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Key themes for the global energy economy in 2022

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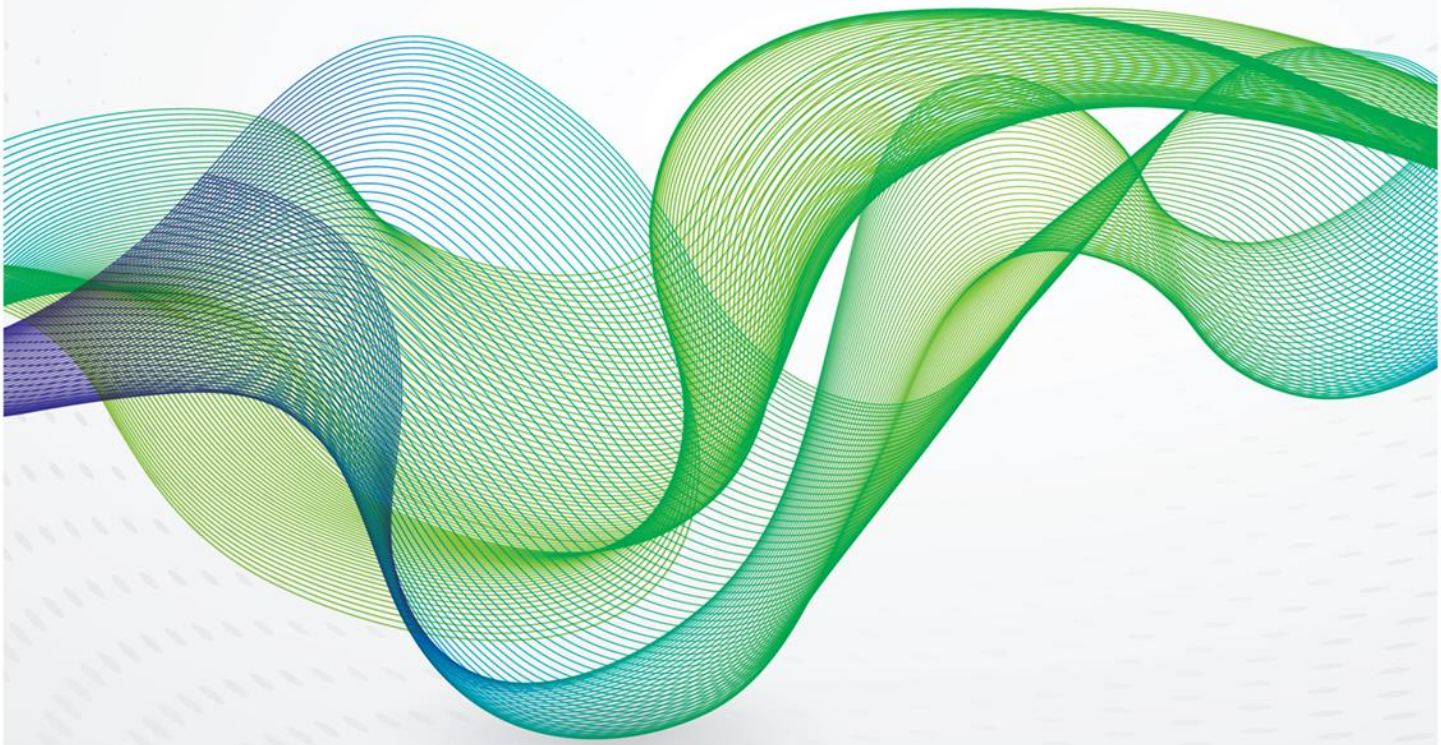
THE OXFORD INSTITUTE FOR ENERGY STUDIES

January 2022

Key Themes for the Global Energy Economy in 2022



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Contents

Figures ii
Introduction 1
1. The outlook for oil markets 4
2. The UK government's response to electricity price volatility 7
3. Outlook for gas prices and supply to Europe 10
4. LNG FIDs in 2022 – outlook and implications 12
5. Gazprom's export strategy and the Electronic Sales Platform 14
6. Nord Stream 2: a roadmap for 2022 16
7. The Road to COP27 – key milestones and objectives 19
8. The need to update NDCs in 2022 21
9. Will the Global Methane Pledge achieve critical mass in 2022? 23
10. US-China relations: a COP-ing mechanism for 2022 25
11. Prospects for hydrogen projects in 2022 27
12. UK Carbon Capture and Storage – third time lucky? 29
13. From `Carbon-Neutral' to `Greenhouse Gas Verified' LNG cargos in 2022 31
14. COP26 'Article 6' rulebook tees up continued expansion of voluntary carbon markets 33
15. Road to net zero: New oil assessments for 2022 36
16. EU regulatory themes for 2022 38
17. The future of nuclear in Europe: Critical decisions in 2022 40
18. Will 2022 be the year for rethinking wholesale electricity market design in Europe? 42
19. Will India's 2015 renewable energy target of 175GW be met in 2022, and what are the implications for its energy transition? 44
20. China in 2022: Stability over sustainability? 47

Figures

Figure 1.1: Oil forecasts for 2021 4
Figure 1.2: Oil market outlook in 2022 6
Figure 2.1: UK Wholesale Electricity Prices, Jan-Oct 2021 (£ / Megawatt-hour) 7
Figure 2.2: UK Retail Electricity Bills – Breakdown (%) 8
Figure 3.1: TTF Front-Month Price (EUR/MWh) 11
Figure 4.1: LNG Export Capacity 12
Figure 5.1 ESP Sales by Delivery Schedule (mmcm/month) 15
Figure 6.1: Nord Stream 1 and Nord Stream 2 pipelines 16
Figure 7.1: Implications of various emission targets for global warming outcomes 20
Figure 8.1: Pace of carbon emission growth versus carbon budget 21
Figure 11.1: 2023/4 Onstream hydrogen projects by region 28
Figure 11.2: European Low-carbon capacity additions 28

Figure 13.1 Carbon-neutral LNG Cargos 2019 - November 2021: sellers and countries of delivery ... 31
Figure 14.1. Recent trends in voluntary carbon offset transactions on Xpansiv market CBL 34
Figure 14.2. Global Emissions Offset (GEO) and Nature-Based Global Emission Offset (N-GEO) Prices, US Dollars per metric ton (MT) of CO2 equivalent 35
Figure 15.1: Attributes (API and CI) of some crudes at USD50/MT carbon 37
Figure 17.1: The presence of nuclear power in Europe..... 41
Figure 19.1: India – Installed Electric Capacity (Gigawatts) 45
Figure 19.2: India – Installed Electric Capacity by Ownership Type (per cent) 45

Introduction

In the series of short articles included in this paper, research fellows from OIES outline their thoughts on 20 key themes in the global energy economy for 2022. The aim of these short pieces is to catalyse the debate on some of the important issues that will face the energy industry over the next 12 months and beyond. We would welcome further discussion on any or all of them, and the contact details for the corresponding authors are included at the end of each article.

We start with a review of short-term issues in the oil, gas and electricity markets. *Bassam Fattouh and Andreas Economou* consider the outlook for oil demand over the next 12 months and discuss the ability of OPEC+ producers to manage a gradual increase in production to balance the market, even as demand growth is expected to soften. Their conclusion is that the oil price will remain within a $70-90 per barrel range, while refilling depleted storage will be a key issue. Price volatility, in light of considerable uncertainty about both supply and demand, as well as political responses to high prices will remain dominant issues in 2022. *Anupama Sen, David Robinson and Rahmat Poudineh* then discuss government responses to current electricity price volatility, using the UK and Spain as examples of different responses to providing protection for low-income consumers. They see the issue becoming increasingly relevant as the energy transition progresses and suggest that government intervention could become less and less effective unless energy policy is well designed.

In a somewhat similar vein, *Mike Fulwood and Jack Sharples* consider the outlook for gas prices and supply to Europe and the implications for the global LNG market. Replenishing European storage will be a critical issue in 2022, with LNG supply, Asian demand and pipeline exports from Russia being key drivers to watch.

In this context, *Mike Fulwood* then considers the prospects for LNG supply in 2022. He highlights the number of projects that are set to come onstream in the next 12 months, reversing the trend of supply shortage seen over the past year, and speculates on the level of final investment decisions that will be taken for new projects. His estimate is a range between 10-50mt of new capacity, which could be onstream by mid-decade and would keep the world well supplied with LNG through 2030. However, this could be the last chance for a significant number of FIDs to be taken before the push towards decarbonisation takes hold.

Jack Sharples then examines Gazprom's export strategy, highlighting in particular the company's use, or lack of it, of its Electronic Sales Platform during 2021. He suggests that increased use of the ESP in 2022, if it occurs, could be a leading indicator of a change in Russian strategy and would suggest a loosening of the gas market in Europe. On a linked topic, *Katja Yafimava* discusses the prospects for the Nord Stream 2 pipeline, outlining the current state of negotiations and suggesting that we will almost certainly have to wait until the second half of the year before we see any significant gas volumes flowing to Europe via this route.

Decarbonisation and the energy transition have become major research themes at OIES over the past three years and many of the subsequent key themes in this paper reflect this increased focus. *James Henderson* discusses the outlook for COP27, which is set to be held in Egypt in November and where the focus will be ensuring that the promises made in Glasgow at COP26 are being implemented. Aside from the regular UNFCCC negotiations many side agreements were reached on issues such as methane emissions, zero emission vehicles, deforestation and reducing coal use in power generation and it will be vital to see whether action has been taken in the subsequent 12 months. In a separate article the same author highlights the particular importance of monitoring the review and update of countries' nationally determined contributions that was agreed should take place in 2022. This

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exceptional step was taken because the current agreements are inadequate to meet climate targets, and so it will be essential for governments to increase their ambitions, and be seen to do so, this year.

On the specific topic of the Global Methane Pledge, *Jonathan Stern* points to two crucial issues for 2022. Firstly, the 111 countries that have signed up need to demonstrate serious commitment to the 30 per cent reduction goal and to the measurement, reporting and verification of their efforts. Secondly, some big emitters that did not sign up (China, Russia, India and others) need to be included soon if the pledge is to have any real force as a global agreement. Methane emissions is one of the topics that the US and China agreed to discuss in 2022 as part of the surprise announce of their bilateral agreement at COP26. *Barbara Finamore* and *Michal Meidan* outline the potential importance, and the challenges, of this dialogue both as part of global climate negotiations and also as a potential route to soften US-China tensions.

A number of other energy transition themes are then discussed. *Martin Lambert* highlights the prospects for hydrogen projects in 2022. He emphasizes the fact that many new projects will need to start taking FIDs in 2022 if targets for 2024 and 2030 are to be met and reiterates that blue hydrogen projects will likely be needed to supplement green hydrogen developments, at least during this decade. Related to the topic of blue hydrogen is the development of carbon capture, utilization and storage projects, and *Alex Barnes* picks up this theme in an article about the prospects for CCUS in the UK. After a couple of false starts he argues that 2022 could be a catalyst for a more positive outcome for investment in CCUS, with the UK potentially providing an example of how a business model for this technology could be created.

We then turn back to the global market for three articles on how suppliers of LNG and oil are adapting to the energy transition and how carbon offset trading is expanding. *Jonathan Stern* raises the debate around "carbon neutral LNG" and suggests that 2022 should be the year when definitions around the greenhouse gas emissions in the LNG value chain should be tightened to allow for accurate measurement, reporting and verification. Indeed, he argues that the term carbon-neutral LNG should be abandoned in favour of "GHG verified LNG (with or without offsets)." *Jeff Cohen, Bassam Fattouh and Owain Johnson* then describe how the trading of carbon offsets in the voluntary market has grown rapidly over the past year and suggest that the finalization of the Article 6 rules at COP26 could be the catalyst for a further dramatic surge in activity in 2022. They also argue that a two-tier market could emerge for adjusted and non-adjusted credits, depending on whether they have fully accounted for the corresponding adjustments outlined in the Article 6 rules. From an oil perspective, *Adi Imsirovic* discusses the emergence of a new carbon intensity calculation which will allow a carbon intensity premium to be allocated to different grades of oil and for a new set of benchmarks to emerge. This form of trading has started to emerge in 2021 and it is expected to grow rapidly in 2022.

The final group of articles is focused on a number of key regions. Firstly, *Alex Barnes, Anouk Honoré* and *Katja Yafimava* address the further development of energy regulation in the EU and highlight the significant discussions which will take place in 2022 around the Fit for 55 package, the Hydrogen and Gas Market Decarbonisation Package and the TEN-E Regulation focused on energy transport infrastructure. They also suggest that 2022 will be an important year for many EU states as they introduce new domestic legislation or deal with the impact of key elections. *Anouk Honoré* then highlights the outlook for nuclear power in Europe, as the debate around its inclusion in the EU taxonomy continues. She points out that there is a significant division among member states about the efficacy of nuclear power as an environmentally friendly fuel, but suggests that it may be essential if EU emissions targets are to be met. *David Robinson* then continues the discussion on the future of electricity in the EU by raising the question of optimal market design. He points out that ACER will be publishing a report in April 2022 which is likely to support the current market model, although he

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suggests that a number of countries in the south of the region believe that the prevalent energy-only model is unsustainable. 2022 will be the year when this debate comes to the fore, with potentially significant implications for the electricity sector. This suggests that in addition to looking at EU frameworks in 2022, specific country trajectories and policies matter just as much.

This is also the case outside of the EU. We conclude this section with two articles on major Asian energy consumers – India and China. *Anupama Sen* highlights the fact that India is unlikely to fully achieve its 2022 renewable capacity target (set in 2015), but has nevertheless raised ambition on its new targets for 2030 and beyond. She argues that significant progress has been made but that the achievement of future goals will require financial stability in the distribution sector and investments in grid modernisation and flexibility, as well as a strategy to cope with external shocks that does not deflect the Indian government away from climate and environmental objectives in favour of short-term fiscal stability. Finally, *Michal Meidan* discusses the development of Chinese energy and environmental policy in 2022 and argues that during the next 12 months the domestic priority is likely to be economic stability ahead of the 20th Party Congress in November. As a result, although the environment, and blue skies, will remain important, they may take something of a back seat for a while until the political situation, and the future of Xi Jinping, is confirmed towards the end of the year.

Although this list of themes is long it is clearly not exhaustive. However, it highlights many of the topics which we will be researching at OIES during 2022 and we would encourage you to access our written output at www.oxfordenergy.org. For further details about how to join the discussion at the many events which we hold for our sponsors and benefactors, please contact Kate Teasdale at kate.teasdale@oxfordenergy.org

James Henderson

Director, Energy Transition Research

Michal Meidan

Director, China Programme
Director, Gas Programme

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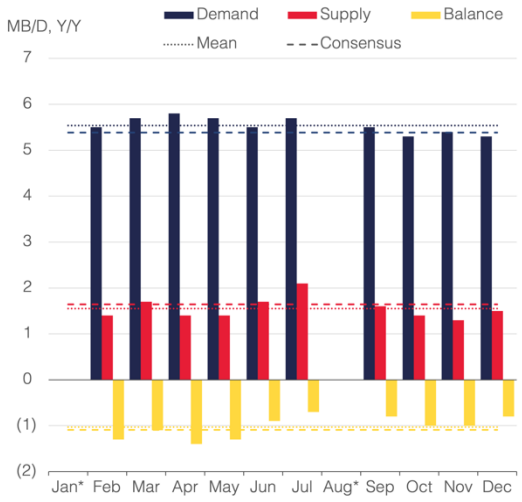
1. The outlook for oil markets

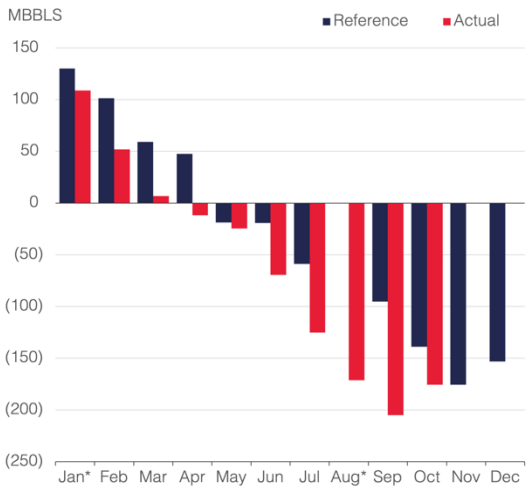
The oil rebound in 2021 was remarkable and characterised by some key features: the strong but uneven demand recovery across regions and products; OPEC+ strong cohesion and high compliance; the modest rebound in non-OPEC supply amid disciplined US shale producers; and a sharp drawdown of crude and product stocks. Identifying these features early in 2021 was key in shaping our projections for the year (Figure 1.1).[1] The supply/demand balances surprised few people with the market deficit in 2021 expected to average near -1 mb/d (see Figure 1.1A). Surplus OECD stocks however drew down massively and faster than anticipated, falling below their 2015-2019 average within nine months from their peak of 268 mbbls in June 2020 and reaching -205 mbbls below the average by September 2021 (see Figure 1.1B). The uncertainty over new COVID variants and the evolution of an OPEC+ policy roadmap, as well as the emergence of new exogenous shocks (e.g. Hurricane Ida in the US and the sharp rise in gas prices and the substitution from gas to oil) had a greater impact on monthly oil price expectations than our reference forecast, but this was mostly confined to H1 2021 and failed to break prices out of our expected price bounds throughout the period (see Figure 1.1C). Overall, the Brent price in 2021 averaged USD70.8/bbl, rising from USD42.3/bbl in 2020, an increase of USD28.5/bbl and shaving-off its annual losses not only of 2020 (-USD21.7/bbl), but also 2019 (-USD7/bbl).

Figure 1.1: Oil forecasts for 2021

A. Supply/demand balance



B. OECD commercial stocks vs 2015-19 avg



[1] OIES Oil Monthly Issue 1, 03 February 2021.

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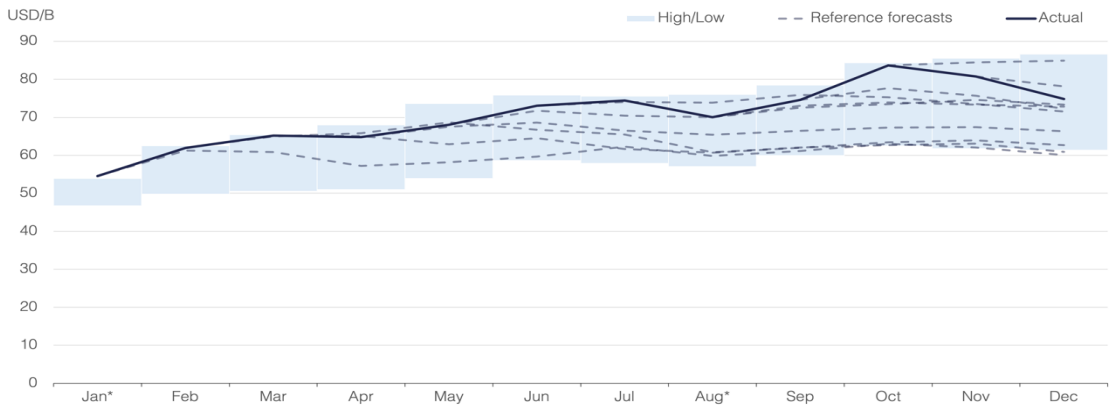
C. Monthly Brent price



*Forecasts are not published in January and August. Notes: Forecasts in Figure 1.1A report average growth estimates/balance for 2021 and consensus reports the averages from IEA, EIA and OPEC as of December 2021. OECD commercial stocks in Figure 1.1B refer to end-of-period. Source: OIES Oil Monthly

In 2022, we expect the key factors that shaped the oil market in 2021 to remain relevant. We highlight two such factors.

