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Continued Reliance on Gas Will Weaken the UK Economy

Higher Energy Costs, Reduced Security of Supply, and Huge Economic Leakage From the UK Economy Are the Consequences of Continuing to Rely on Fossil Gas for Energy

Executive Summary

Sustaining gas demand to 2050 at levels suggested by the Climate Change Committee *"Balanced Net Zero Pathway" (BNZP)* will create huge economic outflows from the UK economy, while accentuating energy security risks through continued exposure to supply threats and pricing volatility.

The National Grid's *Future Energy Scenarios "Leading the Way"* (FES-LTW) illustrates an alternative pathway that encourages increased renewable energy and efficiency and would result in 65 percent lower gas demand than the BNZP case in 2050.

Under BNZP, the UK is set to face more than £470 billion in fuel costs for the purchase of gas, of which more than £100 billion could be avoided by switching to FES-LTW.

The UK will also have to spend an additional £21 billion on emissions allowances under the BNZP scenario vs. the FES-LTW, as legislation evolves to expand the existing UK emissions trading scheme with a cross-border adjustment mechanism that we assume comes into effect from 2035.

Continued support of gas as a material part of the UK's future energy mix is difficult to justify in the face of lower cost, zero-emission renewable technologies that can support progress towards the UK's 2050 net-zero obligations.

Using gas for power generation with carbon capture and storage (CCS) is at least 50 percent more expensive than offshore wind, and relies on unproven CCS technology. Gas use for blue hydrogen production carries the same burden: Higher cost, higher implementation risk, and higher GHG emissions relative to expected green hydrogen production.

A pathway that de-emphasizes gas investments and encourages renewables would not only offer a more technically sound net-zero strategy, it would also improve energy security, stimulate long-term employment and productivity, foster local supply chains and reduce the UK trade deficit.

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Introduction

The Climate Change Committee (CCC), a UK government advisor, has created a number of pathways to achieve net zero by 2050. Its baseline scenario, the Balanced Net-Zero Pathway (BNZP), assumes that the UK will consume 20 billion cubic meters (bcm) of gas at the end of the period. This is approximately equivalent to 25 percent of the UK's 2020 gas demand, or all of Poland's gas use today.[1]

The fossil gas is to be used mainly for power generation with carbon capture and storage (CCS), and as feedstock in the production of "blue hydrogen" with CCS. Although carbon capture has a poor track record and remains costly,[2] the CCC asserts that the technology would enable most carbon emissions from gas use to be captured, making it compatible with net-zero requirements.

Using gas for power generation with CCS is at least 50 percent more expensive than offshore wind, the most expensive renewable source. It also relies on unproven CCS technology that isn't used for any gas-fired power station today. Gas use for blue hydrogen production carries the same burden: Higher costs relative to cleaner green hydrogen production and similar emissions risks.

There are alternative decarbonisation pathways that can vastly reduce the nation's reliance on fossil gas by focusing on increasing renewable power generation capacity. The Future Energy Scenarios (FES) "Leading the Way" forecast developed by the National Grid Electricity System Operator (ESO) is one pathway that demonstrates there are alternative routes the UK can follow to reduce the economic and environmental risks of continued gas use.

There are alternative decarbonisation pathways that can vastly reduce the nation's reliance on fossil gas.

The difference in requirements means that, relative to BNZP, the National Grid pathway would reduce gas demand by 400 bcm or 27% over the period. By 2050, underlying gas demand would be 7 bcm, or 65 percent lower than the BNZP scenario, reducing the UK's gas cost burden by more than £100 billion through 2050.[3]

In addition to the £100 billion of additional spending on gas purchases under BNZP, another £21 billion will be required to meet emissions payments through 2050. This is due to an additional 230 million metric tons of CO_2 equivalent ($MtCO_2e$) of carbon emissions from the use of high-emissions intensity liquefied natural gas (LNG)

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[1] BP. Statistical Review of World Energy 2022. June 28, 2022.
[2] IEEFA. The Carbon Capture Crux. September 1, 2022.
[3] IHS Markit. European Gas Long-Term Price Outlook, June 2022. July 1, 2022.

imports, which will be captured by a Cross-Border Adjustment Mechanism (CBAM) and UK Emission Trading Scheme (ETS) payments for combustion emissions.[4]

Sustaining gas demand at levels suggested by the Climate Change Committee's BNZP creates huge economic leakage from the UK economy. All of the £100 billion is classified as "expense," sent to third parties outside the UK, and none of it supporting long-term UK investment. The funds could instead be used to support domestic investment in infrastructure and capacity, skilled employment, and increased economic productivity, while providing security of supply to UK consumers by not relying on high-emission, high-cost imports for energy supply. These are investments that provide a long-term return to the UK economy.

UK Gas Demand

Historically, the UK has benefited from significant gas reserves and associated production, which in turn has created a large domestic market for gas. Natural gas currently provides 41 percent of total energy requirements, followed by oil at 32 percent, and biofuels and waste at 10 percent.[5] The UK's gas producers and gas infrastructure have met the nation's gas needs over the decades, and continue to provide the backbone of domestic and commercial heating and cooking supply, in addition to the majority of its power generation.

In 2019,[6] demand for natural gas was dominated by domestic (or household) requirements for heating and cooking, and gas-powered electricity generation at around one-third each, with the balance roughly split across industrial,[7] services,[8] and other energy services.[9]

