The European Wholesale Electricty Market: From Crisis to Net Zero

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THE EUROPEAN WHOLESALE ELECTRICITY MARKET: FROM CRISIS TO NET ZERO

REPORT

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LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
CACM	Capacity calculation and congestion management
CCS	Carbon Capture and Storage
CEER	Council of European Energy Regulators
CfD	Contracts for Differences
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
ETS	Emissions Trading System
GW	Gigawatt
HMMCP	Maximum and Minimum Clearing Price
KWh	Kilowatt Hour
LCOE	Levelised Cost of Electricity
MCO	Market Coupling Operation
MIFID	Markets in Financial Instruments Directive
MiFIR	Markets in Financial Instruments
MWh	Megawatt Hour
NBP	National Balancing Point
NEMOs	Nominated Electricity Market Operator
NRAs	National Regulatory Authorities
PPA	Power Purchase Agreement
RED	Renewable Energy Directive
REMA	Review of Electricity Market Arrangements
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RES	Renewable Energy Sources
SDAC	Single Day-Ahead Coupling
TCM	Terms and Conditions
TFEU	Treaty on the Functioning of the European Union
TSO	Transmission System Operator
TTF	Forward Price of Gas
WTP	Willingness To Pay

ABOUT CERRE

Providing top quality studies and dissemination activities, the Centre on Regulation in Europe (CERRE) promotes robust and consistent regulation in Europe's network and digital industries. CERRE's members are regulatory authorities and operators in those industries as well as universities.

CERRE's added value is based on:

- its original, multidisciplinary and cross-sector approach;
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EXECUTIVE SUMMARY

Background

The aim of this report is to examine **wholesale electricity market design** and **proposed changes and interventions** in the light of Europe's current **energy crisis** and **climate neutrality goals**. While much of what we discuss is motivated by the crisis we are facing, **any short-term action may have lasting repercussions**, and we draw out some initial learnings on what this means for energy market regulation as Europe tries to move out of this crisis and towards net zero. **Wholesale and retail electricity markets are closely linked**, and this paper is a companion paper to our recent CERRE paper on retail energy markets (von der Fehr et al., 2022).

This European energy price and supply crisis, triggered by Russia's invasion of Ukraine, is severe and unprecedented in the history of the single market in gas and electricity. It is impacting households, industries, and energy companies experiencing liquidity issues and/or bankruptcy risk. It is a wake-up call for energy analysts, regulators, and policy makers on the need for and the implications of a net zero energy system, which will have high-priced marginal units of energy.

Several points about the operation of both European gas and electricity markets are clear from the start:

- First, Europeans are in this together at the level of the wholesale market, and this crisis calls for a **joint approach**. Despite diverging national proposals, **EU solidarity mechanisms have been activated, and new common approaches proposed** by the European Commission and backed by the Council of the EU.

- Second, as we approach the winter when gas supply could be very tight, it will be **Russian gas-dependent countries** that will **especially need the integrated energy mar**ket to support them.

- Third, the gas and electricity price crunch has been worsened by the **effect of climate disasters** on the **energy value chain and electricity output**. Weather conditions are important considerations in the design of future electricity markets.

- Fourth, **markets deliver security of supply by raising prices** in times of scarcity, creating **windfall profits for some**, and leaving **some market parties exposed** to unhedged high prices or certain customers' inability to pay.

- Fifth, **political concern** about the **distributional impact of high prices on European households and industry is inevitable**, especially in a context of high inflation and monetary policy tightening. The competitiveness of national industries is a concern for the whole internal market. Such **impact should be adequately addressed** on a **temporary basis**.

- Sixth, such a large rise in prices and volatility has raised **concerns about whether the current market design for electricity is working and fit for Europe's net zero ambitions**.

The current wholesale market design

The current market design is based on a set of fundamental principles including separation of monopolistic and competitive activities, decentralised decisions, and the availability of marketplaces where participants can trade. It has resulted in an **integrated, or "coupled", European market** where generation and supply is undertaken by a range of different companies competing for customers, and trade takes place both on and outside organised marketplaces.

Together, these marketplaces always ensure a **balance of demand and supply, and cost-efficient dispatch and supply security**. They drive the price up or down to signal scarcity or abundance and encourage producers and consumers to adjust accordingly. They also expose participants to swings in their revenues and costs. Participants are free to move between marketplaces, so **prices tend to be equalised** across them, and any **policy attempting to influence the one, will affect the others**.

Energy prices vary considerably (although not always as widely as recently), and market participants often wish to hedge against the price risk. An open question **is how well the markets for risk hedging work**, and hence whether the current market design does provide **sufficient hedging opportunities**, especially for generators who have to **invest in plants with a long lifetime**.

