Introduction

The European gas market has been volatile since August 2021, with dramatic price spikes in October and December 2021. In January and February 2022, prices were still twice the pre-2021 record when the Russian invasion of Ukraine on 24 February triggered a third spike at the beginning of March 2022. Summer 2022 saw a decline in Russian pipeline gas supplies to Europe between June and August, and a corresponding increase in prices to their late-August peak. Thereafter, prices fell until 31 October, but have since risen again. In short, prices remain both high and volatile, reflecting a tight market with significant uncertainties over both supply and demand in the coming weeks and months.

This edition of the Quarterly Gas Review focuses particularly on supply-side dynamics in Europe in recent months, including the decline in Russian pipeline supply, the rise in European LNG imports and sendout, and the record net storage injections. This is complemented by an analysis of the global LNG market, with a particular emphasis on the supply available to Europe, and a review of European gas demand in recent months. These form the basis for a scenario for the European gas market for the period December 2022 to March 2023 (‘winter’) and April to October 2023 (‘summer’). This scenario works backwards from the target of having European gas storage stocks at 99 Bcm by 1 November 2023 (as on 1 November 2022). Given the assumptions regarding European production, pipeline imports, LNG imports, and demand, we estimated how much gas could be injected into storage in summer 2023 and, by extension, how much needs to be left in storage at the end of winter 2022/23 to render those summer 2023 injections sufficient to meet the 1 November storage target. The balancing element in this scenario is therefore European gas demand between 1 December 2022 and 1 April 2023. We estimate that European demand in this period needs to be roughly 5 per cent lower than in the same period in winter 2021/22, and 10 per cent lower than the average for 1 December to 1 April for the five winters between 2017/18 and 2021/22.

While European gas demand in January-November 2022 is approximately 14 per cent lower year-on-year, and recent months showed much greater year-on-year declines in demand, the variability of gas demand for power generation (as a balancing element relative to renewables and nuclear) and weather-dependent gas demand for space heating means that a 5-10 per cent reduction in winter gas demand relative to recent years is by no means assured. Furthermore, any reduction on the supply side would imply a greater target for demand reduction. The dynamics of the coming months will have significant implications for European winter storage stocks – and market sentiment – ahead of winter 2023/24.

If you would like to discuss any of these issues further then please contact Mike Fulwood (mike.fulwood@oxfordenergy.org), Jack Sharples (jack.sharples@oxfordenergy.org), or Anouk Honore (anouk.honore@oxfordenergy.org).
1. Price analysis

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

1.1 European prices

Gas prices in 2022 have remained elevated on the back of the Russian invasion of Ukraine and the gradual reduction in pipe imports into Europe from Russia. Prices had already been rising in 2021 due to a tightening market as the world recovered from COVID-19 and supplies were increasingly constrained. As Russia invaded Ukraine prices shot up immediately. They then came back down as flows from Russia continued at high levels. In mid-June as flows along Nord Stream began to fall, prices gradually began to increase, peaking at the end of August as Nord Stream was finally closed completely. Prices then began a gradual decline as LNG imports into Europe continued at very high levels and storage filled up. With Russian flows now at very low levels, the risk premium of these flows disappearing is much lower and is reflected in the declining prices. Prices began to rise again in November as the weather finally began to get cold and withdrawals from storage stepped up.

Figure 1.1: European prices

The other story has been around the differentials in the prices, with NBP and the LNG NWE prices being at a discount to TTF since the beginning of April. The discount opened up between NBP and TTF as the UK imported large quantities of LNG and effectively re-exported volumes down the Interconnector and BBL, at full capacity. The gap, which has now narrowed with the prospect of reduced flows from the UK as the weather gets colder, is a classic symptom of congested infrastructure. There has been a similar gap between TTF and the LNG NWE price assessment with the three northwest European terminals at Dunkerque, Zeebrugge and Gate, operating at full capacity, in fact above nameplate capacity. The discount is likely to remain until the new German terminals come onstream.
1.2 Carbon prices and inter-fuel competition in Europe

Figure 1.2 compares TTF prices with the coal and carbon prices. The coal price (ARA – Amsterdam, Rotterdam, and Antwerp) is adjusted for the relative efficiency of gas power plants to coal power plants and the relatively higher carbon costs of coal.

**Figure 1.2: TTF gas and Rotterdam coal prices (adjusted for carbon price) and ETS prices**

![Graph showing TTF gas and Rotterdam coal prices (adjusted for carbon price) and ETS prices.](source)

Source: Argus Media, ICE. Forward curve at 9 December 2022

Note: ETS refers to the EU Emissions Trading System (ETS) price of carbon credits, in US$ per tonne.

In early 2019, as TTF prices declined, we saw them fall well below the adjusted coal price, and this continued in 2020 as the impact of COVID-19 put significant downward pressure on prices. As a result, there was significant coal to gas switching in 2019 and in 2020 even some lignite to gas switching in Germany. The sharp rise in TTF prices in early 2021 might have been expected to lead to a significant loss of competitiveness of gas relative to coal. However, coal prices also rose sharply, although by less than the TTF price, but the EU ETS price also rose to provide a further boost to the carbon-adjusted coal price. Gas, therefore, maintained its competitive position, providing some support to gas demand in Europe through the middle of 2021.

The rise in prices since August 2021, however, pushed gas prices well above the adjusted coal price, encouraging a switch to coal. The invasion of Ukraine pushed gas prices a lot higher, but coal prices have also risen dramatically as well. However, gas prices are so high that there is still a large incentive to switch to coal in those markets where it is possible. Coal burn has certainly increased in Europe, but gas demand in power generation has not fallen as expected because of issues with nuclear plants, especially in France, and poorer renewables performance. Since April 2022 there has been a significant differential between the TTF price and the adjusted coal price and this will continue into 2023. This is likely to maintain the level of coal-fired power generation in 2023 and gas demand could suffer if nuclear and renewables recover.

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2. European gas market dynamics

2.1. European production and non-Russian pipeline imports

European supply in 2022 has been influenced by three main factors: the decline in Russian pipeline supply, the rise in European LNG imports and sendout, and the increase in net storage injections. Those key factors are discussed in detail in subsequent sub-sections of the quarterly review. For now, it is sufficient to note that in the period January-November (compared to January-November 2021), pipeline supply from Russia declined by 70.4 Bcm, LNG imports rose by 52.5 Bcm, and net storage injections increased by 48.5 Bcm, year-on-year. Taken together, these three factors reduced supply to the European market by 66.3 Bcm (15.5 per cent) year-on-year.

