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Burning the Bridge to Ostpolitik?
Stress-Testing Europe's Shift from Russian Gas to Renewables Using a Global Energy Model

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The contents of this paper are the author's sole responsibility. They do not necessarily represent the views of the Oxford Institute for Energy Studies or any of its Members.

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Executive summary

This study examines the structural changes in Europe's energy landscape following the loss of over one-third of its natural gas supplies from Russia due to the war in Ukraine, which disrupted the traditional gas trade route between Russia and Europe. Amid Europe's significant integration into global energy markets, this paper, using a global energy market model, evaluates the mid-term market and policy impacts of shifting towards renewable energy sources and the global LNG market to lessen its dependence on Russian gas. Key findings include:

- *Europe's Energy Transition and Interconnection Needs*

Due to geopolitical tensions, Europe's strategic pivot away from Russian natural gas has underscored critical vulnerabilities within its energy infrastructure. With natural gas still vital for residential, industrial, and power generation sectors and traditionally sourced significantly from Russia, stakeholders must now robustly reassess the interconnection frameworks. The 2022/23 energy crisis and the modelled scenarios to 2030 highlighted the necessity for enhanced electrical and gas cross-border interconnections to mitigate high-impact, low-probability shocks. Strengthening these interconnections will facilitate more effective cross-border electricity trade and energy flexibility, leveraging underutilised coal, gas, and hydro resources across the continent.

- *Consequences of phasing out the remaining Russian gas supplies*

Depending on the timing of new LNG supply projects, the complete cessation of Russian gas imports under severe weather scenarios will likely increase gas prices globally and a shift towards coal usage, exacerbating global CO_2 emissions. This shift is particularly pronounced under severe weather conditions and spikes in energy demand. Europe's reaction – a significant uptick in LNG imports – highlights its new dependency on global spot LNG markets, increasing potential price volatility.

- *More renewable is socially optimal, requiring public support*

The modelling results show that the social benefits of REPowerEU's incremental wind and solar capacity target can offset the capital expenditure needed for these additional investments. However, to unlock these investments, public support is needed to underwrite them and policies aimed at bringing these new capacities to the market, including investments in associated infrastructure (grid reinforcement and balancing costs of intermittency). In the long run, this shift will alleviate Europe's gas demand – thus dampening global gas prices – and aid in the global phase-out of coal, thereby reducing overall carbon emissions and supporting environmental targets.

- *Policy recommendations to manage uncertain and volatile energy market*

The modelling results suggest that beyond 2025, mandatory gas storage targets may not be necessary due to decreasing European gas demand from decarbonisation and abundant LNG supplies. Yet, these targets could help stabilise near-term market prices and provide visibility. To avoid stranded assets and market distortion, gas storage filling targets should be aligned with expected gas demands, taking into account weather effects and cross-border interconnections, and should consider adjusting carbon emissions permits. The role of hydroelectricity as interseasonal storage is expected to grow, particularly in shock scenarios when gas storage filling is regulated, necessitating closer regulatory oversight to prevent market power abuses in the electricity sector. The European Commission set a gas savings target of 15% relative to the 2017-22 average until 2024. Based on modelling results, this target should be expanded beyond 2024 to reflect varying climate impacts on overall energy demand. Demand savings targets should also account for cross-border energy capacities and include a contingency analysis of the availability of critical technologies, like nuclear and hydroelectric generation.

In conclusion, Europe's energy landscape is at a pivotal juncture. Phasing out Russian gas, especially under extreme conditions, is sensible only with the expedited rollout of renewables in Europe and certainties regarding the timings of new LNG supply (e.g., from the US). Given environmental and energy security externalities associated with reliance on Russian gas and uncertainties concerning new LNG supplies, there is a case for public support of the expedited rollout of renewables and associated energy infrastructure investments in Europe.

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Figures and Tables

1. Introduction

Natural gas is an important energy source for European economies, representing roughly a quarter of total primary energy consumption (BP, 2022) and more than one-fifth of final consumption (Eurostat, 2022). Natural gas represents one-third of all residential energy consumption, most used for space and water heating and cooking[1] (Eurostat, 2023), while fuel provides 20% of the energy power plants require to generate electricity and heat. At least one-third of energy consumption in the industry comes from natural gas[2], the highest share amongst competing energy sources (Enerdata, 2022).

Russia was the largest gas supplier in the European Union (EU). In 2021, the country supplied ca. 40% of all European gas import needs (EC, 2022a). On February 24, 2022, Russia launched a full-scale military invasion of Ukraine. Europe and its allies subsequently introduced a comprehensive set of sanctions[3] to respond to Russia's military aggression towards Ukraine. At the same time, the European Commission (EC) has developed plans to eliminate dependence on Russian natural gas well before 2030 (EC, 2022b).

In turn, Russia has halted natural gas exports to Poland, Bulgaria, Finland, the Netherlands, and Denmark as these countries refused to pay for gas in Rubles[4], fearing that would breach sanctions imposed by the EC. Further, sabotage activities that blew up Nord Stream 1 and 2 pipelines in late 2022 make it technically and politically impossible to flow gas through them to Europe. The only remaining flows from Russia are through Ukraine and Turkey. Thus, in months since the war in Ukraine started, Europe lost over one-third of its natural gas supplies from Russia. A 'bridge' no longer exists for the transcontinental natural gas trade between Russia and Europe[5].

A complete cessation of Russian natural gas deliveries to Europe has turned from a theoretical and market modelling exercise (see, e.g., Monforti & Szikszai, 2010; Lochner, 2011; Szikszai & Monforti, F., 2011; Chyong & Hobbs, 2014; Richter & Holz, 2015; Egging & Holz, 2016; Baltensperger et al., 2017; Bouwmeester & Oosterhaven, 2017; Deane et al., 2017; Sesini et al., 2021; Sesini et al., 2022) to reality (see recent political calls in Europe to embargo the rest of Russian supplies to the region). Considering the high integration of Europe into the global energy markets and the potential for far-reaching impacts from a shift towards increased renewable energy and a decoupling from Russian gas imports, what are the likely medium-term market and policy implications? This paper aims to answer this question and evaluate policy options using an innovative, detailed global energy market model.

As the 2022/23 crisis showed, Europe's energy system faces significant challenges from high-impact, low-probability (HILP) shocks, emphasising the importance of resilience in supply disruptions, extreme weather events, and the transition to decarbonisation. The continent has managed to navigate the immediate aftermath of the 2022/23 energy crisis, absorbing substantial supply shocks, partly via demand reduction and partly via a significant increase in LNG imports. However, the threat to energy supply and macroeconomic stability persists, underscored by potential gas demand fluctuations of over 98 billion cubic meters (bcm)[6], more than a fifth of Europe's 2022 consumption[7] or ca. 90% of the lost Russian pipeline gas

[1] The role of natural gas use for home heating in the EU is diverse with Hungary and the Netherlands predominantly using gas (share of gas for gas space heating is more than 83%) while Sweden and Finland merely use gas for space heating (share of gas in space heating is less than 0.6%). At the EU level, the share of gas in space heating is 38% and in water heating - 38%, in cooking – 32% (Eurostat, 2022). This data is quoted for the year 2020 taken from Eurostat (2022).

[2] both as feedstock and as the source of energy

[3] The bloc sanctioned coal and oil supplies from Russia but not natural gas

[4] to partially mitigate the negative impacts of the imposed sanctions, Russia requested to be paid in Rubles, its national currency, for its gas supplies to Europe.

[5] For a detailed account of what happened to the Russian pipeline flows to Europe since the start of the war in Ukraine in 2022, see Chyong and Henderson (2024) paper.

[6] This is an average change in total gas demand in Europe between a mild and a very cold scenario in 2023-3031 (see SI2 and SI3 for details).

[7] EU27, UK, Norway, Switzerland, and Ukraine

(2021-2023). This situation underscores the necessity for diversified sources of energy flexibility, including global energy market reliance, European power sector adaptability, consumer demand-side response, and extensive use of gas and hydropower storage, with LNG playing a pivotal role in Europe's energy strategy.

The phased withdrawal from Russian gas and the reliance on renewable sources introduce volatility and a need for proactive energy policies. Europe's power sector leans heavily on firm energy supplies from gas, coal, nuclear, and hydroelectric[8] sources, shifting away from Russian gas. This transition is marked by a reliance on LNG to cover up to 48% of its energy needs in extreme cold scenarios, demonstrating Europe's increased dependency on global spot LNG markets. Demand-side response, particularly from the industrial sector, emerges as a crucial, albeit temporally limited and costly, mechanism to mitigate supply shortages, highlighting a strategic shift in Europe's energy resilience and a need for proactive development of demand management policies.

Modelling results underscore the urgent need for better electrical interconnections across Europe to improve energy flexibility and support cross-border electricity trade, especially as Europe moves away from coal while only modestly developing hydropower, overall reducing power flexibility by the 2030s. This shift highlights the importance of interconnectivity in using underexploited coal[9], gas, and hydroelectric flexible capacities, with 75% of needed flexibility projected from ten countries (Germany, Ukraine, Norway, Italy, Spain, Poland, France, Czech Republic, Switzerland, Sweden), many of which face electrical interconnection bottlenecks. The observed widening geographic distribution of dispatchable generation further emphasises the necessity for a more robust interconnection infrastructure. The modelling shows that the REPowerEU, which aims to reduce fossil fuel use through investments in renewables, will likely save billions in energy costs by 2031 and result in a notable reduction in emissions. Yet, the plan's success hinges on overcoming infrastructural bottlenecks and enhancing cross-border energy exchanges.

The 2022/23 energy crisis underscored the political unacceptability of high energy prices, prompting policy considerations for managing volatile and uncertain energy markets as Europe moves towards decarbonisation and phasing out fossil fuels. Europe's reliance on global energy markets, mainly through gas-to-coal switching and load shedding in Europe and developing countries, has highlighted its economic ability to compete for LNG supplies despite rising global CO_2 emissions and local air pollution. The explicit carbon pricing in Europe raises concerns about increasing gas supply market power and inadvertently increasing emissions due to the absence of strong carbon pricing signals in other regions. The modelling indicates a rise in global emissions from phasing out Russian gas or during extreme weather, emphasising the need for international cooperation to support other regions to shift from coal to minimise emissions and pollution.

Policy responses to these high-impact, low-probability events in Europe include extending gas storage regulations and setting demand savings targets. The modelling suggests that mandatory gas storage targets may not be necessary beyond 2025 due to falling gas demand from decarbonisation efforts. However, storage targets could help moderate price volatility and enhance market stability during a shortage, and if extended, should be supplemented by withholding ETS carbon permits from future auctions and front-loading emissions costs associated with strategic gas stocks. The importance of hydroelectricity as interseasonal storage grows underscores the need for monitoring to ensure their reliability and prevent market power abuse. The modelling results stress the need for a comprehensive *N-X* joint gas-electricity resilience assessment.

The rest of this paper proceeds as follows. The next two sections outline a concise summary of the research methodology, framework and scenarios (full details are given in Supplementary Information, SI1 and SI2). Then, a summary of key findings is presented in Section 4 (a detailed results analysis is presented in SI3). The last section offers conclusions and outlines policy implications and recommendations.

[8] Hydroelectric is firm power in the short-term horizon (months) and for this study it is considered a non-firm in the inter-annual time frame.

[9] Although coal will be gradualy phased-out in Europe, it will remain a substantial source of power generation at least in Germany, Poland and other Central and South European countries, including Ukraine.

2. Methods

For this analysis, a global energy markets model was developed and used (see Supplementary Information, SI 1 for the general mathematical formulation of the model and SI 2 for data inputs and assumptions) to analyse the abovementioned issues and the research question systematically. The analytical framework in this paper is grounded in scenario analysis using this detailed, jointly optimised gas, coal, oil and electricity supply model to meet gas and electricity demand.

The model is a partial equilibrium model formulated as a quadratic programming problem in AIMMS and is solved using a commercially available IBM CPLEX solver. This modelling work contributes to well-established natural gas market modelling literature (see selected papers, e.g., Zwart and Mulder, 2006; Holz et al., 2008; Lise & Hobbs, 2008; Gabriel et al., 2012; Abada et al., 2013; Chyong & Hobbs, 2014; Growitsch et al., 2014) by including multi-fuels in the power sector, weather scenarios, detailed LNG shipping market modelling, and explicit modelling of gas demand-side response. In particular, the paper advances the energy system economics and policy modelling literature as follows:

1) The existing literature using detailed integrated global multi-fuel market models for the security of supply analysis is limited (see, e.g., work by Abrell and Weigt (2016) and Deane et al. (2017), which uses European coupled gas-electricity market models). This paper builds on the earlier work of Chyong and Hobbs (2014), Chyong et al. (2023a) and Chyong and Henderson (2024) to further enhance the global gas market model to capture interactions between gas, coal, oil and electricity at a global scale. This model update explicitly considers demand-side response and inter-fuel competition dynamics in the European and other regional markets. This is the first study with this level of modelling sophistication to analyse the implications of a complete phase-out of Russian gas to Europe and global markets.

2) To capture inter-annual variations in gas and electricity demand and supply, the model leverages more than 35 years of hourly climate data for Europe on temperature, wind speed, solar radiation, and hydro inflows. Considering long-enough weather patterns is important because the impact of a gas supply disruption will have varying intertemporal and spatial effects, depending on the realisation of weather patterns across Europe – these spatiotemporal variations in weather impact gas and electricity demand for heating and renewable electricity generation. None of the existing security of supply studies has this level of detail regarding input data capturing inter-annual and spatial variability of gas and electricity demand and supply for Europe.

3) On the demand side, the study is the first one to incorporate demand side response (DSR) from European industrial gas users by explicitly accounting for the opportunity cost of production curtailment and fuel switching. Further, explicit consideration was given to the residential demand response using a Heating Degree Model (HDD, see Ah-Voun et al., 2024 for details of the model) to estimate and include the impact of changing household thermostats on gas demand in European residential buildings.