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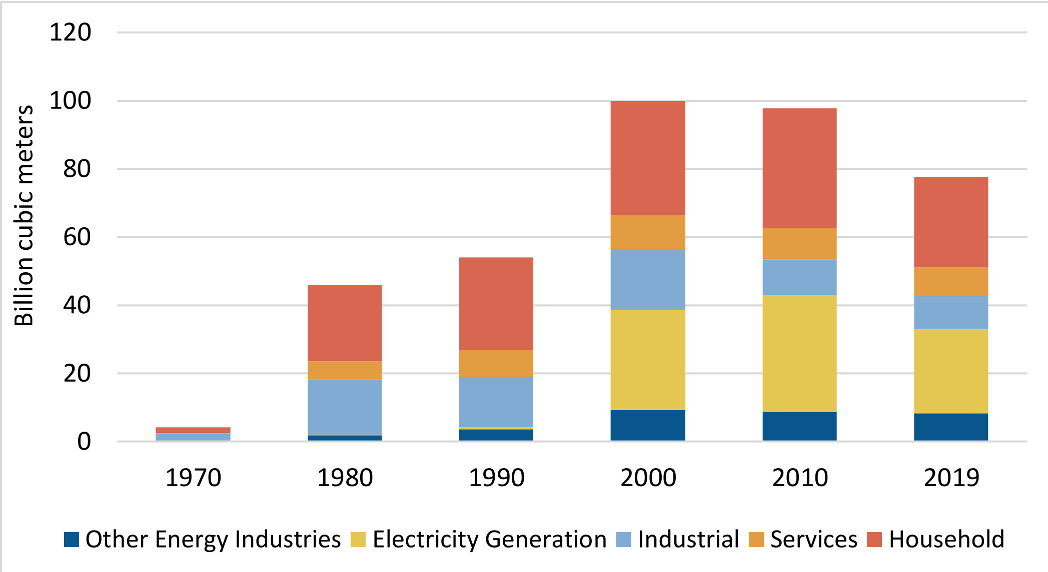
[4] We have assumed that a UK CBAM will be in place and that there will be no unabated gas-fired power generation from 2035. Our ETS analysis assumes gas combustion from 2035 will be coupled with CCS at an 80% capture rate.
[5] IEA. World Energy Statistics and Balances. August 2022.
[6] We have used 2019 as the last pre-pandemic year for illustration.
[7] UK Department of Business, Energy and Industrial Strategy. Digest of UK Energy Statistics (DUKES). Industrial consumption in Chapter 4, Tables 4.1 and 4.2 DUKES plus use in coke manufacture and blast furnaces and non-energy gas use. Last updated July 29, 2021.
[8] UK Department of Business, Energy and Industrial Strategy. Digest of UK Energy Statistics (DUKES). Public administration, commercial, agriculture and miscellaneous in Chapter 4, Tables 4.1 and 4.2. of DUKES. Last updated July 29, 2021.
[9] UK Department of Business, Energy and Industrial Strategy. Digest of UK Energy Statistics (DUKES). Energy industry use in Chapter 4, Tables 4.1 and 4.2 less use in coke manufacture and blast furnaces plus gas transferred to heat for sale. Last updated July 9, 2021.

Figure 1: UK Gas Demand by Sector, 1970 - 2020 (bcm)



Source: Digest of UK Energy Statistics (DUKES).

On the supply side, the UK has historically met its gas demand requirements through domestic production since the first gas was produced on the UK Continental Shelf (UKCS) from the West Sole field in 1967.[10] More fields were to follow, and domestic production increased significantly, triggering supply-led demand growth. The 1990s witnessed a step-change rise with the introduction of combined-cycle gas turbines (CCGT) for electricity generation. Gas demand continued to climb through the decade and into the early 2000s, peaking at 102 bcm in 2004.[11]

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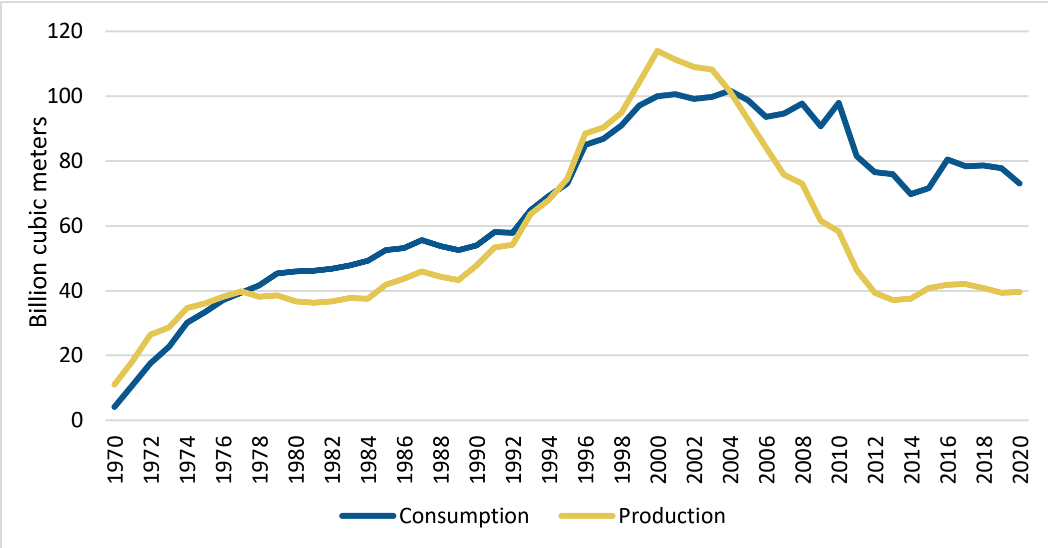
[10] University of Aberdeen. Brief History of the UK North Sea Oil and Gas Industry. June 12, 2006.
[11] UK Department of Business, Energy and Industrial Strategy. Digest of UK Energy Statistics (DUKES). July 28, 2022.

Figure 2: UK Gas Production and Consumption, 1970 - 2020



Source: DUKES.

Since 2000, domestic production has fallen from its peak of 114 bcm due to a combination of field decline, a lack of large new discoveries, and higher operating costs. By 2012, production had dropped to around 35 percent of peak, or 40 bcm, but subsequently stabilised due to operational improvements and the addition of new fields. Longer term, the North Sea Transition Authority predicts that UK offshore gas production will continue to steadily decline over the coming decades to fall to 2.7 bcm by 2050.

In addition to offshore supplies, the UK has potential onshore or shale gas supplies. Since there has been limited exploration or development drilling to date, the scale of reserves and potential production rates are difficult to predict. A study by the Warwick Business School analysed several reports and concluded that UK shale production could range between 90 and 330 bcm over a 30-year period.[12] This equates to around one to four years of UK demand, based on 2019 consumption figures. The lifting of the shale gas moratorium in England, announced on Sept. 8, will likely have a limited impact on reducing the UK's production decline.

As the UK is unlikely to be self-sufficient in gas production again, investment has been directed towards import infrastructure to secure gas supplies. Import pipelines were constructed from Norway—the Langland Pipeline and the Netherlands BBL Pipeline, as well as liquified natural gas import capacity at the Milford Haven Dragon facility and the Isle of Grain. Over the years, the infrastructure has been upgraded and complemented with more facilities, so that the UK had 114 bcm of import capacity by 2020, about 3.6 times the UK's import

[12] University of Warwick. Briefing: Shale Gas and UK Energy Security. March 2020.