The oil demand recovery will remain key in 2022.

The emergence of new COVID variants, slow and geographically uneven progress of vaccination rates, as well as supply-chain and inflationary pressures in the global economy, slowed but failed to reverse the oil demand recovery in 2021 and they will continue to dictate the outlook for this year. After a strong comeback of global oil demand in 2021 that grew by 5.3 mb/d and recouped over 60 per cent of lost growth in 2020 (-8.8 mb/d), we expect global oil demand in 2022 to return to its pre-crisis levels despite softer year-on-year growth. Our model points to a global demand growth of 3.5 mb/d in 2022, with demand recovering and surpassing its 2019 levels as soon as Q2 and breaking the 100 mb/d mark in H2. For the year as a whole, global demand is expected to average 99.6 mb/d versus 99.5 mb/d in 2019. But in terms of products, jet fuel remains a drag and is forecast to persist at 8 per cent below pre-COVID levels by the end of 2022. Uncertainty around these estimates however remains high. The emergence of new COVID variants could still surprise the market, but as has been seen both with Delta and Omicron, the actual impact of new restrictions on global demand (via mobility and activity) gradually weakens, and policy and mobility indicators that helped to empirically assess the shock on oil demand at the start of pandemic have lost their predictive power. More restrictive fiscal policy and tighter monetary policy to combat inflation could dampen global growth prospects. On the other hand, there is still upwards potential for oil demand in 2022 compared to our reference, especially if we start seeing substantial signs that COVID is becoming endemic, rather than pandemic, shifting consumer sentiment and boosting lagging products such as jet fuel.

A key dynamic shaping the market in 2022 will be the ability of OPEC+ producers to meet their targets as they exit the current deal with the size of available spare capacity coming into focus. Having entered the last phase of the historic OPEC+ deal, producers are now set to return another 3.76 mb/d of restrained production back into the market between January and September 2022. Some producers however were already struggling to meet their targets in 2021 (mainly the African OPEC producers) and we expect this situation to become more acute and spill over to more producers. As a result, we project that OPEC+ as a total will struggle to return more than 2 mb/d of withheld supplies in 2022, compared to the headline target of 3.76 mb/d. Even assuming full conformity in December 2021, between August and December 2021 OPEC+ managed to return 93 per cent of the total 2 mb/d target (or 1.86 mb/d), with underproduction from Angola and Nigeria alone reaching 0.53 mb/d.

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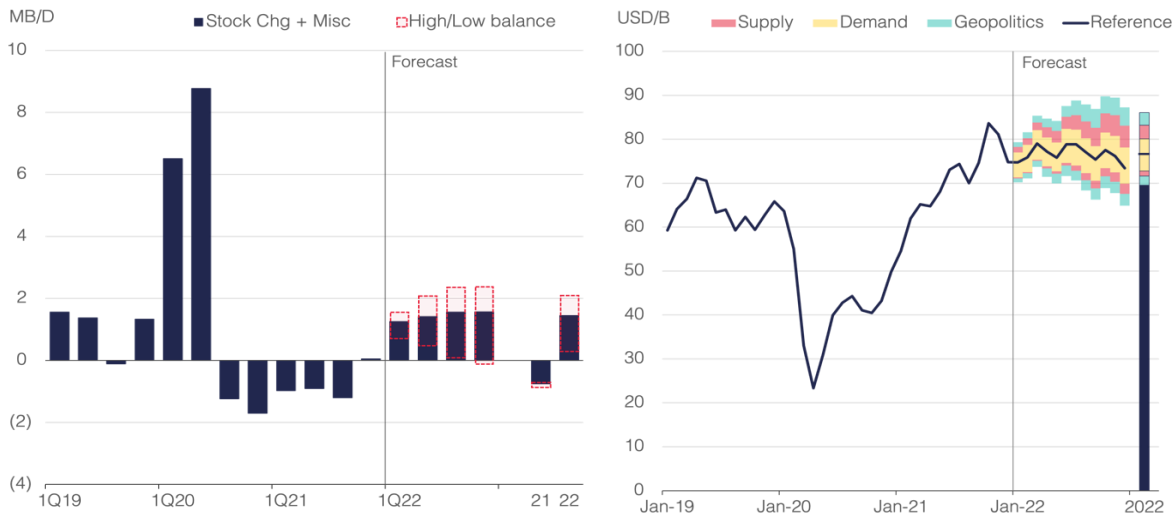
That said, even if OPEC+ underperforms in 2022 and only returns 2 mb/d, we still expect the market to shift into surplus, all else remaining equal (Figure 1.2A). But as OPEC+ starts producing closer to its maximum capacity, the spare capacity cushion is expected to diminish to less than 2 mb/d (excluding Iran) and with it the ability of OPEC+ to control the market on the upside, which is seen as a key factor supporting prices despite the expected surpluses in our reference forecast (Figure 1.2B).

A more balanced market remains a plausible scenario in 2022 (see Figure 1.2A). Following six consecutive quarters of large market deficits since H1 2020, we now expect the market to build into surplus in all quarters in 2022 and average 1.4 mb/d for the year as a whole. The supply-side risks however that started building towards the end of 2021 are expected to carry over in 2022 and remain largely skewed to the downside. First, there are still limited signs that the pressure on US shale producers from their financial backers will ease in 2022, meaning that favouring capital discipline over production growth and consequently the slow supply response to higher prices witnessed during this cycle may persist. This does not imply that this could not change in H2 2022 and US shale could still surprise on the upside, as at current oil prices, US shale producers will continue to generate very healthy cash flows which could be used in part to increase capex budgets and drilling activity. Second, outside OPEC+ and North America, growth prospects are expected to be capped, with gains from pockets of growth being offset by declines elsewhere. Third, the slow progress in the US-Iran nuclear talks and renewed concerns over Libyan production following the abandoned December 2021 elections means that geopolitical risks will remain elevated. But most importantly, with limited buffers in the system (primarily spare capacity and to a lesser extent stocks), the impact from any unexpected geopolitical or weather-related disruptions on markets and prices will be aggravated both in terms of magnitude and duration. Lastly, OPEC+ retains in its policy toolbox the flexibility to pause or even reverse the monthly supply hikes at any point throughout 2022 if unfavourable market conditions call for an intervention.

Figure 1.2: Oil market outlook in 2022

A. Global balance **B. Brent price**



Source: OIES Oil Monthly

Market uncertainty in 2022 will remain confined in the USD70/bbl and USD90/bbl range (see Figure 1.2B). The substantial tightness in OECD stocks in 2021 that drew well below their 2015-2019 average means that even if the expected surpluses in 2022 materialise, there is now an available gap to absorb the surplus leaving prices supported.

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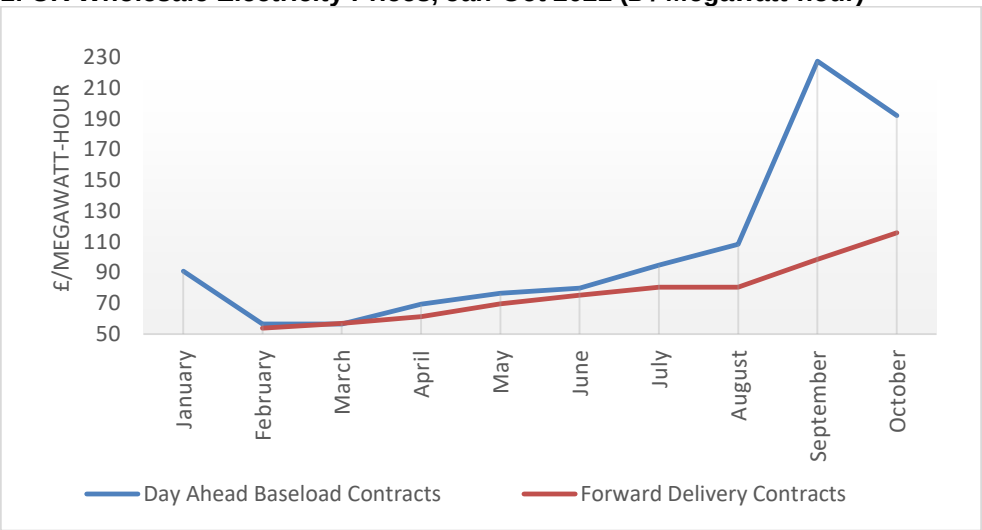
2. The UK government's response to electricity price volatility

In early 2022, UK energy regulator Ofgem is expected to publish the results from its policy consultations on solutions to manage the impact of future price volatility on retail electricity supply companies and their consumers. This follows the spike in wholesale electricity prices in the second half of 2021 (Figure 2.1), which was driven by a combination of supply-side factors – predominantly, the global rise in the price of natural gas (accompanied in Europe by a rise in the CO_2 price), which often sets the wholesale electricity price at the margin – and by a post-pandemic rebound in global energy demand.[2]

Governments have reacted to the price spike in different ways. In the UK, Ofgem's *price cap mechanism* limits the rate at which suppliers can pass through wholesale costs to retail electricity consumers who are on Standard Variable Tariffs (SVT).[3] The 2021 price spike was followed by the failure of around 30 small retail suppliers serving around 4 million households. Higher wholesale prices in the presence of inadequate hedging by smaller and unintegrated retailers, have resulted in a situation in which the gap between suppliers' costs and revenues has risen sharply. This has been exacerbated by sluggish price adjustment in the retail market, due to the existence of the price cap – which in turn has become even more popular after the wholesale price spike. Since then, there has been increasing pressure on Ofgem to raise the price cap at its next adjustment, scheduled for April 2022. This in turn has prompted concerns over the impact on retail consumers of a higher wholesale price as a share of the final retail price of electricity.

Figure 2.1: UK Wholesale Electricity Prices, Jan-Oct 2021 (£ / Megawatt-hour)



Source: Ofgem

Ofgem has been seeking consultation on options to deal with future price volatility within the UK's existing legislative framework on electricity market reform, with options including: *ad hoc* adjustments to the cap outside the six-monthly cycle based on certain triggers;[4] quarterly adjustments of the

[2] "Electricity Price Rises: exploring the context and implications", OIES Energy Podcast. https://www.oxfordenergy.org/publications/oxford-energy-podcast-electricity-price-rises-exploring-the-context-and-implications/. Also see Sharples, J. (2021) "A Series of Unfortunate Events: supply-side factors in the European gas price rally in in 2021 and outlook for the rest of winter", Energy Insight 108, OIES. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/12/Insight-108-Supply-Side-Factors-in-European-Gas-Prices.pdf

[3] SVTs are not subject to a contract period and are applied to consumers who do not actively switch to cheaper tariffs. While they can ensure higher revenues, they present volume risks to suppliers, as consumers can switch without exit fees.

[4] "Adapting the Price Cap Methodology for Resilience in Volatile Markets", Ofgem. https://www.ofgem.gov.uk/publications/adapting-price-cap-methodology-resilience-volatile-markets

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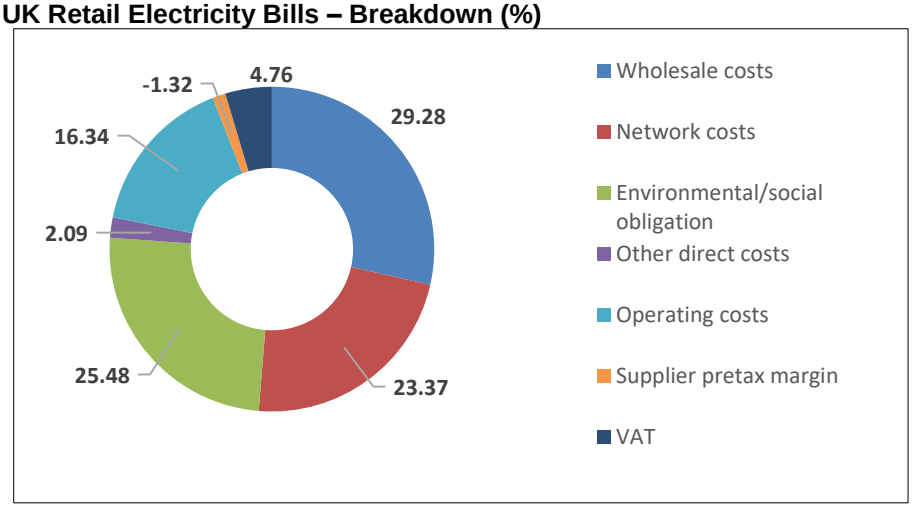
wholesale cost component in price; and a fixed-term default SVT with an exit fee set at a declining rate over the fixed term for consumers who switch. Ofgem is also considering stricter financial prudence tests for new market entrants. The intention is to reduce uncertainty for suppliers and allow them to better hedge for volume risks, avoiding exposure to future price spikes and hence higher wholesale costs.

However, some have argued that policy solutions focusing on the price cap are myopic, as they ignore the larger issue of whether the retail electricity market is still fit for purpose. Recent research shows that measures to reduce barriers to entry for new suppliers have distorted competition, put consumers at risk through unsustainable retail business models, and led to an unfair distribution of system and public policy costs of decarbonization.[5] Policy costs have been levied on retail consumer bills through the environmental/social obligation, which remained uncontroversial as long as cheaper renewable electricity was available to offset rising policy costs. Further price volatility risks disrupting that balance (Figure 2.2) raising questions over how policy costs should be financed going forward. [6]

Figure 2.2: UK Retail Electricity Bills – Breakdown (%)



Source: Ofgem

This also raises a question about the role of the government in protecting consumers against price shocks going forward. One argument is that the majority of consumers can protect themselves by agreeing to pay a premium that reflects the supplier's cost of hedging; it is not obvious that markets are failing when consumers pay the hedging cost in return for fixed prices, and when spot prices reflect the price of natural gas. That, in turn, raises other questions about whether the energy-only market is an efficient model in a decarbonizing world, or whether a new market design is required – this is a Key Theme that is covered separately in this document.

Truly vulnerable, low-income consumers should be protected against price shocks, but governments continue to struggle with doing this efficiently – for example, through transfers and energy sector fiscal policy, as opposed to through market intervention using a price cap or subsidy. For example, Spain initially used a combination of lower VAT, lower policy levies, and recycling of CO_2 allowance revenues,

[5] Poudineh, R. (2019). "Liberalized retail electricity markets: what have we learned after two decades of experience?" OIES Paper EL38, Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/12/Liberalized-retail-electricity-markets-EL-38.pdf

[6] It is important to note here that balancing costs have risen dramatically, in part due to the high fuel cost of flexible generation, but also due to penetration of intermittent renewables. As these costs will become an increasingly important part of consumer bills, it will be important for regulators to determine how these costs should be shared – at present, they are 'smeared' across all consumption rather than allocated to that part of consumption that is specifically contributing to the need for balancing – and to design market and other incentives to encourage flexibility and reduce balancing costs.

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plus windfall profit taxes on generators (that were later amended by the government resulting so far in a negligible net impact), to mitigate the impact on tariffs, with mixed results and not without outcry from both consumers and industry.

These issues are like to become more central to the energy transition going forward, particularly as, if price volatility becomes a recurring feature, the effectiveness of government intervention in the market is likely to be limited in the face of continued exogenous shocks. Furthermore, as the energy transition progresses, the management of public support for decarbonization will also become more important, and electricity (and energy) policy should pay greater attention to planning for the implications of low-probability, high-impact events, of which we now have more than one recent example.

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3. Outlook for gas prices and supply to Europe

The year 2021 saw a rollercoaster ride for European gas prices. The pace of the growth in prices and the absolute peak levels that were reached were exceptional. By 6 January 2022, the TTF Front-Month price was EUR97/MWh, more than five times higher than it had been twelve months earlier (EUR18/MWh). In the coming year, we will continue to analyse these pricing dynamics, identify the key drivers, and then monitor those drivers as 'signposts' for potential near-term future pricing dynamics.

In September 2021, we published our analysis 'Why Are Gas Prices So High?'. This was followed in December by the first part of our trilogy of papers, 'A Series of Unfortunate Events', which focused on supply-side factors in the European gas price rally. The second and third parts of that trilogy - analysing European demand and the role of trading activity, respectively - will be published soon. Finally, a further OIES Comment, 'Surging European Gas Prices - Why and How', has just been published.

Our analyses highlight the role of the European gas market in balancing the global LNG market. Europe benefitted from supply-long conditions on that market in 2019 and 2020. However, a rebound in global LNG demand coupled with unexpected (and unconnected) supply interruptions at various LNG export plants meant that global LNG supply did not keep pace with the rebound in demand, thus tightening the market significantly. The result was a marked decline in LNG supply to Europe in 2021, as cargoes were diverted to Asia especially in the first half of the year.

The EU plus UK market has also faced an ongoing decline in domestic production, which fell from 97 bcm in 2017 to 60 bcm in 2021. Most of that decline is not reversible. Only in the UK and Denmark was the decline in 2021 related to maintenance that will be followed by a rebound in production. Conversely, a major event in mid-2022 will be the cessation of production at the Groningen field in the Netherlands, although the Dutch government recently indicated that it was prepared to allow higher production in H1 2022 to guarantee security of supply. A final decision is due in April 2022.

There was some upside in pipeline imports from non-Russian sources, as imports from North Africa grew from 25 bcm to 38 bcm between 2020 and 2021, thus returning to levels seen in 2017 and 2018. However, this upside is limited by the end of the Algerian transit contract with Morocco for deliveries to Spain. 2021 also saw new supply to South-Eastern Europe via the Trans-Adriatic Pipeline (TAP). As a result, flows from Turkey to Greece rose from an average of 0.7 bcma in 2017-2020 to 8.5 bcm in 2021. As with imports from Algeria, the prospects for further growth in 2022 remain limited. Finally, imports from Norway in 2021 (124 bcm) were slightly higher than in 2019 and 2020 and slightly lower than 2017 and 2018.[7] Growth in Norwegian production and exports in 2022-2025 is forecast to be modest.

Physical flows of gas from Russia to Europe (excluding Turkey) peaked at 178 bcm in 2019, and fell back sharply to 146 bcm in 2020. The rebound expected for 2021 did not materialise. Instead, Russian supply fell to 142 bcm.[8] Russian supply grew modestly year-on-year in each of the first three quarters, but fell by just over 10 bcm (24 per cent) in Q4. The potential rebound in Russian supply in 2022 could be dependent on Nord Stream 2 being approved by the German regulator (BNetzA), which has cautioned that no decision will be made during the first half of 2022. Therefore, the impact of Nord Stream 2 may be felt only in Q3 or Q4 2022.

In this context, Europe relied heavily on storage to balance the market in 2021. Stronger withdrawals in Q1 and weaker injections in Q2 and Q3 left Europe with lower-than-usual stocks at the start of winter 2021/22. Q4 withdrawals were also similar to Q4 2017 and 2020, but much higher than in 2018 and

[7] These figures include UK continental shelf gas production brought ashore at St Fergus and Easington. The data from ENTSOG does not distinguish between UK and Norwegian production brought ashore at these points.

[8] Gazprom increased its sales to Turkey by 10 bcm between 2020 and 2021, meaning that its total sales to 'Europe including Turkey' grew by around 5 bcm year-on-year in 2021, to around 180 bcm. This is still markedly lower than the sales to Europe (including Turkey) of around 200 bcm reported by Gazprom for 2018 and 2019.

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2019. Withdrawals in Q1 2022 will be highly weather-dependent. If Europe ends the winter with very low stocks, the necessity of summer injections will exert upside influence on prices in summer 2022.