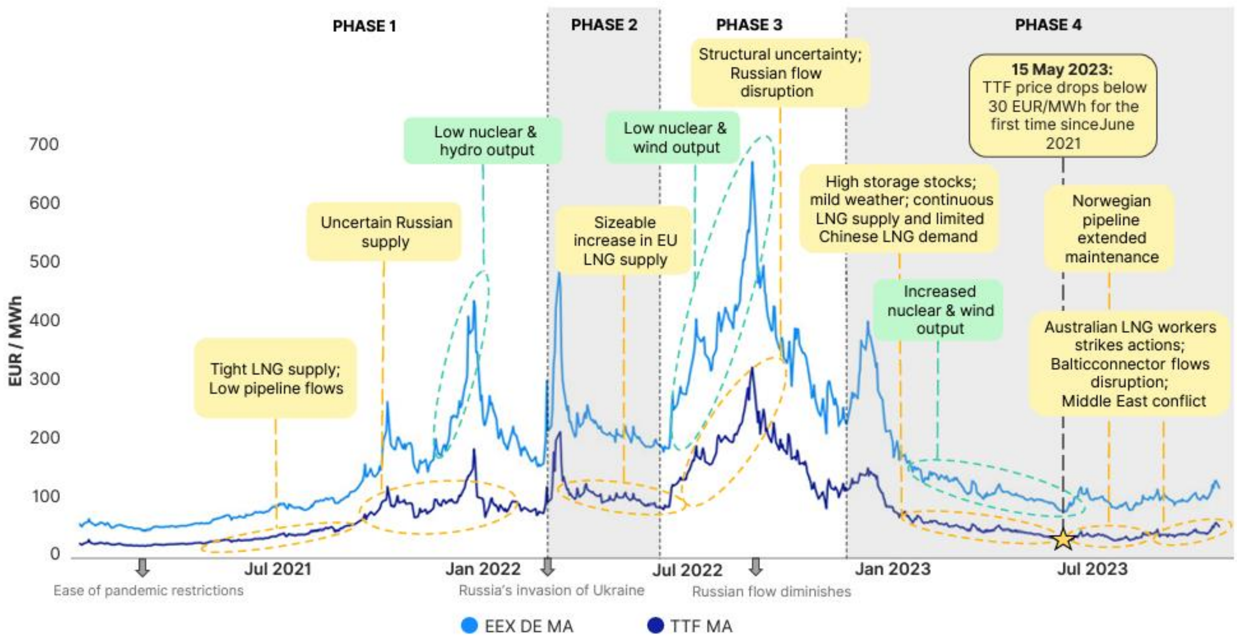
4) The 2022/23 energy crisis showed the growing importance of the global LNG market in providing energy security in times of supply-demand shocks. The model explicitly considers the short-term LNG shipping market and endogenous shipping cost modelling, with 25,782 shipping routes, including seven shipping bottlenecks - Panama Canal, Suez Canal, strait of Good Hope, Cape Horn, Gibraltar, Malacca, Magellan, and Northern Sea Route. This is the first publicly available global energy market model to have such a level of modelling details of the global LNG market, which is becoming increasingly relevant in global energy security analysis (e.g., the ongoing geopolitical tensions in the Red Sea region, potentially disrupting LNG trade flows).

5) Stress-testing the European energy system against HILP events and the sources of flexibility as the region undergoes decarbonisation and diversification. The analysis offers consistent definitions of HILP scenarios (correlated risks) that affect the gas and electricity sectors.

3. Research framework and scenarios

This section briefly summarises the research framework and the scenarios considered. For the modelling, four sets of scenarios were considered relating to (i) geopolitical developments in Europe, particularly uncertainties regarding the remaining Russian gas flows to Europe, (ii) European policy response to Russia's war in Ukraine in terms of scaling up renewable production to mitigate these geopolitical risks while meeting climate policy targets in the longer-term, (iii) implications of these growing renewables on inter-annual variability of energy supply and demand, (iv) and potentially correlated risks of low energy production from nuclear and hydroelectric generation facilities in Europe. The experience of the 2022/23 crisis in Europe reveals that geopolitical, weather-related and technological factors may profoundly affect the energy system (Figure 1) with regional and global implications. Thus, the analysis combines these four dimensions to create a set of 'stress-test' scenarios, gauging the European energy system's robustness to critical energy supply and demand shocks through 2030/31.

Figure 1: 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)

These stress-test scenarios should be considered high-impact, low-probability (HILP) scenarios. For example, a cold winter may occasionally coincide with wind and hydro droughts, producing low hydroelectricity and wind output and high gas demand during winter. This weather year may occasionally occur (Ah-Voun et al., 2024), but in this research, these weather scenarios were modelled assuming their occurrence over several years (i.e., 2023-2031[10]). The principal reason is to identify the most robust set of flexibility options that Europe may use to deal with these HILP energy supply and demand shocks. The rest of this section outlines these four scenario dimensions and the research framework to analyse flexibility options.

[10] 2031 was considered principally to cover the last gas year (2030/31) which runs from 1 October to 30 September the following year

3.1 Policy uncertainties

Russian natural gas supply to Europe

Since Russia's full-scale invasion of Ukraine, the European Commission (EC) and national governments in Europe committed to phasing out Russian gas well before 2030. In 2023, Russia supplied natural gas to Europe via pipelines through Ukraine (13.4 bcma[11] vs. 82 bcm in 2021) and Turkey (16 bcma[12] vs. 10 bcm in 2021[13]), and LNG from the Yamal LNG plant to Northwest (NWE) and South Europe (18.8 bcma in 2022[14] vs. 17.4 bcm in 2021) (13% of EU's 2022 consumption compared to 39% in 2021). For a detailed discussion of the infrastructure availability, export routes, and contracts between Russia and European importers, see Chyong and Henderson (2024).

While Russian gas is the only energy commodity not sanctioned by the European authorities, there are discussions to potentially sanction imports of LNG from Russia and imports via pipelines that are not in use today (i.e., Nord Stream and Yamal-Europe pipelines). Any such actions may provoke Russia, which may impose countersanctions and stop the remaining gas supplies from reaching Europe (see Chyong and Henderson, 2024). With this consideration, there are two scenarios for Russian gas supplies to Europe considered in the modelling:

1. The **baseline** scenario models up to 31[15] bcm of pipeline flows from Russia and no embargo on LNG;
2. The **'great decoupling'** scenario assumes all flows from Russia (pipeline and LNG) to Europe[16] are embargoed.

While there might be other scenarios, such as retaining existing contracted pipeline and LNG flows or indeed a revamp in supplies to the level above the 2022-23 baseline flow to Europe (e.g., increase to ca. 70 bcm/year of contractual volumes, which are under dispute with European buyers), these scenarios are considered politically implausible (for a discussion on this issue, see Chyong and Henderson, 2024) and irrelevant from the perspective of energy system resilience and planning (see Jasiūnas et al., 2021; Baldursson et al., 2024). Thus, adopting a conservative, stress-testing approach aligns with the principle that ensuring energy security necessitates careful and risk-averse planning.

European wind and solar capacity scenarios

Europe has committed to decarbonising its energy system by supporting low-carbon energy sources such as wind and solar (variable renewable energy, VRE) (Figure). As part of its commitment to reach net-zero emissions by 2050, the EU invited its MS to define the 10-year National Energy and Climate Plans (NECP[17]), outlining how it will contribute to this net-zero target. After Russia invaded Ukraine, the EC proposed a more ambitious REPowerEU plan to help the bloc phase out Russia's fossil fuel imports before 2030 while meeting the longer-term climate policy objectives. While the NECP targets are deemed achievable by the EU national governments, the REPowerEU targets for wind and solar are considered unprecedented (see, e.g., IEA (2022) analysis). Thus, achieving wind and solar capacity targets under the REPowerEU plan is an area of significant policy and market uncertainty. Two scenarios for wind and solar capacity expansion in Europe were considered (Table 1):

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[11] At the time of research (July 2023), flows from Russia to Ukraine (via the Sudja entry point) amounted to 407 GWh/day (Refinitiv, 2023)

[12] At the time of research (July 2023), flows from Turkey to Bulgaria (Russian gas via the TurkStream 1 pipeline destined for South Europe) amounted to 486 GWh/day (Refinitiv, 2023)

[13] Turkstream 1 flow only

[14] Based on data from The Energy Institute's Statistical Review of World Energy (2023).

[15] 15 bcma via Ukraine (max flow observed in 2022-23) and 15.75 bcma via Turkey/Bulgaria (capacity of TurkStream pipeline to South Europe).

[16] Exlcuding Turkey

[17] https://energy.ec.europa.eu/topics/energy-strategy/national-energy-and-climate-plans-necps_en

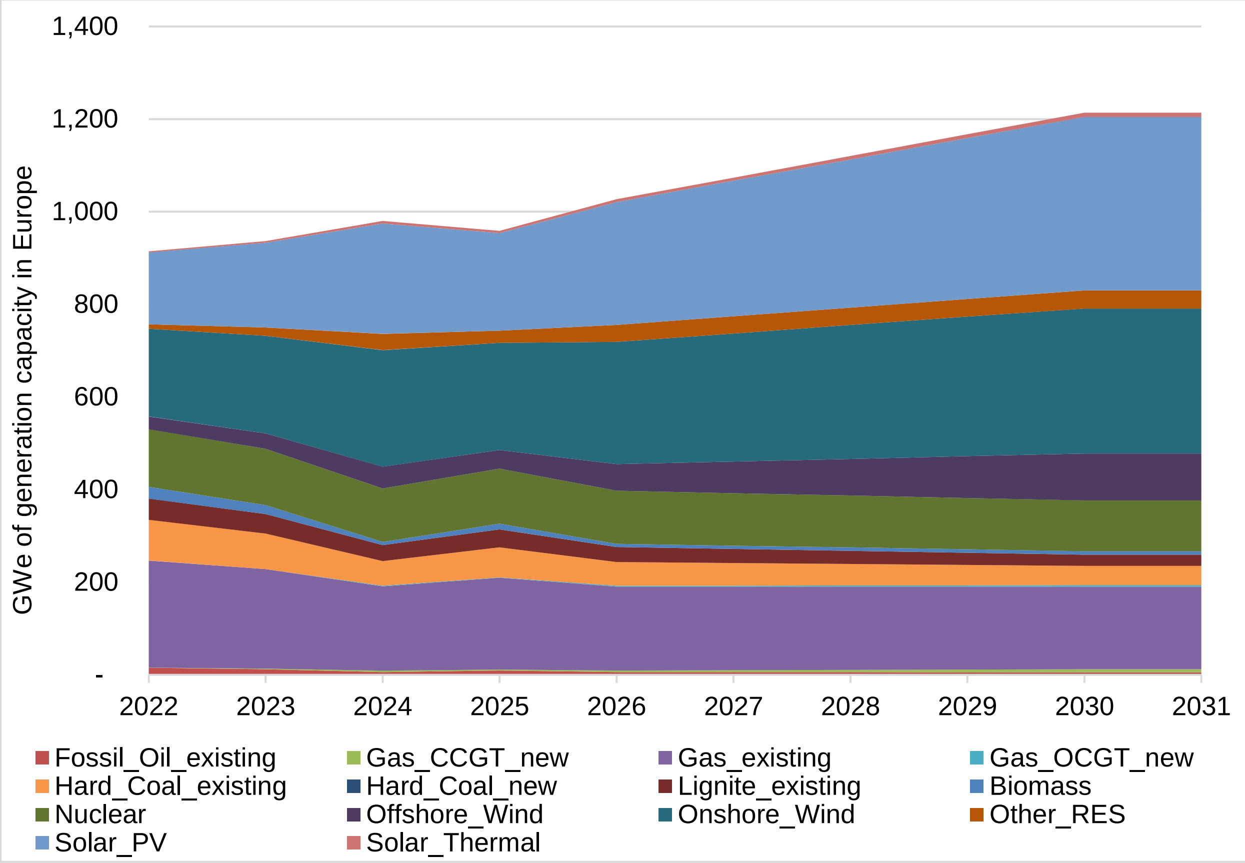
1. In the **baseline** scenario, it is assumed that the EU will achieve the approved (in 2019) NECP targets for wind and solar generation by 2030 (capacity evolution for other generation technologies is reported in Figure, and more details are in SI2);
2. In the **REPowerEU** scenario, it is assumed that the new wind and solar capacity targets are achievable by 2030, while the generation capacity of other technologies is the same as in the baseline.

Table 1: EU's 2030 Wind and solar policy targets

	NECP 2019 National Targets	**Fit For 55 (2021)**	**REPowerEU (2022)**
Installed wind capacity (GW)	401.0	469.0	510.0
Installed solar PV capacity (GW)	378.0	530.0	592.0

Source: Ah-Voun et al. (2024)

Figure 2: Electrical generation capacity in Europe



Source: ENTSO-e (2021) available here: https://www.entsoe.eu/outlooks/eraa/2021/

Thus, four policy and market scenarios were considered for the modelling. These four scenarios assume *normal* winter weather and average historical nuclear and hydroelectricity generation availability. Shock scenarios related to weather impacts on demand and supply are discussed next.

3.2 Weather- and technology-related shocks

On top of the four policy scenarios, four weather-related and two technological scenarios are considered, which could significantly impact Europe's gas and electricity demand and supply balances. They are described below.

Weather scenarios

Weather is an essential factor influencing energy supply and demand dynamics. Wind and solar generation variability is not confined to hourly and daily fluctuations, a well-known challenge (on intra-day variability of VRE, see literature review in Chyong et al., 2023b), but also inter-annual fluctuations (see Ah-Voun et al., 2024 and citations by the authors). Although dispatchable within a year, hydroelectric generation is also subject to these inter-annual fluctuations – for example, drought may influence water availability (see Bras et al., 2023; IEA, 2023), as was in 2022 in Europe (Jones et al., 2023). These inter-annual variations in renewable electricity generation are a growing concern as Europe increasingly relies on renewable sources, especially VRE, to phase out fossil energy.