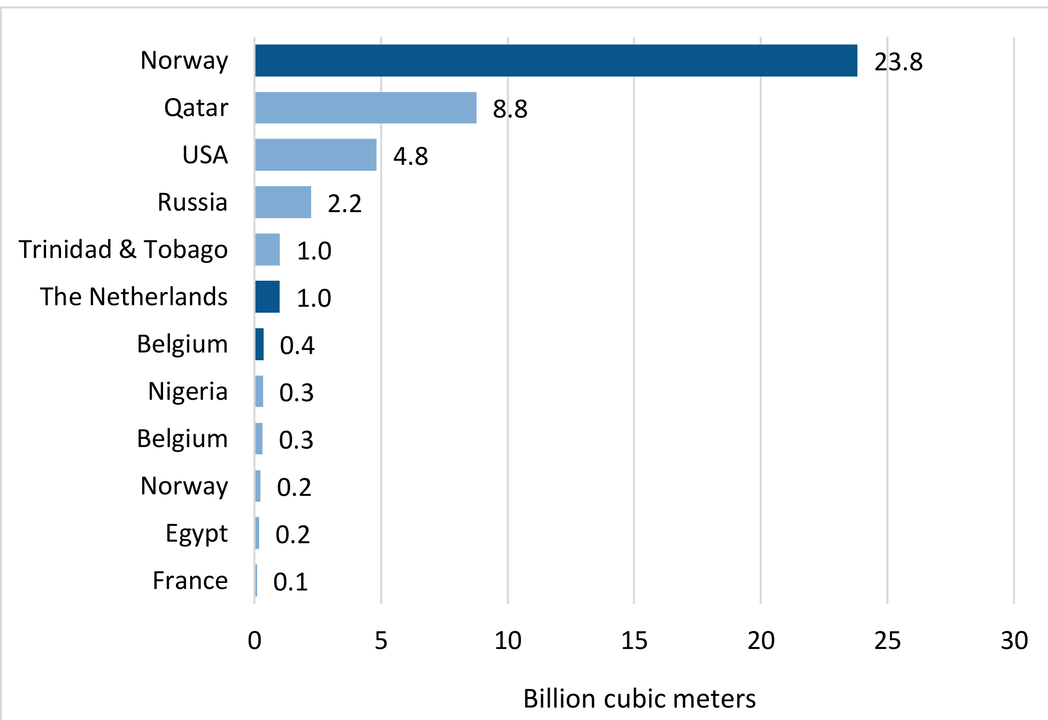
needs.[13] Current flat-to-downward demand trends mean the investment in import infrastructure may be stranded and unproductive.

UK Gas Imports

Norway is the largest supplier of natural gas to the UK. It provided 56 percent of the 43 bcm that was imported in 2020, supplied predominantly through the pipeline network, with 1 percent coming from LNG cargos. The Dutch and Belgian pipelines contributed a modest 3 percent. Collectively, they make up all pipeline imports.[14]

The remaining 42 percent of imports comes as LNG, with a little less than half from Qatar. The balance comes mostly from the U.S. at 27 percent, and Russia at 12 percent. Although imports of Russian LNG will stop by the end of 2022 due to the impending import moratorium on all Russian hydrocarbons, the UK has the capacity and option to obtain LNG from other global suppliers.

Figure 3: UK Gas Imports by Country 2020



Source: DUKES.

From an emissions perspective, not all gas is equal. There are large variances across the different import routes regarding their emissions intensity (EI), a measure of the

[13] UK Department of Business, Energy and Industrial Strategy. Digest of UK Energy Statistics (DUKES). July 29, 2021.
[14] UK Department for Business, Energy and Industrial Strategy. Digest of UK Energy Statistics (DUKES). July 29, 2021.

emissions that is directly associated with the inputs relating to the production and transportation of the gas into the UK transmission network.

The Norwegian pipeline gas has the lowest EI at 17.2 kilograms of carbon dioxide equivalent per barrel of oil equivalent (kgCO2e/boe), some 22 percent lower than the 22 kgCO2e/boe associated with UK production.[15] Within the UK, about 70 percent of emissions is related to the gas power used to support production operations, with the remainder coming from flaring and venting of gas for safety, testing, or disposal reasons.

Figure 4: UK Imported Gas Emissions and Volumes by Country, 2019 - 2020

Country	Emissions Intensity (boe)	Source	Emissions Intensity 2020 (MtCO2e)	UK Supply 2020
Norway Pipeline	17.2	Pipeline	2.7	30%
Netherlands Pipeline	19.1	Pipeline	0.1	1%
Belgium Pipeline	N/A	Pipeline	N/A	N/A
UK	22.0	N/A	5.3	46%
Norway	28.7	LNG	0.0	0%
Russia	51.4	LNG	0.7	3%
T&T	52.6	LNG	0.3	1%
Equatorial Guinea	57.6	LNG	0.0	0%
Peru	63.1	LNG	0.0	0%
Qatar	69.6	LNG	4.0	11%
Angola	71.5	LNG	0.0	0%
Nigeria	83.6	LNG	0.2	0%
Algeria	103.4	LNG	0.0	0%
USA	144.4	LNG	4.5	6%
TOTAL	N/A	N/A	**17.9**	**100%**

Source: EI/boe taken from NSTA analysis, 2020 production figures from DUKES, IEEFA analysis.

While a significant amount of emissions comes from the production and import of gas through pipelines within Europe, the EI from imported LNG is significantly higher. In 2020, imported LNG accounted for 22 percent of overall supply but contributed 55 percent of total emissions. The higher intensities are a function of the power generation used, the extent of flaring and venting in the source country, and the emissions from compression and transportation to the UK.

Examining the main LNG suppliers to the UK— Qatar and the U.S.—their EI is a factor of 3.2 times and 6.6 times higher than UK supply. Although there is a significant transportation requirement for these sources, the high EI reflects poor operational practices from an environmental perspective, and relatively lax oversight and legislation.

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[15] North Sea Transition Authority. Natural Gas Carbon Footprint Analysis. May 2020.

The U.S. EI is the highest of all UK suppliers, which is especially damaging given the significant rise in import volumes. LNG imports from the U.S. to the UK have increased by 54 times since 2017 and are expected to rise more, given the recent pan-European supply issues presented by Russia's reduction of gas exports.

Future UK Gas Prices

Natural gas in the UK is priced and traded through the National Balancing Point (NBP), which is a virtual trading location for the sale, purchase, and exchange of UK natural gas. In this model, gas anywhere in the national transmission system or pipeline network within the UK counts as NBP gas, which allows simplification of trading as buyers and sellers are united in the same marketplace.[16]

Through the ICE Futures Europe (Intercontinental Exchange), natural gas is traded through a contract referred to as the NBP Spot Price, which is the current price that natural gas can be traded for immediate delivery. The market is the oldest and is currently the second-most liquid gas trading point in Europe, trailing only the Title Transfer Facility (TTF) in the Netherlands.

Prices across the two main Northern Europe hubs have converged over time, as a result of the liberalisation of European markets and of interconnectivity improvements through the development of pipeline infrastructure and LNG import facilities across the continent.

