Report

Securing Europe's Net Zero Path with Flexible LNG

Chi Kong Chyong and Muntasir Shahabuddin

September 2024

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About the Authors

Dr. Chyong is an applied energy economist with over a decade of experience in economic analysis and operational research. He holds an MPhil in Technology Policy and a PhD in Energy Economics and Policy from the University of Cambridge. His research interests encompass energy system economics and market modelling, focusing on the impact of deep decarbonisation pathways on power, natural gas, LNG, and low-carbon fuels.

Muntasir Shahabuddin is a doctoral student in chemical engineering at Worcester Polytechnic Institute, with professional and research experience in grid-scale electrochemical energy storage, process electrification, lithium-ion battery manufacture, and chemical plant economics. His current work straddles process electrification and fossil fuel management through the study of biofuel production and energy politics.

We would like to thank Sofia Ferrari for her excellent research assistantship and CERRE’s internal peer reviewer for constructive comments and suggestions.

Executive Summary

This research examines the strategies Europe can employ to ensure energy security while meeting its decarbonisation targets, especially when renewable and nuclear resources underperform due to climatic and technological factors. Through comprehensive energy system modelling, the study quantifies the economic value of flexible LNG supplies for Europe under scenarios aligned with the Paris Agreement's goal of limiting temperature increases to 1.5°C. The findings underscore the significance of LNG as a transitional fuel, particularly during energy crunch scenarios, and inform policies to stabilise energy prices, minimise emissions, and enhance transatlantic cooperation on energy security.

The modelling results indicate that stabilising gas spot prices during periods of market stress is essential to mitigate the economic impacts on Europe. Energy crunch scenarios, characterised by extreme weather and reduced renewable output, can cause substantial spikes in gas prices and consumer costs. The study demonstrates that access to flexible LNG supplies, particularly through LNG agreements (e.g., options, tolling and cap and floor LNG supply contracts) with North American suppliers, is crucial in moderating these price spikes. Such contracts offer European buyers the flexibility to adapt to market conditions, avoiding the long-term liabilities of traditional destination-fixed contracts and ensuring stable prices during high-demand periods. In scenarios without secured LNG contracting, wholesale gas prices could rise to as high as 144 EUR/MWh in 2030 compared to 31 EUR/MWh in the baseline scenario. On the other hand, forward contracts for flexible LNG help maintain prices close to baseline levels, yielding significant economic benefits. In 2030, these contracts are expected to reduce gas consumer wholesale costs by approximately 343 billion euros and energy infrastructure capital expenditure by 25 billion euros[1]. If energy crunch events that we model in this study occur in 2030, 2040, and 2050, the cumulative discounted[2] benefits would amount to 542 billion euros in consumer gas cost savings and 48 billion euros in CAPEX savings.

The second benefit of having access to flexible LNG supplies lies in its potential to support European re-industrialisation. For example, in 2040, forward contracting for LNG leads to lower and more stable gas prices of €32/MWh compared to €68/MWh in the baseline scenario. This price stability mitigates the volatility typically associated with energy crunch events and supports higher gas consumption, projected at 293 bcm in 2040 compared to 253 bcm under the baseline scenario. This suggests that forward contracting for LNG enhances Europe's energy security by hedging against potential supply disruptions and fostering conditions conducive to re-industrialisation. The availability of stable and reasonably priced LNG supplies can revitalise European industrial activity, increasing gas demand within the industry and supporting broader economic growth.

Thirdly, forward contracting for flexible LNG has implications for stabilising electricity and hydrogen prices, which are often closely linked to gas prices. While the direct impact of energy crunch events on electricity and hydrogen prices was not modelled in this study, it is reasonable to infer that the spikes in gas prices under such scenarios could lead to increased costs for electricity and hydrogen, especially when gas-fired power generation and hydrogen production rely heavily on natural gas. Stabilising gas prices through forward contracting would likely stabilise electricity and hydrogen prices.

[1] Discounted to 2025 with a social discount rate of 3%.
[2] Discounted to 2025 with a social discount rate of 3%.

This would be particularly beneficial during future energy crunch events, as it would help prevent cost escalation in these critical sectors, thereby reducing the overall economic impact on European consumers and industries.

Lastly, forward contracting for flexible LNG can avoid the extensive fiscal interventions and macroeconomic instability that Europe experienced during the 2021-2023 energy crisis. During this period, governments across the European Union, the UK, and Norway allocated approximately €651 billion[3] to shield consumers from rising energy costs (Bruegel, 2023). Germany emerged as the largest spender, committing around €268 billion, which accounted for about 7.4% of its GDP (Bruegel, 2023). These extensive fiscal measures were crucial in mitigating the immediate impact of the energy crisis, particularly exacerbated by the sharp reduction in gas supplies from Russia following the invasion of Ukraine (European Commission, 2023).

In addition to direct financial support, the crisis prompted a significant acceleration in investment in renewable energy. For example, approximately 50 GW of wind and solar capacity was installed in the European Union in 2022, a record addition that reduced the reliance on natural gas by around 11 billion cubic meters in the power sector (IEA, 2023). This rapid increase in renewable energy investments was part of broader efforts to enhance energy security and transition away from volatile fossil fuel markets.

However, these sudden and large-scale fiscal interventions had broader macroeconomic implications (ECB, 2023). The energy crisis, coupled with significant government spending, contributed to inflationary pressures with potential adverse effects on political stability, investment, and consumption. While these interventions were necessary to avoid a deeper economic downturn, they could have long-term effects if not carefully managed (ECB, 2023). Thus, the sudden large transfers within society, driven by these fiscal measures, have the potential to distort economic balances and create challenges for future fiscal policy. By stabilising gas prices through forward contracting for LNG, Europe can avoid the need for such large-scale fiscal interventions in future energy crunches. This would help maintain macroeconomic stability, reduce the potential for inflationary pressures, and create a more predictable and stable environment for investment and consumption, ultimately supporting the green transition.

In summary, forward contracting for flexible LNG offers economic benefits by stabilising gas prices and supporting re-industrialisation, stabilising electricity and hydrogen prices, and helping avoid large-scale fiscal interventions. These benefits make forward contracting for flexible LNG a crucial strategy for Europe as it seeks to ensure energy security and economic stability while advancing its decarbonisation goals. However, while stabilising energy prices is essential, addressing the environmental impacts of fossil fuel imports is equally important. The 2021-2023 energy crisis demonstrated how energy flows redirected to Europe, often from regions with less stringent environmental regulations, led to increased coal consumption elsewhere, undermining global decarbonisation efforts (IEA, 2022).

To avoid repeating this scenario, Europe must secure energy supplies and ensure that these imports align with more stringent GHG emissions standards, thereby contributing to the broader goal of reducing global emissions and avoiding unintended consequences of energy crunches. In particular,

[3] from September 2021 to January 2023.

addressing the environmental impact of LNG imports, particularly methane emissions, is a critical first step in reducing fossil fuel imports' overall GHG emissions footprint. The research highlights that extending carbon pricing to the entire fossil fuel import value chain (in addition to pricing combustion emissions via EU ETS) would have only a marginal impact on the EU's total energy system costs, increasing them by about 1% over the period modelled. However, this policy significantly alters global LNG trade flow, creating economic incentives for emissive LNG exporters to improve their emissions profiles to maintain access to European markets. The policy's revenues could also be redistributed within Europe to offset higher consumer costs, supporting public acceptance of stringent climate policy measures.

The EU's comprehensive GHG pricing acts as a de facto climate club by imposing penalties on non-compliant exporters and encouraging cleaner energy supply practices globally. The study shows that when diverted to less environmentally regulated markets in Asia, North American LNG intensifies competition among established exporters like Australia and the Middle East, which in turn could incentivise these exporters to advocate for similar GHG emissions management measures within their primary export markets to maintain their competitive edge. This dynamic has two positive effects: (i) potentially helping to phase out coal consumption in Asia, reducing GHG emissions, and (ii) indirectly promoting wider international cooperation on methane emissions reduction. The reshuffling of global LNG trade flows due to Europe's comprehensive GHG pricing demonstrates how strategic environmental policies can create economic pressures that incentivise wider adoption of similar measures, ultimately contributing to the broader objectives of global GHG emissions reduction.

The EU's liberalised and integrated energy market provides the flexibility to absorb global LNG trade imbalances, positioning the region as a stabilising force during global trade disruptions. Combined with the EU's legal commitment to achieving net zero by 2050, this market structure offers strong economic incentives for global energy players to engage with Europe while aligning with stringent climate standards. Enhancing market integration across Member States would further support efficient energy flows, infrastructure investment, and the balance between market liberalisation and climate commitments, reinforcing Europe's position as a critical player in global LNG trade, even if it is not the largest import market.

The study suggests securing flexible LNG supplies through LNG agreements with key suppliers is crucial to maintaining price stability. In addition, the EU should explore incentive mechanisms to encourage active LNG contracting beyond the existing *AggregateEU* scheme, such as tightening gas security standards to account for various risks, including climate and geopolitical factors. Implementing stricter security of supply standards would enable each Member State to tailor its approach, combining options such as integrated LNG agreements, long-term contracts with emissions offset mechanisms, and demand-side response initiatives.

The EU's commitment to net zero by 2050 is fundamental in providing long-term signals to energy – fossil, renewables and low-carbon – investors and stakeholders, reinforcing the economic viability of the low-carbon transition. Strengthening this commitment through clear and consistent climate targets aligned with energy policies and investment frameworks would attract sustainable investments and bolster the development of low-carbon technologies. Additionally, encouraging Member States to revise their National Energy and Climate Plans to extend beyond 2030 would enhance the credibility of the EU’s climate commitments and provide a clearer pathway to achieving decarbonisation targets.

The critical role of US LNG in addressing Europe’s energy crisis during 2021-23 underscores the need for strengthened transatlantic cooperation on energy security. The EU should seek to establish a cooperative framework with the US to secure a stable and reliable supply of LNG while aligning on environmental standards, particularly those related to methane emissions. Establishing common regulatory standards between the EU and the US would help ensure that LNG imports meet environmental requirements, supporting energy security and climate objectives. This cooperation would also enhance Europe’s ability to phase out Russian gas imports, a necessary step given the geopolitical and security concerns associated with continued dependence on Russian energy.

In summary, the findings suggest that Europe’s energy security during its transition to net zero by 2050 can be enhanced through a combination of market-driven LNG contracting, market integration, credible climate commitments, targeted GHG pricing, and strengthened international cooperation. Flexible LNG supplies are critical in mitigating price volatility during energy crunch events, while comprehensive carbon pricing promotes cleaner global energy supply practices. By adopting a strategic approach that balances economic, environmental, and security objectives, Europe can maintain energy security at a reasonable cost while advancing its decarbonisation agenda.

1. Introduction

The Russian invasion of Ukraine has significantly impacted the global gas market, massively reducing gas flow to the EU, increasing prices, and causing a fundamental shift in global LNG trade. In response to the disruption caused by the invasion, the European Commission (EC), Council and Parliament have issued several legislative proposals and directives, such as the REPowerEU plan, that have kickstarted efforts to phase out Russian fossil fuel imports well before 2030 whilst ensuring the security of Europe’s energy supply. With an emphasis placed on the role of renewable energy as the way forward, alignment with the EU Green Deal ambitions and other climate policies has become essential. The role of Liquefied Natural Gas (LNG) has also heightened regarding its growing role in offering a secure and rapid alternative to Russian gas, particularly in terms of flexibility.

US LNG supplies are based on a ‘tolling model’ and are, therefore, one of the most flexible sources of incremental supplies to the global gas market. Since the Russian invasion of Ukraine, the role of US LNG has become more pronounced in Europe and has consequently begun to play an essential role in the global gas trade. LNG imports accounted for 42.15% of EU gas consumption in 2023 (Energy Institute, 2024), a stark increase from 19.75% in 2021 (BP Global, 2022). During the 2021-23 crisis, LNG was redirected from Asia to Europe, and between February 2022 and September 2023, EU imports from Russia had fallen by 81% (Papunen, 2024). Total EU LNG imports stood at 78.4bcm in 2021 and significantly increased to 134.7 bcm in 2023. LNG imports accounted for approximately 22.5% of the total EU natural gas imports in 2021 (BP Global, 2022), increasing considerably to approximately 33.4% in 2023 (Energy Institute, 2024). In 2021, Russia’s total natural gas exports to the EU (LNG and pipeline) were 146.6bcm; by 2023, this value had decreased to 43.7bcm. The stabilising role of US LNG during the energy crisis allowed the United States to gradually become the EU’s largest LNG supplier by 2023 (almost tripling imports from 2021).

As the EU has a policy determination to decarbonise its energy system through (mostly) direct electrification based on variable renewable energy sources (wind and solar) as well as low-carbon energy sources (nuclear and hydro), there is a looming energy security question – *when these low-carbon variable resources are not performing (on average) as we expect either because of climate and technological (or both) factors, what are cost-effective solutions to meet energy demand while maintaining security of supply at a reasonable cost?* Through rigorous energy system modelling (see Chyong et al., 2024 for details), this research project aims to assess to what extent Europe needs supplies of natural gas and LNG as the region decarbonises its energy system compatible with the Paris goals of limiting the rise in temperature to 1.5 °C. In particular, we aim to quantify the economic value of flexible LNG for Europe under decarbonisation scenarios that reach net zero (NZ) GHG emissions in Europe by 2050. To this end, we model five scenarios (as outlined in Table 1) covering 2030-50, all reaching NZ GHG emissions by 2050.

Table 1: Scenarios considered in this study

Scenario	Name	Comment/Description
Scenario 1	**NZ2050 Baseline**	Europe will achieve net zero by 2050, with global LNG trade following IEA's Announced Pledge Scenario.
Scenario 2	**Energy Crunch**	Baseline scenario (Scenario 1) with a cold year, reduced renewable, nuclear, and hydro production in Europe and no ban on US LNG export (to non-FTA)
Scenario 3	**Energy Crunch with LNG Buffer**	Energy Crunch scenario (Scenario 2) with European support (via forward-contracting) of flexible North American LNG export expansion to stabilise spot prices during energy crunch years
Scenario 4	**Full Carbon Import Tax**	The baseline scenario (Scenario 1) with EU ETS carbon pricing (which at the moment is applied to combustion emissions) extended to GHG emissions of the entire fossil fuel supply import chain into Europe
Scenario 5	**Methane-cleaned North American LNG**	The baseline scenario with a carbon tax on GHG emissions of fossil fuel imports into Europe (Scenario 4), assuming the North American LNG supply chain has reduced methane emissions to zero

By modelling these five scenarios, this study focuses on the energy security and environmental impact of relying on imported LNG as Europe reaches its net zero objective by 2050. In particular, Scenario 2 focuses on securing the physical LNG flow to Europe and the role of flexible LNG supplies. In contrast, Scenario 3 shows the incremental economic benefits of forward contracting for flexible LNG supplies from North America when Europe faces an energy shortage year due to the underperformance of low-carbon energy generation sources. The environmental dimension is then explored by analysing Scenario 4, which assumes that the EU ETS carbon price is applied to the combustion of fossil fuels imported into Europe **and** the whole import value chain (i.e., cradle-to-city-gate). This tax adder applies to **carbon** and **methane** emissions along the import chain for LNG, pipeline gas, and thermal coal into Europe. Lastly, Scenario 5 explores a case in which methane emissions are eliminated from the North American LNG supply chain to support Europe's decarbonisation objectives while maintaining energy security.

Figure 1 maps the modelled scenarios on two dimensions: energy security and environmental benefits. For example, without committing to forward LNG contracts (Scenario 3), price and flow security for flexible LNG supplies cannot be achieved. Similarly, extending carbon pricing to the value chain emissions of fossil fuels imports will likely lower emissions (e.g., by raising the cost of those fossil fuel imports relative to renewable energy), which then may trigger responses from LNG exporters to reduce GHG emissions to secure a higher market share in the energy transition.

The rest of this report proceeds as follows. In the next section, we summarise critical European energy and climate policy legislation and regulations defining a politically firm commitment to decarbonise the region's energy system by 2050. Then, we provide a summary of the global gas market evolution, outlining a structural shift in the European and global gas trade in the aftermath of Russia's invasion of Ukraine and the role of flexible LNG supplies. In Section 4, we summarise the role of natural gas in the transition to a low-carbon energy system, stressing its potential to phase out thermal coal and the challenges of fugitive emissions (methane) that need to be addressed by the gas industry to have a place in this transition. The following two sections then focus on modelling results. First, in Section 5, we present the role of flexible LNG in the decarbonisation of the European energy system and the quantification of the flexibility of LNG in this transition. Then, in Section 6, we present the modelling of the impacts of GHG value chain emissions on the role of natural gas in Europe and the impact of reducing methane emissions on the competitiveness of gas and other energy vectors. Lastly, Section 7 discusses crucial modelling results and offers policy recommendations. We offer concluding remarks in the last section of this report..

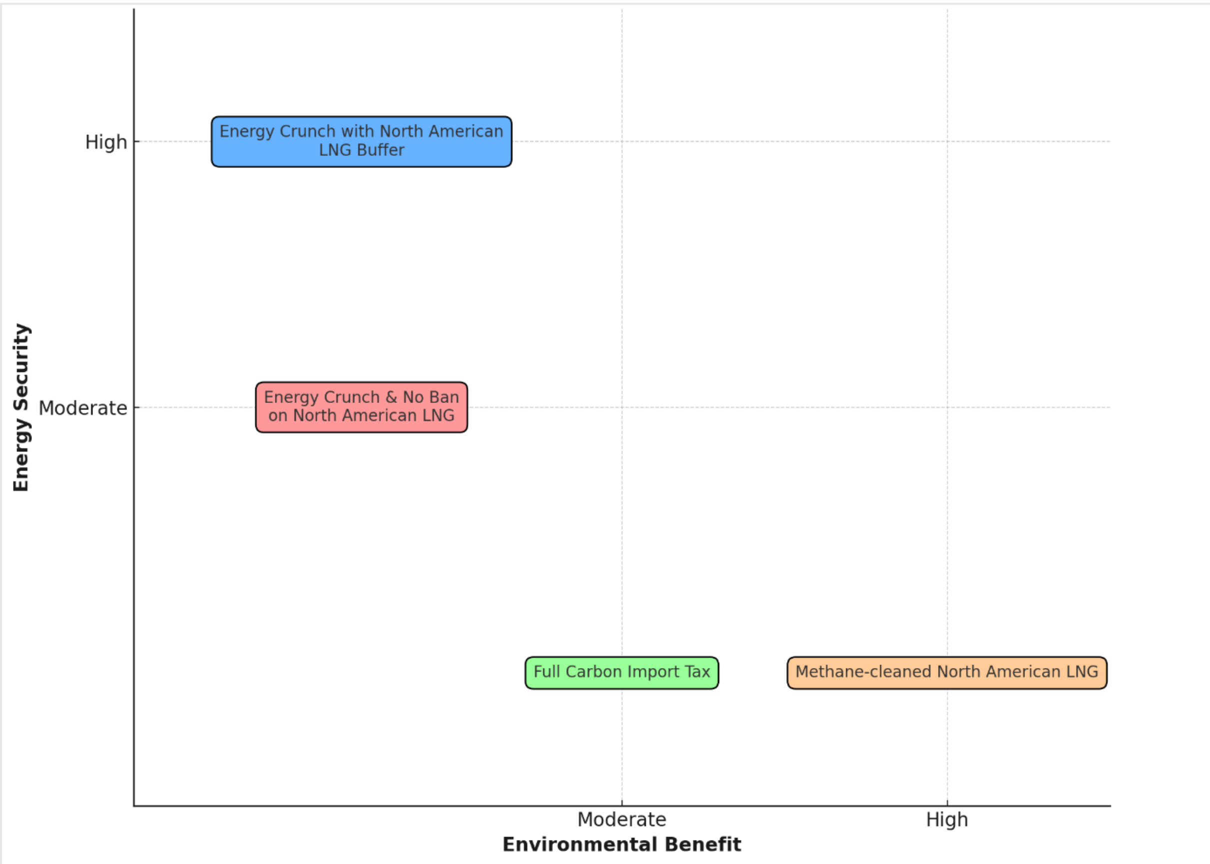


Figure 1: Mapping the modelling scenarios against energy security and environmental benefit dimensions

2. European energy and climate policy direction

After the Russian invasion of Ukraine, the EU's legal framework regarding energy supply has highlighted the importance of effective EU coordination, particularly concerning supply security. Past legislative actions have not always fully incorporated this coordination: The Treaty on the Functioning of the European Union (TFEU, 2007), for example, aims to ensure a secure energy supply. However, it does not consider the independence and variation between Member States (MS). Other legislative measures, such as The Security of Supply Regulation EU 2017/1938 (European Parliament and Council, 2017), concern safeguarding the security of gas supply with essential considerations of potential emergency measures and emphasise the importance of coordination at the national, regional, and Union levels. The regulation aims to stabilise spot prices and safeguard an uninterrupted supply of gas throughout the EU, establishing a common framework in which security of supply becomes a shared responsibility of natural gas undertakings, EU countries and the EC to enhance EU energy preparedness and resilience to gas disruptions. The same regulation was amended during the gas crisis that followed the Russian invasion of Ukraine, using Article 122 of the TFEU to rapidly adopt temporary measures to maintain secure gas supplies while also committing to the phasing out of Russian gas. Among these measures were: (i) a 15% voluntary reduction in gas demand (compared to the previous 5-year average – 2017-21), (ii) a coordinated demand aggregation for gas (equivalent to 15% of EU storage capacity) through the *AggregateEU* mechanism, and (iii) gas storage filling obligations effective until 2026.