Based on Ah-Voun et al. (2024) clustering of 40 years (1980-2019) of the hourly temperature of European countries*,* four weather scenarios were defined for this analysis:

1. Mild (warmer than normal) winter
2. Normal winter (baseline)
3. Cold winter
4. Coldest winter

Those weather scenarios are then used in a Heating Degree Demand (HDD) model to simulate gas demand for space heating in European residential and commercial buildings. Those weather scenarios are then used to choose electricity demand, wind, solar, and hydroelectric generation resource availability from the Pan-European Climate Dataset (PECD) for European countries (for details of the HDD model and scenario clustering, see Ah-Voun et al., 2024). Therefore, the weather scenarios used for the modelling in this paper influence the gas and electricity sectors, ensuring consistency across demand and supply conditions of Europe's gas and electricity sectors.

Nuclear and hydroelectricity generation scenarios

The baseline scenario assumes average (2016-21) nuclear generation. However, as 2022 showed, technical issues prevented nuclear generation in France from operating at normal conditions – the nuclear fleet in France generated 70% of the average generation achieved in 2000-21[18]. Furthermore, in 2022, Europe faced its worst drought in at least 500 years (Jones, 2023), resulting in a generation drop of 12% from the average in 2000-21. Thus, a not unimaginable HILP scenario of a shortage of electricity supply in Europe will involve the underperformance of nuclear and hydroelectric generation. This possibility is considered in this analysis, too. Therefore, there are two scenarios related to nuclear and hydro generation:

1. The baseline nuclear generation scenario assumes average (2016-21) nuclear availability, while hydroelectric generation is sampled from the PECD in line with the weather scenarios discussed above;
2. The low nuclear and hydroelectric generation scenario assumes that the French nuclear fleet generates electricity at the 2022 level, while hydro generation is sampled from the PECD at its minimum level (the climate year 1991 in the PECD has the lowest hydro energy inflows).

[18] See Energy Institute's Statistical Review of World Energy (2023)

3.3 Research framework

This subsection summarises the research framework, highlighting the critical steps in developing the analysis and conclusions regarding flexibility options to mitigate against HILP events affecting European energy markets.

First, a baseline is defined for comparison with all other scenarios. The baseline scenario assumes (i) the technology pathway envisaged in National Energy and Climate Plans approved in 2019 (NECP19), (ii) maximum possible gas flows from Russia to Europe not exceeding the 2023 levels (see §3.1.1), and (iii) a *normal* winter year, with an average historical (2000-2020) nuclear and hydropower availability (§3.2). The rest of the paper will refer to this scenario as the *baseline*.

A scenario without access to Russian gas is referred to with the short abbreviation '/w.o. RU gas'. Weather scenarios include *"mild"* for a warmer-than-normal winter, *"cold"* and *"coldest"* for colder-than-normal winters, with "coldest" indicating the coldest winter in forty years (1980-2019) (see Ah-Voun et al., 2024 for details). The *"coldest+"* scenario combines the coldest winter with low nuclear and hydroelectric generation availability (see §3.2.2 for more details). Figure summarises the scenarios and naming conventions for the three main dimensions – (i) European renewable technology pathway, (ii) Russian gas supplies to Europe, and (iii) interannual climate variability.

The energy market impact of these scenarios is quantified by calculating the difference ("delta") between the baseline and the alternative scenarios. For example, the *"Delta /w.o. RU gas"* step quantifies the change along the dimension of Russian supplies to Europe, taking the difference between the baseline scenario and a scenario of a complete phase-out of Russian gas. A dotted plot font represents this difference in all visuals. Further, the *"Delta Coldest+"* step represents the change along the weather dimension from a *normal* to the *coldest*+ scenario. The difference between the *coldest*+ and *normal* weather year scenario is represented with dashed plot font in all visuals. For some analysis in this paper, 2023 is used as a reference year to gauge the impact of HILP events on flexibility and how this impact changes over time. The analysis is structured as follows:

1. **Effect of a complete elimination of Russian gas**

The model results of scenarios with and without Russian gas are presented first. The goal is to see how such a politically driven outcome would affect energy market prices and costs in Europe and key regional gas markets.

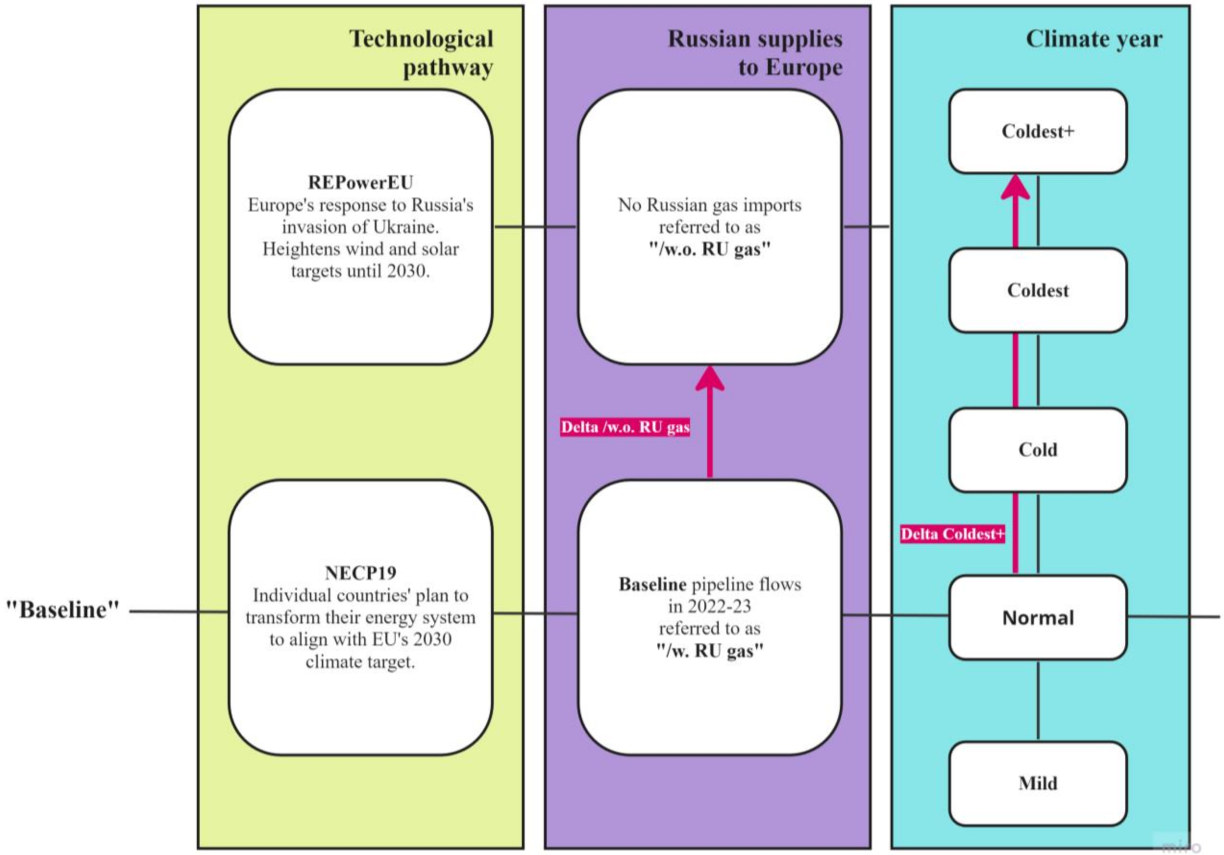
2. **Europe's power and gas sectors under interannual climate variability**

The potential impact of weather- and technology-related HILP scenarios on the European energy system is then quantified. The aim is to study the impact of weather scenarios with increasing intensity (see §3.2 for scenario details) on coupled gas and power sectors. The role of four flexibility sources in Europe's response to these events is compared: (1) redirection of global gas flows, (2) power sector fuel switching, (3) gas demand-side response, and (4) interseasonal storage (gas and hydroelectricity). Next, building on these results, the impact of phasing out the rest of the Russian gas supply is quantified under these climate-driven scenarios. The objective is to analyse how Europe mitigates energy security threats, having to (i) tackle weather-driven shocks (reduced energy supply and increased demand) under (ii) geopolitical conditions without access to Russian gas, which it has historically relied upon under similar circumstances.

3. **Analysis of the impact at the country level**

Finally, a more detailed analysis is conducted to underscore the variances in impact at the level of European countries. The analysis covers (i) the relative exposure to shocks, defined by dependency on gas and the capacity of installed renewables, and (ii) the flexibility resources countries possess to mitigate threats to energy security. Additionally, the gas and electricity transmission infrastructure connecting European nations, essential for exchanging flexible resources, is examined.

Figure 3: A research framework and scenarios

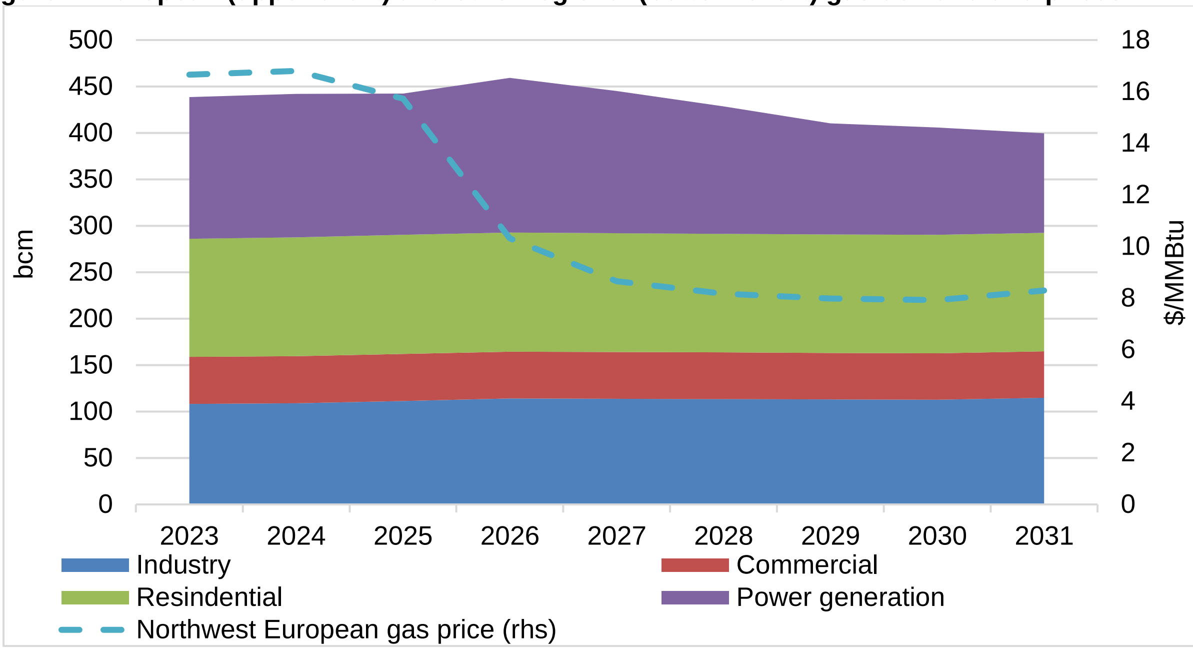


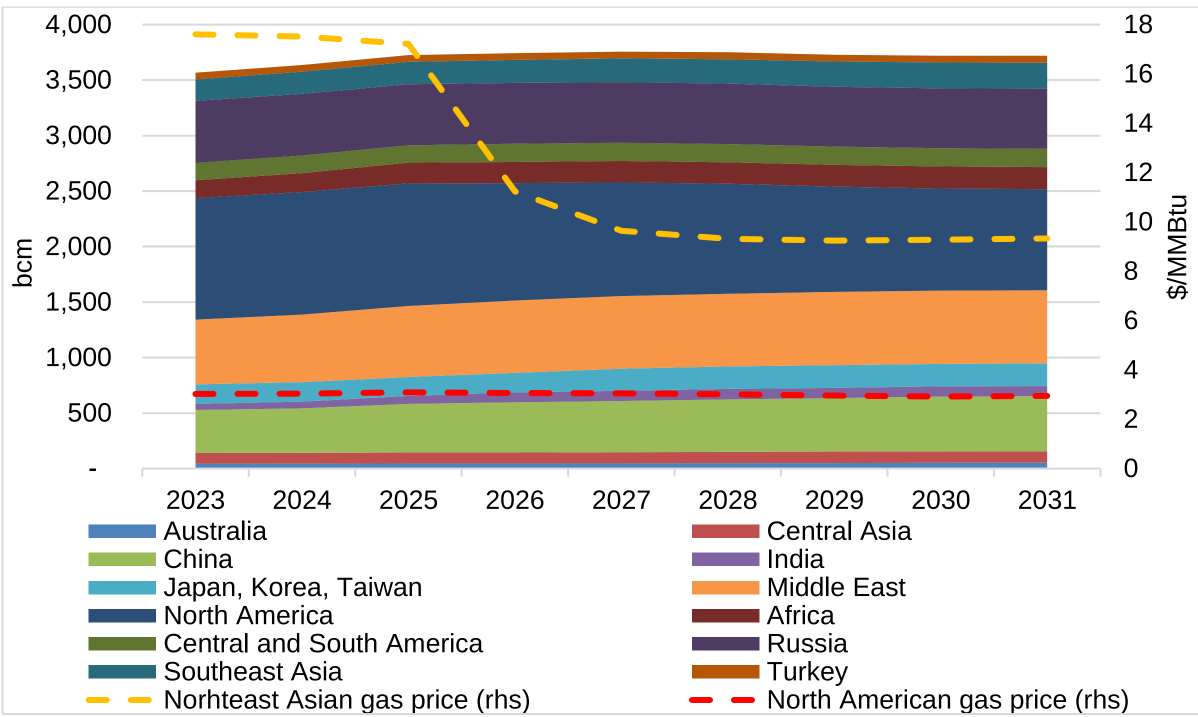
4. Key results

4.1 Baseline results

The section summarises the key results for the baseline scenario (for a detailed analysis of results, see SI3) through 2031. European gas markets are expected to be tight in the short term (before 2026) and loosen as more LNG and renewable electricity supplies are commissioned (see Figure 4 for price and demand evolution). Total gas demand in Europe is projected to increase by 1.6% until 2026, primarily driven by power sector growth as the region phases out coal plants. As renewable capacity increases, gas demand in the power sector declines steadily after 2027, reaching ca. 108 bcm by 2031 (70% of 2023). Gas demand in the building and industrial sectors will remain flat in the modelling horizon. Overall, European gas demand will decline by 1% pa, continuing the observed decline in demand in 2011-21. Gas demand will be 460 bcm in 2026 (+5% higher than in 2023), with gas prices reaching $10/MMBtu and then declining to 400 bcm in 2030 (-9% relative to 2023), with prices expected in the range of $8/MMBtu. After 2026, gas prices steeply decrease to an average of 8.2$/MMBtu (from 2027 to 2031) due to a significant increase in global LNG supply (Figure 5) and domestic renewable supplies, reducing gas demand in power generation.