Even if European demand in 2022 is weaker than in 2021, the need to replenish storage will exert a significant pull on global supplies. Global LNG supply is expected to rise as new US projects (Sabine Pass Train 6 and Calcasieu Pass) come onstream and the supply issues, at least in some of the LNG export plants, are resolved. However, if demand from China continues to grow at a rapid rate and other Asian importers also increase their requirements, the availability of LNG for Europe may again be limited.

In such a scenario, with weak European production and little prospect of additional imports from Norway, North Africa, and Azerbaijan, all eyes will be on flows from Russia. The large fall in supplies along the Yamal Europe route in Q4 2021 prevented prices falling back to more reasonable levels. The key question for 2022, therefore, is whether Gazprom will continue to withhold supplies from the spot market rather than utilizing the available capacity on Yamal Europe, waiting for Nord Stream 2 to be approved, or will Gazprom relent and increase flows prior to any approval?

Figure 3.1: TTF Front-Month Price (EUR/MWh)

Source: Data from Argus

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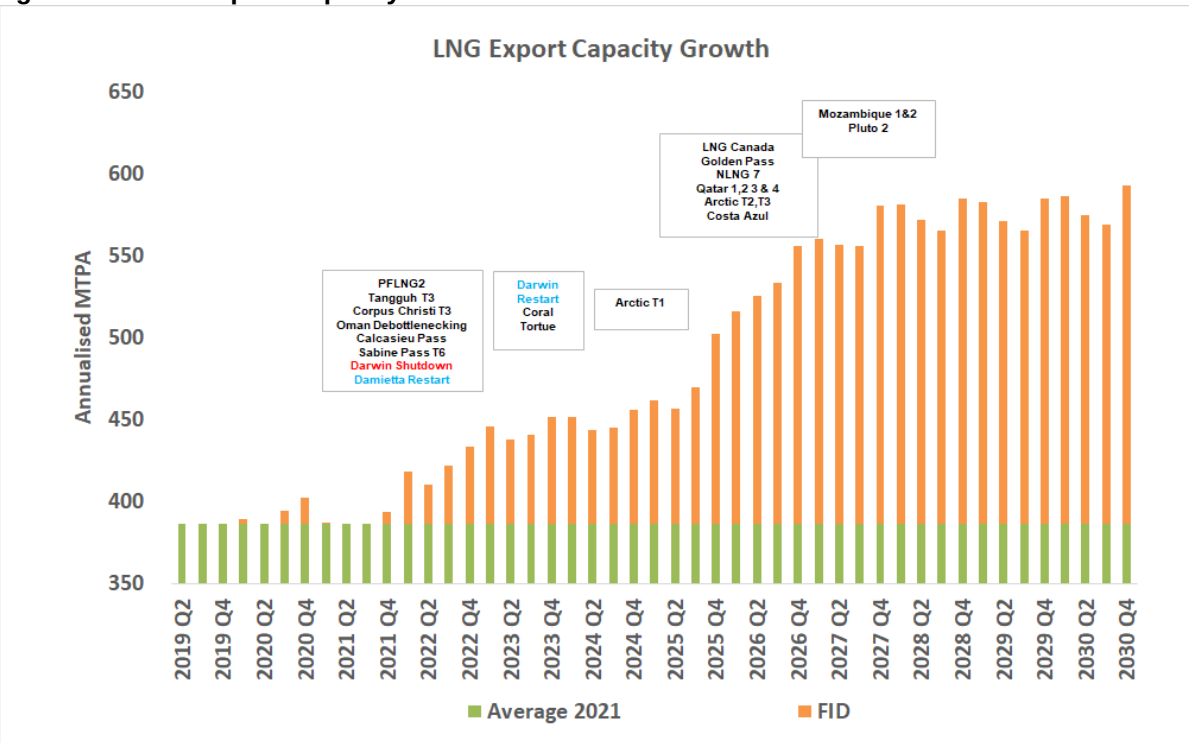
4. LNG FIDs in 2022 – outlook and implications

The constraints on LNG supply were a key factor driving the rising wholesale gas prices in 2021, and the healthy margins generated have raised the prospect of more FIDs for new LNG projects. There was a wave of FIDs in 2019 but the approval of new projects dried up as prices fell and the COVID-19 pandemic hit. After a significant increase in 2022, the additions to LNG export capacity in 2023-2024 are not expected to be that large, raising the prospect of a continuing tight LNG market in the short term. However, the earlier wave of FIDs is expected to bring some respite from late 2024 onwards. The likely operational dates of those projects (OIES estimates - not necessarily the developers) which have taken FID are as follows (the nameplate mtpa of capacity is in brackets):

- 2022[9] – Sabine Pass T6 (4.5), Calcasieu Pass Phase 1 (10), Tangguh T3 (3.8)
- 2023 – Coral FLNG (3.4), Tortue FLNG (2.5)
- 2024 – Arctic LNG 2 T1 (6.67)
- 2025 – Arctic LNG 2 T2 (6.67), Baltic LNG (13), LNG Canada (14), Golden Pass (18.1), Costa Azul (3.25), Qatar Additional T1/T2 (16)
- 2026 – Qatar Additional T3/T4 (16), NLNG T7 plus debottlenecking (8), Arctic LNG T3 (6.67)
- 2027 – Mozambique LNG T1/T2 (12.88), Pluto T2 (4.7).

Figure 4.1: LNG Export Capacity



Source: OIES Analysis, NexantECA World Gas Model

The total amount of additional capacity between now and 2027 for the projects which have taken FID is some 150 mtpa, compared to the global nameplate capacity at the end of 2021, which was some 460

[9] Both Sabine Pass T6 and Calcasieu Pass began commissioning in last 2021.

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mtpa. However, this number significantly overstates the amount of LNG export capacity actually available, due to technical and feedgas issues and maintenance. Adjusting for these issues, available capacity at the end of 2021 is estimated to have been just under 400 mtpa.[10] The additional capacity of 150 mtpa, therefore, represents an increase of some 40 per cent. This would represent the largest ever increase in capacity over a six-year period, of around 6 per cent per year.

Against this background of a large potential wave of new supply, especially from 2025 onwards, an interesting question is whether we are likely to see more FIDs in 2022, which would be adding to supply possibly as early as 2026. There are a number of candidates (the nameplate mtpa of capacity is in brackets):

- Tellurian's Driftwood Phase 1 (11) – contracts are in place for much of the capacity
- Venture Global's Plaquemines (20) – contracts in place for some of the capacity suggesting a first phase of 10 mtpa may be possible
- Next Decade's Rio Grande (27) – a decision has been delayed until 2H 2022 but an initial 9 mtpa might be developed
- Texas LNG (2) – some contracts in place
- Woodfibre LNG (2.1) – FID has been deferred but has contracts
- Rovuma LNG (15.2) – Exxon/ENI Mozambique project was expected to take FID in 2020 until COVID-19 hit but could well decide this year
- Papua LNG (5.33) – Total-led project reportedly could take FID in 2023
- Qatar Additional T5/T6 (16) – depending on the success in developing the first 4 trains of the expansion
- Russia projects could include another Novatek project – Arctic LNG 1 (20) – an expansion of Sakhalin (5.4) by Gazprom plus the possibility of the Rosneft led Sakhalin project (6.2).

This list is not necessarily exhaustive but the total approaches some 100 mtpa, which adds a large amount of capacity to the market and would keep the world well supplied with LNG through 2030. However, even if many of these projects were ultimately to be developed, the FID may not be taken until 2023 or 2024. For 2022, the range of FIDs might be from 10 mtpa to as much as 50 mtpa but the top end of that range looks optimistic.

The key factor in determining the taking of a FID is whether there are sufficient contracts in place to enable the financing of the project. Projects which include large, well-capitalised IOCs/NOCs can be, and often are, self- or equity-contracted, where the developers agree to offtake the LNG themselves e.g. LNG Canada, Golden Pass, Tortue. These are somewhat easier to get off the ground than projects where the developers have to get third-party finance on the back of long-term contracts with creditworthy offtakers. A further consideration is that any new FIDs will be taken on the basis that these projects will be operational well into the 2040s, when, if the required level of decarbonization is to be achieved, the outlook for unabated gas demand could look significantly different. At some point, if the rise in global temperature is to be limited to 1.5 degrees C, then even abated gas demand may need to peak and decline at some point. The next few years, therefore, could be the last chance for a significant number of FIDs to be taken before the push towards decarbonization takes hold.

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[10] 2021 was a year of a number of supply issues which is thought to have reduced capacity by some 10 to 15 mtpa during the year

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5. Gazprom's export strategy and the Electronic Sales Platform

As discussed earlier in this compilation, the decline in physical flows of Russian pipeline gas to Europe in 2021 - relative to both 2020 and the pre-COVID-19 average for 2017-2019 - was a significant factor in the tightening of the European market, especially in Q4 2021.

In 2021, Gazprom physically delivered 142 bcm to Europe and approximately 26.5 bcm to Turkey, giving a total of 168.5 bcm. Gazprom also made a net withdrawal of 5 bcm from its European storage stocks during the calendar year 2021. This means that Gazprom's total physical supply to Europe was around 173.5 bcm, which closely corresponds to Gazprom's reporting that its sales to Europe (including Turkey) in 2021 totalled 176.5 bcm.[11]

The vast majority of Gazprom's sales to Europe are under long-term contracts. In its 2021 Investor Day presentation, Gazprom implied that its long-term contract portfolio is around 175 bcm per year, including 30 bcm to Turkey and 145 bcm to the rest of Europe.[12] Such contracts have flexibility embedded that allows Gazprom's counterparties to reduce their offtake to 70-80 per cent of the annual contractual quantity (ACQ) or increase it to approximately 110 per cent of the ACQ.[13]

Gazprom also sells volumes on the spot market, both on European hubs via its trading subsidiaries and via its own Electronic Sales Platform (ESP). Although data is not available for Gazprom's sales via its trading subsidiaries, there is data on its sales via the ESP. In 2021, Gazprom delivered 8.4 bcm to the European market that had been sold on its ESP in either late 2020 or 2021.

When the volumes sold on the ESP are subtracted from Gazprom's physical delivery to Europe (excluding Turkey) of 147 bcm in 2021, the figure that remains (139.6 bcm) is almost 4 per cent lower than its estimated long-term contract portfolio. If this estimation is correct, the implication is that Gazprom's long-term contract counterparties were perhaps nominating down on their contractual volumes, instead choosing to draw on their storage stocks to meet demand in the hope that hub prices would have fallen by the time their storage stocks ran out and they were obliged to take greater volumes under their long-term contracts in order to meet demand.

In 2021, as the European market was getting tighter and prices were rising dramatically, Gazprom repeatedly affirmed it was meeting its long-term contract nominations - a view echoed by its counterparties. Therefore, the drop-off in supply was caused by Gazprom ceasing to offer volumes to the European spot market, both via its ESP and via its trading subsidiaries, and potentially exacerbated by its counterparties reducing their nominations, especially when European prices skyrocketed in Q4.

As Figure 5.1 illustrates, Gazprom effectively ceased prompt and balance-of-month sales via the ESP in May 2020, as European demand fell during the first wave of the COVID-19 pandemic. Gazprom's sales for Front-Month, Month-2, or Month-3 delivery then ceased in November 2020. Since December 2020, almost all of Gazprom's ESP sales have been for flat-rate delivery on a quarterly, seasonal, or calendar year basis, with a substantial quantity of those sales being for delivery in 2022 or even in 2023. Finally, on 13 October 2021, Gazprom halted all sales activity on the ESP.

The reasons behind Gazprom's decision to effectively cease spot sales in Europe in 2021 - despite hub prices reaching record levels - has been much debated. Two potential reasons may be discerned. Firstly, in a tight market, Gazprom can ease high prices (or sustain them), by offering additional spot volumes to the market (or not). Given that the prices in Gazprom's long-term contracts in Europe (with the exception of Turkey and some of the smaller markets of SE Europe) are now largely indexed to European hubs, Gazprom has a commercial incentive to maintain high prices, and in a tight market it

[11] As measured in standard cubic metres

[12] In its 2020 Annual Report, Gazprom stated that its 19.99 bcm sales via the ESP were equal to 11.4 per cent of Gazprom Export's contracts with European countries beyond the former Soviet Union in 2020 (see page 123)

[13] These are very rough approximations

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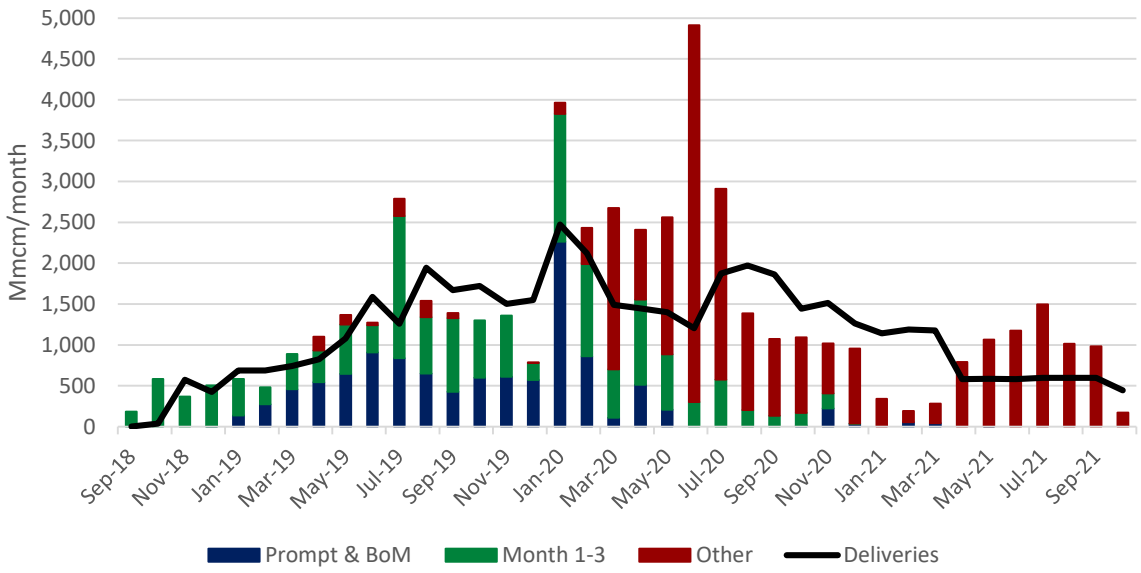
has the ability to do so. Commercially speaking, a 'sweet spot' for Gazprom is to sell just enough on the spot market to maximise its sales volumes, but not so much as to cause prices to fall, potential long-term demand destruction caused by sustained exceptionally high prices notwithstanding.

A second potential reason - much debated in the press - is that Gazprom wanted to put pressure on the approval process for Nord Stream 2 by withholding spot volumes and implying that they will only resume when Nord Stream 2 is approved. For Gazprom, both these reasons may be in play simultaneously.

Looking ahead, we await the resumption of Gazprom's spot sales via the ESP. This may occur when the tightness of the European market eases and Gazprom's pricing power is less evident, causing a shift in calculation of how to maximise sales revenues. The launch of Nord Stream 2 could also herald the resumption of Gazprom's spot sales. Indeed, the launch could coincide with the easing of the European market tightness around Q3 2022. Either way, the resumption of spot sales will indicate a shift in Gazprom's sales strategy, which is currently causing the company to win record profits but, perhaps, few friends in Europe.

Figure 5.1 ESP Sales by Delivery Schedule (mmcm/month)



Source: Data from Argus

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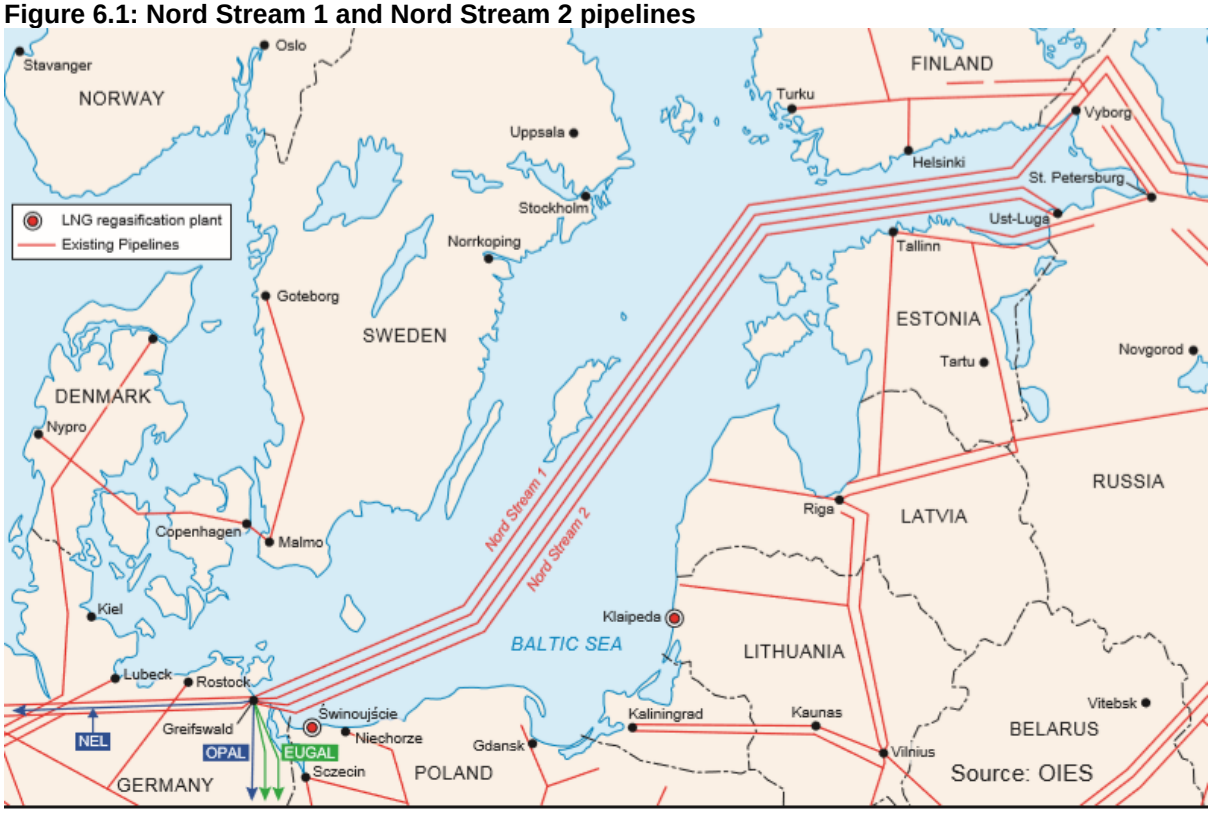
6. Nord Stream 2: a roadmap for 2022

At the start of 2022, Nord Stream 2 (NS2) - an offshore gas pipeline system, consisting of two parallel lines connecting Russia and Germany (Figure 6.1) - is on the verge of sending gas to Europe as both lines are filled with gas at pressure sufficient for starting flows. As documented by OIES at the start of 2021, construction and technical certification of the pipeline and regulatory certification of its operator are the two key factors which will determine when NS2 will start flowing gas.[14] NS2 AG - a Swiss-registered project company, established for planning, construction, and operation of NS2, which is owned by Gazprom subsidiary, Gazprom International Projects LLC - had finally overcome challenges related to pipeline construction and technical certification in 2021. But it is yet to obtain certification from the German regulatory authority, BNetzA, which would confirm the operator's compliance with the Gas Directive, including in respect of unbundling and the lack of negative impact on the security of energy supply in Germany and the EU.

