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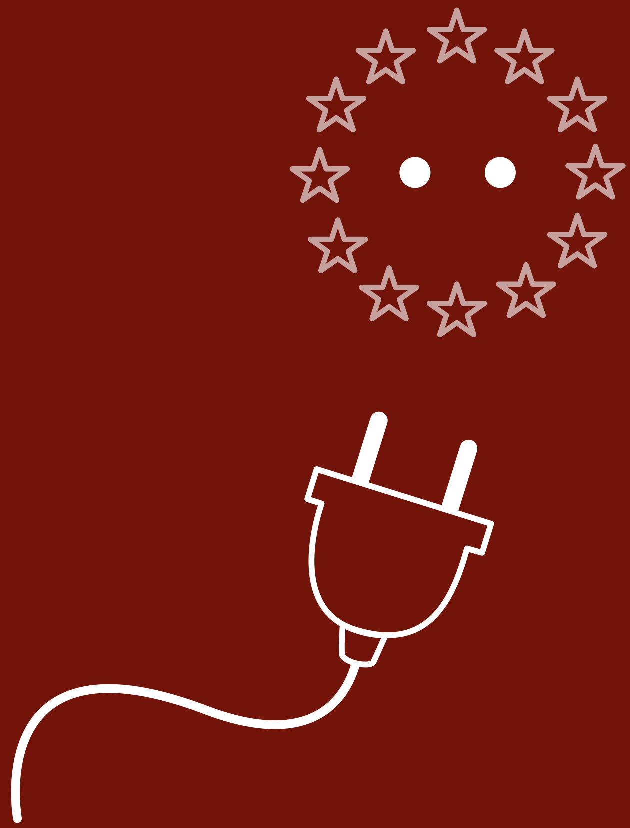

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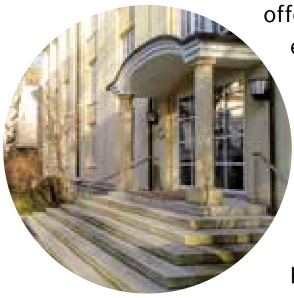
The current energy crisis in Europe is bringing about profound changes that can accelerate the transition to a more sustainable and secure energy system. Yet, it is a supply shock of unprecedented scale and complexity, most noticeable in the markets for natural gas, coal, and electricity. Winter promises to be tough - especially for low-income households that use gas for heating and for small and medium-sized industrial companies. Short-term policy measures aim to shield consumers from the effects of the crisis: these include gas and electricity price brakes and energy subsidies for households. At the same time, many governments in the EU are now trying to increase or diversify oil and gas supplies and also accelerate structural change. The articles in the “Policy Debate of the Hour” section of this issue of EconPol Forum examine the causes of the crisis, analyze its effects, critically assess the policies already in place, and propose new short- to medium-term energy policies to better manage it and strengthen the EU’s systemic resilience to energy market volatility.



In our evidence-based policy evaluation section, an article offers insights into the revenue implications of a global effective minimum tax, followed by an international comparison of the effects of pandemic severity and the stringency of government restrictions on work from home in the “Institutions across the World” section. Last but not least, in this issue of the EconPol Forum, we examine the success of the social integration of Syrian refugees in Germany as part of a Big Data study.

POLICY DEBATE OF THE HOUR

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Introduction to the Issue on

How to Deal with the European Energy Crisis? Core Challenges for the EU

Chang Woon Nam

Europe is in the grip of the most severe energy crisis in half a century. Triggered by Russia's invasion of Ukraine, it has laid bare how unprepared most countries were for such a shock, and how vulnerable their energy policies had made them over the years. While the shock may accelerate the transition to a more sustainable, secure, and resilient energy system, the severe impact on natural gas, coal, and electricity markets is driving energy prices to unprecedented levels. The high costs for energy make low-income households, SMEs and the industry in general face the coming winter with trepidation. The energy crisis will not be for a short term in Europe. If anything, the winter of 2023-24 is expected to be even tougher. Energy-intensive industries fear for its competitiveness in the world, households for the loss of prosperity. European governments are eagerly seeking ways to defuse the situation by implementing short-term measures to protect consumers and firms from the effects of the crisis (e.g., gas and electricity price brakes, VAT cuts on gas, households' energy subsidies, and many more). While national solutions may entail the risk of a subsidy race in Europe, some measures can also undermine climate protection goals. Many governments in the EU are now taking longer-term measures, aimed at increasing or diversifying energy supply, accelerating structural change and promoting renewable energies, or even by extending the use of nuclear energy. Finally, Europe will succeed only if they cooperate closely.

The articles in this issue of EconPol Forum examine the causes of the crisis, analyze its effects, critically assess the strategies already in place, and propose new short- to medium-term energy policy measures to better address the current crisis and strengthen the EU's systemic resilience to energy market volatility.

According to *Andreas Goldthau* and *Nick Sitter*, the EU's traditional strategy (based on the liberal market model) for ensuring energy security has been challenged not only by the Ukraine crisis, but also because current EU energy and clean transition policies have become highly interventionist. Taking into account the political and economic trade-offs of each model, the authors posit future energy priorities and strategies.

Reyer Gerlagh, *Matti Liski*, and *Iivo Vehviläinen* find that a coordinated introduction of energy demand reduction would go a long way towards stabilizing the EU electricity market. They propose lowering the price cap to €1,000/MWh across the EU, as this would save consumers money, would not harm supply, and would significantly reduce the need for redistributive measures.

Daniel Gros points out that, given that the global supply of natural gas is fixed in the short term, Europe can only replace the lack of Russian gas if it offers more than what consumers elsewhere are willing to pay. For this reason, EU policy should focus on how to save gas, not on how to protect consumers from the current high prices.

The European electricity system is currently under pressure, as it depends on natural gas to balance the grid and to meet demand. *Mathias Mier* predicts that electricity prices will be six times higher than they would have been without the current natural gas crisis. Germany appears to be better diversified in this context, and price hikes are expected to be less severe.

Svetlana Ikonnikova and *Sofia Berdysheva* shed light on the problem of short-term energy security and affordability in Germany, which is urgently seeking substitutes for Russian energy. They also examine the importance of the energy transition on Germany's vulnerability to energy price shocks, and its failure to take security considerations into account in its trade arrangements.

Finally, *Alari Paulus* and *Karsten Staehr* explain the Baltic perspective on the energy crisis, in which higher energy prices have led to very high inflation and lower growth. Although many of the current challenges apply to practically every country in Europe, they are particularly serious in the Baltic states because of their energy-intensive economies, large dependence on energy imports, and limited grid interconnectivity. The authors believe that short-term measures must limit extreme energy prices, while monetary policy must avoid exacerbating the cost-of-living crisis. In the short- and medium-term, diversification of energy supplies is a must.

We hope you enjoy this Policy Debate of the Hour!

Andreas Goldthau and *Nick Sitter*

Whither the Liberal European Union Energy Model? The Public Policy Consequences of Russia's Weaponization of Energy

KEY MESSAGES

- **Energy is primarily a private good but also has public goods characteristics. The EU's traditional strategy to cater to the strategic goods element – energy security – was the liberal market model**
- **The Ukraine crisis has fundamentally put the liberal model in question. The present EU measures are deeply interventionist**
- **Renewables are elevated to matters of national interest. Combined with massive public funds, this accelerates the clean transition and is likely to put structural breaks into the incumbent energy system**
- **Going forward, the EU has three options: a return to the status quo ante (the liberal model); a more robust "public interest" model accounting for the risk of high political costs; and a Colbertist model putting the state in charge of managing markets and the clean transition**
- **The Ukraine crisis highlights each model's political and economic trade-offs. Policy priorities and strategies need to be revisited in light of these trade-offs. This is a watershed moment in European energy policy**

Russia's invasion of Ukraine on February 24, 2022 brought energy security to the top of the European Union energy policy agenda. Since the liberalization of gas and electricity markets in the 1990s, EU energy policy has been built on three pillars: a competitive Single European Market, environmental sustainability, and energy security. Security took a backseat; competition came first. In the first half of 2022 the EU reversed this, with considerable effect. National and EU-level measures focused on enhancing gas storage, adding more pipeline gas from Norway and North Africa and more import of Liquefied Natural Gas, facilitating new import infrastructure, swapping gas for other fuels, including coal and renewables, reducing consumption, and supporting firms and consumers hit by high prices. By September Russian gas was down to less than 10 percent of EU imports, from more than 40 percent at the beginning of the year (Gasworld 2022). Yet, since most of these initiatives involve significant state intervention, the EU's ad hoc measures for surviving an upcoming winter raise important and more fundamental questions about the future of EU energy markets.

We argue that the Ukraine crisis is a watershed moment in European energy policy because two major shifts are unfolding in the shadow of short-term crisis management. The first is a paradigm change, from a liberal to a more interventionist approach to the EU energy market and international energy trade.[1] Because of the national security implication of energy trade, EU governments are unlikely to relinquish their newfound role in energy markets in the way that they wound down state intervention after the financial crisis. The second shift involves the securitization of the transition to a low-carbon economy. Because renewable energy has acquired a role in national security, it is now subject to a much broader range of policy tools than merely those of climate policy. This throws up questions about the EU's strategic options for dealing with energy security.

THE LIBERAL EU MODEL: ENSURING ENERGY SECURITY THROUGH FREE TRADE

The policy measures that the EU and its member states are working on signal a potential break with the EU's established energy strategy. In public policy terms, energy is primarily a private good. Oil, gas, coal, or electrons are rival and excludable in consumption. In Europe, the production, trade, and pricing of such goods is therefore largely left to the market. Yet, energy also has public goods characteristics, in the sense that it includes elements that are non-rival and non-excludable. Inelastic supply, wide price swings, bottlenecks in shipping, and other cases of market failure may put in question the reliable supply of energy at affordable prices. Because the latter is important both for industry and society, it warrants careful policy design, notably in regions that rely on imports for most of their energy needs, such as the EU. The fact that energy security also has national security consequences makes energy a strategic good. Disputes over energy cause conflict and energy revenues sustain conflict, but more importantly, a reduction in energy supply can be used as a tool for political influence or as a means of inflicting harm on an opponent's economy.

The EU dealt with this strategic goods element with a liberal approach to energy markets. This was a deliberate choice. The principal idea was to create

[1] Paradigms are understood as the dominant economic, social, or technological model. For a discussion of policy paradigms in energy, see Goldthau (2012).

a vast and integrated market that was attractive for international suppliers to ensure competitive pricing. Beginning in the 1990s, the EU adopted a series of "energy packages" that liberalized the gas and power sectors, broke up national monopolies, and integrated formerly balkanized European markets. A determined pro-market push in EU energy regulation – the software, as former EU Energy Commissioner Maroš Šefčovič put it – ensured price competition between different sources of gas supply, including from Russia, Norway, Algeria, and global LNG. Inside the EU, third-party access to pipelines and unbundling of operation and ownership in infrastructure fundamentally changed the energy industry. The European Commission even forced amendments to existing gas contracts that included territorial restrictions in resale to further promote intra-European gas-on-gas competition.

The hardware component included infrastructure measures to ensure the free flow of gas (and electricity) across borders. The Commission supported interconnectors and other strategic pipeline projects to a limited extent by funding, but more importantly by facilitating the planning process and through strategic signaling by labeling them 'Projects of Common Interests'. The hardware component of the Single European Energy Market became even more important after the 2009 gas crisis and the 2014 annexation of Crimea, with a focus on improving reverse-flow gas pipeline capacity so that Eastern member states could be supplied from the West.

The liberal approach did not always adhere to textbook principles of pro-market regulation. As some observers argued, the Commission sometimes used the regulatory toolbox in a strategic way, notably by stopping the Russia-sponsored South Stream pipeline and when it extended the Security of Supply Directive to import pipelines (Goldthau and Sitter 2020 and 2015). Moreover, some EU countries showed little appetite to let go of their prerogatives in the domestic energy industry. This delayed or prevented strategically important cross-border infrastructure projects, such as the Bulgaria-Greece-Hungary interconnector or the MidCap pipeline linking Spain and France. In addition, gas storage remained a weak spot.

Overall, however, the liberal model delivered what was intended: gas prices came down. Even long-term contract prices converged across the bloc. This in turn shifted the economic rent from producers to consumers (Stern and Rogers 2017). What is more, Russia lost the ability to charge different prices to various European consumers. In terms of the public goods element of energy, the model catered to the aim of having choice in terms of sources, and affordability in terms of prices. In security terms, it was based on the idea that Russia could not afford to put its oil and gas sales to Europe at risk by interrupting supplies, since fossil fuel pre-crisis sales made up some 45 percent of the Russian state budget (IEA 2022). Moreover, increased energy trade with Russia fit a long-term strategy of drawing Moscow towards the liberal West through globalization and interdependence.

THE SHIFT IN ENERGY REGULATION: FROM MARKET TO PLAN

The Ukraine war caused a fundamental change in European perspectives on energy security. Against the backdrop of supply shortages, the specter of gas rationing and skyrocketing wholesale prices –with TTF futures hovering around EUR 200 per MWh for a good part of 2023 – the crucial question is whether the liberal gas market model is a fair-weather phenomenon. Does it deliver only under the condition of a buyers' market, unfit to cope with structural shortage?

Addressing pressing pricing and supply challenges, European governments opted for bold interventions in gas and electricity markets. The most important examples include Germany nationalizing UNIPER, France EDF, and the Netherlands and the UK pondering similar measures. EU leaders started facilitating gas deals around the world, including in Norway, Algeria, Qatar, and the US. In the German case, the government ended up paying some EUR 3 billion out of tax money for LNG cargos. The Commission suggested joint gas purchases, which, after the Council agreed, yielded the EU Gas Platform, which is now suggested to become the legally required vehicle to procure at least 15 percent of the 2023 storage needs. In addition, discussions on price caps on gas are gaining speed. Most member states have taken measures to shield households and industry from the impact of unprecedented price levels.

These steps may turn out to be temporary public policy responses to a severe crisis. However, they could also signal a fundamental shift in the energy policy paradigm, from market (back) to plan. The specter of a EU monopsony in gas purchase, a limited role of trading hubs in delivering price signals, and a flurry of gas diplomacy challenge fundamental building blocks of the liberal model. On September 21, in her State of the European Union Speech, European Commission President Ursula von der Leyen emphasized the need to "keep working to lower gas prices," called for "a more representative benchmark" than TTF, and declared that "The current electricity market design – based on merit order– is not doing justice to consumers anymore" (Von der Leyen 2022). With this, the President of the European Commission

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effectively questioned the very principles that had driven three decades of energy liberalization.

THE SHIFT IN ENERGY TRANSITION: FROM MARKET TO SECURITY

The second fundamental shift brought about by the Ukraine war relates to decarbonization. EU climate policy is primarily driven by regulation (such as the Renewable Energy Directive), by mandated targets (e.g. related to CO_2 emissions or renewable energy), and by subsidies (such as feed-in tariffs). These are here to stay, but targets have become much more ambitious since the Russian invasion.

For example, Germany now set the goal of 80 percent renewables in power generation by 2030 (Cleanergywire 2022), whereas the UK aims for "home-grown power" to achieve net zero by 2035 (HM Department for Business 2022). The Netherlands is to double offshore wind capacity by 2030 (Reuters 2022c), while Italy is eying "several tens of gigawatts of offshore wind power" (RFI 2022). Belgium, Denmark, Sweden, and Germany have unveiled plans to effectively turn the North Sea into a green power plant, aiming for 150 gigawatts in wind capacity by 2050 (Reuters 2022a). In addition to supply-side measures, structural demand destruction is hitting both oil and gas markets, as the EU agreed to phase out internal combustion engine vehicles by 2035, as governments aim to retrofit residential housing and heating systems to move them away from gas and energy-intensive industry is relocating.

Moreover, the EU and its member states have mobilized massive public funds in support. The EU's REPowerEU plan is set to unlock EUR 210 billion in funds towards clean energy investment (S&P Global 2022). Germany alone pledged more than EUR 200 billion for industrial decarbonization (Reuters 2022b), with similar measures being taken in other EU countries, including France (Euractiv 2022a). To be sure, supply chain bottlenecks, shortages in skilled personnel, and notoriously protracted planning processes still pose challenges, and not all of the pledged funds are in fact "new" money.

The new dynamics of the green transition is that decarbonization has been securitized. In German finance minister Christian Lindner's words, in the context of Russia's war against Ukraine renewables represent "freedom energy" (Euractiv 2022b). This has been widely echoed in European political circles and lies at the heart of the REPowerEU plan. This changes the way in which renewables are perceived, and how they are treated. It elevates them from the climate domain to the security domain. Renewable energy is no longer merely a long-term matter of saving the planet or achieving cost competitiveness with fossil fuels. Now, it is imperative for the national interest. In international relations terms, European energy has become – or more correctly, it is once again – a matter of "high politics" (Hoffmann 1966). Securitizing renewables enables extraordinary measures: additional public funding, flexibility on state-aid rules, as well as clear decisions on trade-offs between, for example, environmental protection and a fast ramp-up of offshore wind farms.

The effects of elevating the clean energy transition to a matter of national security will unfold in the longer term. Short-term measures could become the structural breaks in the energy industry that are necessary to decarbonize on a large scale. This is likely to shift European energy trade, both in terms of share of imports in the energy balance and in terms of the type of energy resources imported. Natural gas will be sourced in the shape of LNG, rather than from pipelines. This might require long-term contracts. Clean liquids from newly emerging energy partners such as Canada and North Africa could replace some of fossil imports. In short, the Ukraine war may well put the EU green energy transition on steroids.

POLICY CONCLUSIONS: FUTURE PERSPECTIVES AND STRATEGIC OPTIONS

The measures that the EU and its member states are putting into place to meet the challenges raised by Russia's invasion of Ukraine and weaponization of energy have been developed at break-neck speed. The core short-term challenges are to ensure sufficient supply of energy for the coming winter, manage the social and economic consequences of high prices, and maintain political unity in the face of Moscow's aggression. But whatever the outcome of Russia's war in Ukraine – be it victory, loss, a frozen conflict, or even escalation – these policy choices will have significant long-term consequences. How this plays out will depend on which goals are prioritized: price, resilience, or security. The EU faces three scenarios, each of which is also a strategic option for EU energy policy.

The first scenario is a return to the pre-crisis liberal EU energy regime. This means prioritizing price and accepting the risks of high-cost energy crises in the future. A change of regime in Russia is arguably a precondition for such a strategy. This could reverse the structural changes in demand away from gas to other fuels and restore the idea of gas as bridge fuel for the green transition. The main advantage of this scenario is tough gas-on-gas competition benefiting the EU again, if low-cost pipeline gas from Russia comes back. However, as the present crisis drives home, it has important drawbacks both in terms of security and political economy. It does not price in the political risk and leaves the EU vulnerable to Russian weaponization of energy in the future. Moreover, it leaves many EU firms stuck with the long-term, high priced energy deals they are striking with LNG suppliers this year, raising doubts over the economic validity of such a scenario for a key sector in the European economy. Finally, the return to the status quo ante becomes more unlikely the longer the crisis continues, as governments, firms, and households are taking measures with lasting effect.

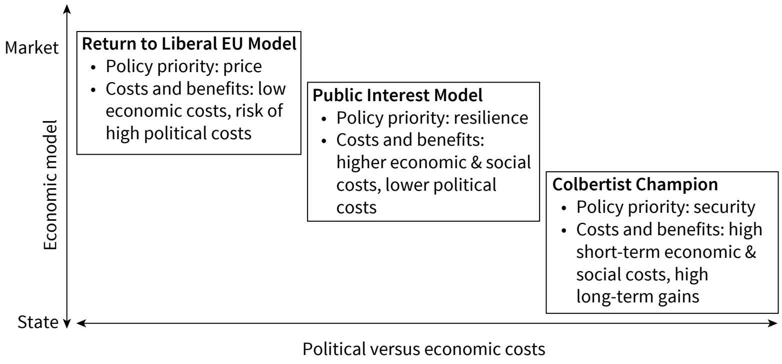
The second scenario centers on building a more robust regime, which prices in the negative externalities (political and environmental) associated with a liberal market model. This scenario puts the public interest first, defined as prioritizing resilience. The economic costs are significantly higher than in the liberal scenario, but they are known and involve less exposure to risk. Costs stem from improving storage, enhancing LNG import facilities, and interconnecting national markets in the short term, and accelerating the structural demand-shift away from gas to renewables in the medium term. It features long-term contracts with non-Russian external gas suppliers, which in turn may require protecting high-cost importers from competition from cheap Russian gas. The advantage of this scenario lies in combining market competition with risk management, both in terms of security and the energy transition. But it involves social and economic costs, as energy prices affect industry, the labor market, and the cost of living.