Investment in generation capacity is **in principle market-based** but has in recent years to a very large extent been **driven by government interventions**, including capacity markets and various forms of incentives for renewable energy. If the ambitious **climate and energy targets** are to be achieved, **government support will be required**. In the longer run, as installed capacity approaches the end of its subsidy period, and as the cost of renewable generation becomes competitive, one would expect **unsubsidised renewable generation** to be dominant. Whether this will require further development of **long-term contractual arrangements** is an open, important question.

Discussion of suggested interventions

We examine the proposals put forward by **ACER, Great Britain, Spain, Greece**, and the **European Commission** to deal with the crisis, as these are either implemented or well documented.

Some suggested design changes to the operation of current electricity markets are **sensible in the long-term**, but even in aggregate they **do not offer the likelihood of significant short run reductions** in prices.

A frequently suggested change both well before and during the crisis is for governments to **sign longer term contracts with generators on behalf of customers**. The point about this sort of contracting to reduce bills now is whether it is efficient because it effectively **borrows money at a high cost of capital** from private energy firms.

There have been **several versions of a 'two-market' solution**. Long-term markets already offer a form of two-market solution, via long-term auctions for renewables. **Two markets in the short run** raises difficult issues whereby **market efficiency is likely to be reduced**, potentially substantially. In the short-term, the marginal cost of extra low carbon output from a given facility can be high and this should be priced.

Two surprising observations are that, despite the European Commission's efforts and sensible recent proposals for electricity and gas demand reduction, more has not been done across Europe to **prioritise actual demand reduction for electricity and gas**, and that **completion of the single market** to protect periphery countries in both electricity and gas is not being further accelerated.

A missing element in suggestions for changes to market design is the **macroeconomic aspect** of energy markets. This crisis is about more than simply what is happening in the energy sector. High prices which are outside the normal range of prices require some **tough political decisions** to be taken on how to **ration energy for European industries and households**.

A final point is that many of the proposals for market design **mix up sensible long-term measures** for net zero **with interventions in the current design** driven by the **nature of the war economy**. Sensible long run design suggestions will take time to have an effect, whereas short run market interventions will not be sensible in the longer term. **Being clear about the timeframe** of suggested interventions and their likely **impacts** is important.

The energy crisis, net zero, and electricity market design

Empirical evidence shows the **impact of market design on market outcomes is small**, the day-ahead auction rules do not matter much. Market outcomes are determined mainly by **market fundamentals** (generation mix, fuel prices, demand levels), and by **market structure** (horizontal market concentration, contracting positions and vertical integration).

Policies aimed at paying firms different short run prices for what is in essence the same product, by creating **multiple separate markets in a hybrid setting** or by **moving from a uniform-price to a pay-as-bid to a pay-as-bid** auction, inherently **increase system cost** and in expectation consumers will have to pay for the overall system costs, which are higher if markets are inefficient.

RES production relies on the availability of scarce natural resources. This does not require a change in market design. **High returns** can be captured by **profits taxes**.

One option is to require all **RES** investors to sign **long-term energy contracts with the government** which include some risk and output sharing agreements. **Auctions for PPAs** are a good way to lock in lower costs for consumers.

We expect that the use of **long-term contracts** by **private parties** will increase in the net zero scenario, due to the higher price volatility, the phasing out of government price guarantees for RES, and stricter regulation of the retailers' risks.

There are **good arguments for government intervention in the contracting marke**t such as: regulating the risk of retailers, standardising contracts to simplify netting, improving transparency on contract prices and positions, contracting on behalf small consumers. However, an **important role remains with private contracts** between generators and large customers.

Whether Member States provide **long-term government backed financial PPAs**, should be left to the **subsidiarity principle**, and depends on the preferences of individual member states.

The energy sector currently has some characteristics of a war economy and skimming the **windfall profits** of RES and nuclear generators might be justified for **equity reasons**. The best method to tax windfall profits is one that keeps incentives to **efficient operation of the spot market intact**, and focusses on the **genuine inframarginal rents** of firms.

Legal aspects of wholesale market (re)design

The legal architecture supporting wholesale market design has evolved remarkably over time through the adoption of different legislative packages. EU rules have become more detailed, prescriptive, and technical in nature. They also increasingly reflect elements of **co-regulation**, with a shift marked in the third energy package with a **more decentralised approach of law-making** resulting in the adoption of network codes, guidelines and terms and conditions (TCMs). Much of these rules now regulate detailed aspects of wholesale energy trading and wholesale market intervention would require the involvement of a series of different entities.

While **Article 194 of** the Treaty on the Functioning of the European Union (TFEU) is the specific legal basis for EU energy policy based on a shared competence between Member States and the EU, the EU emergency measures adopted to deal with the energy price crisis since July 2022 have been based on **Article 122 TFEU**. This is a notable development, as it leaves the **Council with a large influence on the choice and the drafting of EU measures.**

A central question to the market design legislation today is whether it is still **fit for purpose** for the main part and just **needs the adoption of supplementary mechanisms** to deal with specific, temporary challenges, or if it requires a **broader revision**. There is therefore a need to clearly **distinguish** between what should be a future-proof market design under net zero objectives and **medium- to long-term** constraints, and the toolbox of **temporary measures** that can be adopted by governments or market actors to respond to short-term disruptions.