Figure 6.1: Nord Stream 1 and Nord Stream 2 pipelines



Source: OIES

BNetzA accepted the NS2 AG certification application on 8 September 2021, thus setting off a 4-month period within which it must produce a draft certification decision, but then suspended the certification process on 16 November on the grounds that under EU and German law only a German-registered company can be certified as an operator, a condition which means the Swiss-registered NS2 AG is not compliant. On 25 October, three weeks prior to suspension, the German Federal Ministry for Economic Affairs and Energy, BMWi, issued its assessment, confirming that certification of the NS2 operator

[14] Yafimava (2021a): Yafimava K., 'The Outlook for Nord Stream 2' in Quarterly Gas Review: short and medium-term outlook for gas markets, OIES, January 2021

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would not endanger the security of gas supply to Germany and the EU.[15] This assessment forms an integral part of BNetzA's certification procedure and is not expected to be reviewed once suspension is lifted.[16]

BNetzA's suspension decision (and its justification) has raised a few eyebrows. Indeed, had German registration been a pre-requisite for certification, BNetzA must have known about it at the start of the process and had a choice of simply not accepting the NS2 AG certification application until and unless this condition was fulfilled. We analysed the possible reasons behind the suspension elsewhere, suggesting these were both of technical/procedural *and* political nature.[17] By accepting the NS2 AG certification application, BNetzA has effectively created 'a safety valve' for itself, enabling it to suspend temporarily the certification process on procedural grounds *at any time of its own convenience* – useful if politics around NS2 were to become too difficult. The timing of the suspension is hardly coincidental as it has allowed BNetzA to 'wait out' a politically turbulent period, both domestically (the change of government in Germany) and internationally (worsening relations between the West and Russia over Ukraine and Belarus and a threat of US NDAA 2022 sanctions on NS2). The length of the suspension depends both on NS2 AG (which will have to establish the new German subsidiary to resubmit the application) and BNetzA (which will have to check 'whether the documentation resubmitted by the subsidiary, as the new applicant, is complete'[18]).

BNetzA is obliged to issue a draft certification decision within six weeks of the suspension being lifted, in which it will have to assess compliance of the new German subsidiary with the Gas Directive's requirements. The draft decision will then be sent to the EC, which has up to four months to issue a (non-binding) opinion, and BNetzA will have to issue a final decision within the next two months.[19] Suspension will inevitably delay the certification process. While previously the final certification decision was expected in July 2022 at the latest, after suspension it is expected in July 2022 at the earliest. This was confirmed by the head of BNetzA, Homann, who said the final certification decision will not be issued in the first half of 2022.[20]

If BNetzA and the EC use the entire time available to them to conduct the regulatory certification, indicating that any pre-certification flows would be penalized, no gas will flow via NS2 until the second half of 2022 at the earliest. Therefore delayed certification will contribute towards high European gas prices throughout winter 2021-22, as under this scenario Russia's pipeline gas exports to Europe (excluding Turkey) would be limited by the amount of *firm* capacity booked (or available for booking) on the existing export routes *for as long as NS2 capacity remains unavailable* - that is ~170-175 bcma (including up to 45.5 bcm via Ukraine[21]) - thus significantly limiting its contribution towards alleviating

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[15] BMWi (2021): 'The Federal Ministry for Economic Affairs and Energy transmits the security of supply analysis in the Nord Stream 2 certification process to the Federal Network Agency', press release, https://www.bmwi.de/Redaktion/DE/Pressemitteilungen/2021/10/20211026-bmwi-uebermittelt-versorgungssicherheitsanalyse-im-zertifizierungsverfahren-nord-stream-2-an-bundesnetzagentur.html

[16] In December 2021, the Ukrainian TSO, GTSOU, has requested the German Ministry for Economic Affairs and Energy to review its security of supply assessment, see GTSOU (2021): GTSOU, press release, 'GTSOU sends a letter to the German Ministry of Economy on supply security threats posed by Nord Stream 2', 22 December 2021, https://tsoua.com/en/news/gtsou-sends-a-letter-to-the-german-ministry-of-economy-on-supply-security-threats-posed-by-nord-stream-2/

[17] Yafimava and Fulwood (2021): Yafimava K. and Fulwood M., 'German regulator's decision to suspend certification of Nord Stream 2 AG: F.A.Q'., *OIES Energy Comment*, November 2021, https://www.oxfordenergy.org/publications/german-regulators-decision-to-suspend-certification-of-nord-stream-2-ag-f-a-q/

[18] BNetzA (2021): 'Certification procedure for Nord Stream 2 suspended', press release, 16 November 2021, https://www.bundesnetzagentur.de/SharedDocs/Pressemitteilungen/EN/2021/20211116_NOS2.html;jsessionid=C8D4FA64CB04CC6AAA8AB873690051FB

[19] Yafimava (2021b), 'Nord Stream 2: on the verge of sending gas to Europe', *OIES Energy Insight* 103, November 2021, https://www.oxfordenergy.org/publications/nird-steam-2-on-the-verge-of-sending-gas-to-europe/

[20] 'Nord Stream 2 won't go live in first half of 2022, German regulator warns', *Reuters*, 16 December 2021.

[21] 40 bcma booked under 2020-24 Ukraine transit agreement and ~5.5 bcma offered as additional firm capacity.

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any European gas supply crunch in winter 2021-22 and European gas supply balance in the run up to winter 2022-23. This volume could even be lower if Gazprom continues to refrain from selling gas on the European hubs or on its Electronic Sales Platform (ESP) in addition to gas sales made under its existing long-term supply contracts (LTSCs). At the same time, it cannot be ruled out that BNetzA *may* allow gas flows via NS2 while certification of its operator is pending. The likelihood of this scenario depends on the following factors: weather, the dynamics of European gas storage levels, and an agreement on continued transit of gas across Ukraine post-2024.[22]

By suspending the NS2 certification process, BNetzA may have intended to pacify the staunchest critics of NS2 in Europe (especially Poland and Ukraine) and defuse the threat of US sanctions by demonstrating that it abides 'by both the letter and the spirit' of the EU law with respect to NS2 in line with the July 2021 German-US agreement.[23] This strategy may have worked – to an extent – as in January 2022 the US Secretary of State, Blinken, and the German Foreign Minister, Baerbock, re-confirmed their countries' adherence to the July 2021 agreement.[24] Also the new sanctions legislation (advanced by Senator Cruz),[25] mandating sanctions in respect of NS2 and revoking the US President's right to issue waivers without Congressional approval – referred to as the 'Protecting Europe's Energy Security Implementation Act' – is opposed by the Biden administration and is expected to be voted down by the US Senate.[26] However, another piece of legislation (advanced by Senator Menendez),[27] envisaging sanctions inter alia in respect of NS2 in the event of military escalation in Ukraine – referred to as the 'Defending Ukraine Sovereignty Act of 2022' – has also been advanced in the Senate. It is understood to be supported by the Biden administration and – if voted in – would mandate an imposition of sanctions in respect of NS2, subject to the US Department of State's affirmative assessment that the sanctions waiver in respect of NS2 AG and its CEO, granted in May 2021, is no longer 'in the best interest' of US national security. This legislation was advanced following the inconclusive US-Russia and NATO-Russia meetings, held on 10 and 12 January respectively, aimed at de-escalation of the Ukrainian security crisis. Also, Polish and Ukrainian opposition to NS2 shows no sign of abating, with both countries continuing to call for NS2 'cancellation'. Nonetheless, we do not expect any of this to derail NS2 and believe the certification process will resume in the first half of 2022 and the NS2 operator will be certified and start flowing gas before the end of 2022.

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[22] Yafimava (2021b), 'Nord Stream 2: on the verge of sending gas to Europe', *OIES Energy Insight* 103, November 2021, https://www.oxfordenergy.org/publications/nird-steam-2-on-the-verge-of-sending-gas-to-europe/

[23] US Department of State, 'Joint Statement of the United States and Germany on support for Ukraine, European energy security, and our climate goals', 21 July 2021, https://www.state.gov/joint-statement-of-the-united-states-and-germany-on-support-for-ukraine-european-energy-security-and-our-climate-goals/

[24] US Department of State, 'Secretary Antony J. Blinken and German Foreign Minister Annalena Baerbock at a Joint Press Availability – remarks', 5 January 2022, https://www.state.gov/secretary-antony-j-blinken-and-german-foreign-minister-annalena-baerbock-at-a-joint-press-availability/

[25] Protecting Europe's Energy Security Implementation Act (draft).

[26] 'Dems shift gears on Russian pipeline, backing Biden against Cruz's gambit', *Politico*, 5 January 2022, https://www.politico.com/news/2022/01/05/nord-stream-pipeline-russia-biden-526579

[27] Defending Ukraine Sovereignty Act of 2022 (draft).

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7. The Road to COP27 – key milestones and objectives

Many commentators have concluded that COP26, held in Glasgow in November 2021, produced a mixed set of results. Politicians, led by UK Prime Minister Boris Johnson, had created high expectations for a conference described as 'the last best hope to keep 1.5 alive', but although some progress was made towards developing bolder strategies to limit global warming, any positive news included numerous caveats. The UK's bold assertion that the world should 'power past coal' was diluted in the final conference memorandum when the commitment to a 'phase-out of unabated coal' was changed to a 'phase-down' in the Glasgow Climate Pact after an intervention by India and China. Promises to increase climate finance for the developing world were undermined by the fact that the developed world has still failed to meet the USD100 billion target it set for 2020. Excitement about an agreement between the US and China to cooperate on environmental issues and to hold bilateral talks in 2022 was tempered by the fact that Chinese President Xi Jinping did not attend the conference, China failed to sign many of the multilateral agreements reached in Glasgow, and even the US failed to commit itself to key objectives on reducing coal use in the power sector and accelerating the use of zero-emission cars.

As a result, UN Secretary General Antonio Guterres felt the need to apologise to young people and climate activists, saying, "I know that many of you are disappointed…the path of progress is not always a straight line…we won't reach our destination in one day or one conference…COP 27 starts now."[28] With these words he fired the starting gun for the next COP, which is due to take place in Sharm-el-Sheikh in Egypt in November 2022. Traditionally, every fifth COP is seen as a major event, as the Paris Agreement signed at COP21 developed a 5-year reporting schedule for progress and the updating of countries' Nationally Determined Contributions (NDCs), with Glasgow being the first opportunity to do this (delayed for one year by the COVID pandemic). However, with numerous key issues left unresolved in Glasgow, COP27 finds itself as another important milestone in global climate negotiations.

Perhaps the most urgent matter to address for the 193 parties who take part in the UNFCCC process is the matter of their NDCs, which comprise their commitment to reduce greenhouse gas emissions. In fact, only 165 have submitted NDCs at all, while only 124 had updated them in line with UNFCCC guidelines by the end of COP26.[29] Although the updated NDCs do cover more than 90 per cent of global emissions, the commitments they contain (to 2030) will only keep global warming to 2.4^{o} C above pre-industrial levels, well short of the 1.5^{o} C target. Even if one takes into account further pledges made beyond 2030, the most optimistic outcome would be 1.8^{o} C of warming (see Figure 7.1) with the result that all countries have been asked to review and update their NDCs again during 2022, rather than wait another five years. The consequence is that COP27 has become another vital measurement point for global emissions targets, with a further ratcheting of ambition clearly required.

Another major priority for COP27 will be climate finance, as a number of issues on this topic were left unresolved at COP26. Firstly, developing countries promised to meet their USD100 billion financing target by 2023 at the latest (delayed from 2020) and potentially in 2022. As a result, COP27 will be an opportunity to review progress and, hopefully, report that the goal has been met. Secondly, developing nations made a commitment to double funding for Adaptation to USD40 billion by 2025, and COP27 will offer an opportunity to affirm and review progress on this pledge. Thirdly, and perhaps most importantly, the issue of loss and damage, which was left almost completely unresolved in Glasgow, will certainly be on the agenda. The Egyptian government has framed its role in hosting COP27 as an opportunity to allow African views to be heard 'with one voice' as the continent underlines its commitment to climate action but also makes the case for technical and financial support to mitigate the impact of climate change which it has done little, if anything, to cause. At COP26, only the host country Scotland committed actual money (albeit a minimal £2 million) to a loss and damage fund, but

[28] https://unfccc.int/news/secretary-general-s-statement-on-the-conclusion-of-the-un-climate-change-conference-cop26
[29] https://climateactiontracker.org/climate-target-update-tracker/

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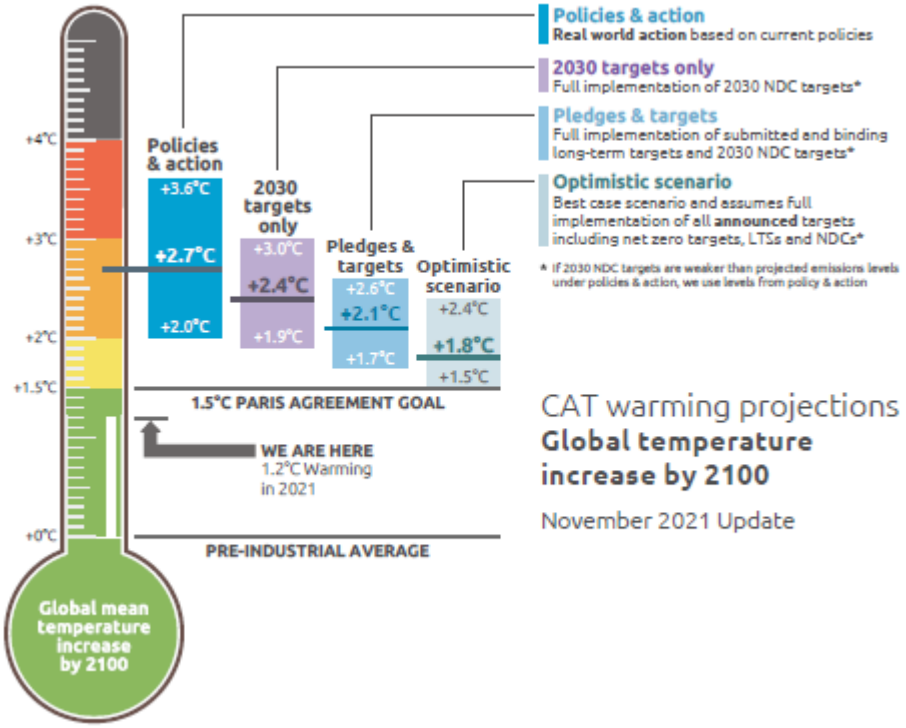
the issue will certainly be raised again in Sharm el-Sheikh and could become a major source of dispute between the developed and developing world.

Figure 7.1: Implications of various emission targets for global warming outcomes



Source: Climate Action Tracker, "Glasgow's 2030 Credibility Gap", p.1

The first opportunities to discuss all these topics will come in the various meetings that are scheduled for 2022 in the run-up to the COP. These include the Middle East and North Africa Climate Week in early March, the London Climate Action Week in late June, the G7 summit planned for the summer in Germany, the UN General Assembly meeting in September which will take place alongside the New York Climate Week, and the G20 summit taking place in Indonesia at the end of October, just before the COP starts. These gatherings will provide vital indicators of the progress that is being made and of the main debating points which remain to be resolved at COP27 and will also provide further evidence as to whether the pledges made at COP26 can be taken seriously or whether the disappointment acknowledged by Secretary General Guterres was justified.

Three other key dates in 2022 will mark the publication of the next documents in the IPCC's Sixth Assessment Report (AR6). These will include a review of climate impacts, adaptation and vulnerability in February, an analysis of climate mitigation in March and a synthesis report in September which will bring the entire AR6 analysis together prior to COP27. Each publication is likely to put further pressure on policy-makers to increase both their pledges and actions and will be closely watched by all players in the energy sector.

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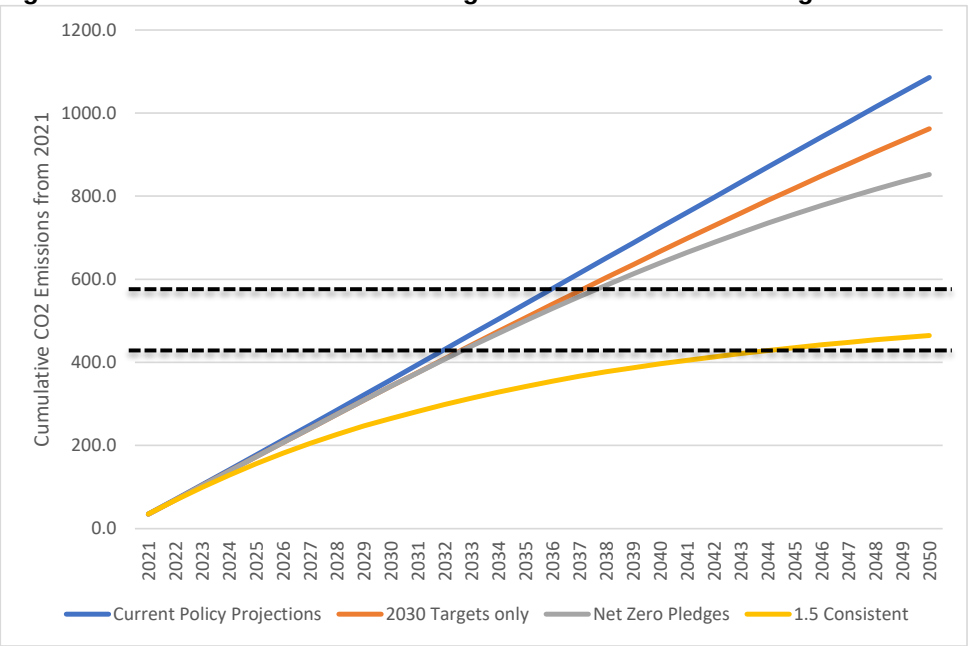
8. The need to update NDCs in 2022

Although the results of the COP26 climate conference in Glasgow were somewhat mixed, with bold new pledges being offset by concerns over implementation and a reluctance by some major emitters to commit to key objectives, one of the more positive outcomes was the commitment, signed by all parties in the Glasgow Climate Pact (Article 29), to review their Nationally Determined Contributions again in 2022, rather than to wait for another 5-year cycle to pass. This accelerated process was driven by the worrying revelation that the NDCs in their current form do not even get the world close to meeting its 1.5º C temperature increase target, and indeed as can be seen below, they actually imply that the global carbon budget remaining to meet this goal will be completely exhausted by the early to mid-2030s. As a result, 2022 has become a vital year for the UNFCCC process and much attention will be paid to how, and by how much, NDC targets will be strengthened by various countries around the world.

Figure 8.1: Pace of carbon emission growth versus carbon budget



Source: OIES analysis based on UNFCCC data

However, although the goal of making all the NDCs 1.5º C compliant is the ultimate aim, the realistic outlook for the next 12 months varies due to the different starting points of the 193 parties in the UNFCCC process. As noted by the UNFCCC in its synthesis report published in October 2021, 165 initial NDCs representing 192 countries have been submitted, but of these only 116 (representing 143 countries) had been updated by the time of the COP26 conference. Although some further updates had been provided by the end of the conference, the priority for 2022 will be to complete the roster of fully updated NDCs as stated under the Paris Agreement.

Among those countries that did provide updated NDCs, though, there is a wide disparity of results. Significant work analysing the implications of the NDC commitments has been carried out by a number of NGOs, with Carbon Action Tracker perhaps being the most prominent. Their assessment of the recently updated NDCs suggests that a number offered no strengthening of ambition in their new pledges, contrary to the UNFCCC objective that each round of NDCs should 'ratchet up' the objectives in order to reach the overall climate target by 2050. Major emitters in this category include Australia, Russia, Brazil, Mexico, and Indonesia and so there will be significant attention paid to whether these countries provide new NDCs during 2022.