The third scenario, and strategic option, assigns the state a bigger role in the energy economy. Here, energy security is the priority. It goes hand in hand with a fast green transition that is not just managed, but actively steered, by governments. It requires the EU to abandon its somewhat unique liberal approach to energy and makes it join much of the other importing blocs in treating oil and gas first and foremost as strategic goods. Competition is no longer the principal instrument for ensuring supply security. In this scenario, EU member states promote national champions or European champions: firms that are big enough to play a dominant role on world markets, and robust enough to make long-term deals and hedge risks though their sheer size and ability to trade in volumes that shape international prices. At home this means a more Colbertist approach to trade, distribution, infrastructure, and storage: state ownership and more comprehensive EU regulation across the board. As a corollary, market competition may play a reduced role in setting prices and promoting renewable energy. The costs and benefits associated with this scenario go in the same direction as in the second scenario but are bigger in magnitude: both the short-term costs and long-term benefits are higher.

The EU is at a crossroads. The policy choices that are made in the coming months to meet urgent challenges have long-term implications. Both short-term policy options and long-term strategies are contested at the time of writing (October 2022). Yet one thing is almost certain: The EU's era of low gas prices is over. A model that has served the EUs economy for some 20 years has most likely come to an end. And so has the liberal paradigm that served as its blueprint.

Figure 1

The EU's Strategic Options in Energy Policy



Source: Authors' compilation.

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Reyer Gerlagh, Matti Liski and *Iivo Vehviläinen*

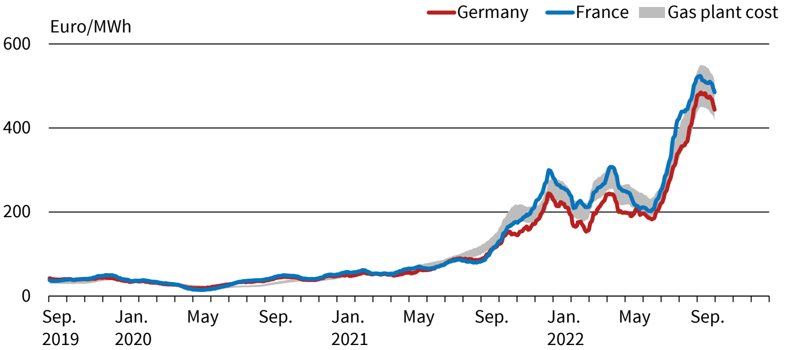
Stabilizing the EU Electricity Market: Mandatory Demand Reduction and a Lower Price Cap

KEY MESSAGES

- **A coordinated roll-out of energy-demand reduction would create large external benefits in Europe.**
- **Lowering the price cap to €1,000 /MWh in the harmonized EU electricity market would save on costs for users, would not harm supply, and would substantially reduce the need for redistribution policies.**
- **European electricity market operators should prepare for the coming winter by adopting well-defined protocols for not only managing electricity shortage situations by rationing, but also for managing extreme spot price levels by rationing. This calls for dynamic price level targets that depend on how demand responsiveness develops during the crises.**

Electricity and natural gas are essential goods in modern society. Aware of this, the Russian strategy in the build-up to and during the Ukraine war was (and is) to use the scarcity of energy supply to blackmail Europe. Russian gas made up about one-third of EU gas consumption before the onset of the war; the subsequent reduction in supplies increased EU gas prices about tenfold compared to the long-run stable prices before 2020. As gas-fired power plants provide the variable capacity to accommodate changing electricity demand and intermittent renewable supply, rising and volatile gas prices are almost one-to-one transmitted to the wholesale electricity market. Electricity spot prices thus moved in tandem up with gas prices, as Figure 1 shows.

Figure 1
Electricity Current Market Prices



Note: Rolling 30 day mean of the day-ahead electricity spot prices in France and Germany. "Gas plant costs" present the short-run marginal cost of a typical gas plant using gas spot price, carbon price, and efficiency range from 45% to 55%. The gap between electricity-from-gas and average electricity prices arises because of hours in which renewable supply is sufficient to push gas power plants out of the supply chain.
Source: Authors' calculations. © ifo Institute

However, the electricity wholesale spot markets are volatile, and most households and industry purchase electricity at prices that are fixed for some months, quarters, or years ahead. The forward market prices are traded in the derivatives contract markets that reflect the market's expectations of the costs of gas and electricity production. In the past, future markets provided stability for producers and consumers alike, but the crisis has removed the stability; the prices of electricity futures have risen as much as spot prices after spring 2022, and prices for 2023 even peaked above current spot prices at the end of August 2022, as Figure 2 details.

The two graphs support two observations:

- Demand for gas and electricity is very inelastic: reducing gas supplies by about one-third increases prices by a factor of 10. It is not a short-term phenomenon; it applies to 2023 equally.
- From April 2022 onwards, future electricity prices rose above the future costs of gas-based power, especially for France but also for Germany. That is, the electricity crisis deepens in these countries beyond the gas crisis (Bloomberg 2022b; Bundesnetzagentur 2022; Reuters 2022).

Both observations lead to non-standard policy recommendations. First, for the coming winter, Europe needs to reduce energy demand by more than what market prices can deliver. Second, Europe needs to protect the electricity price against "too-high" price hikes for those hours when supply cannot match demand. Below we discuss both recommendations in detail.

DEMAND-SIDE POLICIES

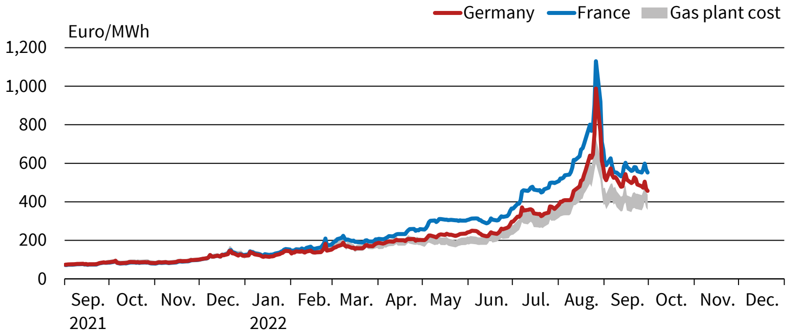
At the EU level, a variety of interventions have been entertained, ranging from the suspension of the markets to price ceilings and other non-market mechanisms (European Commission 2202a). The most recent proposal calls for mandatory demand reductions, interventions in excessive profits (windfall taxes), and the redistribution of those profits to consumers (European Commission 2022b). Here we highlight the importance of, and reasoning behind, mandatory energy savings.

The 2022 price hike is an unambiguous sign of a very low elasticity of demand for gas. If a reduction in supply by 30 percent increases prices by a factor of 10, the elasticity of demand is about –0.2. The hourly electricity spot markets show even lower values for demand elasticity during peak hours. A key reason for the low elasticity is that most consumers, firms, and households do not respond much to prices in the short term. Demand is sticky, based on behavior calibrated during previous periods when prices were low. Stickiness results in misallocation when prices deviate from the past. When prices rise as much as in 2022, it becomes efficient to nudge or force consumers into energy savings, since a sticky market on its own cannot deliver an efficient outcome.

Importantly, inelastic demand also implies an inverse effect: small reductions in demand can bring about large price drops. Suppose Europe succeeds in reducing energy demand (at constant prices) by 1 percent. Fixed supply and inelastic demand with a –0.2 elasticity means that prices would fall by 5 percent. The households and firms that initiated the demand reduction evaluate the gains from their own actions as 1 percent of energy expenditures. They do not attribute the price reduction to their own actions and consider it an external change in the market, even if it is endogenous. Stated differently, indirect aggregate cost reductions exceed direct individual cost reductions by a factor of 5. Every euro that a company or household saves on its energy bill by being frugal saves 5 euros elsewhere in Europe. The effect is akin to, but not equal to, a standard externality. The price advantage for consumers in Europe is paid for by gas producers, including Russia. It seems acceptable in these times not to include declining profits for Russia in our measure of welfare.

We now have two reasons for market intervention: stickiness at the individual level, and inelastic demand at the aggregate level, leading to a positive energy savings externality. We fully support the European Commission when her president in her speech on September 7 announced targeted policies to reduce overall energy demand by 10 percent, and peak-hour electricity use by at least 5 percent. Belgium, Germany, Hungary, Ireland, Italy, and Spain have introduced regulation whereby offices may not be heated above 19 degrees Celcius. Germany further-

Figure 2
Electricity Future Market Prices



Note: Electricity forward market prices for the year 2023 in France and Germany, and the short-run marginal cost of a gas-fired power plant with a 45–55% efficiency using 2023 forwart price for gas.
Source: Authors' calculations.
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more has banned the heating of private swimming pools and public areas with open doors. Such measures may appear draconian, but we believe that the social gains provide sufficient reasoning for support. Europe needs a coordinated roll-out of energy demand reduction.

ELECTRICITY PRICE RISES BEYOND MARGINAL COSTS

Figure 2 depicts the extraordinary hike in the market's electricity price expectations. Here, we connect a significant part of the increase to higher risk premiums: the market expects frequent events where supply falls short of demand, with electricity rationing, and prices set by an administrative price cap.

Beginning in 2022, the EU set an electricity wholesale price cap of €3,000/MWh, as well as an automated rule stipulating the ceiling to increase by €1,000/MWh five weeks after each time the realized market price, at any hour in any market area within the EU, was above 60% of the current price limit. The rule was triggered in April and August 2022. A high and increasing price cap, as is the current protocol in Europe, increases the average costs of electricity – and substantially so. We thus argue for a reduced price cap for the duration of the current energy crisis.

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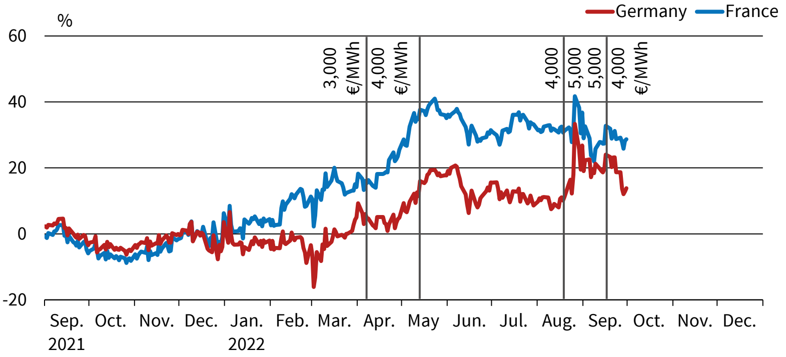
Figure 3
Risk Premium



Note: Differences between the electricity forward 2023 market prices in France and Germany, and the short-run marginal cost of a typical gas-fired power plant (cf. with Fig. 2).
Source: Authors' calculations. © ifo Institute

Figure 3 shows the risk premium; it equals the electricity selling price minus gas-power production costs divided by the price, based on Figure 2. In France, the risk premium started to increase in spring of 2022. There were two small events with substantive consequences that we believe connect to this risk premium. First, on April 4, 2022 (vertical red line), the hourly wholesale price of electricity in France reached the current price cap, after which the EU protocol raised the price cap automatically from €3,000/MWh to €4,000/MWh (CRE 2022a). Importantly, while the event took place in one area, the price cap increase applied to the wholesale market for the entire EU, after a regulatory five weeks' delay (dashed line). The second event occurred on August 17, 2022, when prices in the Baltics area hit the EU's price ceiling, automatically lifting the cap throughout the EU to €5,000/MWh (second vertical red line) (NEMO Committee 2022). The two events proved to the market that electricity prices can rise above the gas-generated power costs.

The market anticipates that such events may happen more frequently, or over longer periods, in 2023. (CRE 2022b). The risk of having to deliver electricity while prices skyrocket demands a substantial risk premium. Importantly, the EU protocol – put on hold (on September 13, 2022, third vertical red line in Figure 2) but we do not know for how lo ng – raises the risk premium each time the market observes a supply shortage. Not only does the high price yield enormous rents for energy companies, it also risks destroying the electricity future market.

Indeed, the high prices of Figure 1 call into question the stability of Europe's integrated electricity market. Firms have sold contracts at normal price levels and now face margin calls; they must prove solvency and provide collateral, measured at over a thousand billion euros (Bloomberg 2022a), for their positions at central counterparty clearing houses (CCPs). As a response, Finnish and Swedish governments have already committed to 33 billion euros in additional loans and guarantees to avoid a "Lehman Brothers of energy industry" (Financial Times 2022).

The potential for systemic risk had already been predicted earlier (Systemic Risk Council 2022b); the current market conditions prove that the optimistic views on preparedness were wrong (Systemic Risk Council 2022a).

The high prices demand a response: it is crucial to rein in expectations about how high the price of electricity will be allowed to rise in the wholesale market in the coming winter. EU decision-makers should commit to do "whatever it takes" to bring price control to the wholesale market. The sooner the EU decides what measures to take to reduce price expectations, the faster the prices of derivatives will fall. Demand rationing as discussed above is one immediate implication of this argument. But the risk premium, that is, the price gap with marginal costs, suggests a distinct electricity market crisis additional to the gas market crisis, which requires a targeted response.

EFFICIENT RATIONING

Electricity markets have been designed with the aim of efficient allocation in normal times. Part of the blueprint has been to allow for the possibility of occasional high prices at infrequent times, when peak demand combines with an unexpected cut in supply. But now the market faces a persistent supply shock, which together with inelastic demand leads to extreme price levels that are not rare events, but can become recurrent over weeks or months, before the long-term adjustments lead to a new equilibrium. Conditions, mechanisms, and incentives are different and require other rules than those in times of stable energy supply.

The ceiling price is a social contract that defines what can be charged for electricity if there is a shortage. Its level should be such that producers are compensated and thus have an incentive to invest and keep capacity for disruptive situations. The high price is acceptable when it is rarely paid, and only over short periods. The crisis caused by the Russian invasion is different because the disturbance is persistent. The ceiling price must be lowered when the frequency and length of disturbances increases, and can be lowered while keeping the same overall compensation promised to reserve suppliers. We believe a price cap of €1,000/MWh is more reasonable under the current circumstances, and it will substantially reduce the risk premium.

A common concern is that lowering maximum prices may lead to reduced supply, increasing the need for quantity rationing. The data, however, tell us this problem is insignificant. There is virtually no additional supply above €1,000 /MWh.

Despite the valuable efforts to increase demand elasticity across Europe, significant stickiness of demand likely remains. One reason is that both private and industrial consumers' technology choices have been optimized for price expectations that do not include the possibility of war in Europe. In this new state of the world, the past choices have led to a misallocation in the market that cannot be immediately resolved. In a working paper (Reyer, Liski and Vehviläinen 2022), we show that the efficient intervention corrects for the misallocation by introducing an aggregate "demand response" through rationing not only when the market fails to clear, but whenever the market price exceeds the social value of consumption.

We calculate the social value of rationing using basic price theory, and illustrate it in a specific context, the Nordic market for wholesale electricity (see Figure 4). The supply and demand bids to the exchange contain information on the social value of rationing, and they form the basis for calculating the optimal price cap, hour by hour. The bids indicate how the demand changes in response to the shock, which is essential for the optimal adjustment of the price cap. In any given hour, if the clearing price rises above the optimal price cap, the mechanism implements the cap by an elimination procedure for the demand bids to obtain the required rationing. We quantify the mechanism using the actual bids in 2019–2022 as data.

In our working paper, we find several strong predictions for the optimal intervention. First, under persistent supply crises, the optimal price cap is only a fraction of the actual harmonized EU price cap. The rudimentary reason for the difference is that the harmonized price cap pays no attention to the welfare gains from a demand response achieved through rationing. The mechanism has no bearing on market clearing in normal times; it gained traction only after the onset of the supply crises in winter 2021–2022. The second prediction is that with a lower technical price cap, the rationed quantities remain minuscule in relation to total volumes in the market, suggesting that executing the physical rationing in regions that participate in trading should not be a major hurdle. Third, the intervention has strong distributional implications; a small demand reduction leads to a large price drop. In our stress tests, the policy leads to transfers from producers to consumers measured in billions of euros over a short period of time, although it should be borne in mind that our theory is justified by efficiency and not by redistribution objectives. Finally, the mechanism can be adopted without reforming the market clearing rules in place.

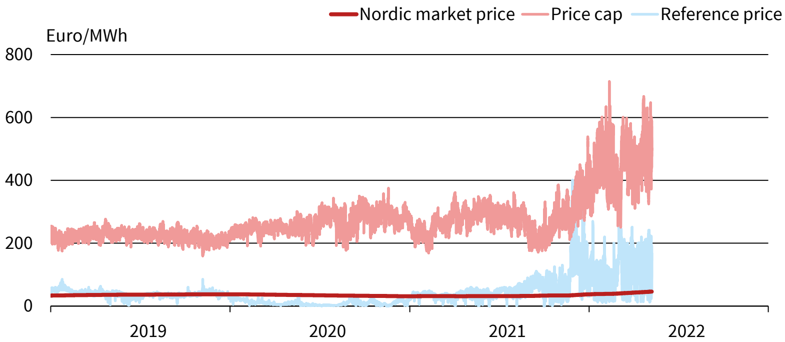
These results remind us that the price control and demand response are two sides of the same coin: when demand response is missing, the optimal policy involves price control. Put alternatively, the efforts to increase demand responsiveness are needed, but if they do not result in a significant increase in such responsiveness, price controls have their place in policy packages.

POLICY CONCLUSIONS

In these times of recurring supply shortages, the price of electricity for users should not run into the thousands of euros per MWh. Mandatory energy savings and lowering the price cap save on costs for users, do not harm supply, and substantially reduce the need for redistribution policies. We recommend that the technical price cap in the harmonized EU electricity market be lowered to €1,000/MWh to protect the integrity of the market. This price ceiling would not distort allocations to any significant degree, and it would further stabilize the forward market by reducing the system-level risks in the coming winter.

In addition to these measures, we strongly recommend that the European electricity market operators prepare for the coming winter by adopting well-defined protocols for not only managing electricity shortage situations by rationing, but also for managing extreme spot price levels by rationing. This calls for dynamic price level targets that depend on how the demand responsiveness develops during the crises. European day-ahead electricity clearing is done simultaneously with the same clearing algorithm (EUPHEMIA) for 25 countries. The first-best approach is to apply the price-control protocol at this EU-level market clearing. It is important for the EU market to remain integrated and avoid fragmentation in the name of "energy nationalism" because in that case the supply capacity in the EU is de facto reduced below the level that would be technically available to the EU member states.

Figure 4
Nordic Market Price, Price Cap, and the Reference Price



Note: Data form January 1, 2019 to May 10, 2022. The reference price is a rolling three-year average of the historical market prices.
Source: Authors' calculations. © Authors

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Daniel Gros

Implications of Gas Scarcity for European Energy Policy

KEY MESSAGES

- **The global supply of natural gas is fixed in the short run. Europe can replace the missing Russian gas only by bidding more than consumers elsewhere, especially in Asia, are willing to pay**
- **The supply of gas available for Europe is thus highly inelastic; therefore, the marginal cost is an order of magnitude higher than the price**
- **Consumers do not factor this externality in their decisions. They should be given extra incentives to save**
- **Individual countries will engage in insufficient gas-saving efforts because they do not take into account that their national gas savings will benefit all their partners through lower import prices**
- **EU policy should concentrate on ways to save gas, not on how consumers are protected from the current high prices**

The nature of the "gas challenge" facing Europe has become crystal clear since the explosions which put the Nordstream pipeline(s) out of operation. Before it invaded Ukraine, Russia met over a third of Europe's gas needs. Its share fell until summer to less than 10 percent, and even this remainder seems destined to stop soon. European countries were able to compensate for the loss of Russian gas mainly through higher imports from other sources and energy savings, and allowing gas storage levels to increase more quickly than planned. More of both will be needed during the winter heating season.

All EU governments are desperately trying to find additional sources, mostly in the form of liquefied natural gas, LNG. But this takes time because most LNG is committed under long-term contracts. Some reduction in gas use in Europe during the next winter is thus unavoidable.

On the savings front, Europe's record so far has been a mixed bag. The high price of gas has already led industry to cut back and resort to alternative fuels or reduce production, with German companies using 20 percent less gas in June compared to last year. It seems that the price signal has had an impact on German industry. However, in other countries little reduction in gas consumption has occurred.

Industry accounts for the bulk of gas demand during the summer months because during the spring and summer little gas is needed for heating. Winter will be very different. During the heating season, demand for gas increases fourfold and most of this additional demand comes from households. European governments are already imploring consumers to turn down the thermostats and take fewer hot showers. But such appeals are likely to have little impact. In Italy, the government has decided to shorten the heating season by a few weeks – but this decision applies only to condominiums. Tightening rules for public buildings is expected to produce similarly small savings.

Ensuring that households take gas scarcity to heart will be crucial for getting Europe through the winter without having to resort to rationing. This will not be easy, since households cannot quickly switch fuel and, as the weather gets colder, it will be difficult to convince people to cut back on heating their homes.