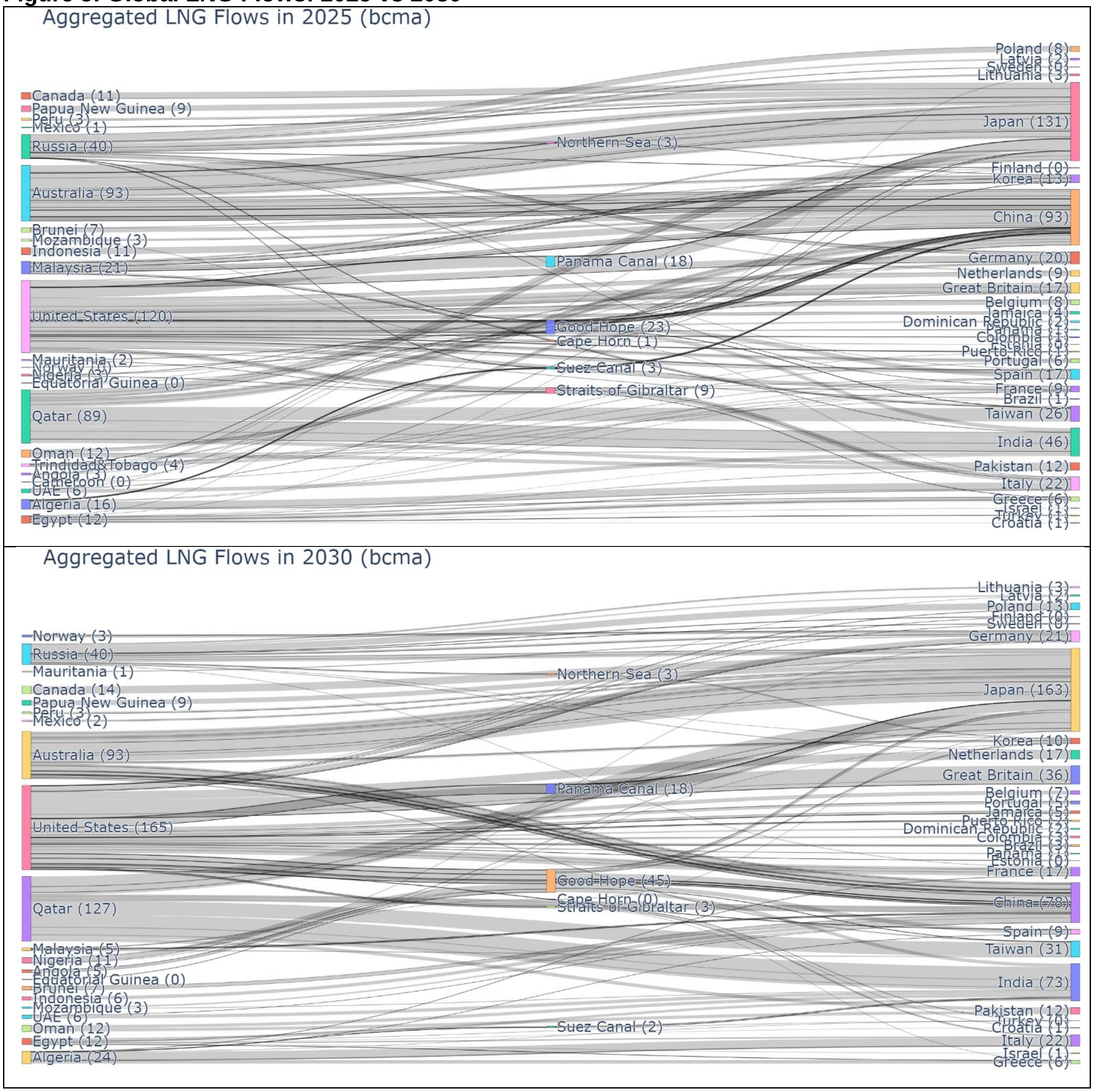
Figure 4: European (upper chart) and other regional (bottom chart) gas demand and prices





Outside Europe, gas demand is expected to grow at an average rate of 0.5% pa, with North America and Russia seeing a decline, while Asia Pacific and Southeast Asia are increasing gas demand, a trend consistent with regional policies, economic development and energy price developments[19] (Figure 4). On the LNG supply side, it will grow from 542 bcm in 2022 to 580 bcm in 2026 and 633 bcm in 2030. This growth is equivalent to an average of 3.6% pa, compared to an average growth rate of 5.3% pa in 2012-2022.

Figure 5: Global LNG Flows: 2025 vs 2030



[19] For energy and carbon price projections, see SI2.

LNG flows follow two important modelling assumptions: (1) global LNG flows are fully optimised (i.e., no point-to-point long-term supply agreements were considered), and (2) only LNG projects that took a final investment decision by the end of 2022 were included in the modelling. Thus, in practice, LNG shipping costs and "transhipment" volumes through critical maritime chokepoints (e.g., the Suez Canal) are likely higher than in the modelling (if contracts are accounted for). However, considering new LNG supply projects (e.g., Qatari's North Field South project or other US LNG projects[20]) means lower prices.

Lastly, Russia's total gas exports will grow from 139 bcm in 2023 to 172 bcm in 2030, compared to 234 bcm in 2021. Most of the growth is supported by LNG and exports to non-European destinations (primarily China; see Table 2). Thus, by 2030, Europe will account for about a quarter of Russia's total exports, whereas in 2021, this share was 90%.

Table 2: Baseline Russian gas exports (bcm)

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Pipeline to Europe	26	28	29	29	30	30	29	29	31
Pipeline to non-Europe*	58	57	55	55	55	55	54	54	53
LNG to Europe	17	17	16	19	18	18	18	18	17
LNG to non-Europe	16	20	25	21	23	23	23	23	23
Total export	**139**	**151**	**163**	**173**	**173**	**173**	**172**	**172**	**172**

Notes: * China, Turkey, Belarus, South Caucasus

The rest of this paper outlines three key findings regarding the impact of more renewables under extreme weather scenarios and with no Russian gas flows on European energy markets. It looks at system resilience against HILP events at the European level. Then, the paper explores how different European countries cope with these events. Lastly, the paper discusses the implications of results on the environment and renewable investment.

4.2 System resilience against high-impact low probability shocks

The importance of energy system resilience, particularly in extreme weather events and supply shocks, highlights the need for robust infrastructure and effective demand-side management. While Europe seems to have successfully managed to absorb the supply shock since the start of the war in Ukraine (2022), new challenges may threaten its energy supply, hence macroeconomic stability. The analysis shows increasing uncertainties as Europe decarbonises its energy system. Fluctuations in energy supply and demand due to a combination of weather and technological factors could change gas demand by more than 98 bcm, a fifth of Europe's total gas demand in 2023 (and a fourth of 2031 demand) and ca. 90% of the entire loss of Russian pipeline gas in 2021-2023.

This wide range of demand fluctuations calls for understanding key flexibility sources contributing to Europe's energy system resilience. There are four sources of flexibility to mitigate HILP shocks available to Europe: (i) reliance on global energy markets to deliver energy when needed (i.e., global gas flow redirection), (ii) power sector flexibility within Europe, (iii) demand-side response by industrial and residential consumers, and (iv) large-scale gas and hydropower storage.

In colder scenarios, Europe's increased demand for natural gas in the heating and power sectors causes global market prices to rise. Before 2028, Europe heavily depends on LNG, with a demand reduction outside Europe accounting for 65% of its flexibility requirement. Europe requires significant LNG volumes in the *coldest* scenarios, covering 43%-48% of total requirements, indicating a greater dependence on LNG

[20] A total of 229 bcma (2030) of North American LNG supply is modelled. However, in 2023 till April 2024, 31 bcma (by 2030) of US LNG took final investment decisions; similarly, the additional export capacity of Qatari's NFS is ca. 22 bcma.

markets. On the other hand, in warmer scenarios, reduced heating demand in Europe lowers global gas prices and shifts LNG flows to global markets. Extreme weather scenarios without Russian gas tighten global markets further. The economic impact is particularly notable in the *coldest*+ scenario without Russian gas, leading to a $2-3.5/MMBtu increase in European gas prices compared to the *normal* scenario and a significant ~+$8/MMBtu difference (100% increase relative to the baseline prices) in 2029-2031. This highlights the intensified competition in global gas markets due to the loss of the remaining pipeline flows and the redirection of Russian LNG to non-European regions.

In extreme weather conditions, Europe's power sector taps into various flexibility sources to address supply and demand variability, notably in scenarios where Russian gas is phased out. The sector experiences a significant reduction in variable electricity supply in colder scenarios, leading to an increased demand for peak generation and a consequent rise in power prices. Specifically, before 2026, Europe primarily depends on coal for electricity generation. Post-2026, the sector transitions towards using gas, nuclear, and hydroelectric power, particularly in years with diminished VRE output. Hydropower plays a pivotal role in this transition, offering the flexibility needed to shift energy from periods of high coal availability to fill gaps left by the coal phase-out scheduled between 2025 and 2028.

Despite the variability in weather scenarios, the impact of weather on the power sector's dynamics is relatively consistent across the modelled years. Notably, the power sector's adaptability is illustrated by its capacity to switch between coal and gas and the strategic utilisation of hydropower storage. However, the scenario of phasing out Russian gas introduces significant changes. Gas generation sees an average decrease of 77 TWh/year, compensated for by an increase in coal and hydropower generation. This adjustment leads to a more prolonged use of coal in Europe's energy mix, with an additional 77 TWh/year of coal-fired electricity generated on average, peaking at 164 TWh in 2026. Furthermore, hydropower generation adjustments, with an increase in years like 2025 and 2028, highlight the sector's flexibility in response to the absence of Russian gas. Based on the behaviour of hydropower systems in the *coldest*+ scenario (with and without Russian gas), 2025, 2027 and 2028 are years for which Europe has limited flexibility options.

Demand-side response (DSR) emerges as a critical flexibility mechanism for Europe in addressing the challenges of the Russian gas phase-out. It significantly contributes to the flexibility of the European energy system, with a notable peak of seven billion cubic meters (bcm) until 2024 in the industrial sector and an average of three bcm annually in the residential sector from 2023 to 2025. DSR activation remains critical even with Russian gas imports at baseline levels, driven by the tight global gas markets due to geopolitical tensions and the energy crisis of 2022/23. However, the residential sector lacks demand flexibility, highlighting an opportunity for expanding DSR capabilities to meet the challenges of increasing market volatility.

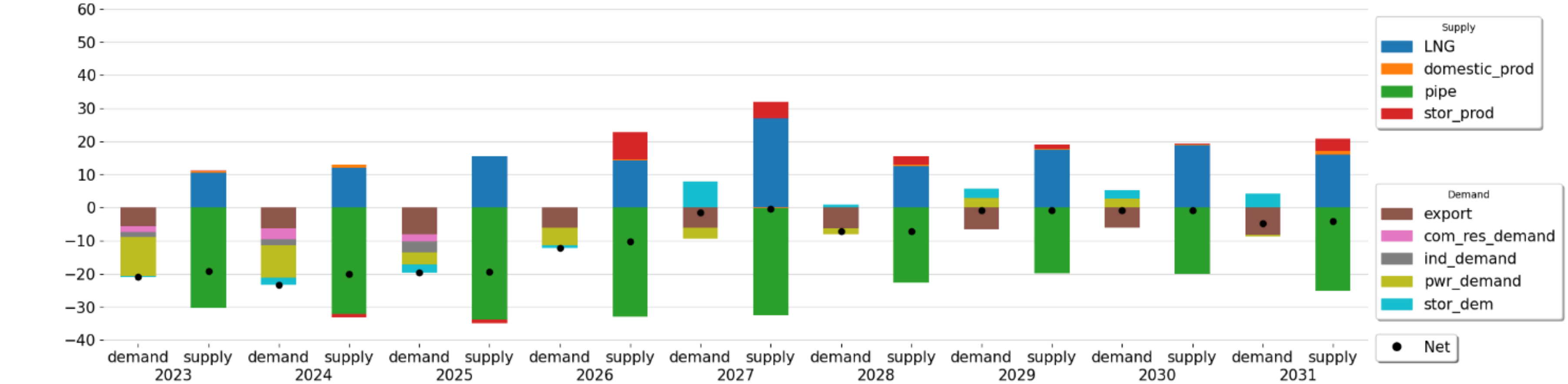
The impact of higher energy prices has already led to reduced industrial output, with a potential risk of prolonged deindustrialisation, especially among energy-intensive industries. Before 2026, DSR effectively replaces 3-5.6 bcm/y of Russian gas, but its importance is expected to decline after 2026 as the global LNG market expands. This change underscores the temporal nature of DSR's effectiveness in managing supply and demand shocks, with its influence waning after 2026 despite its initial contribution to moderate the gas shortage caused by the energy crisis and geopolitical tensions. The analysis highlights the immediate need for DSR in light of the 2022/23 energy crisis and its continued importance in managing extreme weather conditions, particularly for the industrial sector beyond 2027.