In March 2022, the EC proposed an amendment to this regulation, including measures to deal with the market imbalances for energy and enhancing the resilience of the EU's energy system. This proposal included a requirement for EU countries to ensure that the storage infrastructure in their territories is filled up to at least 90% of capacity by 01 November of each year. Furthermore, in 2024, the revision of the EU gas market directive, as part of the Fit for 55 legislative package, incorporates renewable gases and hydrogen as crucial components of future gas markets, including phasing out long-term fossil gas contracts by 2049. These measures, among others, allowed EU MS to plan for a more rapid diversification of their energy supplies. EU imports of Russian pipeline gas dropped by 80.5% between 2021 and 2023 due to a significant shift to LNG imports and other pipeline gas suppliers.

Reducing emissions is a central issue within the European energy system, particularly in the transition towards decarbonisation. Policies such as the EU Emissions Trading System[4] (ETS) aim to reduce emissions based on a 'cap and trade' principle (European Commission, 2024). Between its launch in 2005 and 2021, emissions from power generation and energy-intensive industries have been reduced by 42.8%, compared to 1990 levels (European Commission, 2021). In 2024, as part of the 'Fit for 55' package, the Commission began revising the ETS, notably to introduce cap and trade (ETS 2) for the buildings and road transport sectors, aiming to align it with the target of 55% reduction of net GHG emissions by 2030, compared to 1990 levels. ETS 2 will subject all fuel suppliers to carbon pricing, meaning that direct combustion of methane for heating and within non-ETS-covered industries will be

[4] Directive 2003/87/EC.

subject to emissions control. The EU has also introduced a Carbon Border Adjustment Mechanism (CBAM), which further introduces an ETS-related tax on the carbon content of certain high-carbon imports to the EU, including hydrogen and electricity. These developments represent an increase in the scrutiny of the carbon content of fuel imports.

Since the introduction of the Renewable Energy Directive in 2009 (2009/28/EC), the EU renewable energy target has been revised multiple times: building on the 20% target for 2020 set in 2009, the 2018 recast (2018/2001/EU) established a new target for 32% in 2030 which was then increased to 42.5% in 2023.

The delivery of the European Green Deal, COM/2019/640 (European Commission, 2019), commits to a climate-neutral Europe by 2050, with legislation packages such as the Fit for 55 implementing its goals. The Fit for 55 package, COM/2021/550 (European Commission, 2021), aims to achieve a 55% emissions reduction by 2030 (as compared to 1990), focusing on a wide range of policies, including the regulation of methane emissions. The REPowerEU gas demand scenario of May 2022 sets a higher target for higher gas demand reduction than the ones proposed in the Fit for 55 legislative packages. Whilst the Fit for 55 demand reduction target aims for a decrease of 30% in 2030 (relative to 2019 levels), REPowerEU demand reduction targets aim for an additional decrease of approximately 100 bcm of gas by 2030 (relative to the targets previously published in Fit for 55).

Whilst the Energy Efficiency Directive (EU/2023/1791) aims to reduce energy usage overall at the EU level, the once again revised Renewable Energy Directive (EU/2023/2413) sets an increased target to produce 40% of energy from renewable sources by 2030. In December 2021, the Hydrogen and Gas Markets Decarbonisation Package was published, revising the Gas Directive 2009/73/EC (European Commission, 2009) and Gas Regulation (EC) No 715/2009 (European Commission, 2009). The legislative proposals aim to decarbonise the EU gas market by promoting renewable and low-carbon gases (including hydrogen) and reducing methane emissions. The policies put forward by the package are necessary to support the creation of infrastructure and efficient markets (European Commission, 2021). The package will cover the governing, construction, and access to hydrogen networks whilst repurposing and decommissioning natural gas networks in the EU, ultimately aiming to decarbonise the natural gas market and ensure the security of supply. Most notably, the Renewable Natural Gases and Hydrogen (RNGH) Directive prohibits the signing of new long-term contracts for unabated fossil gas with a duration beyond 2049.

Moreover, the European Commission has proposed additional targets for 2040 to reach climate ambitions. In February 2024, the Commission recommended a 90% net greenhouse gas emissions reduction by 2040 compared to 1990. To reach this target, the proposals outline the importance of fully implementing the existing EU laws aimed at reducing emissions by 55% (compared to 1990 levels) by 2030, as well as continuing efforts to decarbonise industry and increase domestic manufacturing. Implementing these measures is aligned with the targets of Net Zero 2050, aiming to facilitate the long-term transition towards a secure supply of decarbonised gas.

3. Global gas market evolution

Throughout its development in the mid-1990s, LNG trade did not grow substantially in the European market as opposed to Asian markets, mainly due to cheaper pipeline supplies from Norway, North Africa, and Russia. Whilst the 2000s and 2010s saw a significant global increase in LNG trade, European imports only peaked in 2022 as demands grew in the face of sanctions against Russian energy imports. Natural gas was the fastest-growing fuel in the global energy market in 2000, with both pipeline and LNG trade rising by 8% and 10.3% relative to 1999, respectively. Global natural gas consumption rose by 4.8%, reaching its highest rate since 1996. Global LNG trade has existed since 1959, reaching its first export peak in 1960 with only two deliveries. This number has grown exponentially since then, reaching a new peak each decade. In 1970, the number of LNG deliveries globally increased to 129; by 1980, this number had increased to 704. In 1990, the number of deliveries reached 1342, almost tripling by 2010 to 3951 deliveries and 6184 deliveries in 2021 (*Global LNG Trade*, n.d.). The number of LNG-importing countries has also grown approximately five times what it was in the 1990s. In 2021, the LNG global trade connected 20 producing countries with 44 importing markets, and by 2023, the number of importing markets increased to 48 (*International Gas Union 2023 World LNG Report*, 2023). Between 2011 and 2021, global LNG trade saw a growth rate per annum of 4.6%, whilst pipeline trade was only growing at 0.8%. Between 2013 and 2023, global pipeline trade had a negative progress of -1.7% growth rate per annum (a result of a sharp decrease in Russian pipeline deliveries to the EU), whilst the LNG trade grew at a rate of 5.3%. In 2023 alone, the global LNG trade growth rate per annum was 1.8%. Meanwhile, the pipeline trade rate was -8.3%.

In 2023, the US, Qatar and Russia dominated as sources for EU's LNG imports in 2023, with 45.20% of imports coming from the US (60.9 bcm), 13.43% (18.1 bcm) coming from Qatar and 13.36% (18 bcm) still from Russia. The shares were distinctly different in 2021, when only 28.57% (22.4 bcm) was sourced from the US, 20.80% (21.62 bcm) from Qatar, and 13.36% (17.48 bcm) from Russia. Between 2021 and 2023, Russian LNG supply to the EU increased by 25.87% despite efforts to phase out Russian fossil fuels (Energy Institute, 2024). The increase comes from (1) the need to maintain a secure supply of gas in Europe: not enough LNG had been imported before the war due to heavy reliance on piped gas from Russia, (2) as well as the continuation of long-term contracts (Hancock & Tani, 2023). As the EU imports of LNG increased between 2021 and 2023, pipeline gas imports decreased. In 2021, EU pipeline imports from leading extra-EU importers (Norway, Azerbaijan, Russia, Algeria, and Libya) stood at 258.6 bcm. In 2023, imports from these sources had fallen to 155 bcm. Russia, Azerbaijan and Algeria remain amongst the EU's main gas providers by pipeline in 2021 and 2023 [5]. However, in 2023, Russia exported only 25.7bcm of pipeline gas to the EU, a significant decrease from 132.3 bcm in 2021. Meanwhile, 30.6bcm were imported to the EU from Algeria in 2023, slightly decreasing from the 34.1bcm in 2021. The pipeline gas sourced from Norway has increased slightly, remaining the EU's largest provider, from 80.9bcm in 2021 to 85.1bcm in 2023.

Notably, decreased natural gas imports between 2021 and 2023 are also related to EU-wide consumption reduction in households and industry (e.g., demand destruction in fertiliser, paper,

[5] 2021 top pipeline gas importers to the EU: Russia (132.3bcm), Norway (80.9bcm), Algeria (34.1bcm), Other European non-EU countries (11.2bcm), Azerbaijan (8.2bcm).
2023 top pipeline gas importers to the EU: Other European non-EU countries (95.6bcm), Norway (85.1bcm), Algeria (30.6bcm), Russia (25.7bcm), Netherlands (18.0bcm).

aluminium and steel sectors) due to exceptionally high prices resulting from the loss of Russian gas supplies, lower energy generation from nuclear and hydro facilities (see Figure 2). Total gas consumption in the EU has decreased from 397bcm in 2021 to 319.5bcm in 2023, representing a growth rate per annum 2023 of -6.9%. More specifically, between August 2022 and March 2023, EU consumption of natural gas fell by 17.7% compared with average gas consumption in the same months between 2017 and 2022. The REPowerEU plan set the Council Regulation (EU) 2022/1369 on coordinated demand-reduction measures for gas with a reduction target of 15% set for August 2022-March 2023, relative to the same months of the past five years. This emphasis on demand reduction, diversification of suppliers, and phasing out of Russian fuels have brought LNG to the forefront of the gas market. The newly emphasised role of US LNG as the major exporter to the EU has opened a discussion about the effectiveness and sustainability of European energy strategies, specifically regarding the EU's ambitious climate and security goals to build a greener and more affordable energy system. This research project aims to objectively model Europe's LNG and natural gas supply needs to reach its Net Zero targets by 2050. It will also seek to assess the energy security implications in this context as Europe increases electrification based on variable energy sources and ongoing energy needs in hard-to-abate sectors.

In 1995, Indonesia, Malaysia, Algeria, Brunei, and Australia were among the leading LNG exporters globally, with Asia being the main importing region (primarily Japan, South Korea, and Chinese Taipei). By 2000, Qatar had become one of the top five exporters; however, the LNG global market remained relatively unchanged since 1995 (OEC, 2022). Meanwhile, between 2016 and 2018, Russia and the United States became prominent LNG exporters, and the number of European countries importing LNG also increased. By 2020, Russia and the United States became the top natural gas exporters alongside Qatar, Australia, and Malaysia (IEA, 2024).

In 2022, these five countries dominated global LNG trade, exporting mainly to Asia and Europe. The quantity of LNG exports from Qatar has remained relatively unchanged in the last decade, exporting 105 bcm in 2024 compared to 103 bcm in 2014. Although always consistent amongst top exporters, Australia's exports increased significantly from 30 bcm in 2014 to 107 bcm in 2024. The United States showed the most export increase, starting at 0 bcm in 2014 and reaching 113 bcm by 2024. A sharp increase in US LNG exports occurred between 2020 (80 bcm) and 2024 (113bcm), with 95 bcm exported in 2022. This peak reflects European sanctions against Russian energy imports, whose LNG exports have stagnated between 37 bcm and 38 bcm since 2020.

Overall, global LNG trade reached 397 million tonnes in 2023, showing an increase of 16 million tonnes from 2021. Since the invasion of Ukraine, global LNG consumption has increased by more than 40 bcm (reaching 557 bcm in 2023), with Europe increasing demand and accounting for more than a quarter of total LNG trade. The change in LNG demand in EU27 countries between 2021 and 2023 was 57bcm. The contract flexibility of LNG elevates its role in the global gas market. This flexibility allows LNG to become a prominent factor in European energy security, especially in the aftermath of the 2021-23 energy crisis. Due to climate policies, affordability, energy security factors, EU gas demand, and ultimately, EU LNG imports are expected to decrease over time. On a global scale, the LNG market is expected to grow, with projects in development that add almost five times as much new liquefaction capacity from 2025 through 2028 compared to the previous four-year period (IEEFA, 2024).

4. The role of natural gas in the transition to low-carbon energy systems

Natural gas is a leading fuel in the energy sector, accounting for almost half of the growth in total global energy demand in 2018. Natural gas accounts for 144 EJ of global primary energy consumption in 2023 (Energy Institute, 2024) as the third primary energy source behind oil (196 EJ) and coal (164 EJ). The share of natural gas in global primary energy consumption has since increased from 2020 levels of 138 EJ yet shows a slight decrease from more recent 2021 levels of 145 EJ (BP Global, 2022). For various climate and political factors, amongst which the need to decarbonise energy systems and the phasing out of Russian fuels, the role of natural gas in global energy systems has become more emphasised in recent years. Its assessment as a transition fuel has become critical to understanding what is at stake for Europe— namely, in terms of energy security, meeting climate policy targets and affordability. Whilst the coal-to-gas switch alone does not respond sufficiently to climate change, its utility in the transition to renewables is essential to note. The switch from coal to gas has saved around 500 million tonnes of carbon dioxide between 2010 and 2018, offering a less emission-intensive substitute for coal (IEA, 2024). Countries have displayed different market and policy responses considering global climate and transition efforts.

In countries such as China, attention to air quality has increased gas demand and pushed the case for switching in some sectors. Although China's share of gas in primary energy has increased from 1% in 1990 to 7% in 2018 (a step in the right direction), the country's share of coal has also increased slightly from 61% in 1990 to 63% in 2018. Other countries like India have yet to make significant progress in large-scale switching, but supply constraints, affordability, and lack of infrastructure are stumbling blocks. However, the country still shows slight progress, with primary energy shares of gas rising from 4% in 1990 to 6% in 2018. This progress is dampened, however, by India's share of coal, which also increased from 30% in 1990 to 44% in 2018. The EU and the US development of climate-focused policies in the past decade has meant that transition efforts in the energy system have seen notable progress. In the US, since 2010, the market share of gas has increased more than any other energy source: the US share of gas in primary energy has increased from 23% in 1990 to 30% in 2018, whilst the share of coal has decreased from 24% to 15%. EU ambitious climate targets have been successfully pushing for the phasing out of coal, an effort reflected in shares of coal in primary energy decreasing from 28% in 1990 to 14% in 2018 (albeit a temporary increase in coal consumption during the 2021-23 crisis), with the share of gas rising from 18% to 24%.

The effectiveness of coal-to-gas switching has been widely evaluated, and much debate has been made on the impact of methane emissions along the natural gas supply chain. Concerns over gas emissions are particularly relevant in the context of new infrastructure, as they relate to the costs and feasibility of gas grid expansion. Nonetheless, the transition still shows emissions reduction by 50% when producing electricity, and 33% when providing heat, demonstrating the comparative benefit of gas over coal. Although the spike in EU gas prices in the wake of Russia's invasion of Ukraine caused a stunt in the transition to renewables, coal-to-gas switching has proven integral in helping Europe reach its climate policy targets. A continued significant reduction in carbon dioxide emissions is necessary to fulfil Fit for 55 emission reduction targets. An increased EU reliance on US LNG imports to secure supplies also comes with environmental costs. This development has opened discussion on the EU's ability to meet its climate targets in contemporary to a secure and affordable energy market. Although necessary to ensure this security of supply, the climate implications of carbon and methane emissions and affordability still take the forefront when dealing with the new EU-US LNG trade reality.

In May 2024, MS approved new legislation that imposes heightened monitoring and reporting of methane emissions in Europe's gas, oil and coal industries (European Union, 2024). The regulation imposes mandatory measurement, reporting and verification (MRV) requirements for emissions at the source level, including for non-operated assets. New measurements within the regulation include mandatory leak detection and equipment repair for all facilities, a ban on routine venting and flaring, and a limitation on venting from thermal coal mines. Additionally, implementing a global methane emitter monitoring system, rapid alert mechanism, and new import contracts that mandate equivalent MRV requirements for exporters to those established for EU producers puts pressure on international suppliers and introduces stricter requirements for exporters. The new regulation is particularly relevant within the gas market as US LNG exports to the EU increase in relevance. It discusses the environmental implications of gas production and how these can be monitored to ensure the EU reaches its climate targets. The amount of natural gas flaring associated with the global LNG supply chain is particularly relevant. Six main sectors along the LNG supply chain contribute to emissions: upstream production, upstream transportation, liquefaction, shipping, regasification, and end-use. Although flaring from LNG represents only a tiny percentage of total flaring, it can still be a significant component of the global LNG system (Capterio, 2021). Total world emissions from natural gas flaring increased by 7% between 2012 and 2023 and by 0.6% in 2023. Total global gas flaring volumes rose 7% in 2023, reaching 148 bcm compared to 139 bcm in 2022 (World Bank Group, 2024).

EU-US LNG trade has developed significantly since the sanctions on Russian fossil fuels began. Most recently, implications of the Biden administration's export freeze have begun to signal the environmental costs of LNG trade. In January 2024, a US presidential election year, the Biden administration temporarily paused pending approvals for LNG exports. The pause allows the US Department of Energy to develop up-to-date economic and environmental analyses regarding LNG exports' climate and financial impacts. The decision to pause new export project approvals comes mainly from the environmental concerns related to natural gas production and exportation, as seen in the White House statement highlighting the administration's climate commitments and determination to lead global clean energy efforts (House, 2024). US Energy Secretary Jennifer Granholm offers a more comprehensive list of motivations behind this decision, explaining how the pause is designed to *'avoid export authorisations that diminish our domestic energy availability, weaken our security, undermine our economy or the environment'*. The pause brings into discussion the pollution levels in the LNG industry and the consequences it might bring to worsen the climate crisis, with particular attention to methane emissions. The Biden administration has taken steps to reduce methane emissions in the oil and gas industries, implementing new regulations and targets to reduce methane emissions by 80% between 2024 and the end of the decade (US EPA, 2023). The estimated methane leak rate from oil and gas operations is 2.3%, as referenced in the White House Methane Action Plan of November 2022 (House, 2022). The US has established 0.2% as the new methane intensity benchmark for US natural gas production, which aligns with the EU proposed benchmarks for LNG and pipeline import regulations (concerning emissions in the production phase specifically).

To summarise, European energy and climate policies set a course for rapid decarbonisation with a careful approach to supply security, ensuring that the crisis of 2021-23 never happens again. In this respect, understanding the role and contribution of flexible LNG supplies to European energy security while minimising LNG's negative climate impacts is crucial. This is the aim of the following two sections.

5. Valuing flexible LNG in Europe's decarbonisation

The 2021-23 crisis in Europe highlights how geopolitical, weather-related, and technological factors can significantly impact European energy (Figure 2) and other regional markets. To assess the role of flexible LNG in balancing potential supply and demand shocks in Europe, we first model a baseline scenario and then a 'stress-test' scenario (*energy crunch* scenario), combining weather and technological factors that may increase demand and reduce the energy supply to Europe. The stress-test scenario is considered a high-impact, low-probability (HILP) event. For instance, a cold winter might coincide with low hydroelectric and wind output due to droughts increasing gas demand (for a more comprehensive analysis of these factors influencing supply and demand variability, see Ah-Voun et al., 2024).

The rest of this section focuses on presenting the baseline modelling results first (§5.1). Then, we present the role of flexible LNG supplies in managing stress events (§5.2) and discuss how forward-contracting and buyer commitment can minimise the cost of these events (§5.3).

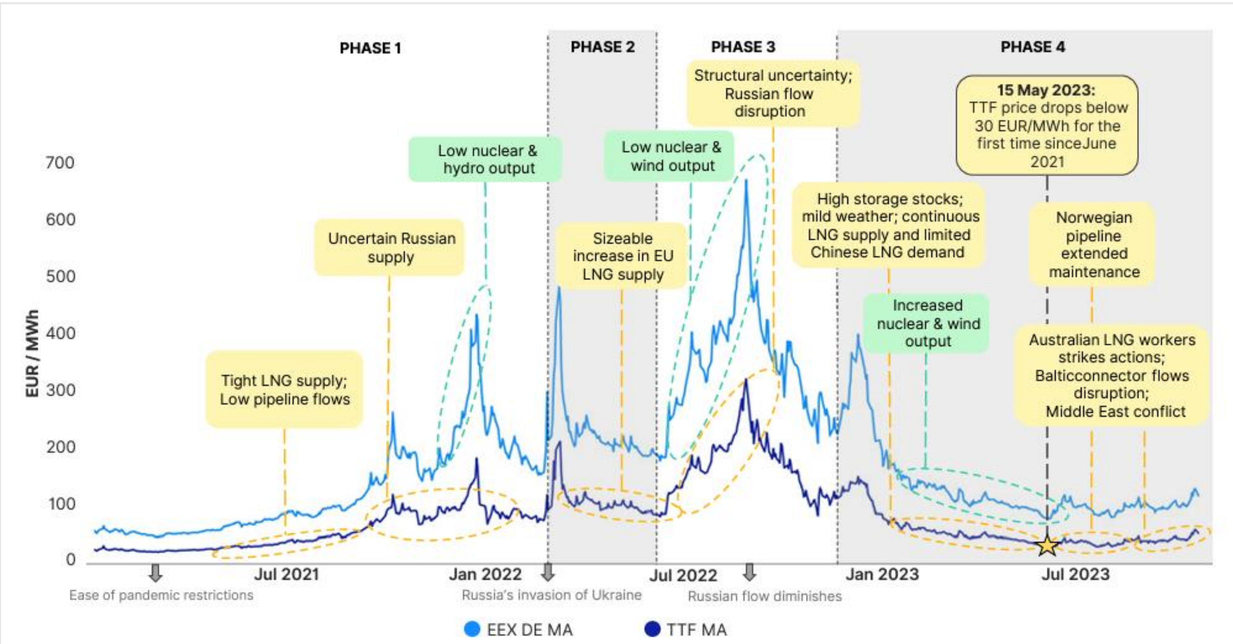


Figure 2: Geopolitics, weather and technological impacts on energy prices in Europe – 2021-23.