A key element in reducing the fiscal cost of a gas savings subsidy is the fact that VAT revenues increase automatically with higher gas prices. Governments could rebate these revenues to those consumers who reduce their gas consumption. This would be much preferable to reducing VAT rates on energy in general, which lowers the price for all consumers and provides no incentive for savings.

THE HIGH COST OF NOT SAVING GAS

Increasing the production of gas takes time. Contrary to oil, there is no spare capacity in gas because it is technically difficult to reduce production from an existing field. However, for Europe, supply is not given, as it depends on the global price, which induces consumers elsewhere, especially in Asia, to use less gas.

This implies that while one can take the global supply of gas as a given in the very short run (i.e., the next few months), Europe can increase its imports if it is willing to pay a higher price.

One can thus define a supply curve at the EU level by $Q=Q(p)$, with $Q'>0$. One must assume any additional gas for the EU would come from imports (and, equivalently, any cubic meter not consumed in Europe reduces European import demand by one cubic meter).

What is then the marginal benefit from any additional quantity not consumed? It is the change in the gas import bill (= pQ) that

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arises because of a reduction in European demand, dQ. Formally, this is given by the following:

(1) Marginal cost of gas

$$= \frac{d(import\ bill)}{dQ} = \frac{d(pQ)}{dQ} = p + Q\frac{dp}{dQ} = p + Q\frac{pdp}{pdQ},$$

which can be written in terms of the elasticity of the gas supply abroad (for the EU), which is defined as

$$(2)\ \sigma \equiv \frac{dQ/_{Q}}{dp/_{p}}.$$

Using this elasticity, the marginal cost can be expressed more simply as

(3) Marginal cost of gas

$$= \frac{d(import\ bill)}{dQ} = p(1 + \sigma^{-1}).$$

A first immediate corollary is that the cost of additional imports is higher than the price. How much higher depends on the (inverse of the) elasticity of foreign supply.

This elasticity of gas available for import by the EU must be assumed to be very low in the short run because it is based on consumers elsewhere reducing their gas use, thus liberating some gas for Europe. One should thus assume that it is of a similar order of magnitude as the elasticity of demand within Europe, which is often estimated to be only 0.1 (but with the opposite sign).

The reason for this large difference between the price and the marginal cost is that higher import demand leads to a higher import price, which implies large terms of trade loss for Europe.

This simple consideration shows that the benefit from importing one less cubic meter of gas is much higher than the price quoted on the spot market. With a rather inelastic supply (as one must assume since demand abroad is likely to be as inelastic as demand in Europe), the benefit could be several times higher. For example, an elasticity of foreign supply (= elasticity of household demand abroad, i.e., the countries from which the additional LNG would have to be diverted from, like Japan or Korea) of only 0.1, the equation above would lead to the conclusion that the marginal cost of gas is 11(= 1+1/0.1) times higher than the price.

The intuition behind this result is straightforward: each unit of gas not consumed in Europe diminishes demand on the LNG market, which is (in the very short run) very inelastic. This means that even a small amount of gas saved in Europe can have a large impact on the price and thus on the cost of importing all gas.

An individual gas consumer or individual government does not take this effect into account because an individual consumer (or a single member country) accounts only for a fraction of EU consumption. If one denotes the share of overall EU gas consumption of any individual country by α, the marginal cost perceived reduces to the following:

(4) Marginal cost of gas to individual country

$$= \frac{d(import\ bill)}{dQ} = p(1 + \alpha\sigma^{-1}).$$

For a very small entity (a single firm or a small member country), α would be very small and the marginal cost of importing more gas would thus be close to the price. This explains why individual governments act as if their actions do not affect the import price of the EU. There is thus an external effect operating, whereby each individual government does not face a strong incentive to encourage gas savings at home.

This is why some EU member countries have announced the intention to give special subsidies to energy-intensive industries to allow them to continue production and why Spain has elected to subsidize the cost of gas for power generation. These policies impose enormous economic costs. The opposite should be done. Governments should offer energy-intensive industries subsidies to close down temporarily or at least diminish production, and these subsidies should be proportional to the gas saved in this way. However, individual countries do not follow this type of policies because they do not take into account the impact of their actions on the import price.

However, at the EU level there should be a strong interest in incentivizing gas savings and encouraging member states to follow this policy. Unfortunately, there is little the EU can do to force countries to change their policies. The “Save Gas for a Safe Winter” plan of the European Commission contains only a “voluntary” gas demand reduction target of 15 percent from 1 August 2022 to 31 March 2023.

A GAS SAVINGS SUBSIDY FOR HOUSEHOLDS

The high spot market prices for gas over the last months are now feeding through to higher prices for consumers.[1]

A regular survey of residential energy costs finds that, on average across the 27 EU capitals, household gas prices have roughly doubled since August 2021. This is an average; some countries (like France) have limited the price increase, whereas in others the price has risen to three times the status quo (average of previous years), but with new prices applying mostly only to consumers who switch suppliers. Many consumers still have old contracts at prices which are not indexed on the market price and therefore have not increased by much.

Thus, the reality is that many consumers do not face even the market price and, as argued above, even for those who do face higher prices, the price does not reflect the marginal cost to the EU as a whole.

One way to increase the incentive for consumers to save on gas would be a “gas savings subsidy”: the

[1] The Rotterdam TTF spot price is now around 200 euros per megawatt hour, but the average price paid by German imports is still below 100 euros.

government should temporarily offer consumers a “subsidy” for any “reduction” in their use of gas (instead of subsidizing gas consumption). The aim would be to further increase the marginal benefit households (or firms) obtain from gas savings during the crucial coming heating season.

In concrete terms, the government could offer households the following scheme: households pay the market price for the gas they consume. But the government provides them with a payment equal to x euros per cubic meter (or kWh) of gas that is saved during the winter of 2022/3 compared to the previous heating period (e.g., October to March 2021/2).[2]

This would mean that for households the marginal gain from reducing gas consumption below the benchmark of last year would be even higher than the price they pay. The benefit for consumers of each cubic meter saved would equal to the sum of the price and the subsidy, increasing the incentive to save.

THE COST FOR PUBLIC FINANCES

The cost for public finances would of course depend on the take-up of the scheme. Here, we provide a simple simulation for Germany, assuming a strong reaction by consumers.

The starting point is that German households consume a bit less than 300 billion kWh in gas per calendar year (most of which over the winter season).[3] If households reduce their gas consumption by 20 percent (relative to 2021/22), the cost to the government would be 60 billion kWh times the subsidy. This savings is possible since a subsidy rate of 12 cents per kWh would amount to 50 percent of the price and can thus be expected to have a significant impact on demand. 12 cents per kWh would lead to a total cost of EUR 7.2 billion (at the country level in Germany) if consumption falls by one-fifth. If households react even more strongly, i.e., if consumption falls by 30 percent, the government would pay households more in subsidies, but the cost would still be moderate, at about EUR 11 billion.

The cost of subsidizing a reduction in gas consumption would thus amount only to a fraction of the overall cost to German public finances of the latest “Doppel Wumms” package, under which the German government put aside EUR 200 billion to ameliorate the burden of high gas prices.

POLICY CONCLUSION

With Russian gas no longer available to Europe, gas has become a very scarce and very expensive resource. Many governments are providing support to households and industry to mitigate the impact of higher energy prices, implicitly subsidizing the use of gas. The opposite approach is needed: scarce public resources should be used to reinforce the incentive to save on gas. If governments pay people to use less gas, prices do not need to go much higher to reduce gas consumption. A gas savings subsidy thus offers a way to satisfy voters (at least partially) without sacrificing economic efficiency.

The gas savings subsidy scheme proposed could make a substantial contribution to lowering household gas demand during the next, absolutely critical, heating season. If extended to large users, it could also change the marginal cost of using gas for industry, without eating into their profits. The fiscal cost should be moderate because the cost of the savings subsidies arises only at the margin (via the amounts saved) instead of the whole amount, as in the case of a general price cap or subsidy.

If a gas savings subsidy could be applied across the EU, it could also lead to lower gas prices, thus lessening the terms-of-trade loss that the current high prices impose on Europe. The fiscal cost of the subsidy would hence implicitly be borne by gas suppliers.

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[2] This would thus remain an exceptional measure, limited to the 2022/3 heating season, because of the exceptional circumstances created by the war in Ukraine. However, the subsidy scheme proposed here should have also some beneficial longer-term effects even if offered only during one heating season, because it induces consumers to find ways to use less gas, which they might not have considered beforehand. Habit formation can have a longer lasting impact on demand.

[3] Over the year, household demand accounts for between 40 percent and 50 percent of all gas use (including the gas employed in power generation), but during the heating season households constitute the bulk of demand. Incentivizing energy-intensive industries to save on gas (maybe by switching fuel, or by reducing production) remains important, but measures to reduce residential demand become more important during the winter. A recent publication by Agora Energiewende provides some basic data and calculations of the potential savings up to 2024 (Baumeister et al. 2022).

Mathias Mier

European and German Electricity Prices in Times of Natural Gas Crisis*

KEY MESSAGES

- **Nuclear stretching operation in Germany until April 15, 2023 brings down German (European) power prices by 6.01 percent (1.51 percent) until April 15, 2023 and by 2.98 percent (0.65 percent) in 2023, saving 4.8 TWH (8.6 TWh) of natural gas and 3.3 Mt (4.5 Mt) of CO_2 emissions in 2023**
- **Nuclear extension in Germany until 2029 would bring down German (European) power prices by 7.31 percent (1.79 percent) in 2023 and 2.95 percent (0.92 percent) in 2024, saving around 6.6 TWh (12.9 TWh) of natural gas and 13.3 Mt (17.8 Mt) of CO_2 emissions in 2023**
- **Reduced 2022 hydropower generation and reduced 2022 French nuclear availability contributes 2.21 percent (32.3 percent) to 2022 German (European) electricity price increases**
- **Windfall tax is preferred to the revenue cap for "inframarginal" generators suggested by the European Commission**

Electricity is different from other goods because it is not sufficiently storable at reasonable cost, i.e., supply must match demand at every point in time to be transportable from supplier to consumer.[1] The overall importance of this constraint is reinforced by the fact that demand varies seasonally and daily, as does the supply from intermittent renewables generators (wind, solar, and hydro). Further complexity arises from the possibility of unpredictable power plant outages, ramping and start-up times/cost of different power plant types, and grid congestion constraints. However, electricity is the most homogenous good in the world because there is no quality difference; meaning that only the cost in combination with technological constraints (ramping up, start-up, congestion) and the availability pattern of a technology (solar peak at noon, higher wind in winter) are decisive.[2]

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[1] Natural gas is easily storable, as is gold, food, or iPhones.
[2] Indeed, electricity does not have the preference factor or social status that comes with food or iPhones.

* All calculations based on assumptions from October 10, 2022.

THE PRINCIPLES OF MARGINAL PRICING AND MERIT ORDER

Marginal costs are the variable part of cost that occur when a generator is used but not when it lies idle.[3] Generators are ordered according to their marginal cost: those with the lowest marginal cost (wind, solar, hydro, nuclear, lignite) are dispatched first, whereas generators with the higher marginal cost (coal, natural gas, biomass, oil) might be used only when demand is high (in peak times) or supply of intermittent generators (wind, solar, hydro) is low (Boiteux 1949; Steiner 1957; Joskow 1976). Such ordering of generators according to their cost gives the supply function and is called merit order. This merit order ensures the cost-optimal dispatch of generating units and provides the optimal long-run incentives to invest in specific technologies at the right locations. The market clears at the intersection of supply and demand, which results in a uniform price in the respective price zone for all dispatched generators, no matter the technology-specific variable cost. The margin between price and variable cost is used to cover the fixed cost of the specific generator.[4] This margin ensures that private investment decisions are socially optimal because private firms or investors, respectively, would invest in a specific technology as long as the margin is sufficient to cover their fixed cost.[5] Note that there are no incentives for generators not to reveal the true cost under such merit order with uniform pricing, because each generator would like to get dispatched as long as the price is above its own variable cost. Bidding below variable cost comes with losses when the resulting price is below own variable cost. Bidding above variable cost might lead to not getting dispatched; such behavior would risk potential revenues to cover fixed costs.[6]

PRINCIPLES INTO MARKET DESIGN

The nature of electricity and the principles of marginal pricing, as well as merit order ranking, spawned two

[3] Variable cost cover fuel cost, cost for CO_2 allowances, and variable operation and maintenance cost.
[4] Fixed cost cover investment cost, including equity cost with reasonable return-on-investments and financing cost, as well as fixed operation and maintenance cost.
[5] Socially optimal in the sense that also consumers are best off, i.e., electricity prices are lowest.
[6] Such bidding of true cost only holds under uniform pricing, but not when generators receive the price of their own bid. Under such a pay-as-bid system, generators do not reveal their true cost but bid above their variable cost. Indeed, it is optimal for generators to bid the expected price from a uniform price auction. The market cannot order generators according to their lowest cost and the resulting system is only optimal when private information about true cost is publicly available.

major philosophies in electricity market design (see Wilson 2002; Cramton 2017; Wolak 2020; Mier 2021). The bid-based approach is mainly applied in Northern America and combines a day-ahead market for optimal scheduling of power plants, given ramping and start-up constraints, with a real-time market for security-constrained economic dispatch that ensures the physical integrity of the demand-equals-supply constraint given all uncertainties that eventually arise. The exchange-based approach is mainly applied in Europe and combines a day-ahead with intraday and balancing markets that overtake the role of the real-time market from the bid-based approach. Theoretically, both systems are equivalent, but intraday and balancing markets show poorer pricing than real-time markets due to generally lower trading volumes (Cramton 2017). The bid-based approach often includes more complicated bid structures to ensure that the dispatch is indeed cost-optimal (ramping/start-up times/cost). The market settlement is not decentralized anymore because of the complicated bid structures. Instead, optimization models determine which generator is dispatched and determine electricity prices via shadow prices of the clearing constraint. The exchange-based approach often only has simple bid structures that do not account for ramping or start-up requirements. Both approaches are well tested and balanced over decades to achieve close to optimal market outcomes. Changes or fundamental revisions would require careful and very precise operations while the market still runs, which is comparable with open-heart surgery in a field hospital while artillery shells out the electricity supply.

CURRENT AND FUTURE PRICE SITUATION

Markets run into stress when the cost of the most expensive and often price-setting technology (natural-gas-fired power plants) suddenly increases, as is currently the case: Natural gas spot prices increased tremendously since Russia invaded Ukraine, peaking at almost 320 €/MWh on August 29, 2022, in the German price zone (Trading Hub Europe). Natural gas future prices were at 270 €/MWh for 2023 and 73 €/MWh for 2026. The minimum electricity day-ahead price on that day was at 516 €/MWh and the peak was at 794 €/MWh. 2023-base-futures were traded at 760 €/MWh and peak-ones at even 1,442 €/MWh. The 2026-futures were at 200 €/MWh and 239 €/MWh, respectively.

However, while the current and future price development for natural gas and electricity shows a slow relaxation, it hints that a pre-crisis level might never reached.[7] For instance, natural gas prices were below 10 €/MWh and electricity prices did not exceed 47 €/MWh on August 22, 2020.

CRISIS SCENARIOS: PRICE RECOVERY OR HIGH PRICES?

Suppose there are two possible developments in the future. In *recovery*, the price for natural gas drops to *pre-pandemic* projected levels (20.20 €/MWh) from 2035 onwards. In *high*, the price remains at twice the level (40.40 €/MWh). Table 1 shows *pre-pandemic* projections and contrasts them with the current developments and with the assumptions from *recovery* and *high*. Observe that prices for hard coal, crude oil, and enriched uranium reach *pre-pandemic* projected levels from 2027 onwards. Lignite prices are indeed unaffected because lignite is not traded. Biomass prices, in turn, are structurally above *pre-pandemic* levels because the general demand for biomass (construction, heating, industry, and electricity generation) increased unexpectedly.

Investment decisions from the *pre-pandemic* case are fixed for the other two scenarios because invest-

[7] Natural gas spot prices dropped since the end of August and were at 100 €/MWh on October 6, 2022. Future prices indeed dropped as well, to 170 €/MWh for 2023 and only 59 €/MWh for 2026. Also, electricity day-ahead prices dropped to 9 €/MWh (minimum) and 360 €/MWh (maximum) for that specific day. Electricity futures cost 438 (base) to 609 (peak) €/MWh for 2023 and only 158 or 203 €/MWh for 2026, respectively. Prices even continued to drop until mid of November.

Table 1

Current and Projected Commodity Prices

Fuel	Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
Biomass	Pre-pandemic	29.1	29.2	29.4	29.5	29.7	29.9	30.0	30.2	30.3	31.5	32.6	33.7	34.9
	Recovery/high	58.2	52.0	45.7	44.9	44.6	44.8	45.0	45.2	45.5	47.2	48.9	50.6	52.3
Hard coal	Pre-pandemic	8.2	8.2	8.2	8.2	8.1	8.1	8.1	8.1	8.0	7.9	7.9	7.8	7.7
	Recovery/high	44.9	32.8	24.5	16.3	12.2	8.1	8.1	8.1	8.0	7.9	7.9	7.8	7.7
Lignite	All	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Natural gas	Pre-pandemic	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
	Recovery	198.5	188.7	120.3	82.9	56.8	40.4	35.3	30.3	25.2	20.2	20.2	20.2	20.2
	High	198.5	188.7	120.3	82.9	56.8	40.4	40.4	40.4	40.4	40.4	40.4	40.4	40.4
Crude oil	Pre-pandemic	41.1	41.2	41.3	41.3	41.4	41.5	41.5	41.6	41.7	42.2	42.7	43.3	43.9
	Recovery/high	61.7	57.7	53.7	49.6	45.5	41.5	41.5	41.6	41.7	42.2	42.7	43.3	43.9
Enriched uranium	Pre-pandemic	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
	Recovery/high	4.9	4.2	3.7	3.3	2.8	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3

Pre-pandemic reflects the projected commodity price developbased on a pre-pandemic sitiation in 2019. Recovery and high reflect true prices in 2022 and deviate only from 2028 onwards for natural gas. All prices are measured in €/MWh. 2022 prices on information gathered on October 6, 2022.
Sources: Tradenomics for current levels; natural gas price development until 2026 from EEX; all other price developments are based on own assumtions.

ment decisions are sticky. Photovoltaic (wind onshore, offshore) investments are fixed until the end of 2022 (2023, 2024). Slight increases are possible in the three following years. For example, Germany can expand photovoltaic capacity by 150 percent of *pre-pandemic* planned expansion plus 5 GW on top of this value in 2023. In 2024 (2025), those values increase to 200 percent (300 percent) and 10 (15) GW. With the same time lags, wind onshore and offshore can be adjusted. The 5, 10, and 15 GW are reference values for Germany and adjusted according to demand shares for the other regions, i.e., countries with lower demand may add less capacity. Intuitively, it is not possible to plan and build a new wind park within five years, but it might be possible to add a couple of wind turbines to already-used or planned locations or even antedate projects. All other technologies are fixed until 2030 because it takes a reasonable number of years to plan, approve, and build power plants. This is particularly severe for nuclear power plants; therefore, all nuclear investments are fixed until 2035.

HIGH PRICE VARIATIONS: NUCLEAR EXTENSION OR STRETCHING OPERATION?

The *high* price scenario seems to be the most reasonable given the current situation. Germany planned to exit nuclear power by the end of 2022, but the current situation brought up political discussions about extending (new fuel rods) or stretching (no new fuel rods) the usage of nuclear power in Germany to reduce electricity prices (and increase grid stability considering the North-South differential). On October 17, 2022, stretching operation of the three still-running German nuclear plants until April 15, 2023 became the official policy. However, an extension of the three still-running German nuclear power plants by 7 years until 2029 is still under discussion.