Elsewhere, European gas production in the same period has been almost completely flat, rising by just 151 MMcm year-on-year. The more notable developments have been in pipeline supplies from non-Russian sources, where the combined year-on-year increase in Norwegian and Azeri supplies more than offset the year-on-year decline in supplies from North Africa, leading to a net increase of 5.5 Bcm in non-Russian pipeline supply in the year to date.

Figure 2.1.1: Daily pipeline flows to Europe (MMcm/d)

![Graph of daily pipeline flows to Europe (MMcm/d)](image)

Source: Data from ENTSOG Transparency Platform. ¹ Graph by the author

Specifically, pipeline supply from Norway in January-November increased by 6.55 Bcm year-on-year while pipeline supply from Azerbaijan increased by 2.85 Bcm, and supply from North Africa fell by 3.9 Bcm. As the graph above illustrates, supplies from Azerbaijan have been the most stable, with only a minor dip in August during maintenance works on the Trans-Adriatic Pipeline (TAP). With TAP operating at full capacity, there is no scope for a meaningful increase in supply from that source in the near future.

Pipeline supply from North Africa – delivered from Algeria to Spain via the Medgaz pipeline, from Algeria to Italy via the Transmed pipeline, and from Libya to Italy via the Greenstream pipeline – has been somewhat more volatile. The latest data suggests that in the period January-August, Algerian gas production fell by 2.7 Bcm year-on-year, with exports (pipeline and LNG combined) falling by 1.8 Bcm and domestic consumption falling by 0.7 Bcm. The decline in exports was split between a 0.4 Bcm decline in LNG exports and a 1.4 Bcm decline in pipeline exports.

Given the prevailing high prices throughout 2022, this would seem to suggest a strain on Algeria’s ability to produce enough gas to export. However, it should be noted that Algerian gas production in January-

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August 2022 was 6.1 Bcm (10 per cent) above the average for January-August in 2017-2021, while exports were 4.2 Bcm (14 per cent) higher and domestic supply was 1.9 Bcm (7 per cent) higher.\(^2\)

The Medgaz pipeline has a capacity of 30 MMcm/d and the Transmed pipeline has a capacity of 105 MMcm/d, although Algeria’s pipeline exports on these two routes combined in 2022 were rarely above 100 MMcm/d until they peaked at 113-114 MMcm/d for several days at the end of November. Libya’s pipeline exports remain limited to less than 10 MMcm/d. As the colder weather made itself felt from mid-November onwards, Algerian supplies to Spain via Medgaz remained constrained by pipeline capacity, Libyan supplies to Italy remained at 10 MMcm/d, but Algerian supply to Italy via Transmed rose to 80 MMcm/d by 14 December, raising total North African pipeline exports to 116 MMcm/d on that date. Whether those North African supplies will continue at that level throughout winter remains to be seen.

Finally, Norwegian pipeline supplies to Europe dipped in Q3-2022, due to maintenance conducted during September. However, the most significant part of that decline was in flows to the UK (via the Langeled pipeline), while supplies to continental Europe remained closer to non-maintenance levels.

Between September 2021 and November 2022, the monthly average flows to Dornum (60-66 MMcm/d), Emden (82-88 MMcm/d), and Zeebrugge (41-44 MMcm/d) remained within relatively narrow boundaries, with slightly more variation in flows to Dunkerque (44-53 MMcm/d). By contrast, the monthly average flows to Easington (UK) via Langeled ranged between 42 MMcm/d and 75 MMcm/d in all but one month in that period, dropping as low as 22 MMcm/d in September 2022.

For comparison, the capacity of Norway’s export pipelines to Belgium, France, and Germany/Netherlands is around 250 MMcm/d. The connections to Germany/Netherlands at Dornum and Emden have a combined capacity of around 150 MMcm/d, while the connections to France at Dunkerque and to Belgium at Zeebrugge have capacities of 55 MMcm/d and 45 MMcm/d, respectively. To the UK, Norway has 76 MMcm/d of pipeline capacity via the Langeled pipeline. The capacity for Norwegian flows to St Fergus is unclear, as it shares capacity with UK continental shelf production that is also brought ashore at St Fergus. In addition, the Baltic Pipe – a spur from the Europipe II (which terminates at Dornum) to Poland via Denmark – entered full operation on 30 November. That pipeline has a capacity of 10 Bcm/a (27.4 MMcm/d).\(^3\)

The addition of the Baltic Pipe does not mean that significantly more Norwegian gas will flow to Europe in the coming winter. Rather, it seems that the Norwegian production system cannot offer significantly more than 350 MMcm/d. For example, while flows on the Baltic Pipe rose to 17 MMcm/d on 2 December, and flows via Langeled, Zeebrugge, and Emden reached full capacity at the same time, flows via Dunkerque and Dornum remain lower than capacity, and Gassco (operator of the Norwegian offshore pipeline system) reported total system exit nominations of 335 MMcm/d on 2 December.\(^4\)

Overall, in Q3 2022, maintenance resulted in decreases in flows from Azerbaijan in August and from Norway in September, while flows from North Africa dipped between mid-October and mid-November. However, by mid-December, supply from all three sources appeared relatively robust, peaking at a combined 489 MMcm/d on 12 December, with only limited scope for further increases in supply.

2.2. Russian pipeline gas supplies to Europe

The previous edition of the OIES Quarterly Gas Review referred to the decline in flows of Russian pipeline gas to the European market\(^5\) as a ‘major development in the second quarter of 2022’. If anything, these dynamics were even more dramatic at the start of the third quarter, when the flow of

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\(^5\) EU plus UK and non-EU Balkans, but excluding Turkey

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gas via the Nord Stream pipeline halted entirely. This brought the total daily flow of Russian pipeline gas to Europe (excluding Turkey) to a range of 50-85 MMcm/d between September and November 2022. This is significantly lower than the range of 261-403 MMcm/d experienced in the same period in 2021, and far below the pre-COVID range of 445-559 MMcm/d of Russian pipeline supply delivered to Europe in the same period in 2019.