Notes: EEX DE MA – wholesale electricity price; TTF MA - wholesale gas price
Source: ACER (2023)

5.1 Baseline scenario results

Between 2010 and 2020, the EU27 countries experienced a significant reduction in total gas consumption, decreasing from 420 bcm to 338 bcm, representing a 19.5% decline (Figure 3: upper panel). This trend of de-growth is projected to continue and accelerate, with total gas consumption expected to fall to 300 bcm by 2030 (8% higher than the policy target in the Fit For 55 package and 60% higher than the target under the REPowerEU plan) and further to 156 bcm (of which 97 bcm is demand for biomethane) by 2050, marking a dramatic reduction of approximately 48% from 2030 levels. The decline in gas demand is evident in natural gas used for transformation and final consumption as Europe decarbonises its energy system. Natural gas in transformation dropped from 154 bcm in 2010 to 112 bcm in 2020 and is projected to decrease to just 43 bcm by 2050. Similarly, natural gas in final consumption fell from 266 bcm in 2010 to 227 bcm in 2020, with a more pronounced reduction expected post-2030, reaching 16 bcm by 2050.

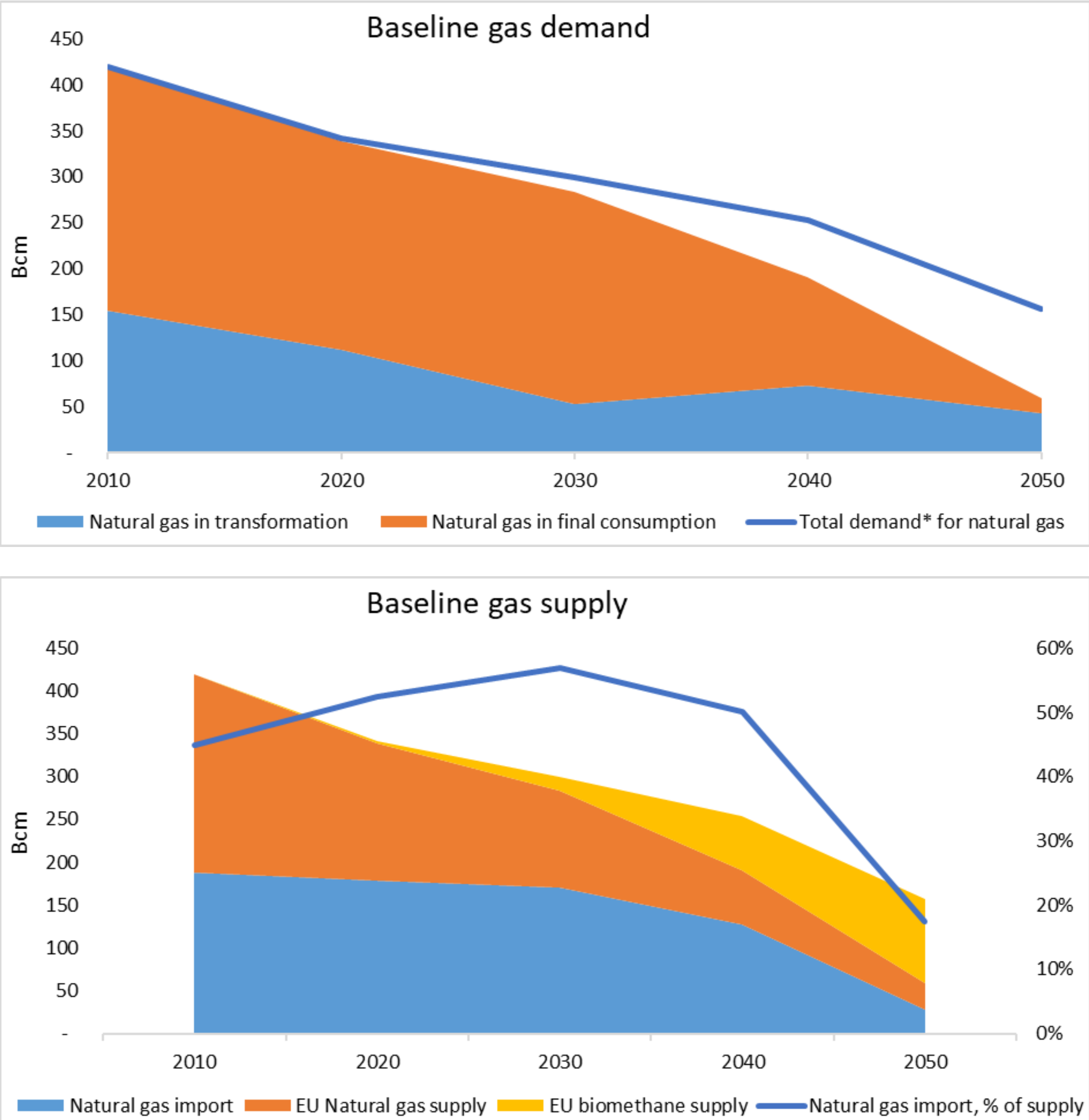


Figure 3: Gas demand (upper panel) and supply (lower panel) for 2010-2050

*Notes: * total demand for natural gas is the sum of natural gas and biomethane consumption; consumption includes EU27, Norway and Switzerland; historical years (2010, 2020) taken from EC Reference Scenario (2020) dataset and include only EU27; the difference between the total demand for natural gas and total consumption is EU biomethane supply.*

The supply dynamics also reflect this transition, with the EU natural gas supply (including supplies from Norway) significantly decreasing from 232 bcm in 2010 to 160 bcm in 2020 and further down to 32 bcm by 2050. Although fossil gas imports decreased slightly from 188 bcm in 2010 to 179 bcm in 2020, the reliance on imports increased, peaking at 57% of supply in 2030 (Figure 3: lower panel). However, by 2050, imports are projected to drop to 27 bcm, constituting only 17% of supply, indicating a shift towards greater self-sufficiency and alternative energy sources. The rise in EU biomethane supply, from zero in 2010 and 2020 to 97 bcm by 2050, highlights the strong transition towards renewable gas sources. Demand for methane also shows a consistent decline from 420 bcm in 2010 to 341 bcm in 2020, with a projection of 156 bcm by 2050, underscoring the EU27's commitment to decarbonisation and reduced dependence on fossil fuels. This shift towards renewable energy and increased self-sufficiency demonstrates a strategic move towards a more sustainable and resilient energy future for the EU27 countries.

Modelling results for the gas imports by source reveal significant changes in the EU's energy import landscape over the years (Figure 4). In 2010, the EU imported 233 bcm of gas, predominantly from Eurasia[6] (112 bcm, 48%), with significant contributions from North Africa (63 bcm, 27%) and other regions (22 bcm, 9%). By 2020, total imports had increased to 261 bcm, with Eurasia's share growing to 145 Bcm (55.6%), reflecting continued dependence on this region, particularly Russia. Notably, imports from North America began to emerge, contributing 18 bcm (6.9%), while imports from North Africa decreased to 35 bcm (13.4%).

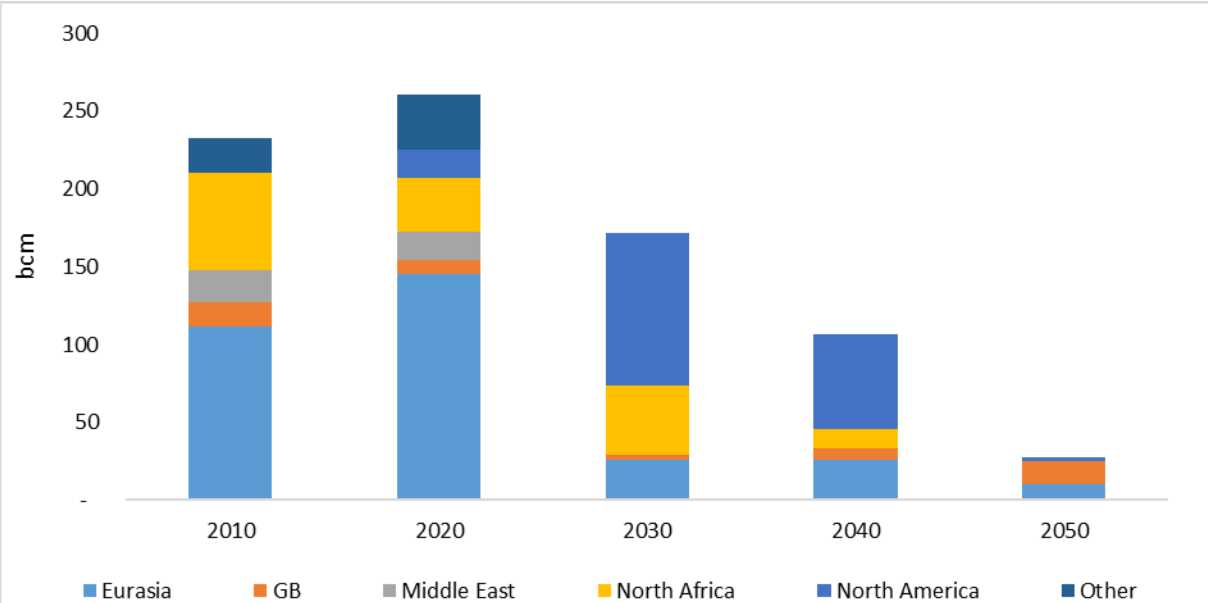


Figure 4: EU gas import by sources.

*Notes: * EU27 supplies include Norway but exclude the UK; 2010-2020 are historical data from BP Statistical Review of World Energy (2011;2021), the EU Reference scenario (2021); the data presented is for EU27+NO+CH.*

By 2030, under the baseline scenario, total gas imports are projected to decrease to 171 Bcm. There is a substantial reduction in imports from Eurasia to 26 bcm (15.2%), underscoring the EU's efforts to reduce reliance on Russian gas amid geopolitical tensions. Instead, North America becomes a major supplier, with imports surging to 97 bcm (56.7%), highlighting the strategic pivot towards more stable and flexible LNG supplies. North Africa maintains an important role with 45 bcm (26.3%), while imports from other regions drop, indicating a consolidation of supply sources.

[6] Mostly Russia.

As Europe continues decarbonisation via renewable energy sources, looking ahead to 2040, total gas imports are expected to decrease to 107 bcm. Imports from Eurasia remain unchanged at 26 bcm (24.3%), while North America's contribution will likely decrease to 61 bcm (57%), still the dominant supplier for the region. North Africa's share drops to 12 bcm (11.2%), reflecting limited potential to increase supply from the region. By 2050, total gas imports are projected to plummet to 27 bcm, with near-complete energy independence as Europe must reach its net zero GHG emissions target by then. Eurasia's share diminishes to 10 bcm (from the Caspian region) (37%), and North America's contribution falls to 2 bcm (7.4%). Interestingly, imports from Great Britain increase to 15 bcm (55.6%), a combination of LNG imports, indigenous supplies from the continental shelf and Norway. These minimal import volumes highlight the EU's successful shift towards renewable energy and significant progress in achieving decarbonisation goals.

Between 2010 and 2020, the EU27 countries experienced notable shifts in their electricity generation capacity (Figure 5). In 2010, the total installed capacity was approximately 805 GWe, heavily reliant on fossil fuels, with CCGT (CH4) contributing 176 GWe (21.8% of the total) and coal 155 GWe (19.2%). Nuclear and hydro also played significant roles, with capacities of 123 GWe (15.2%) and 157 GWe (19.5%). Renewable energy sources such as wind and solar were relatively small, with wind contributing 80 GWe (10%) and solar 30 GWe (3.7%).

By 2020, the total installed capacity had increased to approximately 975 GWe. There was a noticeable increase in renewable energy, with wind growing to 178 GWe (18.3%) and solar to 126 GWe (12.9%). Biomass also grew substantially, from 25 GWe to 58 GWe (5.9%). Despite these increases, CCGT (CH4) and coal remained significant, contributing 166 GWe (17.0%) and 131 GWe (13.4%). Nuclear and hydro saw slight decreases, maintaining 107 GWe (11.0%) and 163 GWe (16.7%).

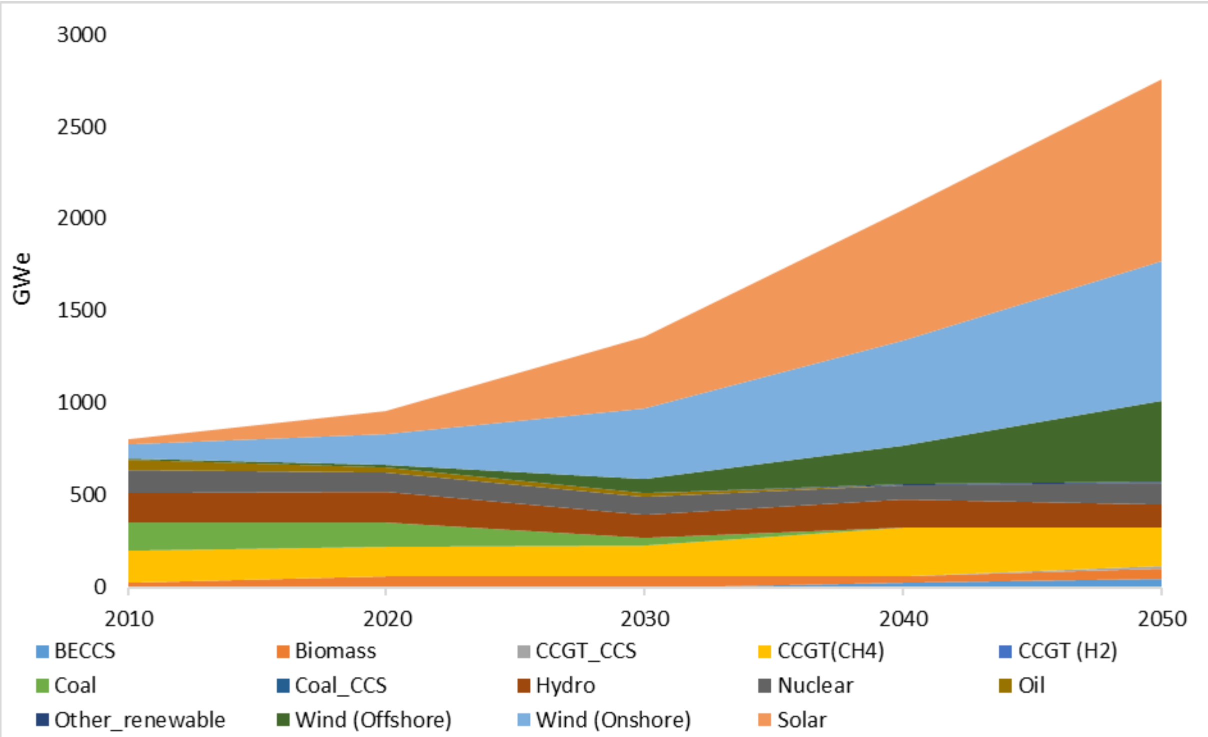


Figure 5: EU electricity generation capacity.

Notes: 2010-2020 are historical data from the EU Reference scenario (2021); The data presented is for EU27+NO+CH.

The baseline scenario projections from the model indicate a dramatic increase in renewable energy capacities, reflecting the EU's commitment to achieving net zero GHG emissions by 2050. By 2030, the total installed capacity is projected to reach around 1,255 GWe, with wind and solar expected to surge to 456 GWe (36.3% of the total) and 394 GWe (31.4%). Biomass will continue to rise to 61 GWe (4.9%), while CCGT (CH4) remains significant at 162 GWe (12.9%). Coal's capacity is projected to plummet to 48 GWe (3.9%), signifying a clear move away from high-emission energy sources. By 2040, the total installed capacity is expected to reach 1,652 GWe, with wind projected to reach 780 GWe (47.2%) and solar 710 GWe (42.9%). BECCS (Biomass Energy with Carbon Capture and Storage), a negative emissions technology, will significantly grow to 24 GWe (1.4%). CCGT (CH4) is projected to increase to 264 GWe (16.0%), reflecting its role in balancing intermittent renewable sources. Coal is expected to be phased out completely. These trends are consistent with the recent developments in the European energy market post-2021-23 crisis, where, in 2023, renewables generation, in particular solar and wind, reached a new all-time high (Ember, 2024).

By 2050, the total installed capacity is projected to increase to around 2,149 GWe, with wind and solar dominating at 1,192 GWe (55.5%) and 987 GWe (45.9%), respectively. BECCS will grow to 45 GWe (2.1%), indicating the importance of technologies that reduce atmospheric CO_2. CCGT (CH4) will likely remain significant at 208 GWe (9.7%), while coal and oil will be completely phased out. Nuclear capacity will increase to 113 GWe (5.3%), reflecting its continued role as a low-carbon baseload power source. These changes in electricity generation capacity are closely linked to the gas demand and supply trends (Figure 3). The projected growth in renewable energy sources and the phasing out of coal and oil align with the EU's strategic goals to reduce fossil fuel use and increase reliance on renewable energy. The decrease in fossil gas imports, particularly from Eurasia due to geopolitical tensions and sanctions, underscores the need for continued energy diversification.

By 2050, the EU aims to significantly diminish its dependency on fossil fuels to reach the carbon neutrality objective. This reduction in fossil fuels is reflected in the reduced contributions from gas, coal, and oil in electricity generation and the increased adoption of biomethane and renewable sources. By 2050, the EU's energy landscape is expected to be dominated by renewable sources, with significant contributions from wind (55.5%) and solar (45.9%). This transition supports reducing fossil gas demand, with CCGT (CH4) remaining important for grid stability and balancing renewable intermittency. Integrating BECCS and other negative emissions technologies will be crucial for offsetting residual emissions, ensuring the EU meets its ambitious net-zero targets.

5.2 The role of flexible LNG in energy crunch events

The analysis of the *energy crunch* scenario, reflected in Figure 6, reveals significant changes in gas demand and supply under increased energy demand due to cold weather and low renewable production.

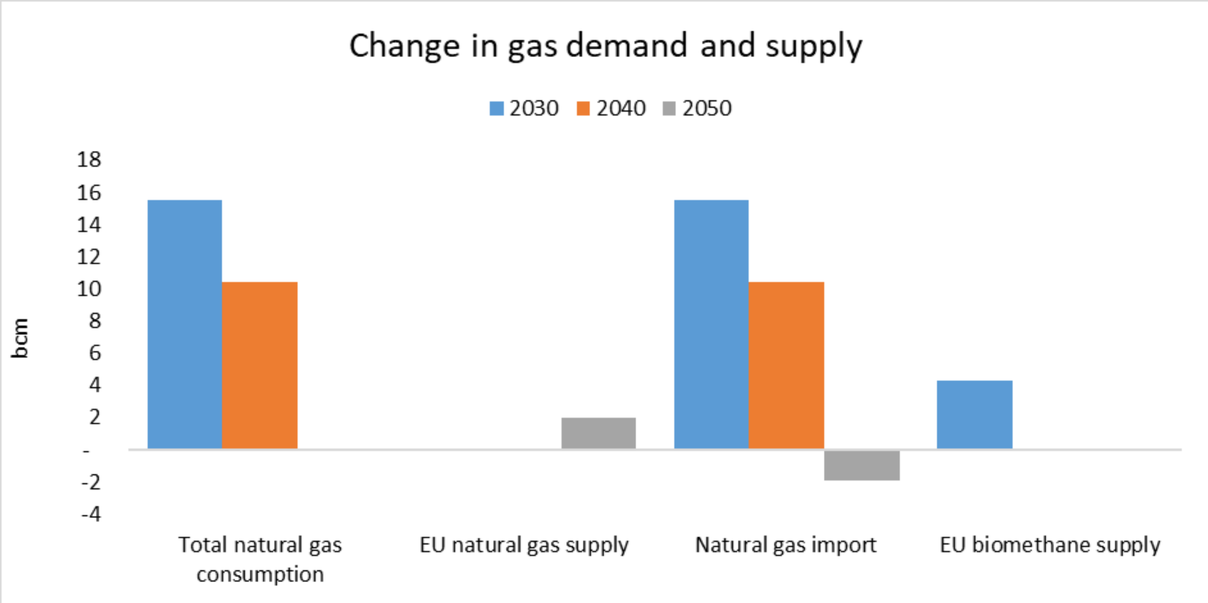


Figure 6: Impact of the coldest scenario (high demand, low renewable and nuclear generation) on gas demand and supply.

Notes: The chart shows the differences in demand and supply relative to the baseline scenario.

In 2030, the total natural gas consumption increases by 16 bcm compared to the baseline scenario, driven by a substantial 25 bcm rise in fossil gas used for transformation processes, despite a reduction of 9 bcm in final consumption due to high energy prices in the crunch event (Figure 8). This additional demand is primarily met through increased natural gas imports by 16 bcm, highlighting the EU’s reliance on external sources to address supply shortfalls. EU biomethane supply contributes an additional four bcm, reflecting the early stages of integrating renewable gases into the energy mix. The overall demand for methane (CH4) rises by 20 bcm, underscoring the critical role of flexible LNG supplies to buffer against extreme weather impacts and maintain energy security in Europe.

By 2040, improvements in energy efficiency and the integration of renewables reduce the additional natural gas consumption to 10 bcm, with imports increasing by 10 bcm to meet this incremental demand. The EU biomethane supply remains unchanged, indicating a stable but limited role in addressing supply gaps. By 2050, the impact of the *supply crunch* scenario is significantly mitigated, with no changes in total natural gas consumption. This reflects the success of the EU’s decarbonisation efforts and the near elimination of natural gas in transformation processes.

The *energy crunch* scenario analysis reveals significant shifts in global gas trade flows, highlighting the critical role of flexible LNG supplies, especially from North America, in meeting increased demand in the EU due to cold weather and low renewable and nuclear production (Figure 7). In 2030, North American LNG supplies to Europe (EU+GB) surge by 20 bcm (74% of incremental gas demand due to the *energy crunch* events in Europe), showcasing the flexibility and responsiveness of North America to raise production when needed and also to redirect LNG exports to Europe. This trend continues into 2040, with an increase of 7.4 bcm LNG from North America to the EU, principally redirected volumes from Asian markets. By 2050, due to reduced natural gas consumption, the impact of the *energy crunch* on the reshuffling of global LNG trade will be limited.