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Next, there is one country, India, which has proposed a stronger set of targets in its NDC but has yet to submit it. We discuss the situation in India in another article but as the world's third largest emitter it is clearly important to understand what the country's plans are for managing its environmental goals. Prime Minister Modi has clearly stated that any further increase in the country's ambitions will have to be supported by increased financial assistance from developed countries (see below) and as a result the debate around the Indian NDC has broad implications for global climate negotiations.

Finally, there are countries which offered NDCs with strengthened targets but where the overall ambition is still not sufficient to meet the 1.5^{o} C temperature target. In fact this includes pretty much every other country that has submitted an updated NDC, as none are assessed as being fully compliant with the UNFCCC target. Furthermore, as most of the largest emitters are developed countries, they not only have an obligation to ensure that their domestic economies meet emissions targets but also need to support the increased ambitions in developing countries. Even if developed countries meet their domestic targets, their consumption of imports from developing countries with higher emissions means that their overall carbon footprint remains unacceptable, and as the prime minister of India has pointed out, developing countries cannot be expected to meet the burden of emissions mitigation without support.

One key indicator of how this support could be managed also emerged from COP26 with the agreement of an USD8.5 billion finance package to retire coal plants in South Africa, supported by France, Germany, the UK, the US, and the EU. It will be important to monitor progress on this initiative in 2022 as it could provide a model for a just transition in other developing countries, involving not only the removal of coal but the deployment of renewable energy and the re-training of workers who have lost jobs in traditional energy industries.

Two other points about the updating of NDCs in 2022 are also worth noting. The first is that many should start to include the impact of the new sectoral initiatives that were announced at COP26. For example, the application of objectives from the Global Methane Pledge, the coal phase-out from the power sector initiative, the deforestation promises, and the zero emission vehicle plans should start to feed into NDCs for those countries that signed up for any or all of these agreements, and the potential involvement of countries that did not sign will also be anticipated, if not expected.

Secondly, there is also some hope that many countries will improve the clarity of their NDCs, especially around target setting. Many governments have opted to set targets relative to business-as-usual scenarios rather than providing specific emission reduction targets in absolute terms, and clearly it would be helpful if each country had a more precise goal against which performance could be measured. Countries such as Iran, Mexico, the UAE, and Thailand fall into this category, and although this issue is not critical it would certainly help to improve the credibility of the NDC process.

Overall, then, 2022 is set to be a vital year for making further progress in the UNFCCC process of ratcheting up climate goals. The catalyst is the fact that existing NDCs are not doing the job, and of course even if they are strengthened the climate goals will only be reached if the promises are actually implemented. However, the first step is to ensure that the goals for the next five- and ten-year periods are compliant with the overall 2050 objective, and that is a task which will be essential to achieve in the months ahead of COP27 in November 2022.

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9. Will the Global Methane Pledge achieve critical mass in 2022?

In September 2021, the US, EU, and seven additional countries committed to a Global Methane Pledge. Two months later, the launch of the Pledge was one of the high-profile successes at COP26. The Pledge is:

> '… a collective effort to reduce global methane emissions by at least 30 per cent from 2020 levels by 2030 which could eliminate over 0.2 degrees C warming by 2050. Participants also commit to moving towards using the highest tier IPCC good practice inventory methodologies, as well as working to continuously improve the accuracy, transparency, consistency, comparability, and completeness of national greenhouse gas inventory reporting … and to provide greater transparency in key sectors.'

Methane is the second-largest contributor to warming after carbon dioxide and by far the biggest contributor of the non-CO_2 gases. It has attracted increasing attention because of the urgency to implement measures which can have an immediate impact on global warming over the next several decades.

The Pledge includes methane from all anthropogenic sources, which means agriculture and waste as well as fossil fuels. But while agriculture (and in some countries waste) accounts for a larger share of methane emissions than fossil fuels, the latter are the immediate focus because, compared with other sectors, reductions involve a relatively small number of companies at relatively low and (at 2021 international prices) negative costs. Both the International Energy Agency and UNEP's Climate and Clean Air Coalition have set targets of at least 75 per cent of methane reductions from fossil fuels by 2030 (compared to 2020). The Pledge combines with the European Union's proposed Regulation on Methane Emissions Reduction, and the work of the International Methane Emissions Observatory (IMEO), to promote corporate reporting of emissions based on the Oil and Gas Methane Partnership framework Version 2.0 (OGMP2) Gold Standard.

At the end of 2021, the Pledge had 111 country signatories but lacked many key fossil fuel producing, consuming, and exporting countries including China, India, Russia, Qatar, Australia, Algeria, Egypt, South Africa, Azerbaijan, and all Central Asian states. Equally problematic is that companies from most of these same countries have not yet joined the IMEO and their companies are not listed among the 74 members of the OGMP2 framework accounting for around a third of oil and gas production from operated and non-operated assets. A rough estimate is that Pledge signatory countries accounted for 63 per cent of global crude oil and condensate production, just under 50 per cent of natural gas production, and less than 20 per cent of coal production in 2020.

The absence of China is significant as at COP26 the US and China signed a Declaration on Enhancing Climate Action with specific emphasis on cooperating, '… to develop additional measures to enhance methane emission control, at both the national and sub-national levels.' The IEA considers China a 'committed country' with respect to methane reduction, due to the Chinese Oil and Gas Methane Alliance. China's reluctance to sign may relate to high levels of emissions from its coal sector. Indian failure to sign could relate to both coal production and its agricultural sector. Russian absence may reflect current political tensions with both the US and Europe, as well as the fact that at least in relation to the oil and gas sector, there is already regulation in place with methane having been classed as a pollutant since the end of the Soviet era. Even within the EU, many eastern and south-eastern member states have yet to sign.

For many governments – and especially those for which these emissions are related to a significant share of their GDP either in relation to fossil fuels or agriculture – the consequences of signing the Pledge may need more time to analyse, and there are hopes that 2022 will see more countries come on board. To achieve critical mass, the Pledge needs big emitters, with China, India, and Russia probably essential for any claim for it to be considered a truly global - as opposed to a largely US-European - initiative. While the Pledge does not constitute a legally binding commitment, it indicates

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that governments recognise the importance of methane and are willing to step up efforts to reduce emissions. Failure to sign up in 2022 could be construed as indifference which, given the importance and urgency to reduce greenhouse gas emissions this decade, would not be a good signal for progress on global climate action.

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10. US-China relations: a COP-ing mechanism for 2022

As COP26 in Glasgow drew near to what seemed like an unremarkable end, a joint declaration by the US and China on 10 November 2021, signaling the two countries' intention to cooperate on enhanced climate action and meet the Paris Agreement goals in the coming years, injected renewed momentum into the talks. Although the declaration falls short of the 2014 Joint Announcement and 2015 Joint Statement, which were widely credited as the enablers of the Paris Agreement, it is nonetheless an important step forward for US-China relations and for global efforts to tackle climate change. In 2022, efforts to implement the declaration will highlight both the potential benefits of joint efforts as well as the challenges of deeper collaboration between the US and China.

Importantly in 2022, the Joint Declaration will pave the way for progress on methane emission reductions. The two countries pledged to convene a meeting in the first half of the year to focus on the specifics of enhancing the measurement and mitigation of methane, including through standards to reduce methane from the fossil and waste sectors, as well as incentives and programs to reduce methane from the agriculture sector. In addition, the US and China intend to develop additional measures to enhance methane emissions control at both a national and sub-national level ahead of COP27, dovetailing also with China's commitment to develop a comprehensive and ambitious National Action Plan on methane with a view to control and reduce methane emissions in the 2020s.

Whether the meeting will share and compare policies or include concrete steps to issue joint standards, involving wider participation from local governments, think tanks, academics, and other stakeholders from both countries will be indicative of the depth of the conversation and its potential impact. Given that agriculture reportedly accounts for 40 per cent of China's total methane discharge and around 36 per cent of the US's methane emissions, even preliminary discussions sharing policy experiences and best practices could prove fruitful. The Biden Administration's Methane Emissions Reduction Action Plan, issued in November 2021, includes a greenhouse gas (GHG) measurement initiative that will identify, confirm, and track methane and other GHG emissions and carbon sequestration, with a special focus on those associated with climate-smart agriculture practices throughout commodities' supply chains. It also includes programmes to use methane for on-farm renewable energy applications, suggesting that there is scope for collaboration on both measurement and control of methane emissions as well as their reduction. Moreover, since the energy sector - mainly coal - contributes around 45 per cent of China's total methane emissions, US efforts to reduce methane emissions by remediating abandoned coal mines could prove valuable for China. While methane emissions from coal in the US account for a smaller share of total emissions than in China, reclamation projects that employ dislocated energy workers touch on key questions of social justice in China's energy transition.

Beyond joint efforts on methane emissions, the Joint Declaration highlights additional areas for collaboration on renewable energy and power generation, including the effective integration of high shares of low-cost intermittent renewable energy, transmission policies that encourage efficient balancing of electricity supply and demand across broad geographies, distributed generation policies that encourage integration of solar, storage, and other clean power solutions closer to electricity users, as well as energy efficiency policies and standards to reduce electricity waste. But whether these statements can help lead to significant shifts in nationally determined contributions or become influential in shaping future COPs will depend on implementation. Indeed, the Joint Declaration currently only reflects the two sides' existing climate policies and injects very little new ambition. But it also calls for the creation of a *Working Group on Enhancing Climate Action in the 2020s*, a bilateral mechanism that aims to facilitate future climate cooperation. The working group will focus on discrete and tangible activities, resulting in short-term outcomes, and will potentially build the trust required for deeper, long-term collaboration.

While the areas of common interest and potential common action are numerous, 2022 will offer the first indications of whether the Joint Declaration will remain a tool aimed at rebuilding trust between the US and China or whether it can become an effective tool for tackling climate change. The frequency and

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makeup of the meetings in 2022 will be important to watch. Indeed, the 2014 Joint Announcement and 2015 Joint Statement introduced structures of sectoral cooperation, domestic dialogues, and policy dialogues which put in place measures to promote robust cooperation. But these were also part of existing dialogues and technical programmes, of which there are fewer today. The new working group will need to do something similar to play an influential role in shaping US-China climate cooperation and informing global practices.

What is more, even though both the US and China have expressed a strong commitment to tackling climate change in domestic pledges and joint action, a number of challenges remain. For one, bilateral relations remain fraught and while there has been a thawing of tensions since late 2021, any progress on climate change could come undone by a broader deterioration in relations. Second, President Biden's funding for measures to fight global warming and meet the administration's climate goals, the Build Back Better bill, continues to face domestic challenges. In the context of a challenging bilateral relationship and with the US struggling to implement its own targets, Washington's efforts to share experiences could ring hollow. Finally, even though Beijing remains committed to its 2030 and 2060 carbon targets, recent government statements continue to emphasize the importance of coal in the energy system. And while the government is now talking about 'phasing out' fossil fuels, new coal-fired power plants are already being added and more will start up in 2022. And as the Chinese government prioritises stability in 2022, its own green credentials could come under question. 2022 will therefore be an important year for the US-China Joint Declaration: is it a trust-building mechanism and the only clear deliverable capable of placing US-China relations on an even keel, or can it become an accelerator of global efforts to tackle climate change?

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11. Prospects for hydrogen projects in 2022

The years 2020 and 2021 saw the publication of many bold strategies and ambitions related to low-carbon and renewable hydrogen production.[30] A few examples illustrate this (and the list is far from exhaustive):

- The EU hydrogen strategy (July 2020), with a focus on renewable hydrogen set a target of installing 6GW of electrolysers by 2024 and 40GW by 2030:[31]
- The UK hydrogen strategy (August 2021) was open to both blue and green hydrogen and set an ambition for 5GW of low-carbon hydrogen production capacity by 2030;[32]
- Chile's National Green Hydrogen Strategy (November 2020) set targets of 5GW of electrolysers under development by 2025 and 25 GW operational by 2030;[33]
- China's Hydrogen Alliance (Sept 2021) announced a target of 100GW of renewable hydrogen production by 2030.[34]

By contrast, total global electrolyser capacity in 2020 stood at 0.3 GW.[35] Total low carbon hydrogen production is less than 20 TWh per year (less than 1 per cent of global hydrogen production) and is forecast to grow to around 60 TWh globally by 2023.[36]

To be on track to reach these targets, there will need to be some significant progress on large-scale projects, including some Final Investment Decisions (FID), during 2022. Thus, as a key theme for the year, OIES will be monitoring the progress of significant low-carbon hydrogen projects, and in particular, how many such projects take a positive FID.

According to the IEA Hydrogen Project Database,[37] globally there are thirty low-carbon hydrogen projects with capacities greater than 100MW under development which are not yet under construction and which have announced onstream dates in 2023 or 2024. It is reasonable to assume that many of these should take FID during 2022 if they are to be onstream as projected. The majority of these projects are in Europe, but the database also includes significant projects outside Europe, including the 1000 MW Intermountain power/green hydrogen project in Utah, US, the 175MW Haru Oni plant in Chile, the 100 MW Donghae offshore wind plant in Korea, the 500 MW Southland green hydrogen project in New Zealand, and green ammonia plants in Oman (250MW) and Trinidad (150MW). The chart below summarizes the total plant capacities by region, if all projects were to come onstream as projected. OIES aims to monitor the progress of actual FIDs against these projections.

[30] There is no commonly accepted terminology to classify hydrogen by production method. Most current (so-called 'grey') hydrogen production is from fossil fuels and typically emits around 10 tonnes CO2 per tonne of hydrogen. 'Renewable' or sometimes 'green' hydrogen is generally understood to be from electrolysis using renewable electricity. 'Blue' hydrogen is made from natural gas, with the CO2 captured and stored. For simplicity, this article uses 'low-carbon' hydrogen to mean any hydrogen where the production process emits much less CO2 than grey hydrogen – say, less than 2 tonnes CO2 per tonne of hydrogen.

[31] https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

[32] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011283/UK-Hydrogen-Strategy_web.pdf

[33] https://energia.gob.cl/sites/default/files/national_green_hydrogen_strategy_-_chile.pdf

[34] https://www.argusmedia.com/en/news/2256750-china-hydrogen-alliance-seeks-100gw-renewable-capacity

[35] IEA Renewables 2021: https://www.iea.org/reports/renewables-2021

[36] IGU Renewable Gas Report, edited by OIES: https://www.igu.org/resources/global-renewable-low-carbon-gas-report/

[37] https://www.iea.org/data-and-statistics/data-product/hydrogen-projects-database

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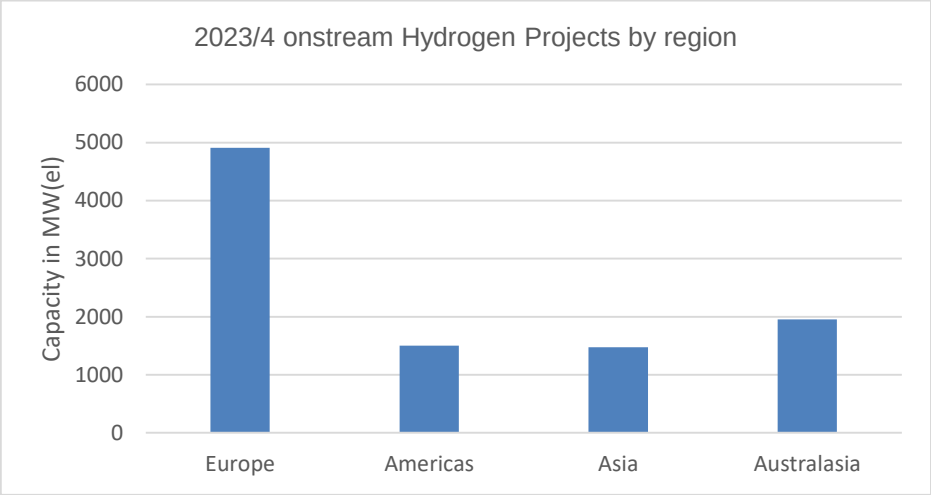
Figure 11.1: 2023/4 Onstream hydrogen projects by region

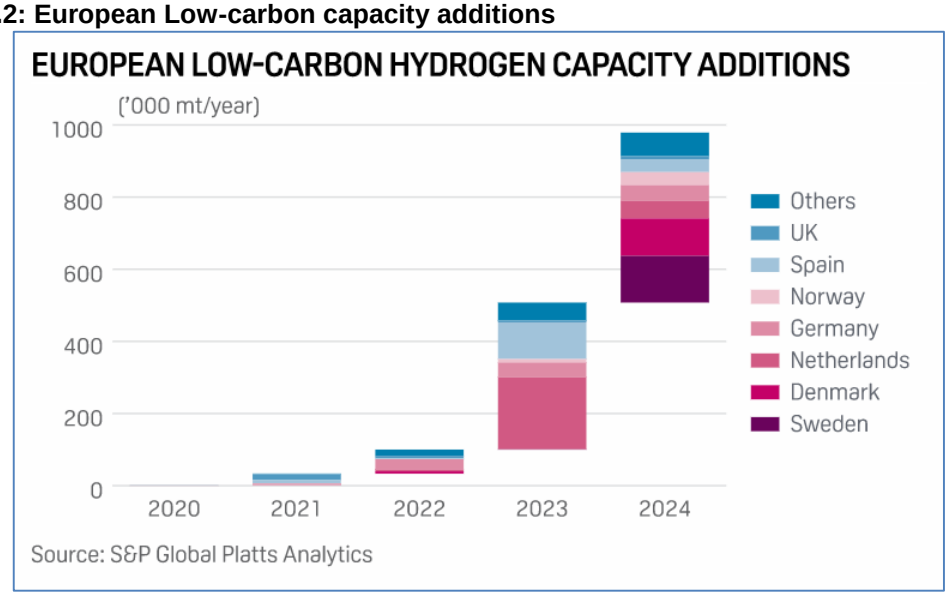


Source: Author's analysis of IEA data

Focusing on Europe and drawing on a slightly different data source, Figure 11.2 from Platts Analytics provides an overview of the significant ramp-up in capacity additions envisaged for 2023 and 2024, totaling around 1 million tonnes by end-2024. If that were all supplied as green hydrogen, it would require electrolysers powered by around 12 GW of electricity, well in excess of the EU target of 6 GW capacity by 2024, or the 5 GW shown in Figure 11.1. However, some of these low-carbon hydrogen capacity additions are for blue hydrogen (for example part of the Porthos project in NL or the UK government supported CCS projects).

Realistically, of course, not all projects will proceed in line with the (often ambitious) schedules announced by project developers, but by end-2022, a comparison of actual FIDs with announced aspirations should put us in a better position to judge the success rate for low-carbon hydrogen projects. This in turn will inform policy makers on what further action, if any, will be required if they are to deliver on the targets set out in their hydrogen strategies.

Figure 11.2: European Low-carbon capacity additions



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12. UK Carbon Capture and Storage – third time lucky?

During 2022 there should be an agreement for the funding of the first two UK Carbon Capture, Storage and Utilisation (CCUS) clusters, and hence, at last, the start of major investment in CCS in the UK. By the time the projects come online in the mid-2020s, the UK will have been talking about CCS for over 20 years, but the sector has had a troubled history, with not one, but two failed government attempts to kick start the industry. Hopefully this will be a case of third time lucky. The success of CCS in the UK is important not just for the UK - which needs CCS to meet its net zero targets - but also for the development of some of the first commercial-scale industrial CCS and blue hydrogen projects, as well as continued use of natural gas as part of the UK's energy mix. Key to success will be whether the UK's proposed CCS business support models will be sufficient to give companies the confidence to take Final Investment Decisions.

