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What to cap?

Emergency Interventions in the European Electricity and Gas Market

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What to cap? Emergency Interventions in the European Electricity and Gas Market

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Executive summary

"Perfect is the enemy of good"
-Voltaire

Since the quasi-7-fold increase of the price of gas in the last year (consequently electricity prices as well), member states and the European Commission came under increasing pressure to rapidly 'find a solution' to the economic and social consequences, inter alia by intervening in the electricity and gas markets. In September 2022, the European Commission proposed a twofold approach to address the ongoing energy crisis, caused by the increase of energy prices, involving both (i) a cap on the revenue of inframarginal energy producers, and (ii) electricity demand reduction measures.

The revenue cap includes several exemptions, and most notably does not include all renewable energy generation. Furthermore, revenues from baseload could be lower than expected due to the high share of hedged volumes. In our view, this questions its success in achieving the EUR 117 billion in revenues that the Commission plans to. Our analysis shows that a technology-specific revenue cap would allow for the generation of more government revenues. However, it is connected to a higher risk of causing market distortions and its implementation is considerably more difficult than that of a uniform revenue cap. In the end, these distortions could decrease the potential revenues of a technology-specific price cap. Therefore, we recommend the use of clearly time-limited, carefully calibrated, least disruptive, uniform revenue cap when faced with the choice between the two instruments. We support the idea to base payments on physical production multiplied by the Day-Ahead price to keep incentives for generators to dispatch in the market they add the highest value to. The revenue cap should also include financial trades, which need to be linked to a generation technology, for example through a trade registry. To simplify the implementation of the cap, only new contracts should be subject to the regulation.

Demand reduction is the most important measure when facing a supply shock and high energy crisis costs. Demand-side response is already reacting to current price signals. New or existing instruments focussing on large energy consumers should target additional capacities to have an impact. We suggest that any scheme should target the hours in which gas-fuelled power plants are running, to target it more specifically towards gas savings. The baseline needs to be well defined to ensure that demand reductions are taking place and market participants do not game the system.

At the same time, none of the proposed measures targeting the electricity market solves the problem of record-high gas prices. This still remains a hugely pressing issue for the industry, since funds from both a revenue cap on inframarginal generators and a foreseen 'solidarity contribution' from companies in the gas, coal and refinery sectors will likely not be enough support.

Regarding an assumably unavoidable gas market interventions, we propose a price limit for the EU domestic market, which has the potential to effectively respond to abuse of dominant position by Europe's pivotal supplier Gazprom: A limit for the TSOs imbalance price. All market participants can – as fall-back option – access gas through the TSO at this price. Should there be insufficient gas available at the price, then the TSO will apply curtailment according to the agreed protocol. It has the effect, that no gas suppliers will be willing to pay for gas a price exceeding the limit. Gas producers therefore will have to reduce the price at which they offer new contracts to levels at or below the price limit to continue to profit from sales in the EU market. Such a price provides clarity about price developments in case of a supply interruptions, and thus can largely reduce risk premia on forward prices.

It can be considered to combine an EU scale price limit with a premium system or contract for difference for LNG imports. Should competing LNG importing countries strategically escalate prices, this would provide an adequate response of the EU to continue to maintain suffiecient volumes of LNG shipments to the EU as a back-up measure.

However, the reduction of the wholesale price level will reduce gas prices incentives for gas savings. Therefore, a price limit needs to be combined with a binding EU agreement on gas saving targets. This would provide the basis for national governments to implement programs and measures to reliably realise gas savings. These can include pricing structures, e.g. a high surcharge for gas-consumption exceeding 80% of consumption in the preceding year, tenders for gas saving by industry, shared communication.

All interventions should be limited to addressing the current energy cost crisis, and not to overhaul the principles of the market design.

Overview of proposed policy recommendations for the electricity market

Windfall profit levy	**Explore feasibility of a windfall profit tax at the corporate level to be levied on inframarginal power producers.** Such a tax could be designed to be consistent with the tax on oil and gas producers/refiners, that is, to collect profits that exceed the average profit of the last three years by at least 20%. This definition could be extended to electricity producers and traders.
Revenue cap	**If a revenue cap is implemented:** 1. **Uniform revenue cap**: the revenue cap should be uniform, across all Member States, to allow for the least disruptive and feasible solution. While technology-specific revenue caps might lead to higher revenues for the member states, implementation is substantially more administratively complex and error-proneprone to unintended effects than a uniform revenue cap. **2.** **Time-bound**: to ensure the efficient functioning of the electricity market, any revenue cap should have a clear deadline to address the current energy crisis, while leaving investment incentives in place in the long term. We suggest that the cap shall remain in effect as long as the three-month rolling average of baseload futures is higher than 180 EUR/MWh and should in any case be phased out completely no later than two years from now (winter 2024/2025). **3.** **Allow efficient dispatch across markets**: if the revenue cap equalises profit opportunities across all markets, market participants have no incentive to provide system services such as balancing and redispatch. We therefore support the proposal[1] to base payments on physical production multiplied by the Day-Ahead price to keep incentives for generators to dispatch in the market they add the highest value to. **4.** **Linking generation technology and trading**: The revenue cap should include financial trades. As those cannot be based on a physical production schedule, the financial trades need to be linked to a generation technology, for example through a trade registry. **5.** **Apply revenue cap only to new contracts:** to simplify the implementation of the cap, only new contracts should be subject to the regulation.

[1] Maurer, Christoph, Ingmar Schlecht and Lion Hirth, "Six flaws in the EU Electricity Emergency Tool and how to fix them", Euractiv (2022)

	6. **Cross border sales need to be regulated**: For cross border sales outside of the EU, excess profits need to be extracted in the market in which selling entity sits. This is needed to avoid distortions at the border.
Demand reduction measures	Explore adapting existing demand response mechanisms, or establishing new demand response tenders for large energy consumers, that are: 1. **Additional**: as demand-side response is already reacting to current price signals, any scheme should target additional capacities of demand response to have an impact. 2. **Target hours of peak gas use**: Any scheme should target the hours in which gas-fuelled power plants are running, to target it more specifically towards gas savings. 3. **Protected against gaming**: The baseline of any scheme needs to be well-defined to ensure that demand reductions are taking place and market participants do not game the system. At the household and small business level: 1. **Establish systems and campaigns** such as the French EcoWatt model to encourage power saving at times of peak prices at the household level. 2. **Preserve existing retail tariffs for 80% of historical consumption**, coupled with support to utilities to cover the difference in cost, while leaving the remaining 20% of historical consumption exposed to wholesale prices to encourage energy saving.

Overview of proposed policy recommendations for the gas market

Gas price limit for EU domestic market	**Set a limit for the TSOs imbalance price:** All market participants can – as fall-back option – access gas through the TSO at this price. Should there be insufficient gas available at the price, then the TSO will apply curtailment according to the agreed protocol. This provides clarity about price developments in case of a supply interruptions, and thus reduce risk premia on forward prices. 1. **Price limit to be set high enough to continue to motivate gas producers to deliver gas at full capacity** 2. **The price limit influence the extent to which Asian power sector will shift from gas to coal and oil generation**. The price limit needs to be high enough for possible coal and oil price scenarios, or indexed to global oil and coal prices if these exceed thresholds. 3. **Engage early with all gas suppliers** like Norway, Algeria and major LNG producers on such an approach to ensure a shared understanding of objectives and rational.
LNG imports	**Explore combining the EU scale price gas limit with a premium system or contract for difference for LNG imports.** Should competing LNG importing countries strategically escalate prices, this would provide an adequate response of the EU to continue to maintain suffiecient volumes of LNG shipments to the EU as a back-up measure.

Firm gas saving targets and programs	**Introduce legally binding and credible fixed gas saving targets**, which deliver additional saving at the scale of 6% and mitigate the inefficiencies of the price limit mechanism. 1. **Maintain incentives for gas saving** with a levy for gas consumption exceeding 80% of previous year consumption, to allow for incentives for gas savings at a similar scale to the incentives without a price limit. 2. **Additional gas saving potentials in industry** available at prices exceeding the (limited) wholesale price can be realized through public tenders for gas savings (analogous to existing tenders for demand side response). 3. **The implementation of a price limit, will require a change in the design of incentives to avoid financial hardship** (at high gas prices) towards incentives to retain marginal saving incentives (with price limits).

1. Introduction

The Russian invasion of Ukraine marks a turning point for the European energy markets. Unprecedented levels of gas prices developed into a 'perfect storm' with an all-time low of available capacity to generate electricity in Europe, which led to questioning of the market fundamentals, such as the merit-order. Since the quasi-7-fold increase of the price of gas in the last year[2] (consequently electricity prices as well), Member States and the European Commission (the 'Commission' hereafter), came under increasing pressure to rapidly 'find a solution' to the economic and social consequences, inter alia by intervening in the electricity and gas markets.

In September, the Commission tabled several proposals designed to address the short-term issues in European energy markets and complement additional reform proposals to improve the functioning of the energy markets in the longer term. On the electricity side, it proposed a mandatory cap on revenues of inframarginal electricity producers exceeding 180 EUR/MWh, and mandatory demand reduction targets for Member States. The propositions are very high-level in character, since they introduce mandatory obligations for Member States, but state these in general terms only. However, to provide significant relief to European power consumers while leaving the wholesale electricity market intact, remaining gaps in the suggested interventions need to be addressed and carefully calibrated.

At the same time, none of the proposed measures targeting the electricity market solves the problem of record-high gas prices. This still remains a hugely pressing issue for the industry, since funds from both a revenue cap on inframarginal generators and a foreseen 'solidarity contribution' from companies in the, gas, coal and refinery sectors will likely not be enough support. So far, measures to reduce wholesale or import gas prices are missing, although these have been discussed by the Commission and Member States in recent weeks. Yet, the pressure to introduce a gas price cap is bound to increase as rapidly as the approaching cold season.

Regarding electricity market interventions, this paper analyses open questions to be addressed for introducing a uniform or technology specific revenue cap on inframarginal pricing. It also provides policy recommendations for a time-bound, flexible, least disruptive, and functioning cross-border implementation of such price caps. Furthermore, it discusses how to unlock additional demand-side response in the short term, since demand reduction is the most important measure when facing a supply shock and high energy crisis costs.

Regarding the assumably unavoidable gas market interventions, the second part of the paper analyses the options for a European gas price limit and how it could be implemented. The paper examines and outlines a price limit design based on the TSO imbalance mechanism, which has potential to effectively respond to abuse of dominant position. It also explores the necessary supplementing measures for ensuring sufficient LNG deliveries to Europe and the importance of gas saving targets to tackle the inefficiencies of the price limit mechanism.

The remainder analyses the interrelations between the examined measures on the electricity and gas side, and it discusses the level of a time-bound gas price limit to ensure efficient power generation. This paper argues that interventions should be limited to addressing the current energy cost crisis, and not to overhaul the principles of the market design, which is able to integrate increasing amounts of renewables, and to provide the needed price signals for flexibility.

[2] ICE Endex, "ICE Futures And Options" (2022)

2. The problem to be addressed by any reform of the EU's energy market design

What exactly is the problem we are facing right now, and how did we get there?

The Russian invasion of Ukraine on 24 February 2022 marks a turning point for European energy markets. Unprecedented levels of gas and electricity prices led to questioning of the market fundamentals.

The situation on the energy markets escalated step by step. Already in autumn 2021, energy prices were well above long-year averages. While in previous years gas storage capacities have been filled during the summer months, in 2021, gas prices remained high during the summer, and North-West-European storage remained about 10 percentage points below the levels usually seen.

On 22 February 2022, German Chancellor Olaf Scholz withdrew the certification of a second North Stream pipeline considering rising tensions with Russia. In reaction to the Russian invasion of Ukraine, Western countries stood together and decided on sanctions on multiple areas, from banking to imports - but exempting the energy sector. The importance of Russian energy imports for the EU was too high to come to a quick and shared response. To address this dependency, the Commission published its REPowerEU Strategy on 8 March 2022. It aims to ramp up biomethane and renewable hydrogen as alternative gases as well as incentivise energy efficiency and renewables buildout. Reacting to the imposed sanctions, Russia stopped gas export to different importers. On 15 June 2022, North Stream 1 gas flows drop to 40% of its capacity before being fully put to a halt at the beginning of September.

The gas crisis quickly transformed into an energy crisis, impacting the electricity sector. When a gas plant is producing electricity, the high costs it pays for the fuel it uses translate to the electricity price.

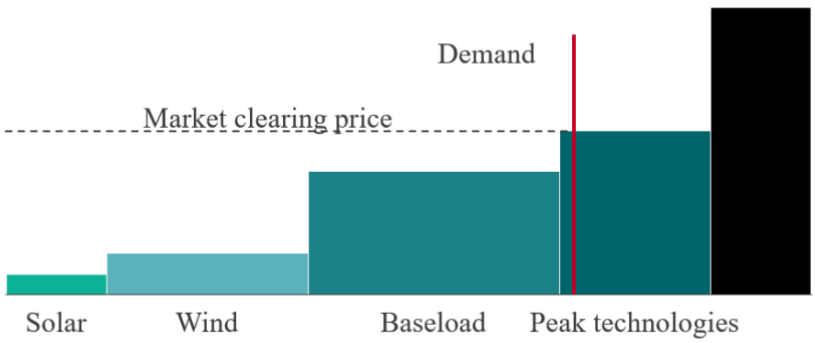

Figure 1: Exemplary Merit Order of the electricity market

Power is traded on a market. Generators place a bid on the level of their costs to produce an additional kWh of electricity (short-run marginal costs, SRMC). The technologies are ranked from the cheapest to the most expensive ("merit-order"), as depicted in Figure 1. The cheapest technology is deployed first, and more expensive sources are added if demand requires it. The most expensive technology sets the price that all suppliers receive ("marginal pricing"). If demand is low, it may be only renewable energy sources and nuclear reactors producing electricity. If demand increases, other, more expensive technologies are dispatched. This reflects economic theory of homogenous goods to coordinate demand and supply and ensures an efficient dispatch. This means that electricity prices are not coupled to gas prices, as it is often stated. Indeed, in moments in which gas-fuelled power plants are the marginal technology, the gas price impacts the electricity price. However, in hours in which renewables

and lower-cost baseload technologies are able to fully cover demand, the gas price does not set the electricity price.