Australia also plays a pivotal role in balancing global gas trade but with a more regional focus on Asian markets. For example, modelling results suggest that in 2040, Australia redirects around 17 bcm from other Asia Pacific markets to China, allowing North America to divert LNG from China to Europe, prioritising supply to regions with a spike in demand. This substantial reallocation demonstrates the interconnected nature of global LNG markets and the impact of demand fluctuations in one region on supply distributions in others. The shift highlights the need for destination-flexible LNG supply and responsive trading strategies to address regional imbalances.

While the primary adjustments in global gas trade involve North America, Australia, and, to a lesser extent, the Middle East, changes in gas trade flows for other regions are relatively minor. For instance, a slight reshuffling of LNG supplies to India and the rest of the world is observed from the modelling results. Still, these changes are minimal compared to the significant shifts involving North American and Australian LNG in balancing the global supply and demand changes. Thus, unimpeded market-based growth in LNG supplies is crucial to energy security in importing regions.

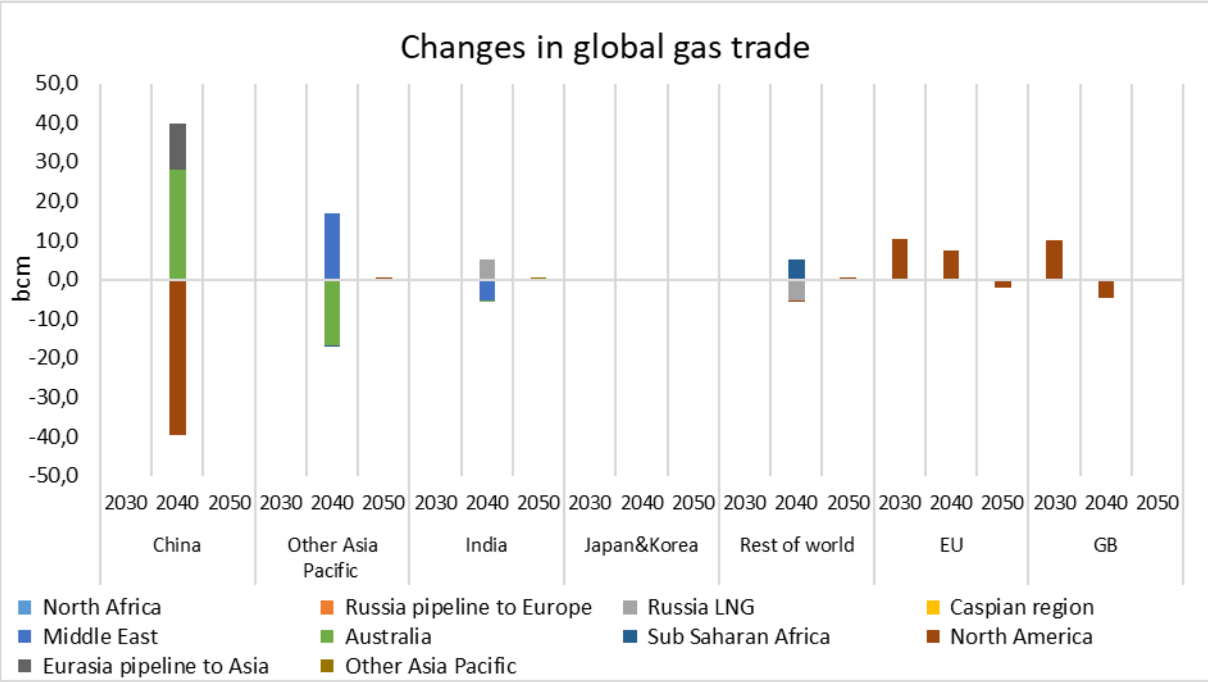


Figure 7: Impact of the energy crunch scenario (high demand, low renewable and nuclear generation) on global gas trade.

Notes: The chart shows the differences in gas trade relative to the baseline scenario; the bars show the changes in gas flows to the import regions in 2030-50 from the export regions in the legend at the bottom of the chart.

5.3 Minimising the cost of energy crunch events

Analysing the EU's total capital expenditure on energy infrastructure and gas consumer cost (Table 2) and wholesale gas prices (Figure 8) under various scenarios – Baseline, *Energy Crunch*, and *Energy Crunch with LNG buffer* – reveals the economic and financial impacts of extreme weather and fluctuating renewable energy production.

Table 2: Total capital expenditure on energy infrastructure and gas consumer cost (Euro billions) in 2030-50 under the baseline and weather scenarios.

	Gas consumer cost*			Energy infrastructure CAPEX**			Total undiscounted consumer and capex costs for three years
	2030	**2040**	**2050**	**2030**	**2040**	**2050**	
Baseline	104	192	33	412	510	739	1,990
Energy Crunch	512	414	35	563	593	1,015	3,132
Energy Crunch with LNG Buffer	114	106	34	534	570	997	2,355

*Notes: *Gas consumer cost is defined as a product of wholesale price (Figure 8) times total gas consumption for respective scenarios; **capital expenditure reflects annual investment in energy infrastructure needed to meet energy demand and GHG abatement targets (for the detailed formulation of the model, see Chyong et al., 2024).*

When comparing the Baseline scenario with the *Energy Crunch* scenario, the modelling results reveal the profound impact that adverse weather conditions and reduced renewable and nuclear production can have on the economic cost of Europe's energy system. In the *Energy Crunch* scenario, consumer costs rise dramatically, reaching 512 billion euros in 2030, compared to just 104 billion euros under the Baseline scenario. This significant increase is mirrored in the wholesale gas prices, which spike from 31 EUR/MWh in the Baseline to a staggering 144 EUR/MWh in the *Energy Crunch* scenario for the same year (Figure 8). The elevated gas prices reflect the scarcity of supply relative under stress conditions and the resulting strain on the spot gas market, driving up the cost for consumers and leading to an overall increase in the economic burden for Europe. Furthermore, the total undiscounted infrastructure capital expenditures (CAPEX) also escalates sharply, from 1,661 billion euros under the Baseline to 2,171 billion euros in the *Energy Crunch* scenario over the three critical years (2030, 2040, and 2050). This highlights the increased need for investment in energy infrastructure to handle the surge in demand during such crises.

However, it is important to note that the economic burden of such scenarios could be somewhat mitigated by pre-emptive measures, such as securing fixed-price contracts for renewable energy. These measures can provide a degree of insulation from the volatility of marginal price contracts, which residential and small commercial customers often default to during crises. Nevertheless, the lesson from the 2021-23 energy crises indicates that despite these insurance measures, exposure to high spot prices can still lead to significant economic strain (Pollitt et al., 2024). This highlights the necessity for a diversified approach that combines investment in infrastructure with robust market mechanisms to protect consumers from extreme price fluctuations.

The linkage between gas consumer costs and wholesale gas prices is evident: as prices soar due to supply constraints, the direct result is a proportional increase in gas consumer costs. This relationship is critical in understanding the economic impacts of energy crises. In 2040, for instance, gas prices in the *Energy Crunch* scenario remain elevated at 141 EUR/MWh, which translates into continued high consumer costs of 414 billion euros (the slight reduction relative to the 2030 gas consumer cost is the result of lower gas consumption in 2040 relative to 2030). This sustained high pricing and cost scenario underlines the vulnerability of the European energy market to supply and demand shocks and the cascading effects on the overall economy, as witnessed in the 2021-23 energy crisis.

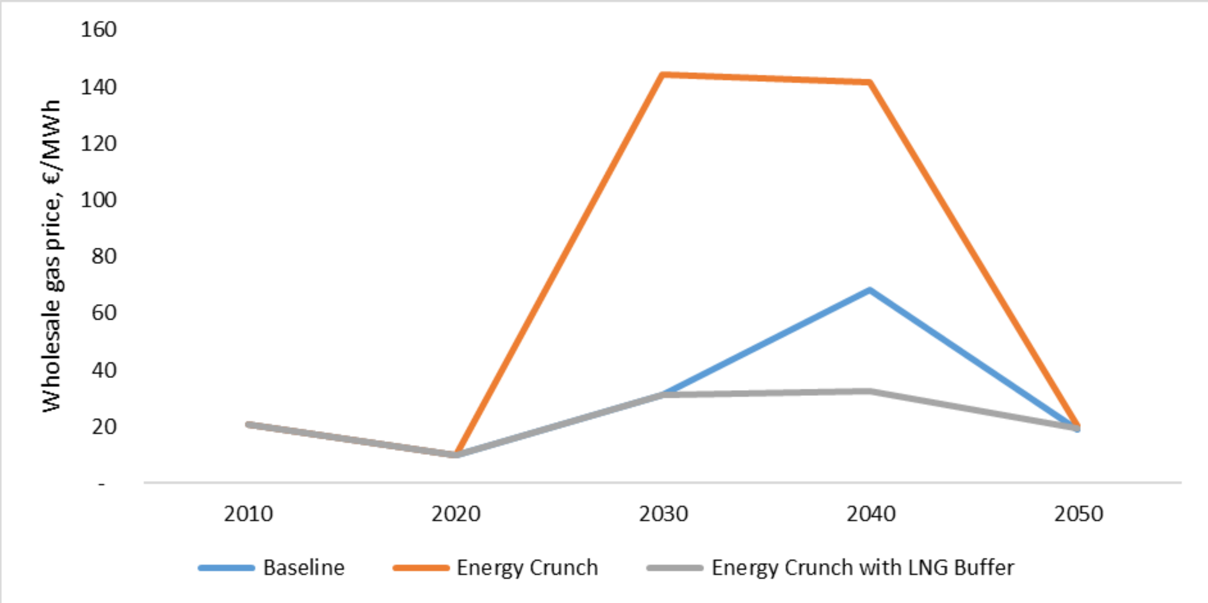


Figure 8: EU wholesale gas prices under the baseline and weather scenarios.

Notes: The chart shows the average gas prices for Germany, the Netherlands and France.

Thus, introducing an LNG buffer (*Energy Crunch with LNG Buffer* scenario) in the form of potential forward contracts to secure flexible LNG supplies may serve as a vital mitigating factor against these extreme conditions. In this scenario, Europe can stabilise spot gas prices, which remain at 31 EUR/MWh in 2030 and only slightly increase to 32 EUR/MWh in 2040, before returning to 19 EUR/MWh in 2050. This price stability directly translates into lower gas consumer costs, which drop significantly from the *Energy Crunch* levels to 114 billion euros in 2030 and 106 billion euros in 2040. The total undiscounted energy infrastructure CAPEX also sees a reduction, falling to 2,101 undiscounted billion euros over the three years, compared to the 2,171 undiscounted billion euros required in the *Energy Crunch* scenario without the LNG buffer. This scenario underscores the potential of strategic LNG agreements between EU buyers and flexible LNG suppliers to buffer against extreme conditions and maintain more predictable energy system costs.

The role of North American flexible LNG is pivotal in this context. As previously discussed, North America's ability to potentially increase supplies and redirect substantial LNG volumes to Europe during high-demand periods is crucial. In the *Energy Crunch* scenario, the increased imports from North America help mitigate the physical energy shortage, ensuring Europe can meet its demand even when renewable and nuclear sources underperform. This flexibility addresses immediate physical supply shortfalls, but preventing dramatic spot price spikes (as in the 2021-23 crisis) and reducing the overall economic impact of adverse weather conditions requires LNG demand commitment from buyers.

Most of the Middle East LNG supplies require long-term supply agreements in place, which contradicts both the EU's commitment to phase out those long-term supplies by 2049 (see Sections 2 and 3) and given a dramatic fall in EU's import requirement (see Figure 3 and Figure 4) might not be feasible for EU buyers. Most US LNG is based on tolling agreements (Chyong, 2016). Under these agreements, buyers can sign long-term contracts to access LNG export facilities. This arrangement provides flexibility to access the liquid US gas market and procure gas under shorter-term contracts. This flexibility, including access to US storage infrastructure and the extensive pipeline network, aligns well with the EU's decarbonisation timeline. It helps minimize the risk of stranded assets and avoids locking into long-term fossil fuel import contracts that extend beyond 2050.

To quantify the benefits of flexible LNG, we can compute the annual benefit (for 2030, 2040, and 2050) by considering the difference between the gas consumer cost and energy infrastructure capex (reported in Table 2) under the *Energy Crunch* with and without the LNG buffer (see Figure 9). Thus, in 2030, the LNG buffer yields a benefit of 397 billion euros in reduced gas consumer costs. This significant reduction directly stems from the stabilisation of spot gas prices, which, as previously analysed, remain at a moderate 31 EUR/MWh under the LNG buffer scenario, as opposed to the staggering 144 EUR/MWh seen in the *Energy Crunch* scenario without the buffer (Figure 8). Stabilising gas prices is crucial in mitigating the economic strain on consumers during extreme weather and low renewable output. Additionally, the LNG buffer provides a 29 billion euro reduction in energy infrastructure CAPEX in 2030, underscoring its role in minimising the need for extensive capital investments that would otherwise be required to manage energy shortages and maintain system reliability under stress conditions (Figure 9).

By 2040, the benefits of the LNG buffer continue to be substantial despite lower gas demand, with a 309-billion-euro reduction in gas consumer costs and a further 23-billion-euro savings in CAPEX. These benefits highlight the continued importance of LNG in providing energy security and economic stability. The scenario without the buffer, where gas prices remain high at 141 EUR/MWh, clearly demonstrates the cost implications of insufficient supply flexibility in Europe. The buffer's ability to maintain prices at a more manageable 32 EUR/MWh again showcases its critical role in reducing the financial burden on consumers and the energy system.

Further, in the 2040 scenario with the LNG buffer, the lower gas consumer cost compared to the baseline scenario can be attributed to the impact of long-term contracting for LNG. Specifically, under the LNG buffer scenario, Europe secures additional LNG supplies through forward contracts, stabilising gas prices at €32/MWh. In contrast, the baseline scenario, which does not include forward contracting, results in a significantly higher gas price of €68/MWh for 2040. This price stabilisation under the LNG buffer scenario mitigates the volatility typically associated with energy crunch events and supports higher gas consumption, evidenced by the projected 293 bcm of gas demand in 2040 compared to 253 bcm in the baseline scenario. This implies that forward contracting for LNG enhances Europe's energy security by hedging against potential supply disruptions and fosters conditions conducive to re-industrialization. The availability of stable and reasonably priced LNG supplies can revitalise European industrial activity, increasing gas demand within the industry and supporting broader economic growth.

Interestingly, by 2050, the benefits of the LNG buffer decrease significantly, with only a 1-billion-euro reduction in gas consumer costs and a 17-billion-euro reduction in CAPEX. This decline suggests that as Europe progresses towards deeper decarbonisation and potentially more diversified and resilient energy sources, the reliance on LNG as a critical buffer diminishes. However, the **cumulative discounted**[7] **benefits** over the three years – **542 billion euros in consumer gas cost savings** and **48 billion euros in CAPEX savings** – clearly illustrate the importance of securing flexible LNG supplies in the near to medium term, especially during the transitional period when the energy system remains vulnerable to supply shocks and extreme weather conditions.

Lastly, the potential impacts of the energy crunch events on electricity and hydrogen prices, often linked to gas prices, were not considered in the analysis. However, in the Energy Crunch scenarios, a spike in gas prices could lead to increased prices for electricity and hydrogen, particularly during high demand for gas-fired power generation or when hydrogen production relies on natural gas. In contrast, stabilising gas prices at a lower level in the LNG buffer scenario would likely also stabilise electricity and hydrogen prices, assuming these sectors remain closely coupled to gas prices. This stabilisation effect is crucial during energy crunch events, as it helps to prevent cost escalation in electricity and hydrogen markets, thereby reducing the overall economic impact on consumers and industries in Europe. Thus, the role of natural gas and LNG as an energy transition fuel for Europe seems crucial from economic and energy security perspectives.

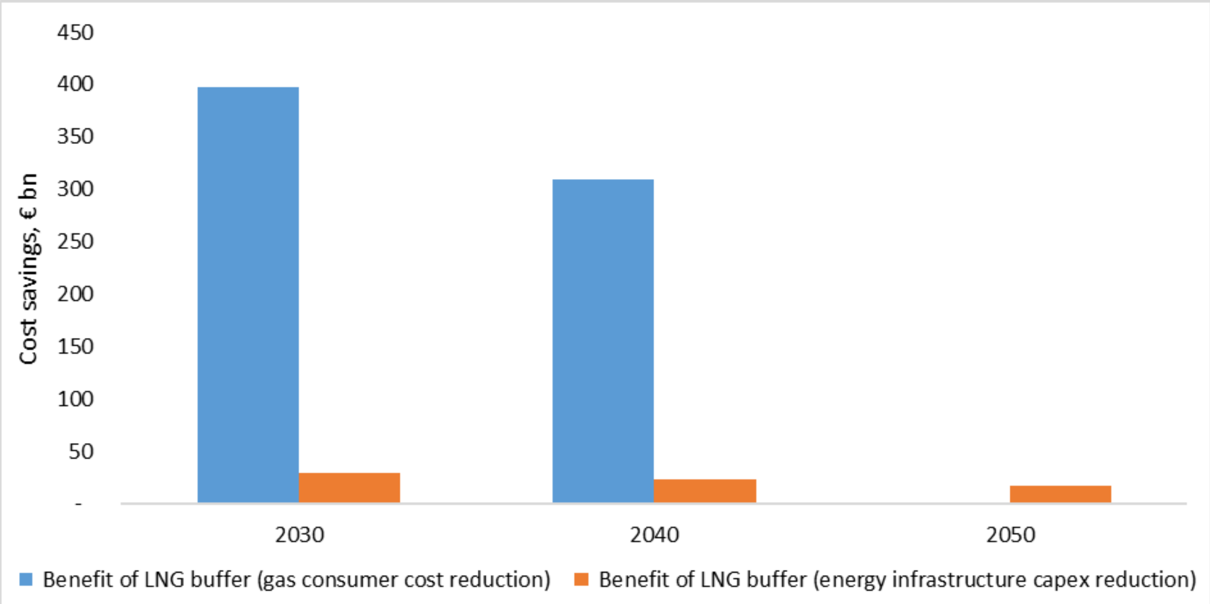


Figure 9: Potential benefit of forward contracting for flexible LNG supplies.

[7] Discounted to 2025 at 3% social discount rate for European countries based on estimates by Florio and Sirtori (2013).

6. GHG emissions of LNG and its competitiveness in Europe's decarbonisation

In the transition to a low-carbon energy system, it is crucial to incorporate whole value chain GHG emissions into the analysis of imported fossil fuels, particularly natural gas and LNG as a transition fuel. Traditionally, environmental impact assessments of energy supply have focused primarily on combustion emissions, overlooking significant emissions during extraction, processing, and transportation stages. Including these upstream and midstream emissions provides a more comprehensive understanding of coal, natural gas, and LNG's actual carbon footprint. The rest of this section proceeds as follows. The next section analyses GHG emissions of fossil fuels (natural gas by pipelines, LNG, and thermal coal) imports into Europe, focusing on upstream and midstream sectors (§ 6.1). We then present modelling results of putting a price on GHG emissions of the whole value chain to Europe (§6.2) and how addressing methane emissions alone for the North American LNG may benefit both the exporting region and Europe (§ 6.3).

6.1 Life-cycle GHG emissions of fossil fuels imports into Europe

Figure 10 displays responsibility for production vs. transportation on cradle-to-destination city emissions and implies that fossil fuel sources from North America and Russia exhibit the highest specific emissions regardless of the sourced fuel. In contrast, those from the Middle East consistently demonstrate the lowest specific emissions. Thus, for a given region, the reduction in emissions from LNG to pipeline emissions can range from 5% (Russia) to nearly 50% (Africa). This reduction could be attributable to the energy-intensive liquefaction and gasification steps required for LNG. The significant disparity in this reduction between regions is due to Russian pipelines in the studied dataset having, in comparison to other regions, notably more significant pipeline emissions. It is also worth noting that this result may result from a potential underestimation of fugitive emissions in our pipeline delivery emissions methodology. However, this observation aligns with existing literature, which, with strong agreement, has suggested that LNG has higher emissions due to the energy of liquefaction and regasification (Shaton and Harald, 2020). These differences in emissions have significant implications for the cost of abatement, as illustrated in Figure 11.

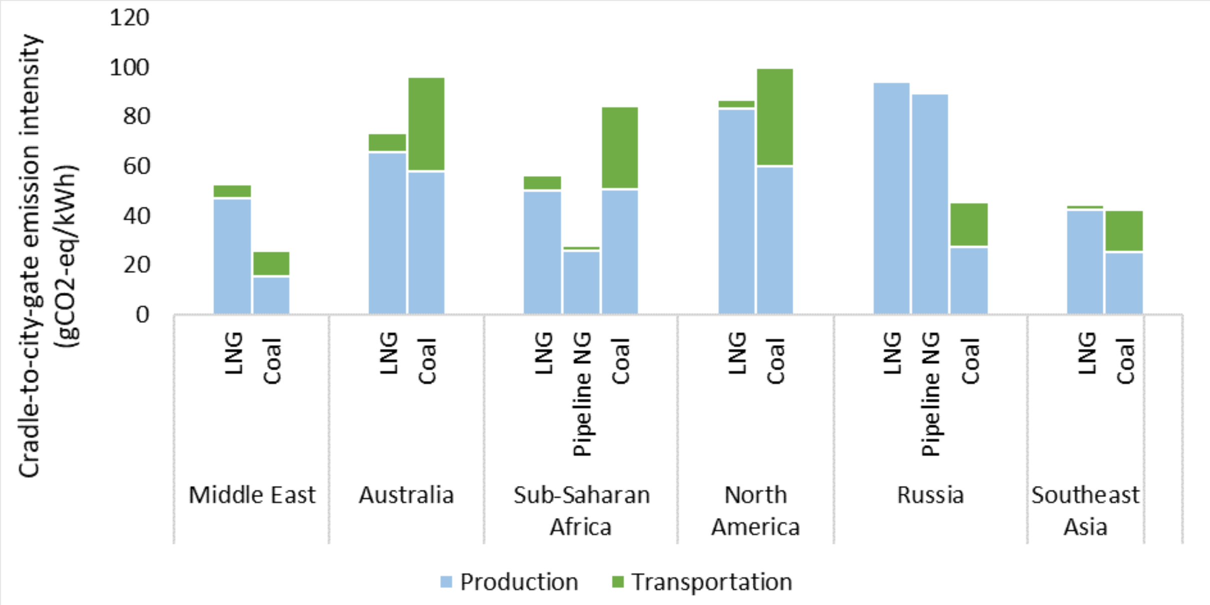


Figure 10: Average production and transportation emissions for LNG, pipeline natural gas, and coal to Northwest Europe.