A troubled history.

As early as 2003 the UK recognised CCS as a 'promising way forward'[38] to meet climate change targets. Its case has been strengthened since the UK adopted a 2050 net zero target in 2019 compared to its previous target of an 80% reduction. In 2021 the UK also adopted the Sixth Carbon Budget proposed by the Climate Change Committee which aims to reduce emissions by 78% by 2035 as a stepping-stone to net zero in 2050. The Sixth Carbon Budget highlights the importance of CCS - not only in reducing emissions from industry, waste to energy, and fossil fuel power generation required as a complement to intermittent renewables – but also for negative emissions using either Bioenergy Carbon Capture and Storage (BECCS) or Direct Air Capture and Storage (DACS) to offset residual emissions from very hard-to-decarbonise sectors.

In 2007 and 2012 the UK government launched competitions to secure funding for CCS, only to cancel them at the last moment in 2011 and 2015 respectively, much to the annoyance of the companies which had spent time and money participating. A UK parliament report noted that such 'late cancellations have grown scepticism of the UK's commitment amongst investors.'[39] In both cases the UK Treasury (Finance Ministry), which controls the government purse strings, was instrumental in the cancellation, as part of general spending cuts. Following the COVID pandemic, UK debt levels are at their highest in sixty years. Political pressure is already growing to cut 'green levies' to ease the burden on energy consumers following recent increases in energy prices. Until deals between government and industry are signed, there remains a risk that the Treasury may again pull the plug.

A renaissance?

Despite the cancellations, work on CCS continued in the background including the CCUS Cost Challenge Taskforce Report published in 2017, and consultation on CCS business models from 2019 onwards. In 2019, £4.2m was granted toward an industrial scale demonstration plant at Tata Chemicals Europe in Northwich, due for completion in 2021.[40] CCS received a major boost when it was Point Eight of the Prime Minister's 'Ten Point Plan for a Green Industrial Revolution' in late 2020. This promised two industrial CCUS clusters by the mid-2020s and a further two in place by 2030, capturing up to 10MtCO2 per year.[41] Support would be provided by a £1bn CCS Infrastructure Fund (CIF).[42][43] The clusters would be chosen from six potential locations which account for half of the UK's manufacturing

[38] https://researchbriefings.files.parliament.uk/documents/CBP-8841/CBP-8841.pdf
[39] https://publications.parliament.uk/pa/cm201719/cmselect/cmbeis/1094/1094.pdf
[40] https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution/title
[41] https://www.gov.uk/government/publications/the-ten-point-plan-for-a-green-industrial-revolution/title
[42] https://www.gov.uk/government/publications/design-of-the-carbon-capture-and-storage-ccs-infrastructure-fund/the-carbon-capture-and-storage-infrastructure-fund-an-update-on-its-design-accessible-webpage
[43] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future/energy-white-paper-powering-our-net-zero-future-accessible-html-version

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and refining emissions - Humberside (10.0 MtCO2e), South Wales (8.9 MtCO2e), Merseyside and Grangemouth (5.0 MtCO2e each), Teesside (3.9 MtCO2e), and Southampton (3.2 MtCO2e).[44] On 19 October 2021[45] the government granted 'Track 1' status for the first two clusters to the East Coast Cluster project[46] led by BP, storing emissions from Teesside and Humberside, and the Hynet project[47] in Merseyside led by ENI. The Acorn project,[48] based on the Grangemouth cluster led by Shell and Harbour Energy, is being held in reserve. Track 1 projects will negotiate with the government during 2022; if the government decides they represent value for money they will receive support. Successful negotiations are thus crucial if the UK's CCS ambitions are to be realised.

Different business models for carbon transport and storage, and power and industrial carbon capture.

After lengthy consultations with industry, the UK government has developed three different proposed business models to provide the mechanisms for government support[49] which have been updated in late 2021 and early 2022. However, as the government notes, the proposals are not yet final and are subject to Ministerial and Parliamentary approval. Significantly, the government also states that it 'reserve(s) the right to review and amend all provisions here, for any reason and in particular to ensure that proposals provide value for money and are consistent with the current subsidy control regime, and that government is comfortable with any balance sheet implications.'[50] As noted above, the government's balance sheet is already severely stretched thanks to COVID.

The different models are adapted to the different risk profiles and government preferences. For example, the power carbon capture model is designed so that CCS-enabled power generation is not called upon before all renewable generation has been utilised, but ahead of any unabated power generation via a so-called Dispatchable Power Agreement. It includes two payments - one for availability and a variable payment. Support for industrial carbon capture includes capital grants and ongoing revenue support. Transport and storage support is via an Economic Regulatory Regime based on regulated third-party access and user-pays tariffs. However, support will be needed in the early years as the network will be 'right sized' for future use but initially demand for capacity will be less than that available. The government favours up-front capital grants to overcome the resultant revenue gap but is also considering other options such as loan guarantees.

The Track 1 projects are the pioneers for these business models. If negotiations in 2022 are successful, it will set the precedent for future projects, including BECCS and DACS. If not, government and industry may need to rethink their CCS ambitions.

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[44] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future/energy-white-paper-powering-our-net-zero-future-accessible-html-version
[45] https://www.gov.uk/government/publications/cluster-sequencing-for-carbon-capture-usage-and-storage-ccus-deployment-phase-1-expressions-of-interest/october-2021-update-track-1-clusters-confirmed
[46] https://eastcoastcluster.co.uk
[47] https://hynet.co.uk
[48] https://theacornproject.uk
[49] https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models
[50] https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models/november-2021-updates-on-the-industrial-carbon-capture-and-dispatchable-power-agreement-business-models

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13. From `Carbon-Neutral' to `Greenhouse Gas Verified' LNG cargos in 2022[51]

In 2019, the first LNG cargos designated 'carbon-neutral' were delivered to Japan, Korea, and India by Shell and JERA. The table below shows that, up to November 2021, more than thirty cargos of carbon-neutral LNG had been delivered to (mostly) Asian destinations with Japan as the principal market. The term 'carbon' is misleading since most of these cargos claim to be measuring not just carbon dioxide emissions but also other greenhouse gases (principally methane and nitrous oxide). The term 'neutral' in this context means that offsets have been purchased equivalent to the greenhouse gas emissions of the cargo for the full supply chain from production through liquefaction, shipping, and regasification to end-use. (Some cargos have offset emissions from only a part of the chain.)

Figure 13.1 Carbon-neutral LNG Cargos 2019 - November 2021: sellers and countries of delivery

SELLER OF CARGO	COUNTRY OF DELIVERY
Shell 8	Japan 13
Inpex 3	China 4
Mitsubishi/DGI 2	Taiwan 3
BP 2	South Korea 2
Sakhalin Energy 2	Mexico 1, Dominican Republic 1
Petronas 2	Europe 3
Not Known 4	
Others: Jera, Total, Mitsui, Gazprom, RWE, Cheniere, Oman LNG, ENI	

There has been very limited transparency surrounding some of the cargos with the origin, buyer, and type of offset not disclosed. The volume of gas or quantity of emissions from the cargo were stated in very few cases, and some of those which did cited a standard UK government methodology, based on a European Union study with data from 2012. So far as can be judged without the benefit of publicly available documentation, carbon-neutral cargos appear to attribute a standard quantity of emissions to the full life-cycle of the cargo including emissions from the importing country market. This falls significantly short of a requirement for accurate measurement, reporting, and verification (MRV) of emissions from individual cargos, without which it is impossible to know the size of the offset which is required.

Offsets introduce another level of complexity. For cargos delivered by Shell, the GHG footprint of the entire LNG value chain has been offset by purchasing emission credits from (mostly) forest projects largely or wholly owned by the company. There are a range of projects (including efficiency, forestry, renewable energy, emissions capture) and a range of registries for the credits. Carbon-neutral LNG cargos have used credits from the voluntary carbon market which is rapidly increasing in size and popularity. More than half of the cargos have used the Verified Carbon Standard (Verra), while others used include the Climate Action Reserve, American Carbon Registry, Gold Standard, and California

[51] More detail on carbon neutral LNG can be found in Stern, J. (2022) "Measurement, Reporting and Verification of Methane Emissions from Natural Gas and LNG Trade: creating transparent and credible frameworks", Working Paper ET06, Oxford Institute for Energy Studies at https://www.oxfordenergy.org/publications/measurement-reporting-and-verification-of-methane-emissions-from-natural-gas-and-lng-trade-creating-transparent-and-credible-frameworks/

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Climate Action. Costs of credits have been assessed in the range of $0.45–0.55/mmbtu, which corresponds to Platts' carbon-neutral LNG price assessment of Corsia-eligible credits in the voluntary carbon market for Q3 2021. These costs would have looked high in 2020 when LNG prices were in low single digits, but much less so at the price levels of 2021.

Pavilion's Statement of Greenhouse Gas Emissions (SGE) Methodology, and GIIGNL's MRV and GHG-Neutral LNG Framework, both published at the end of 2021, set out frameworks for transparent measurement reporting and verification of GHG emissions from LNG cargos. Both have detailed requirements for MRV of the different stages of the export supply chain: exploration and production, transportation to the liquefaction plant, liquefaction, shipping and (in the GIIGNL framework) regasification and end use. An academic article sponsored by Cheniere with methodology and data related to emissions from its 2018 Sabine Pass exports, is the first public documentation with details of emissions and the methodology used to calculate them, and will be followed in 2022 by emission tags for each cargo exported from the company's two liquefaction plants. These frameworks are good starting points for what is needed to provide credibility to the LNG industry's sustainability claims.

The term `carbon neutral' LNG is a misnomer and should be replaced by `greenhouse-gas verified' LNG matched with full or partial offsets (if required), and accompanied by publication of data on emissions and offsets and how these were calculated. This is a change that needs to happen in 2022 as without empirical MRV of emissions from these cargos and much more transparency about the process, the credibility of GHG-related claims associated with LNG trade is open to serious question, and undermines claims that it can play a positive ongoing role in the low-carbon energy transition.

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14. COP26 'Article 6' rulebook tees up continued expansion of voluntary carbon markets

After six years of tough negotiations, rules for cooperative implementation of carbon targets under Article 6 of the Paris Climate Agreement were approved in the 26th Conference of the Parties (COP26) in Glasgow. Article 6 was originally introduced into the Paris Agreement to enable countries to achieve their emission mitigation goals ('Nationally Determined Contributions', or NDCs) at lower cost and facilitate enhanced ambitions by governments. The new rules clarify how countries can implement NDCs either through working together directly or using international transferred mitigation options. Article 6 allows for multiple cooperative systems, including linkage among homogeneous market-based policies (e.g., cap and trade) and heterogeneous policies (e.g., carbon tax and performance standards), and innovations such as regional 'carbon clubs' which have already begun to form.

While challenges remain, for example, in establishing viable projects in developing countries, there is widespread expectation that the Article 6 rulebook will create conditions for effective, international carbon markets to thrive, including continued, significant growth in private sector investments through voluntary carbon offset projects. In 2020, regional compliance carbon markets were valued at USD272 billion, while voluntary carbon markets, fueled by corporate 'net-zero' pledges, were valued at USD1 billion in 2021. A recent study estimates that if parties to the Paris Agreement work cooperatively under an international mechanism such as Article 6 and engage in emissions trading to reach net-zero emissions, unified global carbon markets could facilitate transactions of approximately USD1 trillion per year by 2050 (Yu et al., 2021).[52] These transactions would lead to significant emission reductions and, depending on the type of projects, support for local communities, sustainable development, conservation and restoration and renewable energies, in addition to a large redistribution of capital across regions from buyers to sellers.

The new Article 6 rulebook paves a pathway for the simplification of carbon markets and a gradual merger of government-led systems and voluntary carbon markets. Specifically, Article 6.2 allows a host country where GHG emission reductions are generated and issued under the Article 6.4 crediting mechanism,[53] to transfer internationally traded mitigated outcomes (ITMOs) to a credit-buying country. To ensure that carbon credits are only claimed once, the host country must make a 'corresponding adjustment' which is a guarantee that the transferred credits will not be used against its own NDCs and would only be used once against the NDCs of the credit-buying country.

Especially relevant to voluntary markets is that Article 6.2 also specifies that a corresponding adjustment must be made whenever ITMOs are transferred abroad, even if the credits are used by companies to offset their own emissions or in market-based schemes such as the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) (referred to as 'other international mitigation purposes').

Consequently, a two-tier system could evolve with two types of carbon credits in voluntary markets:

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[52] Yu, S., Edmonds, J., Forrister, D., Munnings, C., Hoekstra, J., Steponaviciute, I. et al. (2021). The Potential Role of Article 6 Compatible Carbon Markets in Reaching Net-Zero. University of Maryland and International Emissions Trading Association. https://www.ieta.org/resources/Resources/Net-Zero/Final_Net-zero_A6_ working_paper.pdf

[53] Article 6.4 establishes a centralised carbon market and certification system regulated by the UNFCCC, with oversight by a Supervisory Body, which will replace the Clean Development Mechanism (CDM) that previously operated under the Kyoto Protocol. The Parties agreed to limit the amount of legacy CDM credits that would be eligible to be rolled into future periods, thereby reducing the risk of an oversupply of 'old credits' affecting voluntary markets. Trading in earlier iterations of the EU Emissions Trading System (EU ETS) shows that such oversupply can severely impact the orderly functioning of carbon markets.

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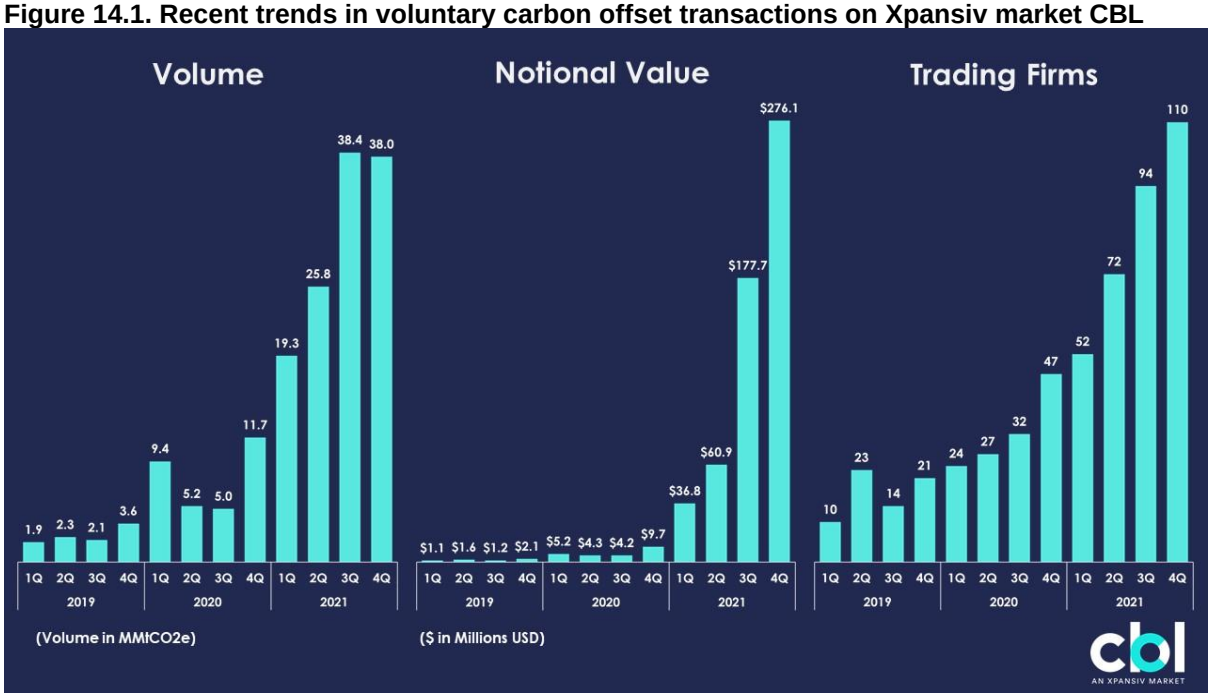
- Companies will be able to select for 'adjusted credits' that eliminate the risk of double counting, possibly with higher perceived value in pursuit of science-based targets and net-zero emissions.
- Other 'non-adjusted' credits could be used to support claims for other environmental or social indicators, or for emission reductions that have a lower perceived value in terms of science-based targets required to achieve net zero emissions.

Beginning in 2022, participants in voluntary carbon markets will be closely examining the implications of Article 6 for their activities, for example, balancing investments in adjusted versus non-adjusted credits and accessing high quality projects within their own countries. Market participants will also be monitoring clarifications from a variety of sources including the UNFCCC Article 6 Supervisory Body (scheduled to meet twice in 2022), the Integrity Council for Voluntary Carbon Markets (an extension of the TSVCM), the VCM Integrity Initiative, and the various standards organizations (e.g., Gold Standard, Verra).

While significant work remains to operationalize a new, cooperative global system, the completed Article 6 decision marks an important milestone in providing clear accounting guidance for emissions trades between countries and launching a new crediting mechanism that will give access to all countries interested in attracting investment through carbon markets. As a result, many of the trends witnessed in 2021 such as the drive for standardization of contracts, higher volumes of trade through exchanges[54] and the emergence of a new set of players (see Figure 14.1), the development of new instruments (notably standardized spot and futures contracts for the Global Emission Offset (GEO) and the Nature-Based Global Emission Offset (N-GEO)), and the increase in the price of carbon credits (see Figure 14.2) are more likely to continue in 2022 and beyond.

Figure 14.1. Recent trends in voluntary carbon offset transactions on Xpansiv market CBL



Source: CBL

[54] For example, between 2019 and 2021, with future deliveries included, voluntary carbon offset transactions on Xpansiv market CBL increased over 12-fold, corresponding to an 93-fold increase in market value over the 3 years.

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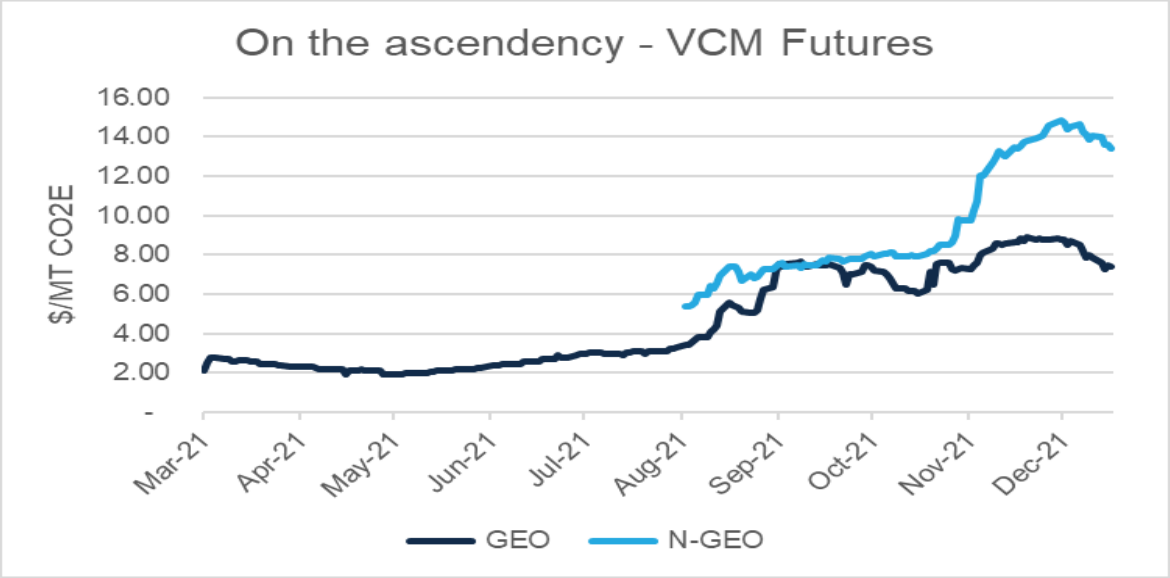
Figure 14.2. Global Emissions Offset (GEO) and Nature-Based Global Emission Offset (N-GEO) Prices, US Dollars per metric ton (MT) of CO2 equivalent



Source: CME Group

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15. Road to net zero: New oil assessments for 2022

As investors pull back from oil and gas investing, the spectre of climate change has ravaged shareholder sentiment, making many market participants evaluate their business models in accordance with COP26 pledges and look for ways to win the mandate for capital in a sustainable way.[55]

The most familiar approach to reducing the carbon footprint is the purchase of carbon neutral claims or carbon offsets provided by projects aimed at reducing GHG emissions, traded in voluntary carbon markets (VCMs).[56]

The latest tools[57] available to consumers are carbon-adjusted oil price benchmarks, price assessments of the value of individual types of crude oil adjusted for the cost of carbon equivalent emissions associated with their production.

