markets, the concept of spare capacity that has previously been used in the oil market before the US shale revolution should now be used by the gas industry, where the lead time to build major projects (upstream for LNG and pipe) is still measured in years. According to our research, global spare capacity reached a record low level in 2017 due to a rebound in demand (in China and in the EU at least), the cap on Groningen production and record Russian exports. This number should slightly increase in the coming years due to major developments that were launched prior to the drop in oil and gas prices (2015). But our simple ex-ante analysis shows that if we slightly increase demand from our low base case to the Shell base case, then spare capacity could further contract in 2021e. Therefore, the industry should not be complacent. FIDs should be taken soon if we want to avoid the usual boom and bust cycle. Such an upward cycle<sup>74</sup> could be a major blow to gas demand as it will fast track consumers' willingness to move away from fossil fuels produced in far-away countries towards local renewables. If China wants to increase the share of gas in its energy mix and if the EU wants to continue to grow gas demand, then those customers must also be ready to engage with producers to foster new FIDs in gas producing areas. As for ExxonMobil, in its 7 March presentation, management recognised that LNG contracting "is not changing as fast as people are anticipating": traditional contracts are still needed both on the consumers' side and on the producers' side alongside newer hybrid models to underpin new FID. "LNG is a market in transition and that

<sup>74</sup> If this happens, it would then impact all markets except Russia and North America.

transition period could take multiple decades". So, who will be brave enough in this uncertain world to take the next first new major project FID to provide a buffer post 2021e?

Since 2017, gas has overtaken coal to become the primary source of electricity output in OECD countries<sup>75</sup>, so gas security of supply is becoming ever more important as a supply crunch will be detrimental for both gas and electricity demand.

The last few years have seen impressive gas discoveries (Mozambique, Tanzania, East Med, and Senegal to name but a few). In a world where growing demand will not allow spare production capacity to rebound to a level able to mitigate any unforeseen supply disruptions, the news flow to watch in 2018 should be companies' willingness to FID new gas projects. But with banks still mostly stuck in the old world (where oil indexation and 20-year terms contracts with credit worthy customers are needed) where could new forms of financing come from for those major new projects? The industry will need to solve this investment problem to satisfy growing demand; with the short-term problem being to start getting FIDs for some projects. The problem is that collectively there should be, as demonstrated, an interest in enabling new projects but no-one wants to be the first-mover and create more supply which their competitors would benefit from. Both metrics (spare capacity on an annual basis and the more seasonal LNG tightness (USGC FOB LNG – HH)) should help to monitor the effective tightness of the global gas market.

We leave you with a final point to consider. With LNG demand growing, the storage business will be impacted as we've already seen this winter. Europe, which is currently long on storage,<sup>76</sup> should focus on this to find an alternative solution to the one being pursued today, namely closing down storage. LNG supply cannot provide any swing capacity at liquefaction plants but can provide it at the regas level (more ships berthing during winter) and more importantly, the more LNG carriers the more LNG on the water that can be considered as storage. Again, an old oil concept that could become important for gas traders.

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<sup>75</sup> Shell LNG outlook 2018 – slide 10

<sup>76</sup> If we focus the analysis on Europe only. As described in this paper if Europe provides the storage service for the all Northern Hemisphere then storage capacity could even be viewed as too low.