FURTHER PROBLEMS: MISSING RAIN AND FRENCH NUCLEAR POWER

2022 has been one of the driest years on record, with hydropower generation currently around 10 percent lower than it was in 2020 or 2021, respectively. Moreover, half of the nuclear power plants in France are offline, mainly due to unexpected technical problems. Nuclear power makes up 70 percent of French electricity production and accounts for more than half of the entire European nuclear share. *Pre-pandemic* projections missed these two problems. Real-world data from the OECD about monthly electricity generation by technology is used to calibrate for those effects. Data for the years 2020 and 2021 are available in full, but for 2022 only for January to April. For *pre-pandemic* projections, the average for 2020 and 2021 is used for 2022. For French nuclear power, only 2020 is used because 2021 was already affected by technical problems. For the two crisis scenarios, the monthly availability of those sources is then reduced according to the reduced availability in the first four months of 2022. Altogether, this reduces both nuclear and hydropower availability by more than 10 percent.[8]

MODEL

I use EUREGEN that optimizes dispatch, investment, and decommissioning decisions in 28 countries (EU27 minus Cyprus and Malta plus Norway, Switzerland, and United Kingdom) of the European power market to obtain the cost-minimal technology mix.[9] EUREGEN optimizes years 2020 to 2030 and from 2035 in five-year steps intertemporally, thereby using a less fine-grained hourly resolution per year. European electricity demand is assumed to keep almost constant until 2025 (at around 3,000 TWh) and then more than doubles until 2050 (to 6,200 TWh) due to electrification (heating, mobility, hydrogen production), intensified cooling, digitalization, and economic growth. The other driving force is the EU ETS, including the market stability reserve (MSR), that is adjusted to reflect recent ambitions regarding carbon neutrality by 2045. I link EUREGEN iteratively with a model of the EU ETS that simulates in detail the dynamics of the MSR (Azarova and Mier 2021). I determine industrial emissions within the EU ETS based on a marginal abatement curve in relation to electricity sector emissions for our *pre-pandemic* projection but keep industrial emissions constant for the two crisis scenarios because industrial emissions currently show an adverse behavior to electricity emissions.[10]

RESULTS

Figure 1 shows the technology mix and related CO_2 emissions when taking *pre-pandemic* projections (first bar in each cluster), price *recovery* (second), or *high* prices (third) as given. Observe that the CO_2 emissions

[8] Maintenance intervals of still-running French nuclear power plants were adjusted and usage of the working fleet intensified, so that overall nuclear production in 2022 is projected to drop only from 681 to 655 TWh (all over Europe). This effect covers rebound effects of high natural gas prices. Hydropower generation drops from 559 to 475 TWh.

[9] See Weissbart and Blanford (2019), Mier, Adelowo and Weissbart (2022), and Mier and Adelowo (2022) for the basics of the model; and Mier and Weissbart (2020), and Azarova and Mier (2021) for some applications. Investment cost functions are adjusted according to Mier and Azarova (2021 and 2022). Technological calibration mainly stems from Mier et al. (2020 and 2022) and Siala et al. (2022).

[10] There is much similarity to the study setup in Mier (2022). However, the calibration with OECD data is new, and current as well as future price developments are calibrated to the beginning of October (before beginning of August). Demand projections are adjusted so that electricity demand keeps almost constant until 2025 and starts growing from 2026 onwards. Also, the plans of a stretching operation of nuclear plants were not public before and are thus adjusted in accordance with the findings discussed: January 2023 would be used to prepare reactors for the stretching operation. Old fuel rods would be used so that availability is reduced in January to 75 percent (preparation time and due to aged fuel rods), in February to 80 percent, and in March as well as April to 70 percent of maximum power. The extension works with historical availability patterns of nuclear power plants in Germany and lasts until the end of 2029. Another difference is the detailed modeling of German combined-heat-and-power (CHP) generation to account for must-run natural gas in the system due to heating requirements.

are by far higher in the two crisis scenarios than under *pre-pandemic* projections until 2027. This is because the commodity price situation fosters a shift towards lignite and coal, whereas natural gas usage is reduced. Also, biomass is by far more competitive under the two crisis scenarios, although biomass prices are above *pre-pandemic* projections. CO_2 emissions from the crisis scenarios come close to *pre-pandemic* levels in 2027 and are lower from 2028 (*recovery*) or 2030 (*high*) onwards because the MSR contains fewer allowances that are fed back into the system. However, overall invalidation of allowances is 735 million lower in the *high* scenario, hinting that the current crisis is not only bad for electricity bills but also for the climate.[11] Interestingly, even the *recovery* technology mix deviates slightly from the *pre-pandemic* mix because of substantially higher investments in wind and photovoltaic as long as natural gas prices stay high, so that the entire system needs less gas but more nuclear in the long run.

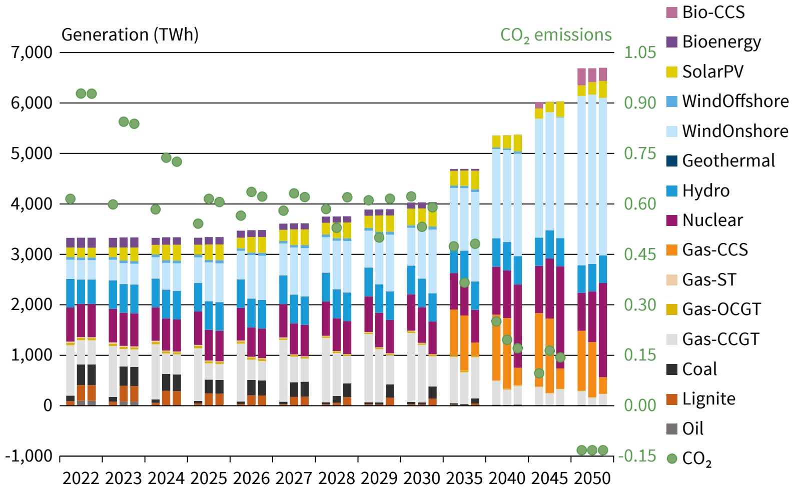
The *high* prices even increase nuclear capacity so that nuclear is used to regionally dominate systems and even partly balance intermittent renewable supply. Shares of gas-fired power plants in combination with carbon capture and storage (Gas-CCS) in turn are by far the lowest. Whether the natural gas price drops to *pre-pandemic* levels or stays at twice that level will decide the future of nuclear power in Europe. The substituting technology would be gas-CCS.

Now let's turn to the electricity prices that result from the different scenario assumptions. Table 2 shows that *pre-pandemic* projections yield European average electricity prices of 65 €/MWh in 2022, increasing slightly until 2030 and then dropping to 62 €/MWh in 2050. Thus, decarbonization of the system (2050 comes with negative CO_2 emissions from electricity generation of -132 Mt that are counterbalanced by 132 Mt of industrial and aviation emissions) and doubled demand increases prices only in the mid-term but not in the long-term due to massive usage of onshore wind and the availability of cheap natural gas in combination with CCS. Natural gas prices remain *high* until 2030 under *recovery* assumptions, resulting in considerably higher prices. However, the long-run price is like the *pre-pandemic* one. In total, early adjustment processes in 2023 to 2026 due to substantially higher natural gas prices finally yield a slightly more expensive system because less gas-CCS is used and substituted by wind and nuclear power. Under *high*, the natural gas price remains high. The price development is like *recovery* until 2027. The long-run equilibrium price is slightly higher than under *recovery* (69 vs. 65 €/MWh).

High imposes a completely different system with structurally higher nuclear and photovoltaic shares.

Figure 1

Technology Mix and Carbon Emissions in the European Electricity Market



Note: This figure shows three scenarios. The pre-pandemic projections (first bar in each cluster), and two crisis scenarios: price recovery (second), or high prices (third). CCS (carbon capture and storage), CCGT (combined cycle gas turbine), ST (steam turbine), OCGT (open cycle gas turbine), and SolarPV (photovoltaics).
Source: Author's calculations.

The latter stems from early investment in 2023 to 2025, while higher nuclear goes back to the doubling of natural gas prices, so that it is optimal to invest heavily into nuclear power from 2040 onwards.[12]

The German price development is like the European one, but German crisis prices are considerably lower because the system is more diversified and less reliant on natural gas. In the two crisis scenarios, the 2022 price is around 150 €/MWh lower, while the 2023 price is lower still, by 38 €/MWh. Moreover, German prices can be further reduced if operation of the three existing nuclear power plants is extended. The price effect would be -7.31 percent in 2023 and -2.95 percent in 2024. From 2026 to 2029, the price effect drops considerably. Stretching operation reduces prices only in 2023, by 2.98 percent. Moreover, nuclear extension adds around 30 TWh of electricity generation to the German system and substitutes around 3.2 TWh (6.5 TWh) of electricity generation by gas-fired power plants in Germany (Europe) in 2023, reflecting 6.6 TWh (12.9 TWh) less natural gas consumption.[13]

Now let's turn to the effect of the reduced nuclear availability in France and of reduced hydropower generation due to low rainfall in the first half of 2022. The German prices under the *high* scenario would be 2.21 percent lower without both occurrences. European prices would be even lower by 32.3 percent, whereas the single effects are at 15.05 percent (for French nuclear) and 19.66 percent (for hydro). This shows that the currently *high* electricity prices (in Europe) are driven to two thirds by higher commodity prices (mainly natural gas); the last third comes from

[11] The invalidation of allowances finally decides about the climate impact of the crisis and related policy measures. The stretching operation (nuclear extension) increases the invalidation volume by 2.6 (24.8) million allowances and thus the true climate impact is considerably lower (higher) than the 2023 savings.

[12] Countries without nuclear history are not able to build nuclear power plants, same as Germany, but in the latter case due to Germany's nuclear exit. The expansion of nuclear thus comes solely from nuclear-using countries. Non-nuclear countries instead invest in gas-CCS.

[13] Other considerable substitutes are bioenergy, coal, lignite, and photovoltaic. Stretching operation saves 4.8 (6.8) TWh of natural gas consumption in Germany (Europe).

Table 2

Electricity Prices in Europe and Germany

Price	Scenario	2022	2023	Jan-Apr 15	2024	2025	2026	2027	2028	2029	2030	2035	2040	2045	2050
European	Pre-pandemic	65	65	78	69	66	68	70	70	72	86	75	67	65	62
	Recovery	371	253	314	177	118	98	85	86	84	84	75	68	67	65
	High		249	311	171	117	98	82	86	86	85	100	76	74	70
	German nuclear extension until 2029	370	245 −1.79*	305 −1.85*	169 −0.92*	115 −1.12*	97 −1.16*	83 0.28*	85 −0.65*	86 −0.65*	86	101	76	74	69
	German nuclear streching until April 2023		248 0.65*	306 −1.51*	171	117	98	82	86	86	85	100	76	74	70
	Normal French nuclear	322 15.05*	250	312	171	117	98	82	86	86	85	100	76	74	70
	Normal European hydro	309 19.66*	250	313	171	117	98	82	86	86	85	100	76	74	70
	Normal French nuclear and European hydro	208 32.30*	250	312	171	117	98	82	86	86	85	100	76	74	70
German	Pre-pandemic	66	68	80	70	66	67	69	70	72	86	76	72	65	62
	Recovery	226	214	295	161	97	88	79	84	82	83	76	72	69	65
	High		211	293	148	93	88	76	81	84	84	100	84	77	70
	German nuclear extension until 2029	244	195 −7.31*	271 −7.43*	144 −2.95*	91 −3.04*	86 −2.27*	76 0.04*	80 −1.30*	82 −2.10*	86	100	83	77	70
	German nuclear streching until April 2023		204 −2.98*	275 −6.01*	148	93	88	76	81	84	84	100	84	77	70
	Normal French nuclear	223 0.66*	211	293	149	94	88	76	81	84	84	100	84	77	70
	Normal European hydro	220 1.78*	211	294	149	93	88	76	81	84	84	100	84	77	70
	Normal French nuclear and European hydro	219 2.21*	211	294	149	94	88	76	81	84	84	100	84	77	70

* in percent.

Pre-pandemic reflects the projected commodity price develop based on a pre-pandemic situation in 2019 with normal French nuclear availability in 2021 an 2022 as well as normal European hydrpower generation in 2022. Recovery and high reflect true prices with sticky investment planning based on a pre-pandemic situation. High scenario variations calculate changes resulting from nuclear extension (until 2029) or streching (until April 15, 2023) operation. Normal French nuclear and normal European hydro calculate prices under normal French nuclear availability and normal European hydrpower generation.

Source: Authors` calculations.

the unique situation of low hydropower generation and low nuclear generation in France.

POLICY CONCLUSIONS

The European electricity system is under stress because natural gas is essential to ensure reliability of service and satisfy demand. The current answer to this stress still only takes the form of high electricity prices, which are predicted to be six times higher than what they would be without the current natural gas crisis. Germany is better diversified, and price rises are predicted to be less severe. Extending or stretching nuclear usage in Germany would help to bring prices further down, by 7.3 percent or 3 percent in 2023. However, electricity prices are going to drop even without Germany reconsidering its usage of nuclear power as soon as either natural gas prices drop, or the system can adjust through investments to reach a new long-run equilibrium. Investment uncertainty remains high because actors do not know the new equilibrium price of natural gas, which will decide whether Europe is going to be a wind-power-dominated system with gas-CCS as balancing technology, or nuclear becomes an option again.[14]

In reaction to rising prices, policymakers have suggested subsidizing natural gas prices and are discussing capping revenues from high electricity prices for "inframarginal" producers, i.e., those that do not rely on gas (such as renewables, nuclear, and lignite). The European Commission has suggested such a revenue cap.[15] While it would not reduce electricity prices in the short run, because the resulting market price would remain unchanged, it would reduce the "margins" for all "inframarginal" generators to a socially acceptable level. Let us assume that those non-inframarginal generators cover only power plants burning natural gas and suppose the market clearing price is 400 €/MWh. Gas-fired power plants would receive the 400 €/MWh. All other power plants would only receive 180 €/MWh, and the 220 €/MWh gap would be a kind of tax that flows to the government budget and can be used to finance relief packages. Again, the revenue cap would not reduce the bills to final consumers. However, it might play a part in the relief packages to do so.

These changes are theoretically sound. However, when looking into the details trouble starts. For example, a great deal of electricity in Germany is traded over-the-counter (OTC) and thus not exchanged in the spot market. OTC contracts are bilateral, often long-run, delivery obligations. Suppose that generator A and consumer B have such an OTC contract for 2023 promising that A delivers a certain amount of electricity to B at price 300 €/MWh. B is unaffected by the proposed revenue cap and pays 300 €/MWh. How much of those 300 €/MWh stays in A's pocket? This question cannot be easily addressed. Suppose that A generates electricity with gas-fired plants, but also with coal, lignite, nuclear, and renewable energies. How much of each technology is A using to satisfy the contract with B? The situation becomes more complex when A is active on the spot market in parallel. Moreover, the contract is already a portfolio decision and

[14] Nuclear investment cost used are around 6,000 €/kW and social costs stemming from decommissioning or waste disposal are more or less ignored, as was historically the case.

[15] https://ec.europa.eu/commission/presscorner/detail/en/IP_22_5489.

thus A might run into significant trouble in the face of a revenue cap. If all electricity were traded in spot markets and bids were technology-specific, the situation would be less complex, but this is not the case.[16]

On top of the OTC contracts, there are financial assets traded (so-called futures) ensuring a certain price for A. Suppose A bought such a future that ensures him to obtain 600 €/MWh for all electricity produced in 2023. Is such financial contract affected by the revenue cap? If it is, then A would first need to give away 220 €/MWh (400 – 180) from the physical market and then 200 €/MWh or even 400 €/MWh from the financial one? Again, the portfolio of technologies used is not clear because A signed the contract for its entire portfolio.

There is further trouble stemming from such a revenue cap. The definition of "inframarginal" is spongy and contextual. When looking at prices of generators, then power plants burning biomass and oil are also close or even above the mentioned 180 €/MWh, as are combined-heat-and-power plants using biomass, oil, and gas. Coal indeed is below the 180 €/MWh, but in fact often a marginal, i.e., price-setting technology.[17] The role of coal is very important. Should regulators allow massive profits for coal or not? Does this reflect our ambitions to reduce carbon emissions? In the end, much ideology is put into market design by such a revenue cap, while technologies are not treated equally, leading to windfall profits for the lucky ones with the most suitable generation and contract portfolio (OTC, futures). However, the revenue cap would not hamper security of supply, because the margins in the market stay positive, so that providing generation is the best option for each firm in the market. Also, investments are sticky, so that short-term changes in profits do not change the long-term investment incentives no matter whether such revenue cap applies or not. Finally, such a revenue cap would only apply for clean technologies (wind, solar, hydro, nuclear) and lignite as the dirtiest one. But lignite availability is very regional and thus the relevance for the whole of Europe is reduced. Moreover, many of European systems are natural gas-driven and thus a revenue cap would also raise little money, while increasing uncertainty in the market.

Among the possible solutions is to slap a windfall tax on generators to reduce their excess profits. The idea is to allow for a reasonable return-on-investment (ROI), but then tax the profits that exceed such a reasonable ROI – albeit at rates below 100 percent, so as to keep incentives to invest and maximize profits. Suppose that the historical ROI of an electricity generating company is 10 percent. The regulator might allow 20 percent ROI during this crisis, but all profits above this 20 percent would be taxed at a rate of 90 percent. Assume that a big company usually makes profits of €1.5 billion (reflecting a 10 percent ROI), but its 2022 profits hit €10 billion. Of this, €3 billion would be allowed under the "up to 20 percent ROI" rule, and the remaining €7 billion would be taxed at 90 percent, leading to a €6.3 billion contribution to the government budget. €700 million of the excess profit would remain with the company, for a final overall profit of €3.7 billion.

The advantage of such a windfall tax lies in the equal treatment of technologies, thus being less erratic than would be the case under the uncertain definition of "inframarginal" in revenue cap regulation. Focusing on excess profits would also account for the fact that some companies are just lucky due to long-term-delivery natural gas contracts, meaning that the price they currently need to pay for natural gas is below the market price. Such excess profit regulation comes with lots of work, and money lands in governments' coffers with time lags, but public refinancing via debt was not problematic in the last decade. Furthermore, electricity generation is dominated by big companies that can easily shoulder the burden of additional information provision when doing their tax declarations. Such a windfall tax scheme would also entail an additional burden for public authorities, but European society has been in crisis for more than 2.5 years, with certain groups of professionals – nurses, doctors, intensive-care personnel and so on – being asked to devote more time and effort than usual. The difference now would be that officials engaged in regulating electricity supply would be among those asked to dedicate extra work to reduce cost to a socially acceptable level.

While none of the suggested electricity market changes would directly reduce electricity prices – because neither supply would be increased nor demand reduced by such changes – they would indeed contribute to the fiscal purse at times of greatly expanded outlays.

[16] Indeed, bid-based system as applied in Northern America would be far more suitable, because more information is collected, and the market clearing is more centralized.

[17] Actually, intermittent renewables such as hydro, wind, and solar are also often marginal.

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Svetlana A. Ikonnikova and *Sofia Berdysheva*

Managing Energy Security: The Analysis of Interfuel Substitution and International Energy Trade

KEY MESSAGES

- **Energy security and affordability are major concerns in the coming winter as Germany seeks substitutes for Russia's energy supplies**
- **We highlight the role of energy transition on its exposure to energy price shocks and its failure to include security considerations in its trading arrangements**
- **We analyze the global trade of coal, oil, and natural gas to track 1) interfuel switching, and 2) cross-country variance in security of supply (i.e., import concentration)**
- **We examine how energy security and affordability can be improved by domestic production, interfuel demand allocation, and trade balance**
- **We provide policy recommendations on coordination in 1) domestic energy production, 2) energy mix, and 3) new imports by destination, emphasizing the role of multinational coordination.**

Over the past two decades, global energy markets have undergone major shocks and dramatic transformations in demand and supply. The "Shale Revolution" in the US brought new and vast supply possibilities for natural gas and oil, and economic growth in China greatly increased demand for energy. A decade ago, the International Energy Agency's (IEA) report on the future of natural gas envisioned an increasingly prominent role for natural gas in global and individual countries' energy mix as a result of the climate change agenda (Birol et al. 2011). However, reliance on natural gas has put many countries into a vulnerable position because Russia, the top producer and exporter of fossil energy, had severe sanctions imposed on energy supplies after the start of the Russian-Ukrainian war.

Energy scarcity and high prices pose a major threat for an increasing number of countries around the world, including Germany, which was especially dependent on Russian imports. Although energy transition objectives have attracted increasing policy and economic attention, energy security issues are gaining heightened relevance in many countries, especially those with large import and export volumes.

Using UN Comtrade, the BP Statistical database, and IEA data on international energy flows, domestic production, and consumption, we uncover some important patterns in trade concentration. Our analysis suggests that countries not only compete in the markets by determining prices and trade volumes, but also consider the distribution of trade across their trade partners, i.e., optimizing trade concentration (Berdysheva and Ikonnikova 2021).

Expanding our analysis to assess energy portfolios and account for the share of domestic versus imported supplies, we have found that countries with a more balanced portfolio, with respect to both supplier and fuel diversification, are less exposed to security risks.

Using the results of the data analysis and our empirical observations, we discuss Germany's current position and develop policy recommendations. In particular, we point out the need to diversify suppliers, and/or make trade with existing suppliers more balanced in terms of their concentration. In addition, we explain how diversification across fuels and growth in a country's own supply, e.g., through investments in renewables, may help to boost energy security and mitigate potential future risks. We emphasize that governmental support may need to be coordinated across countries when devising energy transition incentives, energy security, and scarcity management measures (i.e., energy rationing). Finally, we highlight the positive impact of such international coordination.

GLOBAL ENERGY BALANCE AND THE GERMAN ECONOMY

While Germany is the European Union's largest economy, its GDP accounting for around 25 percent[1] and its total primary energy consumption (TPEC) for about 20 percent,[2] its share in the global TPEC has fallen from nearly 5 percent in the 1990s to only 2 percent in pre-Covid 2019. Such a dramatic reduction is linked to the decrease in country's energy consumption, which dropped by around 12 percent in total and by 17 percent in per capita terms. A further contributing factor to the change in Germany's position is the growth in global TPEC, almost 75 percent over the past 30 years, largely driven by economic growth in developing countries, in particular China and India.