Historically, the market was much less liquid. Gas was purchased under long-term fixed price or oil indexed contracts, which protected consumers from pricing volatility to some extent. Today, almost all gas supply contracts are indexed to benchmarks, which is the case for pipeline and LNG supply in the UK. As such, there is little difference in the prices paid for gas, irrespective of its source, and all consumers are exposed to fluctuations in European pricing benchmarks.

All consumers are exposed to fluctuations in European pricing benchmarks.

NBP gas prices are affected by seasonality. Demand increases over the winter months to support increased heating requirements, driving prices higher before retreating during the summer months. During the third quarter of 2021, the market had been under significant supply strain from reductions in domestic supply due to temporary offshore field shutdowns; operational issues including reduced supply from Russia; and the market's lack of preparedness for post-lockdown increased demand.

In 2022, the Russian invasion of Ukraine and the initial threat of disruptions in supply compounded the problem, causing the NBP Spot Price to spiral to a daily

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[16] ERCE. UK Natural Gas NBP Spot Price.

peak of over 500 pence per therm in March and averaging more than 200 pence per therm during the first quarter of 2022,[17] which is more than double historical seasonal highs. Since then, NBP Spot Price has spiked repeatedly, averaging more than 400 pence per therm in August. At the time of this writing, it traded at about 270 pence per therm. While the Ukraine conflict continues and European countries, including the UK, look to find alternative supply outside Russia, expectations are that European gas prices will remain significantly more than average at 119 pence per therm during the 2020-35 period, falling to 92 pence through 2050.[18]

The UK Emissions Trading Scheme (ETS) and Cross-Border Adjustment Mechanism (CBAM)

The UK ETS is a government-run cap and trade scheme to support the reduction of the UK's greenhouse gas emissions. The scheme came into effect in 2021 after the UK withdrawal from the European Union ETS. Although the UK ETS is relatively new, it effectively mirrors the EU scheme.

In simple terms, the UK ETS creates a market and puts an economic value or price on carbon emissions. Each year, maximum emissions are set by the government and are considered part of a system of tradeable allowances. Participants are required to obtain and surrender allowances to cover their annual greenhouse emissions. Allowances are either purchased at auction or traded, creating a carbon market and a carbon price. The scheme is designed to incentivise decarbonisation, given that the number of allowances is reduced each year.

Participation in ETS schemes does not cover all industries or sectors, although it applies to the oil and gas industry in the UK scheme. The scheme currently covers carbon dioxide emissions from the production, flaring and transport of hydrocarbons, but does not cover venting or other non-combustion processes. However, there is a consultation in process that has called for evidence to include these areas in the scheme.[19]

Since the introduction of the EU scheme, the price of the ETS per tonne of CO_2e had averaged roughly £22 from 2008 to 2020, but it has been rising rapidly since. During 2021, the price increased to £66, and forecasts for 2022 predict an average of £90,[20] more than four times the historic average. The significant increase has been driven by expectations of tightening legislation and reduced ETS allowances in the market, as many countries become more aggressive with their carbon reduction policies. This has been accentuated by an increased use of coal for power

[17] A therm is a non-SI unit of heat energy equal to 100,000 British thermal units or 29.31 kWh.
[18] Average nominal prices; IHS Markit. European Gas Long-Term Price Outlook, June 2022. July 1, 2022.
[19] Conversation with sector specialist solicitor at Herbert Smith Freehills LLP.
[20] IHS Markit. European Power Wholesale Price and Spreads Projections to 2050—Planning Case. February 2022.

generation, and higher emissions, since fuel switching has occurred due to high gas prices[21].

The UK parliament is currently considering the introduction of a Carbon Border Adjustment Mechanism (CBAM) to prevent offsetting of the UK's greenhouse gas emissions reduction efforts through imports of products manufactured in countries where climate change policies are less ambitious. The mechanism would function in parallel with the UK ETS, eventually mirroring its application and costs on imported goods.

As of March 2022, the EU had agreed on regulation to introduce its own CBAM to ensure parity and competitiveness for EU industries, and to encourage better environmental practices in non-EU states. The industries covered are some of the most carbon-intensive: Cement, fertilizers, iron and steel, aluminium, and electricity production.[22] To date, the legislation does not include the import of hydrocarbons, most likely due to the lack of EU domestic production and the additional cost that would be passed on to consumers.

There is clearly a trajectory towards increased and likely significantly higher carbon taxes in the UK.

In the UK, the creation of a CBAM is still under review. It may differ from the EU legislation in that it will seek to capture upstream oil and gas imports due to the relative scale of the domestic industry, ensuring domestic producers are not disadvantaged. The levelling up of emissions costs could potentially add significant costs on importing gas to the UK, especially from higher-polluting LNG. Any legislation will take time to implement, it will not apply to all industries initially, and it will be challenging to determine the specific emissions from import sources. However, there is clearly a trajectory towards increased and likely significantly higher carbon taxes in the UK that will also be applied universally to imported products.

[21] Refinitiv. Carbon Trading: Exponential Growth on Record High. February 18, 2022.
[22] Council of the European Union. Press Release: Council Agrees on the Carbon Border Adjustment Mechanism (CBAM). March 15, 2022.

Future Gas Gemand Scenarios: The CCC Net-Zero Pathway

The 2008 Climate Change Act commits the UK government to reducing greenhouse gas emissions by at least 100 percent relative to 1990 levels, or "net zero" by 2050. The act also established the Committee on Climate Change (CCC), a division within the Department for Business, Energy and Industrial Strategy (BEIS), to ensure that emissions targets are evidence-based and independently assessed.[23] In addition to their oversight role, the CCC has produced a series of carbon budget advice reports that provides guidance to government ministers on the volume of greenhouse gases the UK can emit to meet the net-zero pathway by 2050.