Last year, S&P Global Platts (Platts) test-launched the first ever daily Platts Carbon Removal Credit Assessment, alongside its monthly carbon intensity (CI) calculations for selected global crude oil fields. Combined, the two facilitate a calculation of the carbon intensity premium (CIP)[58] for individual grades of oil, alongside their oil market price assessment. It would be no surprise if the other price reporting agencies followed.

For 2022, Platts will extend the assessments of CI to forty different grades of oil. They are measured in kilograms of CO2 equivalent per barrel (kgCO2eq/boe) and their estimated CIPs are USD per barrel.

The key variable in the assessment is the CI calculation based on an open-source model developed at Stanford University, the Oil Production Greenhouse Gas Emissions Estimator (OPGEE 3.0) [59]. The calculation includes the emissions associated with the production, flaring and venting, maintenance, processing, and transport of individual crude oils to the storage hub from which they are commonly traded. The idea is for the CIP[60] to become just another attribute of any given type of crude oil, just like their specific gravity and sulphur.

For example, the production of a heavy, bitumen-based Canadian crude oil, Cold Lake, extracted using hot steam and therefore a lot of energy, is estimated to be associated with 81.87 kg of carbon dioxide equivalent emissions per barrel and has a CIP of USD4.09/bbl.[61] The carbon intensity of this process dwarfs that of a Norwegian grade of North Sea crude, Johan Sverdrup, which is calculated to emit only 3.73 kgCO2eq/boe and which has a CIP of only USD0.19 a barrel (both using an arbitrary but not unrealistic carbon price of USD50/ tonne, see Figure 15.1).

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[55] Organizations such as Science Based Targets initiative (SBTI), are providing companies with a clearly defined paths to achieving their goals in line with the Paris and Glasgow Agreements; Race to Zero campaign, an UN-backed global campaign rallying companies, cities, regions, financial and educational institutions and The Glasgow Financial Alliance for Net Zero (GFANZ).
https://www.gfanzero.com/about/ . It is a part of the 'Race to Zero' umbrella organisation.

[56] For details about their application, see the OIES PAPER ET03: 'Voluntary markets for carbon offsets: Evolution and lessons for the LNG market' by A. Bose et.al.

[57] Another example is the Methane Performance Certificates (MPCs), created for oil and gas producers to sell instruments representing zero methane emission from natural gas production. See:
https://xpansiv.com/methane-performance-benchmark-launched-in-natural-gas-market/ also
https://press.spglobal.com/2021-10-18-S-P-Global-Platts-and-Xpansiv-Launch-Methane-Performance-Benchmark-in-Natural-Gas-Market Each MPC represents 1 MMBtu of gas produced with zero methane emissions and their trade reveals the market value of reducing (methane) impact of such production.

[58] It is really a GHG or carbon-equivalent intensity premium, but Platts call it CIP for short.

[59] https://eao.stanford.edu/opgee-oil-production-greenhouse-gas-emissions-estimator

[60] See footnote 57.

[61] As calculated by Platts in June 2021. See:
https://www.spglobal.com/platts/en/about-platts/media-center/press-releases/2021/092721-platts-launches-crude-carbon-intensity-calculations-daily-carbon-offset-premiums

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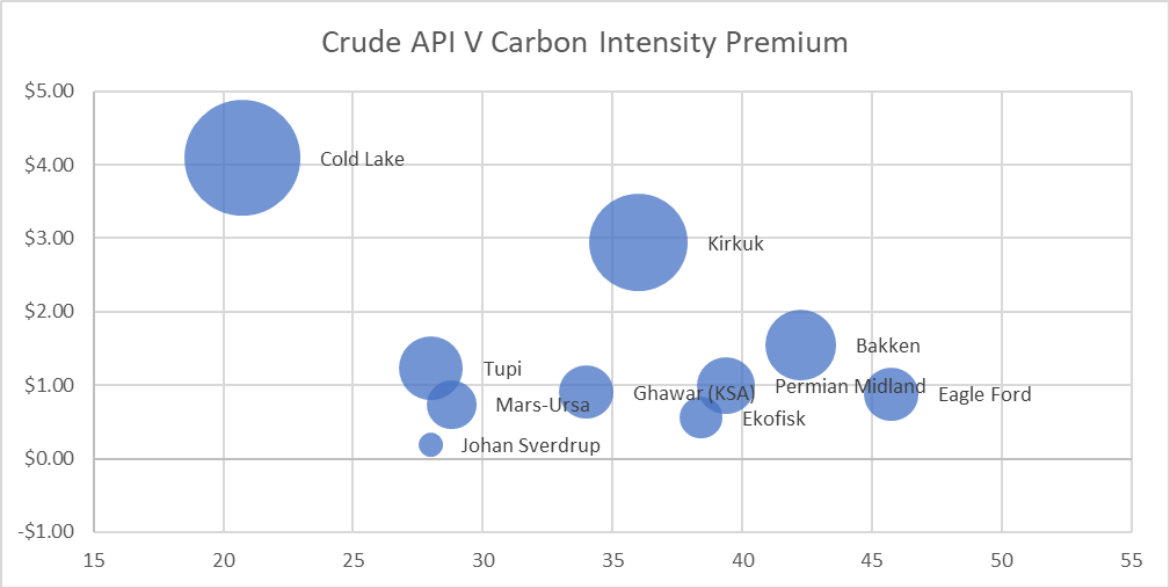
A higher carbon intensity and the associated crude oil premium would indicate a greater environmental cost (using the voluntary carbon credits in this case) needed to offset emissions associated with such crudes.

Figure 15.1: Attributes (API and CI) of some crudes at USD50/MT carbon



Source: Platts

For now, this new carbon intensity adjusted assessments will primarily provide transparency with regards to emissions and the associated environmental cost of individual crudes. Once the verification process gets perfected and if government policies such as the Carbon Border Adjustment Mechanism come into force, such ESG assessments could become the norm and the market participants may decide to trade crude oil at these prices. This would turn these assessments into environmentally adjusted benchmarks.

Eventually, with advances in blockchain technology and digitising the supply chains using 'smart' contracts, it may be possible for individual crude oil cargoes to have their own associated carbon intensity (as well as other attributes such as sulphur, API density etc.) and a carbon adjusted price in a digitised (tokenized) form. The owners of the cargo would simply own digital tokens, representing ownership of the cargo with the given attributes. [62]

If these new market mechanisms and benchmarks are facilitated by greater public and private investments, they can add value to both shareholders and public institutions and provide for more sustainable allocation of resources and therefore smoother energy transition.

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[62] So called non-fungible tokens (NFTs) have been all the rage in the art world for some time now. See: https://www.economist.com/the-economist-explains/2021/10/12/what-is-an-nft Also see: https://cms.abaxx.fi/uploads/Smarter_Markets_Maryam_Ayati_Energy_industry_veteran_vision_for_tokenizing_supply_chain_24d7911305.pdf

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16. EU regulatory themes for 2022

In 2021 the EU Commission published legislative proposals aimed at meeting 55 per cent emissions reductions by 2030 and net zero by 2050. 2022 will see the final texts agreed between the Commission, EU Parliament and the EU Council which represents the Member States. The sheer scale and ambition of the legislation offers plenty of opportunity for 'horse trading' and discussion will be intense. MEPs are often more ambitious in terms of the green agenda whilst Member States are concerned about the impact on their businesses and voters.

The July 'Fit for 55' Package included proposals to: increase countries' targets for emissions reduction; extend and tighten the EU ETS; increase ambitions for renewable energy including a 2.6 per cent renewable (green) hydrogen share of all transport fuels and a 50 per cent renewable hydrogen share of industrial hydrogen use by 2030; create tight definitions of what counts as renewable hydrogen; revise energy taxation so that it is based on carbon content; and to introduce a carbon border tax. The December Hydrogen and Gas Market Decarbonization Package defined low-carbon (blue) hydrogen as a 70 per cent GHG saving, and proposed strict regulation of future hydrogen infrastructure whilst re-emphasizing the role of markets in setting natural gas prices.

The legislation will have far reaching impacts. Transport consumed 289.4 Mtoe in the EU 27 in 2019, so even small changes are important but tensions between countries on several key aspects of the energy transition could slow down the whole process. Member States share responsibility to reach overall EU targets, but each country is largely free to decide the structure of its own energy mix. Opinions diverge on the means of meeting the targets, as seen during the discussions on the proposed extension of the ETS to road transport and buildings. Definitions of what counts as renewable or low carbon will have a significant effect on how countries decarbonize, since they determine what counts towards EU targets. Indeed, there is already a major row over the draft of the Taxonomy Regulation regarding whether natural gas and nuclear should have been included as sustainable sources of energy (in the current draft they have been). In addition, some countries want more state intervention in gas markets because of the recent rise in gas prices.

Early progress has been made on revision of the TEN-E Regulation which provides a regulatory framework for the development of cross-border electricity, gas (methane), oil, and carbon dioxide (CO2) infrastructure. This includes Project of Common Interest (PCI) status for key projects which benefit from faster permitting and regulatory approval, and eligibility for EU financial assistance. Formal adoption of the revisions is expected in early 2022 following a provisional agreement in December 2021 between the Council, Parliament, and the Commission. The Regulation's three main objectives - security of supply, market integration/competition, and sustainability - remain but the focus is shifted towards sustainability which is added as a mandatory criterion for all PCIs. The list of priority energy corridors is revised to exclude oil and natural gas infrastructure, but hydrogen corridors are added, underlining the desire for a pan-European hydrogen market similar to the current one for natural gas. There will be a transitional period during which hydrogen infrastructure, converted from natural gas infrastructure, could be used for transportation and storage of (bio)methane and hydrogen blends thus making projects associated with retrofitting and repurposing of existing gas networks eligible for PCI status and financial assistance until 31 December 2027. CO2 storage and transportation projects will be eligible for PCI status, with various modes of CO2 transport being allowed. The final version is less hostile to natural gas than the Commission's original proposals, but the shift away from fossil fuels is clear.

It will also be important to understand what happens at the national level in 2022. Two recent examples include (1) the coalition treaty agreed in November 2021 in Germany that aims to bring forward the country's coal phase-out date from 2038 to 2030, with gas-fired plants expected to help bridge the gap left by nuclear (to be phased out by end 2022) and coal plants (30 per cent of its electricity generation in 2021) during the transition phase, and (2) the coalition deal passed in the Netherlands in December 2021 which, on the contrary, plans for two new nuclear power plants to complement renewables energy and limit gas use (and imports) in the future. Several key elections are planned in 2022, including the

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French presidential election and the Hungarian parliamentary election in April, the results of which could also potentially shake up the political dynamics in Europe if Macron, an EU supporter, or Orban, an EU critic, were to win or lose their elections.

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17. The future of nuclear in Europe: Critical decisions in 2022

In Europe, nuclear energy is used in 15 countries (see map 17.1 below), accounting for 25 per cent of its overall electricity generation (with about half of this in France), and 50 per cent of its low-carbon electricity generation (2021 data). Nonetheless, the role of nuclear, both present and future, is a polarizing issue and a major bone of contention.

After months of negotiations, the European Commission released its proposal to include nuclear power in the green taxonomy on 31 December 2021. This was followed by an intense backlash and charges of greenwashing from various Member States, especially Germany, Austria, and Luxembourg. Opponents to nuclear energy cite risks with large-scale consequences, challenges of radioactive waste disposal, length of construction (new plants would not help with short-term emission targets), high investments and costs overruns (which divert funds from renewables projects), and difficult economics (low profitability and high maintenance costs).

Contrary to these critics, a 10-nation 'nuclear alliance', led by France, had called for nuclear to be recognised in the EU green taxonomy. Supporters see nuclear as an emission-free and dispatchable energy source that can help meet emission reduction targets, at least during the transition phase, and facilitate the integration of additional renewables. Energy sovereignty and self-sufficiency are also often mentioned, for instance in Eastern European countries and more recently in the Netherlands.

2022: a decisive year for the future of nuclear in Europe

2022 marks the end of nuclear generation in Germany, with the final reactors to be shut down by the end of the year. It also marks the beginning of the nuclear phase-out in Belgium, which is to be finalised by 2025. How the energy systems in these countries cope over the next few months/years, and the impact this will have on energy prices, will be carefully studied. In Belgium, the coalition agreement passed in December 2021 left open the possibility of extending the life of two reactors if it could not otherwise ensure energy supplies and even left the door open for small modular reactors (SMR) in its future energy mix. Two more European countries (Spain and Switzerland) are looking to phase out their nuclear capacity, though probably only in the 2030s.

In contrast, lifetime extensions, uprating of existing plants and/or building new capacity are being considered or under way in other countries. As of January 2022, almost 8 GW of nuclear capacity is under construction in Europe. After being delayed by more than a decade, the biggest nuclear reactor in the region and the first EPR in Europe, the 1.7 GW Olkiluoto 3 nuclear reactor in Finland, will finally come on stream in 2022 and start regular electricity production from June. Expected to cover about 15 per cent of Finland's electricity production, a positive impact on energy prices could help make the case for future nuclear projects in Europe. In Slovakia, the 471 MW **Mochovce 3 reactor** is also expected to start in 2022, with a second one planned for 2023. Three more EPRs with a combined capacity of over 5 GW (Flamanville 3 in France expected in 2023 and two units at Hinckley Point in the UK in 2026 and 2027) are currently under construction.

During the 2020s, nuclear capacity closure - due to end of operating lifetimes or a political decision - is expected to outweigh new capacity additions. The 2030s and beyond are more uncertain. EU countries need to review their energy policies to meet the more ambitious emission reduction targets of the EU Green Deal, and they also need to prepare for the expected rising demand for carbon-free electricity - including for hydrogen production. These developments have resulted in renewed interest for nuclear in many countries: Bulgaria, Czech Republic, France, Finland, Hungary, Lithuania, the Netherlands, Poland, Romania, Slovakia, Slovenia, and the UK are all already planning for, or considering, new nuclear plants.

Conclusion

Despite strong opposition and profound division among European countries, 2022 could be a turning point for the future of nuclear in Europe. The inclusion of nuclear in the taxonomy will be the subject of

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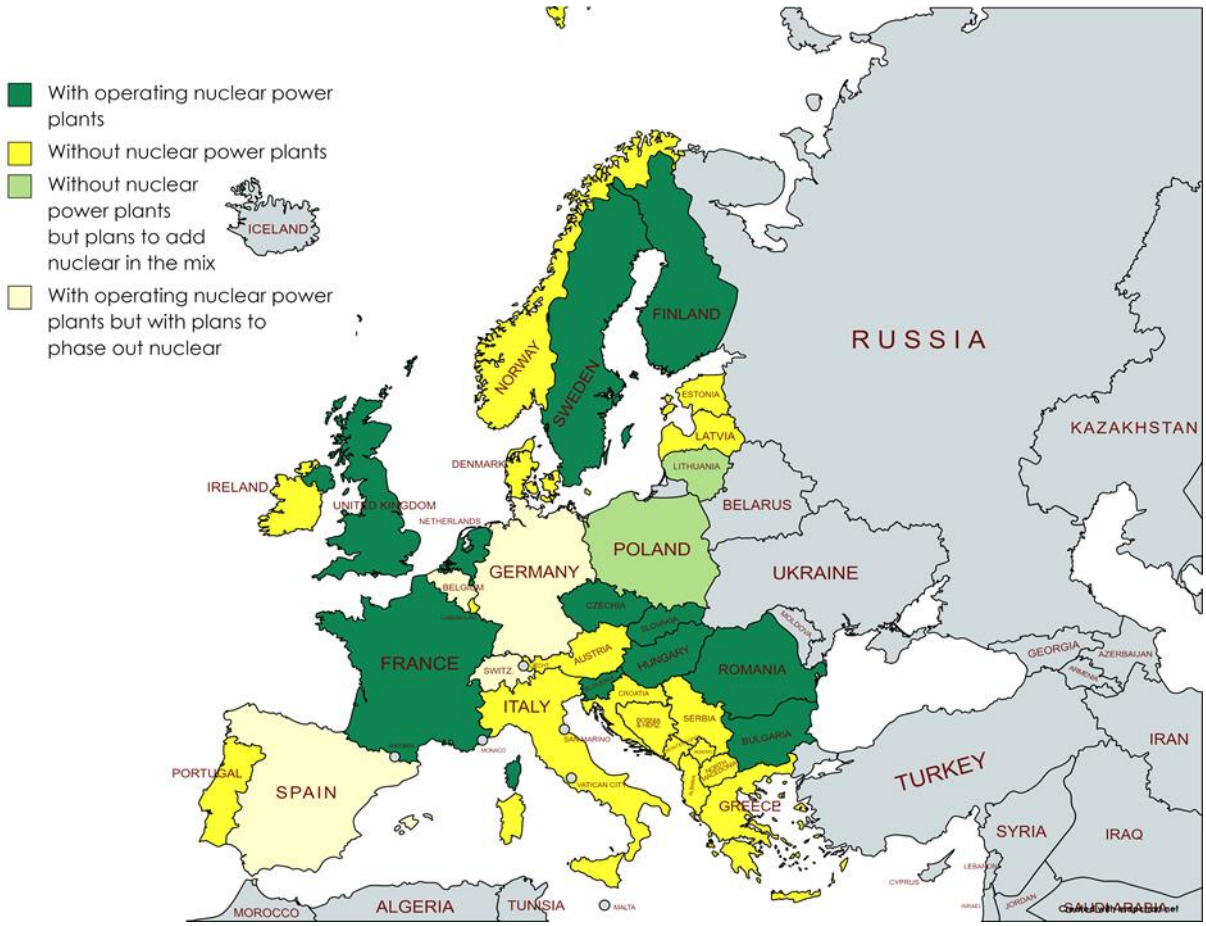
intense discussions over the next few months, but it is likely to enter into force from 1 January 2023, and this will facilitate investments in future nuclear projects over the next two decades. Other factors to keep an eye on this year include the April elections in France and in Hungary (both countries are part of the 'nuclear alliance') and the evolution of the energy crisis and its impact on energy policies. Several European countries have already announced plans, or at least kept the door open, for new nuclear plants as part of their future energy mix. The French EU presidency in the first half of 2022 will also contribute to keeping the future of nuclear power at the centre of energy discussions in Brussels. Its programme clearly states that '[France] will ensure that EU regulations remain consistent with development of nuclear energy'. The second half of the year is likely to follow the same line, as the Czech Republic, another nuclear supporter and part of the 'nuclear alliance', takes over the presidency.