Figure 2.2.1: Daily Russian pipeline flows to Europe (MMcm/d)

The previous edition of the OIES Quarterly Review noted the flow via Nord Stream had fallen to just 33 MMcm/d by the end of July, as a result of turbines being taken offline at the Portovaya compressor station, at the Russian end of Nord Stream. On 19 August, Gazprom announced that the final turbine in operation at Portovaya would be shut down for maintenance for three days between 31 August and 2 September, and that the capacity of Nord Stream would be reduced to zero during this period. This provoked concern that once the total shutdown of flows via Nord Stream had begun, those flows may not restart. These concerns proved to be well-founded.

On the evening of 2 September, Gazprom announced the discovery of oil leaks at Portovaya, and that the compressor station would be shut down completely until the leak had been repaired. Then, on 27 September, explosions damaged both Nord Stream 1 and Nord Stream 2. The investigation into what caused the explosions remains ongoing, but in any case, it is reasonable to assume that Nord Stream 1 will not return to operation in the foreseeable future.

Elsewhere, Russian flows to north-western Europe via the Yamal-Europe pipeline remain at zero and are also unlikely to return, given that the final halt in flows (which had been declining since mid-2021 in any case) was caused by Russian sanctions against the operator of the pipeline on Polish territory, EuRoPol Gaz. Those sanctions – which prevent Gazprom from using the pipeline – are unlikely to be lifted in the foreseeable future.

The third quarter of 2022 also saw the final Russian pipeline flows to the Baltic region. Direct flows to Finland had already halted in May, following Gasum’s refusal to pay for its long-term contract supplies in rubles, rather than euros. There were no long-term contracts for supply to Estonia or Lithuania. On 29 September, the Estonian government announced that a ban on the purchase or import of Russian gas would come into effect on 31 December 2022. Given that Estonia ceased imports of any Russian gas in April 2022, this ban simply confirms that Russian gas will not return to the Estonian market.

Source: Data from ENTSOG Transparency Platform. Graph by the author.


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In Latvia, Latvijas Gāze has a long-term contract with Gazprom that is valid until 2030. However, the supply halted on 30 July, with Gazprom announcing the suspension of supplies for an unspecified ‘violation of conditions’. This may be related to the formal announcement on 28 July, by the Latvian President, of the entry into force of amendments to the country’s Energy Law, which will prohibit the import of gas from Russia from 1 January 2023.\(^8\) \(^9\)

**Figure 2.2.2: Daily Russian pipeline flows to Europe by route in 2022 (MMcm/d)**

![Daily Russian pipeline flows to Europe by route in 2022](image)

Source: Data from ENTSOG Transparency Platform.\(^10\) Graph by the author

These developments in Q3-2022 mean that Russian pipeline gas is currently flowing to Europe only via Ukraine and via the Turkish Stream pipeline. At present, Russian gas transited via Ukraine exits the Ukrainian system only on the border with Slovakia, at Uzhgorod/Velké Kapušany. The Russian gas delivered via Turkish Stream enters the market of south-eastern Europe at Strandzha-2, on the Turkey-Bulgaria border.

The recent reduction in Gazprom’s supplies to Moldova and the dispute with Moldovagaz have generated concern for the stability of Russian gas transit via Ukraine. Gazprom currently supplies gas to state-owned Moldovagaz under a five year-contract that entered into force on 1 November 2021. The import volume is more than 3 Bcm/a, split between the separatist region of Trans-Dniester (2.1 Bcm/a) and the rest of Moldova (1.2 Bcm/a).\(^11\) When the new contract was signed, it was acknowledged that the questions of Moldova’s debts for supplies previously received remained to be negotiated. On 1 October, Gazprom announced that it would deliver only 5.7 MMcm/d to Moldova, instead of the 8.1 MMcm/d nominated by Moldovagaz, and that Gazprom reserved the right to suspend supplies at any time, pending the solution of the debt question. Crucially, Gazprom blamed the ‘blockage of transit via Ukraine’ for its inability to provide the full volume to Moldova.\(^12\)

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The dispute intensified on 22 November, when Gazprom announced that it had received partial payment from Moldovagaz, but accused Ukraine of taking gas intended for Moldova. As a result, the volume crossing the Ukraine-Moldova border was less than the volume entering Ukraine intended for delivery for Moldova. Gazprom then threatened to begin reducing flows into Ukraine on 28 November in proportion to those volumes it believed to be ‘missing’ in Ukraine.

Both the Ukrainian and Moldovan governments reacted by accusing Gazprom of ‘energy blackmail’. From their perspective, Moldovagaz was simply using ‘backhaul’ (‘virtual reverse’) to move volumes back to Ukraine, for injection into Ukraine’s large seasonal gas storage. The tensions eased on 28 November, when Gazprom announced that Moldovagaz had paid for its supplies, including those ‘lost’ in Ukraine, and that Gazprom would therefore not reduce supplies. However, Gazprom reiterated that it reserved the right ‘to reduce or completely suspend gas supplies in case of failure to make payments for them’. Given that Russian gas now flows into Ukraine via a single interconnection point (Sudzha), any reduction in supplies at this point (even if intended for delivery to Moldova) will surely raise concerns for those in central Europe that receive their Russian gas via Ukraine.

Looking ahead to the coming winter, the reasons for the decline in Russian pipeline flows to Europe via the various routes all suggest that those flows will not resume in the foreseeable future. This decline has contributed decisively to the tightness in the European gas market, and will be felt in the coming six months. Between 1 December 2021 and 31 May 2022, Russian pipeline flows to Europe averaged 295 MMcm/d. Between 1 December 2022 and 31 May 2023, Europe is likely to receive less than one-third of that volume from Russia. This will make it more challenging to meet winter demand in Q1 2023 and begin the task of replenishing storage stocks in Q2 2023, with Europe relying on a combination of continued high levels of LNG imports and curbs on European gas demand.

2.3. LNG supplies to Europe

The loss of Russian pipeline gas supplies to Europe between April and September 2022 necessitated a substantial increase in LNG imports. This increase in LNG supply to Europe had begun in Q4-2021, attracted by high prices, and the growth continued to a peak in April 2022, when Europe imported more than 10 million tonnes of LNG in a single month for the first time. A new record was again set in November, with 10.63 mt of LNG imports. If Turkey is included, November 2022 was also the first time wider Europe had imported more than 12 mt in a single month.