The escalations leading to higher gas prices developed into a 'perfect storm' with an all-time low of available capacity to generate electricity. Climate policies in all European member states have rendered coal, lignite, and oil plants uneconomical, or mandated their phase-outs altogether. Additionally, Germany is in the process of phasing out its last nuclear capacity, and nuclear reactors in France generated around 20% less electricity than in 2021[3] due to partly unforeseen maintenance. On top, this summer was one of the driest summers recorded, aggravating the problems in the energy sector: Hydropower plants were producing less electricity. Water levels in main European rivers were too low to transport coal to the power plants, and too warm to be used for cooling, impacting especially nuclear reactors.

The supply shock led to gas-fuelled power plants setting the price in the electricity market more often. Together with rising gas prices, this means that wholesale power prices increased considerably, as can be seen in Figure 2.

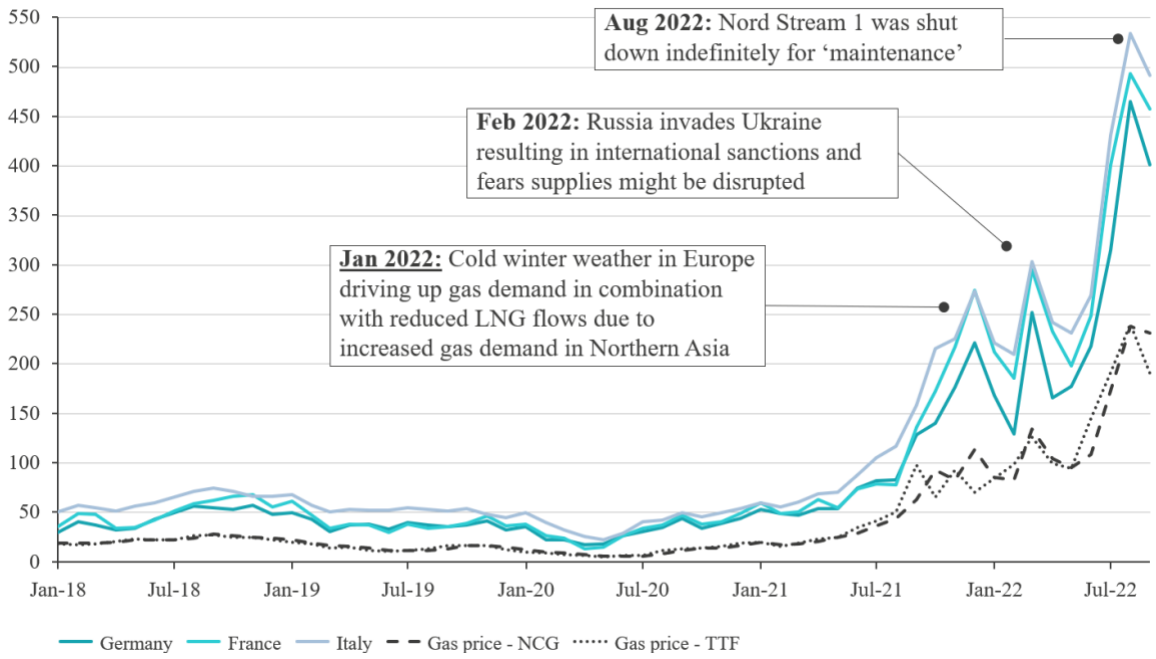

Figure 2: Development of wholesale power prices

High prices on the wholesale power market result in high power prices for industrial and residential consumers. Even though consumers (especially residential consumers) are partly protected from sudden price increases, the overall part of energy costs based on their overall spending is predicted to increase drastically, leading to more energy poverty. Considering the disruptive effects of higher power prices on businesses and end consumers, member states face high pressure to act.

A brief calculation shows that the additional expenditures on electricity alone compared to pre-crisis levels might be substantial. We find that those additional expenditures over a period of one year could be equivalent to 5.8% of 2021 GDP in Germany, 6.5% in Italy, 7.5% in France and 4.4% in the Netherlands. However, one should note that these estimates represent an upper bound of the

[3] EDF, "Financial and Extra-Financial Performance: Nuclear Output in France", (2021)

potential burden.[4] Based on our method of calculation, the total yearly expenditures on electricity of the four countries mentioned above usually amount to 1 to 2% of GDP.

Why is a European level intervention in this crisis necessary?

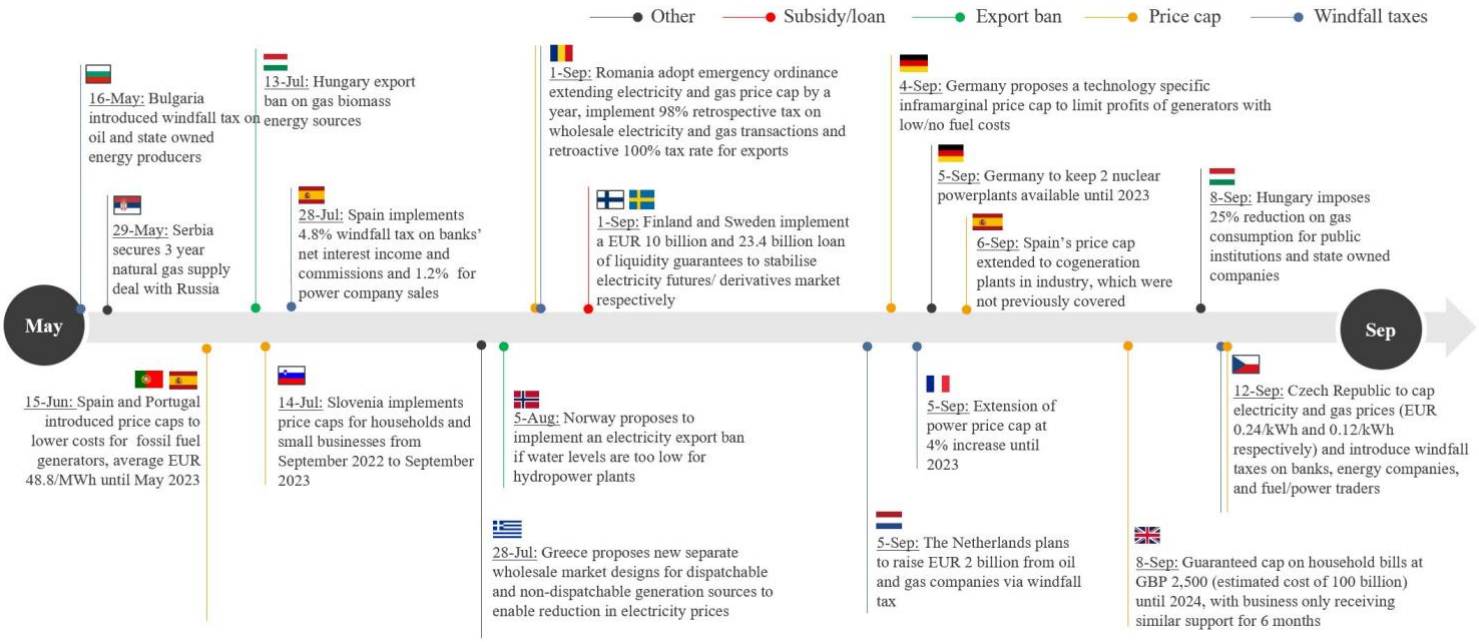

Figure 3: Timeline of EU member states measures

Over the past few months, several national governments have proposed or introduced short-term market interventions to manage the crisis. An overview of the implemented measures is depicted in Figure 3. While emergency measures targeted a broad scope of instruments, such as subsidies, export bans, price caps, windfall taxes and market design changes, they failed to provide an efficient and consistent answer to the ongoing crisis. Part of the reason is that national measures only have a limited, and often even adverse, impact in the interconnected European energy market.

A concrete example is the Iberian price cap to lower costs for fossil fuel generators introduced in June 2022. While it was meant to reduce prices for consumers, it had adverse effects. In comparison to the first days of June, combined cycle power plant (CCGT) generation increased by 52% with the application of the price cap. Whereas Spain mainly imported electricity from France before the application of the price cap, afterwards, it exported up to 60 GWh/day. Next to diluting gas saving price signals, France is profiting most from cheap electricity prices in Spain, as it does not pay the adjustment value. Thus, Spanish electricity consumers pay for lower electricity prices in France.

To create a level playing field and ensure a consistent approach, interventions across Europe need to be aligned. Accordingly, the President of the Commission committed to proposing energy market reforms to address the ongoing crisis. Key proposals circulated at the beginning and in the middle of September in preparation of, and following, the meeting of the EU's energy ministers. This paper will address these.

[4] Price difference is calculated as difference in average Day-Ahead price between August 2021 and August 2022 for the respective country.

The Commission's interventions are designed to address short-term issues in European energy markets and complement additional reform proposals to improve the functioning of the energy markets in the longer term. The distinction between short- and long-term measures is important to consider, as short-term measures would in principle be time-limited to the expected period during which gas markets face a material security of supply risk. The European Commission is also considering long-term market reforms, questioning the principle of marginal pricing. However, it is important to note that in the long-term, the current market design can integrate increasing amounts of renewables and to provide the needed price signals for flexibility. Interventions should therefore address the current energy cost crisis, not overhaul the existing market design, as shown in Figure 4. Further recommendations on how to efficiently design a market fit for renewables have been assessed in two recent studies of the EPICO Policy Accelerator[5].

Short-term

Concern:

- Governments are concerned due to the current high gas and power market prices, questioning merit-order principle

In the short-term, the market efficiently coordinates supply and demand and provides scarcity signals

- Current prices reflect the situation on the gas market and are signaling scarcity
- Measures that mitigate the impact for consumers, while keeping the merit order principle, are suited short-term measures

Long-term

Concern:

- How can our current market design ensure security of supply at low costs while being fully decarbonised?

In the long-term, the market values generation and flexibility and will enable efficient dispatching

- Despite rapid renewable buildout, prices will not collapse as peaking plants and flexible technologies will be price setting in many hours

Figure 4: Short-term and long-term market design

The reason for this is that the energy cost crisis is temporary. As explained above, the Russian invasion of Ukraine resulted in a sharp increase of gas and electricity prices, further pushed by a supply crunch. However, the current gas and electricity prices do not reflect the cost of production and transport, but the demand reduction for gas and power is setting the price. The Aurora energy market model foresees this supply crunch to be resolved over the next two years, supported by additional supply from floating LNG terminals. As a result, gas prices will come down, as can be seen in Figure 5. It shows the difference of the Aurora gas price forecast to the base year 2020.

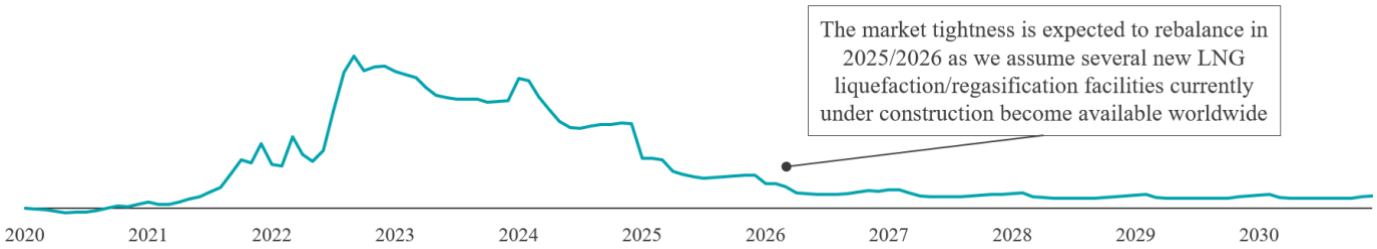

Figure 5: Delta of TTF benchmark wholesale gas price to 2020 base level

[5] EPICO KlimaInnovation, "Der Weg zum klimaneutralen Stromsystem – Aufbruch zu einem marktwirtschaftlichen Erneuerbaren-Zubau in Deutschland" (2021), Berlin; see also EPICO KlimaInnovation, "Ein flexibler Strommarkt für die Energiewende" (2021), Berlin

3. Taking stock: Actions taken on the EU-level

Since an October 2021 Communication[6], the Commission sought to tackle the increase of wholesale electricity prices. By then, twenty member states had already implemented or planned measures, such as price caps and temporary tax breaks for vulnerable energy consumers, or vouchers and subsidies for consumers and businesses. The Commission suggested to reduce taxation rates for vulnerable populations, and to shift financing of renewables from levies to sources outside the electricity bill, favouring marginal pricing. It suggested conservative instruments to protect consumers, that allowed member states to intervene in the energy market in different ways. It proposed aid to both consumers and industry, while phasing out from fossil fuels. Aid would also be directed at expanding access to renewable energy sources (RES) to small and medium-sized enterprises (SME).

In the 8 March 2022 Commission Communication REPowerEU[7], the argument narrowed down to recommending EU law-compatible regulated prices in the retail electricity market. The Commission suggested, inter alia, the possibility of taxing windfall profits, to provide financial relief at the consumer-level. Annex 1[8] insisted that member states should prioritise empowering consumers rather than undermining competitive markets. This would be achieved through increasing access to RES, putting in place a flexible electricity system, and achieving greater energy efficiency. Annex 2[9] further made the argument that by shifting revenues from fiscal measures on infra-marginal rents to consumers, these would be protected from a potential spread of high gas prices to household bills. Such measure suggest the preference to maintain the current wholesale market. This is even clear from the Commission's Communication from 23 March[10] (Figure 5). This also reiterated the importance of a pan-EU coordinated answer, designed for an exceptional and short period.

Financial compensation		Regulatory
Retail	Wholesale	
Income support	Cap on price of fuel for fossil generators (electricity for vulnerable groups can be sold on favourable commercial models)	Fixed price for generators
State aid	Cap on electricity price or compensating financially fossil-based electricity generators	
Reduced taxation		

Figure 6: Table of the European Commission's options (March 2022)

The 29 April 2022 ACER's study on the wholesale electricity market design[11] locates two issues, i.e. lack of supply and lack of investments in RES. These are mirrored by options to overcome these, i.e. (i) competitive long-term markets which (limit risks), and (ii) support schemes for renewables. Finally, ACER locates a set of issues to take into account when shaping the electricity market design (e.g. ensuring electricity as a basic right for vulnerable consumers and reduce costs and windfall profits), implicitly agreeing with the wholesale's status quo, defending the current marginalist system. The May

[6] European Commission, "Tackling rising energy prices: a toolbox for action and support" (2021)
[7] European Commission, "REPowerEU: Joint European Action for more affordable, secure and sustainable energy" (8 March 2022)
[8] European Commission, "Annex 1, Guidance on Application of Article 5 of the Electricity Directive", Communication, (8 March 2022)
[9] European Commission, "Annex 2, Guidance on Application of Article 5 of the Electricity Directive", Communication, (8 March 2022)
[10] European Commission, "Security of supply and affordable energy prices: Options for immediate measures and preparing for next winter", Communication, (23 March 2022)
[11] ACER, "Final Assessment of the EU Wholesale Electricity Market Design", (April 2022)

2022 REPowerEU Communication on the Electricity Market Design[12] mentioned the possibility of emergency liquidity support measures for commodity traders who encounter an increase of prices. It also discussed a potential "administrative price for gas" (i.e. a *de facto* cap). The Commission suggested establishing common principles across the Union. De facto, it pivoted from its original position, as it sets a fixed price for gas, limitedly to the Iberian Peninsula. The 30 June-time limit is removed as to include the following heating season. Shortly after, President Ursula Von der Leyen claimed that the electricity market is not RES-proof, that it is "designed in a way like it was necessary twenty years ago"[13], and that it needs to be reformed.