In response to the phase-out of Russian gas supplies, storage dynamics, particularly for gas and hydropower, are undergoing significant changes. Until 2025, there is a notable shift towards drawing from storage, with hydropower acting as a critical inter-annual flexibility resource due to its ability to balance cost variations between years. This adaptation comes in light of European regulations mandating specific gas storage fill targets until 2026, which restrict gas storage's capacity for year-to-year energy shifts. After this period, the landscape changes with storage levels stabilising and the advent of a global gas supply development alongside Europe's pivot to LNG, effectively curtailing inter-annual gas storage arbitrage opportunities. Specifically, hydropower storage's strategic role becomes evident, holding 43 TWh (ca. eight bcm-eq of gas) more in the early years for later use, contrasting with gas storage's release of six bcm in the same timeframe. The *coldest+* scenario further underscores the strategic utilisation of storage, with hydroelectricity reserves being significantly higher early on to cater to future demands, highlighting its increased economic value. This insight starkly contrasts gas storage, which sees a 12-15 bcm release before 2025 and a notable underutilisation of 30-40 bcm annually post-2026[21].

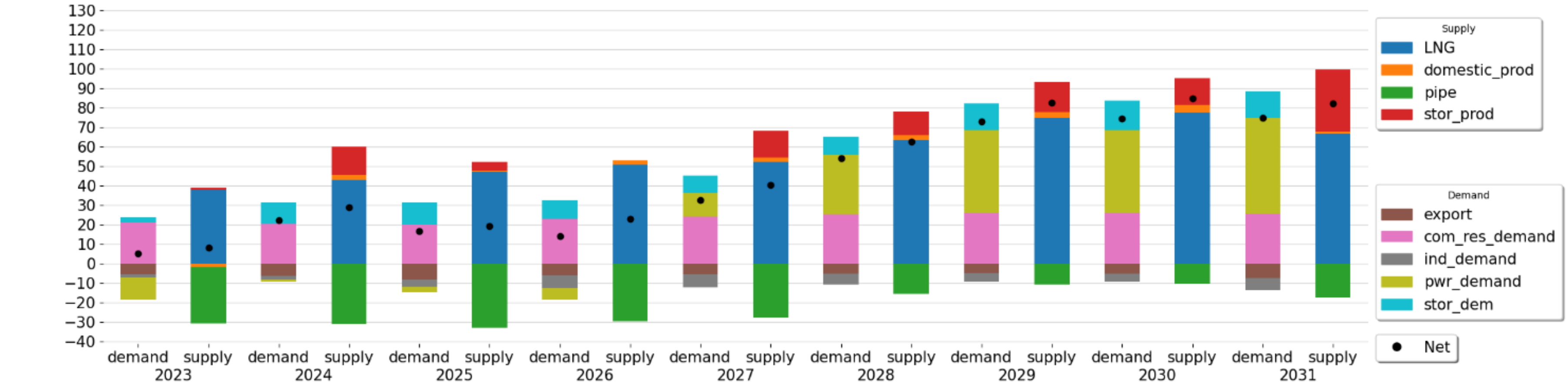
In conclusion, there is a critical need for resilience in Europe's energy system amidst extreme weather events, supply shocks, and the challenges of decarbonisation. Europe's strategy relies on a mix of global market flexibility provision, sectoral flexibility, demand-side response, and strategic use of energy storage (gas and hydropower) to navigate the uncertainties and potential threats to its energy supply and economic stability. The heavy reliance on LNG, the phase-out of Russian gas, and the significant role of storage and demand-side measures underline the complex policy and market balancing act required.

[21] In cold weather years more gas will likely be released from storage in the winter which then requires refilling to a comfortbale level in the summer to prepare for the next winter. Therefore, a prolonged period of cold weather (for two or more consecutive years) will limit gas storage's ability to respond.

Figure 6: The impact of the Russian gas phase-out on gas demand-supply balance under the baseline (first row) and coldest+ (second row) weather scenario (bcm)

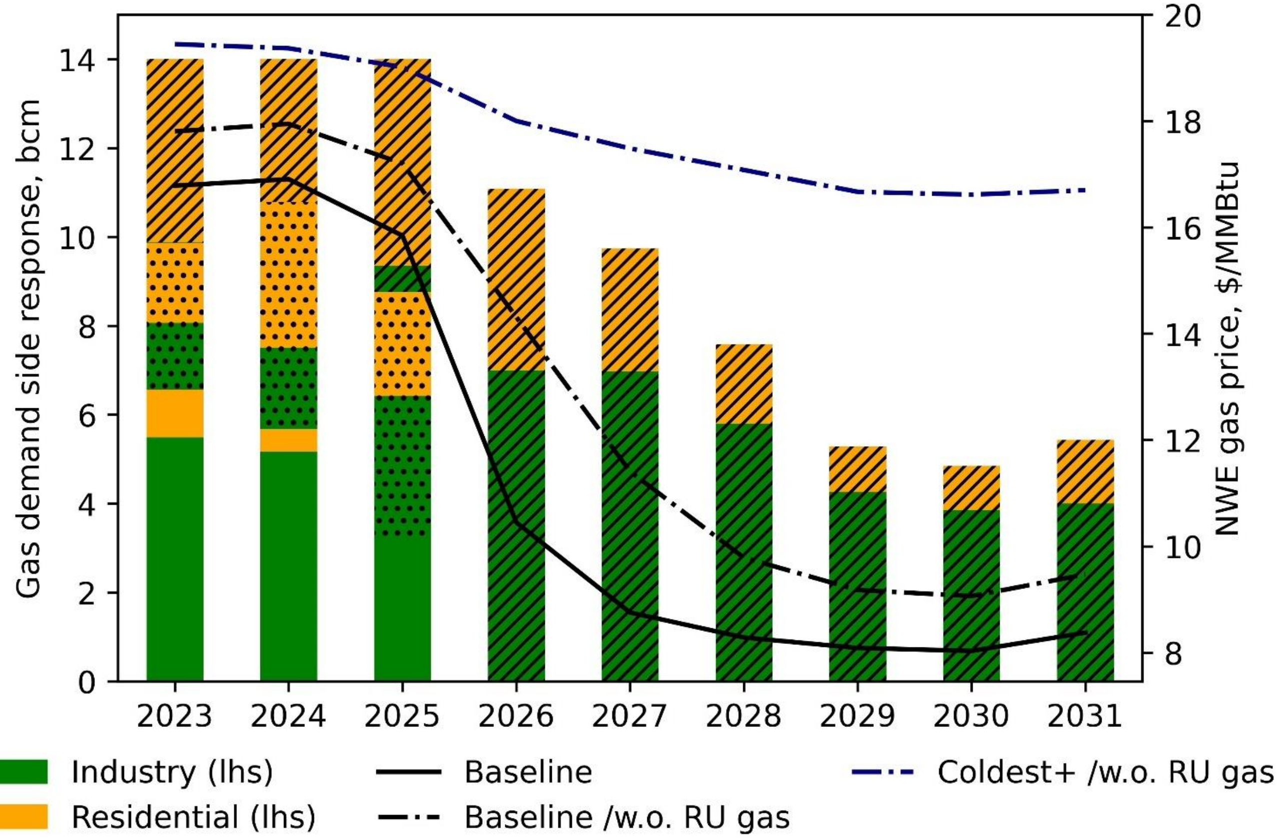


Notes: The chart represents changes from baseline Russian gas to a complete phase-out scenario in the NECP technology mix. The supply side accounts for LNG and pipeline imports from non-European regions, European domestic production, and gas storage withdrawal. The demand side describes consumption changes in all gas sectors, including gas DSR mechanisms, exports to non-European regions, and gas storage injection.



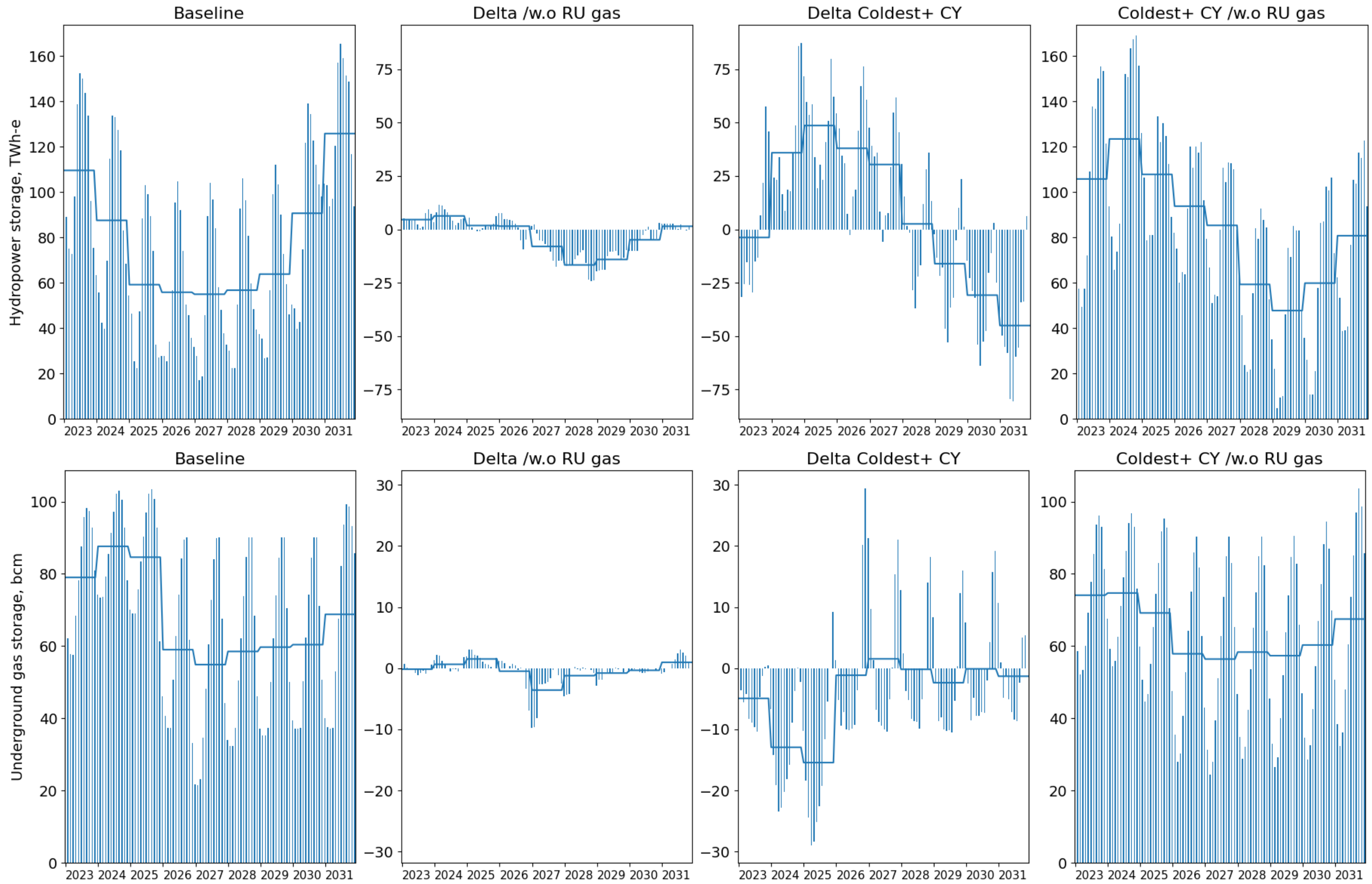
Notes: The chart represents changes from the baseline scenario to the *coldest+/ w.o. RU gas*

Figure 7: Gas demand side response (bars) and prices (lines) in different shock scenarios without Russian gas