In the year to date (January-November), the greatest proportional year-on-year growth in LNG imports occurred in north-western Europe (+129 per cent) and the UK (+70 per cent). However, growth in other regions, including north-eastern Europe (+47 per cent), the Mediterranean region (+55 per cent), and Iberia (+34 per cent) was also significant. In the year to date, those increased imports have been facilitated by increases in global LNG supply and the utilization of previously unused capacity at import terminals.

This led to a situation in which the terminals of north-western Europe in particular operated at close to capacity – and sometimes above nameplate capacity – for much of the period since April 2022. At the same time, LNG cargoes arrived in the UK, were regasified and then re-exported to continental Europe via the Interconnector to Belgium and the Bacton-Balgzand Line (BBL) to the Netherlands.

14 The UK has three LNG import terminals (Isle of Grain, South Hook, and Dragon), while the region of north-western Europe includes the terminals at Dunkerque (France), Zeebrugge (Belgium), GATE Rotterdam and Eemshaven (Netherlands)

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As a result, the Interconnector and BBL pipelines, operated close to their combined capacity of 70 MMcm/d for most of the period between April and October, as illustrated in the graph below. It should be noted that the decline in flows from the UK to Belgium in November was due to the pipeline being taken offline for maintenance from 15 to 29 November.

Source: Data from ENTSOG Transparency Platform. Graph by the author
In the year to date (January to November), LNG imports into Europe (EU-27 plus UK) grew by 39.7 mt (65 per cent) year-on-year. Imports from the United States alone grew by 27.6 mt (176 per cent), while imports from other sources grew by 12.1 mt (27 per cent). In that same period, global LNG exports grew by 18.8 mt (5.5 per cent), of which growth in exports from the United States accounted for 8.1 mt. The key point here is that European LNG imports grew faster than global LNG supply, and in particular, European LNG imports from the United States grew faster than total US LNG exports.

**Figure 2.3.3: European LNG imports by source (million tonnes of LNG)**

Source: Data from Kpler LNG Platform (subscription required). Graph by the author

Europe’s ability to source these additional LNG cargoes was contingent upon four factors. Firstly, the absolute decline in Chinese LNG imports (from 71.7 mt in January-November 2021 to 57 mt in January-November 2022 – a decline of 14.7 mt) effectively made additional volumes available to the global LNG market. Secondly, demand in Asian markets (Japan, South Korea, and Taiwan) that would ordinarily compete strongly on price with European buyers was flat year-on-year. Thirdly, LNG imports in more price-sensitive markets (India, Pakistan, and Bangladesh) declined by around 5.3 mt (15 per cent), as LNG cargoes were attracted to the premium European market. Finally, better hydroelectricity performance in Brazil meant that Brazil’s LNG imports fell dramatically by 4.7 mt year-on-year, back to the 2020 level. Taken together, those four factors effectively made an extra 24.7 mt available to the global LNG market. When the 18.8 mt increase in global LNG supply is added to the extra 24.7 mt available, the net increase in global LNG availability was 43.5 mt, which was sufficient to enable a 39.7 mt year-on-year increase in European (EU-27 plus UK) LNG imports.

In terms of European regasification capacity, the first phase of the expansion of the Swinoujscie LNG terminal was completed in January 2022, with the second phase due by the end of 2023, at which point Poland will be able to import an additional 1.8 mt per year. In September 2022, the Eemshaven LNG import facility (comprising two FSRUs) was launched, adding 5.9 mtpa of import capacity and enabling an uptick in Dutch LNG imports. However, the most significant capacity increases are yet to come. Three FSRUs (with capacities of around 3.7 mtpa [5 Bcm] each) are planned for launch in Germany by the start of 2023, and three more by the end of 2023. The similar-sized Exemplar FSRU, currently undergoing winterisation in the Spanish port of Ferrol, is due to begin operations in the Finnish port of Inkoo before the end of December. The other LNG import capacity additions expected in 2023 are the Cape Ann FSRU, planned for operation at Le Havre (France) from September 2023 and the Alexandroupolis FSRU planned for operation from December 2023.

Reflecting on 2022, it seems that Europe benefitted from a relatively benign set of circumstances regarding LNG supply, although high prices had to be paid to attract cargoes from other markets. This
led to a situation of record European LNG imports and regasification capacity being used at its fullest, to the point of bottlenecks emerging in north-western Europe. These bottlenecks caused the price differentials discussed in the first part of this review. Although Europe is on track to add a substantial volume of regasification capacity by the end of 2023, the more pressing question for winter 2022/23 is whether Europe will continue to be able to attract LNG cargoes, as temperatures drop and demand rises across the northern hemisphere. At the time of writing (mid-December), it appears that China’s zero-COVID policy is being dismantled, which could herald a resurgence in Chinese economic activity and, by extension, LNG demand. Likewise, Europe looks set to continue outbidding LNG buyers in many other markets. What remains to be seen, however, is the intensity of competition between Europe and north-east Asia (Japan, South Korea, and Taiwan) for midwinter spot LNG cargoes.

2.4. European gas storage

With volatility in imports and prices throughout summer 2022 a recurrent theme, concerns over supply to the European market in winter 2022/23 prompted a concerted effort to build storage stocks. As early as March 2022, as part of its initial response to the Russian invasion of Ukraine, the European Commission set a draft target for EU gas storage capacity to be 90 per cent filled by 1 October. This target was subsequently relaxed to 80 per cent filled by 1 November.\(^\text{15}\)

In the event, the original, more stringent, target was close to being met, with EU gas storage stocks on 1 October at 92.6 Bcm - 89 per cent of the EU storage capacity of 104 Bcm. By 1 November, stocks were 99.0 Bcm - 94.9 per cent of capacity. The net injection of 6.4 Bcm was a new October record – significantly higher than the previous October record net injection of 4.7 Bcm, achieved in 2018. In the wider scale, the net injection of 71.6 Bcm between 1 April and 1 November was also a new record, 0.1 Bcm greater than the volume injected during the same period in 2018. The net injection between 1 April and 1 November 2022 was 23.5 Bcm (49 per cent) greater than the volume injected in the same period in 2021 (48.1 Bcm).