On 1 September 2022, a leaked non-paper by the Directorate-General for Energy (DG ENER)[14] proposed measures focusing on demand reduction, suggesting a cap on inframarginal electricity generation, using revenues to subsidise consumers. The Commission shifted its position coherently to its communication of 23 March 2022, yet providing a more detailed option, and hinting to the possibility of intervening at the level of wholesale. Indeed, on 7 September 2022, the President announced intentions of "lowering the costs of gas [and proposing] a price cap on Russian gas"[15]. The Council Presidency, at the Extraordinary Energy Council on 9 September, insisted on a common response[16]. Another leaked non-paper by DG ENER[17] provided two independent possibilities, i.e., a cap on solely Russian gas, and applying and coordinating administrative pricing where Russian gas disruption has greater negative effects – seeking interventions at the level of wholesale. Another option would be that of creating two different markets out of the existing one, separating LNG from gas flowing in pipelines, opening up to a new perspective that would not be limited to solely the short term.

In her 'State of the Union' speech, President Von der Leyen insisted on the need to reform the energy market design, reinforcing the position she took in early June 2022. Specifically, she proposed to "raise more than EUR 140 billion for member states to cushion the blow directly"[18], by taxing windfall profits of non-gas power producers. The proposed measure also suggests to add a "temporary contribution on surplus profits in the fossil sector"[19]. Such instrument would allow redistributing profits from cheaper sources of energy generation across member states, as to "mimic the market outcome that producers could have expected if global supply chains would function normally"[20]. Remarkably, in the medium- and long- term, the Commission's aim is that of decoupling the price of electricity from gas. The Commission also proposed an emergency intervention to address high energy prices[21]. While demand reduction would not be compulsory, it would come with a mandatory de facto tax on production of infra marginal generators (yet excluding biomethane, waste, nuclear, lignite, crude oil and other oil products) at 180 EUR/MWh – 20 EUR/MWh less than previously suggested – and applicable to both existing and future contractual obligations. The proposal also exempts companies from having to pay such EU-wide cost, if already subjected to national measures, and ensures a system whereby member states can share with other member states additional revenues. As this still maintains such measure at the level of retail, it would be extendible to SMEs.

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[12] European Commission, "Short-Term Energy Market Interventions and Long Term Improvements to the Electricity Market Design – a course for action", Communication, (18 May 2022)
[13] As reported by Simon, Frédéric and Nikolaus Kurmayer, "EU chief announces electricity market overhaul amid 'skyrocketing' prices", Euractiv (10 June 2022); see also IENE, "Can Europe's Electricity System Deliver More Competitive Prices?", analysis (June 2022).
[14] European Commission Directorate-General for Energy (DG ENER), "Non-paper on Emergency Electricity Market Interventions"
[15] European Commission, "Statement by President von der Leyen on energy", speech (7 September 2022)
[16] Council of the EU, "Extraordinary Transport, Telecommunications and Energy Council (Energy)", (9 September 2022)
[17] European Commission, "Non-paper on emergency wholesale price cap instruments for natural gas"
[18] European Commission, "2022 State of the Union Address by President von der Leyen", speech, (14 September 2022)
[19] European Commission, "Proposal for a Council Regulation on an emergency intervention to address high energy prices", (14 September 2022)
[20] Ibid.
[21] Ibid.

4. Electricity Market Interventions and Reforms

Cap revenues of non-gas power generators

In the latest 'Proposal for a Council Regulation' on the matter issued on 14th September 2022, the European Commission suggested the introduction of a **maximum revenue cap** in the electricity market on inframarginal plants, i.e. generating plants which are not price-setting in each dispatch period. The proposal sets the cap to 180 EUR/MWh. This means that the marginal pricing principle would be maintained, but the generators would face a post-settlement revenue cap. With this intervention the Commission aims to raise a total revenue of EUR 117 billion at the EU level and proposes that governments should be allowed to use the generated revenues to mitigate the difficulties that households and businesses are facing. A further EUR 23 billion is to be raised through a windfall profit tax/levy on oil and gas producers and refiners.

Which assets would fall under the revenue cap according to the current proposal? Which assets would be excluded, and what are the implications?

The cap is supposed to apply to a comprehensive list of generation technologies including renewables as well as nuclear and lignite plants.

At the same time, the Commission intends to exclude a significant part of electricity generation. First, coal-fired power plants would not fall under the cap according to the proposal, assumably since it has high marginal costs. Demand-response and electricity storage should not be targeted by the instrument either. Furthermore, generators below 20kW, biomethane and demonstration plants are excluded from the cap. Also, it shall apply to realised revenues only. By this, the Commission aims to exclude PPAs and forward hedges that have been settled at a price lower than the revenue cap.

For this reason, not all nuclear and renewable power generation will be subject to the revenue cap. As mentioned above, generation from existing contracts is not considered if the price level is below the revenue cap and the instrument should not apply to revenues stemming from subsidies. It is our understanding that installations subject to feed-in tariffs and two-sided CfDs would therefore be excluded from the cap, as they do not profit from the current high prices. On the other hand, electricity generation not sold on forward contracts as well as renewables supported with one sided premia and merchant renewables (not covered by forward contracts or PPAs price above the revenue cap) will be subject to the mechanism. How the cap would apply to power producers in selected markets is shown in Figure 7.

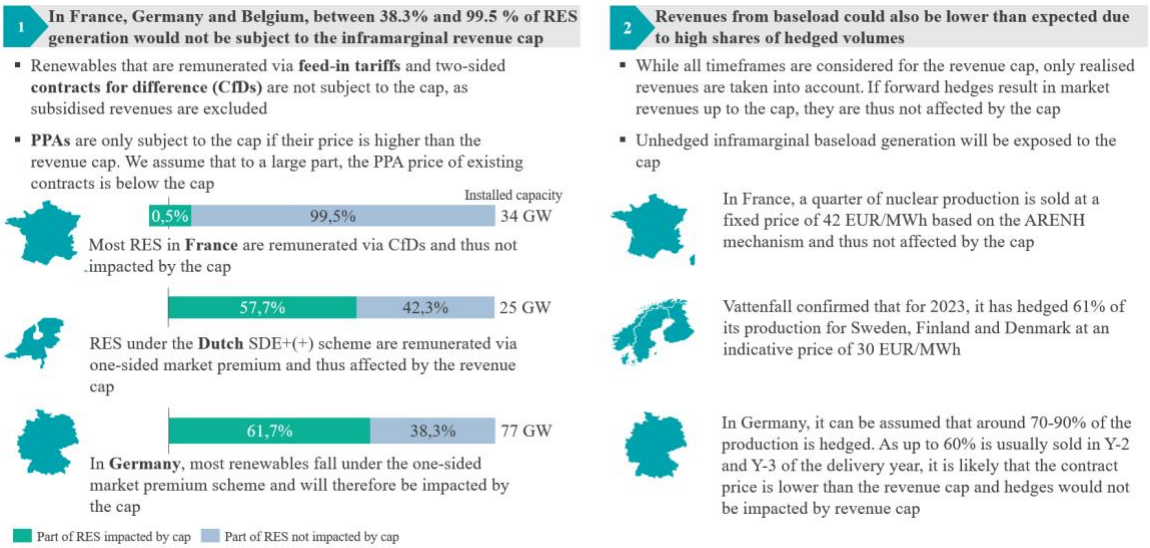

Figure 7: Generation covered by the revenue cap

High-price hours with prices above the cap have a disproportionately smaller share of electricity generation from renewables compared to lower-price hours in which the price is below the cap. For example, indicatory calculations looking at the German market show that generation from renewables in hours above the cap only comprises 21% of total generation, compared to an average share of 35% across all hours. This suggests that even if the proposed wide-ranging exceptions on generation from renewables are eased, the maximum available revenues from renewables generation are limited when compared with thermal assets.

The design of the revenue cap also means that assets will be affected differently in different member states. For example, some member states will be able to generate more revenues than others, for instance France (with a high share of nuclear) as well as the Nordics (with a high share of hydro) and Poland (with a high share of lignite). Germany is less likely to generate the same volumes in relative terms, particularly as its significant amount of solar generation has very low load factors during the inter season. There is a risk that the proceeds of such a revenue cap will not be equitably realised across member states.

Given the limited scope of the proposal, and absent further supporting evidence behind the estimated revenues targeted, it is unclear whether it will succeed in generating the EUR 117 billion in revenue targeted by the Commission.

How does the draft Regulation affect PPAs and futures contracts?
The draft decision does not distinguish between new and existing PPA and hedging contracts, although the draft Regulation states that "the cap should apply to realised market revenues only". On this basis, we understand that existing PPAs/futures contracts with strike prices below 180 EUR/MWh would not be affected by the cap. This is because the maximum revenue that power producers can realise is limited to 180 EUR/MWh.

However, as can be seen in Figure 8, producers with contracted hedges (like PPAs and futures) that realise revenues above the revenue cap level in a settlement period must pay a part of their revenues to a regulating entity. This is because power producers may still retain revenues above 180 EUR/MWh even after accounting for the share of revenues that accrue to the offtaker.

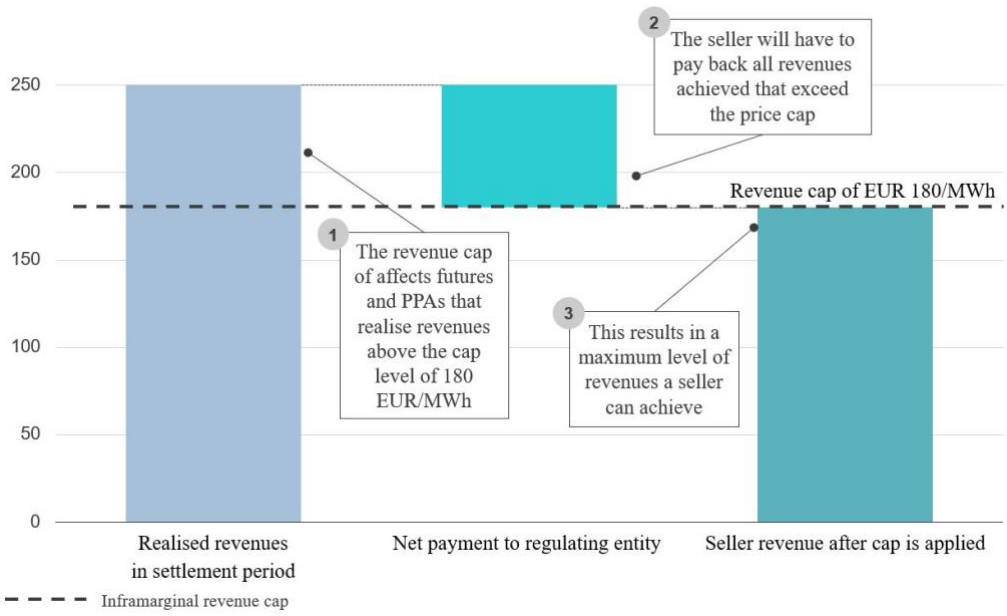

Figure 8: PPA/future contract price and revenues in a given settlement period after application of revenue cap

Short term contracts which have been concluded recently, such as for monthly futures for winter 2022/23, might in contrast well have been concluded at a strike price above the revenue cap recently, and could be impacted by the Regulation. The extent of the impact on such contracts is unclear, both in terms of commercial and legal risks. To simplify the implementation of the cap and to avoid such risks materialising, the revenue cap should only apply to new contracts. For PPAs/futures executed after the implementation of a revenue cap, power producers will have a clear incentive to price PPAs at or below the revenue cap and design them as pay-as-produced.

How does a uniform revenue cap compare to a technology-specific cap?

The recent policy debate has been dominated by two versions of a revenue cap on inframarginal generators: Governments could either implement a uniform or a technology-specific cap. While the European Commission's latest proposal recommends the introduction of a uniform revenue cap, it explicitly allows for the implementation of measures by individual member states which further limit the revenues of producers. This applies to the technology-specific revenue cap put forward by the Federal Government of Germany, for instance.

Figures 9 and 10 illustrate the key differences between a uniform and a technology-specific revenue cap. One important feature of the two interventions is the amount of revenues they generate. As can be seen in the illustrations, the government revenues are likely to be larger in case of a technology-specific cap. Accordingly, the revenues to be kept by renewable electricity generators would be lower for this policy instrument.

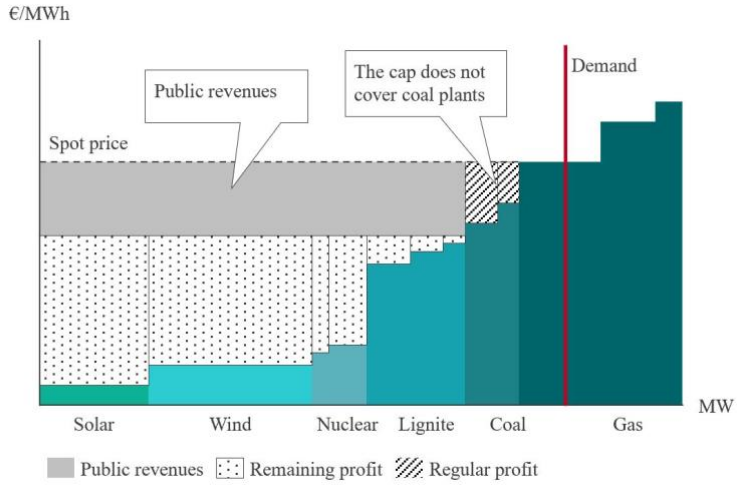

Figure 9: Exemplary merit order with uniform revenue cap on inframarginal plants

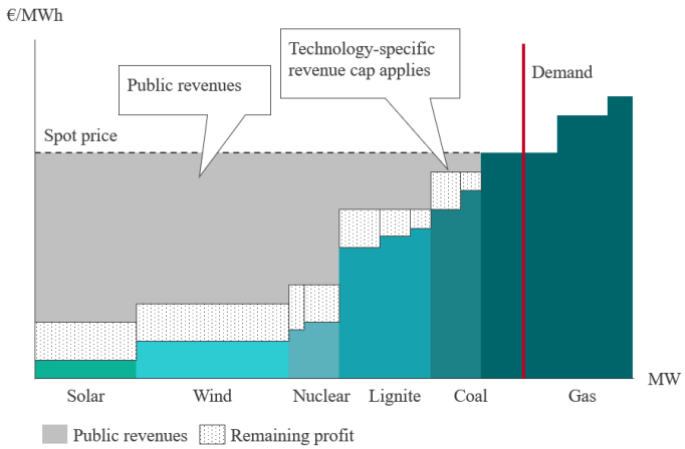

Figure 10: Exemplary merit order with technology-specific revenue cap on inframarginal plants

The implementation of a technology-specific revenue cap is more challenging and associated with a larger risk of causing unintended effects. It requires an assessment of the appropriate revenue level and hence of the marginal costs for each individual technology type. Thus, the transaction costs associated with a technology-specific revenue cap, when each member state adopts different revenue caps for multiple technologies, are significantly higher, for both regulators and market participants. For this reason, the definition of several cap levels is also more prone to errors in its administration and implementation and opens the room for unforeseen interactions between the different caps.