Motivated by environmental considerations, Germany has incentivized advances in energy efficiency and the transition to low-carbon energy sources, such

[1] Throughout the paper, we use a database developed by compilation of UN Comtrade, the BP Statistical database, and IEA data. Unless mentioned otherwise, we refer to 2019 energy balances for consistency.
[2] In what follows, unless mentioned otherwise, we refer to the database combining BP Statistical Survey data, IEA, and UN Comtrade following Berdysheva and Ikonnikova (2021).

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as wind, solar, biomass, and hydrogen. As a result, not only has Germany's total energy use decreased, but also its fossil fuel use has lessened. Despite being the fourth-largest global economy, with nearly 4.5 percent of the world's GDP, Germany consumes only ~2 percent of the fossil fuels produced globally.[3] In contrast, China, the world's second-largest economy and four times larger than Germany, consumes almost a quarter of the global energy to meet its demand and to fuel economic growth (Table 1).

Following the Kyoto Protocol and then the Paris Agreement, Germany has been replacing high-carbon with low-carbon energy sources, notably by replacing coal and (heating) oil with natural gas (Figure 1, left). A versatile fuel, natural gas is used in (1) heating, with the share of close to 45 percent, (2) power generation, where its share surpassed 30 percent in 2020 and 2021, and in (3) transportation, directly in (compressed) natural gas vehicles and indirectly in electric and fuel cell cars.[4]

Increased use of natural gas has helped Germany address its environmental goals, but it has made its economy more exposed to natural gas market shocks than previously. Germany's position in the international energy trade is remains prominent: it accounts for about 5 percent, 7 percent, and 9 percent of world oil, coal, and natural gas trade, respectively (Dale 2021).

In 2019 and until the war in Ukraine, Germany's primary energy trade partner, Russia, provided about 35 percent of its oil, around 55 percent of its coal, and almost 50 percent of its natural gas imports, both directly and indirectly. The heavy reliance on a single supplier, meeting about 45 percent of the entire country's energy need, has been a concern for several decades (Duffield 2009; Westphal 2014; Ikonnikova and Zwart 2014; Finley 2019). Yet, as its EU neighbors and other large energy buyers, including China, were working on diversifying towards liquefied natural gas (LNG), German policy objectives, focused primarily on the environmental sustainability agenda, paid scant attention to energy security. The transition to clean energy was expected to boost domestic energy production and therewith, to reduce the dependence on the imported fuels. Hence, investing in clean energy solutions should have improved energy security, considering the envisioned future fuel mix with the sharply reduced share of fossil fuel. In this context, the financial gains from trade with Russia were supporting the transition and future security. Neglecting the current security issues, Germany has avoided the costs of diversifying its supplies.

In the current reality, with a growing list of sanctions on Russia and its energy supplies, however, Germany and other countries are faced with energy scarcity and high prices. Our goal in this article is to offer some practical advice on energy mix rebalancing and trade rebooting, using the knowledge gained on energy markets participants' behavior combined with energy security concerns.

ENERGY SECURITY: INTER- AND INTRA-FUEL VIEW

Using UN Comtrade data, our analysis of energy import concentration across countries reveals an interesting pattern. Countries with smaller import volumes exhibit higher concentration, as measured by the Herfindahl-Hirschman Index (HHI).[5] In contrast, most large energy buyers show lower concentration and more even distribution with respect to trade partners (Figure 2). However, Germany has not reduced its supply concentration despite the increasing reliance on natural gas and growing import volumes. It appears as a visible outlier on the plot presenting 2019 data. It

[3] According to the World Bank database.

[4] Based on the 2019 Energy Balance reported by AG-Energiebilanzen.

[5] The HHI varies between 0 and 1. The higher the HHI is, the higher is the concentration and the lower the security.

Table 1

Total Primary Energy Consumption (TPEC) by the Major 2019 Economies as percent of the World TPEC

	Oil	Natural gas	Coal	Nuclear energy	Hydro- electric	Renewables	Total energy
USA	19	22	7	30	6	20	16
China	14	8	52	12	30	23	24
Japan	4	3	3	2	2	4	3
Germany	2	2	1	3	0	7	2
India	5	2	12	2	4	4	6
United Kingdom	2	2	0	2	0	4	1
France	2	1	0	14	1	2	2

Source: Authors' Calculation based on the BP database.

is worth noticing that France, Japan, and China have been especially successful in reducing supplier concentration by expanding the number of trade partners through liquefied natural gas (LNG) trade.

Following Berdysheva and Ikonnikova (2021), we have accounted for domestic production and calculated the concentration of individual non-EU suppliers in Germany's total primary energy import (HHI) and consumption. The latter has been described by the Consumer Security Index (CSI).[6] We have found similar trends of increasing concentration in natural gas and coal. Since the reduction in coal consumption has coincided with the abandonment of domestic production, the security of coal supplies has decreased. Finally, we have considered all the primary energy source concentration and revealed that despite significant investments in renewable energy, there has been only a small change in combined-energy security. We attribute this result to two factors: the cutback in coal and the expansion of natural gas, which together outweigh the gains brought by diversification of the energy mix through renewables.

COMPETITION FOR SECURITY

These observations and our review of ongoing policy discussions in the major global economies motivated us to perform a formal analysis and develop a model in which market participants – namely, buyers and suppliers – try to achieve the best possible trade concentration in addition to trade surplus maximization. This trade concentration, measured through HHI, was used to both characterize and proxy the security of supply, in line with the IEA definition. The outcome of the model describes market interaction and includes 1) the volumes traded (bought or sold) by an individual country, 2) the quantity exchanged between each importer-exporter pair, and 3) the trade concentration index for an individual country and the market as a whole.

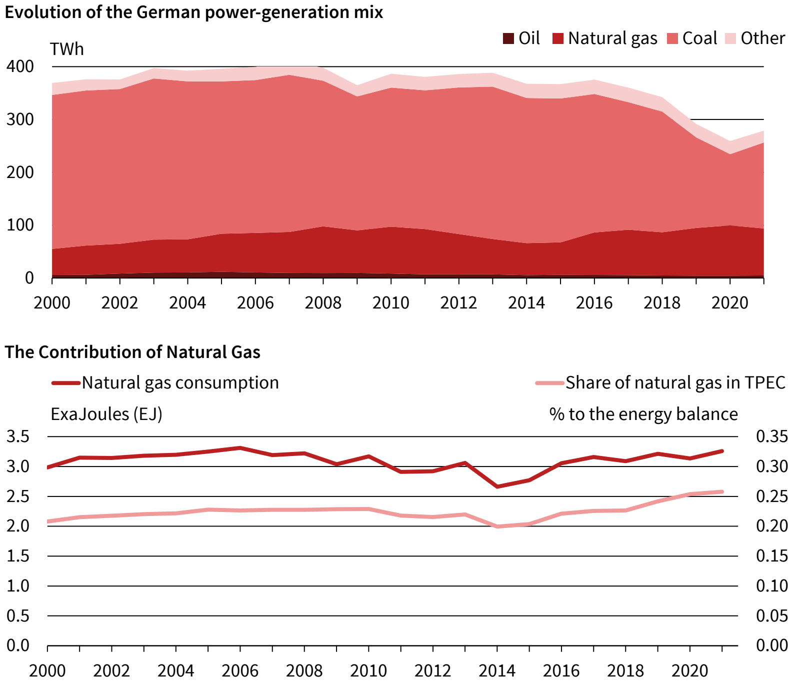
Solving for security and trade surplus optimization, we considered sequential interaction. First, market participants communicate their demand and supply preferences to sign long-term contracts and bid on the spot market. Then, they finalize the trade by choosing the distribution of supply and demand volumes across the trade partners. Instruments such as swap and resale contracts, along with the hub trade, allow for the redistribution of volumes among the EU buyers.

Using data on volumes traded in the EU market, we have found that the optimal distribution of quantities sold and bought correlates with the patterns revealed by our empirical analysis. Hence, we explain the tendency of larger buyers to have a lower concentration index with a view to attaining higher security of supply. Based on our analysis, Germany should trade more with other suppliers than it currently does. Thus, in the case of the natural gas market, we have

[6] With the total consumption instead of the total import used as a base for CSI, its values range between 0 and 1 for importing countries and can be greater than 1 if a country (re-)exports. Thus, Figure 2 indicates that Germany re-export natural gas and exports coal.

Figure 1

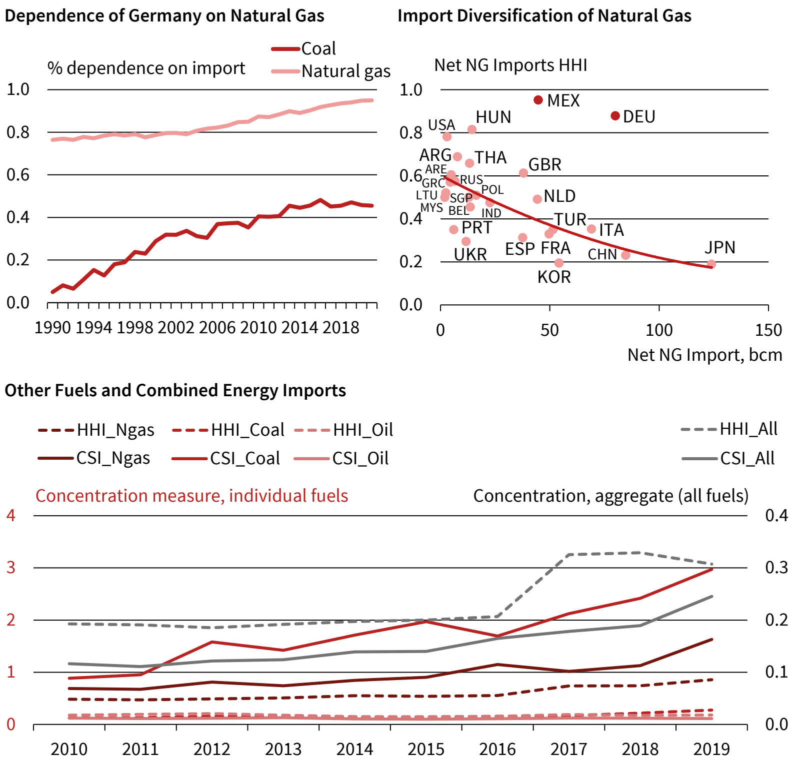
Electricity Generation And Natural Gas Consumption in Germany



Source: BP 2020 Energy Statistical Report. © ifo Institute

Figure 2

Natural Gas and Other Fuels



Note: The growing dependence of Germany on natural gas imports and stagnating reliance on coal has been accompanied by the weak import diversification, especially in the case of natural gas, but also in other fuels and combined energy imports.

Source: BP 2020 Energy Statistical Report; Authors' calculations. © ifo Institute concluded that Germany should have a more diverse trade, e.g., buy more Algerian gas or LNG, for example, by means of swap contracts with France if not through physical deliveries.[7]

INTERFUEL SUBSTITUTION AND MARKET INTERACTION

The conducted analysis allows highlighting how both trade and the security outcome depend on supply and demand. If a country changes its demand for a given fuel, for instance, replacing coal with natural gas, its security would be affected unless further actions are taken.

Understanding the interdependency of security of supply and the distribution of energy demand across different energy sources brings us to the interfuel trade analysis. We examined how trade and its concentration change if countries choose their energy demand allocation across various fuels, first, and then interact in the individual fuel markets. Similarly, we considered energy suppliers, like Russia, which may manipulate their supply of different fuels in order to affect market prices and profits. The Nord Stream 1 and 2 pipelines' leakage and the OPEC quotas can also be seen as such manipulations.

We have studied the energy demand allocation to gain intuition critical for current decisions on investments in non-fossil energy supply and rebalancing of energy demand between coal and natural gas. Our analysis addresses the developments in the natural gas and coal markets in late 2021 and the current year (2022), when shortages of natural gas, caused by Russian gas export disruptions, have spilled over into the coal market: soaring natural gas prices stabilized and even exhibited some short-term downward trend, even as the coal prices rose. Subsequent fluctuations in coal, natural gas, and oil prices, in part, are the result of fuel substitution and its limitations.

Adding another stage to the model and solving it, we found that buyers' demand allocation across the fuel markets depends not only on competition on the seller-side, but also on buyer-side competition. Thus, an increase in the number of buyers in one market might induce some buyers to reduce their demand, shifting the difference to other fuel markets. Similarly, the elimination of a seller or decrease in its supply capacity would incentivize buyers to turn over to other fuel markets, just as observed in the natural gas and coal markets in 2022. Naturally, the change in the number of participants, their willingness to buy, and willingness to supply, might affect trade and, consequently, inter-participant flows, altering the concentration index and security of supply.

Finally, our analysis ends with an examination of a hypothetical scenario in which buyers may affect the size of their import demand through investing in domestic production, e.g., of renewable energy. The results are non-trivial: a reduction in import translates into an increase in trade concentration and thus, security is likely to worsen. However, the shrinkage of the total and individual fuel import share in total consumption has an opposite effect: improving security. In other words, reducing the reliance on import makes the concentration of import flows less important.

POLICY CONCLUSIONS: PATHWAYS TO IMPROVE SUPPLY RESILIENCE

Our analysis leads us to several key observations, policy-relevant conclusions, and recommendations on how to respond to the energy crisis. We start by highlighting the developments that have contributed to Germany's vulnerability.

Focused on its transition to carbon neutrality, Germany, along with many EU members, has envisioned its energy mix diversification and security improvement through the development of alternative energy sources and switching to natural gas. In the short- and mid-term, however, this transition has been thrown out of balance, with high import share and concentration of some fuels making Germany increasingly dependent on a single energy exporter, Russia. Investments in "clean" energy sources have not been sufficient to mitigate the loss in security of supply in Germany.

The energy mix transformation could have been more successful in terms of security had it been accompanied by supplier diversification. Russia has gained overwhelming power over German energy markets by delivering a significant share of total (primary fossil) energy. Yet, the interdependence has become increasingly asymmetric, as Russia has been diversifying its export through trade with Asia. By 2022, at the outbreak of war in Ukraine, Germany had limited ability to substitute Russia as the main energy supplier, which held a pivot position in the EU fossil energy market and a sizable share in the Asian region. Infrastructure constraints and lack of established trade relationships prevent Germany from getting new suppliers or expanding its imports in the short-term, with some exception for coal and oil (where the grade of fuel matters).

Investment in Fuel and Supply Source Diversity

The reviewed results and analyses suggest some useful insights for policy and ongoing energy-related planning. Germany is working on developing new energy supply routes and trade relationships to overcome its energy shortage. While finding another large partner to substitute for the lost one appears as a time- and monetarily efficient solution, its short-term benefits, including the savings on infrastructure and possible wholesale discount, may be overblown and hence should be weighed against the costs of

[7] Here we assume that most of the flows from the Netherlands to Germany consist of redirected Norwegian flows.

hold-up. The risk of renegotiations is especially high, given that many countries face energy shortages and might have incentives to try to entice suppliers.

Taking a lesson from the situation with Russia, Germany should *monitor the allocation of demand and trade across the markets*. Individual energy-buying companies often specialize in specific fuels and ignore developments in other fuels. It should be a governmental role to monitor that new supplies do not worsen the country dependence in the energy markets. The likelihood of a country's dependence on a particular specific fuel exporter, however, is high because oil, coal, and natural gas resources are frequently found in the same geographical locations.

Finally, the push to invest in fossil energy alternatives, including renewables, biofuels, and hydrogen, should be evaluated and coordinated with the individual fuel and across-fuel diversification mentioned above. Development of domestic production will improve energy security if it reduces import dependence. But an increase in reliance on imported energy, e.g., hydrogen, accompanied by the growth in energy demand, might lead to the opposite effect. Hence, the alternative energy policies should account for and be examined in light of the concentration and co-alignment with other energy trade plans.

Strategic Coordination and Buyer Competition

Despite the different conditions in which individual countries are finding themselves in these energy crises, the problems and the solutions considered are often similar. We observe a run into coal spurred by the unprecedented increase in natural gas prices, talks and steps towards establishing price ceilings or corridors, and accelerated development of hydrogen supplies and other alternatives, including nuclear energy.

The ongoing situation could be described as a buyers' "war of attrition." Competition for scarce energy supplies highlights the need for coordination among the energy-import dependent economies to survive and not to slip into severe energy poverty. Competition between European and Asia-Pacific markets has already brought a new kind of supply contracts, indexed to several, rather than one, trading hubs. While countries compete for resources and security of supply, demand size and fuel-switching capability limitations put them in unequal positions. To meet UN Sustainability Goals and to support equality, along with energy affordability, coordination of transition and diversification strategies at both global and regional levels is required.

To enable such coordination and cooperation, improved connectivity and inclusivity are needed. Developing countries with lower ability to pay should not be left to deal with politically unstable and geopolitically isolated countries, such as Russia, that are willing to expand into "indiscriminate" markets and expand their sphere of influence. Communication and coordination with other countries on energy trade and infrastructure development is critical, especially with developing nations. Such action is needed to avoid political and economic polarization that could boost insecure and unstable energy suppliers that threaten the market and geopolitical order.

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Alari Paulus and *Karsten Staehr*

The Energy Crisis in the Baltic States: Causes, Challenges, and Policies*

KEY MESSAGES

- **The energy crisis has meant dramatically higher prices on energy in the Baltic states, and led to very high inflation and lower growth**
- **Short-term measures must cap extreme energy prices, monetary policy must avoid deepening the living cost crisis**
- **Policies to diversify energy supplies are needed in the short and medium term**
- **Energy conservation and a switch to sustainable and independent energy sources will be pivotal in the longer term**

The Russian military build-up and subsequent invasion of Ukraine in February 2022 led to sudden and large increases in energy prices, pronounced uncertainty about the availability of gas and electricity, and a more pessimistic sentiment among households and businesses.

At the time of writing in October 2022, the energy crisis had already exerted severe economic consequences that may well prove long-lasting. This was indeed the pattern after the oil price shocks of the 1970s, which resulted in prolonged periods of stagflation, characterized by low GDP growth and high inflation (Kilian 2008). Few studies have at this stage considered the economic consequences of the Russian invasion and the related energy crisis for countries in Europe (Hutter and Weber 2022; McWilliams et al. 2022).

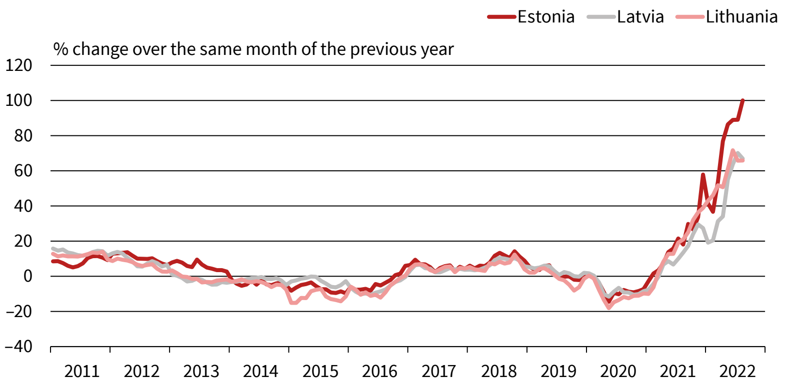
It is pertinent to consider the consequences of the energy crisis in the three Baltic states. They are the only EU countries to have been part of the Soviet Union, until they regained their independence in 1991. The countries were closely integrated in the Soviet energy systems and Russia was an important source of energy before the invasion of Ukraine. The Baltic economies are, moreover, small and energy-intensive, which makes them vulnerable to hikes in energy prices or disruptions to supply.

We consider the economic aspects of the energy crisis in the Baltic states, link the developments to key features of the energy markets in the region, and provide some policy perspectives. The paper should be seen as a primer to the complex nexus of economics, social policy and energy planning in the Baltic states that has been exposed by the energy crisis.

* We gratefully acknowledge helpful comments by Olavi Miller, Kaspar Oja and Mari Pärnamäe. The views expressed are those of the authors and not necessarily those of the Bank of Estonia or other parts of the Eurosystem.

Figure 1

HICP Consumer Price for Energy



Source: Eurostat.

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THE ENERGY CRISIS – AND THE ECONOMIC CRISIS

The most direct, and arguably the most visible, impact of the energy crisis in the Baltic states has been the much higher prices for energy, particularly electricity and gas. The higher prices affect households and firms in numerous ways. Figure 1 shows the annual price increases for the energy component of the Harmonized Index of Consumer Prices (HICP) up to August 2022. The striking rise in prices began in the second half of 2021 but accelerated rapidly during 2022.[1]

Energy accounts for a relatively large part of consumer spending in the Baltic states. As well as energy being relatively expensive, demand is high as the climate is cold and energy efficiency is low in the transport sector and in the housing stock inherited from the Soviet Union. The higher energy prices, combined with higher prices for food, have caused overall consumer price inflation to increase dramatically in 2022. Figure 2 shows overall consumer price inflation as measured by the Harmonized Index of Consumer Prices (HICP).