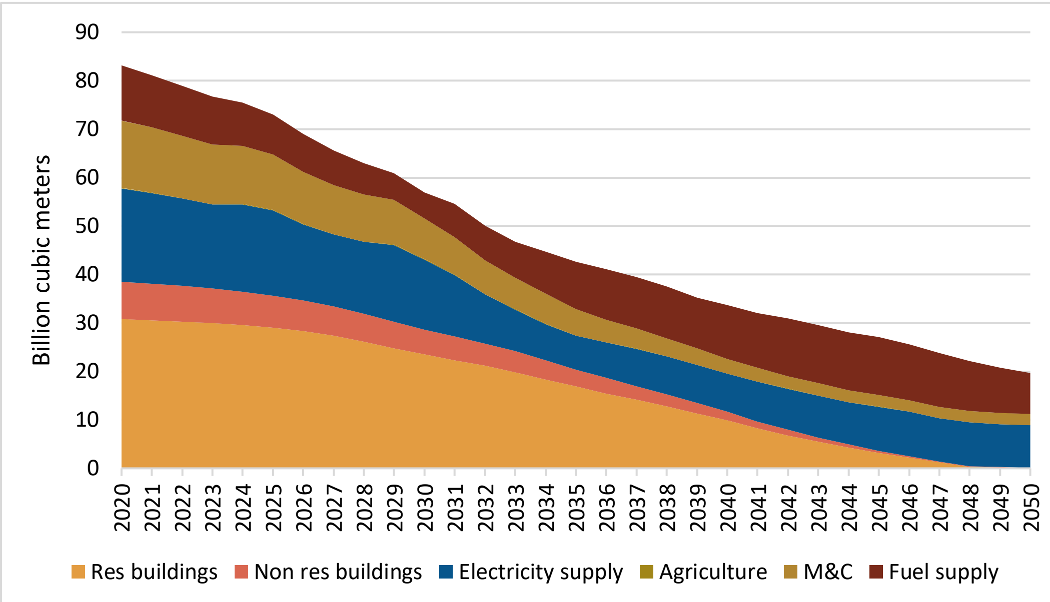
The Sixth Carbon Budget was released in December 2020 and is the most recent edition of the CCC's guidance. The report examines all greenhouse emissions sources from production and consumption within the UK, and it provides targets on emissions reduction through a variety of methods such as fuel switching, increased low-carbon electricity supply, capturing CO_2 and other emissions, consumption and behavioural change.

As a material component of UK energy supply, the future contribution of gas is a prominent feature in the CCC's analysis. As part of the Balanced Net-Zero Pathway (BNZP) scenario—effectively their baseline—the CCC anticipates that gas will still provide a significant part of the future energy mix by 2050. However, under this scenario, scope 1 and 2 emissions from production and transportation will be reduced, while combustion (scope 3) emissions will be mitigated through extensive use of carbon capture technologies.

The two main categories of future demand are electricity supply at 45 percent, to drive CCGT power generation with CCS, and fuel supply at 43 percent, as a feedstock for hydrogen production, more commonly referred to as "blue hydrogen." Although gas demand in the BNZP is expected to decline though increased use of heat pumps and increased electricity use in residential and commercial buildings, it will remain at 25 percent of 2020 demand levels, or 20 bcm. This would lock in the UK's reliance on the fossil fuel, its higher costs and emissions.

[23] Climate Change Committee. Climate Change Act 2008. A legal duty to act.

Figure 5: CCC Balanced Net-Zero Pathway Gas Demand to 2050 bcm



Source: Sixth Carbon Budget.

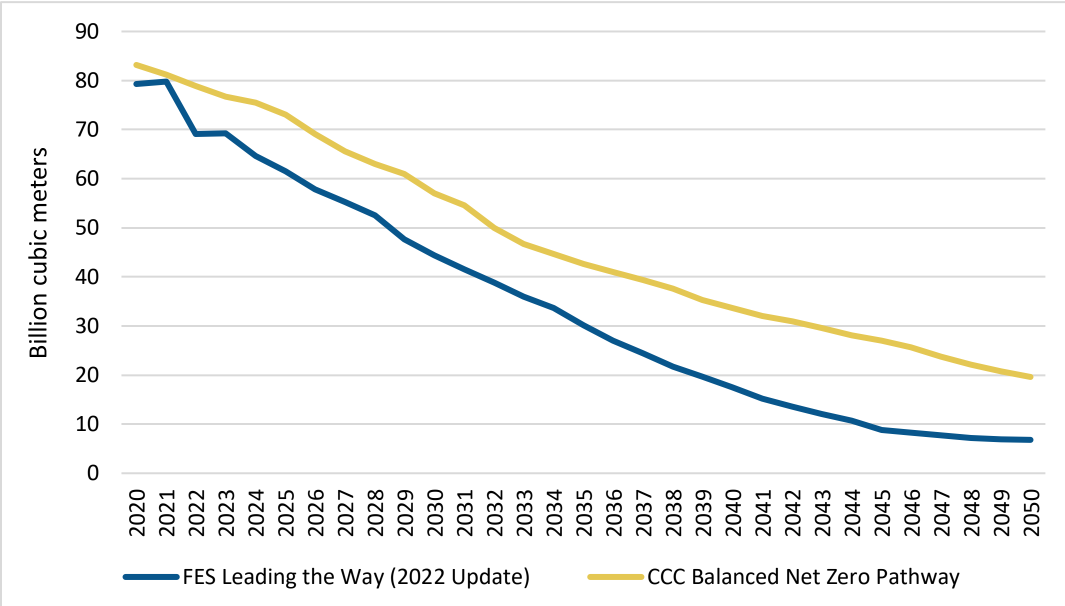
Continued use of natural gas to this extent presents an excess economic burden. This is significant, considering the rising cost of gas as an input fuel for CCGT and blue hydrogen production, in addition to the potential carbon costs from ETS payments or atmospheric emissions. Gas use in power generation and blue hydrogen production are relying on successful CCS rollout and high capture rates far beyond what the technology has shown to date, increasing technical risks and processing costs.

An Alternative Pathway: Future Energy Scenarios, "Leading the Way"

The CCC Balanced Net-Zero Pathway relies on continued gas use in the UK's energy mix by 2050, but there are alternative scenarios that could mitigate the cost and emissions risk from continued fossil fuel use. The National Grid ESO's Future Energy Scenarios (FES) illustrate alternative pathways that can lead the UK to meeting its net-zero targets while reducing the nation's reliance on fossil gas.

In the FES Leading the Way (LTW) scenario, there is a greater emphasis on fuel switching from natural gas towards renewable power generation to provide for increased electricity demand and for green hydrogen production. This is coupled with demand reduction from appliance efficiencies, increased insulation, the removal of gas boilers and gas for cooking, more green hydrogen use, and pumps for heating. As a result, gas demand would reduce to 7 bcm annually by 2050, or 35 percent of the CCC case.

Figure 6: FES Leading the Way and CCC Balanced Net-Zero Pathway Gas Demand, 2020-2050 (bcm)



Source: National Grid ESO 2022, Climate Change Committee Sixth Carbon Budget.