As opposed to a uniform revenue cap, the Greek government introduced a technology-specific price cap in the electricity wholesale market in July 2022. The individual cap levels are updated on a monthly basis based on the latest generation costs. The price for electricity generated by renewables is capped at 85 EUR/MWh in September. The cap level on hydro was set at 112 EUR/MWh and that on lignite at 214.2 EUR/MWh in this period.

The design of the cap also impacts how difficult it is to calculate the payments that revenue-cap facing generators must make. One potential strategy for the regulating entity is to take the daily schedule of generation of each generator and then calculate the generation-weighted average price achieved across all markets. Afterwards the cap could be applied to that number. This calculation would need to be pursued separately for technology-specific revenue caps. As the Commission is seeking to implement measures in the market that take effect as of 1 December 2022 this year, consideration should be given to which measures can be effectively implemented over the coming ten weeks while mitigating the risk of adverse impacts in the market.

The implementation of different cap levels could create more leeway for litigation by renewable generators who do not accept the obligation to give away a larger share of their profits compared to other market participants. Also, different technology-specific cap levels between countries could lead to distortionary shifts in cross-border flows of displaceable fuels and electricity. This effect might occur because the presence of diverging potential revenue levels across countries would induce incentives to move sales across markets in an inefficient way. Different cap levels between countries also create incentives to capture arbitrage through regulatory loopholes (e.g between markets or for operators/owners of combined portfolios).

Finally, the two instruments could also cause different degrees of uncertainty about the severity of future interventions in the electricity market. This uncertainty might slow down investment activity and renewables buildout in the medium term. A technology-specific revenue cap may be seen to even more strongly reflect the concept that generators lower in the merit order, which sets a potentially damaging precedent for future regulatory interventions. Renewables generators will typically face a lower cap level in case of a technology-specific cap and hence retain less revenues if this approach is chosen. Therefore, this intervention could affect the investment incentives required for an ambitious renewables buildout more heavily – particularly if the period during which this measure is implemented is extended.

The above analysis has shown that a technology-specific revenue cap would allow for the generation of more government revenues. However, it is connected to a higher risk of causing market distortions and its implementation is considerably more difficult than that of a uniform revenue cap. In the end, these distortions could decrease the potential revenues of a technology-specific price cap. Therefore, we recommend the use of a uniform revenue cap when faced with the choice between the two instruments.

How can incentives to provide system (ancillary) services be preserved?

Prices differ between markets and timeframes, to ensure that supply is provided where it is most efficient. Typically, markets closer to delivery incorporate important real time information. As the market clears in sequences (Futures, Day-Ahead, Intraday- Balancing, Redispatch), market participants observe price signals and adjust their positions accordingly. This flexibility is needed to balance the power system. When the system is short, the price on balancing markets typically ensures that it is attractive for market participants to provide additional electricity.

The Commission has proposed that the revenue cap applies "regardless of the market timeframe in which the transaction takes place". As the revenue cap equalises the profit opportunities on all markets, market participants are indifferent as to in which market they realise their revenues. However, their contribution does not yield the same value across all markets.

If the revenue cap is applied to all markets, including balancing and ancillary service markets, it will effectively reduce the incentive for generators to provide upwards frequency response services. This is because generators typically need to increase their output to provide additional active power into the grid, and they bid higher than the spot price to recover the additional variable costs of doing so. Whether this risk materialises depends on which generators provide such services in each market – in markets where these are provided by hydro generators that are subject to the cap, such as the Nordics, the risk of a perverse distortion in ancillary markets is higher.

A straightforward solution that would also simplify the calculation of the payment based on the revenue cap is to take the physical production schedule across all markets multiplied with the Day-Ahead price as a basis for the payment calculation, as suggested in an article by Hirth, Maurer and Schlecht.[22] This would mean that a generator is able to fully capture all revenues above the Day-Ahead price. As pointed out by the authors, this would incentivise generators to dispatch where the value of their generation is the highest and resemble the existing contracts for difference. While revenues for the state would be slightly lower, it would ensure efficient dispatch.

Worked example

A hydro power generator is subject to the revenue cap of 180 EUR/MWh. The generator sells 10 MWh at the Day-Ahead market for 250 EUR/MWh. As the time of delivery approaches, the Intraday price is high as less wind production is available than predicted. The hydro generator sells additional 2 MWh on the Intraday market for 300 EUR/MWh. If the revenue cap payment is calculated based on the generation schedule and Day-Ahead price, the generator can keep the price difference between the Intraday and the Day-Ahead price. The generator gets to realise 10 MWh *180 EUR/MWh + 2 MWh* 230 EUR/MWh = EUR 2260.
In a situation where the payment would be calculated for each market separately, the generator would realise a lower revenue of 12 MWh* 180 EUR/MWh = EUR 2160. As shown in the example, the calculation based on the Day-Ahead price both simplifies the settlement of the revenue cap and incentivise generators to dispatch in the market where they achieve highest value.

This approach creates the risk that generators withdraw bids from the Day-Ahead market in order to realise higher revenues in the intraday and balancing markets. This risk may be mitigated through bidding behaviour, as market participants would seek to guarantee some level of revenue in the Day-

[22] Maurer, Christoph et al., "Six flaws in the EU Electricity Emergency Tool and how to fix them", op. cit.

Ahead market rather than leave themselves exposed to the volatility of the intraday and balancing markets. Absent detailed dispatch modelling it is not possible to further quantify this risk.

Experience from the Greek implementation of an inframarginal technology revenue cap is not directly relevant here. This is because the cap is applied only to the Day-Ahead market, and not to the balancing/ancillary service markets. Moreover, unlike in more liberalised markets in Western and Northern Europe, generators are mandated to bid into the balancing/ancillary service markets, so such distortions have not been observed.

How to link trades and technologies?

Irrespective of whether a uniform or a technology-specific revenue cap is implemented, for it to be effective, the relevant regulatory/government body overseeing the cap must be able to identify which market trades are associated with specific types of power generating technologies. This is more problematic under a technology-specific cap, as the number of technologies is large, while it is somewhat more feasible under a uniform cap, as potentially gas, coal and oil generation need to be distinguished from everything else.

Trading in Europe does not only take place physically, but also financially. As electricity is typically traded several times before it is produced, defining the resulting payment of a revenue cap is challenging. Market participants typically trade and hedge based on portfolios and not on assets, meaning that it is not possible to identify which trade is linked to which physical asset, and hence to which technology.

Often, it is proposed to calculate the revenue cap based on the physical generation schedule instead of bids to avoid the problem mentioned above. However, this causes a different problem: If the payment is calculated based only on the physical generation schedule, financial trading would be exempted from the revenue cap. While financial trading is an important part of the power system and provides liquidity and hedging opportunities, this might lead to distortions in power trading.

In case financial trading is exempted from the cap, physical producers would face an incentive to sell their output to a financial trader below the cap. The financial trader in turn could sell the produced power at prices higher than 180 EUR/MWh without being impacted by the revenue cap (as they have no generation schedule). As a result, the revenues that the Member State intended to collect would have been instead collected by an intermediary market participant.

Evidence of this risk materialising from the implementation of an inframarginal revenue cap in Greece this year is inconclusive. This is because the Greek futures market is relatively illiquid, and most volumes of power are traded on the wholesale spot markets by market participants who own generation assets. The risk is therefore higher in markets where significant volumes are traded on futures markets.

How to solve this dilemma? A way forward would be to either revert to asset-based bidding during the application of the cap. This is however a fundamental change and not easy to implement. A second option would be to base payments on the physical generation schedule and the Day-Ahead price as discussed above, but to extend the revenue cap mechanism to financial trading. This would mean that financial traders would have to prove which technology mix is behind their bids, for example based on a registry. While this solution would come with a considerable administrative burden, it would avoid that physical producers use financial traders to circumvent the cap. This would for example apply if a

financial trader bought electricity and resells it on the Day-Ahead, Intraday or Balancing market.[23] In the case of a uniform revenue cap the administrative burden would be lower than in the case of technology-specific revenue caps, as financial traders would have to link their bids only to inframarginal technologies in general, and not to specific technologies.

Trade registration already takes place in certain markets. The MIBEL (Spanish and Portuguese market) is a gross pool. The market operator has visibility on all generation and bilateral trades need to be reported to the system operator. Intercompany trades also need to be reported.

How is cross-border trading impacted?
The more harmonised the revenue cap is designed across European countries; the less distortions will be observed. While Day-Ahead and Intraday on the exchange are coupled markets (where demand and supply are matched in a common optimisation with available interconnector capacity), OTC markets would allow to deliberately sell electricity into another country and explicitly reserving transmission capacity to do so.

Different revenue caps in different countries incentivise market participants not to sell where the supply is most needed (i.e. where the price is the highest), but in the market in which they can realise the highest revenues. This might increase inefficient power flows across countries. Therefore, cross border distortions need to be addressed, either at EU border, or between member states with different caps. This is best done by basing the calculation always on the delta between the revenue cap and the Day-Ahead price of the country where the asset is located. This would mean that trade signals are not distorted but the cap cannot be avoided. In order to minimise the risk of further regulatory loopholes being exploited, the revenue cap should be as harmonised across member states as possible.

How will intervening in the power market affect renewables investment costs more generally?
The possibility of high prices makes investments in renewables more attractive and there are products, like PPAs etc. out there which translate the possibility of high prices into continuous revenue streams, which are needed to finance these investments. The risk of capping the upside is that the value of these products is also lowered.

A revenue cap of 180 EUR/MWh is high enough to make renewable investments profitable, and justified given the current crisis, but the risk of market intervention, prolonging the current one, decreasing the price cap etc. will be priced into the cost of capital for these investments. It is plausible that once an inframarginal revenue cap is in place and effective enough to generate a substantial amount of revenues, policy makers will be tempted to keep it in place – particularly when they are under pressure to avoid spiralling increases in gross government debt. Hence it is crucial to have a clear deadline and phase out process for this emergency market intervention.

The Commission's proposal currently requires the measures to be implemented over a four-month period from 01.12.2022-31.03.2023, while gas prices are predicted to stay significantly higher until 2025/26. Should the proposed measures be extended beyond March 2023 in a few months' time, it will introduce further uncertainty into a market that has already been "spooked" by the threat of regulatory intervention. Extending the measures now to better align with the expected period of high energy prices could provide market participants with more certainty – but only if there is confidence in the market that these measures will be revoked once prices are under control. We suggest that the cap shall remain in effect as long as the three-month rolling average of baseload futures is higher than

[23] Consumers are not captured by the revenue cap, so they would not have to pay anything back in case of financial trades. This is important to achieve the goal of lower energy costs and keep incentives for hedging.

180 EUR/MWh and should in any case be phased out completely no later than two years from now (winter 2024/2025)

The amount of investment needed to transform the energy sector in the EU over the next decades is massive – almost EUR 340 billion over the next decade - and needs to largely come from the private sector. Increasing the cost of capital of this investment by 100 basis points already increases financing costs by around EUR 17 billion[24]. This has flow-on effects in terms of renewables investment and the commercial environment for private off-take arrangements such as corporate PPAs, which is an emerging driver of new renewables build out. The impact of heavy-handed regulatory intervention in the power sector therefore needs to be taken into account when considering the net benefits to society of such short-term measures.

Case study: regulatory risk in Spain

In practice, the Spanish government's retroactive change to its subsidy scheme in 2010/12 provides a negative example for how uncertainty regarding government intervention can be detrimental to the buildout of renewables. In this case, the Spanish government reduced the scope of the feed-in tariff scheme – partly retroactively – by lowering the number of installations the instrument was applicable to as well as the fixed remuneration level for those generators still benefiting from it after the adjustment. The resulting increased uncertainty and reduction in revenues from subsidies led to a complete collapse in further buildout of renewables. While double-digit percentage increases in capacity were commonplace prior to the changes to the regulatory framework, no additional renewables capacity was installed between 2012 and 2016.

What will the effect of this market intervention be on innovation in the energy sector?

It is much harder to quantify is the long-term effect of market-based prices on innovation. Volatile prices will (and do already) drive innovation that will help to integrate renewables into the system.

The proposal to establish revenue caps by reference to specific technologies carries risks. For example, it is not necessarily clear when a small hydro plant would be classified as a hydro plant, which is covered by the EU's proposal, or as a storage facility, which is not. Similarly, a renewable plant which is co-located with a storage asset has characteristics of both assets – how much storage do you need to classify a co-located asset as storage to be exempt from the price cap? Similar questions arise in terms of combined technologies e.g. co-located renewables and electrolysers, and the aggregation of rooftop solar (and storage).

At the same time, the focus in power market design on avoiding excessive profits from technologies that have received extensive public support in previous decades through a revenue cap creates the opportunity to retain the marginal power pricing signal intact. All flexibility options can continue to capture the value the flexibility offers to the system. It's impossible for governments and regulators to foresee all possibilities, but regulating prices for some technologies/business models but not for other, requires them to take a stance, which could lead to suboptimal outcomes, e.g. by creating perverse incentives. At the very least it will create uncertainty until these questions are solved and therefore delay innovation that is needed to accelerate the transition to clean energy technologies.