New actors and services have gained recognition in the Clean Energy for All European Package (flexibility services, aggregators, energy communities and prosumers), but they still do not yet represent big volumes on the market. As an additional challenge, a future-proof marked design should contribute to the **resilience of the energy system** to respond to more structural risks. Short-term interventions should reflect this ongoing evolution.

In the context of the current debate on market design, and when assessing the need to revise EU market design legislation, regulatory intervention can be split between **short-term** (toolbox for crisis management), **mid-term** (risk management and adjustments), and **long-term** (towards market reform) processes. Any short-term intervention should not jeopardise the functioning of the internal energy market, in a time where solidarity and complementary are required. As concerns market reforms, two main sets of proposals are identified, focusing on "**price formation**" and "**market behaviour**".

The EU regime of PPAs will probably further evolve as part of the Renewable Energy Directive (RED), rather than as an element of market design legislation. **Legal barriers to PPAs** clearly stem from certain **national legislation**. PPA drafting and provisions will remain an issue for negotiation between parties to the agreement, but the **EU can encourage their adoption** to support the deployment of **renewable generation**. If governments are to be involved in the PPAs, this would require an assessment under state aid rules, and clarifications by the European Commission or the adoption of EU harmonised rules.

Concluding thoughts

- **Maintaining and deepening European electricity market** solidarity is important. Short-term changes to the single electricity market should not undermine its continuing long-term operation and threaten the central part it needs to play in a net zero energy system in Europe.

- Any **short-term action** aimed at high energy prices to protect European households and industries should therefore be **carefully designed and executed at European level**. It is critical to avoid go it alone decisions that undermine solidarity and market integration.

- **Reducing the demand** for gas is key to reducing electricity prices and reducing electricity demand has a disproportionate effect on prices. Every 1% reduction in electricity prices, will reduce prices by of the order of 5-10%. **Ambitious policy and regulatory approaches can drive such reduction**, and it is important that gas supplies to Europe are improved.

- A consistent suggestion is that **low carbon generation should be moved to long-term fixed price contracts**. It is important to recognise that all such contracts represent a **bet on the future** and the nature of discount rates. While this might be sensible for new contracts it is **not obviously beneficial for existing contracts**. The extent of the signing of long-term contracts by the state for power should be a matter of **national preference**.

- The actual reduction in the net present value of the flow of financial payments to low carbon generation over the longer run will likely involve some sort of **appropriation of revenue via increased profits taxes**.

- **Marginal regulated retail prices should reflect wholesale prices**, to incentivise demand reduction and energy efficiency investment. This could be done this winter with well-calibrated **rising block tariffs**.

- **Regulatory barriers** to additional **low carbon generation** and **distortionary taxes on marginal electricity production** should be **removed**.

- **Some of the suggestions** for electricity market reform are **sensible** but they will not address the magnitude of the energy crisis in the time frame required. However, accelerating some of them would bring forward their benefits. Such changes would have to be looked at in the **medium run** in the context of the road to **2030 and 2050 climate goals**.

INTRODUCTION

The aim of this report is to examine wholesale electricity market design and proposed changes and interventions in the light of current energy crisis in Europe, and to draw some initial learnings on what this means as Europe tries to move out of this crisis and towards net zero. It is a companion paper to our recent CERRE paper on retail energy markets (von der Fehr et al., 2022), and precedes our final recommendations paper, to be published in the coming weeks.

The nature of wholesale electricity markets

Electricity is one of the most important commodities in the economy. It is an intermediate good which is the energy carrier of the modern world, valued both for its flexibility and lack of environmental impact at point of use and because it can be produced in a variety of ways. The hopes for complete decarbonisation rest on the **extension of electrification** (to heating and transport) and the production of **hydrogen from electrolysis** (see Pollitt and Chyong, 2021).

Electricity is subject to a lot of **government energy policy**. Indeed, the **energy trilemma**, how to simultaneously provide secure energy at reasonable prices with good environmental outcomes, plays out in electricity strongly. In addition, electricity can be a key part of national industrial policy, being a substantial share of fixed capital formation, with the potential to promote regional policy if investment can be directed to areas of high priority for jobs and new investment. What constitutes 'good energy policy'[1] with respect to electricity varies in time and place, with some jurisdictions favouring more use of market signals and others favouring less, and some jurisdictions favouring closer government direction of investment and others favouring less. These differences between European states often reflect **national preferences** with respect to the operation of the market and the desirability of state intervention.[2]

The physics of electricity presents a challenge for the design of markets. Supply must equal demand at all nodes in the electricity market in real time, with storage being expensive unlike fossil fuels, where storage is relatively cheap. Electrification has been considered by governments as something to be encouraged, and electricity prices have been subject to regulation since at least the 1920s in many countries[3]. High capital costs, inflexible demand, and the need for physical balancing of supply and demand led to widespread integration of generation, transmission, distribution, and retailing, with separation occurring in the presence of long-term contracts. In 1975, a radical idea was noted (by Weiss): that there was the potential for competition between generators and the creation of a wholesale market for power. Meanwhile, power exchanges trading electricity between integrated companies subject to long-term contracting gradually developed. When formal power markets began

[1] See Ozawa et al. (2019).