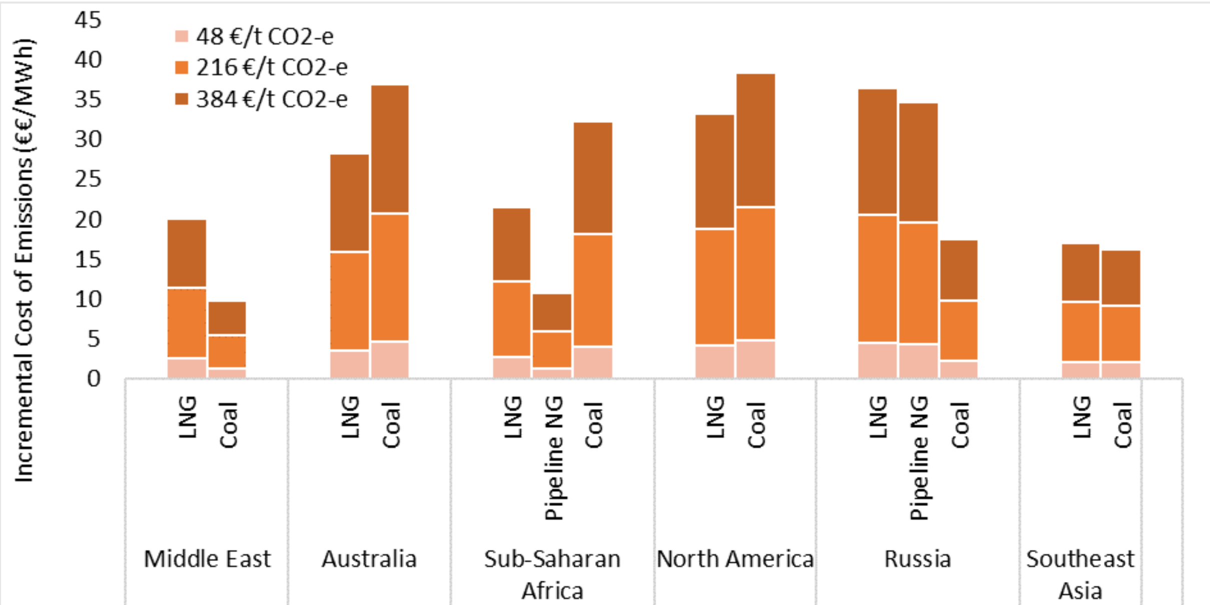


Figure 11: Incremental impact of three carbon price assumptions on the cost of emissions.

Figure 11 evaluates the incremental impact of three EU ETS carbon price assumptions (€48/tCO2e by 2030, €216/ b y 2040 and €384/tCO2e by 2050) (used in our energy system modelling and used by the EC’s long-term energy strategy modelling and the Fit for 55 impact assessment; see Appendix 1.2.). It demonstrates that a lower carbon tax not only results in a reduced cost of emissions but also a relatively low opportunity cost for opting for a more emissions-intensive option. In other words, a higher carbon tax makes emissions costs more “sensitive” to emissions differences between different fuel options.

The GHG emissions intensity of natural gas supply in the US varies significantly across different supply regions. For instance, emissions are relatively minimal in the Appalachian Basin but are substantially higher in the New Mexico Permian Basin (Sherwin et al., 2024). These regional discrepancies have important implications for how imported LNG from the US is accounted for under the EU's methane regulation, which mandates source or site-level emissions reporting (Smith and O'Sullivan, 2024).

As noted earlier, the US LNG stands apart as a destination-flexible supplier. This flexibility allows US LNG to adjust to price dynamics and optimise global trade flows, making it the marginal supply source in the global LNG market, particularly in response to Europe's marginal gas demand during energy crunch events.

An important consideration in this context is the newly introduced methane emissions charge under the US Inflation Reduction Act (IRA), which ranges between €32-54/tCO2e. This charge is significantly lower than the EU ETS carbon prices, which averaged €84/tCO2e in 2023 and much lower than the prices used in modelling deep decarbonisation pathways in the EU and our analysis (see Appendix A1.2). As a result, marginal US LNG exports will likely have lower methane intensity, with higher-emission sources choosing the domestic US market where the emissions tax is lower. This preference for the US domestic market becomes particularly pronounced when European gas prices are low, as the netback calculation favours selling domestically due to the emissions tax and transport cost differential.

However, if European gas prices rise to a level that negates the emissions tax and transport cost differential, higher-emission US LNG sources may instead be directed to Europe, leading to a higher emissions content in the marginal LNG supply.

Given that GHG emissions are a global commons problem, the EU's approach to tackling methane emissions in imported LNG should not rely solely on reporting source or site-level emissions. Instead, it should focus on the marginal emissions profile of the US gas supply industry. This shift would better account for the impact of US LNG's role as a marginal supplier in the global market. Nevertheless, the EU must balance the need for supply security during energy crunch events with the environmental impacts of that security.

In this study, we model an average emissions profile for US LNG (§6.2) and a sensitivity scenario (§6.3) in which we assume no methane emissions from US LNG. While this scenario is hypothetical, it helps illustrate the potential benefits of reducing methane emissions from the US gas supply chain, even though, in practice, there will always be some level of methane emissions due to the complexity of the gas network and the diversity of the US gas industry.

6.2 Impact of taxing GHG emissions of fossil fuels imports

The imposition of pricing on average GHG emissions across the entire value chain (cradle-to-city-gate) has profound implications for the EU's gas demand (Figure 12), its low-carbon energy sources (Figure 13), global gas trade, and particularly North American LNG exports (Figure 14). Analysing the changes relative to the baseline scenario reveals how stringent carbon pricing policies can reshape the energy supply, drive the transition to low-carbon energy systems, and affect international gas trade dynamics.

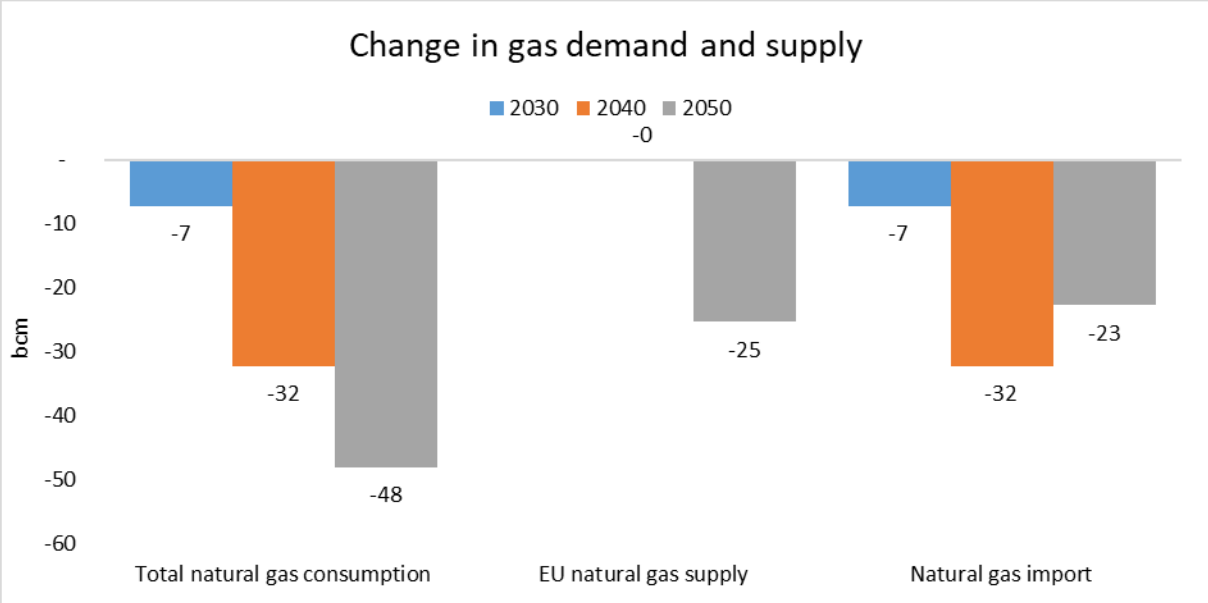


Figure 12: Impacts of pricing GHG emissions of fossil fuel imports' value chain (cradle-to-city gate) scenario (Full Import Carbon Tax) on EU's gas demand and supply.

Notes: The chart shows the differences in demand and supply relative to the baseline scenario.

The modelling results indicate a significant reduction in Europe's natural gas consumption under a stringent GHG pricing scenario. By 2050, total gas consumption in Europe decreases by 48 bcm compared to the baseline. This decline is primarily driven by reductions in natural gas in transformation (-42 bcm) and final consumption (-6 bcm). For example, less natural gas is used in the transformation to blue hydrogen because imposing a carbon tax on GHG emissions essentially increases the cost of gas for blue hydrogen production, making green hydrogen relatively more competitive (see changes in installed capacity of the low-carbon hydrogen sources as well as lower CCGT capacity in Figure 13). Correspondingly, gas imports decrease by 23 bcm by 2050 (total gas import in 2050 is ca. four bcm). These changes underscore the effectiveness of carbon pricing in reducing fossil fuel dependency and promoting cleaner energy sources. The EU's strategic shift towards less GHG-intensive gas sources is further evidenced by the increased imports from the Middle East (23 bcm in 2040) as North American LNG imports drop significantly (by 61 bcm in 2040 relative to the baseline).

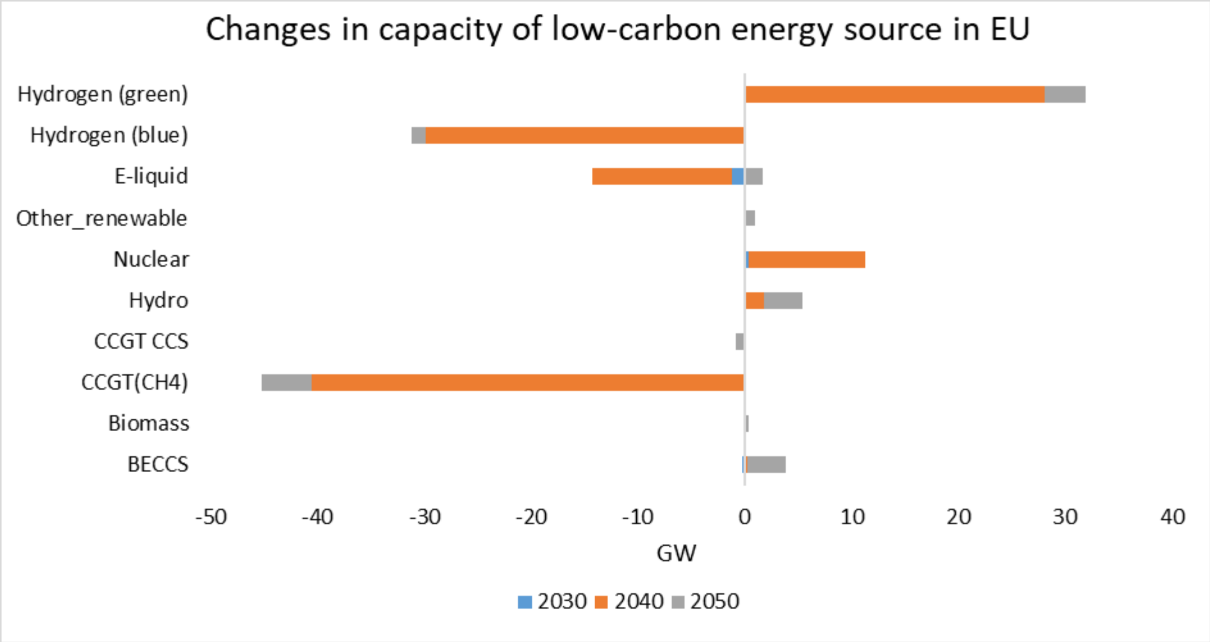
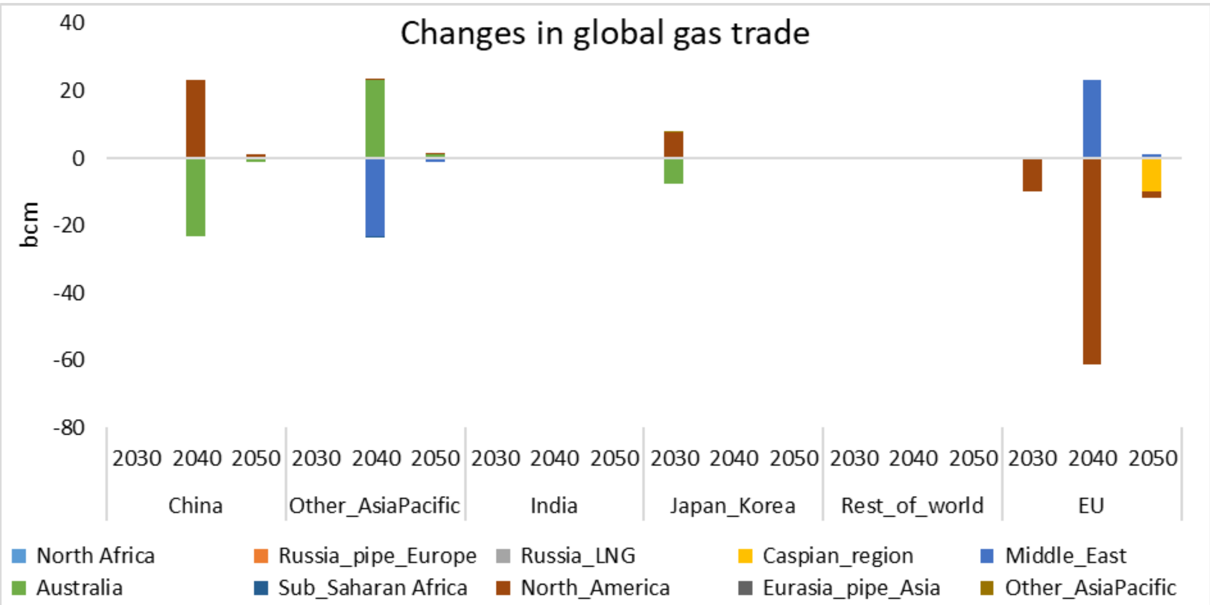


Figure 13: Impacts of pricing GHG emissions of fossil fuel imports' value chain (cradle-to-city gate) on EU's installed low-carbon energy sources.

Globally, Europe's full import GHG pricing impacts gas trade flows significantly, redirecting LNG from North America to other regions. North America's LNG exports are projected to decrease by a cumulative 41 bcm in 2030, 2040, and 2050. In contrast, with its relatively cleaner gas, the Middle East increases exports to Europe, highlighting a shift in trade patterns favouring less GHG-intensive suppliers. Australia and the Caspian region also see reductions in exports (-8 bcm and -10 bcm, respectively), reflecting the broader impacts of full GHG pricing on regions with higher associated GHG emissions. These shifts illustrate the potential for carbon leakage, where GHG-intensive LNG is redirected to regions without stringent carbon pricing.



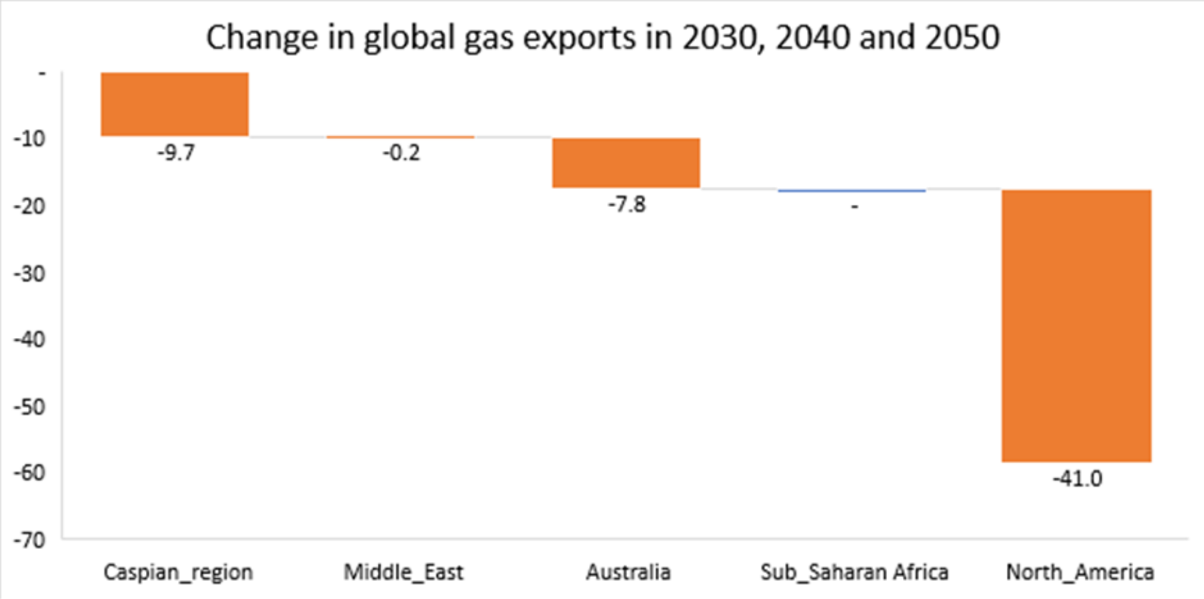


Figure 14: Impacts of pricing GHG emissions of fossil fuel imports' value chain (cradle-to-city gate) on global gas trade (upper panel) and exports (lower panel).

Notes: The upper chart shows the differences in gas trade relative to the baseline scenario; the bars show the changes in gas flows to the import regions in 2030-50 from the export regions in the legend at the bottom of the upper chart.

The issue of carbon leakage is particularly notable in the trade flow changes among various exporters and importers. For instance, Middle Eastern LNG, which is relatively less GHG-intensive, is increasingly diverted to Europe. In 2040, Middle Eastern LNG exports to Europe increase by 23 bcm, while North American LNG exports to Europe decrease by 61 bcm in the same year. Conversely, GHG-intensive North American LNG is redirected to regions like China and the rest of Asia. In 2040, North American LNG exports to China increase by 23 bcm, indicating a shift of more carbon-intensive gas supplies to markets with less stringent carbon management policies. Similarly, Australian LNG exports to Japan and Korea decrease by eight bcm in 2040, reflecting a redirection towards other Asia Pacific regions. This redirection causes Middle Eastern LNG, which previously supplied other Asia Pacific markets, to be diverted to Europe.

These changes underscore the importance of a coordinated global approach to GHG emissions management to prevent carbon leakage. The redirection of GHG-intensive LNG to regions without stringent GHG emissions policies undermines the effectiveness of the EU's climate policies. It highlights the need for comprehensive international agreements on GHG pricing, particularly on issues of methane emissions associated with LNG trade.

The modelling results underscore the importance of taxing GHG emissions from the whole fossil fuel import value chain in transitioning to a low-carbon energy system. This approach ensures that all production, transportation, and distribution stages are considered, promoting a potential reduction in GHG emissions associated with international fossil fuel trade. The modelling results show that such policies can significantly alter trade flows, encouraging the use of cleaner energy sources in Europe.

6.3 Competitiveness of LNG from North America: benefits of reducing methane emissions

While North American LNG is flexible, it is a marginal supplier in the global LNG market, so there is economic and environmental urgency to minimise GHG emissions, particularly methane. Thus, to explore the potential benefits of reducing methane emissions from the North American LNG supply chain, we model a scenario where North American LNG supplies are assumed to be methane leakage-free. In particular, in the ‘Methane-cleaned North American LNG scenario,’ we apply the EU’s carbon price to the entire import value chain **but** assume zero methane emissions from North American LNG supplies. This allows us to quantify the potential benefits, including lower emissions and reduced costs for Europe, as the region seeks to meet its decarbonisation goals while maintaining energy security.

Analysing Europe’s energy system costs reveals notable impacts under different carbon pricing scenarios. In the baseline scenario, the total energy system cost is projected to be 3,287 billion euros for 2030, 2040, and 2050. When GHG cradle-to-city-gate pricing is applied to imported fossil fuels, the total system cost increases to 3,313 billion euros (or just 1% higher than the baseline cost), reflecting limited additional investments needed to substitute more GHG-intensive fossil fuels with other low-carbon energy sources (such as green hydrogen, see Figure 13). However, when methane emissions from North American LNG are eliminated, the total system cost is reduced to 3,296 billion euros (9 billion euros, or 0.3%, higher than the baseline cost). This reduction highlights the economic benefits of cleaner energy supply practices, as addressing methane emissions can mitigate some of the increased costs associated with the EU’s comprehensive carbon pricing.

Wholesale gas prices vary more across the different scenarios than the total system cost. Under the baseline scenario, gas prices are projected to rise from 31 €/MWh in 2030 to 68 €/MWh in 2040 before dropping to 19 €/MWh in 2050. With GHG cradle-to-city-gate pricing, wholesale gas prices peak at 84 €/MWh in 2040 due to the added marginal GHG costs associated with imported fossil fuels. However, gas prices peak at a lower 73 €/MWh in 2040 when North American LNG has no methane emissions associated with its supply chain. This price reduction underscores the economic benefits of minimising methane emissions for European importers, which helps reduce the financial burden on consumers and industries by lowering the carbon cost impacts.