[24] Assuming financing charges represent 40% of capital expenditure, and the weighted average cost of capital increases from 8 per cent to 9 per cent.

Windfall profit tax as alternative short-term measure

Our analysis revealed that both uniform and technology-specific revenue caps are complex to implement and prone to causing market distortions. At the same time, expected revenues are likely lower than expected by the European Commission, as a large part of generation does not realise the current high spot market prices.

The Commission aims to generate revenues of windfall profits to finance support measures for energy consumers. As an alternative to a revenue cap, a tax on windfall profits could be a suitable measure and should be further investigated. Such a tax would be calculated based on the overall profits of electricity producers and traders and dealt with through the taxation system, rather than through the settlement infrastructure of exchanges, settlement agents, market operators etc.

The current proposal of the European Commission already foresees a one-off windfall profit contribution for fossil fuels in 2022. Revenue from the windfall tax on oil and gas companies will contribute towards a solidarity payment that should go towards supporting vulnerable households and domestic (renewable) energy sources. This windfall profit tax could be extended to cover electricity producers and traders.

How to calculate windfall profits?

The crucial part of the measure would be to identify what is the windfall profit of a company. For the oil and gas companies, the European Commission defines windfall profits as those that exceed the average profit of the last three years by at least 20%. This definition could be extended to electricity producers and traders.

What are the advantages of the approach compared to a revenue cap?

- Compared to the revenue cap, the windfall profit tax offers several advantages: the windfall profit tax generates additional income for the state to finance measures to alleviate the impact of high energy costs. While the tax may impact the behaviour of electricity generators and traders, distortions between different markets, timeframes and technologies are less likely
- If the tax is correctly implemented, only extraordinary profits which do not come from market fundamentals and thus, have not been anticipated in investment decisions, are taxed
- In general, the windfall profit tax is easier to implement than a revenue cap, and can be implemented through the taxation system without interfering with market operations and settlement infrastructure across utilities, power producers, exchanges and market operators.

What are the disadvantages of the approach?

However, potential disadvantages need to be assessed further:

- A windfall profit tax is less targeted than a revenue cap and therefore constitutes a second-best solution
- It can still lead to market distortions, for example if the windfall profit is not correctly calculated and companies are taxed on an incorrect basis, incentives might arise to produce and trade less
- In case the windfall profit tax is not applied consistently, distortion of competition is a possibility

Different countries have introduced windfall profit taxes, such as Spain, Greece, Italy and Romania. Such taxes have been implemented at speed – in Spain, for example, the tax was announced in July this year and is planned to be implemented from 1 January 2023. Other experiences so far show that revenues might be lower than expected, as they apply to less companies than expected or are actively contested. For example, the Italian government has only been able to collect EUR 2

billion on from their 25% windfall tax on banking and energy groups despite expecting to collect between EUR 10-11 billion to help fund a relief package.[25]

The windfall profit tax also still constitutes a market intervention and therefore impacts market confidence, innovation and renewable investment costs. However, it avoids impacting trading and market operations in the way that a revenue cap risks doing.

Implementation recommendation: Which short-term measure addresses the power price crisis most efficiently?

As described above, the implementation of a uniform or technology-specific revenue cap is technically challenging. There is a non-immaterial potential for generators and traders to find loopholes, while the expected revenues are limited and risk falling short of the figure given by the European Commission.

We therefore propose that the feasibility of a tax on windfall profits of power producers be further investigated, as it would be the most effective and least risky measure that can be implemented at speed. Given that the profit baseline is defined such that windfall profits can be identified, this could lead to less market distortions, while still allowing to generate revenues. Also, a one-off windfall profit tax is per definition a one-time measure, that will not become a feature of future market design. Given the risks and complexity associated with the implementation of a revenue cap, serious consideration should be given to a taxation-based measure.

In case that a revenue cap is maintained as the preferred measure, we see the risk of potentially severe market distortions. It seems challenging to address all risks in the ten weeks until the measure should be implemented. Based on our analysis we set out below a non-exhaustive list of key actions that should be taken to avoid the worst of potential market distortions:

1. **Uniform revenue cap**: the revenue cap should be uniform, across all Member States, to allow for the least disruptive and feasible solution. While technology-specific revenue caps might lead to higher revenues for the state, implementation is substantially more administratively complex and error-prone than a uniform revenue cap.
2. **Time-bound**: to ensure the efficient functioning of the electricity market, any revenue cap should have a clear deadline to address the current energy crisis, while leaving investment incentives in place in the long term. We suggest that the cap shall remain in effect as long as the three-month rolling average of baseload futures is higher than 180 EUR/MWh and should in any case be phased out completely no later than two years from now (winter 2024/2025)
3. **Allow efficient dispatch across markets**: if the revenue cap equalises profit opportunities across all markets, market participants have no incentive to provide system services such as balancing and redispatch. We therefore support the proposal by Hirth, Maurer and Schlecht[26] to base payments on physical production multiplied by the Day-Ahead price to keep incentives for generators to dispatch in the market they add the highest value to
4. **Linking generation technology and trading**: The revenue cap should include financial trades. As those cannot be based on a physical production schedule, the financial trades need to be linked to a generation technology, for example through a trade registry.
5. **Apply revenue cap only to new forward and futures contracts**: to simplify the implementation of the cap, and avoid commercial and legal risks arising from its implementation, only new PPA and futures contracts should be subject to the Regulation.
6. **Cross border sales need to be regulated**: For cross border sales outside of the EU, excess profits need to be extracted in the market in which selling entity sits. This is needed to avoid distortions at the border.

[25] Reuters, "Italy collects around $2 billion from energy windfall tax, sources say", (9 September 2022)
[26] Maurer, Christoph et al., "Six flaws in the EU Electricity Emergency Tool and how to fix them", op. cit.

Electricity demand reduction

Electricity demand reduction is an important cornerstone of the EU emergency measure. In general, demand reduction is the most important measure when facing a supply shock and helps to reduce the costs of the energy crisis. The aim is to achieve a coordinated reduction in EU electricity demand and thus prices, and in turn gas consumption. To this end, the Commission proposes a 5 per cent mandatory peak demand reduction target (equivalent to 3-4 hours per day) as part of an aspirational goal to reduce overall electricity consumption from all consumers by 10 per cent. The Commission recommends demand reduction tenders as the way to achieve these goals.

The effect of this is to i) reduce power price peaks and ii) to reduce the run time of gas plants which are providing peaking capacity. It is thus important that peak hours are defined as hours in which gas production is typically high. As our analysis in Figure 11 shows, peak price hours and periods of high gas generation are not strongly correlated with peaks in demand, but rather periods of low renewable generation. Such periods are challenging to predict daily, which calls into question whether peak demand is the appropriate metric to use to reduce prices and gas consumption.

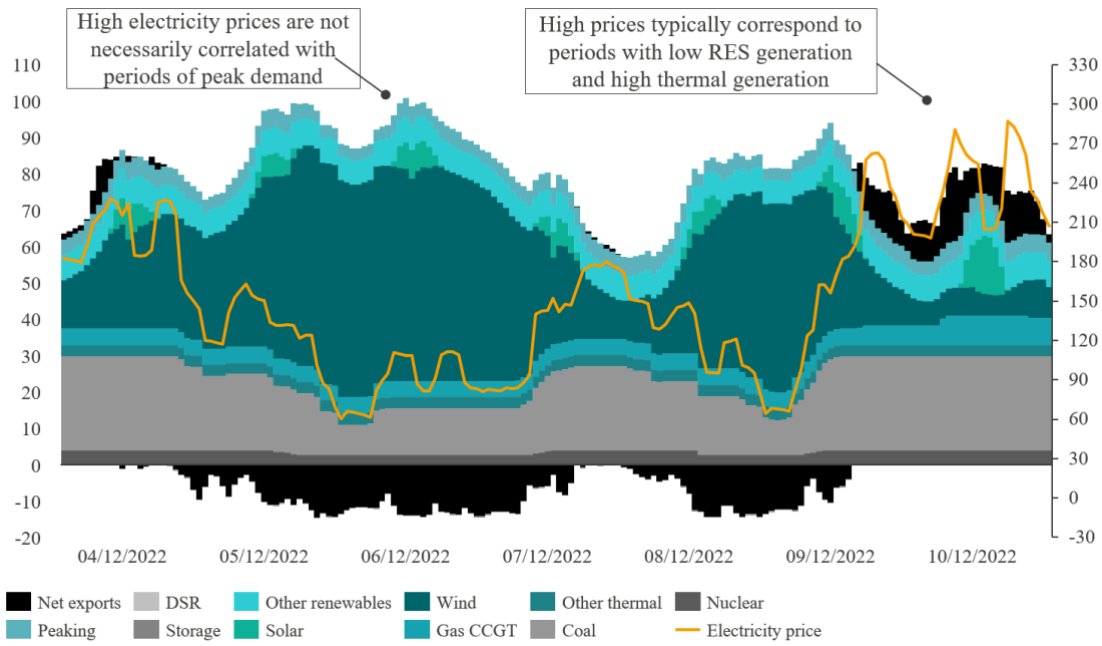

Figure 11: Average demand and generation over a tight week in winter

How to unlock additional demand side response in the current market conditions?
In the current market design, price signals already set incentives for demand reduction. That means that currently, demand side is already reacting to the unprecedented costs of energy. In fact, the current energy crisis acts as a demand reduction mechanism.

While residential consumers face the costs of increased energy costs often indirectly and with a delay, industrial consumers are exposed stronger to increasing prices. This means that even without any additional regulation in place, they face strong incentives to reduce their consumption. In some cases, it even makes sense to stop the production. In Germany for example, a survey by the German Industry

Association (BDI) revealed that almost every tenth company has currently curtailed or interrupted production.[27] European gas demand has reduced by 20% year-on-year as a result of the crisis.

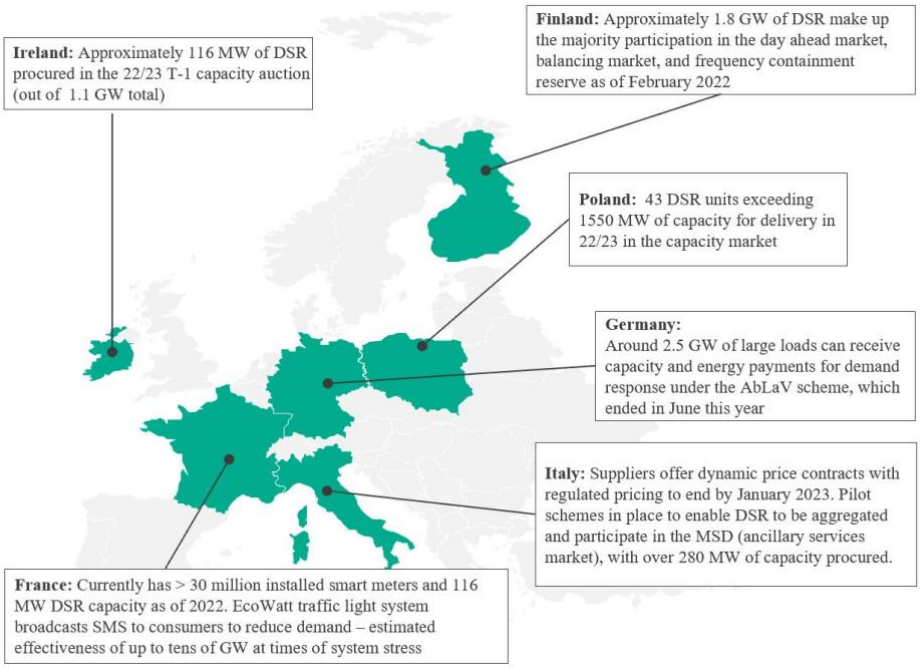

Figure 12: European countries with DSR capacity available or mechanisms in place

As shown in Figure 12, mechanisms already exist within Europe to respond to and reduce demand at times of system or market stress. Wholesale markets, capacity markets and reserve schemes have been increasingly opened to demand-side response participation for example in France and Belgium, and explicit demand response schemes and long-term contracts have been set up (Ireland and France). It is thus possible that even if the right incentives are set to reduce electricity demand both overall and in peak hours, the technical potential on the demand side is limited. This is because a large part of flexible demand on the industrial side has already reacted to the price signal, whether directly or via demand response mechanisms.

How can residential consumers contribute to reducing electricity demand?

While industrial consumers already react to high power prices, residential consumers do this only to a limited extent. The reason behind this is that they are usually not exposed to prices in real time due to contract design and lack the technical equipment to get information on real time prices and consumption, for example through smart meters.

Setting incentives for residential consumers to reduce their demand is therefore challenging. Schemes such as charging a regulated price for a fixed "basic electricity budget", and a higher price for everything consumed above that budget, can contribute to an overall demand reduction. The Commission has provided for this in its draft Regulation, by proposing to derogate from the EU rules on public interventions in price setting. The draft Regulation specifically limits such interventions to 80% of consumers' final demand over the past five years.

However, consumers still lack real time information to fully realise their technical reduction potential. Addressing this issue is high importance to increase resilience of consumers towards high prices and the system efficiency in the mid-term. Regarding possible emergency measures to face the high crisis costs for energy, it is important to implement communication campaigns and targeted consumer

[27] BDI, "Umfrage: Lagebild im industriellen Mittelstand", (6 September 2022)

information and where possible make more frequent information on electricity consumption and therefore savings available at the household level to unlock the highest residential demand reduction possible. This will ultimately also contribute to lowering the energy costs of households directly.

Which additional demand-side measures can be implemented in the short term?
In the long-term, several measures can be implemented that would reduce electricity demand, notably in terms of retrofitting buildings to improve energy efficiency, deploying smart meters associated with time of use tariffs, market-based system services, aggregation or smaller bid sizes. However, the challenge is to unlock additional demand-side response in the short term, particularly in households, whose exposure to price signals is more limited. To this end, two initiatives are recommended, partly based on non-price communication interventions, partly on price incentives:

- Following the guidance in the Commission's draft Regulation, splitting the electricity consumption of households into two buckets. The first bucket would cover a base consumption (i.e., 80% of past consumption) and would be priced at a lower price, while the remaining consumption would be priced at the current price level to encourage savings. However, this also deprives utilities of revenues to cover higher wholesale costs, so states need to be prepared to provide additional support to utilities to make such offers feasible.
- In France, the EcoWatt initiative allows end consumers to make smarter choices. Consumers are guided by clear indicators and can adapt their consumption to renewable generation and reduce their consumption to prevent power cuts. Consumers receive text messages to guide them[28]. The model relies on voluntary savings and does not offer payments for savings. Such a model could potentially be rolled out at scale and would allow households to play a more active role in reducing wholesale power prices and in turn gas consumption.