[2] This varies considerably across European states, see: Janik et al. (2021).

[3] See Priest (1993) on the rise of regulation of electricity in the US.

to appear (e.g. in Great Britain in 1990 and Norway in 1991)[4] these were based on concepts of short-term merit order dispatch developed in France in the 1950s within large generators (see Boiteux, 1960).[5] By 2015, ACER noted that 85% of all day ahead power in Europe was effectively part of a single short run market for energy, via the EUPHEMIA market coupling algorithm which links power exchanges across Europe[6].

While there has been an impressive and long-running development of short run power markets, both for energy and ancillary services (such as balancing services and frequency response), long-term power markets have developed much more slowly. Up until 1990, much of the generation capacity built in Europe had been financed with explicit or implicit state support. The choices of generation technology were typically made with the approval of government energy ministries. There then began a brief period when much new capacity was combined cycle gas turbines, built on a merchant basis, under shorter term (e.g. 15-year) often private contracts.[7] This period lasted until the early 2000s, when new capacity increasingly started to be wind and solar added as the result of government support schemes arising from renewable targets (themselves motivated by successive renewable electricity - 2001/77/EC - and renewable energy directives - 2009/28/EC). In this environment, it was once again the case that much new capacity was being directed and supported by state governments. Unsurprisingly, continuing government interest in new generation technologies has limited the development of longer-term private power markets. **Net zero extends government interests** in new technologies to heating and transport and suggests more, not less, interest in what investments are occurring in the heating and transport sectors.

The reality of government direction of longer-term investment in the electricity sector does not undermine the role for **efficient short run markets** in energy and ancillary services to make **best use** of the **available generation** capacity (minimising short run system cost) and to provide **real time energy security** (to 'keep the lights on') in conditions where reserve capacity is expensive and supply interruption is very costly. Indeed, many 'competitive' markets operate in conditions where significant government-backed investments influence incentives for long run investment and skew the operation of short-term markets.

Equally, it is important not to overstate the potential for disconnection between short and long run prices in electricity. While much investment is determined by governments, longer-term investors – even governments – clearly do pay attention to **short run market prices** for electricity. They make use of these within their own planning and use them in guiding prices that they might be willing to pay for longer-term investments. Short run market prices are very visible and can and are used to justify

[4] See Newbery (2021) and Le Coq and Schwenen (2021).
[5] The Norwegian market, which traces its origins back to the 1960s, was not based on merit-order dispatch, but rather operated as an exchange where hydro generators could swap energy on a daily basis, much like today's power exchanges.
[6] See Pollitt (2019).
[7] As noted by Helm (2004).

increased longer-term government commitments to support new capacity when high, and reduced commitments when low. Electricity competes with gas and oil at the margin in industrial power, in heating and in transport[8]. Hence the **price of electricity** is **influenced** directly in production and in use by the **prices of other energy sources** in the **longer run**. If these other types of energy are subject to global market forces, then electricity will be influenced by them.

High prices are a potential problem in short run wholesale electricity markets. This is because consumer willingness to pay to avoid an instantaneous short run interruption to supply (the value of lost load) is very high and the very short run demand response to high prices may be very low. Every short run electricity market in the world has made decisions about the maximum bid value that is allowed in the market and prices can, at times, rise towards this value. As prices rise there is the potential for gaming, whereby any individual generator, by withdrawing a small amount of their capacity, can raise the price significantly. While high prices for very short periods do not make much difference to average annual consumer bills, they can catch out unhedged consumers (and other counterparties to short run contracts, such as market makers). The early infamous case of this is California in 2000-2001 (see Sweeney, 2002). High short run electricity prices sustained for long periods are more likely to attract government intervention to reduce them.

Wholesale and retail electricity markets are **closely linked**. A key reason for this is that a dominant industry model that has emerged is the **generator-retailer**, whereby generators active in wholesale markets are also integrated with retail businesses selling directly to customers (see Pollitt, 2019). Stand-alone retailers without electricity generation (or being incumbent gas companies) have struggled in many markets. The current crisis, which has precipitated the failure of stand-alone retailers, only seems to have strengthened the attractiveness of the dominant business model (see von der Fehr et al., 2022).