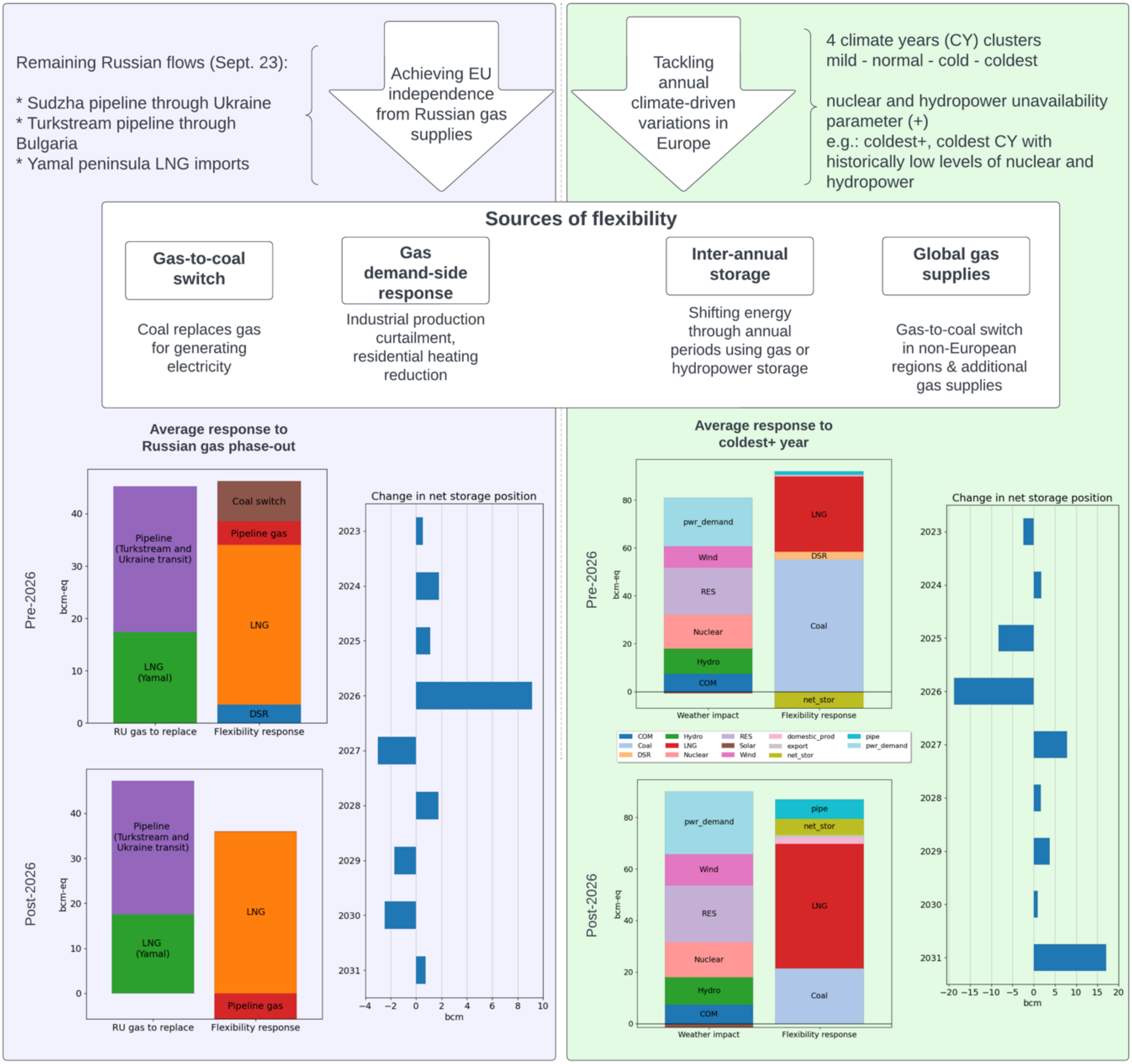
Note: Values represent the gas demand side response (DSR) from a normal weather year scenario to the extreme weather year scenario (*coldest+*). Solid fillings represent the DSR in normal weather years, the dotted fillings represent the additional DSR due to the Russian gas supply phase-out, and dashed fillings represent the additional (when no Russian supplies are available) DSR triggered in extreme weather events.

Figure 8: Gas and electricity storage levels in normal and coldest+ scenarios, with and without Russian gas



Note: The chart shows storage (large-scale gas and electricity storage) levels and changes in 2023-2031 (monthly level) from a baseline scenario to a scenario without access to Russian gas supplies and under a *coldest+* scenario. The bars show monthly values, while the lines show the annual average level. Note that, for comparison, one can convert the gas bcm in storage to electricity generation equivalent TWhe-e using a median CCGT efficiency of 0.48 in Europe. For example, 80 bcm of gas in storage is equivalent to 426 TWh-e, which is roughly three times higher than the hydro storage level in 2031 in the baseline.

Figure 9: Summary of the impact of phasing out Russian gas in Europe



4.3 Variability of Impacts at the Country Level

The differentiated impact of the transition on European countries underscores the role of national capacities, policies, and geopolitical considerations in shaping energy strategies. The transition affects European countries differently, and their capacity to respond points to the significant variability in impacts and strategies across the region.

In Europe, the energy landscape is unevenly distributed, with France and Germany holding a significant portion of variable energy capacity (VES [22]), with 35% and 33%, respectively. Renewable energy development focuses on six countries: Germany, Spain, the UK, France, Italy, and the Netherlands. The exposure to weather-induced variability in energy output differs among countries, with certain ones more reliant on wind, solar, hydropower, and nuclear energy. Specifically, Germany, France, Spain, Italy, the UK, and Switzerland, which rely on wind and solar, produce 65% of Europe's electricity. In contrast, France, Norway, and Sweden account for just under 50% (with France representing ~30%) of the region's total nuclear and hydropower capacity. Renewables are set to replace 236 TWh of gas-fired electricity, 228 TWh from coal, and 75 TWh from nuclear in 2031 (see Figure for electricity generation projection). Germany and Italy must replace coal, 17 and 6 GW, respectively, and a net 23 GW of nuclear capacity is to be phased out in Europe. Further, coal is concentrated in three countries (Germany, Poland, and Ukraine), which hold 65% of Europe's coal capacity. The distribution of hydropower is sparser, with fourteen countries having direct access to more than 1GW of capacity each.

Despite a shift towards electrification for heating, gas consumption remains substantial, especially in the residential and commercial sectors, which account for 30% and 12% of total gas usage. Eight countries – Germany, the UK, Italy, France, the Netherlands, Spain, Poland and Belgium – contribute approximately 80% of Europe's gas demand. These countries are exposed to a double burden in colder winters: a reduced electricity output that potentially triggers higher gas demand in the power sector and higher gas demand for heating. The UK, Italy, Germany and France are especially exposed to energy supply and demand shocks, as they each consume over 40 bcm/y of gas[23] and have more than 90 GW of VES capacity installed. Together, they account for ~60% of the gas demand and ~50% of the VES capacity in Europe in 2023-2031. These shocks are exacerbated by colder winters and geopolitical events, highlighting the critical need for strategic whole energy system planning and risk management in the face of potential energy supply and demand shocks.

The capacity of a European nation to offer flexibility to others hinges on three key factors: (i) the extent of coal generation capacity in these countries and the rate at which it is used, indicating their ability to switch fuels, (ii) the accessible dispatchable hydropower capacity that can serve as energy storage over several years, and (iii) the capabilities to import and export electricity to leverage the diversity of electricity production across Europe.[24]

In the baseline scenario, Europe is moving towards decommissioning coal plants, except Poland, and experiencing only minor development in dispatchable hydropower. This shift decreases available power flexibility from 1512 TWh (45% of annual generation) in 2023 to 1307 TWh (36% of annual generation) by 2031. Poland, Germany, and Ukraine are the main contributors to coal-power flexibility in 2031. Additionally, Europe's ability to manage cross-border electricity flow is crucial for utilising coal and hydropower flexibility in response to energy supply and demand shocks. However, 75% of this flexibility is expected from ten countries: Germany, Ukraine, Norway, Italy, Spain, Poland, France, Czech Republic, Switzerland, and Sweden. Despite this, limitations arise due to the lack of a direct interconnection with Ukraine and lower

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[22] Wind, solar, nuclear and hydro; wind, solar, and hydro are subject to interannual variability due to climate conditions while nuclear, a stable baseload technology, is subject to technological risks affecting duration of its maintenance and extent of its unavalability.

[23] Across commercial, residential, industrial and power sectors

[24] While there is enough of gas-fired generation capacity, in the *coldest+* scenarios gas supply to Europe becomes scarce, and therefore gas-fired generation cannot provide additional flexibility to meet electricity demand. Woth noting that gas is also needed for non-power needs as well.

import and export capacities in Eastern European countries like Poland, Slovakia, and Hungary. Countries such as Italy, Spain, Poland, and Sweden face challenges in exporting power flexibility due to low export capacities, indicating a focus on domestic use rather than cross-border 'solidarity' efforts.

Further, Italy, Denmark, and Hungary will see significant decreases in power sector flexibility (respectively -33%, -100%, and -100% from 2023 to 2031) without corresponding improvements in electricity interconnections (respectively +0.4%, +6.9%, and -5.2% for the same period). This trend indicates a need for closer scrutiny of these countries' ability to switch fuels and develop cross-border electricity connections. Furthermore, limitations in export capacities compared to available generation from coal or hydropower were observed in Ukraine, Sweden, Poland, Italy, Spain, and Switzerland, with France and Poland experiencing bottlenecks that could hinder flexibility provision to the rest of Europe in shock scenarios. Lastly, Ukraine's coal capacities, being close to Russian borders, face vulnerabilities to physical or military threats and limited interconnection, making them an unreliable source of power flexibility for Europe.

Thus, European nations are adapting to the cessation of Russian gas supplies and extreme weather differently. In 2025, a net decrease of 3.7 bcm in gas generation will be fully compensated by coal[25], especially in Germany and Poland. There is also a change in gas-fired (by two bcm) and hydroelectricity (by one bcm-eq) generation locations. Spain's gas generation is increasing to support electricity exports to countries facing shortages from the Russian gas phase-out, such as Germany, Austria, and the Netherlands. These countries turn to coal or hydroelectricity, sourced domestically or through imports from nations with alternative resources. Gas DSR is also activated in Germany, Italy, and France due to gas scarcity, indicating higher gas costs.

In 2029, gas-fired generation shifts location while total power generation increases slightly by 0.8 bcm due to the phase-out of Russian gas and the replenishment of hydro-based electricity storage that had been used up (-2 bcm) when gas was costlier (before 2026). Spain and Italy ramp up gas-fired electricity production, while the Netherlands cuts back, with Denmark opting for cheaper imports from Norway and the UK. The Russian phase-out elevates gas costs (see §4.4), notably affecting Germany, the Netherlands, and Austria. Countries prioritise gas for heating and industry without Russian supplies, resorting to coal, hydropower, or electricity imports from nations with easy access to global LNG, like Spain, Italy, and the UK, when necessary[26].

In exploring the impact of extreme weather scenarios (the *coldest+* scenario) and the phase-out of Russian gas, the UK, Germany, France, Italy, and Austria experience significant increases in gas demand for heating. In response to these challenges, by 2025, Germany emerges as a critical flexibility provider by substituting gas-fired electricity with coal generation and exporting excess electricity. This period also witnesses a notable gas-to-coal switch[27], mainly in Germany, Poland, and Romania, compensating for reduced gas consumption in the power sector in Italy, the UK, Spain, and Austria. Additionally, Spain and Austria generate more electricity from hydro to meet their needs, while Germany, France, and the Netherlands activate gas DSR in the heating sector to manage shortages. By 2029, with the total VES capacity increasing, gas-fired generation provides essential flexibility, supported by the significant role of coal in countries like Germany, which faces the most substantial impact from the Russian gas phase-out.

Analysing power sector cross-border flexibility reveals some bottlenecks, particularly under the *coldest+* scenario and Russian gas phase-out. In 2025, gas flexibility (cross-border and generation) is maxed out in several countries (see Figure 12). Norway, Portugal, France, Ukraine, and Greece fully utilise their electricity export capacities, even though their coal, gas, and hydropower plants could still generate electricity. This

[25] The economics of running coal vs gas generation depends on relative fuel prices and other costs associated with burning coal and gas, for more details about coal and other commodity price assumptions, see SI2.

[26] While gas can be more efficiently moved (in terms of cost per energy volume) than electricity, in shock scenarios some countries are facing cross-border bottlenecks to import gas (see Figure 9)

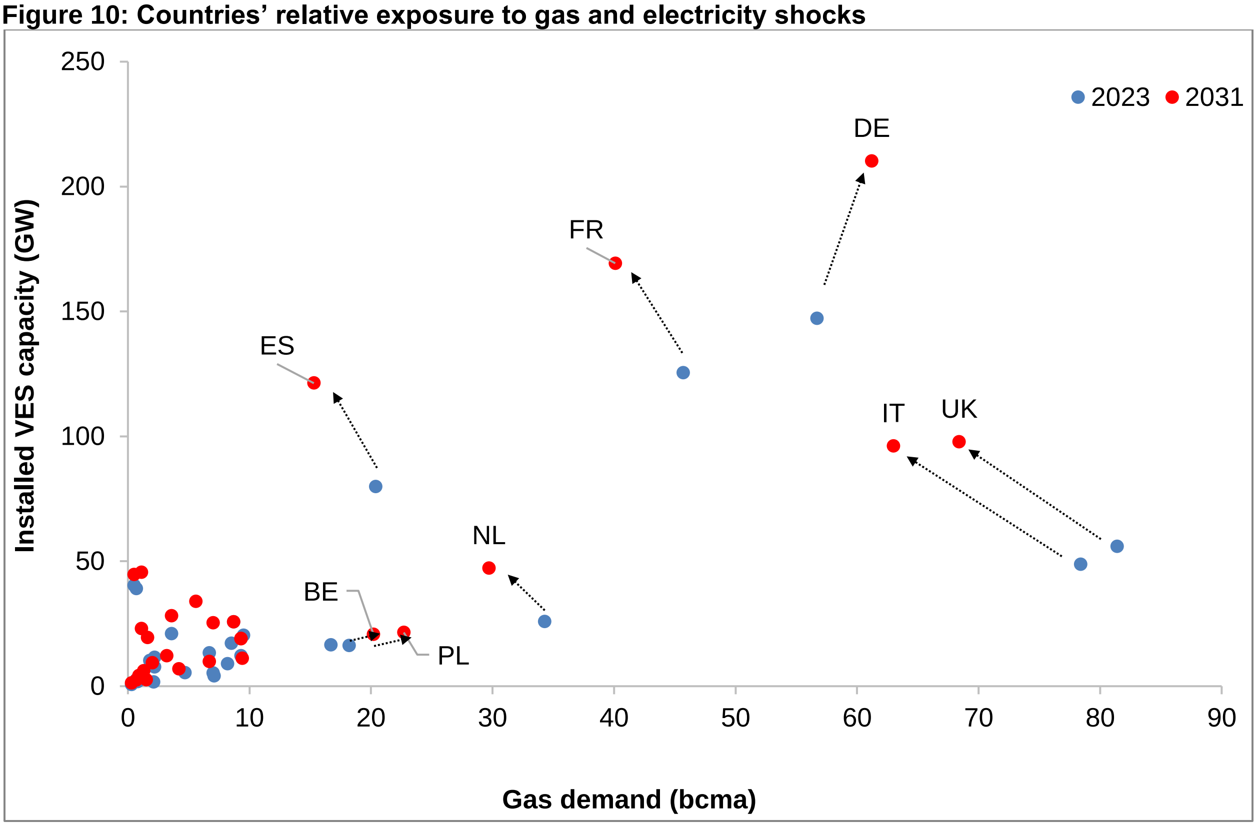
[27] Apart from regional coal prices, which was modelled endogenously using coal supply functions (see SI2 for details), other fuel and carbon prices were assumed exogenous to the model. This is an area for future research.

scenario shows less cross-border electricity trade, a significant gas-to-coal switch in the Czech Republic, Denmark, and Germany, and a redirection of LNG to countries like Germany, the Netherlands, the UK, France, and Spain due to *coldest+* events.