**Figure 2.4.1: European gas storage stocks (Bcm)**

Source: Data from Gas Infrastructure Europe Aggregated Gas Storage Inventory.\(^\text{16}\)


\(^{16}\) Gas Infrastructure Europe (2022). Aggregated Gas Storage Inventory. [https://agsi.gie.eu/#/]

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Remarkably, the storage injections continued throughout the first half of November, with the first net withdrawal taking place only on 14 November. The initial net withdrawals in the third week of November were slow, and stocks did not fall below the 1 November level until 22 November. Finally, by 30 November, stocks were back to the same level as on 16 October.

This continuation of storage injections during the early part of winter was made possible by relatively robust supply (in the form of production and imports) and, perhaps even more importantly, by temperatures that were unusually mild throughout October and the first half of November. For example, in the UK (where almost 80 per cent of households use gas central heating), the Transmission System Operator, National Grid, publishes its Composite Weather Variable (CWV), which calculates an effective average temperature.\(^{17}\) That CWV was reportedly 9.9 degrees Celsius in 1-14 November 2022, compared to an average of 8.0 degrees Celsius in the same period in 2015-2021.\(^{18}\) Data from National Grid suggest that in the first half of November, Local Distribution Zone (LDZ) gas demand (which includes residential demand and most commercial and industrial demand) was 113.6 million cubic metres per day (MMcm/d). However, as reported by Argus:

‘But had LDZ demand been as responsive to the CWV as in the previous seven years, consumption would have been expected to rise to 130 MMcm/d over the period — 13 per cent, or 16.7 MMcm/d, higher than actual demand during that time. This suggests that households and small businesses are hesitant to switch on their heating and are consuming less than in previous years relative to the weather.

That said, weather-adjusted LDZ demand has been closer to the seven-year average so far in November than in October. Actual consumption of 84.6 MMcm/d in October was 21 per cent — or 22.6 MMcm/d — below what it could have been based on the relationship between demand and the CWV in 2015-21. This suggests that as the weather turns colder, the effects of consumer behaviour changes to conserve gas in response to higher energy bills may be diminished.’\(^{19}\)

Those conclusions — drawn by Argus in mid-November — seem to be holding true at the beginning of December. In the period 1-13 November, total supply (implied consumption) in Europe averaged 1,039 MMcm/d. In 14-27 November, that figure was 1,305 MMcm/d. Finally, with temperatures dropping in the final days of November, total supply between 28 November and 1 December averaged 1,693 MMcm/d. As demand rose, storage withdrawals accelerated accordingly. Net withdrawals between 14-27 November averaged 123 MMcm/d, rising to 446 MMcm/d from 28 November-1 December.

By 1 December, it was possible to state unequivocally that winter had begun, and that storage was now playing a significant role in European supply. On that date, with total supply at 1,702 MMcm, net storage withdrawal provided 28.5 per cent of supply, a similar share to LNG sendout (28.8 per cent) and only slightly below total pipeline imports (31.5 per cent) — all far above European production (11.2 per cent).

Looking ahead, the rate at which storage stocks are drawn down over the course of the coming months has two key implications. Firstly, the more quickly stocks are drawn down, the less remains in storage as a buffer in the event of a late-winter surge in demand. For example, the ‘Beast from the East’ blast of intensely cold weather hit north-western Europe for around 10 days between the end of February and beginning of March 2018. The ability to cope with such a late-winter surge in demand, and the sharpness of price spikes associated with such a surge in demand, will depend on the volume of gas left in storage at the time. Having more gas held in storage towards the end of winter has two important benefits: the market is more reassured that supply remains available and the daily withdrawal capacity of storage facilities is higher, due to higher pressure in those facilities.


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A second key implication of the storage withdrawal rate is that the slower stocks are depleted, the more is likely to remain in storage at the end of winter. In turn, this means that less needs to be injected during summer 2023 to bring stocks by 1 November 2023 back to their 1 November 2022 level. The ability of the European market to facilitate such a stock replenishment in summer 2023 is analysed in the scenario discussed in Section 5 of this review.

2.5. European supply-demand balance
Taking together all the sources of supply discussed above, it is possible to generate a ‘top-down’ picture of European gas demand, by combining European gas production, pipeline and LNG imports, and net storage withdrawals. Logically, of the supply hitting the market, anything not injected into storage must be either consumed or (to a very minor extent) consigned to network losses.

Figure 2.5.1: Total supply to the European market (MMcm/d)

This ‘top-down’ picture suggests that European gas consumption remained lower year-on-year throughout 2022, and that from May 2022 onwards it remained below the range exhibited in 2017-2020. Indeed, the extent to which implied European gas consumption fell below the 2017-2021 average increased during Q3 2022, and peaked in October (2022 demand being 28 per cent below the 2017-2021 average, rising to 26 per cent below the 2017-2021 average in November). Since then, with colder weather since mid-November, this ‘top-down’ implied consumption rose from 1,032 MMcm/d on 13 November to around 1,750 MMcm/d in the first half of December, before peaking an average of 2,004 MMcm/d on 12-14 December - a level typical of cold spells in December in the past five years.

Looking ahead, it seems likely that the figures for implied consumption between December 2022 and March 2023 could rise towards the average for the past five years, although the extent of the convergence will depend upon a combination of supply and demand-side factors.

Dr Jack Sharples, Research Fellow, OIES

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3. How much LNG will be left for Europe in winter 2022/23?

The dramatic decline in Russian pipe imports into Europe left a huge supply deficit to be filled, especially in the second half of 2022. A sharp increase in LNG imports, both directly into the EU and also to the UK (then used as a land bridge to re-export to the EU), went a long way to filling the gap. For 2022 as a whole, Europe is likely to import some 164 Bcm of LNG, up over 60 Bcm on 2021. While global LNG supply increased during 2022, Europe attracted significant volumes of LNG away from Asia and South America, benefitting from the fact that China’s gas demand in 2022 was very weak and LNG imports fell sharply.

In the last quarter of 2022, Europe is likely to have imported around 45 Bcm of LNG, some 15 Bcm higher than Q4 in 2021. The mild weather, until recently, and the high levels of gas in storage have enabled European gas markets to get by with vastly reduced flows of gas from Russia.