The advantage of effectively designed demand-side measures in the power sector is that they will reduce power prices, reduce gas consumption, reduce fiscal burdens and reduce the cost of power to end-users, all of which to some degree reduces the need for potentially more disruptive interventions. For example, a 10 per cent reduction in overall power demand in Germany alone could save up to EUR 25 billion over the winter heating season.[29] In absence of direct impact of price signals, consumers need to be targeted through communication and awareness campaigns to establish an energy saving norm, preferably with clear additional incentive structures to reduce consumption.

|In terms of large energy consumers, in designing an effective demand response mechanism, the following principles should be followed:

1. **Additional**: as large energy consumers are already reacting to current price signals; any scheme should target additional capacities of demand response to have an impact
2. **Target hours of peak gas use**: as larger consumers are likely to have high resolution metering in place, any scheme should consider the hours in which gas-fuelled power plants are running, to target it more specifically towards gas savings.
3. **Protected against gaming**: The baseline of any scheme needs to be well-defined to ensure that demand reductions are taking place and market participants do not game the system

[28] RTE France, "Enlightening the end consumers", (2022)
[29] An estimated 35 TWh of demand could be shaved off the German power demand baseline for the upcoming winter 2022/23 period as a result of the Europan Commission's 10% reduction mandate. Assuming futures currently trading at EUR 600-700/MWh, compared to historical electricity price of EUR 50/MWh.

To further explain how a demand response mechanism could look, we investigate an auction mechanism as a case study.

Case study: a new demand response auction mechanism

- Auction: capacity payment to large off-takers and "turn off price (who form their own balancing responsible party and are measured individually), coupled with an energy bid for a specified amount of load shedding
- The baseline should be set by reference to historical demand profiles, as well as some expectation of demand over this winter – although this requires further attention to take into account reductions already expected in response to high prices
- Participants are obliged to sell power in intraday/balancing market if DA prices are above a their "turn off price" (which should be above the price to make sure these are hours in which gas sets the price)
- Additional protections to avoid gaming include overcontracting capacity and introducing random selection into the procurement of demand response, to preserve incentives for users to set accurate baselines
- With capacity payments and longer-term auction, you could get market participants to do the fixed cost investment to flexibilise their consumption. However, capacity payments should only be paid out on an ex-post basis so long as actual, announced, expected and historical schedules are consistent to avoid gaming.

As previously discussed, the current price signal (and possibly existing demand side mechanisms) already provides effective incentives especially for industrial consumers to reduce their consumption. Any demand side reduction mechanism that is successful in reducing price peaks might result in a rebound effect, meaning that the lower prices incentivise market participants to increase their consumption. It is crucial to ensure that any such mechanism is designed in a way to drive additional reductions in consumption beyond current levels – otherwise the effectiveness of such a scheme - and the cost-effectiveness to taxpayers – is eroded.

Recommendation Box

Windfall profit levy	**Explore feasibility of a windfall profit tax at the corporate level to be levied on inframarginal power producers.** Such a tax could be designed to be consistent with the tax on oil and gas producers/refiners, that is, to collect profits that exceed the average profit of the last three years by at least 20%. This definition could be extended to electricity producers and traders.
Revenue cap	**If a revenue cap is implemented:** 1. **Uniform revenue cap:** the revenue cap should be uniform, across all Member States, to allow for the least disruptive and feasible solution. While technology-specific revenue caps might lead to higher revenues for the state, implementation is substantially more complex and error-prone than a uniform revenue cap. 2. **Time-bound**: to ensure the efficient functioning of the electricity market, any revenue cap should have a clear deadline to address the current energy crisis, while leaving investment incentives in place in the long term. We suggest that the cap shall remain in effect as long as the three-month rolling average of baseload futures is higher than 180 EUR/MWh and should in any case be phased out completely no later than two years from now (winter 2024/2025).

	3. **Allow efficient dispatch across markets**: if the revenue cap equalises profit opportunities across all markets, market participants have no incentive to provide system services such as balancing and redispatch. We therefore support the proposal by Hirth, Maurer and Schlecht[30] to base payments on physical production multiplied by the Day-Ahead price to keep incentives for generators to dispatch in the market they add the highest value to. 4. **Linking generation technology and trading**: The revenue cap should include financial trades. As those cannot be based on a physical production schedule, the financial trades need to be linked to a generation technology, for example through a trade registry. 5. **Apply revenue cap only to new forward and futures contracts**: to simplify the implementation of the cap, and avoid commercial and legal risks arising from its implementation, only new PPA and futures contracts should be subject to the Regulation. 6. **Cross border sales need to be regulated**: For cross border sales outside of the EU, excess profits need to be extracted in the market in which selling entity sits. This is needed to avoid distortions at the border. Furthermore, the revenue cap should be as harmonised as possible across member states.
Demand reduction measures	Explore adapting existing demand response mechanisms, or establishing new demand response tenders for large energy consumers, that are: 1. **Additional**: as demand-side response is already reacting to current price signals, any scheme should target additional capacities of demand response to have an impact. 2. **Target hours of peak gas use**: Any scheme should target the hours in which gas-fuelled power plants are running, to target it more specifically towards gas savings. 3. **Protected against gaming**: The baseline of any scheme needs to be well-defined to ensure that demand reductions are taking place and market participants do not game the system. At the household and small business level: 1. Establish systems and campaigns such as the French EcoWatt model to encourage power saving at times of peak prices at the household level. 2. Preserve existing retail tariffs for 80% of historical consumption, coupled with support to utilities to cover the difference in cost, while leaving the remaining 20% of historical consumption exposed to wholesale prices to encourage energy saving.

[30] Maurer, Christoph et al., "Six flaws in the EU Electricity Emergency Tool and how to fix them", op. cit.

5. Gas Market Interventions and Reforms

None of the proposed and above discussed measures targeting the electricity market solves the problem of record-high gas prices. This still remains a hugely pressing issue for industry and households, since funds from both a revenue cap on inframarginal generators and a 'solidarity contribution'[31] will likely not be enough to subsidise industry and support households to a sufficient extent.

Reduced deliveries of Russian gas and indications of potential further future interruptions create uncertainty and risk premia which escalate gas prices and as a result also power prices. Governments across Europe are devising support programs to compensate households and industry for the cost increases at unprecedented scales.

In the following we discuss the different options for temporary gas market interventions and explore in more detail one such price limit for the EU domestic market: A limit for the TSOs imbalance price with the potential to effectively respond to abuse of Gazprom's dominant position. Although we believe that gas markets should not be undermined by imposing caps or prices, we consider such interventions as potentially temporary conducive in the current extreme situation, where a functioning market is most probably hindered by effective market manipulation of its pivotal supplier.

The European Commission already investigates Gazprom over concerns of abuse of dominant position. Strategic behavior may be responsible for recent price developments. the EU may therefore consider to apply tools of competition policy, namely a price limit, rather than merely subsidizing households and industry so they can afford to pay manipulated gas prices. Thus, the EU can:

- Avoid that Russia as pivotal supplies increases gas prices and revenues if it reduced deliveries.
- Reduce costs of gas purchases currently at EUR 740 billion, or 5% of EU GDP (x10 historic levels)[32].
- Reduce the wholesale gas price to reduce power costs of EUR 910 billion (x5 historic levels)[33].

A variety of detailed design options to reduce wholesale or import gas prices are debated and were also discussed by the Commission and member states in recent weeks. Price limits are proposed for prices paid for gas delivered on specific import channels. They could realize savings in the range of EUR 60 – 330 billion[34]. However, price limits on imports may risk a reduction of imports, or even involve significant risks of contract litigation and supply interruptions. Furthermore, these price limits on imports cannot resolve uncertainty about potential market outcomes (and prices) in case of full supply interruptions and hence will not mitigate risk premia in forward markets that also drive spot market

[31] European Commission, "Proposal for a Council Regulation on an emergency intervention to address high energy prices", op. cit.
[32] Assuming historic EU gas demand of 4000 TWh, 15% gas saving and gas import prices of 200 EUR/MWh.
[33] Assuming EU power demand of 2800 TWh, power price set by gas power generation at 43% efficiency with carbon price of 80 EUR/t and carbon intensity of 0,4 t/MWh, and longer-term contract coverage reducing exposure of some asset.
[34] All calculations based on data set provided by McWilliams, Benjamin et al., "European natural gas imports", Bruegel Datasets (29 October 2021); Assumptions (i) Import volumes for 2022 were projected by scaling imports from first 36 weeks to full year based on ratio of these imports in average years in first 36 weeks compared to full year. (ii) Same share of all imports are re-exported according to EU Energy Balance, Eurostat, April 2022, Eurostat statistics (iii) Russia will deliver 800 TWh to EU (650 to stay within EU), below the 60% of historic volumes delivered in first 36 months) (iv) Domestic production remains at 400 TWh (v) Extra 200 TWh storage filling to recover low storage levels will not need to continue (vi) Based on these assumptions we find a 7% lower demand than in average years – comparable to other estimates (vii) LT contract share corresponds to minimum volume delivered in previous year, all additional volumes are classified as ST.

prices. They will also not achieve further reduction in electricity prices, beyond the inframarginal cap applied to power generators.

Alternatively, price limits can be set defined at the scale of the EU domestic gas market. Such price limits have the potential to reduce overall wholesale prices for gas and thus also for electricity. They can thus deliver costs savings to gas consumers and electricity consumers at the scale of EUR 560 and 490 billion. As such price limits do not constitute an intervention in existing contracts and do not specifically address imports, risks of contract litigation and conflicts that trigger supply interruptions are minimized.

The reduction of the wholesale price level will reduce gas prices incentives for gas savings. Therefore, a price limit needs to be combined with a binding EU agreement on gas saving targets. This can facilitate political provide the basis for national governments to implement programs and measures to realize gas savings. These can include pricing structures, e.g. a high surcharge for gas-consumption exceeding 80% of consumption in the preceding year, tenders for gas saving by industry, shared communication to create a societal norm that everyone needs to save 20% gas supported by frequent information on individual progress to facilitate learning. These measures would need to be robust and reliable to achieve binding gas saving targets. This would be needed to avoid that a gas price cap causes a gas shortage, which would then need to be managed afterwards by additional public intervention.

Different options for gas-market interventions on imports

A price limit imposed on Russian gas imports would reduce the payments to Russia and thus also save expenditure on gas import contracts at **the scale of EUR 100 billion.** This price limit could also involve a single buyer mechanism. However, as this option intervenes in existing contracts it involves a risk of full supply interruption or subsequent litigation of contracts.

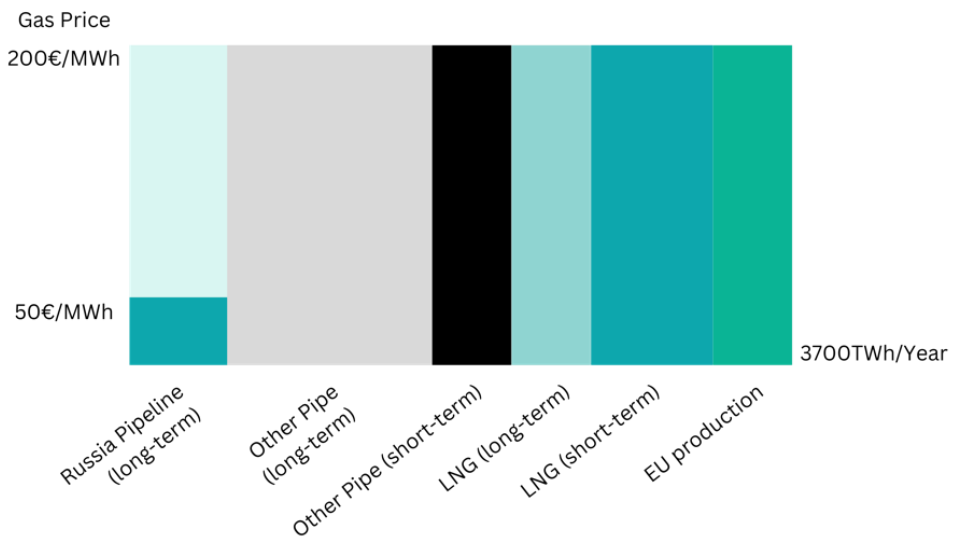

Figure 13: A price limit imposed on Russian gas imports

A price limit imposed on all pipeline gas imports into Europe if applied to all short-term contract pipe imports could reduce costs for EU by about **EUR 60 billion.** If the price limit also covered imports under long-term contracts with Russia and other suppliers, it could reduce costs by up to **EUR 330 billion.** Also, this option involves a risk of supply interruption or subsequent litigation of contracts and thus also of power price increases.

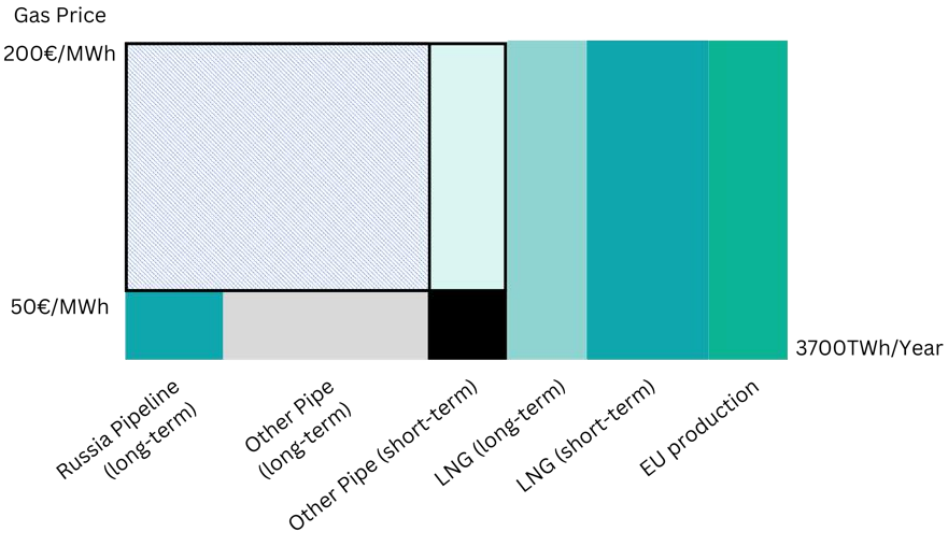

Figure 14: A price limit imposed on all pipeline gas imports into Europe

An EU single buyer could coordinate short-term or new long-term purchases. An EU single buyer might be able to leverage EU purchasing power where pipeline suppliers have limited outside options (notably Norway and Algeria) – thus this approachh could deliver similar savings for short-term pipeline gas imports (EUR 60 billion)**.** If the single buyer also coordinated purchases of short-term LNG imports, it could realize cost savings in the range of **EUR 170 billion,** albeit at the risk that the global market LNG supplies available to Europe would decline and with risks of individual member states receiving attractive offers from suppliers to break the coalition. The role of a single buyer for longer-term contracts is not assessed here.