Increased electricity generation is fundamental to reducing reliance on fossil fuels. An increase would be met through greater reliance on wind, in addition to solar capacity that is projected to increase from 112 terawatt-hours (TWh) in 2021 to 624 TWh by 2050. Together, these sources would account for 84 percent of UK power generation. The balance will be met by nuclear, bioenergy with carbon capture and storage (BECCS), and some residual gas with CCS. High levels of interconnection, storage, and some flexible hydrogen generation to meet peak demands would also be required.[24]

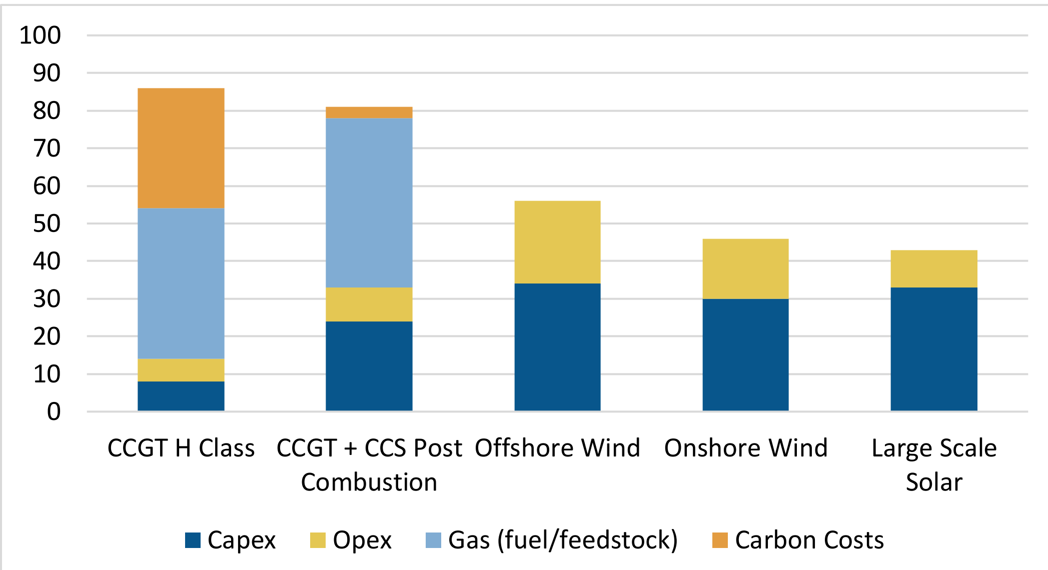
Recent events highlight supply-side threats and pricing volatility for any nation that continues to rely on fossil fuels as part of their energy mix. In the FES-LTW scenario, the movement towards increased electrification has the potential to remove one-third of gas demand from the UK by 2030. Most of the gas required could be met via imports from Norway and domestic production. Although this would create some supplier concentration and associated risk, the benefit of low-carbon supply and reduced exposure to pricing volatility as the demand curve is continually lowered would potentially outweigh the risks.

[24] National Grid ESO. Future Energy Scenarios 2022. July 2022.

The High Economic Costs of Continued Gas Reliance

In 2020, BEIS produced an analysis of electricity generation costs, comparing CCGT with and without CCS, relative to renewable alternatives from wind and solar. The analysis considered how these costs, or pounds per megawatt-hour (MWh), would evolve based on changing cost estimates for fuel, the evolution of carbon costs, technology maturation and cost reduction scenarios. Estimates were provided that showed the cost per MWh in 2025, 2030, 2035, and 2040.

Figure 7: Electricity Generation Costs in 2025



Source: BEIS Electricity Generation Costs 2020.

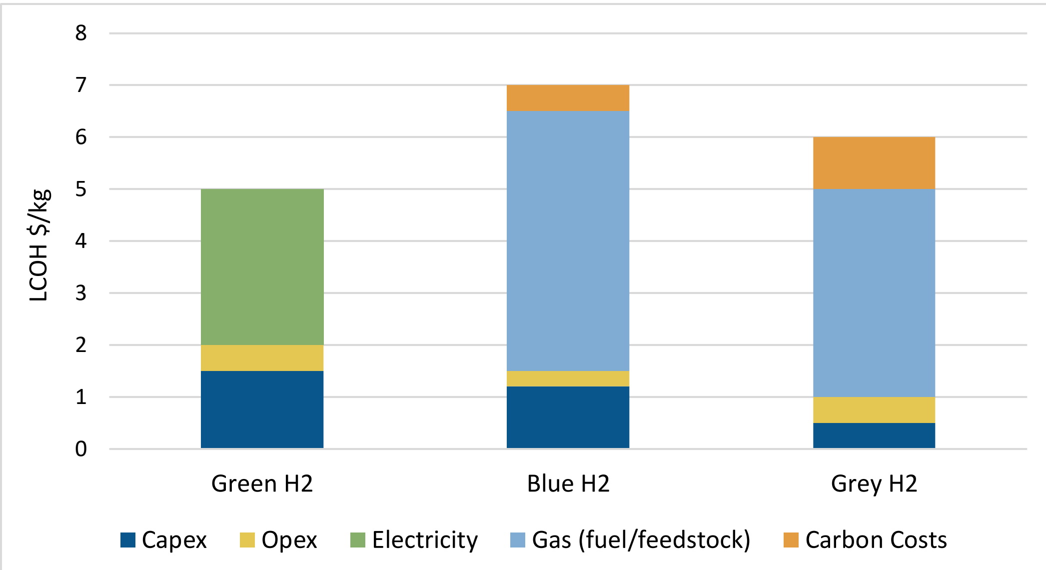
The chart above pulls from the 2025 analysis, which clearly shows that continuing to rely on CCGT for power generation in the near term is a significantly more costly than renewable sources, with additional emissions costs arising either through carbon payments or actual emission releases to the atmosphere. At £85/MWh for CCGT both with and without CCS, it represents an almost 50 percent increase in costs relative to offshore wind, the most expensive renewable solution.

Examining the longer-term projections in 2030, 2035, and 2040, the economic and environmental case for renewable solutions only strengthens. Despite innovation and cost reduction in the use of CCGT and CCS, it remains more than twice the cost of offshore wind at £82/MWh in 2040.

It should be noted that gas prices, or the fuel cost component in this calculation, remain relatively static over the period and do not represent current price forecasts, which are higher today given the gas price crisis. As gas purchases make up about half of the generation costs for CCGTs, higher gas prices will raise CCGT generation costs significantly, making them even less economical than wind and solar.

In July 2022, the UK government completed its largest ever allocation round for contracts for differences supporting clean energy projects. Eleven gigawatts of solar and wind projects were procured for less than £50/MWh (including 7 GW of offshore wind at less than £40/MWh). These will come online between 2023 and 2027, strongly validating the BEIS projections.

Figure 8: Hydrogen Production Costs (Illustrative)



Source: IEEFA Report, Russia Sanctions and Gas Price Crisis Reveal Danger of Investing in "Blue" Hydrogen.

In August 2021, the UK BEIS published its perspective on hydrogen production costs.[25] To illustrate recent gas price increases and their impacts, IEEFA provided an updated analysis of the current gas price impact on hydrogen economics.[26]

The report notes that industrial gas prices in the UK have been higher than the BEIS sensitivity upper limit for blue hydrogen costs. The analysis shows the BEIS outlook is outdated and presents an overly optimistic view of blue hydrogen. The IEEFA report shows that blue hydrogen production costs (shown as levelized cost of hydrogen) have already risen by 36 percent since BEIS published the document last year.