Net zero, the longer term and the current crisis

While much of what we discuss is motivated by the **current crisis**, we draw out lessons for the longer term and the electricity on the path to **net zero**. We note two important starting points relative to the longer term. First, many used to worry that we were creating an electricity market where the short run prices would be too low compared to the level required to facilitate long run investment in low carbon generation. This was the theme of a 2018 CERRE report (Pollitt and Chyong, 2018). In this report we discussed the '**missing money**' problem facing generators, whereby short run market prices would not recover long run average costs, potentially requiring capacity markets and 'subsidised' long-term contracts for new generation. We pointed out that with declining renewable generation costs and reasonable expectations of carbon and gas prices, short-term prices could be high enough to support merchant investment in new low carbon generation. Second, **modelling of net zero** does give some guidance on what technologies need to be developed to decarbonise the energy system

[8] For an early discussion of this see Felton (1965).

completely by 2050 and guidance on the interaction between gas and electricity markets in net zero. This was the topic of a major CERRE on net zero and how to achieve it in the European energy system by 2050 (Chyong et al., 2021; Pollitt and Chyong, 2021).

Our 2021 report highlighted some important points about the long run nature of the net zero energy system, which are essential in considering the short-term actions proposed to address the current energy crisis. This report concentrated on the fact that **green gas and electricity markets remain coupled in net zero**, with electricity being used to produce hydrogen, and hydrogen also being produced by steam-reformation of methane with carbon capture and storage (CCS). This implies that even in net zero, **wholesale electricity prices will be linked to global hydrogen and methane prices**.

Our modelling of net zero showed:

- a large increase in energy efficiency (relative to business-as-usual);
- a large increase in fixed costs of energy system and hence in the level of investment;
- a very large increase in long run system marginal cost of energy relative to 2018;
- the need to address substantial payment issues, whereby a system where much of the costs are fixed (as opposed to driven by variable fossil fuel costs) but need to be covered from variable energy charges;
- and the likely need for support from general taxation and cross-subsidies between energy sources, especially as the new technologies of net zero are scaled up (i.e. low carbon renewables, hydrogen, biomethane and CCS).

This energy crisis is a **wake-up** call on the **need for and the implications of a net zero energy system** which will have very **high-priced marginal units of energy**.

We suggested that carbon prices might need to be EUR 350 per tonne of carbon dioxide. This implies EUR 64 / MWh gas at TTF, CH_4: 189c / therm of gas at NBP and that is just the CO_2 climate externality, not the security externality. All of this implies a big rise in the true system marginal price of energy if gas at margin, relative to 2019 (c. TTF: EUR 20 / MWh; NBP: 41c / therm).

Currently, **prices are above even long-term net zero levels**. This implies that we do not need prices as high as this for net zero, let alone the pathway to it. However, **sustained high prices for fossil fuel-based energy** are a feature of net zero. Hence some attention to what we can learn about how to adjust to high fossil fuel prices is important and we should not necessarily aim to get prices or policy settings back to 2019 levels. We should instead **prioritise dealing with the distributional implications** of high prices, **increasing energy efficiency**, promoting the required **low carbon technology investment**, etc.

Electricity and gas prices are currently not only **high average**, but they are also exhibiting **high volatility**. This has created **liquidity problems** in short run markets and sparked an increase in bilateral trading.[9] High volatility exposes market makers and purely financial players – who may over derivative products - to **increased risk**. These players may leave the market or require greater capital.

Net zero modelling shows that flexibility will be a key challenge for the 2050 energy system in Europe. A requirement to dampen price volatility in response to national preferences for price smoothing or in order to reduce risks to investors would seem to require **long-term contracting** and **deep demand flexibility**.

The background to the current crisis

The energy price and supply crisis in Europe is severe and it is unprecedented in the history of the single market in gas and electricity, which dates from around the end of the 1990s, following the first electricity (96/92/EC) and gas (98/30/EC) market directives.

The war in Ukraine and the consequent significant curtailment of European gas trade with Russia has sharply raised the price of gas and consequently the price of electricity, further exacerbating the price increase driven by post-covid recovery in global gas demand.[10] The wholesale electricity prices in Europe are now around double (in real terms) the level they have been at any time since 1999.[11] They have been around this level for an unprecedented number of months . What is more, **high prices are expected to continue** for at least two and a half years by **forward markets**. The forward price of electricity at the time of writing in 2025 is expected to be over twice its normal level[12], while the forward price of gas (TTF) is expected to be over four times its normal level in March 2025.[13]

Such an unprecedented and prolonged price rise **cannot be characterised as a temporary price spike**. It is an **enormous micro and macro-economic shock** similar in magnitude to the first oil shock of 1973-74. It is testing current market arrangements and causing them to reconsider, as we discuss below.

Some starting points for our discussion are detailed below. Several points about the operation of both European gas and electricity markets are clear from the start.