By 2029, the focus shifts to increased coal generation in countries like the Netherlands, Poland, and Slovenia, despite higher carbon prices and a boost in gas generation triggered by expanded LNG import capacity. This period sees a reduction in coal and gas generation as renewables take precedence, but interconnection congestion remains unresolved, highlighting ongoing challenges in cross-border electricity exchange. Countries like Germany, the UK, Italy, France, the Netherlands, Spain, Poland, and Belgium are most affected by gas shocks, showing varied vulnerabilities and responses to energy supply challenges, with Poland, Ireland, Hungary, Lithuania, Switzerland, and the Czech Republic identified as particularly at risk due to limited alternatives to LNG and moderate to high gas exposure.

Overall, Europe's energy transition highlights the importance of addressing bottlenecks in electricity and gas interconnections and enhancing cross-border exchanges to ensure energy security and sustainability. As European countries shift towards more renewable energy sources, the disparities in their adaptation abilities underscore the necessity for improved infrastructure and strategic planning. Bottlenecks in electricity export capacities and interconnections limit the region's ability to respond effectively to energy supply and demand shocks, particularly in the face of geopolitical events and extreme weather. Strengthening the infrastructure for cross-border electricity and gas exchanges is crucial for leveraging the diverse energy landscape of Europe, enabling countries to share resources and buffer against potential shortages. Simplifying this, the future of Europe's energy transition depends on overcoming interconnection challenges and enhancing the framework for energy exchange, ensuring a resilient and sustainable energy system across the region.

Figure 10: Countries' relative exposure to gas and electricity shocks



Note: The chart represents countries' VES capacity (nuclear, hydropower, wind, and solar) and total gas demand (across all sectors) as gas risk factors.

Figure 11: Extreme weather under the baseline (A), the impact of Russian gas phase-out (B), and total changes in electricity and gas consumption (C)

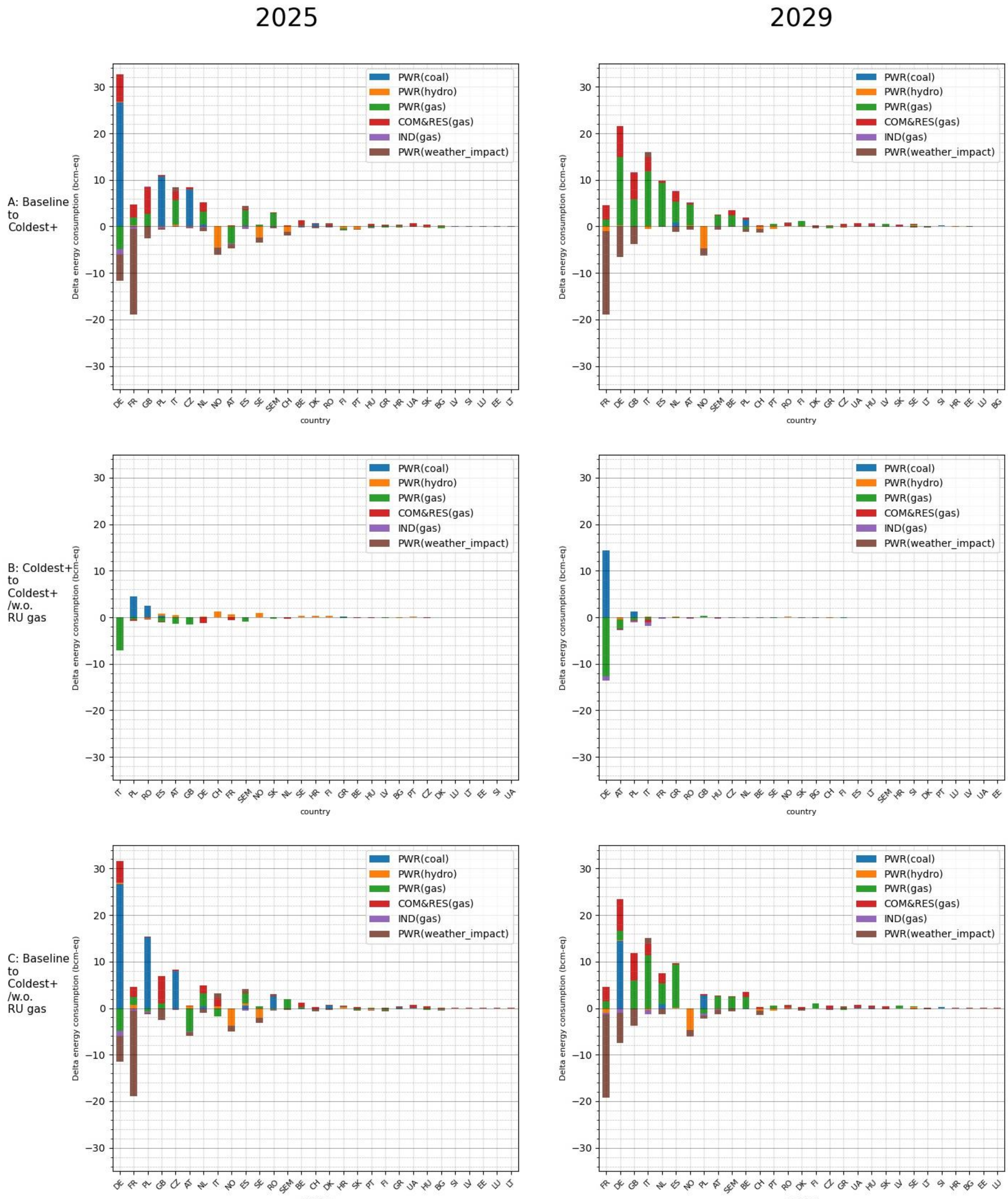
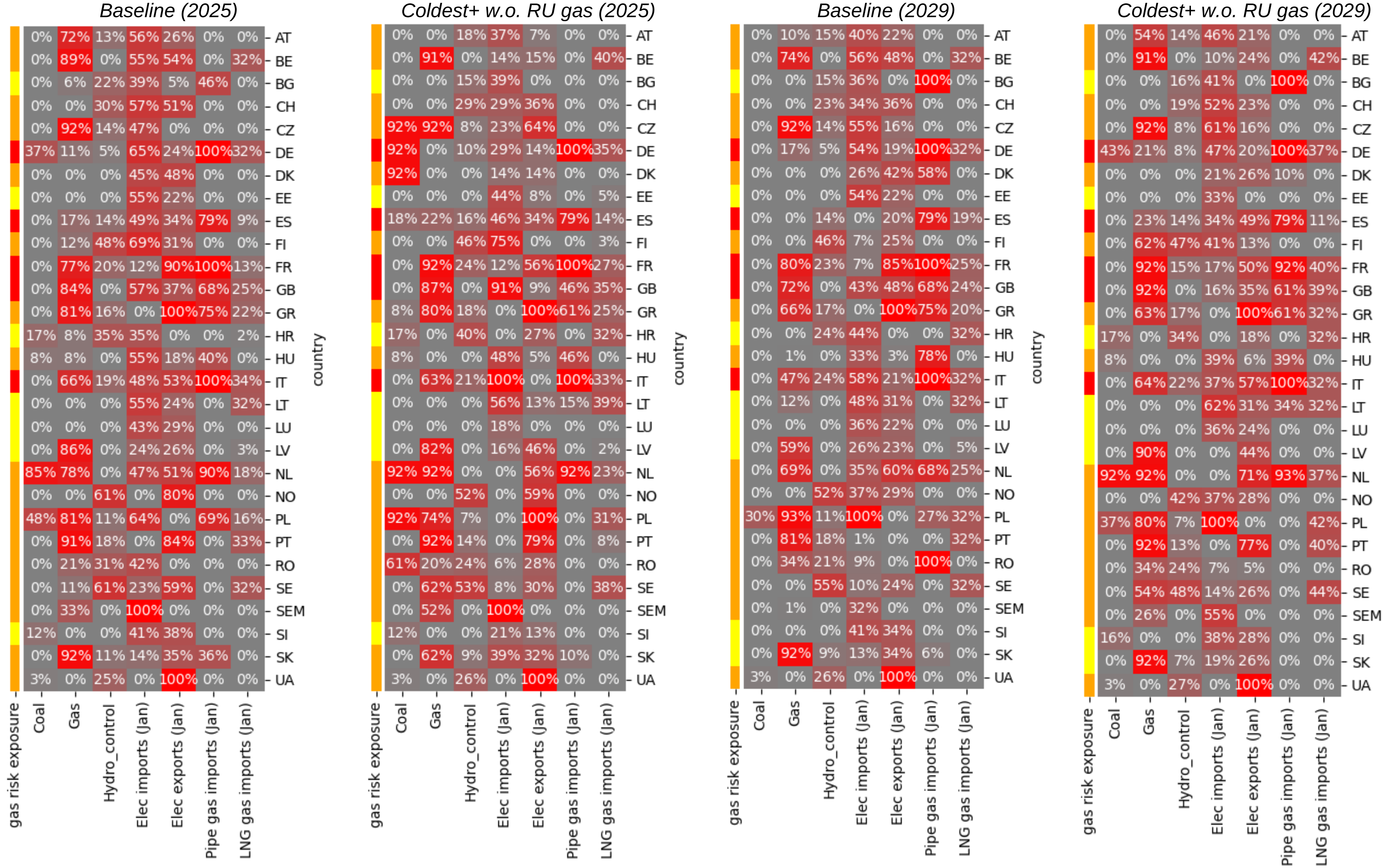


Figure 12: Utilisation rates (first row) of flexibility resources and their changes (second row) in Europe under modelled scenarios



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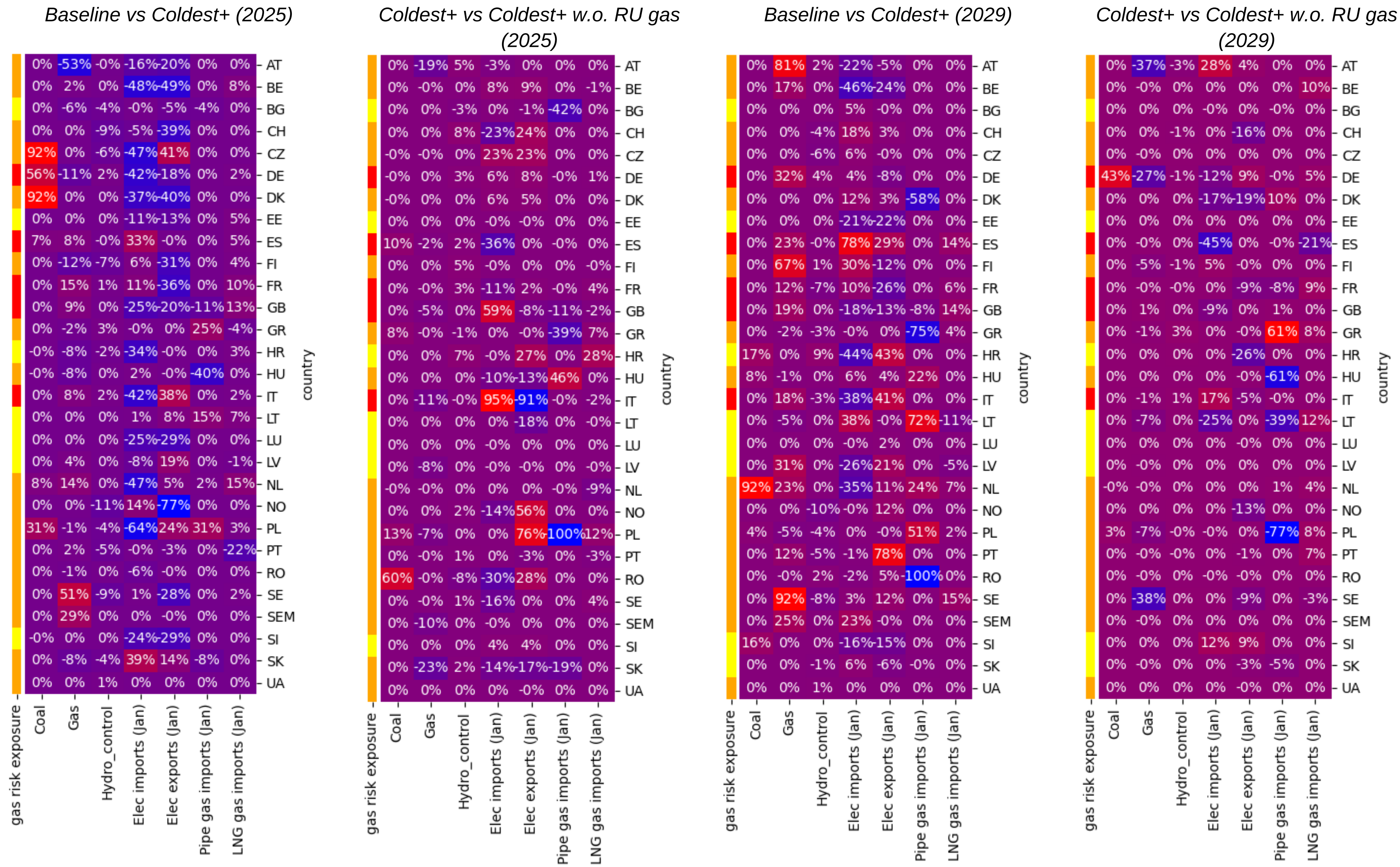


Note: Threshold values for gas exposure (bcm-eq) red: >100, orange: 100> & >10, yellow: 10>

4.4 Environmental and renewable investment implications

Even under the worst weather scenarios, Europe can eliminate its reliance on Russian gas by using coal for power, reducing gas demand, or importing gas, primarily through the global LNG market. Despite geopolitical uncertainties, Europe ceased coal imports from Russia by August 2022 and increased LNG imports due to reductions in pipeline supplies from Russia. This shift, however, raises wholesale energy costs due to increased coal imports and the volatile global LNG market, with price spikes influenced by economic and political events.