[25] UK Department of Business, Energy, and Industrial Strategy. Hydrogen Production Costs 2021. August 17, 2021.
[26] IEEFA. Russia Sanctions and Gas Price Crisis Reveal Danger of Investing in "Blue" Hydrogen. May 23, 2022.

Blue hydrogen was previously advertised as cheaper to produce than its green equivalent because the underlying coal or gas technology is commercially mature, even though CCS is not.[27] It is hard to see a dramatic technology breakthrough that could reduce key costs for blue hydrogen, especially since CCS has already suffered decades of failed investments.[28] Meanwhile, assuming there will be sufficient demand for hydrogen globally, the long-term price forecasts for green hydrogen are getting cheaper. In particular, the cost of electrolysers is expected to fall rapidly in coming years as companies and governments around the world invest in projects, production capacity, and technology research and development.[29] As a result, global green hydrogen costs are expected to fall significantly in the coming decade.

It is hard to see a dramatic technology breakthrough that could reduce key costs for blue hydrogen.

CCS for Emissions Abatement

In addition to gas price volatility, there are more cost and emissions implications of continuing to rely on fossil fuels as part of any future energy mix. CCS will not only add costs to power generation (currently between $50 and $100 USD/tonne Co2),[30] but its effectiveness is questionable. There are no CCGT power plants in the world currently using CCS. Commercial adoption that effectively captures the carbon released from combustion is fraught with challenges.

By its own admission, the Global CCS Institute, an industry-sponsored think tank, recognizes that the largest challenge facing CCS deployment is commercial. Creating CCS infrastructure is capital-intensive. In addition to the capture plant, it also requires transport pipelines and proximity to geological storage. Applications of CCS are limited, regulation is absent in most cases, and there are no familiar business models, structures or practices.[31]

One of the main technical difficulties facing natural gas combustion is the relatively low CO_2 concentrations from the flue gases that make them difficult and costly to

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[27] Bloomberg. Blue Hydrogen Could Become the White Elephant on Your Balance Sheet. December 16, 2021.
[28] Institute for Energy Economics and Financial Analysis (IEEFA). Federal Blue Hydrogen Incentives: No Reliable Past, Present or Future. February 8, 2022.
[29] Institute for New Economic Thinking. A New Perspective on Decarbonising the Global Energy System. April 20, 2021.
[30] IEA. CCUS in Clean Energy Transitions. CCUS Technology Innovation. September 2020.
[31] Global CCS Institute. Carbon Capture and Storage: Challenges, Enablers, and Opportunities for Deployment. July 30, 2020.

capture. The National Energy Technology Laboratory (NETL) in the U.S. reports that flue CO_2 gases from natural gas combined cycle plants typically contain about 4 percent by volume, compared to 12 to 15 percent from coal plant flue gas, providing less driving force for CO_2 separation and requiring greater energy input to capture.[32]

Although CCS technology is often cited as relatively mature—the first CCS plant was opened in 1972 at Terrell, Texas—[33] there are very few such plants in operation globally. Of the 27 facilities the Global CCS Institute cites as being in some form of operation, only one is associated with power generation. The majority are associated with natural gas processing and connected to enhanced oil recovery operations. These operations are considered economic, given CO_2 concentrations are two to three times that of a coal-fired power plant and the captured CO_2 is used to maintain oil or gas field production. For the plants in operation, the evidence of reliability and capture rates is far from compelling.

Research conducted by Global Witness shows that Shell's Quest blue hydrogen plant in Alberta emits more carbon than it captures.[34] Despite having captured 5 million tonnes of carbon across a five-year period, it has emitted 7.5 million tonnes of polluting gases during the same time. This mirrors broader difficulties with CCS technology.

In April 2022, an IEEFA report highlighted how the world's largest CCS project at Gorgon LNG in Western Australia—backed by Chevron, ExxonMobil and Shell—failed to meet its target by 50 percent during the first five years of operation.[35] The project eventually managed to reinject about 70 percent of the carbon that would otherwise be released into the environment.

More recently, IEEFA research covering 13 flagship projects around the world found that failed or underperforming projects considerably outnumbered successful experiences. It found that historical evidence confirms that using carbon capture to extend the life of fossil fuel power plants is a financial and technical risk. There is a track record of technical failures since 2000, with almost 90% of proposed CCS capacity in the power sector having failed at the implementation stage or suspended early.[36]

Nevertheless, there are a number of CCS projects planned over the coming decade to capture CO_2 from gas-fired power stations, although none are expected to open until

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[32] National Energy Technology Laboratory (NETL). Point Source Carbon Capture Program. Advancing technologies for the capture of CO2 from point sources, such as natural gas power and industrial facilities, with minimum cost and energy penalty.
[33] Global CCS Institute. Lessons Captured from 50 Years of CCS Projects. July 23, 2021.
[34] Global Witness. Hydrogen's Hidden Emissions. January 20, 2022.
[35] Institute for Energy Economics and Financial Analysis (IEEFA). Gorgon Carbon Capture and Storage-The Sting in the Tail. April 26, 2022.
[36] IEEFA. The Carbon Capture Crux. September 1, 2022.

after 2025.[37] With construction timelines of six to 10 years,[38] there is a risk that the technology will fail to deliver the proposed emissions reductions through the 2030s and beyond; that costs will remain high; and that the lack of scale or economic model will stifle the required investment. IEEFA analyses in the U.S. have highlighted how large commercial CCS projects have not achieved the industry target rate over time,[39] despite years of investment and projects.

The Economic Benefits of Reducing Gas Demand

Although many groups believe that natural gas has a role to play in supporting the transition to lower carbon energy, it is increasingly clear that its economic and emissions costs are too high to support a long-term contribution. Our analysis shows that by aligning to the CCC BNZP over the 2020-50 period, UK consumers are exposed to more than £120 billion in additional costs from gas purchases and emissions from the widespread application of ETS and CBAM schemes from 2035, compared to the FES-LTW.

Economic and emissions costs are too high to support a long-term contribution.

The additional gas demand over the FES-LTW scenario equates to 400 bcm, and using the IHS Markit long-term price forecast for NBP, the total cost burden is £100 billion. This takes into account longer-term assumptions that the NBP price will fall from current highs over the long term with an average price of 119 pence a therm during 2020-35, and falling to 92 pence through 2050.