The three Baltic states have experienced larger rises in consumer prices than the rest of the EU countries in the first nine months of 2022, with annual

[1] The somewhat different dynamics of energy price inflation may reflect the different composition of energy consumption in the three Baltic states, but the differences in the energy price inflation in 2022 appear to be very large.

rates reaching above 20 percent in the autumn of 2022 and climbing a little higher in Estonia than in Latvia and Lithuania.

While wage growth has been substantial in 2021 and 2022, average wages have still trailed consumer prices, leading to a cost-of-living crisis as many households have seen their purchasing power plummet. The cost-of-living crisis has affected households very differently, depending on how much energy they consume: households living in dwellings that are heated by gas, electricity, or firewood have been severely affected. It is notable in this context that the Baltic states have inequalities of income and wealth that are wider than those in the nearby Nordic EU countries.

While the direct effects of the energy crisis are severe enough, the effects over time on economic development may be just as serious. Figure 3 shows GDP growth in 2020 and 2021 and the forecasts for 2022 and 2023 from the October 2022 forecasts of the International Monetary Fund. The forecast projects a steep decline in growth from 2021 to 2022 and 2023.[2] The markedly lower growth rates that may result from the energy crisis will over time lead to lower employment, and eventually to higher unemployment and economic hardship for those who lose their job.

The decline in GDP growth in the Baltic states has been caused by several factors. The higher prices for energy and other inputs hurt firms and may result in cuts in production or closures. The extensive use of energy in the Baltic states makes them vulnerable to high energy prices. Other factors have also made the business climate worse. Exports to Russia and Belarus have declined because of the disruptions caused by the war in Ukraine and the various sanctions imposed by the EU since 2014 and tightened after the invasion of Ukraine. Demand may also have been held back by souring sentiment among households and in the business sector. Businesses face increasing uncertainty about future energy prices and possible supply disruptions.

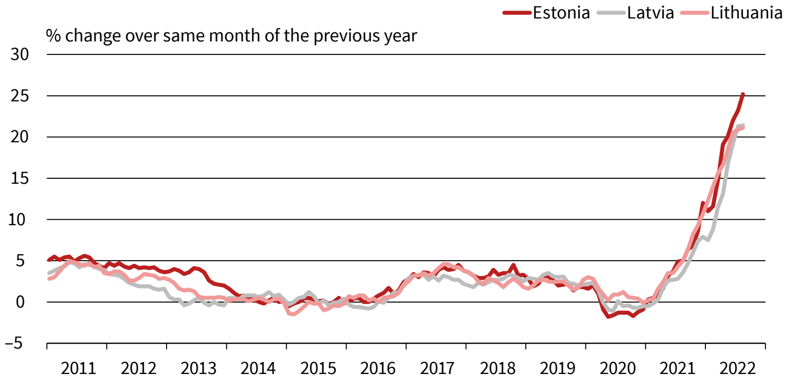
This brief description underscores that the Baltic states face many challenges from the disruption of energy supplies from Russia and the resulting jumps in prices. The governments in all three Baltic states have taken a number of measures since late 2021, several of which have resulted in additional government spending and lower tax revenues. The energy crisis is therefore likely to strain public finances in the three countries.

ENERGY IN THE BALTIC STATES

At its core, the energy crisis is a negative supply shock that has led to increases in energy

Figure 2

HICP Overall Consumer Price



Source: Eurostat.

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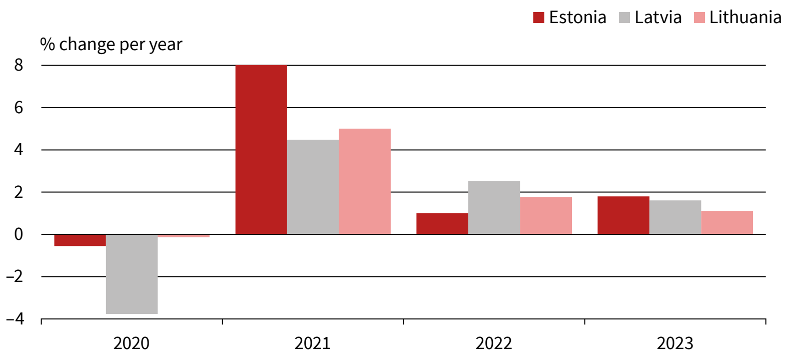
Figure 3

GDP Growth in the Baltic States



Note: Forecasts for 2022 and 2023.
Source: IMF (WEO database, Oct. 2022).

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prices comparable in magnitude to those after the oil price shocks of the 1970s. This section discusses the factors and developments that have contributed to the supply problems and the very large energy price increases in 2022.

A key trigger was the tightening of gas supplies from Russia preceding the invasion of Ukraine. Gas stored in Gazprom's facilities in Europe had reached historic lows in spring 2021 and Russia started reducing gas deliveries to Europe a few months later (McWilliams et al. 2021). This resulted in notable increases not only in the price of gas but as a spillover effect also in the prices of CO_2 emissions and elec-

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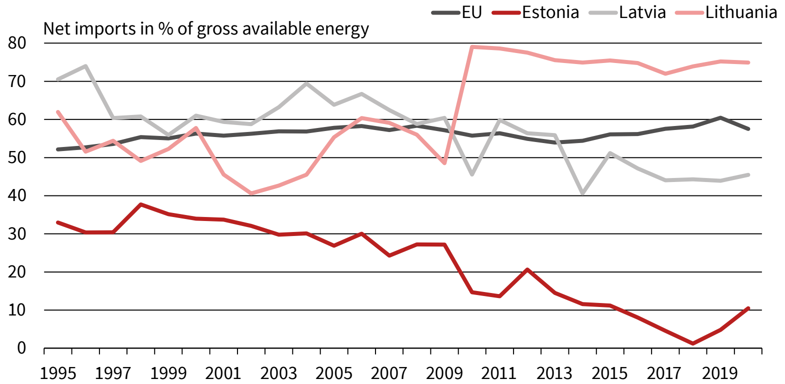
[2] The forecasts for 2022 and 2023 have been revised downwards by 2–3 percentage points since the October 2021 forecasts of the Fund.

Figure 4

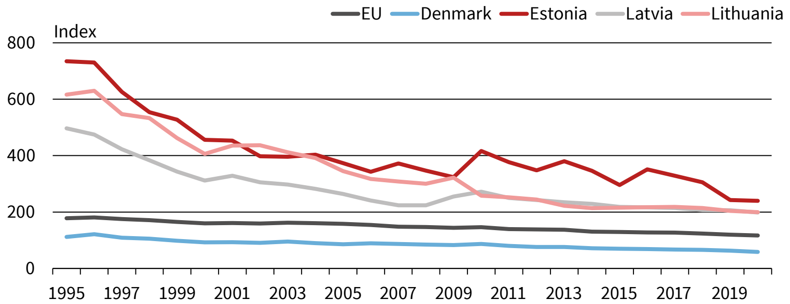
Energy Dependence



Source: Eurostat. © ifo Institute

Figure 5

Energy Use per Unit of Real GDP [a]



[a] The figure shows an index of the energy use per unit of real GDP where real GDP is an index with the base year in 2010. The figure is useful for showing developments over time within a country, but energy use may also be compared across countries with the base year 2010, keeping in mind that real GDP is not adjusted for the different levels of purchasing power in the various countries.
Source: Eurostat. © ifo Institute

tricity. European countries started to divert rapidly away from the energy supplied by Russia, and that drove prices up further as short-term bottlenecks and shortages emerged.

The effects of the reduction in energy exports from Russia were aggravated by a number of factors within the Baltic states. The first was a failure to diversify energy suppliers sufficiently and so reduce dependence on Russian energy. Several other European countries have long relied on abundant and cheap Russian fossil-fuel energy, but in the Baltic states this interdependence was a direct consequence of the Soviet occupation from 1944 to 1991, which had left the energy systems of the Baltic states more closely integrated into the Soviet systems than most other countries in Europe.[3]

There are important differences between how dependent the three Baltic states are on imports of energy. Figure 4 shows their net energy imports relative to energy consumption and, for comparison, for the EU. Estonia has a broad balance between energy consumed and energy produced because it uses oil shale to produce electricity and some oil products, while Latvia and Lithuania show large production deficits. Energy dependence in Lithuania has exceeded that of the EU since 2010. Lithuania had a Soviet-era nuclear power plant that had enough capacity to cover most of the electricity needs of all three Baltic states, but it was shut down in 2010 for safety concerns as part of the agreement to join the EU (Bompard et al. 2017). No new plant has been built despite extensive discussions between the governments of the Baltic states.

The Baltic states took an important step in 2020 when they decided to stop importing electricity from Belarus and limit electricity imports from Russia. However, insufficient domestic capacity for producing and transmitting electricity left the system vulnerable to external shocks. Electricity imports from Russia to Finland and the Baltic states ceased completely in May 2022.

The transition to cleaner energy sources has also created challenges. The transition has made the supply of electricity in the Baltic states less secure in the short term. An important example is the EU Emissions Trading System (ETS), which could be seen as an effective tool for reducing emissions, but also gave an unfair advantage to imported electricity, primarily from Russia and Belarus, as it did not cover electricity producers outside the EU. This may even have contrarily increased energy dependence on Russia in the Baltic states. In 2019, about 35 per cent of the electricity sold in the region came from Russia and was not subject to the ETS (Konkurentsiamet 2021). Moreover, extensive use of green energy requires managed and flexible production capacity using other sources of energy or large-scale energy storage facilities to smooth out the volatility in production from renewables.

Further aggravating the crisis is that energy is used relatively inefficiently in the Baltic states. Figure 5 shows indexes of the energy use per unit of real GDP for each of the Baltic states, and for comparison for the EU and Denmark, the latter being one of the most energy-efficient countries in Europe; see also the figure note. Energy use per unit of GDP decreased very rapidly in the Baltic states in the 1990s as the economies went through major restructuring, shifting away from energy-intensive sectors such as agriculture and heavy industry, but the pace of decline has slowed considerably since the beginning of the 2000s. It is notable that energy use in the Baltic states is much higher than that in the EU and, particularly, in Denmark.

Finally, while the market mechanisms such as the ETS and Nord Pool, and infrastructure such as gas storage facilities and grids, seem largely adequate for normal conditions, there appear to be limits to how well they can withstand extreme market disruptions. There are indications that the feedback from price effects is too constrained, as forward equilibrium prices are settled on the basis of predicted demand, but if actual demand turns out to be substantially different, then there are no compensating effects for prices. Furthermore, it is not inconceivable that Nord

[3] In the past, the Baltic states have also been net exporters of electricity to neighbouring regions in Russia.

Pool could be vulnerable to price manipulation under certain circumstances.

POLICY CONCLUSIONS

The energy crisis followed two years of lockdowns in response to the coronavirus pandemic. The crisis led to large rises in energy prices and uncertainty about the supply of energy, and also to concerns about higher inflation and rising cost of living. These challenges are particularly pronounced for the Baltic states, as they have energy-intensive economies, large reliance on energy imports and limited grid connections.

Many of the challenges facing the Baltic states are common to all or most of the countries in Europe, and it is evident that the EU will play a crucial role in formulating policy to address the energy crisis and its economic fallout.[4] There are nevertheless numerous areas where policymaking remains at the national or regional level.

The energy crisis is in some sense a perfect storm, where several risk scenarios have materialized at the same time and amplified their combined impact. The crisis represents such a large shock to the economies in the Baltic states that economic policies will realistically only be able to reduce the burdens for households and firms, but not to ward them off entirely.

One key constraint on crisis policies is the state of the public finances in the Baltic states. The public debt relative to GDP is low in the Baltic states compared to most other EU countries, but several new spending areas have emerged since the invasion of Ukraine. Measured relative to GDP, the Baltic states have been among the largest donors of military and humanitarian aid to Ukraine; the three countries are expanding and upgrading their military forces; and the many refugees arriving in the Baltic states from Ukraine also call for new government spending. While policymakers in the Baltic states have some fiscal space to address the energy crisis, they will have to exert judicious prudence.

It is useful to distinguish between short-term and longer-term policy perspectives within the possible policy avenues for addressing the energy crisis. The most pressing short-term policy issue has been securing sufficient energy supplies.[5] The policy responses have been relatively swift, as the Baltic states together with other European countries have turned to new energy suppliers elsewhere in the world, and Estonia has started construction of a terminal for liquid natural gas (LNG) to supplement the existing one in Lithuania.

Excessively high energy prices hurt businesses and households. A number of relatively broad-based but time-limited subsidy measures were put in place in the Baltic states already from the end of 2021. It is however reasonable to focus on alternative ways to cap extreme energy prices to avoid ballooning public debt and limit moral hazard. This may entail adjustments to how the price of CO_2 emissions is set through the ETS, and the possibility of temporary caps on the price of emissions may need to be considered. There is also room within the Nord Pool electric power exchange for a better coordination of shutdowns of power plants for maintenance and repairs.

Intertwined with the issue of affordability is the problem of rising living costs. Additional support measures for households may be needed to help them withstand the extraordinary energy price shocks, but fiscal considerations suggest that such measures should mainly focus on the most vulnerable households.

The very high inflation rates also represent a serious policy challenge in the Baltic states. As members of the euro area, their monetary policy is directed by the European Central Bank. Tighter monetary policies could dampen inflationary pressures stemming from excess demand, but they will have little direct effect on energy prices and may increase hardship in households with mortgages. The small size of the Baltic states implies that the monetary policies of the European Central Bank will not take great account of developments in these countries.

Although there is scope to alleviate the effects of sudden major shocks with temporary policies such as emergency price or support measures, it is important to maintain the focus on medium-term and longer-term structural imbalances. This concerns energy conservation and improving energy efficiency, speeding up the development of renewable energy, diversifying energy suppliers, and expanding transmission grids.

Energy conservation in the Baltic states needs to be prioritized, particularly in the areas of housing, industry, and transport. Estonia is, for example, the only country in the EU that does not specifically tax the purchase or ownership of cars, and this might hinder the development of alternative and less energy-intensive modes of transport. Similarly, the development of renewable energy sources needs to be strongly prioritized, as progress has been slow in the Baltic states. It requires a systemic approach and needs to overcome ubiquitous not-in-my-backyard attitudes. A greater reliance on renewable energy sources also calls for the development of extensive energy storage capacities, which is currently lagging behind in the Baltic states.

Policies must over time address the shortfalls of energy production in Latvia and Lithuania and the

[4] See von Homeyer et al. (2021) for a discussion of the EU's energy and climate policies before the Russian invasion of Ukraine.

[5] The sanctions on Russia have intensified the immediate energy shortages. There might have been a way to avoid this while still limiting Russian export revenues. Given that Russia has limited influence on the global prices of gas and oil, most of excess profits could in theory have been taxed away in the form of a special levy on energy imports. It is, however, possible that the ultimate outcome would have been the same, with Russia withholding energy exports to the West.

shortfall that may emerge in Estonia once the production of electricity and petroleum products from oil shale is scaled back. The solution is likely to be a combination of measures to ensure the diversification of risk, increased resilience of local energy markets, and better energy security. More extensive transmission links between countries is an important part of that but should complement rather than substitute independent local production capacities.[6]

The challenges stemming from the energy crisis in the Baltic states are substantial and cover economics, social policy, energy systems, infrastructure and foreign policy. In this context, it is important to note that there are likely to be trade-offs between measures seeking to address the energy crisis and measures addressing long-term goals such as global warming. The energy crisis related to the Russian invasion of Ukraine has indeed opened numerous policy challenges in Europe, not least in the Baltic states.

[6] Bompard et al. (2017) discuss the key measures needed to ensure electricity independence in the Baltic States.

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Clemens Fuest and *Florian Neumeier*

The Revenue Effect of a Global Effective Minimum Tax

KEY MESSAGES

- **We estimate the fiscal effect of a global effective minimum tax for Germany, the EU27, and the world**
- **Our results indicate that Germany and – on aggregate – the EU27 would benefit fiscally from a global effective minimum tax**
- **However, the size of the additional tax revenue depends on the design of the carve-out rule and the extent of behavioral adjustments on the side of multinational companies and low-tax countries**

In October 2021, 136 countries and jurisdictions agreed on the introduction of a global effective minimum tax (OECD 2021). The plan is to impose a minimum tax rate of 15 percent on the global profits of multinational corporations (MNCs). If an MNC's effective tax burden in a country is less than 15 percent, additional taxes will be collected until the ratio of tax payments to profits reaches a level of 15 percent. This is to affect all MNCs whose global consolidated revenue is at least €750 million.

However, many aspects related to the minimum tax are still open. For example, an agreement on a precise definition of the tax base has yet to be reached. In this context, it is also unclear how losses are to be offset. If, for example, an MNC carries forward losses to subsequent years, the effective tax burden may fall below 15 percent, even though the tax level in the residence country is actually higher.

The October 2021 agreement provides for certain profits – those than can be attributed to real economic activities – to be exempt from the minimum tax, thereby taxing only the rest of the profits. More precisely, a fixed percentage of the value of tangible assets and payroll is deducted from profits (the so-called carve-out). In case the effective tax burden on profits in a residence country is below 15 percent, only the residual profit determined in this way will be subject to the minimum tax. In the year of introduction, the residual profit subject to the minimum tax equals the total profit reported in the residence country minus 8 percent of the value of the tangible fixed assets and 10 percent of the payroll. Ten years after the introduction, both shares are lowered to 5 percent, with a gradual reduction being applied during the transitional phase: in the first five years after the introduction of the minimum tax, the shares are to be reduced by 0.2 percentage points per year. Five years after the introduction of the reform, the exempt profit would thus correspond to 7 percent of the value of the tangible assets plus 9 percent of the payroll. In the sixth to tenth year after introduction, the share of the value of tangible fixed assets decreases by 0.6 percentage points per year and the share of payroll by 0.8 percentage points per year.

The introduction of a carve-out rule protects a part of MNCs' profits – those that can be attributed to real economic activities – from minimum taxation. The profits of shell companies, on the other hand, are fully subject to the minimum tax, provided that the effective corporate tax burden in the residence country is lower than 15 percent. In this regard, the carve-out rule enables low-tax countries to remain attractive as a destination for real investments, i.e., for production facilities and jobs. A low corporate tax burden is one of the few ways for many developing and emerging economies to attract private investments. Carve-outs reinforce the character of minimum tax as an instrument against tax havens without major real economic activity. At the same time, however, it should be borne in mind that carve-outs can also fuel international tax competition for real investment. While it has so far been possible (within limits) for MNCs to reduce their tax burden by shifting profits on paper alone, the combination of minimum taxation and carve-outs would mean that it is now only possible to reduce the corporate tax burden by shifting real economic activity to low-tax countries. MNCs would therefore, as a result of the carve-out rule, have a much greater incentive than before to relocate real investments to low-tax countries.

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DATA AND ESTIMATION APPROACH

To calculate the revenue impact of a global effective minimum tax, we consider the following carve-out scenarios:

- Scenario 1 (benchmark): No carve-out, i.e., all under-taxed foreign profits are back-taxed.
- Scenario 2: The carve-out is 8 percent of the value of the tangible assets plus 10 percent of the payroll.
- Scenario 3: The carve-out is 7 percent of the value of the tangible assets plus 9 percent of the payroll.
- Scenario 4: The carve-out is 5 percent of the value of the tangible assets plus 5 percent of the payroll.

Scenario 2 reflects the rules that would apply in the year of introduction of the minimum tax; Scenario 3, the rules that would apply five years after the introduction of the reform, and Scenario 4 the rules that would apply from the tenth year. The purpose of considering Scenario 1 is to assess the impact of the carve-out rule on the revenue from the minimum tax.

For our estimation, we have access to information from the so-called Country-by-Country Reports (CbC Reports) of MNCs. The CbC reports contain information on the global business activities of MNCs with global consolidated revenues of more than €750 million. The CbC reports consist of three parts (OECD 2015). To estimate the revenue effects of a global effective minimum tax, we use only information from the first part. This contains basic financial information on the global operations of an MNC, including profit before tax, corporate income taxes paid and accrued, revenue generated by transactions with third parties, revenue generated by transactions with affiliated companies, the value of tangible assets, and the number of employees. The financial information contained in the CbC reports is aggregated at the level of the countries in which a company has subsidiaries, and the data is aggregated across all subsidiaries located in a country. For our estimates, we have access to the CbC reports of all large MNCs active in Germany. Our final dataset covers the years from 2016 to 2019 and contains the data of a total of 3,613 MNCs; of these, 434 are headquartered in Germany.