Policies that help reduce methane emissions from the North American LNG supply chain reduce Europe’s gas import costs while improving the competitive position of North America in global LNG trade (

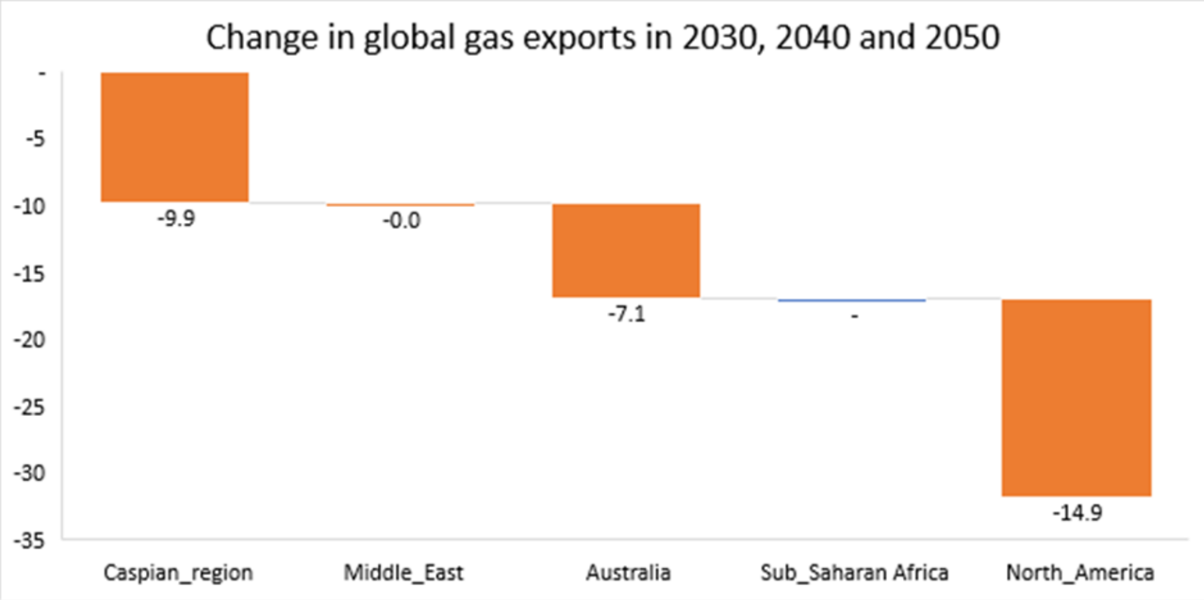


Figure 16) – the LNG from North America is only reduced by 15 bcm compared to 41 bcm (Figure 14) when methane emissions are not addressed. Thus, minimising methane emissions from North American LNG reduces system costs and enhances its competitiveness in a carbon-constrained world, potentially stabilising global gas markets and supporting EU decarbonisation efforts.

Table 3: EU's Energy System Cost (Euro billions) under the baseline and GHG pricing scenarios.

	2030	2040	2050	Total undiscounted for three years
Baseline	954	1,078	1,255	3,287
Full import carbon tax	953	1,101	1,260	3,313
Methane-cleaned North American LNG	954	1,085	1,257	3,296

Notes: Total energy system cost includes technology and infrastructure operational and capital expenditures to maintain the energy demand but excludes carbon costs (for details of the energy system boundary, see Chyong et al. (2024)).

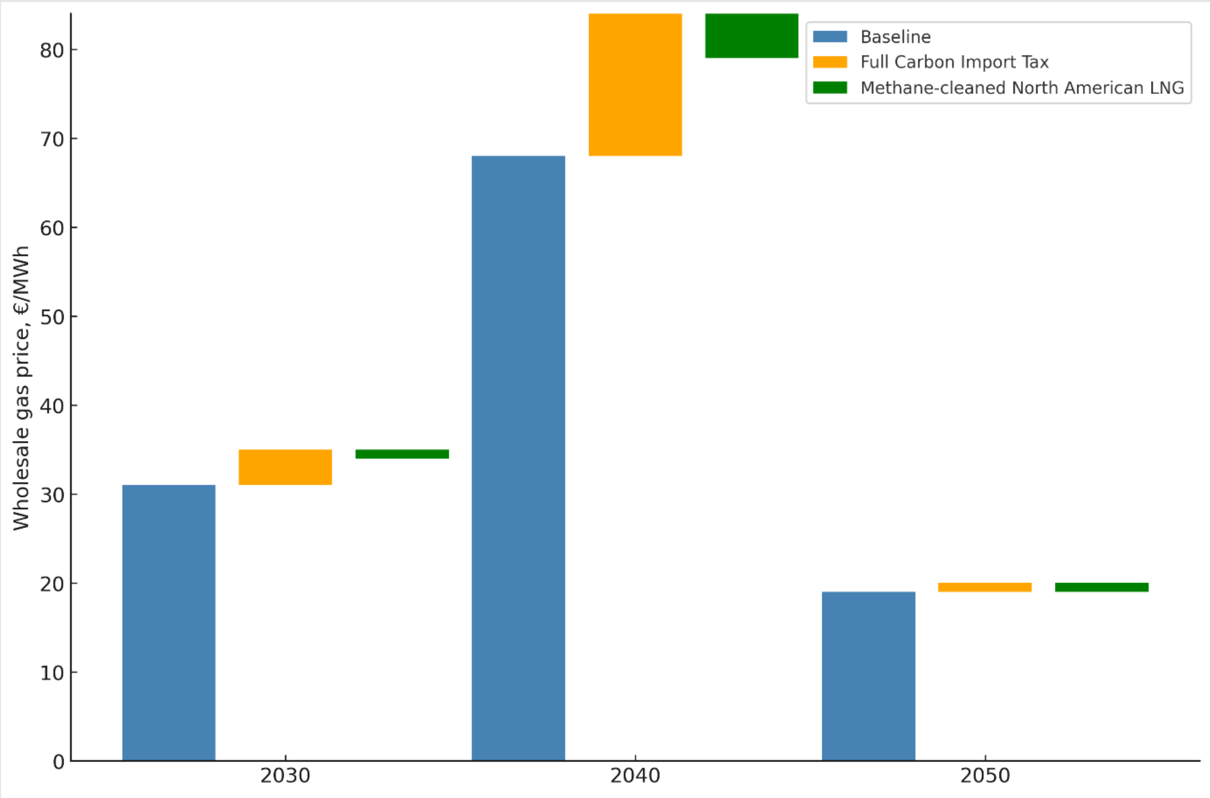
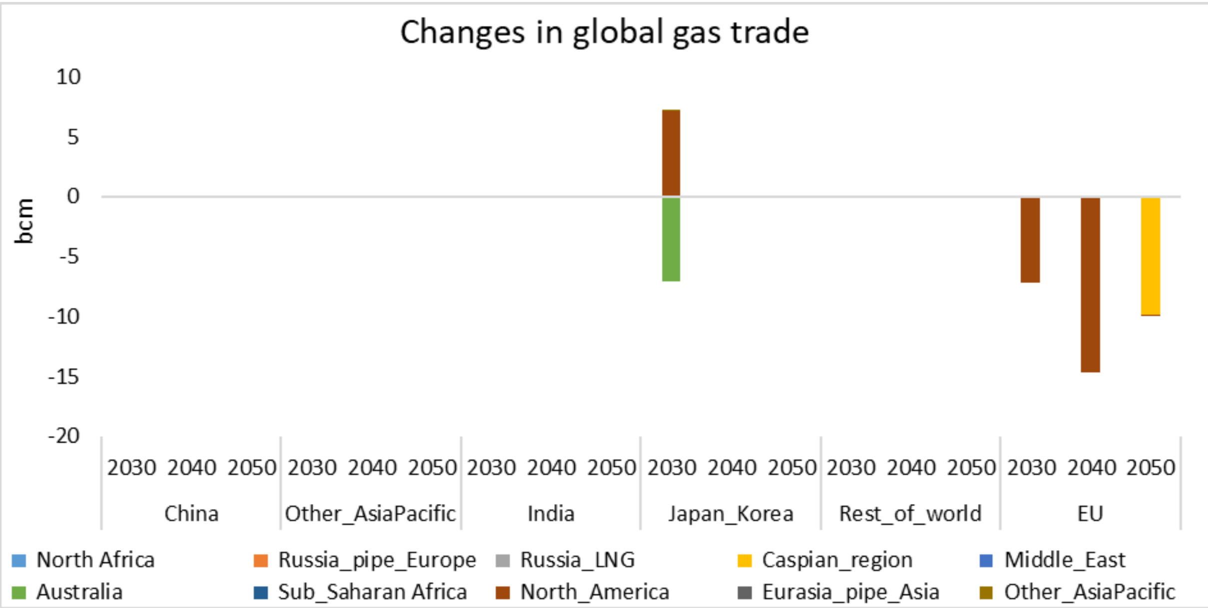


Figure 15: European wholesale gas prices under the baseline and impacts of GHG pricing scenarios

Notes: The chart shows the average gas prices for Germany, the Netherlands and France with the blue bars as baseline prices, whereas yellow bars are the impacts of carbon import tax on the baseline prices, and the green bars are the impact of cleaner North American LNG on the full carbon tax price scenario.



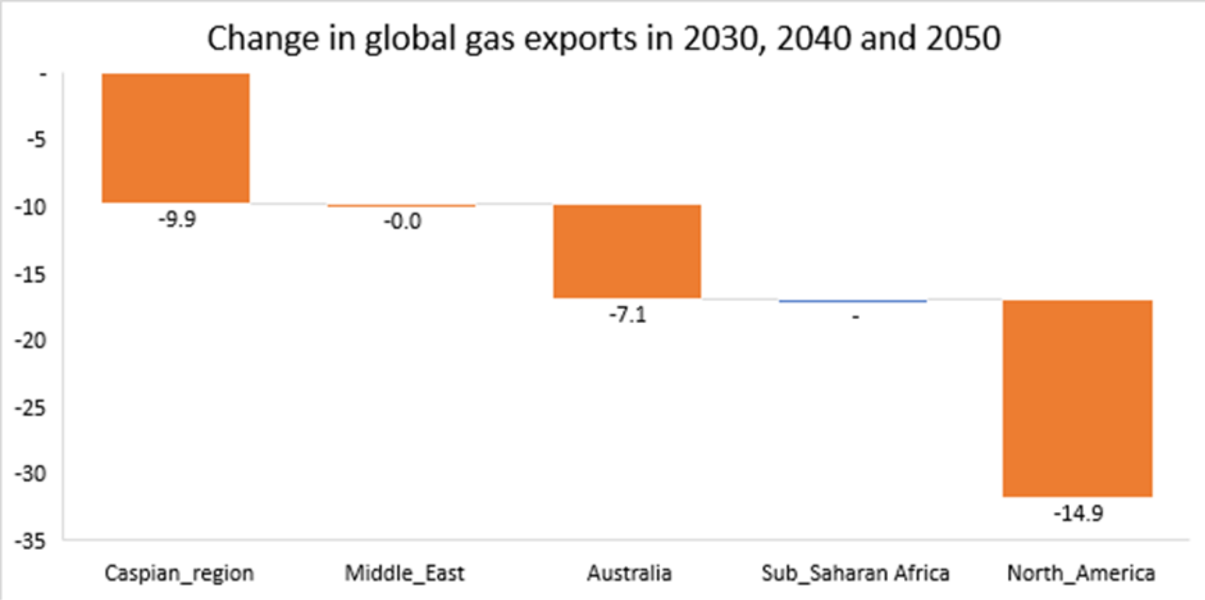


Figure 16: Impacts of pricing GHG emissions without CH4 from North American LNG exports on global gas trade (upper panel) and exports (lower panel).

Notes: The upper chart shows the differences in gas trade relative to the baseline scenario; the bars show the changes in gas flows to the import regions in 2030-50 from the export regions in the legend at the bottom of the upper chart.

7. Discussion of results and policy recommendations

This section discusses the modelling results, framing them in the context of broader policy and the global gas market. It is a foundation for our policy recommendations outlined in the last section of this chapter (§7.3).

7.1 Impact of EU GHG Pricing on LNG Markets

The analysis of modelling results indicates that extending GHG pricing to cover the entire fossil fuel import value chain imposes only a marginal increase – approximately 1% – in the EU's total energy system costs for 2030, 2040, and 2050. However, this policy significantly impacts global LNG trade, particularly high-emission exporters such as North America, Australia, and the Caspian region. Specifically, North America is projected to reduce its LNG exports to global markets by 41 bcm (-10% relative to the baseline export level) across the three modelled years due to the EU's comprehensive carbon pricing regime, which makes its exports less competitive. Australia and the Caspian region are also expected to see export reductions of eight bcm (-4%) and ten bcm (-33%), respectively. This highlights the disproportionate effect of the EU's unilateral carbon pricing policy on these exporters compared to the relatively modest impact on the EU's energy system costs, incentivising these exporters to reduce emissions.

While the EU's system costs increase slightly, the external impact on fossil fuel-exporting regions is substantial. The rise in wholesale gas prices, particularly in 2040 (a 23% increase relative to the baseline projection), reflects the added cost of GHG emissions but also presents an opportunity for European governments. The revenue generated from these import taxes could be redistributed to households to mitigate the effects of higher energy costs, thereby maintaining public support for stringent climate policies.

In contrast, regions with lower emissions, such as the Middle East, might initially benefit by gaining a larger share of the European market. However, as North American LNG is redirected to less environmentally regulated markets in Asia, competition intensifies in these regions, particularly in China, India, and the broader Asia-Pacific market. Moreover, the EU's unilateral GHG pricing policy is poised to create ripple effects across global markets, particularly in Asia. As evidenced by the 2021-23 crisis, Asian importers, especially China, redirected a substantial volume of LNG – primarily from destination-flexible US LNG – initially destined for their markets to Europe (Chyong, 2024). This move was driven by the opportunity to capitalise on elevated spot prices in Europe and to manage over-contracting amid lower-than-expected gas demand in China. Such market dynamics suggest that comprehensive GHG pricing by the EU could indirectly affect suppliers and importers focused on Asian markets, further reshuffling global LNG trade flows.

These changes in trade dynamics align with the broader "climate clubs" theory[8] in international climate policy (Nordhaus, 2015). The EU's unilateral GHG pricing can be seen as a de facto climate club, where stringent carbon pricing effectively penalises non-compliant LNG exporters by reducing their market access and making their goods more expensive in the EU market. As North American LNG becomes less competitive in Europe and is redirected to less regulated markets in Asia, competition in these regions intensifies. This could pressure established exporters like Australia and the Middle East to advocate for similar GHG pricing measures within their primary export markets – Asia – to maintain their competitive edge and protect their market share from more carbon-intensive imports. The reshuffling of global LNG trade flows observed in our modelling underscores this dynamic, suggesting that the EU's policy could catalyse international actions to tackle LNG's GHG emissions by creating economic pressures that resonate globally. As these pressures build, other major LNG exporters and importers may lobby for or adopt similar GHG pricing measures to neutralise the competitive threat of more emissive LNG sources, ultimately driving wider international participation in stringent climate policies concerning LNG trade.

Further, if the US imposed a carbon tax on methane emissions across its supply chain, it could reduce the EU's carbon emissions tax liability since the export prices would already reflect those emissions. This will positively impact the US's public finances as an additional tax income stream. Thus, the incentive to introduce a similar carbon pricing regime in the US is stronger in response to the EU's potential action on pricing GHG emissions of the fossil fuel import value chain. This dynamic also introduces the question of whether LNG shipping emissions would be taxed by the US or EU, potentially affecting who captures the revenue without necessarily impacting overall prices.

We should note that the Inflation Reduction Act (IRA) introduces the first federal fee on methane emissions in the United States, known as the "methane emissions charge," targeting specific entities in the oil and natural gas sector (Webb, 2022). Starting in 2024, the charge will be levied on emissions exceeding certain thresholds and will increase over time. The fee begins at $900 per metric ton of methane (ca. €32.3/tCO2e[9]) and rises to $1,500 (ca. €53.9/tCO2e) by 2026, impacting over 2,100 facilities. While its coverage is limited, the fee represents a significant step toward addressing methane emissions in the US, particularly in a regulatory environment characterised by fluctuations in policy enforcement across different administrations. The fee's impact is expected to raise around $1.1 billion in revenue by 2026, growing to $1.4 billion by 2030. Challenges remain in balancing regulation with economic impacts, as certain emissions thresholds allow for some methane release without penalties, and the fee's reach is limited to the largest emitting facilities (Webb, 2022).

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[8] According to Nordhaus (2015), a climate club is a coalition of countries that agree to implement a minimum carbon price and impose tariffs or other penalties on non-members to encourage broader participation. Nordhaus' climate club theory posits that as one region (in this case, the EU) adopts stringent environmental measures, it creates an economic incentive for other regions to follow suit, particularly if non-compliance results in trade disadvantages. The theory suggests that such economic pressures can drive broader international cooperation, as non-member regions may find it economically beneficial to adopt similar measures to maintain competitive access to major markets or to avoid becoming the dumping ground for more carbon-intensive products.

[9] Assuming methane's GWP of 25 over 100-year time horizon and USD to EUR exchange rate of 1.1139 USD/Euro (European Central Bank rate on 18 September 2024).

In summary, while Europe is not forecasted to be the largest LNG import market[10], its unilateral power to use strategic trade policy stems from two most important pillars of EU's energy and climate policy: (1) a political commitment to reach net zero by 2050 enshrined into law, and (2) the nature of its energy market organisation – a fully liberalised, Pan-European integrated market for gas and power[11] – that offers global players flexibility, acting as a regional market of last resort to navigate global LNG trade imbalances. The first pillar ensures "credible commitment" to tackle GHG emissions associated with the region's economic activities (e.g., imports of fossil fuels). In contrast, the second pillar offers global LNG trade the flexibility it needs and economic incentives to trade with Europe.

7.2 Contractual options for Europe to mitigate gas price volatility

Stabilising gas spot prices during market stress is essential to limit Europe's negative economic and financial impacts. Through energy market optimisation modelling, we quantified that having access to flexible LNG supplies under stress events can mitigate the rise in prices and costs for Europe. In practice, there are many ways to manage such imbalances, from supply-side to demand-side measures (Table 4).

Traditional Long-Term Contracts with Destination Clauses

These contracts offer lower costs and emissions profiles, particularly when sourced from regions like Qatar. However, they present significant drawbacks, primarily their inflexibility due to destination clauses that restrict market redirection unless profit-sharing mechanisms are applied (see Chyong and Kazmin, 2016; Chyong et al., 2023). This limitation clashes with the EU's climate goals, particularly as these contracts often extend beyond 2050, conflicting with the EU's decarbonisation targets. Additionally, the risk of sunk costs for buyers is substantial due to take-or-pay provisions, which can lock in costs for infrastructure and commodities. Furthermore, pricing formulas in these contracts are typically linked to competing fuels with escalation factors, allowing exporters to capture most of the inframarginal rent, reducing the economic benefits for European buyers.

Options Contracts with LNG Portfolio Players (LNG Aggregators)

These contracts offer European buyers more flexibility, as they grant the right, but not the obligation, to take LNG cargoes, mitigating "volume" risks. This flexibility aligns with the EU's need to adapt to fluctuating market conditions and avoid long-term commitments that may become liabilities under stringent climate policies. However, the primary downside is a non-delivery risk, as suppliers may divert cargoes to higher-priced markets, which could exacerbate supply shortages during energy crunch events (Ah-Voun et al., 2024).

[10] based on our modelling, it is the second largest LNG market after China in 2030 and 2040 and the smallest market in 2050; Europe's market share in global LNG trade is 26% in 2030, 17% in 2040 and 3% in 2050.
[11] On the economic benefits of a Pan-European wide single market for gas and power, see work by Chyong (2019) and Pollitt (2019), respectively.

LNG Tolling Contracts to Access the US Spot Wholesale Gas Market

These contracts provide significant advantages, including destination flexibility and the ability to divert cargoes for profit maximisation. They are also shorter in duration, reducing the risk of long-term sunk costs, and offer competitive pricing linked to the US Henry Hub spot price index. This alignment with gas-on-gas competition allows European buyers to capture most of the economic value. However, these contracts come with high costs and a larger emissions profile, particularly when sourced from the US, unless the US suppliers address GHG emissions (e.g., methane). Additionally, the disintegrated contract structure introduces transaction costs, as separate agreements are required for upstream sales and purchase agreements, LNG liquefaction tolling agreements, and LNG shipping.

Integrated LNG Tolling Contracts with Sales and Purchase Agreements with US Producers

These contracts offer price stability (e.g., via price floors and caps, an idea similar to the LNG oil-indexed S-curve pricing formula) and optionality to supplement contracted volumes with spot purchases at US spot gas hubs. They combine the advantages of LNG options and tolling contracts while providing security over contract volumes. However, the volume risk is higher than in simple LNG tolling contracts, which could pose challenges during low-demand periods. This risk can be mitigated with redirection to other regional markets but potentially with lower margins from resales. While this option balances securing supply and maintaining flexibility, it still carries risks associated with US-sourced LNG's more extensive emissions profile unless the US suppliers address these high GHG emissions.

Strategic Gas Storage

This option ensures that gas is under the control and ownership of European entities (e.g., TSOs), allowing for dispatch during energy crunch events. However, purchasing, holding, and restocking reserves could be prohibitively high, making this option less economically viable. Government intervention is likely required, which could lead to market distortions. Additionally, determining optimal storage filling targets is complex due to varying climate, geopolitical, and technological risks, making it challenging to implement this option cost-effectively in practice.