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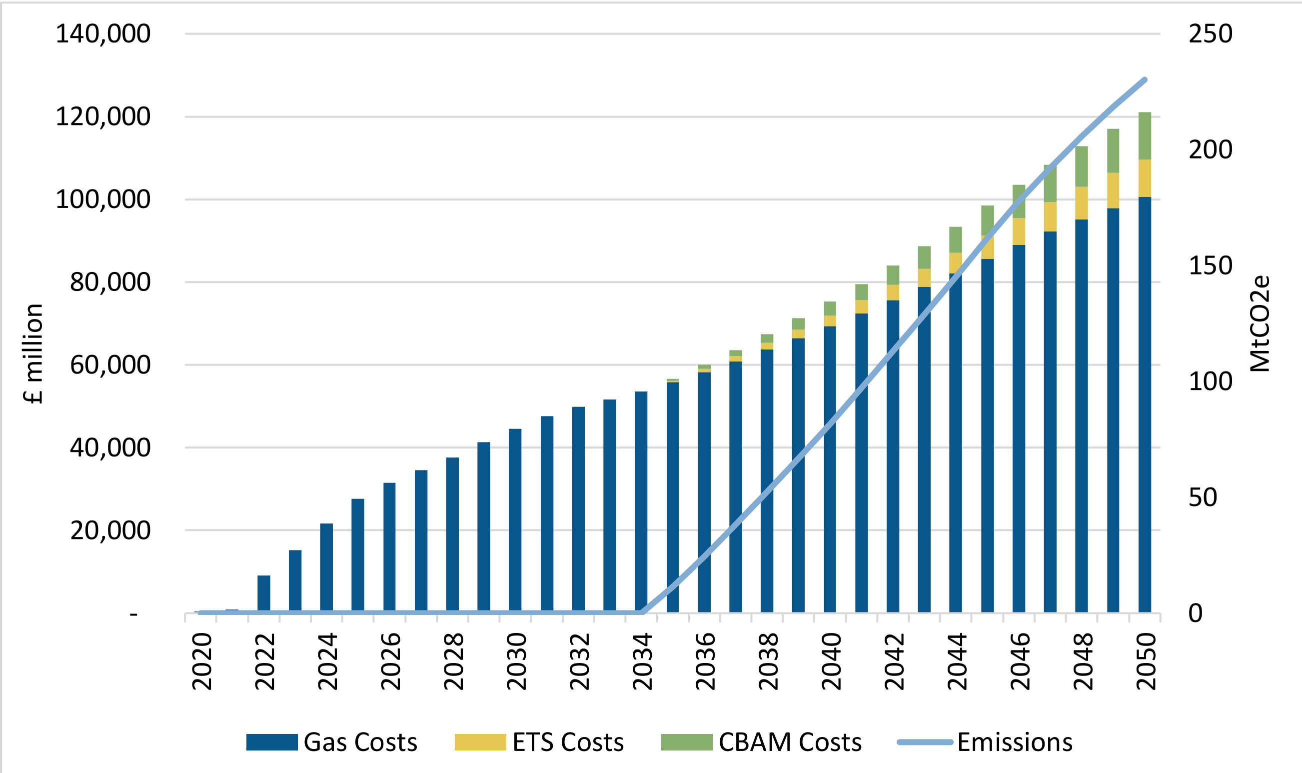
[37] Institute for Energy Economics and Financial Analysis (IEEFA). Reality Check on CO2 Emissions Capture at Hydrogen-From-Gas Plants. February 2022.
[38] Friends of the Earth Scotland and Global Witness. Briefing: Tyndall Centre. A Review of the Role of Fossil Fuel- Based Carbon Capture and Storage in the Energy System. January 11, 2021.
[39] Institute for Energy Economics and Financial Analysis (IEEFA). Blue Hydrogen: Technology Challenges, Weak Commercial Prospects, and Not Green. February 2022.

Figure 9: Cumulative Gas (RHS), ETS Costs (RHS), and Emissions (LHS) 2020-2050



Source: IEEFA analysis, IHS Markit NBP (Real 2021 Prices) and UK ETS price forecast (Real 2021 Prices).

The FES case continues to rely on gas use through the 2020-50 period, although at a lower level than the CCC case with a pathway to vastly reduced gas demand by 2050. We recognise that the resulting energy gap will need to be met by a combination of electricity and energy efficiency investments, and that this will have its own associated costs. The expectation of higher gas prices in the future could be translated to higher electricity costs, which have risen sharply since 2021 from a historical average of £45.90/MWh from 2008-20 to £118.30/MWh in 2021 and a forecast of £152.40/MWh in 2022.[40] However, this coupling is largely due to electricity market rules, which as of July 2022 have been under review by BEIS with a focus on changing this relationship: "Proposals out for initial consultation include exploring changes to the wholesale electricity market that would stop volatile gas prices setting the price of electricity produced by much cheaper renewables."[41]

While we recognise that reduced gas use will increase demand for electricity and that it will have an associated cost, it is important to note that gas is effectively used

[40] IHS Markit European Long-term Wholesale Power Price and Spreads Outlook, May 2022.
[41] BEIS. UK launches biggest electricity market reform in a generation. July 18, 2022.

as a feedstock, which is then converted into electricity or hydrogen as in the CCC case. Reduced gas use has significant implications for the UK economy:

- Energy security: By reducing reliance upon imported energy and exposure to gas price fluctuations.
- Contribution to the UK current account: Improving the UK trade balance by reducing more than £100 billion of payments for gas supply to other international territories.
- Contribution to gross domestic product (GDP) and gross value add (GVA): By reallocating capital that would flow out of the UK towards domestic renewable power projects, increasing economic activity.
- Employment and productivity: The majority of the cost of renewable power per MWh is related to capital and operational expenditures, supporting skilled, long-term employment and productivity.
- Supply chain development: Bolstering the UK supply chain to create a leading domestic industry with the potential to serve export markets as other nations develop their renewables and energy efficiency capabilities.

Conclusions

While we recognise that gas is the incumbent source of energy in the UK today, it is clear that there is little economic sense in continuing to rely on gas for a material part of the UK's future energy mix. As we have noted, using gas for power generation with CCS is at least 50 percent more expensive than offshore wind. It also relies on unproven CCS technology, adds environmental taxes through ETS/CBAM payments and creates significantly higher emissions. Gas use for blue hydrogen production carries the same burden: Higher costs relative to green hydrogen production and similar emissions risks.

The UK is in a strong position to expedite its renewable power generation capacity. It is technically feasible to significantly increase future electricity supplied by renewable sources. Sustaining gas demand at levels suggested by the CCC creates huge economic leakage from the UK economy, funds that could be used to support purchases from domestic renewable power production; support domestic investment in infrastructure and capacity; limit the price fluctuations of fossil gas; and provide security to UK consumers without relying on high-emission, high-cost imports for energy supply.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy.
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