Since the sum of wages paid in a country is not included in the CbC reports, we approximate it by weighting the number of employees by the residence country-specific GDP per capita. Furthermore, no information is available in the CbC reports on the destination countries of payments to affiliates, which is why in our estimates we focus exclusively on the income inclusion rule.[1] Thus, in our analysis, the German fiscal authority imposes the minimum tax only on the (foreign) profits of German companies, the French fiscal authority on the (foreign) profits of French companies, and so on. Moreover, we assume in our analysis that there is also the possibility of loss offsets in the global effective minimum taxation system. To account for the impact of loss offsets, we first compute the ratio of the sum of aggregate losses of the MNCs included in our dataset to the sum of aggregate profits. The ratio is 11.4 percent. Thus, for every euro of profit earned, there are on average about eleven cents of losses. In the second step, we multiply the post-tax profits by one minus this 11.4 percent to obtain a profit measure adjusted for loss carryforwards.

It can be expected that the introduction of a global effective minimum tax will lead to a decrease in tax-motivated profit shifting, as the effective tax burden on profits in low-tax countries will increase. Moreover, low-tax countries may have an incentive to increase their effective tax rates. On the one hand, this allows them to compensate for the loss of tax revenue due to MNCs shifting profits back to high-tax countries. On the other hand, tax hikes by low-tax countries do not impose an additional burden on MNCs, but merely lead to a shift of their tax payments from their headquarter countries to low-tax countries. The latter is true in any case for MNCs subject to minimum taxation. For these reasons, we calculate three versions for each scenario. In the first version, we abstract from behavioral adjustments on the part of both MNCs and low-tax countries and take the global distribution of profits as given. In the second version, we include behavioral adjustments on the part of MNCs in our revenue estimates. We estimate the revenue effects under the assumption that the introduction of a global effective minimum tax leads to a decrease in profit shifting. The approach we use to determine the reduction in global profit shifting is described in detail in Fuest et al. (2022) and Fuest and Neumeier (2022). In the third version, we raise the effective tax rate on profits affected by the effective minimum tax (profit less carve-out) to 15 percent in all residence countries whose tax level is lower. The revenue from minimum taxation thus falls to zero, and all changes in national tax revenue are due to a reduction in profit shifting. The revenue effects from an increase in tax rates in those countries with an effective tax rate below 15 percent before the reform are not taken into account in our version 3 estimates.

We calculate the impact of the introduction of a global effective minimum tax for Germany or German MNCs, the EU27 countries or MNCs headquartered in a EU27 country except Germany, and for all countries in our dataset except the US or US MNCs. The reason is that in 2018, the US already introduced a minimum tax on certain foreign profits of US corporations (Global Intangible Low-Taxed Income, GILTI). Assuming that GILTI continues to exist even if a global effective minimum tax is introduced, US MNCs should be excluded from the revenue estimates because their foreign profits are already subject to a top-up tax under GILTI in

[1] The income inclusion rule allows headquarters countries to tax the foreign profits of an MNC in case these profits are taxed at an effective rate of less than 15 percent.

case of a low effective tax burden. Recall that our dataset does not include all corporations that would be affected by the introduction of a global effective minimum tax, but only those that are active in Germany. Our revenue estimates for the EU27 countries, as well as all countries worldwide, are therefore incomplete, as part of the MNCs relevant for the revenue effects in these country groups are missing from our dataset. However, with Germany as the largest economy in Europe and the fourth-largest economy in the world, it can be assumed that many MNCs headquartered abroad are active here.

RESULTS OF THE REVENUE ESTIMATES

Table 1 shows the domestic and foreign profits and tax payments of German MNCs, of MNCs headquartered in a EU27 country except Germany, and of all MNCs included in our dataset except US MNCs. In addition, the table shows the size of the profits taxed at an effective tax rate of less than 15 percent. German MNCs generate slightly more than half of their annual profits abroad (about 56 percent). Both the profits generated worldwide and the foreign profits of German MNCs are taxed at an average rate of about 16 percent. For 62 percent of profits worldwide and 58 percent of foreign profits, respectively, the effective tax burden on profits is lower than 15 percent. These profits are taxed either in full or pro rata within the framework of a global effective minimum taxation, depending on whether a carve-out is applied or not.

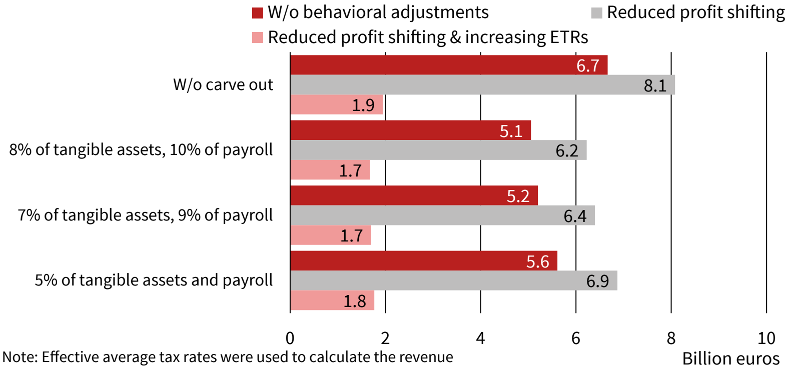
Figure 1 shows the estimated revenue effects of a global effective minimum tax for Germany, Figure 2 for the remaining EU27 countries, and Figure 3 for all countries worldwide except the US. To calculate the revenue effects, we multiplied the changes in the national tax bases attributable to the decrease in profit shifting by the effective average tax rates in versions 2 and 3.

If we disregard the fact that the introduction of a global effective minimum tax reduces the incentives for tax-motivated profit shifting, the estimated annual revenue increase for Germany is between 5.1 billion and 6.7 billion euros (red bars), depending on whether and to what extent some of the under-taxed profits are exempted from the minimum tax. When taking into account that the introduction of a global effective minimum tax is likely to reduce the extent of tax-motivated profit shifting (gray bars), the resulting revenue increase for Germany grows to 6.2 to 8.1 billion euros per year. If all countries in the world respond by raising their effective tax rates to 15 percent (pink bars), on the other hand, the estimated revenue increase drops significantly, to between 1.7 and 1.9 billion euros, depending on the scenario. The reason is that in this case the revenue from the global effective minimum tax falls to zero. Additional revenue is only generated by a decline in tax-motivated profit shifting to low-tax countries.

Figure 2 shows the impact of introducing a global effective minimum tax for the remaining EU27 countries. Here, too, the estimated revenue effect is considerable. Excluding behavioral adjustments, the estimated revenue effect is between around 14 and 24 billion euros per year, depending on the carve-out scenario. Assuming that the introduction of a global effective minimum tax leads to a decrease in profit shifting, the estimated revenue effect increases to

Figure 1

Global Effective Minimum Tax – Revenue Germany



Note: Effective average tax rates were used to calculate the revenue effects attributable to a decrease in tax-motivated profit shifting.
Source: Authors' calculations based on CbC data.

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Table 1

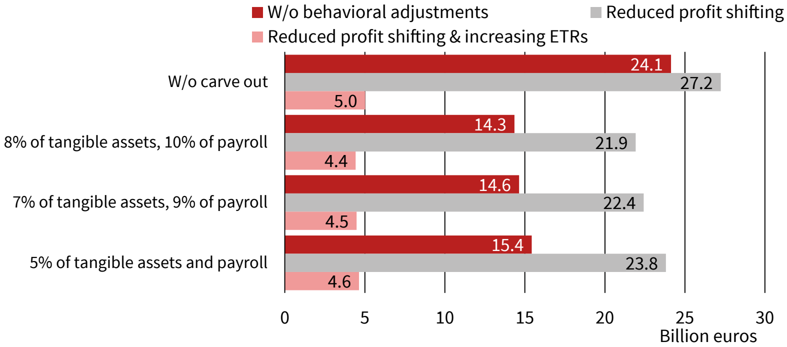
Profits and Tax Payments of Multinational Corporations

	German MNCs		EU27 MNCs excl. German MNCs		All MNCs excl. US MNCs	
	Activities worldwide	Foreign activities	Activities worldwide	Foreign activities	Activities worldwide	Foreign activities
Profits						
Total (billion euros)	229	128	677	440	1178	859
Taxed at less than 15 percent (billion euros)	141	74	418	255	713	505
Share taxed at less than 15 percent	62	58	62	58	61	59
Tax payments						
Total (billion euros)	37	21	111	76	225	158
In percent of profits	16	16	16	17	19	18

Notes: Values represent averages over reporting years from 2016 to 2019.
Source: Authors' own calculations.

Figure 2

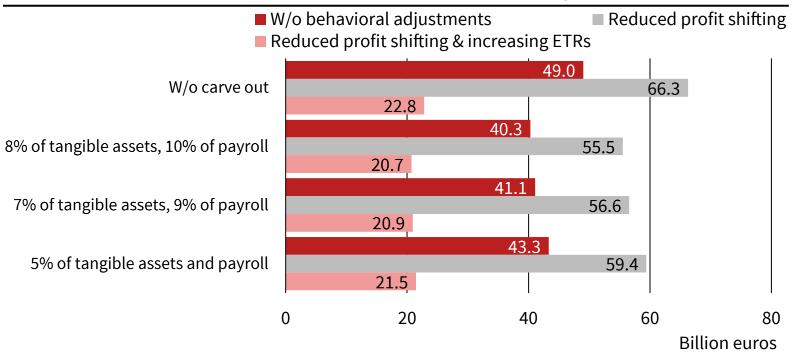
Global Effective Minimum Tax – Revenue EU27 Countries



Note: Effective average tax rates were used to calculate the revenue effects attributable to a decline in tax-motivated profit shifting. The revenue effects were calculated exclusively on the basis of MNCs that are active in Germany.
Source: Authors' calculations based on CbC data. © ifo Institute

Figure 3

Global Effective Minimum Tax – Revenue Worldwide Excluding USA



Note: Effective average tax rates were used to calculate the revenue effects attributable to a decline in tax-motivated profit shifting. The revenue effects were calculated exclusively on the basis of MNCs that are active in Germany.
Source: Authors' calculations based on CbC data. © ifo Institute

about 22 to 27 billion euros. When interpreting the figures in Figure 2, it should be borne in mind that our dataset only includes a portion of those MNCs that have their headquarters in one of the EU27 states and would be subject to a global effective minimum tax – namely those that are also active in Germany. Arguably, this may include most of the MNCs active in the EU, but the figures nevertheless tend to understate the revenue effect of a minimum tax.

Figure 3 shows the global revenue when taking into account all MNCs covered by our dataset, with the exception of US MNCs. Excluding behavioral adjustments, the global revenue from a minimum tax is about 40 to 49 billion euros per year, depending on the scenario. When behavioral adjustments are taken into account, the estimated revenue rises to between 56 billion and 66 billion euros per year. If all low-tax countries in the world were to raise their effective tax rates to 15 percent, the revenue increase would fall to between 21 billion and 23 billion euros a year. This does not take into account the additional tax revenue generated by raising the effective tax rate to 15 percent. Again, it should be remembered that our dataset only includes MNCs active in Germany, which likely leads to an underestimation of total revenue.

Table 2 shows how the introduction of a global effective minimum tax affects the effective corporate tax burden of MNCs. For German MNCs, the tax burden would increase from the current 16 percent (cf. Table 1) to 18.4 to 19.1 percent of profits. Assuming that the introduction of a minimum tax reduces the extent of profit shifting, the effective corporate tax burden would even rise to 18.8 to 19.6 percent. However, this is lower than the average effective tax burden for all MNCs in our dataset. Here, the corporate tax burden rises to 22.5 to 23.3 percent without taking into account behavioral adjustments on the part of MNCs, and to 23.7 to 24.7 percent when taking into account behavioral adjustments.

In our revenue estimates, we focus exclusively on under-taxed foreign profits of MNCs that are taxed under the income inclusion rule. Profits that accrue in the headquarter country and are taxed at less than 15 percent are not included. These profits, if attributable to payments from foreign-based affiliates, could be at least partially taxed in the framework of the global effective minimum tax under the so-called undertaxed payments rule by the countries of origin of the payments. Table 3 shows how much additional revenue would be raised if all of the under-taxed profits booked in the headquarter countries were subject to a minimum tax of 15 percent. In this case, the global revenue from minimum taxation estimated based on our dataset would increase by 14 to 18 billion euros per year, depending on the scenario. However, these figures should be interpreted as an upper limit, as it is assumed that all profits that are under-taxed in the headquarter country are taxed at a rate of 15 percent.

Table 2

Effects of the Global Effective Minimum Tax on Effective Tax Rates

	Without behavioral adjustments			Decrease in profit shifting		
	German MNCs	EU27 MNCs	All MNCs (excl. U.S. MNCs)	German MNCs	EU27 MNCs	All MNCs (excl. U.S. MNCs)
Without carve out	19.1%	20.0%	23.3%	19.6%	21.2%	24.7%
8 percent of fixed assets, 10 percent of payroll	18.4%	18.6%	22.5%	18.8%	20.3%	23.7%
7 percent of fixed assets, 9 percent of payroll	18.5%	18.6%	22.6%	18.9%	20.4%	23.8%
5 percent of fixed assets and payroll	18.7%	18.7%	22.8%	19.1%	20.6%	24.1%

Notes: The values in the table show the effective average tax burden on profits for different groups of companies depending on the individual scenarios. Effective average tax rates were used to calculate the revenue effects attributable to a decline in tax-motivated profit shifting.
Source: Authors' own calculations.

Table 3

Revenue Effects of a Global Effective Minimum Tax under the Undertaxed Payments Rule

	Without behavioral adjustments (billion euros)	Reduced profit shifting (billion euros)
Without *carve out*	18.0	16.9
8 percent of fixed assets, 10 percent of payroll	14.7	13.7
7 percent of fixed assets, 9 percent of payroll	15.0	14.0
5 percent of fixed assets and payroll	15.9	14.9

Notes: The table shows the annual revenue when applying a top-up tax on those profits booked in the headquarters countries that are taxed at a rate of less than 15 percent. Effective average tax rates were used to calculate the revenue effects attributable to a decline in tax-motivated profit shifting. The revenue ef-fects were calculated exclusively on the basis of MNCs that are active in Germany.
Source: Authors' calculations.

COMPARISON WITH OTHER REVENUE ESTIMATES

The OECD has also produced an estimate of the revenue effects of a global effective minimum tax (OECD 2020). As in this study, US corporations were excluded from the analysis because of the GILTI tax. The OECD estimated that the global effective minimum tax generates $40 to $48 billion (i.e., 35 to 43 billion euros) in additional tax revenue worldwide. Behavioral adjustments and carve-outs were not included in this estimate, so this figure should be compared to our estimate of 49 billion euros. Thus, our estimate is higher, and this is despite the fact that our dataset covers only a third (but presumably the largest) of the MNCs subject to CbC. Where does the difference come from? The OECD used aggregate data for its analysis, i.e., the sum of profits and the sum of tax payments of all MNCs with the same headquarter country, separated by headquarter country. The OECD must therefore assume that the effective tax rate is identical for all MNCs in a residence country. On the other hand, by using disaggregated data we are able to determine the effective tax burden on profits for each MNC separately. In doing so, we find numerous cases where an MNC's effective tax burden in a country is less than 15 percent, even though the average effective tax rate across all firms is 15 percent or higher. In fact, of the 505 billion euros in foreign profits that are effectively taxed at rates below 15 percent (cf. Table 1), 47.7 percent are booked in countries where the average effective tax rate is at least 15 percent. If this is not taken into account, the revenue from global effective minimum taxation will be underestimated.

In July 2021, the EU Tax Observatory also published an estimate of the revenue effects of a global effective minimum tax (Baraké et al. 2021). For their estimates, the authors combined aggregate CbC data from the OECD and data from Tørsløv et al. (2018). The authors concluded that the revenue for Germany without carve-out and without considering behavioral adjustments would amount to 5.7 billion euros per year. With carve-out amounting to 5 percent of tangible assets and 5 percent of payroll, the revenue would still be 4.8 billion euros per year. The authors' results are thus quite close to ours, despite the use of aggregate data.

POLICY CONCLUSIONS

Our estimates show that Germany would benefit fiscally from the introduction of a global minimum tax. Abstracting from possible behavioral adjustments among the affected MNCs and low-tax countries, a 15-percent effective minimum tax rate results in an estimated additional tax revenue of 5.1 to 6.7 billion euros per year for Germany. The exact amount depends on whether all profits of MNCs that are effectively taxed at a rate of less than 15 percent are subject to a minimum tax, or whether a so-called carve-out is applied. Carve-out means that the tax base for the global effective minimum tax is reduced by an amount that reflects real economic activities in the country of residence by reducing the tax base by a fixed percentage of the value of tangible assets and payroll. If one also takes into account that the introduction of a global effective minimum tax leads to a reduction in tax-motivated profit shifting, the revenue effect for Germany increases; if, on the other hand, the low-tax countries react by raising their tax rates, the revenue effect may be significantly lower, but the actual objective of the global effective minimum tax – that is, combatting corporate profit shifting – would still be achieved.

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Cevat Giray Aksoy, Jose Maria Barrero, Nicholas Bloom, Steven J. Davis, Mathias Dolls and *Pablo Zarate*

Working from Home Around the World

KEY MESSAGES

- **Most workers were favorably surprised by their productivity in work from home (WFH) mode during the pandemic.**
- **Employer plans for WFH levels after the pandemic rise strongly with these individual-level productivity surprises.**
- **Planned WFH levels also rise with the cumulative stringency of government-mandated lockdowns during the pandemic.**
- **Employees value the option to WFH 2-3 days per week at 5 percent of pay, on average, with higher valuations for women, people with children, highly-educated workers, and those with longer commutes.**

The COVID-19 pandemic triggered a huge, sudden uptake in work from home, as individuals and organizations responded to contagion fears and government restrictions on commercial and social activities (Adams-Prassl et al. 2020; Bartik et al. 2020; Barrero et al. 2020; De Fraja et al. 2021). Over time, it has become evident that the big shift to work from home will endure after the pandemic ends (Barrero et al. 2021). No other episode in modern history involves such a pronounced and widespread shift in working arrangements in such a compressed time frame. The Industrial Revolution and the later shift away from factory jobs brought greater changes in skill requirements and business operations, but they unfolded over many decades.

These facts prompt some questions: What explains the pandemic's role as catalyst for a lasting uptake in work from home (WFH)? When looking across countries and regions, have differences in pandemic severity and the stringency of government lockdowns had lasting effects on WFH levels? What does a large, lasting shift to remote work portend for workers? Finally, how might the big shift to remote work affect the pace of innovation and the fortunes of cities?

THE GLOBAL SURVEY OF WORKING ARRANGEMENTS (G-SWA)

To tackle these and related questions, we field a new Global Survey of Working Arrangements across 27 countries. The survey yields individual-level data on demographics, WFH levels, employer plans for WFH levels after the pandemic, commute times, and more. Thus far, we have fielded the survey online in two waves, one in late July/early August 2021 and one in late January/early February 2022. In our new paper, Aksoy, Barrero, Bloom, Davis, Dolls and Zarate (2022), we study full-time workers, aged 20-59, who finished primary school and investigate how outcomes, plans, desires and perceptions around WFH vary across persons and countries.

Our G-SWA samples are highly skewed to well-educated persons in most countries. Thus, in making comparisons across countries, we consider conditional mean outcomes that control for gender, age, education and industry at the individual level, treating the raw US mean as the baseline value. These values should not be understood as averages for the working-age populations or overall workforces in each country. Rather, they are conditional sample means for relatively well-educated full-time workers who have enough facility with smartphones, computers, tablets and the like to take an online survey.

* This article was published first as a VoxEU column.

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WFH LEVELS AROUND THE WORLD

Figure 1 highlights the global nature of WFH among well-educated workers as of mid-2021 and early 2022. It reflects responses to the question, "How many full paid days are you working from home this week?" Response options range from 0 to 5+ days per week. "HE" next to a country's name indicates that its G-SWA sample greatly overrepresents highly educated persons.

Full WFH days average 1.5 per week across the countries in our sample. We compute this average as the simple mean of the country-level conditional means. These conditional mean values range widely from 0.5 days in South Korea, 0.7 in Egypt and 0.8 in Serbia and Taiwan at the low end to 2.4 in Singapore and 2.6 in India at the high end.

WFH LEVELS WILL PERSIST BEYOND THE PANDEMIC

Figure 2 provides direct evidence that high WFH levels will persist beyond the pandemic. The underlying question is "After COVID, in 2022 and later, how often is your employer planning for you to work full days at home?" If the worker says his or her employer has neither discussed the matter nor announced a policy regarding WFH, we assign a zero value. Employers plan an average of 0.7 WFH days per week after the pandemic, ranging from 0.3 days in Greece, Serbia, and Taiwan to 0.4 in South Korea and Ukraine to 1.0 in Australia and the UK and 1.8 in India. As in Figure 1, there is a wide dispersion in the country-level conditional mean values.