2023, however, may be much more challenging in terms of replacing Russian gas by importing more LNG than in 2022. The figure below shows the expected increase in LNG export capacity in 2023 over 2022. While not many new plants are starting up in 2023, the growth is largely due to the ramp up of new plants in that were launched in 2022 and the removal of technical issues that plagued facilities in 2022 – Norway and Freeport LNG in the US being the main contributors.

An increase of 35 Bcm implies an average 3 Bcm per month extra, although in Q1 2023 the extra supply may only be some 2 Bcm a month, of which half is expected to come from Freeport restarting, compared to Q4 2022 (i.e., a quarter-on-quarter increase).

**Figure 3.1: LNG export capacity in 2023**

![LNG export capacity in 2023](image)

Source: NexantECA World Gas Model, OIES estimates

In Q1 2022, Europe imported 43 Bcm, almost as much as in Q4 2022, so increasing supply above last year to offset significantly lower Russian flows may be problematic. European industrial demand is running at much lower levels and storage withdrawals can probably be used to offset any weakness in supply from elsewhere. That, however, would require storage to be refilled in summer 2023, again relying on LNG imports.

China’s demand for LNG had already begun to weaken in Q1 2022, and any recovery in China would only make it harder for Europe to import more – China’s LNG imports in November and December 2022

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are already running at a higher rate (1 Bcm a month) than in Q1 2022. The very high prices, however, are weighing on demand in India and the emerging Asian markets. These are currently running, in total, at around 1 Bcm a month less than in Q1 2022, offsetting the higher volumes imported by China. If Japan, Korea, and Taiwan and other regions run at slightly lower volumes than in Q1 2022 (which they are currently doing), then Europe could increase LNG imports above the Q1 2022 level, attracting the increased supply outlook from the US in particular.

With abundant gas in storage in Europe and the ability to increase LNG imports above Q1 2022 levels, albeit only marginally, the remainder of winter 2022/23 should be able to be navigated reasonably well, even with colder weather. However, that will be because the ‘can has been kicked down the street again’ and the real test will be to refill storage next summer. Even with an anticipated 35 Bcm rise in LNG supply in 2023, Europe is likely to face increasing competition for LNG supply from Asian markets, especially China, and any LNG supply issues will only exacerbate the situation.

Mike Fulwood, Senior Research Fellow, OIES
4. European gas demand

Despite a sharp rise in gas prices in the second half of 2021, European gas demand was relatively resilient last year. By contrast, gas demand collapsed in 2022 and appears\(^{20}\) to have declined by 13 per cent year-on-year over the period from January to November (Figure 4.1) on the back of mild temperatures, high gas prices and changes in consumer behaviour.

**Figure 4.1: Monthly gas demand in EU27 + UK, 2019-2022 (Bcm)**

While the main drivers were similar across Europe, the evolution of gas consumption has been diverse (figure 4.2). Focusing on the six largest gas markets, which represent over 75 per cent of total demand, trends varied between a moderate 1 per cent year-on-year decline in Spain to a sharp 23% year-on-year contraction in the Netherlands over the first 11 months of 2022. These differences can be explained by a number of country-specific factors including the role of gas in the energy mix, access to alternative fuels and the levels, and extent, of the support measures from governments to shield their national consumers from the worst impacts of high energy and gas prices. For instance, a cap on the price of natural gas used for electricity generation was decided in May 2022 in Spain and Portugal. The aim was to lower the wholesale electricity price in the Iberian market (MIBEL) but this measure also triggered additional gas use for electricity generation, which explains why Spanish demand was only down by 1 per cent year-on-year despite sharp declines in gas demand in its industrial and residential sectors.

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\(^{20}\) The paragraphs in this section present a picture of gas demand in Europe (EU27 + UK) provided by a bottom-up approach. This methodology informs on differences by country and by sector, but the main caveat is that gas demand data is often not readily comparable or even available, with weeks or months long time lags and differences in calculations and definitions. Accessing granular data by sectors and sub-sectors is even more problematic. The analysis of gas demand between countries and sectors in this section is based on publicly available data and calculations by the authors to make up for missing data.

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A sector focused analysis shows that most of the demand reduction in Europe was concentrated in the industrial and in the heating sectors in 2022, while gas use for electricity generation went up.

Figure 4.3 highlights the example of industrial gas demand in Germany, a market which represents about half of the total gas volumes used in this sector in Europe. Consumption was down by an impressive 17 per cent year-on-year over the period from January to November, in line with the European average.

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21 Essentially residential and commercial users

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Figure 4.3: Changes in gas demand in the industrial sector in Germany, January to November 2022 vs 2021 (%)

Source: Data from THE. Calculations and graph by the author

Data granularity does not allow an analysis of the evolution of gas demand by sub-sectors. However, looking at the manufacturing industrial production (which typically represents about 90 per cent of the gas use in the industrial sector\(^{22}\)), it appears that Germany has maintained high volumes of manufactured goods production, at least up to October (the last available data from Eurostat as of mid-December) (Figure 4.4). In other words, the remarkable reduction in the country's industrial gas demand does not seem to correlate with the decline in industrial output.

\(^{22}\) Calculated from Eurostat data

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Other national surveys and data seem to show a similar picture at the European level for the industrial sector. There have been some sectors scaling back production and factories shutting down, for instance ammonia producers, but it seems that the main trends have been toward significant fuel switching and efficiency improvements so far.

Unfortunately, it is not yet possible to differentiate between what has been demand reduction (that could bounce back rapidly) and demand destruction (which will not come back). However, it seems likely that most of the decline has come from reduction measures, which means that when gas/electricity prices go down, be it as a result of the market rebalancing or as a result of support measures from governments, a significant proportion of gas demand in the industrial sector could come back rapidly. This is indeed what happened in October when gas prices reached their lowest levels in months and fertilizer producers restarted production in Europe. This is potentially a warning sign for this winter. Governments face the challenge of designing support measures that offer gas and electricity prices that are simultaneously low enough to prevent widespread closures and bankruptcies, and high enough to prevent a rapid increase in demand, which would undermine other policies aimed at reducing gas demand.