First, **Europeans are in this together** at the level of the wholesale market. This is true of both single market countries (EU27 + Norway) and the UK and Switzerland which are part of European gas and

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[9] For a discussion, see: https://www.esma.europa.eu/sites/default/files/library/esma24-436-1414_-_response_to_ec_commodity_markets.pdf

[10] For a review of current electricity prices and national measures in Europe, see: https://cdn.eurelectric.org/media/6053/overview_national_situation_18082022-h-D24BA028.pdf

[11] For recent and current prices see: https://ember-climate.org/data/data-tools/europe-power-prices/. The previous prices for GB are shown in Levi and Pollitt (2015) for the period 1990-2014, in real terms; and see Ofgem for more recent data (2011-: https://www.ofgem.gov.uk/wholesale-market-indicators

[12] 168 Euro / MWh in calendar 2025 (EEX Power Futures Dutch Base Power on 4 September 2022), against a maximum monthly price in 2019 in the EU of less than 70 Euros / MWh (see Ember: https://ember-climate.org/data/data-tools/europe-power-prices/)

[13] 93.285 Euro / MWh in March 2025 (ICE TTF Futures Price on 4 September 2022), against prices hovering around 20 Euro / MWh for most of the decade from 2010 (see https://www.spglobal.com/commodityinsights/en/market-insights/blogs/natural-gas/070521-ct-european-gas-lng-ukraine-co2-emissions-us-henry-hub-aluminum-coal)

electricity networks and whose prices largely move in line with those in the EU. This implies that **wholesale market security** is a **shared public good** and **attempts to intervene in one country** to suppress the price or to limit flows of electricity or gas across interconnectors **reduces market efficiency** and **shared insurance**. For example, Norway has supported other European countries through increased gas and electricity flows, France has benefitted from exports of electricity from the UK during nuclear shutdowns, while LNG terminals in the UK have been used to land gas for onward flow into the continental European grid. This emphasizes the value of integrated European energy markets for both electricity and gas.

Second, as we approach the winter when gas supply could be very tight, it will be **Russian gas-dependent countries** that will especially need the integrated market to support them, including via reverse flows of gas procured by LNG and pipeline from other countries. Otherwise, there is **a real risk of compulsory rationing and curtailment of demand**.

Third, **markets deliver security of supply** by raising prices in times of scarcity, creating **profits** for some and **leaving some market parties exposed** to unhedged high prices or some customers unable to pay. Higher wholesale prices are inevitable for gas in Europe while Russian gas imports are restricted.

Fourth, the electricity price crunch has been **worsened by the effect of climate disasters** across the energy value chain and on electricity output. So far 2022 has seen much lower output of electricity from hydro across Europe.[14] This is in addition to problems with output from nuclear power plants. The reduction in hydro has been due to drought (itself likely caused by climate change). Some of the reduction in nuclear is also related to the lack of river water for cooling. This illustrates that **climate and weather conditions** are important considerations **in the design of future electricity markets**.

Fifth, **political concern about the distributional** and wider economic impact of high prices is **inevitable**. Something must be seen to be done in a democracy to respond to legitimate political concern about fuel poverty, industrial uses of gas and about potential health impacts from a lack of winter fuel. This need to do something is heightened by the fact that rising energy prices are **macroeconomically significant,** reducing aggregate real GDP and contributing to the inflation. In Germany the estimated loss of GDP from sustained high energy prices is up to 12%[15], while inflation was expected to peak at 13% in the UK following announced price rises in electricity and gas on 1 October 2022, of which gas, electricity and fuel would have been contributing 6.5%[16]. Meanwhile industrial electricity demand is being significantly affected by higher prices. In the UK, for instance,

[14] See Heussaff et al. (2022).

[15] See Bachmann et al. (2022)

[16] 'Electric Shock', *The Economist*, August 13th 2022, p.19.

industrial electricity prices are 44% higher in real terms between June 2019 and June 2022, while industrial demand is -6.1% lower.[17]

Sixth, such a large rise in prices and volatility has raised **concerns about whether the current market design for electricity**, in particular, is **working**. Sustained high prices for electricity, gas and liquid fuel always raise concerns as to whether energy companies are making windfall profits or acting anti-competitively in some way. It is clear that **gas producers are making large profits** (following recent announcements from Shell and BP), but it is **less clear** what the **size of profits is within the electricity sector** itself.

What we look at in this report

In what follows, we begin in **Section 1** with a discussion of **how wholesale electricity markets in Europe are supposed to work**. In **Section 2** we consider some of the **proposals that have been made** to reform the electricity market. In **Section 3** we elaborate in more detail the **theory of market design changes aimed at reducing the price and bill impact**, as well as **volatility**. We next discuss the **legal implications** for the future of the single market in electricity in **Section 4**. The last section offers some concluding thoughts.

[17] See BEIS statistics, Table 5.5 and Table 3.3.1 September 2022. Industrial demand was 8.7% lower in July 2022 than July 2019. Prices for manufacturing industry (excluding CCL) for the three months Apr-June 2019 to Apr-June 2022.