All three interventions on gas imports will not contribute to a reduction of power prices. This is, because the supply demand balance in forward and spot markets in forward markets is not affected, and hence also the gas wholesale prices and the linked power wholesale price will not change. These options also will only address a fraction of the cost increase and reduce import costs in the range EUR 60 – 330 billion. The options only targeting short-term purchase risks reduced import volumes, while the options also addressing long-term contracted gas involve significant risks of contract litigation and supply interruptions.

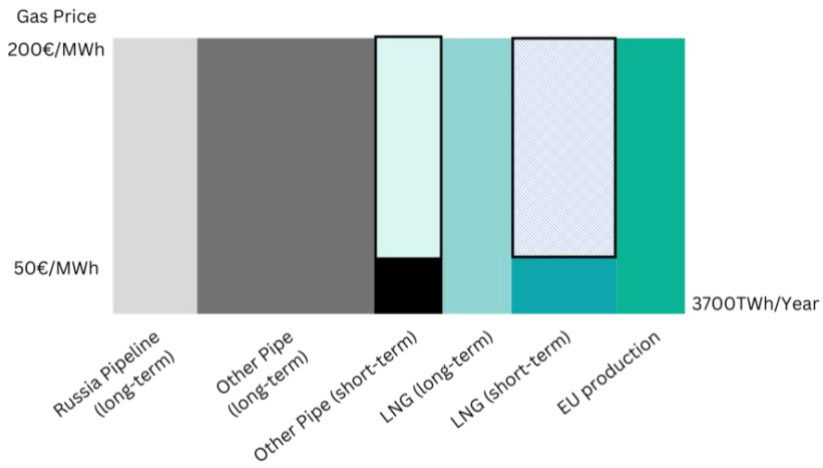

Figure 15: An EU single buyer

EU scale gas price limits

An EU scale price limit has been proposed for all trading on exchanges and OTC (over the counter, e.g. bilateral) by Italy. Such a limit would directly limit the costs for new contracts with domestic or international producers.

Most of the gas is imported on long-term contracts. These long-term contracts do however not comprise a fixed price, but are indexed. Long-term import contracts to Asian buyers are indexed to global oil prices. This protects Asian LNG buyers from the extreme prices in the gas market and abuse of market power by gas suppliers. While no public data is available on the pricing structure of European long-term contracts, it is commonly assumed that most of the import contracts are indexed to short-term prices on TTF and other EU trading hubs with time lags between two months and two years.

An EU-scale price limit will also be reflected in the price indexes, and therefore the price paid for imports on long-term contracts will also fall to the price limit. Together with saved expenditure on domestic production, savings could be at the scale of EUR 560 billion. For a long-term contract indexed for example to a two-year average of hub prices, today' extreme prices will induce price and cost increases over the next two years. Hence also the cost savings resulting from a price limit will be distributed over the two-year period.

A European price limit will also limit the price European buyers pay for LNG in the global markets. If international sellers would insist on prices exceeding this limit, then the European LNG demand which constitutes currently the by far largest share of global demand would vanish. The result would be a supply surplus. LNG prices would decline until demand increases to matches again supply – at the level of the EU price limit.

The reduced LNG prices will however result in less demand reduction in competing LNG importing countries, and will therefore reduce the volume of LNG shipped to the EU. Based on the share of final consumers in competing LNG importing countries that are exposed to global LNG spot prices and using standard assumptions of demand elasticities, we find that if gas and LNG prices are at 50 EUR/MWh instead of 300 EUR/MWh then EU could serve about 6% less of demand with LNG and would hence in a scarcity situation have to deliver 6% additional gas savings.

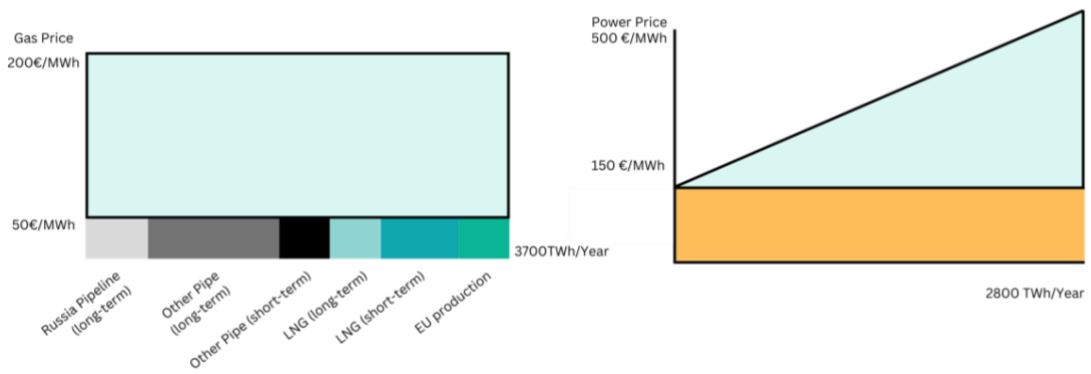

Figure 16: EU scale gas price limit

An EU scale price limit could be combined with a premium system or contract for difference for LNG imports. This would allow the EU to continue to outcompete other LNG importing countries to maintain higher volumes of LNG shipments to the EU.

With continued higher payments for short-term LNG access, overall savings would decline to EUR 440 billion. The EU should also consider, whether a persistently high premium would create incentives to re-route pipeline gas to LNG, and how to allocate the costs for the premium across EU member states. A separate treatment for short-term LNG imports needs therefore also be considered as a back-up measure of last resort, should LNG demand from other importing countries increase beyond the expected price effects due to attempts by third countries to strategically outbid the EU.

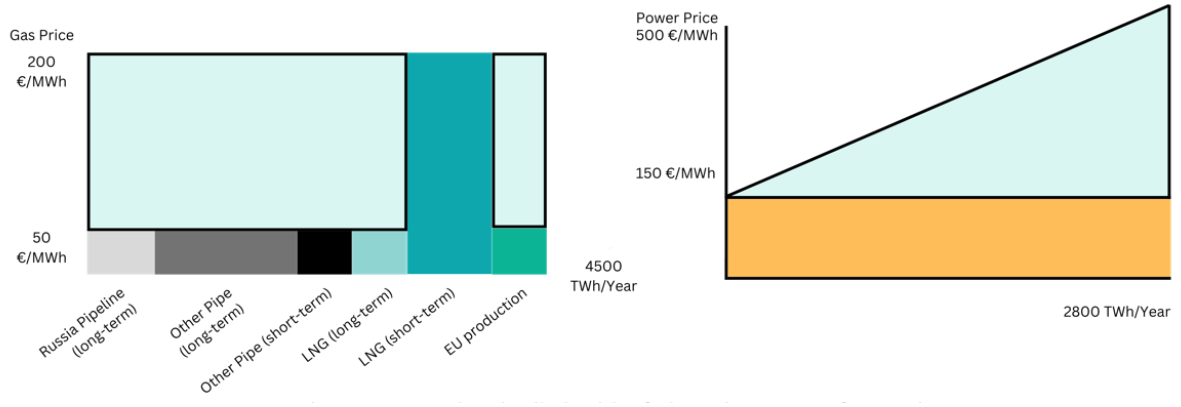

Figure 17: EU scale price limit with CfD/Premium system for LNG imports

3.3 A price limit on the TSO imbalance mechanism would operate by allowing all market participants to acquire imbalance energy at a price not exceeding the set limit. No EU buyer would then be willing to pay above this limit for new contract as it would be cheaper to rely on imbalance energy. With neither TSOs nor market participants prepared to pay above the price limit, the intervention would achieve the same effect as wholesale price cap. Thus, both options are likely to have the same economic effect.

Potoschnik and Conti propose to complement a price limit on the TSO imbalance mechanism with a CfD or premium mechanism to support purchase of additional LNG (short-term contracts) and find the same opportunities and challenges this creates as in the context of a wholesale price limit[35].

A TTF circuit breaker is an option to limit volatility. A circuit breaker may be desirable, and to some extent this approach is already reflected in some of the operational procedures of gas exchanges. It will, however, be unlikely have a significant effect on significantly reducing the level of gas prices. It could, as suggested by Italy, be considered as an option to complement other measures.
In the following we discuss more detail about the TSO imbalance mechanism.

How does the price limit for TSO imbalance mechanism work?
Both a wholesale price limit and a TSO imbalance mechanism have the potential to adequately address the three objectives of mitigating the benefits of dominant players from exercising market power and limiting the costs for gas consumers and for electricity consumers from the abuse of dominant position. We consider the TSO imbalance mechanism TSO imbalance mechanism to allows for and easier and effective implementation, which is why we discuss in the following some more details of this implementation and risks and opportunities this may involve.

[35] See for an discussion of this approach: Pototschnig, Alberto and Ilaria Conti, “Capping the European price of gas”, EUI policy brief (2022)

How does the TSO imbalance mechanism work today?

All gas delivered to households, industry and power generation in Europe is delivered through the transmission system managed by a Transmission System Operator (TSO). Market participants (suppliers) nominate to the TSO how much gas they put into the system and where, and how much gas is delivered to each of their consumers. If there is an imbalance between entry and exit, then the TSO itself acquires gas to balance the system, paying the market price necessary to acquire this gas and passing these costs on to market participants that are not in balance[36].

Prices charged for imbalance gas are not below but potentially above the prices in short-term markets. This creates incentives for market participants to stay in balance. As there is currently no limit set for the imbalance prices, market participants prefer to acquire gas even at extremely high prices over the risk of being in imbalance.

If due to a shortage situation, market participants fail to acquire sufficient gas to serve their customers, and if the TSO then also fails to acquire sufficient gas to meet the imbalance, then non-protected gas consumers are curtailed according to a priority list developed by national regulators which is independent of the contract structures under which gas customers are supplied.

How could a price limit be implemented using the imbalance mechanism?

As part of the security of supply regulation, the EU could implement as a price limit for the maximum price European TSOs are allowed to charge for imbalance energy. In parallel, a common discount would be agreed to avoid that TSOs outcompete each other for imbalance energy. No TSOs would thus be allowed to buy gas to meet the imbalance at prices exceeding the price limit minus this discount. Historically discounts in the range of 0,1-0,2 EUR/MWh were sufficient to ensure market participants contract bilaterally to avoid an imbalance.

If market participants would not obtain sufficient gas to meet the demand of their customers at price at or below the price limit, then they would nominate to the TSO an imbalanced schedule, e.g. the full demand of their customers which falls short of the level of gas that they have contract long-term and could acquire short-term. Because of the opportunity to submit an imbalanced schedule and clarity that the imbalance will not be priced above the price limit, no buyer would sign a new contract for gas that involves a price exceeding the imbalance price limit. Thus, gas producers would have to offer new contracts at a price at or below the price limit if they want to sell to European customers.

Will trading activities persist outside of the TSO imbalance mechanism?

Usually shippers acquire gas several weeks, months or years ahead of delivery, or hedge their deliveries to final consumers. This trading would persist after the implementation of the imbalance price limit. The imbalance price limit would define an upward bound for possible prices, but effective gas saving programs and, in the mid-term, additional supply available from competing LNG importers could result in a reduction of gas prices below this level.

The prices to be therefore expected remains uncertain, albeit within a range more similar to historic price ranges. All market participants will therefore likely hedge against this price risk, using their established risk management practices and exchanges based trading and bilateral contracts. Furthermore, gas producers may prefer to sell to a market participant at the imbalance price level rather than to the TSO at the imbalance price level minus the agreed discount. Further analysis is required to ensure that the TSO imbalance mechanism will continue to only play a very marginal role in terms of gas purchases in particular during a transition period. Risk management requirements for shippers could be strengthened to ensure continued bilateral/exchange-based trading.

[36] European Commission "Regulation (EU) No 312/2014 of 26 March 2014 establishing a Network Code on Gas Balancing of Transmission Network"

What happens to existing contracts with gas producers?
Existing contracts are not affected. The price at which gas is purchased under existing contracts will be dependent on the specific pricing formula and indexation. As in the past, prices exceeding or below the wholesale short-term price will largely be passed to consumers according to contract or tariff structures. The reduction of wholesale prices will thus reduce the value of such contracts and of gas already in storage, similar to any other development like an eventual end of the war.

At what level should the price limit be set in order to secure sufficient gas supply?
A variety of factors will need to be considered when deciding on the level of a price. First, the price limit will need to be set high enough to continue to motivate gas producers to deliver gas at full capacity. Any price limit set at a multiple of historic prices levels of 15-20 EUR/MWh and at or above historic price peaks of 45 EUR/MWh will probably satisfy this requirement.

Second, the set price limit will also determine the extent to which EU will continue to outcompete Asian buyers to attract additional LNG. LNG prices exceed prices for coal and oil used for power generation in Asian countries. To continue to secure the gas volumes from this fuel shifting, the price limit needs to be high enough for possible coal and oil price scenarios, or indexed to global oil and coal prices if these exceed thresholds. This implies a level of about 50 EUR/MWh may need to be indexed to increases oil prices significantly exceeding 100 EUR/barrel.

Third, the level of the EU TSO imbalance price limit will also determine the extent to which high global LNG spot-prices will reduce gas demand in non-EU countries and thus make additional LNG available for the EU. However, in the main competing LNG importers Japan, Korea, China and India only a small fraction of final demand is exposed to short-term LNG prices. We find that for example decreasing LNG prices from 300 EUR/MWh to 50 EUR/MWh would have limited impact on this demand and would therefore only result in 6% less gas available to EU consumers[37].

To avoid the need for indexation of an EU price limit to global oil price developments, additional LNG imports might also be granted a premium or contract for difference. The resulting costs would need to be shared across all or some consumers, possibly raising questions about EU wide allocations. This different treatment of additional LNG imports may be justifiable based on the structural difference between the EU domestic market based on pipeline delivery and the global LNG market, including with regard to reference prices for contracts (TTF versus oil), usage of the gas and associated cost structures (base load delivery versus large share of flexible supply to balance demand). Congestion at intra EU interconnection points might also be a relevant point to consider, as sufficient capacity to transport gas from LNG terminals to central EU might not always be available.