The industrial sector has been the main source of gas demand flexibility so far in 2022, and it is expected to continue playing that role to help balance gas supply and demand in Europe. This might be achieved through voluntary reduction and demand response, but cold weather could exacerbate the need for energy rationing in order to divert supply to protected users. This, in turn, would cause widespread disruption to manufacturing production, though exactly which industries would be targeted first remains largely unclear.

Warm weather at the beginning of the year and similarly, at the beginning of the winter season 2022/23, limited the need for gas use in space heating this year. In addition, mild temperatures and continued high gas prices seem to have facilitated an important demand response from small consumers, a usually rather inelastic sector in the short term, in the form of lower production and fuel switching in small businesses and lower energy use in the buildings sector.

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Participation of consumers in demand saving measures in buildings is going to be essential this winter to limit a sudden surge in gas demand during the coldest days (gas is the largest single source of energy used for heating in the residential sector in Europe, Figure 4.6). But there are two main uncertainties: first, there have been concerns that government intervention in subsidizing energy bills and inappropriate (and/or late) campaigns to save energy could send mixed signals and help keep consumption high; and second, that consumers’ willingness to reduce their energy for heating may erode when cold temperatures finally hit Europe. The early days of December, when temperatures across Europe plunged below their 5-year average, seem to confirm the latter with a sharp rise in gas demand for heating in the residential and commercial sectors (though the impact was not, and is never going to be, uniform across Europe due to differences in weather and in the role of gas for space heating). Figure 4.6 shows final energy consumption in households by type of fuel, of which space heating typically represents about two thirds of the energy used.  

Figure 4.6: Final energy consumption in households by type of fuel in 2021 (shares in %)

In contrast to the trends observed in the industrial and heating sectors, gas used for electricity generation has increased year-on-year in 2022. Three main elements influenced the need to use more gas in the power sector (despite aims to reduce consumption): continued high electricity demand in the first eight months of the year, before energy saving measures and economic slowdown finally started to have an impact from September onward (Figure 4.7); and the low availability of both nuclear and hydropower (Figure 4.8).  

Note: Data for Norway and the UK is for 2019
Source: Data from Eurostat. Graph by the author

27 Eurostat data

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French nuclear generation typically covers as much as 15 per cent of European electricity needs. But in 2022, the French utility EDF faced a wave of repairs following the discovery of corrosion issues and delays to its scheduled 10-year maintenance due the COVID pandemic (as well as strikes in France in October). This forced a record number of reactors offline for most of the year and total generation from the French nuclear fleet was 24 per cent down year-on-year over the period from January to November.28 EDF is racing against the clock to put as many reactors as possible back in service this winter, but uncertainties remain as the company has already revised down its predictions for nuclear generation four times this year.

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Despite a strong decline in the first eleven months of 2022, additional gas demand reduction will be needed in Europe to limit risks of shortages this winter. The EU and national governments face a hard balancing act: incentivizing customers to save energy while, at the same time, protecting them (and the economy) from the worst impacts of record-high gas and energy prices.

Key factors to keep an eye on will be the pace of return of French nuclear reactors, the willingness and ability of consumers to continue adapting their usual behavior in order to use less energy (especially during cold days in the winter), and as a consequence, the evolution of temperatures in the next few weeks because a cold winter is likely to derail most demand-response measures, and finally, the depth of a looming economic recession.

Dr Anouk Honoré, Deputy Director & Senior Research Fellow, Gas Research Programme, OIES
5. A scenario for the period 1 December 2022 to 1 November 2023

This scenario is by no means a forecast. It begins from the aim of returning European gas storage stocks to 99 Bcm by 1 November 2023, the same level as on 1 November 2022. From there, working backwards, assumptions are made for supply and demand in summer 2023, to estimate how much gas might be available for net storage injections. The difference between the 99 Bcm target for 1 November 2023 and the volume that might be injected in summer 2023 provides a target for storage stocks on 1 April 2023. The final step in the analysis is to estimate how much supply might be available for Europe between 1 December 2022 and 1 April 2023, with the final ‘balancing element’ being gas consumption between 1 December 2022 and 1 April 2023.

In general terms, the smaller the volume of gas consumed in winter 2022/23, the greater the volume of seasonal storage stocks left on 1 April 2023, and the less that needs to be injected in summer 2023 to hit the storage target on 1 November 2023. Conversely, the more gas is consumed in winter 2022/23, the more storage stocks will be depleted, and the more difficult it will be to replenish storage sufficient to hit the 1 November 2023 target.

The assumptions for supply and demand in summer 2023 are as follows:

- **Consumption** is the same as in summer 2022 (840 MMcm/d = 179.8 Bcm)
- **Production** is the same as in summer 2022 (197 MMcm/d = 42.1 Bcm)
- **Pipeline supply from Norway** is the same as in summer 2022 (322 MMcm/d = 69.0 Bcm)
- **Pipeline supply from North Africa** is the same as in summer 2022 (93 MMcm/d = 19.8 Bcm)
- **Pipeline supply from Azerbaijan** is the same as in summer 2022 (32 MMcm/d = 6.9 Bcm)
- **Pipeline supply from Russia** is the average for September-November 2022 (68 MMcm/d = 14.6 Bcm)
- **LNG sendout** is the same as in summer 2022 (376 MMcm/d = 80.5 Bcm)
- **Total supply from production and imports** is therefore 232.9 Bcm (1,088 MMcm/d)
- This leaves 53.1 Bcm (248 MMcm/d) available for net storage injections
- **This implies** that storage stocks need to be 46 Bcm on 1 April 2023, in order to return stocks to 99 Bcm by 1 November 2023

The assumptions for supply between 1 December 2022 and 1 April 2023 are as follows:

- **Production** is the same as in winter 2022/23 (219 MMcm/d = 26.5 Bcm)
- **Pipeline supply from Norway** is the same as in winter 2022/23 (345 MMcm/d = 41.7 Bcm)
- **Pipeline supply from North Africa** is the same as in winter 2022/23 (93 MMcm/d = 11.2 Bcm)
- **Pipeline supply from Azerbaijan** is the same as September-November 2022 (33 MMcm/d = 4.0 Bcm)
- **Pipeline supply from Russia** is the average for September-November 2022 (68 MMcm/d = 8.2 Bcm)
- **LNG sendout** is the same as in November 2022 (450 MMcm/d = 54.5 Bcm)
- **Total supply from production and imports** is therefore 146.1 Bcm (1,207 MMcm/d)
- **Stocks on 1 December 2022 were 96.6 Bcm**. To leave stocks no lower than 46 Bcm by 1 April 2023 requires a withdrawal of no more than 50.6 Bcm between 1 December 2022 and 1 April 2023
- **If** storage withdrawal of 50.6 Bcm (418 MMcm/d) is added to production and imports, total supply rises to 196.7 Bcm (1,625.6 MMcm/d)

For comparison, actual European total supply (including storage) was:

- **Average for four winters between 2017/18 and 2020/21**: 221.4 Bcm (1,829.8 MMcm/d)
- **Winter 2021/22**: 207.5 Bcm (1,714.9 MMcm/d)

Therefore, by maintaining supply in accordance with the assumptions above and restricting storage withdrawals between 1 December 2022 and 1 April 2023 to 53.1 Bcm, European gas consumption must be 89 per cent of the average for four winters between 2017/18 and 2020/21 and 95 per cent of consumption between 1 December 2021 and 1 April 2022.

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Given the assumptions for supply remain constant, the variations in storage withdrawals (in the period 1 December 2022 to 1 April 2023) and end of winter stocks (on 1 April 2023) caused by demand between 1 December 2022 and 1 April 2023 being various percentages of demand in the same period in 2021/22 are illustrated in the graphs below. To summarise, every 5 per cent reduction in demand in winter 2022/23 relative to 2021/22 could result in 10 Bcm less of storage withdrawal and, therefore, 10 Bcm greater storage stocks remaining at the end of winter.

**Figure 5.1:** Storage withdrawal (Bcm) if demand between 1 Dec 2022 and 1 April 2023 is X% of demand in same period in 2021/22 (X being between 80% and 105%)

Source: Data on supply and demand from ENTSOG Transparency Platform, Eurostat, Kpler (LNG), and Gas Infrastructure Europe (Aggregated Gas Storage Inventory). Calculations and graph by the author

**Figure 5.2:** Total supply to the European market (MMcm/d)

Source: Data on supply and demand from ENTSOG Transparency Platform, Eurostat, Kpler (LNG), and Gas Infrastructure Europe (Aggregated Gas Storage Inventory). Calculations and graph by the author

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Finally, it is worth highlighting the factors least and most likely to differ from the assumptions presented here. Given that European production and pipeline imports from Norway, North Africa, and Azerbaijan are all seemingly close to full capacity, there is little scope for a significant increase in supply from these sources compared to the scenario outlined above. Conversely, the risk that such supplies could fall is based on the risk of unscheduled maintenance on export pipelines.

With most export routes for the supply of Russian pipeline gas to Europe closed, and only transit via Ukraine and Turkish Stream remaining, there also appears little prospect of a substantial increase in Russian pipeline supply. The potential growth in supply via Turkish Stream is likely to be limited to seasonal increase in demand in Hungary and Serbia, while supply via Ukraine could be increased somewhat by higher long-term contract nominations by Gazprom counterparties in central Europe (Slovakia, Austria, Italy, and Slovenia, in particular). On the Ukrainian route, bringing flows from their present level (45 MMcm/d in mid-December) up to the full capacity available under the present Russia-Ukraine transit contract (77 MMcm/d minus 8 MMcm/d for delivery to Moldova, leaving just under 70 MMcm/d) would add 25 MMcm/d to supply. However, this appears unlikely at present, and in any case would still leave total flows from Russia (90 MMcm/d in mid-December) far below their level in December 2021 (360 MMcm/d). Indeed, most of the risk appears to be on the downside, specifically regarding Russian gas transit via Ukraine, given Gazprom’s threats to both Naftogaz Ukraine and TSOUA (the Ukrainian TSO) regarding Naftogaz’s commercial arbitration case against Gazprom and the flow of gas via Ukraine to Moldova, respectively.

By contrast, there remains wide scope for LNG supply to be either smaller or larger than in the scenario outlined above. On the downside, any curtailment to global LNG supply (unplanned maintenance or a fire at a major export plant, as happened at Freeport in the US in June 2022) or a surge in demand outside Europe (either weather-related demand in north-eastern Asia, as happened in January 2021, or a surge in China’s industrial gas demand and, by extension, China’s LNG import demand) would have the effect of curtailing the supply available to Europe.

Conversely, a combination of increased global LNG supply (OIES estimates a 37 Bcm year-on-year increase in supply in 2023, of which 10 Bcm being added by the restart at Freeport) and continued subdued LNG demand outside of Europe (primarily weak LNG demand in China due to higher domestic, LNG importers in developing countries being outbid by European buyers, and flat growth elsewhere) could see more LNG available for Europe. In addition, the LNG regasification capacity increases in the Netherlands, Germany, France, and elsewhere in Europe could facilitate higher import volumes.

The major factor in meeting end-of-winter and summer replenishment storage targets will, of course, be European demand in winter 2022/23 and summer 2023. While temperatures are the major factor in gas demand for space heating, wholesale prices will influence industrial demand not protected by price caps, and the performance of non-gas power generation assets will influence the demand for gas-fired power generation. It is worth noting that monthly ‘top-down’ implied European gas consumption in 2022 as a percentage of consumption in the same month in 2021 declined as winter began: September (87 per cent), October (77 per cent), and November (75 per cent). Whether demand remains so much lower year-on-year remains to be seen, given that Europe has already picked much of the low-hanging fruit, having benefitted from an unusually mild start to winter and industrial gas demand being suppressed by high prices.

To conclude, the scenario presented here is certainly not a forecast. It does, however, set out a path by which Europe can pass through the winter of 2022/23 without depleting its storage stocks to an extent that replenishment back to virtually full capacity by 1 November becomes unrealistic. That path could be dramatically altered by a cold winter, under-performance in non-gas power generation, or curtailments in gas supply. In that regard, the rate of storage stock drawdown may be considered a gauge, or meter, of Europe’s progress during winter 2022/23. The better that progress, the better prepared Europe will be for winter 2023/24.

Dr Jack Sharples, Research Fellow, Gas Research Programme, OIES

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