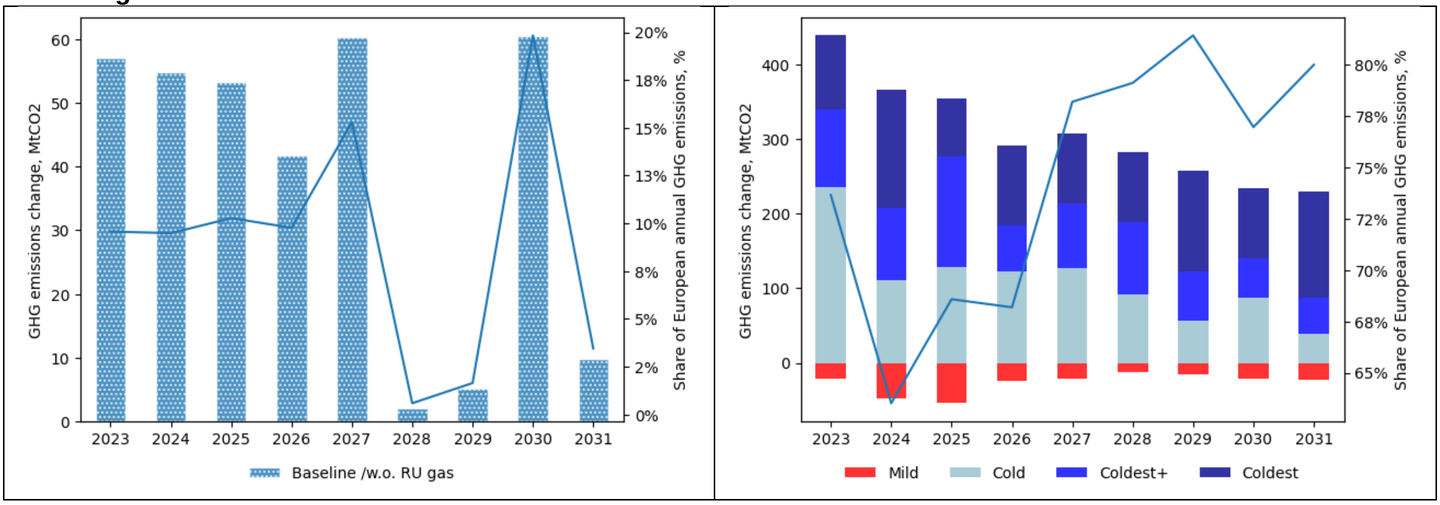
A European embargo on Russian gas would remove pipeline supplies to Europe while increasing the wholesale cost of LNG (compared to the baseline scenario), leading to an increase in coal use and a 0.32% rise in global emissions from 2023 to 2031. Adverse weather conditions in Europe could increase global emissions by 2-3.5% in a year due to a higher reliance on fossil fuels. This trend highlights the impact of European policies on global emissions, with Asia and Europe most affected due to their need for energy imports.

The REPowerEU plan set ambitious targets for investments in renewable technologies, particularly wind, solar, and heat pumps, to reduce long-term fossil fuel use in Europe. Based on the modelling results, this plan could save European consumers $1202 billion in wholesale energy costs from 2023 to 2031 (see SI3), covering 75% of the incremental cost of shifting to higher wind and solar targets and with the wholesale revenue total social benefits could cover 88% of the incremental cost. The plan also reduces the cost of phasing out Russian gas imports (-$283 bn). Thus, considering this cost reduction, the total social benefit of the incremental capacity represents ca. 96% of the total incremental wind and solar investment cost. In addition, the REPowerEU plan has a significant global impact, reducing greenhouse gas emissions by 1.6 $GtCO_{2e}$ (from 2023 to 2031), with 1.25 $GtCO_{2e}$ avoided in Europe thanks to a decrease in fossil fuel generation by 2778 TWh and a shift from coal to gas amounting to 701 TWh outside Europe. This shift, facilitated by Europe's move towards renewable energy, eases global gas market competition, making gas more affordable and supporting coal phase-out elsewhere. Additionally, the plan's effect on reducing wholesale energy costs globally by $444[28] billion compensates for the costs of implementing REPowerEU.

While it seems that the social benefit of the incremental wind and solar capacity addition in Europe (taking the global benefits of the plan into account) exceeds the investment costs, the plan's heat pump target is unlikely achievable based on wholesale price signals alone. Thus, achieving cost-effectiveness for heat pumps over gas boilers under the REPowerEU plan requires substantial subsidies. Furthermore, electrifying the heating sector would mitigate gas supply shocks but place additional demand on the power system. The REPowerEU plan does not fully address the economic costs of weather-related shocks. Thus, further policy measures are necessary to manage the increasing variability in energy supply and demand as Europe moves towards a decarbonised energy system and navigates the challenges of the global LNG market.

[28] Net of increase in wholesale energy costs due to the impact of Russian gas phase-out.

Figure 13: The impact of Russian gas phase-out (lhs) and European weather scenarios (rhs) on global GHG emissions



5. Conclusions and Policy Implications

The 2022/23 energy crisis revealed that a sharp energy price rise for a sustained period is politically unacceptable (see Pollitt et al., 2024), impacting the wellbeing of households (see, e.g., Burlinson et al., 2024). Starting from this perspective, the rest of this section offers some policy considerations to deal with volatile and uncertain energy markets as Europe decarbonises and phases out fossil fuels.

Global energy markets have been crucial for Europe to absorb the shock of energy supply and demand since the start of the 2022 war in Ukraine. The primary mechanism is gas-to-coal switching and load shedding outside Europe (e.g., Parkin and Dempsey, 2023; Stapczynski and Mangi, 2023) to release natural gas for suppliers to divert LNG to Europe. While Europe has shown its economic resilience to absorb the shock and outbid other regional consumers to attract more LNG, the impact on global CO_2 emissions, notably on local air pollution and the potential economic crisis, should be acknowledged.

Secondly, having an explicit price on carbon in the form of ETS has at least two effects – (i) potentially increasing market power of gas supplies to Europe, exacerbating price levels and volatilities (see Newbery, 2008) in times of shocks, and (ii) absent explicit carbon pricing in other regional gas markets will likely increase the emissions (i.e., carbon leakage) when the global energy market is short. The modelling results show that global emissions rise when Europe phases out the remaining Russian gas supplies or under extreme weather conditions, pushing up energy demand in Europe. While carbon emissions are a global commons problem, local air pollution associated with burning coal is a local health issue impacting countries in Europe and outside of Europe. Therefore, the results highlight the need to support other regional markets by switching away from coal. In this respect, the modelling results showed that by implementing the REPowerEU targets, Europe is not just reducing its dependence on fossil fuels but, more importantly, releasing substantial gas resources for other regional markets, which helps to phase out coal generation there and hence minimising global emissions and local pollutants under global shock scenarios.

The second issue is the reliance on the global spot LNG markets and the resulting price uncertainties and volatilities under global shock scenarios. As Ah-Voun et al. (2024) suggested, at least two complementary policy options are available to Europe: (i) extending the gas storage regulation beyond 2025 (i.e., strategic gas stock) and (ii) demand savings targets.

The modelling results suggest that mandatory gas storage filling targets may not be required under the scenarios considered beyond 2025 because European gas demand is falling fast due to efforts to decarbonise its power supply (with renewables) and fewer arbitrage opportunities when relying on plentiful LNG markets in the post-2025. However, storage filling targets may give market participants near-term visibility and moderate price volatility (Au-Voun et al., 2024). Retaining the storage filling targets in the context of falling demand should be done, such as minimising the stranded asset issue and not distorting market signals to decarbonise. In this respect, filling targets could be (a) pegged to expected gas demand properly accounting for weather effects and cross-border interconnections and (b) supplemented with withholding corresponding carbon emissions permits from future auctioning. When faced with acute shock, the front-loading of carbon emissions associated with the potential gas in the strategic stock spreads this cost over a potentially extended period while bringing forward more robust market signals to decarbonise with renewables.

Further, the modelling results showed that hydroelectricity storage would likely play an increasing role as interseasonal storage, especially in shock scenarios when gas storage filling is regulated. Hence, if the gas storage filling regulation were extended, hydroelectricity storage would play an essential role in interseasonal and year-to-year modulation for Europe. It is, therefore, important to monitor the competitive behaviour of large-scale hydro storage operators, limiting the potential for abuse of market power in the wholesale electricity market as they will likely become pivotal suppliers of interseasonal storage services.

The modelling results underscored the importance of a joint gas-electricity resilience assessment. In particular, many European countries (large energy consumers) are exposed to shocks from gas and electricity systems. In extreme weather conditions, these countries are exposed to increased demand for gas (e.g., space heating) and electricity (e.g., due to higher electricity and lower than average renewable generation). The European Commission mandated a gas savings target (15% compared to average gas consumption in 2016-21) until 2024. In light of the modelling results, the energy savings target should be extended to cover a range of climate years and their impact on total gas and electricity demand. Ideally, this demand target should consider available cross-border gas and electricity capacity and an *N-X* analysis of technologies (e.g., reduced availability of nuclear or hydroelectricity generation) that may increase total gas and electricity demand.

The modelling results strongly point to the need for more interconnections between European countries, especially for cross-border trade in electricity. More investments in electricity interconnection are needed to unlock European power sector flexibility. For example, the results showed that many European countries have spare coal, gas, and hydroelectric generation capacities that could be used under shock scenarios. Still, they are used suboptimally because of a lack of electricity interconnection. Furthermore, the results explicitly showcase a trend of widening geolocation of dispatchable generation across Europe, which calls for more investments in interconnection.

To conclude, phasing out the remaining gas flow from Russia under the most extreme weather and technological conditions is possible. Doing so responsibly (i.e., minimising the cost and health impact for developing regions) requires expedited rollout of renewable energy in Europe, such as wind and solar energy, as envisaged by the REPowerEU plan[29]. Achieving the incremental wind and solar deployment targets seems socially beneficial under the scenarios considered in this modelling; therefore, the focus should be on (i) non-economic barriers to faster deployment and connection of wind and solar resources to support the phase-out of Russian gas and decarbonisation in Europe and the rest of the world, and (ii) on the financing of cross-border electricity capacity and technological solutions (e.g., battery storage and long-duration storage technologies) to manage the intermittency of renewables not only over years but also on weekly, hourly and sub-hourly scales.

The research was conducted using detailed and sophisticated modelling tools. However, some limitations deserve future research.

First, it is a perfect foresight model, and as such, the quantified economic impact is likely to be at the lower end because, in practice, the shocks will produce much sharper short-run price responses. If anything, this reinforces our conclusions that investments in local renewable resources and associated infrastructure will dampen short-run price impacts of such shocks.

Second, a comprehensive life-cycle analysis (LCA) of pipeline gas, LNG, other fossil fuel and renewables emissions will give a complete picture of the life-cycle GHG impacts of the shock scenarios.

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[29] The incremental addition (the difference between the REPowerEU target and the NECP19 target) of wind and solar capacity does not significantly increase the IAV of electricity generation (Ah-Voun et al., 2024). In contrast, the impact of this additional capacity on wholesale costs outweighs the capital cost of these additions (see SI3).

Thus, the impact of emissions presented in this research is underestimated. Including LCAs of all energy sources will further support our conclusion that international cooperation is urgently needed to reduce emissions and local pollution at combustion points and along the whole supply chain.

Third, the modelling outcomes are influenced by assumptions about future additions to the LNG supply. The analysis incorporates all LNG projects that made final investment decisions (FID) by the end of 2022. It did not consider projects announced for FID in 2023 and 2024. These projects, including Qatari's NFS and various US projects, are expected to contribute over 53 bcma by 2030. Including these projects suggests that the effects of eliminating Russian gas, especially under severe weather conditions, would likely be minimal regarding wholesale prices and emissions. This is because an increased supply of LNG facilitates the replacement of Russian gas. It also meets the extra demand from weather events with minimal switching from gas to coal in Europe or globally. Consequently, future research must address the timing and probability of these new LNG capacity additions, including the US domestic politics concerning permitting new LNG projects from the region, and explicitly model these supplies.

Fourth, including long-term LNG supply contracts would mean better capturing of price formations for LNG and for LNG shipping fees. Point-to-point contracts reduce shipping capacity relative to the fully optimised global LNG flows (modelled in this paper), meaning higher spot LNG shipping fees and prices when shocks occur in practice.

Further, second-order effects, such as coupling European weather scenarios with supply and demand shocks in non-European regions (e.g., a globally cold year with droughts in major hydroelectric-based economies), were not quantified.

Lastly, while regional coal supply (all regions except Europe) was modelled using supply functions (hence regional endogenous coal price formation in the model), a global multi-commodity (e.g., capturing endogenous price formations, and international trade in crude oil, oil products, coal, gas, electricity, carbon) market model will better capture the effects of extreme shocks on the global energy trade and investment trends.

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