SECTION 1: THE CURRENT WHOLESALE ELECTRICITY MARKET DESIGN

The current market design traces its origins back to the reforms in England and Wales and Norway in 1990, although important elements, such as a competitive power exchange, have an even longer history. In this section, we present the current design and discuss the rationale behind it.

Market architecture

A fundamental principle of the current market design is the **separation of activities** that may be subject to competition and activities where effective competition cannot be achieved. In the former category falls generation (production) and supply, while in the latter category fall networks and other infrastructure, including system operation.

The idea behind this separation was to reap the benefits from competition where possible, and to rely on regulation only where competition was either ineffective or non-existent.

This was a new idea for the electricity industry when it was first introduced, and it stood in sharp contrast to the prevailing market architecture in many European countries, where generation and networks where integrated into the same companies, sometimes in a single market-wide monopoly. In some countries, the reform led to the creation of new transmission and distribution companies which took over responsibility for networks. In other countries, it led to the divestment of generation and supply from existing utilities. Vertical separation was accompanied by horizontal separation, through the breaking up of monopolistic structures in generation and supply, in order to facilitate competition.

Movement away from monopolistic structures were accompanied by a movement away from "**self-governance**" through the establishment of **dedicated government agencies** responsible for regulating the industry. In some countries, such regulatory agencies already existed, but their tasks now went from general oversight of all activities in the value chain to concentration on the monopolistic activities (infrastructure) and measures to promote competitive markets.

While, when new, the current market architecture met with considerable opposition, it now seems well accepted and essentially uncontroversial. Specifically, none of the current proposals for reform address market architecture.

Decentralised decisions and markets

Another fundamental principle of the current market design is **decentralised decision making**. This principle applies to consumers and generators, traders and suppliers and other intermediaries, as well as to marketplaces. The idea behind this principle is that individual agents are better placed to make informed decisions on their own behalf than some central (government) authority.

In generation, each individual company decides on how much electricity it wants to produce at any given time, subject to contractual obligations, market prices and other relevant internal and external conditions. This is contrary to the historic organisation of generation in many European countries, as well as in many other parts of the world, where dispatch was or is centralised.[18]

The decentralised decision model requires means for **balancing generation with consumption**. Balancing is crucial in electricity (less so in gas), since imbalances between what is fed into the grid, and what is drawn from it, will create fluctuations in voltage levels and frequencies that may damage not only the grid itself, but also electrical equipment connected to it.

The bulk of the balancing takes place through trade between buyers and sellers of electricity. Some of this trade is based on bilateral contracts and some occurs in specific marketplaces or power exchanges, where buyers and sellers bid in their demand and supply and trade through the marketplace.

It is notable that the organisation of trade and markets has been developed largely by the market participants themselves. While marketplaces may be subject to regulatory oversight, their establishment and design are first and foremost a result of what market participants have wanted. An exception to this rule was the original pool in England and Wales, which was built on the former central dispatch mechanism, and where participation was mandatory, but this was eventually abandoned and replaced by a voluntary power exchange. More generally, marketplaces evolve over time depending on the needs of participants.

At the core of the electricity market is the **day-ahead or spot market**, where market participants daily make hourly (or half-hourly) bids for the coming 24 hours, and where market clearing prices determine how much each participant will sell or buy. Fundamentally, the market operates as any other commodity market, where prices are determined by bids and offers. This is not to underplay the fact that electricity has certain characteristics, such as the need to match demand and supply at every instant, and the fact that flows of the physical commodity is determined by physics rather than contractual relations, that complicates both the organisation of electricity markets and the difficulty of making them operate efficiently, including avoiding market power. Nevertheless, the basic functioning of electricity markets may be analysed by standard tools, bearing in mind the complexity of the practical reality - more on that below.

The operation of the spot market is illustrated in the figure below. The figure shows “snapshots” of the market in three different circumstances, with low, medium, and high demand, respectively. For simplicity, we have assumed that there are two different generation technologies, base-load and peak-