Demand Reduction Targets

This option presents a potentially low-cost resource during a crisis event, as it reduces the need for gas consumption rather than increasing supply. However, its effectiveness in addressing large-scale market imbalances is limited, particularly for the magnitude of events modelled in this study. Given the unpredictability of climate, geopolitical, and technological risks, setting optimal demand reduction targets is challenging. Moreover, this option requires significant upfront investment in smart grid technologies, consumer acceptance and willingness to adapt usage behaviour, which could be a significant barrier to implementation in the short term.

Table 4: Options to manage gas market imbalances.

Options	Pros	Cons
Traditional long-term contracts with destination clauses	• Lower costs and emissions profile (e.g., from Qatar) • Supply volume certainty	• Inflexible as a diversion to other markets is not allowed or allowed with profit-sharing mechanisms • Not compatible with the EU's climate goals as most contracts likely continue beyond 2050 unless relying on massive BECCS to offset emissions from these contracts • Risk of sunk cost for buyers due to take-or-pay provision covering infrastructure and commodity costs • Pricing formulas are based on competing fuels and escalation factors, so most of the inframarginal rent is captured by exporters
Options contracts with LNG portfolio players (aka LNG aggregators)	• No "volume" risk as European buyers have only the right, not the obligation, to take cargoes • Short-duration agreements, so minimal sunk cost risks	Non-delivery risks as suppliers can divert cargoes to higher-priced markets

Options	Pros	Cons
LNG tolling contracts to access the US spot Henry Hub gas market	• Destination flexibility and cargo diversion for profit maximisation allowed • Shorter duration contracts possible • Covers only infrastructure costs (e.g., LNG liquefaction); the risk of sunk cost is low • Competitive pricing terms based on gas-on-gas competition (e.g., linked to the US Henry Hub price index); therefore, most of the economic value (marginal benefit less marginal cost) is captured by buyers	• High costs and emissions profile (e.g., from the US) • Transaction costs associated with disintegrated contract structure (separate sales and purchase agreement with upstream or procurement on spot market; LNG liquefaction tolling agreement, LNG shipping agreements, access to regasification capacity in Europe)
Integrated LNG tolling contracts with sales and purchase agreements with the US producers	• Price stability, depending on pricing formulas (e.g., collared price structure) to source gas in North America • Optionality to supplement contracted volume with spot purchase at the US wholesale gas hubs • All the above, as in LNG options and tolling contracts	• As in LNG tolling contracts option but with security over contract volume • Volume risk is higher than under the LNG tolling contract options

Options	Pros	Cons
Strategic gas storage	Gas is under the control and ownership of European entities (e.g., TSOs) for dispatch when needed	• The cost of purchasing, holding and restocking the reserves may be prohibitively high • Likely to involve government intervention and support, and hence market distortion is possible • Unclear what are optimal storage filling targets given the varying climate, geopolitical and technological risks
Demand reduction targets	Potentially low-cost resource to tap into during a crisis event	• Limited potential to contribute to a large-scale market imbalance of the magnitude modelled in this study • Unclear what is optimal demand reduction targets and baseline demand given varying climate, geopolitical and technological risks • Requires consumer acceptance of new smart-grid technologies, willingness to participate and adapt usage behaviour • Potentially high upfront investment costs for smart grid technologies

In conclusion, managing gas price volatility during energy crunch events is a complex issue that requires a balanced approach. Each option presents trade-offs between cost, flexibility, and alignment with the EU's energy security and long-term climate goals. Traditional long-term contracts offer lower costs and emissions (if sourced from Qatar, for example) but are inflexible and potentially incompatible with the EU's decarbonisation targets. In contrast, options contracts and (integrated) LNG tolling contracts provide more flexibility. They are better suited to the EU's need for adaptability in response to energy crunch events. However, they come with higher costs and emissions profiles unless suppliers address those high emissions to comply with more stringent European emissions standards. Strategic gas storage and demand reduction targets offer potential solutions but involve high implementation costs and uncertainties regarding their effectiveness in large-scale crises. In light of the EU's policy direction toward decarbonisation and energy security and considering diversity amongst Member States, a combination of these options may be necessary to balance economic, environmental, and security objectives.

7.3 Policy recommendations

Our market modelling results suggest that unimpeded and market-driven global LNG supply expansion contributes to Europe's energy security as the region decarbonises its energy sector to reach net zero GHG emissions by 2050. However, European gas spot prices can rise under energy crunch events without buyers' commitment to expand those supplies. We quantified that the discounted benefits of committing to buy flexible LNG supplies under those stress events could total some 542 billion euros in consumer gas cost savings and 48 billion euros in CAPEX savings for the three years – 2030, 2040, and 2050 – we model. Given these modelling insights and the discussion above, this section offers key policy recommendations for Europe to ensure the security of its energy supplies at a reasonable cost on the path to net zero by 2050.

Ensure Gas Spot Price Stabilisation Under Stress Events

1. The EU should implement robust mechanisms to stabilise gas prices during energy crunch events characterised by extreme weather or reduced renewable energy output. This could be achieved by securing flexible LNG supplies through LNG agreements (e.g., options, tolling, and cap and floor LNG supply agreements), especially with North American LNG suppliers. Such contracts allow European buyers flexibility in purchasing LNG based on real-time market conditions, helping to maintain stable gas prices during periods of elevated energy demand.

2. The EU should also explore incentive mechanisms for active LNG contracting that go beyond the existing *AggregateEU* scheme (that matches potential buyers and suppliers) – for example, tightening gas security standards by considering the impacts of various risks such as climate, technological (such as those considered in this modelling), and geopolitical on gas demand. Imposing stricter security of supply standards will allow each MS to choose a suite of options (some may prefer integrated LNG tolling agreements with US suppliers, while others may choose a combination of long-term contracts with BECCS offsetting the residual emissions and developing demand-side response mechanisms) to hedge against energy crunch events.

Minimise Emissions Consequences of Energy Crunch Events

3. Addressing the environmental impact of LNG imports is crucial, particularly concerning methane emissions. The EU should develop and enforce stringent methane emissions standards across the LNG supply chain. In this respect, extending the carbon pricing mechanism to include the entire fossil fuel import value chain (cradle-to-city-gate) would encourage global uptake of cleaner energy supply practices. This policy would also incentivise

global exporters to reduce emissions, helping to align international trade practices with EU climate goals.

Strengthen EU-US Transatlantic Cooperation on Energy Security and Climate Policy

4. As the 2021-23 energy crisis showed, US LNG was paramount in alleviating the energy supply shortage faced by Europe. The EU should seek to enhance cooperation with the US on energy security and climate policy, focusing on securing a stable and reliable supply of LNG. This could involve setting up a transatlantic LNG trade advisory council chaired by high officials from both regions, ensuring the stability of LNG supplies to the global markets and adherence to the highest possible environmental standards, particularly regarding methane emissions. Establishing common standards and regulatory alignment across the Atlantic would help ensure that LNG imports meet the EU's environmental requirements, supporting energy security and climate objectives.

Strengthening the EU's Credible Commitment to Climate Targets

5. The EU's commitment to net zero by 2050, embedded in law, is one of the critical pillars that gives the region leverage in global energy markets. This credible commitment is crucial for providing long-term signals to energy investors and stakeholders, ensuring that the transition to a low-carbon economy is legally mandated and economically viable. To reinforce this commitment, the EU should continue to refine and communicate its long-term climate targets, ensuring alignment with its energy policies, trade strategies, and investment frameworks. By doing so, the EU can strengthen investor confidence, attract sustainable investments, and support the ongoing development of low-carbon technologies, enhancing the competitiveness of the EU's energy sector.

6. The European Commission should encourage Member States (MS) to revise their National Energy and Climate Plans submitted in 2023 and 2024. These plans should show how each MS plans to achieve the energy and climate policy targets, not just covering the period to 2030 but also outlining their plans for 2030-2040. This will show how each MS can contribute to achieving the EU-wide climate target of a 90% GHG reduction by 2040 relative to 1990.

Enhancing Market Flexibility and Integration to Support Decarbonisation

7. The EU's fully liberalised and integrated energy market provides significant flexibility that can absorb global LNG trade imbalances, making the EU a critical player even if it is not the largest LNG market. To maximise this advantage, the EU should continue to deepen market integration across MS, ensuring that regulatory frameworks, infrastructure investments, and market rules support the efficient flow of energy across borders. This integration will help the EU manage supply shocks and price volatility and reinforce the region's role as a flexible market of last resort for global LNG trade. By maintaining a market structure that balances

liberalisation with firm climate commitments, the EU can continue to drive global market dynamics towards lower emissions.

Phase Out Russian Gas Imports while Maintaining Flexibility to Respond to Geopolitics in the Region

8. Given the geopolitical and security concerns associated with Russian gas imports, the EU should work towards phasing out these imports completely well before 2030. Our modelling assumed that the EU could stop purchasing Russian LNG by 2030 and pipeline gas by 2040. A more expedited timeline for phasing out Russian supplies is possible. However, this should be done flexibly, allowing for adjustments based on geopolitical developments in the wider Eurasian region (on the impact of geopolitics on Russian exports to Europe and consequent wholesale price impacts, see Chyong and Henderson, 2024). To ensure energy security during this transition, the EU should explore mechanisms to secure alternative LNG supplies, particularly through cooperation with North America and other reliable partners. Establishing a flexible framework that allows for adjustments based on changing circumstances will be crucial for maintaining both energy security and geopolitical stability.

8. Conclusions

This research addresses the critical question of how Europe can maintain energy security and meet its demand cost-effectively as it decarbonises its energy system in line with the Paris Agreement's goal of limiting global temperature rise to 1.5°C. Through detailed energy system modelling, the analysis examines the role of natural gas and LNG, particularly flexible LNG, in supporting Europe's transition to a net-zero GHG emissions future by 2050. The findings reveal critical insights into the interplay between energy security, consumer and system costs, and the environmental impacts of LNG imports, guiding policy recommendations to optimise Europe's energy strategy.

The analysis highlights the importance of flexible LNG supplies in stabilising gas prices during stress events, such as extreme weather and low renewable output. Modelling results show that consumer costs and wholesale gas prices spike dramatically in scenarios like the energy crunch, characterised by increased gas demand and reduced renewable and low-carbon generation. Including flexible LNG supplies, mainly through forward contracts with North American LNG providers (e.g., integrated LNG tolling contracts with price floors and caps), significantly mitigates these economic impacts. In the *"Energy Crunch with LNG Buffer"* scenario, forward-contracting LNG stabilises wholesale gas prices, providing total discounted economic benefits of approximately 542 billion euros in reduced gas consumer wholesale costs and 48 billion euros in reduced energy infrastructure capital expenditure in the three years we modelled 2030, 2040, and 2050. These findings underscore the economic value of maintaining access to flexible LNG supplies as a buffer against supply and demand shocks in Europe's evolving energy system.

Moreover, extending GHG pricing to encompass the entire value chain of fossil fuel imports, including extraction, processing, and transportation, marginally increases total energy system costs by approximately 1% but induces substantial changes in global LNG trade flows. High-emission exporters like North America, Australia, and the Caspian region experience significant reductions in gas exports globally. This reshuffling of global trade highlights the effectiveness of carbon pricing in driving a shift towards cleaner energy supply sources and reducing reliance on more GHG emissions-intensive LNG supplies. The modelling suggests that such comprehensive pricing mechanisms could incentivise major LNG exporters to adopt stricter emissions standards, aligning global trade flows with Europe's decarbonisation objectives.

The research also underscores the strategic importance of EU-US cooperation on energy security and climate policy. Given North America's role as a critical supplier of flexible LNG, establishing a framework for stable, environmentally compliant LNG supplies is critical. Policies that enforce stringent methane emissions standards across the LNG supply chain and encourage collaboration on climate goals can enhance the competitiveness of North American LNG in a carbon-constrained market while supporting Europe's broader decarbonisation agenda. The EU's leadership in setting comprehensive GHG pricing could catalyse broader international cooperation, driving global emissions reductions through economic incentives and strategic partnerships.

In conclusion, the research demonstrates that flexible LNG is crucial in Europe's decarbonisation pathway, providing economic and energy security benefits under stress scenarios. Extending GHG pricing to the whole import value chain can further align LNG imports with Europe's climate targets, reshaping global gas markets and encouraging broader international climate cooperation. These findings inform policy recommendations that emphasise securing flexible LNG supplies, implementing comprehensive emissions pricing, and fostering transatlantic cooperation to ensure Europe’s resilient, low-carbon energy future.

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Appendix 1 – Research Methodology

This section outlines the modelling tool used in the report. It then discusses scenarios and policy measures considered in the modelling.

A.1.1. Energy System Optimisation Model for Energy and Climate Policy Analyses (NZESOM)

The energy system model is a partial equilibrium, linear programming optimisation model capable of a detailed representation of a modern and future energy system. It is an economic optimisation model. Its objective is to minimise total energy system costs, comprising capital and operational costs, while meeting exogenously defined (projected) end-user energy services demand, GHG emissions, and other constraints specified by the user (see Figure 17). For details of the first model version's mathematical formulation, data sources, and assumptions, see Chyong et al. (2024[12]).

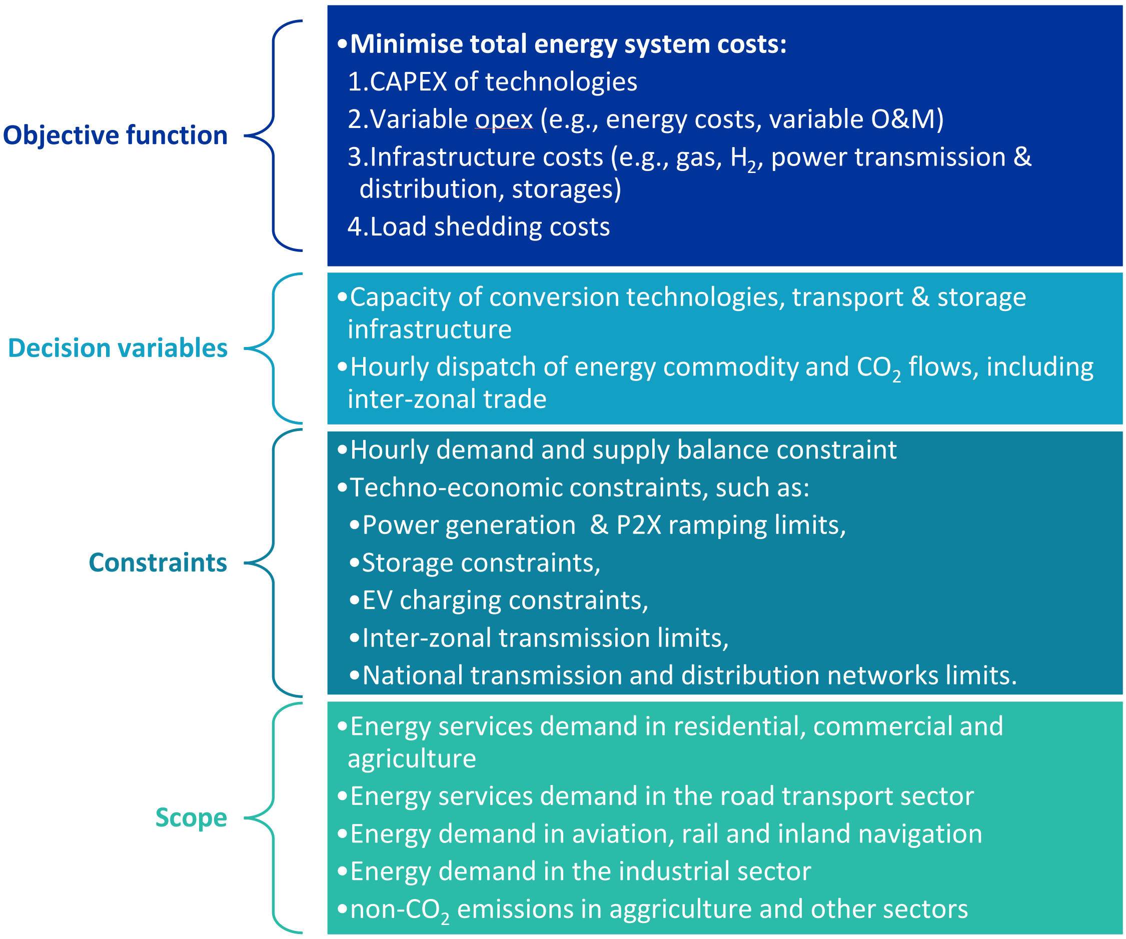

Figure 17: Summary of the NZESOM

Source: Chyong et al. (2024)

[12] Chyong, C. K., Pollitt, M., Reiner, D., & Li, C. (2024). Modelling flexibility requirements in deep decarbonisation scenarios: The role of conventional flexibility and sector coupling options in the European 2050 energy system. *Energy Strategy Reviews*, *52*, 101322.

The model represents 27 regions, allowing endogenous trade in primary energy commodities (

Figure 18 and

Table 5). The model covers hourly dispatch and operations of energy technologies and investment in capacities of power generation, end-use heat technologies, H_2 production, electricity-based fuels production (e-fuels), end-use road transport technologies (EVs, ICs, FCEVs, etc.), storage and networks of CH_4, H_2, electricity and CO_2. The model covers the final consumption sectors – residential, commercial, transport, and industry. For this research project, we have aggregated final consumption as follows:

- The buildings sector represents the final energy services demand of residential, commercial and energy use in the agriculture sectors;
- Road transport represents the final energy services demand for road activities of passenger cars, public road transport and heavy goods vehicles (HGV);
- Industry represents final energy consumption in the industrial sector;
- Other forms of transport represent final energy consumption through aviation, inland navigation, and rail transport activities.

In terms of supply and transformation technologies, the model takes into account:

- power generation and storage technologies for the electricity sector;
- and end-use technologies in buildings and transport sectors;
- cross-border trade in commodities (primary and derived), including via electricity transmission and gas pipelines;
- primary supply sources include coal lignite and bituminous, uranium, biomass, natural gas, and biomethane.

Figure 18: Geographical coverage and network interconnections in the NZESOM.

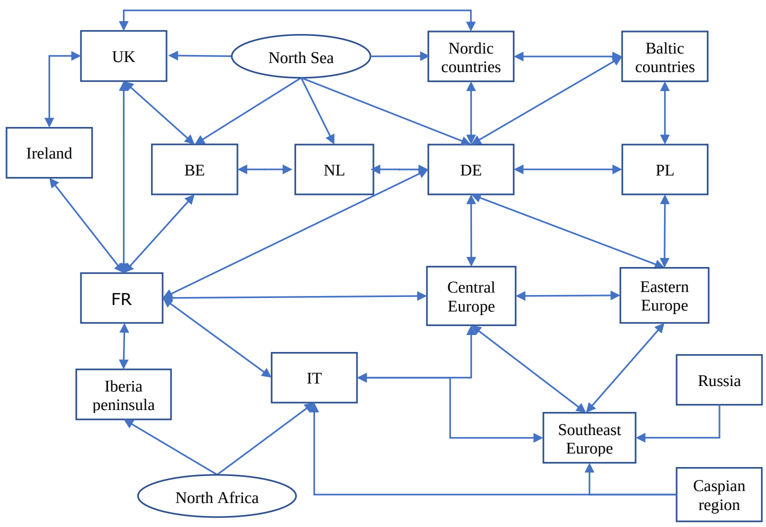

Table 5: Spatial resolution and aggregation in the NZESOM.

Regions in the model	Countries & Comments
UK	United Kingdom (UK)
Ireland	Republic of Ireland
Nordic	Norway (NO), Sweden (SE), Finland (FI), Denmark (DK), pipeline export & import
BE	Belgium (BE), Luxembourg (LU)
DE	Germany (DE)
NL	Netherlands (NL)
FR	France (FR)
IT	Italy (IT)
Baltics	Lithuania (LT), Latvia (LV), Estonia (EE)
PL	Poland (PL)
Eastern Europe	Czech Rep (CZ), Slovakia (SK), Hungary (HU)
Central Europe	Austria (AT), Switzerland (CH), Slovenia (SL)
SEE	Bulgaria (BG), Greece (GR), Croatia (HR), Romania (RO), Malta (MT), Cyprus (CY)
Iberia	Spain (ES), Portugal (PT)
North Africa	Utility-scale solar generation, hydrogen, e-gas, pipeline and LNG export
North Sea	Offshore wind generation
Sub-Saharan Africa	LNG export
Russia	Pipeline gas and LNG export
Caspian region	Pipeline gas export
North America	LNG export
Australia	LNG export

Regions in the model	Countries & Comments
Middle East	LNG export
China	LNG import
Other Asia Pacific	LNG import
India	LNG import
Japan & Korea	LNG import
Rest of World	LNG import

A.1.2. Scenarios considered in the modelling

For the modelling, we consider two sets of scenarios – one related to risks of weather and technological developments (in line with some factors that influenced the 2021-23 global energy crisis) and another set of scenarios related to carbon pricing applied to fossil fuel cradle-to-city-gate GHG emissions. Thus, the first set of scenarios quantifies the benefits of flexible LNG supplies in European decarbonisation. In contrast, the second set of scenarios quantifies the benefits of reducing fugitive emissions (e.g., methane emissions associated with US LNG exports). Five scenarios are modelled for 2030-50, with 2050 reaching net zero emissions for Europe (Table 1) in all these scenarios.

NZ2050 Baseline scenario

Russian natural gas supply to Europe

Following Russia's invasion of Ukraine, the EU and national governments pledged to phase out Russian gas by 2030. In 2023, Russia supplied Europe with gas via pipelines through Ukraine (13.4 bcma) and Turkey (16 bcma) and LNG from the Yamal plant (18.8 bcma). This was 13% of the EU's 2022 consumption, down from 39% in 2021. For more details, see Chyong and Henderson (2024). Though European authorities do not currently sanction Russian gas supply, there are discussions about potentially sanctioning LNG imports and unused pipeline routes like Nord Stream and Yamal-Europe. Such actions could provoke Russia to impose countersanctions, halting the remaining gas supplies to Europe (see Chyong and Henderson, 2024).