What price limit would ensure efficient allocation to EU consumers?
The ACER-commissioned "study on the estimation of the cost of disruption of gas supply in Europe" found from surveys across EU the average cost of disruption of gas supply of 70 EUR/MWh, with large variations across EU member states and sectors[38]. Arguably these stated preferences may have underestimated values and would now require updating based on recent experiences. Governments may want to use a price limit to avoid situations where gas suppliers acquire gas at prices exceeding their valuation of the gas. A price limit may even be set below the cost of disruption of gas supplies because, even if a price limit were to restrain gas supply and trigger supply interruptions, a 6% effect could reduce the prices paid by 94% of remaining consumption by 250 EUR/MWh.

A decision to not implement a price limit may therefore induce additional costs for all consumers from the additional demand served. If it is possible, to realize the additional 6% of savings by strengthening

[37] Neuhoff, Karsten "Defining gas price limits and gas saving targets for a large-scale gas supply interruption", EPRG Cambridge Working Paper (2022)
[38] ACER, "Study on the Estimation of the Cost of Disruption of Gas Supply in Europe", Final Report (November 2018)

gas saving targets and programs, then large benefits can be realized. If it is not possible to realize additional gas savings, but instead curtailment is necessary, then policy makers would have to assess the high risks of curtailment of up to 6% of demand of non-protected consumers (primarily industry). These risks need to be weighted against the cost of avoiding this curtailment at the scale of 94/6 *250 EUR/MWh = 3900 EUR/MWh.

This number seems unusually high compared to historic wholesale price levels in the range of 15-20 EUR/MWh. Two factors are relevant. First, net-supply is highly inelastic at prices exceeding the fuel shifting level, and therefore any additional demand triggers large price increases. Second, because unlike excess profits in the electricity sector, the extremely high profits obtained by global gas producers cannot be taxed to compensate consumers for price increases and hence need to be considered as full cost for the economy rather than a "merely" distributional concern among domestic actors.

What price limit would ensure efficient power generation?
If the price limit is below the fuel shifting price from gas to coal and oil in the EU, which differs from fuel shifting levels in Asia due to CO2 prices and transport costs, then additional gas generation could increase gas demand. At least four options could be considered:

First, the EU price limit could be increased to exceed this fuel shifting level. Second, an additional fee could be imposed on gas incineration to increase marginal cost relative to other fossil generation technologies. This can be easily implemented, but would also result in higher power prices and therefore not allow to for the full benefits of gas reduced gas prices to be transferred to power prices. Third, existing national and cross-border redispatch mechanisms could be used. They are currently used by TSOs to mandate power stations to increase and reduce their production so as to avoid transmission constraints. Equally, TSOs could mandate through an amended redispatch mandate, gas power generation to reduce and other generation (likely coal and oil) to increase. Where this would imply large international redispatch volumes, available transmission capacities feed into the day ahead market clearing algorithm Euphemia could be adjusted. Fourth, it has already been explored in Spain to create two market clearing results in the day ahead market. The clearing including bids from gas power generation is used to determine clearing prices. In a second clearing round, gas power generation bids would be marked up to limit gas incineration.

Firm gas saving targets and programs are necessary

In the case of a persistent interruption of Russian supply to the EU, it remains unclear whether European gas markets will find a clearing price solution to allocate scarce gas across and within EU member states, or whether the escalation of prices will exceed the financial capacity of firms or governments. Hence regulators and TSOs are already preparing curtailment programs to balance supply and demand.

Curtailment of gas supply to customers is however inherently crude and thus inefficient. In particular, as protected customers like households cannot be curtailed (also for technical reasons in distribution gas grid operations), curtailment would be focused on industry. An extended curtailment of industry would not only hurt individual firms, but through supply chains, could have significant consequences across economy. Hence gas saving targets and programs that support gas demand reductions across all consumer groups are essential, and have received European support with a first, albeit non-firm, EU level agreement on gas saving targets to guide national gas saving programs[39].

[39] European Commission, "Council adopts regulation on reducing gas demand by 15% this winter", Press Release (5 August 2022)

Gas saving programs are necessary to unlock savings in all sectors
Government decisions are essential to unlock gas savings by:

- Allowing or mandating adjustments of cooling or heating temperatures and times for buildings
- Mandating measures for building owners to optimize heating- and cooling equipment
- Funding investments in efficiency improvements (building renovation, heat pumps etc.)
- Clear and timely information on gas consumption, costs and saving potentials through behaviour change
- Corresponding measures to save electricity to save gas for power generation
- Prepare for and facilitate fuel shifting from gas to light fuel oil and boilers, turbines and incinerators

Governments can determine the pricing structure of gas to final consumers, and thus have the power to create incentives for gas saving. If a gas price limit reduces prices, governments can maintain incentives for gas saving with a levy for gas consumption exceeding 80% of previous year consumption[40]. This would allow for incentives for gas savings at a similar scale to the incentives without a price limit. For some consumers the focus on the 20% savings to be achieved may increase the savings efforts. Other consumers may respond more strongly, if overall high gas prices are perceived as an existential threat.

Additional gas saving potentials in industry available at prices exceeding the (limited) wholesale price can be realized through public tenders for gas savings (analogous to existing tenders for demand side response). Here, firms bid the price for which they would pause production. Thus, the cheapest saving potentials can be realized. Governments will incur costs – but may have incurred the same costs if high gas prices would have forced a temporary closure and hence the need for governments to support employees and sites. Most of the available programs and measures are essential to unlock gas saving, with or without a price limit. The implementation of a price limit, however, will require a change in the design of incentives to avoid financial hardship (at high gas prices) towards incentives to retain marginal saving incentives (with price limits). For savings achieved by pausing industrial production, the currently discussed measures to support firms to maintain production sites and jobs despite interruptions due to high gas prices, would therefore be shifted towards tenders to pay firms for gas savings – again creating revenue streams to support sites and jobs.

Gas saving targets can foster shared action
The international experience from scarcity situations in power and gas points to the importance of a joint response among EU member states. Gas saving targets at national level that translate into targets relevant for all gas users can help to create a shared norm of gas savings[41]. The successful South African response to the country's experience of water shortage shows how targets then need to be complemented with good communication including on target achievement, and also including compliance mechanisms[42]. In the EU gas situation these may involve incentives for gas consumption exceeding target levels. It is furthermore important to clearly define a gas saving target to allocate responsibility within national governments so that polices will be effectively designed, implemented and managed.

[40] A similar mechanism for electricity has been proposed by Pototschnig, Alberto, Jean-Michel Glachant, Leonardo Meeus and Ilaria Conti, "Consumer protection mechanisms during the current and future periods of high and volatile energy prices", FSR Policy Brief Issue (25 March 2022)
[41] Farrow, Katherine, et al., "Social norms and pro-environmental behavior: A review of the evidence", Ecological Economics (2017); see also Sippel, Maike et al., "Ten Key Principles: How to Communicate Climate Change for Effective Public Engagement", Climate Outreach Working Paper, Oxford University, (2022)
[42] Ziervogel, Gina, "Unpacking the Cape Town drought: lessons learned", African Centre for Cities (2019); see also Gerard, Francois, "What changes energy consumption, and for how long? New evidence from the 2001 Brazilian Electricity Crisis", Resources for the Future Discussion paper No. 13-06 (2013)

EU agreement on gas saving targets can realize positive externalities

In the short-term, in Europe, limited flexibility exists on gas production capacity. Any gas saving in one country will therefore increase the gas available to other countries and reduce scarcity and (if not bound by a price limit) also reduce the gas price. To realize these benefits, a mutual agreement on gas saving targets to be pursued by each EU member state will therefore be beneficial for all countries. To avoid a consumer shift to electricity-use and instead reduce gas power generation, also agreed targets for electricity savings will be necessary.

6. Combined gas saving targets and price limits can unlock synergies

A gas saving target mitigates the inefficiencies of the price limit mechanism

Any price limit will reduce the effect of demand reduction driven by high prices. This in turn could trigger or increase the need for curtailment. A variety of programs and pricing structures determined primarily by national governments can reinstate the marginal incentives while providing support for high levels of gas savings, and thus avoid the risks of increased curtailment.

To reduce forward prices, gas saving targets need to be complemented with price limits

Stringent gas saving targets and programs should, in principle, reduce scarcity and thus also be able to deliver large reductions in gas prices. However, markets are sceptical about the success of government targets and programs, and hence may well require an extended positive experience of these programs if they are to learn to trust that these will be effective. Hence, despite strong gas saving programs, forward gas prices will continue to reflect expectations of potentially extremely high scarcity prices. As a result, even a stringent gas saving program alone may not help to reduce gas costs significantly: a price limit will then help to ensure the benefits of European gas savings also result in price reductions for EU consumers.

An effective solidarity mechanism requires both gas-saving targets and a price limit

Combining the benefits of a price limit – which are larger for countries with less fiscal space to compensate consumers for price increases – with the benefits of an EU level agreement on gas saving targets – which are larger for countries with fewer LNG terminals and non-Russian gas import contracts – could help to find an agreement among EU member states. Overall, we find two options to improve the EU gas market regulation offer the potential to adequately respond to the oligopolistic behaviour of the pivotal supplier and thus reduce gas costs, prices and also power prices: A price limit for the TSO imbalance mechanism and a price limit on trading on exchanges, bilaterally and for TSO imbalance. Both approaches will limit the benefit a dominant gas supplier can draw from withholding suppliers, and the costs such withholding imposes on EU gas and electricity consumers. It is important to engage early with all gas suppliers like Norway, Algeria and major LNG producers on such an approach to ensure a shared understanding of objectives and rational.

A CfD or premium system for short-term LNG imports could complement the price limits. Importers could thus pay for LNG imports prices above the EU price limit so as to better outcompete Asian buyers for marginal short-term LNG suppliers. It would involve economic costs for EU consumers and risk further undermining trusted relationships with emerging economies competing for LNG gas supply. Hence, it may be an option to only implement a CfD or premium system if a competing LNG importing countries would strategically attempt to undermine an EU effort to mitigate the effect of market power abuse. We find that European gas price limit mechanism will need to go hand in hand with an agreement on firm gas saving targets at the EU scale. A price limit will reduce the price incentives for EU industry, households, and the power sector to reduce gas demand, and hence increase the importance of policies and programs to realize these savings. To ensure that all EU member states effectively implement these programs, including marginal incentives for gas saving, gas saving targets are essential. These targets involve a clear compliance mechanism that enhances their effectiveness: in the case of gas shortage, member states with gas demand exceeding their gas saving targets will have to implement curtailment.

Furthermore, with lower wholesale and LNG short-term prices, demand destruction in competing LNG importing countries will be lower, and EU may have to deliver additional saving at the scale of 6% if the price limit results in a reduction of prices from 300 to 50 EUR/MWh. This estimate is however inherently uncertain, as the share of final consumption in competing LNG importing countries is

difficult to estimate precisely, and because there are no estimates for the demand elasticity at price levels exceeding historic price levels. Hence it may be necessary to adjust the gas saving targets dependent on the scale of LNG ultimately available to the EU. This will be necessary irrespective of the price limit, because factors like a cold winter or a faster than expected recovery in China will impact the LNG available to EU.

We find the combination of gas price limits and firm gas saving targets at EU scale could realize cost savings in the gas market of EUR 680 billion. As contracts remain unaffected, litigation and supply interruption risks should be limited. Lower wholesale gas prices would then translate to reductions in power prices and electricity cost savings to power consumers in the range of EUR 490 billion. Some savings in the power sector can be also achieved with a variety of direct interventions in electricity markets with direct support funded through windfall profits taxes, mechanisms to capture inframarginal rents, or with a subsidy for gas power generation to reduce price impacts.

In addition, the approach would facilitate an EU agreement on an effective security of supply solidarity agreement. A price limit based on the TSO imbalance mechanism would resolve disputes on the price to be charged for solidarity gas. Firm gas saving targets would allow for a coordinated application of gas savings and curtailment across EU member states, and thus offer the basis for gas sharing in the case of shortage. This improves the business-as-usual situation where non-coordinated curtailment would very likely need to be implemented during this winter and beyond.

Gas price limit for EU domestic market	**Set a limit for the TSOs imbalance price:** All market participants can – as fall-back option – access gas through the TSO at this price. Should there be insufficient gas available at the price, then the TSO will apply curtailment according to the agreed protocol. This provides clarity about price developments in case of a supply interruptions, and thus reduce risk premia on forward prices. 1. **Price limit to be set high enough to continue to motivate gas producers to deliver gas at full capacity** 2. **The price limit influence the extent to which Asian power sector will shift from gas to coal and oil generation**. The price limit needs to be high enough for possible coal and oil price scenarios, or indexed to global oil and coal prices if these exceed thresholds. 3. **Engage early with all gas suppliers** like Norway, Algeria and major LNG producers on such an approach to ensure a shared understanding of objectives and rational.
LNG imports	**Explore combining the EU scale price gas limit with a premium system or contract for difference for LNG imports.** Should competing LNG importing countries strategically escalate prices, this would provide an adequate response of the EU to continue to maintain suffiecient volumes of LNG shipments to the EU as a back-up measure.
Firm gas saving targets and programs	**Introduce legally binding and credible fixed gas saving targets**, which deliver additional saving at the scale of 6% and mitigate the inefficiencies of the price limit mechanism. 1. **Maintain incentives for gas saving** with a levy for gas consumption exceeding 80% of previous year consumption, to allow for incentives for gas savings at a similar scale to the incentives without a price limit. 2. **Additional gas saving potentials in industry** available at prices exceeding the (limited) wholesale price can be realized through public tenders for gas savings (analogous to existing tenders for demand side response). 3. **The implementation of a price limit, will require a change in the design of incentives to avoid financial hardship** (at high gas prices) towards incentives to retain marginal saving incentives (with price limits).

7. Interrelations between the Electricity Market and Gas Market Interventions and Reforms

What are the longer-term effects of a gas market price cap on the electricity market?

To avoid adverse impacts in the power market from the implementation of a gas price cap, any move to administer wholesale gas market pricing must be time limited. This is for the same reasons to time-limit inframarginal generator revenues - renewable generators need certainty of revenue streams, in particular to support the development of new assets, which in turn relies on having fundamentally modelled power price forecasts that investors and financiers can rely upon.

The risk is that the period during which wholesale gas market price cap applies is uncertain, and in turn its effects on power forward curves, which makes it challenging for renewables generators to conclude power purchase agreements, futures transactions and even sales or acquisitions of existing assets. Uncertainty could dampen or even halt investment signals, particularly for the development of new renewable assets, which would perversely tend to erode expected reductions in gas consumption the power sector.

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