MANY WORKERS WILL QUIT IF REQUIRED TO RETURN TO THE EMPLOYER'S WORKSITE 5+ DAYS PER WEEK

We also find that 26 percent of employees who currently WFH one or more days per week would quit or seek a job that allows WFH, if their employers require a return to 5+ days per week onsite. Using SWAA data for US workers, Barrero et al. (2021a) find that more than 40 percent of those who currently WFH one or more days per week would quit or seek a new job if their employers require a full return to the company worksite.

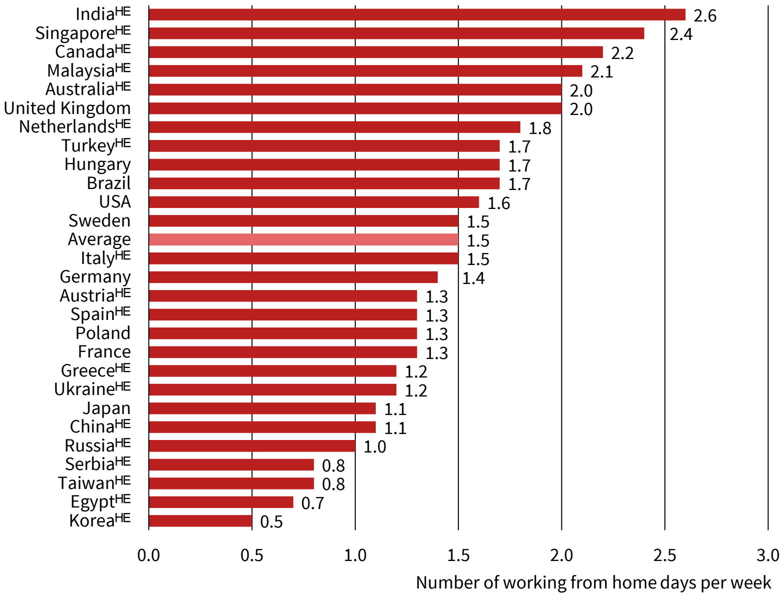
These patterns are in line with other recent empirical evidence. Bloom, Han and Liang (2022) conduct a randomized control trial of engineers, marketing and finance employees in a large technology firm, letting some of them WFH on Wednesday and Friday. This hybrid WFH arrangement cut quits by 35 percent and raised self-reported work satisfaction. After Spotify adopted a "work from anywhere" policy, attrition rates fell 15 percent in 2022 Q2 relative to 2019 Q2 (Kidwai 2022). This fall coincided with sharply increased quit rates for the overall economy.

THE IMPACT OF PANDEMIC-INDUCED EXPERIMENTATION ON PERCEPTIONS ABOUT WFH PRODUCTIVITY

If the survey respondent had WFH experience at some point during the pandemic, we asked "Compared to your expectations before COVID (in 2019) how has working from home turned out for you?" Responses

Figure 1

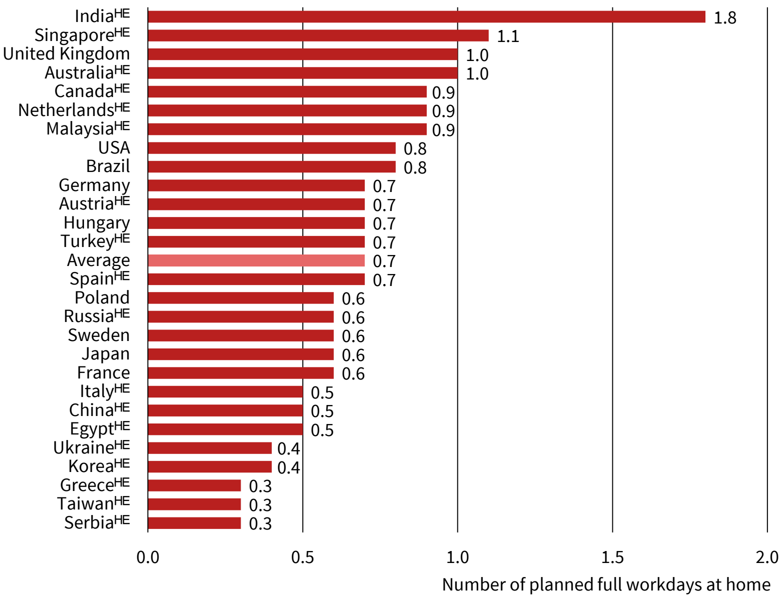
Working from Home is Now a Global Phenomenon Among the Well Educated



Note: HE: Respondents with high educational attainment greatly overrepresented in the sample. This figure shows country-level conditional means for full WFH days in the survey week. We obtain these conditional means from OLS regressions that control for gender, age (20–29, 30–39, 40–49, 50–59), education (Secondary, Tertiary, Graduate), 18 industry sectors and survey wave, treating the raw U.S. mean as the baseline value. We fit the regression to data for 33,091 G-SWA respondents surveyed in mid 2021 and early 2022. The "Average" value is the simple mean of the country-level conditional means.
Source: Aksoy et al. (2022) and G-SWA.

Figure 2

Planned Levels of Working from Home after the Pandemic



Note: HE: Respondents with high educational attainment greatly overrepresented in the sample. This figure shows country-level conditional means, as in Figure 1. We fit the regression to data for 34,875 G-SWA respondents who were surveyed in mid-2021 and early 2022. We limit the sample to persons with an employer in the survey week. The "Average" value is the simple mean of the country-level conditional means.
Source: Aksoy et al. (2022) and G-SWA.

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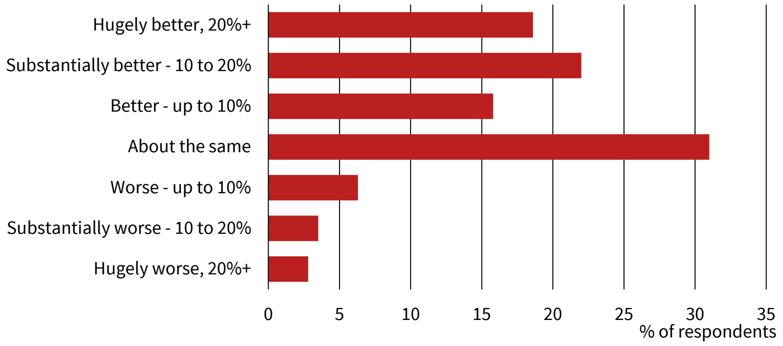
options are expressed in terms of WFH productivity relative to pre-pandemic expectations. Figure 3 shows the raw response distribution in the pooled G-SWA data.

This response distribution has two important features. First, it is highly dispersed. Since WFH levels were quite low before the pandemic – about 0.25 full days per week, according to the American Time Use Survey – wide dispersion in productivity surprises leads to persistently higher WFH levels after the pandemic. Why? Because favorable surprises lead to more WFH in jobs and tasks on the margin, while unfavorable surprises lead to a continuation of near-zero WFH. Second, Figure 3 says that pre-pandemic WFH expectations were overly negative for most workers before the pandemic. That is, pandemic-induced experimentation caused most workers to upwardly revise their self-assessed WFH productivity.

Additional analysis of our survey data shows that the conditional mean WFH productivity surprise is positive in all 27 countries – ranging up to 8 percent or more in Brazil, India, Italy, Spain, Sweden, Turkey, and the United States. Supposing that employer and worker assessments are aligned, these revisions in average perceived WFH productivity drive a re-optimization of working arrangements in jobs and tasks on the margin, contributing to a lasting increase in WFH levels.

Figure 3

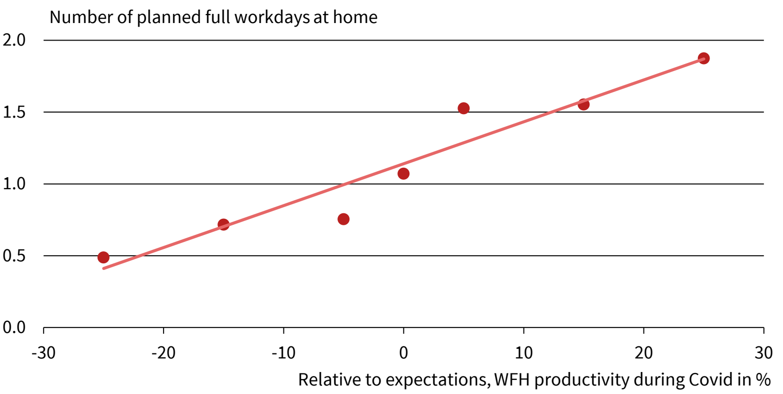
The Distribution of WFH Productivity Relative to Expectations



Note: This figure shows the distribution of WFH productivity relative to pre-pandemic expectations in a pooled sample of 19,027 respondents who worked from home at some point during the Covid-19 pandemic.
Source: Aksoy et al. (2022) and G-SWA. © ifo Institute

Figure 4

The Relationship Between Employer Plans and Productivity Surprises



Note: This figure shows the cross-sectional relationship between employer plans and worker-level productivity surprises in the pooled G-SWA data. The underlying survey questions are, first, "Compared to your expectations before Covid, how has working from home turned out for you?" and, second, "After Covid, in 2022 and later, how often is your employer planning for you to work full days at home? The sample contains 19,027 G-SWA respondents in early 2021 and mid 2022 who worked from home at some point during the Covid-19 pandemic.
Source: Aksoy et al. (2022) and G-SWA. © ifo Institute

PLANNED WFH LEVELS AFTER THE PANDEMIC RISE WITH WFH PRODUCTIVITY SURPRISES DURING THE PANDEMIC

Figure 4 shows the cross-sectional relationship between employer plans and worker-level productivity surprises in the pooled G-SWA data. Planned levels after the pandemic strongly increase with WFH productivity surprises during the pandemic. Moving from the bottom to the top of the surprise distribution involves an increase of about 1.3 days per week in the planned WFH level. This strong positive relationship between WFH productivity surprises and planned WFH levels holds in all 27 countries.

IMPLICATIONS AND POLICY CONCLUSIONS

We also develop evidence that the shift to WFH benefits workers. The reason is simple: Most workers value the opportunity to WFH part of the week, and some value it a lot. It's easy to see why. WFH saves on time and money costs of commuting and grooming, offers greater flexibility in time management, and expands personal freedom. Few people could WFH before the pandemic. Many can do so now. This dramatic expansion in choice sets benefits millions of workers and their families. Women, people living with children, workers with longer commutes, and highly-educated workers tend to put higher values on the opportunity to WFH. Previous studies also document preference heterogeneity around WFH in various settings and using a range of empirical methods. See, Bloom et al. (2015); Mas and Pallais (2017); Wiswall and Zafar

(2020); Barrero et al. (2021); He et al. (2021); and Lewandowski et al. (2022)).

That does not mean everyone benefits. Some people dislike remote work and miss the daily interactions with coworkers. Over time, people who feel that way will gravitate to organizations that stick with pre-pandemic working arrangements. Another concern is that younger workers, in particular, will lose out on valuable mentoring, networking, and on-the-job learning opportunities. We regard this concern as a serious one but have diffuse priors over whether, and how fully, it will materialize. Firms have strong incentives to develop practices that facilitate human capital investments. Individual workers who value those investment opportunities have strong incentives to seek out firms that provide them. If older and richer workers decamp for suburbs, exurbs and amenity-rich consumer cities, the resulting fall in urban land rents will make it easier for young workers to live in and benefit from the networking opportunities offered by major cities.

Many observers also express concerns about what the rise of remote work means for the pace of innovation. In this regard, we stress that the scope for positive agglomeration spillovers in virtual space is expanding, even as the shift to WFH diminishes agglomeration spillovers in physical space. How these countervailing forces will affect the overall pace of innovation remains to be seen, but our paper sets forth several reasons for optimism.

The implications for cities are more worrisome. The shift to WFH reduces the tax base in dense urban areas and raises the elasticity of the local tax base with respect to the quality of urban amenities and local governance. These developments warrant both hope and apprehension. On the hopeful side, they intensify incentives for cities to offer an attractive mix of taxes and local public goods. Cities that respond with efficient management and sound policies will benefit – more so now than before the pandemic. On the apprehensive side, the economic and social downsides of poor city-level governance are also greater now than before the pandemic. For poorly governed cities, in particular, the larger tax-base elasticity raises the risk of a downward spiral in tax revenues, urban amenities, workers, and residents.

This column only scratches the surface of the evidence and analysis in our paper. All G-SWA data are freely available for use by researchers at https://wfhresearch.com/gswadata/.

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Theresa Kuchler and *Johannes Stroebel*

The Social Integration of Syrian Refugees in Germany

KEY MESSAGES

- **Syrians in Germany generally have low levels of social integration compared to German natives, measured by the number of Facebook connections/groups and content posted in German**
- **Social integration in rural regions is higher than in more urban regions**
- **The degree of integration in a region is driven by the local environment, less by the behavior of local natives or the present Syrian population**
- **The availability of integration courses causally drives local integration**
- **Direct personal contact with locals helps integration**

How successful have efforts been to socially integrate Syrian migrants in Germany? What factors influence social integration? Together with researchers from Harvard and Meta, we address these questions in a new research paper working with de-identified data from Facebook.[1]

We construct samples of "Syrian" and native "German" Facebook users in Germany. Our sample of "Syrians" consists of 350k users who have spent a substantial amount of time in Syria, or who report a Syrian hometown.[2] Our sample of native "Germans" consists of 18 million users and is based on self-reported profile information, home region predictions, and German language usage.

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[1] The underlying research paper is "The Social Integration of International Migrants: Evidence from the Networks of Syrians in Germany" by Michael Bailey (Meta), Drew Johnson (Harvard), Martin Koenen (Harvard), Theresa Kuchler (NYU Stern), Dominic Russel (Harvard), Johannes Stroebel (NYU Stern)

[2] This definition of "Syrians" therefore includes people that did not necessarily enter Germany as refugees, as well as people who may not be Syrian nationals.

We measure social integration[3] using three indicators:

1. The number of Facebook friendships that Syrians have with Germans
2. The share of public content shared by Syrians that is in German
3. The number of local Facebook groups, such as local soccer clubs, joined by Syrians

This unique data allows us to precisely measure social integration, generating a number of new insights. For example, we are able to document substantial differences in integration at the county level and highlight factors that drive successful integration. Our findings are important for efforts around the world to facilitate the social integration of current and future refugees.

FINDING 1: SYRIANS IN GERMANY GENERALLY HAVE LOW LEVELS OF SOCIAL INTEGRATION

The average Syrian in Germany has only five Facebook friendships with local Germans, and half of Syrians in Germany have one or fewer. For comparison, Germans, on average, have more than twenty times as many friendships to other local Germans. The other social integration indicators paint a similar picture.

Beyond these averages, there are substantial differences in integration across genders and age groups: men and younger Syrians living in Germany appear to be substantially more integrated than women and older Syrians.

FINDING 2: THERE ARE LARGE GEOGRAPHIC DIFFERENCES IN SOCIAL INTEGRATION

Figure 1 shows large geographic differences in the social integration of Syrians living in Germany. Syrians living in blue regions have, on average, more than twice as many Facebook friends as Syrians living in orange regions.

Rural areas have the highest degree of social integration. For example, Syrians in rural regions of Mecklenburg-Vorpommern, Lower Saxony, Rhineland-Palatinate, and southern Bavaria have more than seven German Facebook friends on average. In con-

[3] While there is no single definition of social integration, the concept is often defined by the frequency of interactions of individuals of different groups. Importantly, there is a distinction between the two-sided process social integration and assimilation. The latter, which is defined in terms of cultural identity, is not the focus of our work.

trast, the social integration of Syrians in medium-sized cities such as Ansbach, Kaiserslautern, and Cottbus is comparatively low. The integration of Syrians living in Germany's largest cities such as Berlin, Munich, and Cologne are somewhere in between.

FINDING 3: LOCAL ENVIRONMENTS, RATHER THAN PEOPLE, LARGELY EXPLAIN REGIONAL DIFFERENCES

There are two possible explanations for these regional differences in integration outcomes. On the one hand, these differences could be due to the causal impact of local environments, including local institutions and policies. On the other hand, the differences could be due to differences in the populations living in the various locations. For example, it could be that Germans in some places are more open towards Syrians, or that Syrians living in some locations are more eager to integrate.

To differentiate between these explanations, we use a research design that compares the integration of "movers," who move from one location (e.g., Kaiserslautern) to another (e.g., Cologne), with the integration of "stayers," who permanently live in these locations.

We observe that, prior to moving, Syrian movers have the same rate of integration as Syrian stayers in their origin location (in the example above, Kaiserslautern). Immediately after moving, their rate of integration becomes similar to that of Syrian stayers in their destination location (e.g., Cologne). This finding suggests regional integration patterns are not driven by systematic differences in Syrians' willingness to integrate across counties. The patterns above, then, are not due to differences in the Syrian population.

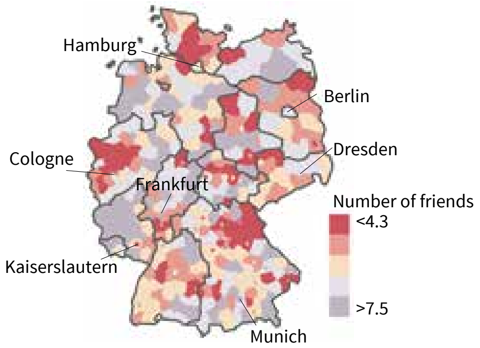
The same methodology also helps us to understand the role of the German population. When Germans move across locations, their rate of making Syrian friends also adjusts quickly to the rate of stayers. However, the adjustment is not full, in particular for older Germans. Differences in the German populations across places therefore contribute somewhat to the observed regional differences in integration outcomes. However, the observed substantial (if not full) adjustment in the behavior of movers suggests that other local factors play an even more important role.

FINDING 4: INTEGRATION COURSES HELP FACILITATE SUCCESSFUL INTEGRATION

Given the important role of place-based factors, we study the effect of federally-funded integration courses,[4] whose availability varied substantially across locations.

Figure 1

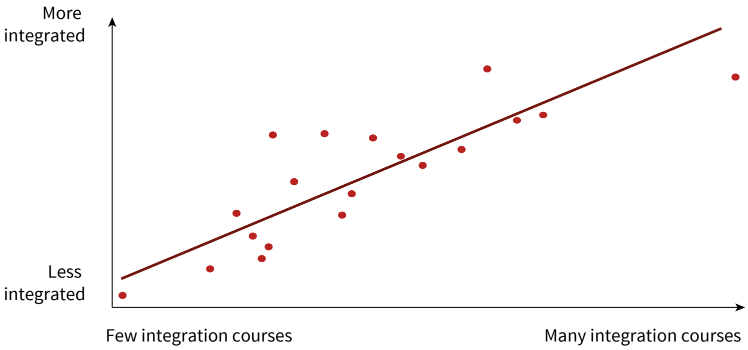
Map of Social Integration



Source: Authors' compilation. © ifo Institute

Figure 2

Integration Courses and Social Integration



Source: Authors' compilation. © ifo Institute

Our findings in Figure 2 show that Syrians in locations with more completed integration courses are, on average, better integrated.

Further analyses (using an instrumental variables approach) show that this relationship is causal. This suggests that increasing the availability of integration courses can lead to both higher levels of German language knowledge and social integration.

FINDING 5: INITIAL CONTACT LEADS TO FOLLOW-ON CONTACTS

Finding 3 highlights that differences across the German population contributed to explaining some of the regional differences in integration. We therefore also studied which factors explain differences in the probability of Germans becoming friends with local Syrians.

We find that German men and younger Germans have more contact with Syrians, perhaps because the population of Syrian migrants in Germany is disproportionately male and young.

In addition, we find that Germans who had contact with Syrians in one setting are often more likely to also befriend Syrians in other settings. We study this in the context of high schools. Germans who shared a high school cohort with a Syrian student have more subsequent friendship links with Syrians

[4] Integration courses, which are intended to teach migrants the German language and other relevant information, are "at the core of the government's integration measures." Over a million individuals have taken these courses since 2015.

outside of high school compared to Germans in the same high school but without a Syrian student in their cohort. Initial contact can thus facilitate substantial follow-on relationships.

This finding suggests that policies that generate opportunities for interactions between Germans and Syrians have the potential to generate long-lasting improvements in integration outcomes.

POLICY CONCLUSIONS

Our study shows that much remains to be done to improve the social integration of Syrian migrants in Germany. Understanding which policy tools might be effective at integrating newly arriving migrants is particularly important in light of the substantial recent influx of individuals fleeing the war in Ukraine. By studying which regions have been relatively more successful at integrating refugees, our work explores the importance of various factors in driving integration. Specifically, we find that increased availability of integration courses can play an important role in improving the social integration of refugees in Germany. Similarly, our work could help policymakers to better allocate newly arriving migrants to regions where they face the most substantial chances of successful integration.