Figure 17.1: The presence of nuclear power in Europe



Source: Author, as of January 2022

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18. Will 2022 be the year for rethinking wholesale electricity market design in Europe?

Electricity is unquestionably the key to meeting net-zero emission targets throughout the world. Renewable power will replace fossil fuels in the power sector and electricity will replace fossil fuels in road transport, buildings and a significant part of industrial activity. Furthermore, it is very likely that many of the remaining 'hard-to-decarbonize' transport and industrial sectors will use green hydrogen, produced using zero-carbon electricity.

It is therefore very important to know what market design will drive investment, operations, and consumption in the power sector. This question has been a topic of discussion among experts for many years and will be one of the big issues of 2022, especially in Europe. The political debate on this subject was expected to occur later, when intermittent renewables had penetrated so deeply that wholesale spot prices would be too low to warrant investment. However, this year, wholesale prices have risen to unprecedently high levels, mainly reflecting the rising marginal cost of generation using natural gas. Furthermore, forward markets suggest that natural gas and power prices will remain high in the first half of 2022 and there is growing concern that high prices may become a recurring problem during the energy transition. A focal point for European debate in 2022 will be a report to be published in April by the Agency for the Cooperation of Energy Regulators (ACER). ACER published its preliminary findings in November,[63] so we have a reasonable idea where they stand, basically behind the current model. However, there is already a lively debate on this topic among Member States.

The current wholesale market design is referred to as a 'pay as clear' (or 'energy only') market, where short-term spot energy prices provide the economic signals to drive investment, operations, and consumption decisions. Pay as clear means that all sellers get paid the same marginal clearing price in the market. The current design includes a sequence of energy markets, including a forward market for hedging risk related to spot prices, a spot (day-ahead and intraday) market, and a balancing market that takes place close to delivery to ensure that supply meets demand at all times. It does not include a separate capacity remuneration mechanism.

The supporters of the current approach are in the 'northern' camp that includes the Netherlands, Germany, and Scandinavian countries among others. Generally, this camp favours reliance on energy markets and regulatory stability as the basis for incentivizing investment. They maintain that the current approach provides efficient economic signals for operations and investment, a position which is far from obvious when a growing proportion of the generation is intermittent renewables with near-zero marginal costs. The new German Government may be reconsidering their traditional support for the current model; it would obviously be very significant if Germany changed its position.

A second camp, which includes Spain, Portugal, Italy and France among other countries, maintains that the pay as clear approach is unsustainable. They have different concerns, but share a view that change is required and that governments will have to play a more important role. On the one hand, with an eye on the immediate price crisis, their proposals range from introducing price caps on the electricity produced from natural gas to applying an average electricity price as a ceiling (e.g., with reference to the estimated financial needs of infra-marginal revenue for particular renewable and other technologies). On the other hand, to address the longer-term problem of excessively low spot energy prices, many governments in this camp favour capacity remuneration mechanisms, such as centralized 'capacity' auctions, to supplement investors' spot market revenue.

The debate on market design is very welcome and the ACER report in April will provide an important reference point. In the view of many, including Senior Research Fellows at the OIES, there are good

[63] https://extranet.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER's%20Preliminary%20Assessment%20of%20Europe's%20high%20energy%20prices%20and%20the%20current%20wholesale%20electricity%20market%20design.pdf

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reasons to argue that the energy-only model is not sustainable for an increasingly decentralized electricity system that relies heavily on intermittent renewable energy with near-zero short-run marginal costs. On the one hand, the non-dispatchable nature of renewables undermines the logic of optimal dispatch in energy-only markets. On the other hand, investors and governments are concerned that wholesale prices will fall to levels that make investment in generation and storage unprofitable, thereby putting supply security at risk. This helps explain why some investors and governments favour central government auctions to ensure cost recovery both for renewables and dispatchable plant. However, the trend towards central purchasing increases the risks associated with government control over investment, the costs of which are typically passed on to final consumers.[64]

But there is an even more fundamental problem. In a zero-carbon world, the whole basis of the present market design – to secure enough generation supply to meet uncertain demand – may fall away. Currently, the policy focus is just to get enough zero-emission supply on to the system, while continuing to balance the system in the usual way, via incentives on the supply side, such as capacity payments and spikes in short-term spot market prices. But as generation becomes less dispatchable and demand-side resources become more dispatchable, the current approach ceases to make sense. We do not know what exactly will replace it, but the priority must be to create a balanced system with the right incentive structure (for demand-side response, storage, power-to-gas, dispatchable renewables or other solutions), rather than a series of random interventions directed by governments that produce a lopsided supply-driven system.

The timing of the debate responds to an immediate concern about high prices, but reform of the market design should focus on the longer-term objective of providing a stable framework for efficient investment to meet net-zero targets.

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[64] See for instance, Robinson and Keay (2020) https://www.oxfordenergy.org/wpcms/wp-content/uploads/2020/10/Glimpses-of-the-future-electricity-system.pdf, Billimoria and Poudineh (2019) https://www.oxfordenergy.org/publications/market-design-for-resource-adequacy-an-insurance-overlay-on-energy-only-electricity-markets/, Keay-Bright and Day (2021) https://es.catapult.org.uk/report/rethinking-electricity-markets-the-case-for-emr-2/.

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19. Will India's 2015 renewable energy target of 175GW be met in 2022, and what are the implications for its energy transition?

In 2015, prior to the COP21 Paris climate talks, India set a domestic target to increase its installed renewable electric power capacity to 175GW by 2022, representing a more than threefold increase from existing capacity at the time. Of this, 100GW was to be based on solar (with 60GW utility-scale and 40GW rooftop), 60GW on wind, and the remainder on bioenergy and small hydro capacity.

As we move into 2022, India has around 1054GW of renewable capacity (excluding large hydro – see Figure 19.1),[65] indicating that 60 per cent of the target has been firmly met so far. A further 50GW is reportedly under various stages of implementation, and 27GW is in the process of being tendered.[66] One assessment of this would be that given the complexity of the Indian economy and policy process, and the legacy of structural bottlenecks, significant progress has been made. It is important to note that the target was not an official commitment under India's NDC submission – which was arguably far less ambitious[67] - but a domestic commitment.

A failure to fully meet the target in 2022 will not deter new aspirations. These have in fact already been set for 2030 at COP26: achieving 500GW of non-fossil fuel capacity, meeting 50 per cent of 'energy requirements' from renewables, and reducing CO_2 emissions by 1 million tonnes. Contrary to expectations, a net-zero carbon emissions target was also announced at COP26, for 2070.

Many have argued that this net-zero target misses the mid-century deadline to mitigate temperature increases. However, given India's recent precedence with its renewable targets, it is not unreasonable to assume that this aspiration could also be accelerated. Regardless, the net-zero target will serve to bookend the window within which the country needs to decarbonize, and this might change the perception of what constitutes 'progress'.

Additionally, near-universal electricity access has reportedly been achieved over the last decade, and India is now estimated to be the world's fourth largest market for electricity.[68] Multiple transition pathways can be modelled based on these targets, but this piece highlights two broad implications for India's energy transition.

The first medium to long-term implication results from the fact that generation capacity additions have tended to be the 'low hanging fruit' in India, given a favourable investment environment and policy signals. There is historical precedence – in its first major power sector reform in the 1990s, India added large amounts of generating capacity contracted from private sector independent power producers, without having to deal with the messier restructuring of other parts of the electricity system, namely, transmission and distribution networks, state-owned utilities, and end consumers. However, the main bottleneck to reform, then as now, lies precisely in these parts and particularly in the distribution sector. Subsidized retail tariffs to residential and agricultural electricity consumers have constrained the revenues of India's state-owned distribution companies (discoms) which account for the majority of retail electricity supply in the country. This has resulted in inadequate resources for investing in grid and system modernisation, and in problems with remunerating even renewable generators on time for contracted power. These problems continue despite attempts to restructure discoms' debt, and as a result, average technical and commercial losses of discoms are as high as 20 per cent in some Indian states. An Electricity (Amendment) Bill introduced in 2021 which sought to introduce reforms to address some of these issues, has come up against stiff opposition from stakeholders, with the government having to drop several provisions and eventually pausing its enactment in 2022.

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[65] Based on latest available data (November 2021) at the time of writing, from the Central Electricity Authority.
[66] India's Ministry of New and Renewable Energy.
[67] *India's Intended National Determined Contribution*, UNFCCC, p.29
https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/India%20First/INDIA%20INDC%20TO%20UNFCCC.pdf
[68] India Energy Outlook 2021, International Energy Agency.

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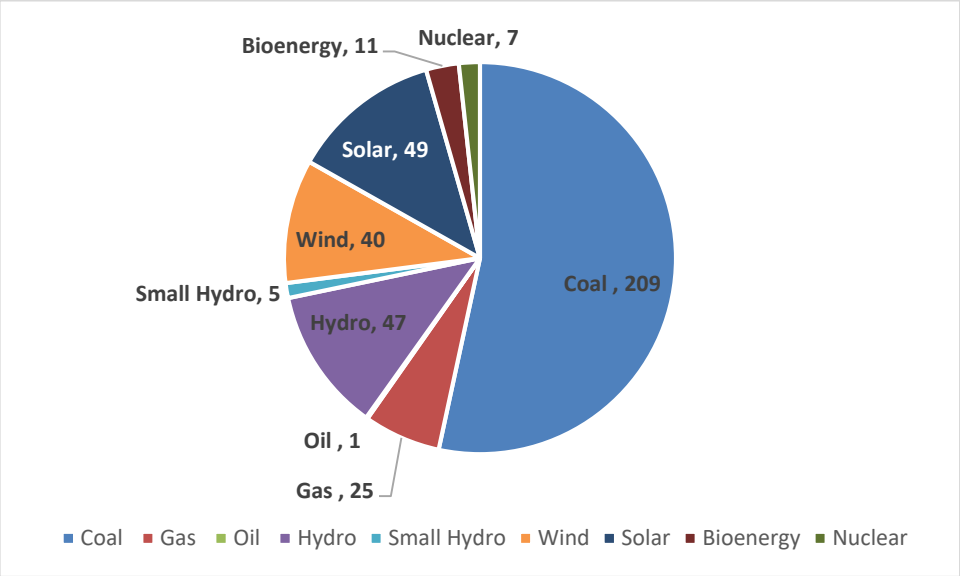
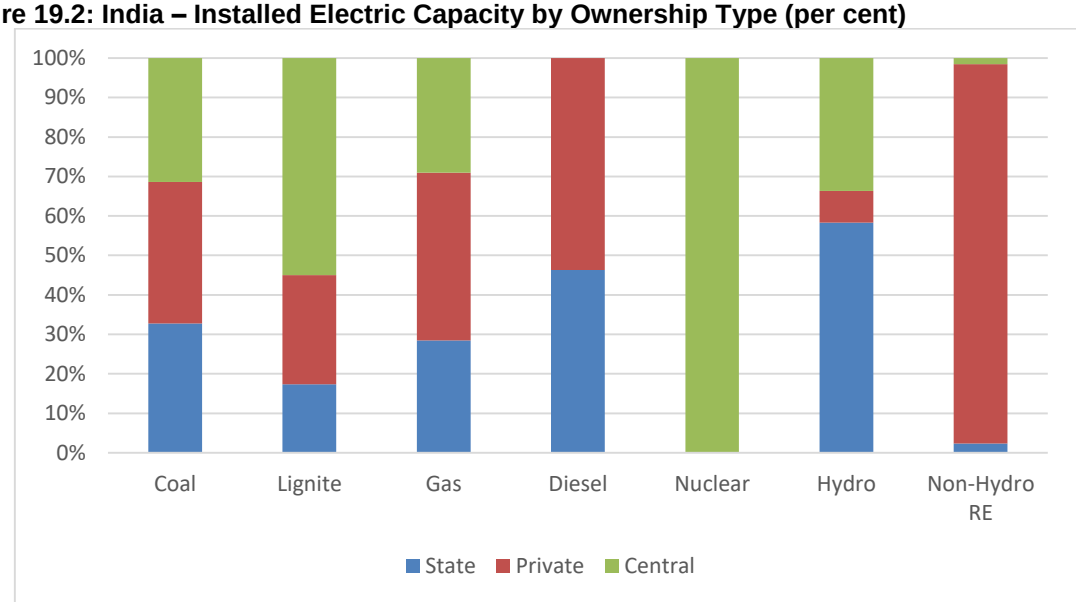
Figure 19.1: India – Installed Electric Capacity (Gigawatts)



Source: Central Electricity Authority

Figure 19.2: India – Installed Electric Capacity by Ownership Type (per cent)



Source: Central Electricity Authority

There are two related issues here that are relevant for the energy transition. First, the need to ensure the continued financial ability of distribution utilities to contract for renewable electricity (particularly from the private sector – see Figure 19.2) alongside any required thermal generation during the energy transition, in order to meet rising electricity demand that will result from urbanisation and electrification of the Indian economy. Second, the need to make investments in grid modernisation and power system flexibility that will inevitably be needed with higher levels of intermittent renewables. While some of these investments could be (and are being) secured through a combination of government support and external finance, any sustainable long-term solutions, it could be argued, would be similar to those being currently debated in advanced markets such as the UK and EU. These solutions involve choices about where in the electricity system investments are made – for instance, enabling storage, distributed

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energy resources – and how appropriate market designs and architecture to support the decarbonization and system flexibility of the power sector are developed.[69]

A second nearer-term implication relates not to how India's energy and climate targets will impact its energy transition, but rather on how external shocks could influence it. Energy policy in India is underpinned by energy security, which equates not just to the security of physical supplies but also to *fiscal* security: the ability to pay for the supply of energy to citizens at affordable prices, taking into account the costs of energy imports and associated domestic subsidies, and the resulting net impact on overall trade and fiscal balances. For instance, the government's strategy for moving to a 'gas-based economy' in 2017 was based on the assumption of low-priced domestic gas and low-priced LNG imports in an oversupplied market. The longer-term shift to renewable energy is based on the same premise, given global cost declines. But as recent events with gas prices show, the tide can turn unexpectedly in international energy markets, and the response in terms of fiscal security has been for the country to fall back on cheaper domestic coal reserves. Even if coal were to be phased out, strategy around managing the energy transition is likely to be closely linked to short-term fiscal security.

International climate and energy debates tend to ignore the granularity of federal politics in India and their impact on policy implementation – seven major state elections are scheduled for 2022, with some parties contesting these reportedly promising free or subsidised electricity as an incentive to voters. This risks putting further pressure on the fragile finances of discoms, and highlights the fact that the path to successful decarbonization lies not only in the raising of ambition and 'big-picture' targets, but in finding resolutions or mechanisms to deal with constraints on the distribution side.

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[69] Poudineh et al. (2021). "The Rise of Distributed Energy Resources – A Case Study of India's Power Market', OIES Paper EL46. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2021/11/The-Rise-of-Distributed-Energy-Resources-a-case-study-of-Indias-power-market-EL46-.pdf

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20. China in 2022: Stability over sustainability?

2022 is a politically important year for China. The 20th Party Congress of the Chinese Communist Party (CCP), that will be held in November, is widely expected to see Xi Jinping voted in for an unprecedented third term in office. This has two main implications: first, that Xi Jinping's political vision and policy agenda matter greatly, and second, that the mantra for 2022 is stability above all. The contradiction between the two, however, could come to the fore in 2022.

Xi's vision clearly includes putting China's growth model on a more environmentally sustainable foundation and reaching the country's 2030 and 2060 carbon targets. But in reality, and because of the political significance of 2022, much will depend on the extent of the economic deceleration. In the past, the year of a Party Congress meant strong economic growth and a stable international environment. 2022 may be different in that the leadership will want to hit around 5 per cent GDP growth but will not want to exceed it. How the Chinese leadership choses to reach its growth objectives and the infrastructure projects that are financed will be important to watch. Renewable energy and low-carbon technologies will receive a massive boost, aided by newly created lending facilities, but equally, the need for reliable power supplies, as highlighted by the 2021 power outages in China, point to more new coal-fired facilities.

Still, economic growth is undoubtedly slowing. This will weigh on demand for commodities and suggests that emissions growth could also be slower than in 2021. These trends may be particularly noticeable through March 2022 as the 2021-2022 Winter Air Pollution Control Plan calls on provinces to cut or stagger production in energy intensive sectors such as iron and steel while also phasing out dispersed coal (replaced by gas or centralised power systems) and limiting the use of diesel trucks. The zero-tolerance COVID-19 policy will last at least until after the Winter Olympics, which will be held in February 2022, suggesting more lockdowns, travel curbs, and lower mobility.

Power price reforms could also weigh on energy demand and alter investment decisions. The new power pricing mechanism introduced in October 2021 is hugely significant as it will end the guaranteed offtake for coal-fired power in China - which has enabled and even incentivised the approval of coal-fired capacity - while also supporting the use of renewables as these are likely to become the cheapest power source on the wholesale market. And since there is already a greater transfer of costs to end users, industrial and commercial consumers will see more volatility in prices which, over time, should introduce greater efficiencies in power use. The expansion of China's emissions trading system in 2022 will also help shape the longer term incentive structures, even though the near-term impact will be limited by low prices.

Additional reforms are likely to be introduced in the power sector in light of the government's pledge to 'accelerate the building of a unified, open, competitive and orderly electricity market system, which is at the same time safe, efficient and well-governed'. But as the history of power sector reform has demonstrated, progress can take years and even decades. The power crisis and the 30-60 targets (to peak carbon emissions before 2030 and reach net zero by 2060) were important triggers for the round of reforms in 2021, but further changes to the pricing system or to distribution companies may need to wait until after 2022.

Indeed, there seems to be an emerging concern in China that regulators took advantage of a reform 'window' that opened up in 2021 to pursue de-leveraging and regulatory actions: they tightened credit, inspected coal mines, levied overdue taxes from refiners, pushed forward power price reforms and closed many regulatory loopholes. In some areas, that reform window seems to be shutting as growth begins to decelerate. As a result of slower growth but also reduced increases in emissions, provinces may be able to focus on limiting energy intensity (energy demand as a share of GDP growth) rather than restricting overall energy consumption.

While local and central officials will be mindful of reaching economic growth targets in 2022, the regulatory wheels toward the 30-60 targets remain in motion. In the run up to COP26, Chinese

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authorities issued a slew of policy documents and while they offered few new details on the way forward, they highlighted the government's continued efforts to produce an overarching and consolidated strategy. Moreover, in 2022 detailed policy measures, including the Energy Five Year Plan and additional targets for both the 5-year policy cycle and the 2030-2060 targets, are likely to be issued.

The extent to which project implementation is held to a higher environmental standard in 2022, alongside provincial governments' appetite to phase out inefficient plants (be it coal, oil refining and petrochemicals, steel, aluminium or cement) will be key signposts of the 2030 carbon peaking trajectory. It is clear that China can peak emissions before 2030, but in 2022, policy framing as well as implementation will determine whether the peak will be around 2026-2027 or dragged out closer to 2028-2029.

So, while environmental protection is clearly part of Xi's political legacy and points to more fundamental changes in the macro environment, it remains to be seen if the regulatory rumble continues in 2022 or slows. Indeed, it would be wrong to assume the leadership has stopped looking at growth metrics altogether. This is because growth still means stability, although in a politically important year such as 2022 it also means an environmental focus on "blue skies" as well.

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