Thus, for this modelling, we assume that Russian LNG is banned from entering Europe and that the flows via the Turkstream pipeline will be phased out entirely by 2040.

Weather and technology risks

Weather significantly affects energy supply and demand. Wind and solar generation variability occur hourly, daily, and annually (see Chyong et al., 2024; Ah-Voun et al., 2024). Hydroelectric generation, though dispatchable within a year, also faces annual fluctuations, such as droughts impacting water availability (see Bras et al., 2023; IEA, 2023), as seen in Europe in 2022 (Jones et al., 2023). These annual variations in renewable energy are increasingly concerning as Europe shifts from fossil fuels to renewables.

Ah-Voun et al. (2024) analysed 40 years of hourly temperature data from European countries to define four weather scenarios: mild, normal, cold, and the coldest. These scenarios were then used to select electricity demand and the availability of wind, solar, and hydroelectric resources from the Pan-European Climate Dataset (PECD). This approach ensures consistent modelling of gas and electricity sectors across various demand and supply conditions in Europe (for details on the HDD model and scenario clustering, see Ah-Voun et al., 2024). In this research, we follow the scenario definition by Ah-Voun et al. (2024).

Our baseline scenario uses 2018 as the climate year and assumes the average (from the techno-economic literature) of nuclear and hydro generation availability.

Policy Measures Modelled in the Baseline Scenario

This research analyses the role of low-carbon hydrogen and renewable gases in transitioning from the 2030 Fit for 55 to 2050 Net Zero policy targets. We do so by updating the energy system model Chyong et al. (2024) developed and calibrating it to the energy scenario produced by the European Commission (EC). In particular, our baseline scenario starts in 2030, calibrating to and extending the 2030 Fit for 55 MIX scenario to reach a net zero (NZ) emissions target by 2050. The NZ target by 2050 aligns with the 1.5 TECH Net Zero 2050 scenario envisaged by the EC's long-term strategy.

The baseline scenario also reflects national preferences (e.g., no nuclear generation in Germany or no further expansion of onshore wind in the UK) and resource endowment differences (e.g., wind and solar resources) in reaching energy and climate policy targets. Any (European) analysis of the Net Zero pathways should consider national differences in resource endowment and public policy preferences towards certain technologies they will likely rely on as they decarbonise their economies. The modelled national pathways and scenarios are based on a review of published analyses and EU countries' long-term strategies to meet their Paris Agreement commitments and the energy union objectives (for a detailed discussion of data sources for calibrating to the EC scenarios and assumptions, see Appendix 1).[13] The rest of this section briefly discusses the main policy measures implemented to model the baseline scenario. It first discusses Pan-European measures and constraints and then summarises country-level constraints in the model.

Table 6 outlines the carbon price and emissions cap implemented in the baseline scenario based on EC's scenarios. In particular, the carbon price is applied to the ETS and the building and road transport sectors, which aligns with the 2023 revisions of the ETS Directive[14]. In addition to the carbon pricing, the baseline scenario implements three pan-European GHG emission constraints. First, an overall emissions cap is introduced so that an optimal solution can be found with net zero emissions by 2050 for Europe. The second and third constraints are related to buildings and road transport emissions such that by 2050, the total emissions from these sectors will not exceed the 2050 limit. This 2050

[13] https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-long-term-strategies_en#long-term-strategies-received-as-of-1-february-2023

[14] https://climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/ets2-buildings-road-transport-and-additional-sectors_en

GHG limit is based on EC's NZ 2050 scenario. Thus, the baseline solution is optimised against these important policy measures and constraints.

Table 6: Assumed carbon price and GHG emissions cap.

	ETS carbon price, €'21/tCO_2	GHG emissions cap, mtCO_{2e}		
		Total emissions	The building sector	The road transport sector
2030	48	2345	396	404
2040	216	1173	213	207
2050	384	0	31	11

Sources: own calculations based on the EC scenarios (see Appendix 1).

Apart from these pan-European measures, we considered the following MS-level measures:

1. A set of constraints related to power generation capacity expansion in 2030-50 based on resource endowments, historical and expected build rates (2020-2030) of key renewable technologies (e.g., wind) and policy preferences (nuclear phase-out in Germany).
2. Importantly, we modelled subsidies (FiT tariffs) for key renewable technologies at the MS level (Table 7, left side) and assumed that total subsidies will be gradually phased out by 2050 (Table 7, right side).

Table 7: Assumed FiT tariffs and total subsidy budget for RES technologies.

	FiT tariffs (€'21/MWh-e)			
	Solar	Wind	Bioenergy	Hydro
Baltics	39	21	34	6
BE	255	71	73	25
Central Europe	198	39	143	2
DE	189	80	132	16
Eastern Europe	314	33	67	25
FR	228	51	182	6
Iberia	156	11	57	1
Ireland	233	36	210	0

	FiT tariffs (€'21/MWh-e)			
IT	286	78	165	24
NL	141	76	0	0
Nordic	55	4	40	0
PL	98	0	2	0
Southeast Europe (SEE)	77	20	29	0

Source: own calculations based on Enerdata, Trinomics, 2023[15] (see Appendix A.1.9 for details).

In line with the ETS2, we expect that by 2030, carbon pricing will be applied to imported fossil fuels, including LNG, thermal coal, and pipeline gas (combustion emissions at consumption).

Energy Crunch scenario

Then, building on the baseline scenario, we model combines the coldest year (the year with the highest HDD in the 40-year dataset by Ah-Voun et al. (2024), hence, higher demand for space heating) with relatively lower nuclear and hydro generation availability (see Table 8 for details of weather-dependent parameters in the scenarios modelled). In 2022, technical issues caused France's nuclear generation to drop to 70% of its 2000-21 average. Additionally, Europe experienced its worst drought in 500 years, leading to a 12% decrease in hydroelectric generation compared to the 2000-21 average[16].

Thus, for the *coldest* scenario, we also consider high-impact, low-probability (HILP) scenarios of electricity shortages due to underperforming nuclear and hydroelectric generation combined with high demand for space heating due to extremely cold winter. In particular, we assume that nuclear generation will drop by 20% relative to the baseline generation while hydro generation will decrease by 10% relative to the baseline.

Table 8: weather-dependent parameters in the baseline and coldest scenarios.

Weather-dependent parameters	*Baseline scenario*	*Energy Crunch* scenario
Heat demand in buildings based on HDD	In 2018, the total HDD was 56019	The coldest year, according to Ah-Voun et al. (2024), is 1985, with HDD being 70131; thus, heat demand is 25% higher than in the baseline dataset, or higher by a factor of 1.25

[15] https://op.europa.eu/en/publication-detail/-/publication/32d284d1-747f-11ee-99ba-01aa75ed71a1/language-en

[16] In 2022, the combined hydro generation of the five largest European countries (excluding Turkey) saw a decrease of 13% relative to the average hydro generation in 2017-21.

Weather-dependent parameters	*Baseline scenario*	*Energy Crunch* scenario
Wind onshore total capacity factors for EU27+UK+NO+CH	In the 2018 baseline dataset, the total resource for wind onshore is ca. 72725	In the 1985 climate year, the total resource for wind onshore is 68171
Wind offshore total capacity factors for EU27+UK+NO+CH	In the 2018 baseline dataset, the total resource for wind offshore is ca. 66771	In the 1985 climate year, the total resource for wind onshore is 73491
Solar PV residential	44,227.80	31567
Solar PV utility scale	49,092.86	35,039

In addition, this scenario is analysed with a possibility of North American LNG supply being available flexibly at a long-run marginal cost of $4/MMBtu (see IEA, 2019[17]). This sensitivity scenario is called ***Energy Crunch with LNG Buffer***.

GHG emissions pricing scenarios

We model two scenarios. First, the **Full Carbon Import Tax** scenario applies EU ETS carbon pricing[18] extended to GHG emissions of the entire fossil fuel supply import chain into Europe. Second, the **Methane-cleaned North American LNG** scenario with a carbon tax on GHG emissions of fossil fuel imports into Europe assumes that the North American LNG supply chain has reduced methane emissions to zero.

This second scenario measures the benefits of minimising methane emissions from the North American LNG supply chain. For this scenario, we assume that CH_4 emissions from the North American LNG supply chain are 66% of total GHG emissions, as Figure 10 in the main text reports. The assumption is based on the average split of CO_2/CH_4 from a review of 5 comprehensive reports of North American conventional gas production emissions (Venkatesh et al., 2011; Timothy Skone et al., 2011; Hultman et al., 2011; Stephenson et al., 2011; Burnham et al., 2012; Howarth et al., 2011).

[17] https://www.iea.org/reports/world-energy-outlook-2019/gas
[18] Which, at the moment, is applied to combustion emissions.

Appendix 2 – Cradle-to-city-gate GHG Emissions from LNG, pipeline gas and coal to Europe

To compare the environmental impacts of LNG, pipeline natural gas, and coal emissions, we have collected emissions associated with transportation associated with each and international mine and gas field data. The analysis can be summarised in two ways: 1) the collection of mine and gas field data to calculate a "cradle-to-gate" emissions factor associated with the *production* of the fuel, and 2) transportation modelling and emissions quantification for each fuel. This study focuses on the short-term impacts of methane and reports greenhouse gas emissions with a 20-year outlook, aligning with the preceding studies that bolster this work.

A.2.1. Origin Point Source Emissions

Natural Gas

Natural gas production emission data was collected from 104 international gas fields and lumped per country and region. Gan et al. (2020) quantify the cradle-to-gate emissions of LNG supplied to China, detailing the emissions breakdowns of 104 international gas fields (Gan et al., 2020). We take each gas field's origin country and calculate the average well-to-shipboard emissions (taking the sum of extraction, processing, transmission to origin port, and liquefaction emissions).

All data is collected from publicly available natural gas field emissions data, with the emissions for each stage of natural gas production tracked: gas extraction ($E_{extract}$), gas processing (E_{proc}), gas transmission (E_{trans}), gas liquefaction ($E_{extract}$), and gas regasification E_{gas}. LNG "indirect" production emissions, i.e. cradle-to-gate (with no delivery emissions), included emissions of all the listed steps barring delivery:

$$E_{i,LNG,indirect} = E_{extract} + E_{proc} + E_{trans} + E_{liq} + E_{gas} \tag{A1}$$

While for pipeline natural gas, emissions for the liquefaction and regasification steps were not considered:

$$E_{i,pipelineNG,indirect} = E_{extract} + E_{proc} + E_{trans} \tag{A2}$$

Country-averaged and regionally averaged production emissions were calculated using the same process shown in Figure 19: fields are annotated by country, and then all fields in a given country are averaged. Similarly, the average emissions of all countries in a given region are averaged for a "regional" emissions value.

To disaggregate emissions by methane and CO_2 contributions, we will assume the CO_2/CH_4 emissions split defined above in the GHG Emissions Pricing Scenarios of 66% CH_4 responsibility across the supply chain. This split includes upstream production, domestic, and international transportation across the reviewed studies.

Coal

To maintain a comparative assessment of fuel production emissions, we track cradle-to-gate emissions of coal delivered to coal-fired power plants. Numerous studies corroborate that generally 88-92% of coal cradle-to-grave emissions (usually ranging from 950-1150 g CO_2e/kWh of electricity can be attributed to actual combustion of the coal for a standard subcritical combustion process not employing CCS (Whitaker et al., 2012; Wang and Dong, 2014; Odeh and Cockerill, 2008a), with the remaining 8-12% of the remaining emissions being considered “indirect” emissions associated with the cradle-to-gate emissions. Of this 8-12%, a similar consensus is that about 60-80% of the indirect emissions originate from coalbed methane (Uchiyama, 1996; Proops et al., 1996; Denholm and Kulcinski, 2004). The remaining is attached to transportation (often 1-3% of total cradle-to-grave emissions) with a balance on the energy required to run equipment at the mine site (Hondo, 2005; Spath et al., 1999; Odeh and Cockerill, 2008b). Because of this strong agreement in literature and data availability, we primarily track coalbed methane to estimate total indirect emissions.

In our analysis, we utilise regional total coal mine methane emissions data sourced from the Global Coal Mine Tracker, which tracks total coalbed methane and the total coal production from operating mines, each by region (Global Coal Mine Tracker, 2024). By dividing these total regional methane emissions by the total regional coal production from operating coal mines in each region, we calculate the methane emissions per metric ton of coal (Mt coal) for each region. To convert to gCO2eq/MJ of coal regionally, we assume a coal heating value of 23.9 MJ/kg (IEA, 2024).

$$E_{coal,CBM,i} = \frac{CBM_i}{\mathrm{P}_{coal,i}} \tag{A3}$$

where $E_{coal,CBM,i}$ is the coalbed methane emissions per unit coal produced (or coal production emissions) for a given country *i*, CBM_i is the total coalbed methane emissions associated with country *i*, and $\mathrm{P}_{coal,i}$ is the total coal produced by country *i* from operating coal mines. $E_{coal,CBM,i}$ is further collapsed per region as per Figure 19. We present coalbed methane emissions as the “production” cradle-to-gate emissions associated with coal, which includes all emissions up to the point immediately before shipping and excludes any end-use emissions.

A.2.2. Transportation

Nautical LNG Shipping Distances

This study analysed nautical LNG shipping distances using marine transportation data from Rosselot et al. (2023), including overall emissions associated with individual marine tanker vessels. These emissions include information bespoke to each ship, including propulsion type—steam, Dual and Tri-Fuel Diesel Electric (DFDE/TFDE), Flexible Dual Fuel (X-DF), M-type Electronically Controlled Gas Injection (Me-GI), and Steam Turbine and Gas (STaGE) engines—each with engine-specific methane slip adopted from Rosselot et al. (2023) Each vessel’s specified capacity, boil-off rate, and fuel consumption contingent on propulsion type were tabulated in Rosselot et al.’s study and adopted in this study as follows.

To compute emissions per unit distance for the average ship from a given country, boil-off rates and methane emissions data were sourced from Balcombe et al.’s study of the Gaslog Galveston LNG tanker (Balcombe et al., 2022). It is assumed that each vessel spent approximately 1.7 days manoeuvring and 3.3 days docked, with a 2.5% ballast, aligning with the analysis of the Gaslog Galveston in Balcombe et al. and used similarly in Rosselot et al.'s work. The per-distance emissions were calculated for each vessel with these operating conditions held constant but with the ship-specific parameters listed above. Although Rosselot et al. lays out this methodology in greater detail, a given ship's emissions can be summarised as:

$$\underbrace{E_i(d, t_{dock}, t_{man})}_{emissions} = \underbrace{C_{A,i} * C_{con,i}}_{ship-specific\ factor} \left(\underbrace{\frac{0.02t}{km} d}_{distance} + \underbrace{\frac{20t}{day} t_{dock}}_{dock\ time} + \underbrace{\frac{16t}{day} t_{man}}_{maneuvering} \right) + \underbrace{0.025 C_{eng,i}}_{engine-specific\ slip} \tag{A4}$$

where $C_{A,i}$, $C_{con,i}$ and $C_{eng,i}$ are ship-specific constants associated with surface area, container technology, and engine type for a given ship *i*, while d, t_{dock} and t_{man} are travel distance, time spent docked, and time spent manoeuvring. Each term includes fuel consumption and boil-off associated with a specified ship/engine type. Per-km emissions estimates for each ship were averaged around 10,000 km – the median trip distance between LNG maritime vessels. That is, per-km distance was calculated as:

$$\overline{E_i} = \frac{E_i(10{,}000km, 3.3d, 1.7d)}{10{,}000\ km} \left[\frac{kg\ CO_2eq}{km}\right] \tag{A5}$$

Vessels were then categorised according to their country of origin; emissions of each LNG shipping vessel from a given country were averaged to calculate the emissions for a representative "average" vessel from that country. For region-to-region comparisons, these values were further extrapolated to the average emissions of all vessels associated with the region.

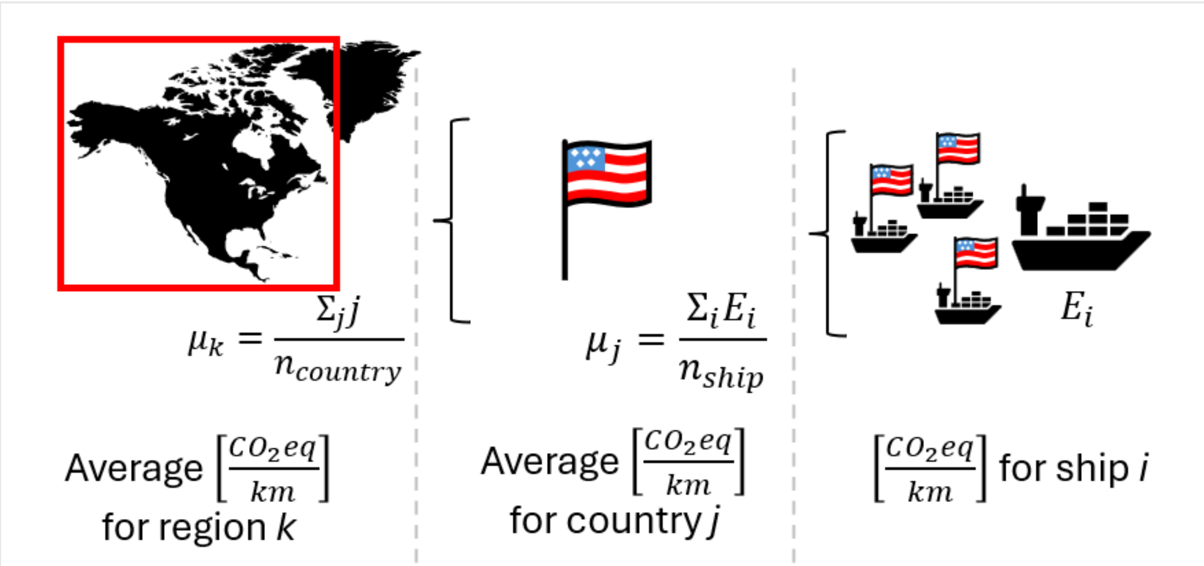

*Figure 19: Emissions calculated for a given ship **i** are averaged per country, then per region to quantify shipping emissions with per-country **j** and per-region **k** granularity.*

Nautical distances from origin to destination were determined using sea-distances.org, and emissions as a function of distance were derived from each point source equation on an emissions-per km-per unit LNG shipped. To convert between mass, volume, and energy, we assume a fixed LNG higher heating value (HHV) of 52.225 MJ/kg, and a density of 450 kg/m³ (Wang et al., 2021).

Pipeline Emissions

We adopted the interstate and domestic pipeline emissions methods described by Jordaan et al. (2022) to calculate pipeline emissions. Specifically, Balcombe et al. (2017) and Jordaan et al. (2022) approximate a pipeline compressor consumption rate of 0.001% of (energetic) natural gas per kilometre of a pipeline, as detailed in Balcombe et al. (2017). Roman-White et al. (2019) found that 0.96% of the natural gas is consumed at compressor stations when tracking pipeline natural gas consumption over a US-based pipeline over 970 km (Balcombe et al., 2017; Roman-White et al., 2019). Jordaan et al. (2022) take this consumption rate alongside Balcombe et al.'s (2017) estimates for compressor station spacing every 120km (Balcombe et al., 2022). Gan et al. (2020) use estimates from Zimmerle et al. (2015) of a 4.02e-6 kg methane/kg-km (2.77e-7 kg CH_4/kWh-km) fugitive emissions/leakage rate. We approximate these in tandem with the rate of CO_2 emitted per distance of the pipeline. These criteria are converted to pipeline emissions via the following equation:

$$GHG_{pipeline} = EF_{CO_2} * d * e_{CH_4 delivered} * 0.00001 + 84 * 2.77 * 10^{-7} * d * e_{CH_4 delivered} \qquad \text{(A6)}$$

where GHG pipeline are the total emissions associated with a given pipeline from source to destination, EF_{CO2} is the emissions factor for CO_2 per unit energy of natural gas consumed (EPA, 2020), d is the distance in kilometres, and $e_{CH4,\ delivered}$ is the total delivered or specific energy of natural gas.

The above applies generically to all pipeline emissions as used in Jordaan et al., where they consider gross domestic and interstate pipeline emissions as a function of total pipeline network distance in a given country (Jordaan et al., 2022). For our study, we consider only internodal distances, and therefore, the generic pipeline emissions model presented above is considered adequate.

A representative natural gas terminal from each region was determined to calculate pipeline distances (as specified in Table 9), and the haversine/great circle distance was calculated from the origin terminal to the Rotterdam Gate terminal.

Table 9: Representative terminals for each pipeline region under study.

Country/Region	Representative Terminal	Distance to Rotterdam Gate Terminal (km)
North Africa	Arzew-Bethioua	1825
Russia	Yamal	3880

Coal Transport

As mentioned, coal indirect emissions (approximately production + transportation) comprise about 8-12% of total cradle-to-grave coal-fired power emissions. About 60% of these indirect emissions (5-7%

total) is attributable to coal production (where coalbed emissions are responsible for the vast majority of this 60%) (Skone et al., 2018a,b). Consequently, the remaining 40% of indirect emissions is generally attached to the transportation of coal and, to a lesser extent, the other raw materials required for coal-fired power (Skone et al., 2018b; Odeh and Cockerill, 2008a). This transport is assumed to be primarily CO_2 emissions. We present coal transportation emissions as 40% of total coal indirect emissions after assuming coalbed methane emissions comprise 60% of indirect emissions:

$$E_{coal,trans,i} = \frac{E_{coal,CBM,i}}{0.6} * 0.4 \quad \text{(A7)}$$