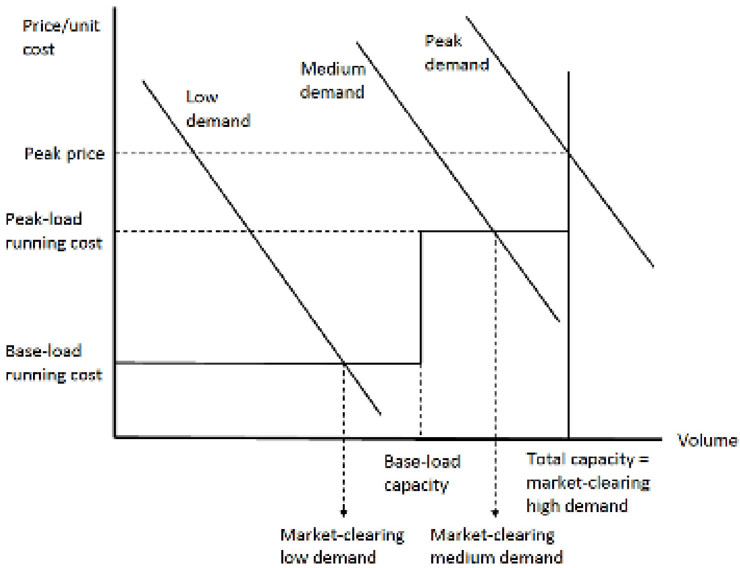
[18] The details of European wholesale markets, including the extent to which generators are mandated to participate and how dispatch is organised, differs across Europe; indeed, some, such as Italy and Spain may perhaps best be characterised as "semi-decentralised". For a discussion of the merits of different organisations, especially between centralised and decentralised dispatch, see Ahlqvist, Holmberg and Tangerås (2022).

load respectively. Base-load generation has low running costs (and correspondingly high-capacity costs, e.g., think of nuclear or renewables), while peak-load generation has high running costs (and correspondingly low-capacity costs, e.g., think of gas). In the market, offer prices reflect costs and hence bids will be stacked in order of increasing running costs, the so-called "**merit order**".[19] Along the horizontal axis we measure volume of supply and demand (e.g., in MWh), while along the vertical axis we measure price and unit running costs (e.g., in Euro/MWh).

In low-demand periods, only base-load generation is required to cover demand, and so price will equal the running cost of this technology. In medium-demand periods, also peak-load generation is required to cover demand, and so price will equal the running cost of this technology. Finally, in peak-demand periods, price will have to be set sufficiently high that demand does not exceed total capacity, and hence exceeds the running costs of both technologies; in other words, in such periods generators earn a "**scarcity rent**". We say that the plant (technology) setting the price is the "marginal" plant (technology) and that its cost is the **"marginal" cost** of the market (in scarcity periods, price instead reflects consumer willingness to pay or value of lost load).

It may be noted that the market delivers both **short run efficiency and security** (we return to the issue of long run security and efficiency, which is determined by investment, below). It delivers efficiency in the sense that demand is satisfied in the least-cost manner, i.e., by generation with the lower cost.[20]

Figure 1: Spot market clearing



It also delivers efficiency in the sense that the composition of generation is cost effective. The low-

[19] We have ignored the issue of market power here – specifically, the ability of generators to set offer prices above costs – as this is not essential to the main points. In practice, market power is a real concern and market design, including expanding and integrating markets, needs to pay careful attention to it.

[20] Strictly speaking, cost efficiency is guaranteed only if the market is truly competitive; when there is market power, the merit order may be affected by the extent to which generators bid above costs, in particular, if generators with low costs bid higher than generators with higher costs.

cost base-load is running all of the time, while the more expensive peak-load technology is only running when needed (the peak-load technology has relatively low-capacity cost, so it is the overall cheapest option to ensure sufficient capacity at all times). The market delivers security in the sense that it always ensures balance between demand and supply, and hence prevents situations of uncovered demand or rationing.

Moreover, if environmental costs of different generation technologies are reflected in their costs, the market also provides environmental benefits. The interaction between the CO_2 permit system – the **Emissions Trading System (ETS)** – and the electricity markets ensure that environmental costs are reflected in the merit order. Specifically, the permit system increases the cost of thermal generation based on hydrocarbons, thereby affecting their competitiveness against other generation technologies. In recent months, coal has made its way back onto the market to compensate for lack of gas (and other generation), **pushing CO_2 permit prices up**. This has **made gas even more expensive** and **impacted further on the electricity price**.

The fact that the merit order reflects the costs of different technologies, implies that changes in costs impact the merit order. An increase in the cost of a particular technology, may move plants based on this technology up the merit order, thereby ensuring that cheaper technologies are operating in its place. Even when the merit order is not altered, the cost increase is reflected in the market price whenever the technology sets the price, thereby signalling to the demand side that the cost of electricity has gone up.

The fact that market prices are set to clear the market implies that prices reflect ’marginal cost’, i.e., the cost of the most expensive generation plant that has its offer accepted. Since all sellers receive the same market-clearing price, sellers who would be willing to produce electricity at a lower price, will obtain a positive margin on what they sell. This allows for **remuneration not only of variable costs,** but also of the **fixed costs of generation**. It is the fact that prices are sometimes set by peak-load plants with high variable (but low fixed) costs (and possible scarcity rents) that allow base-load plants with high fixed (but low variable) costs to have their costs covered.

The fact that prices reflect marginal cost also means that increases in the cost of the marginal generation technology are transmitted to the whole market. In Figure 1, if the running cost of the peak-load technology goes up, prices will be higher whenever this technology is on the margin, and all the capacity operating at such times will receive this price. This is what is currently taking place in the European electricity market, where the higher cost of gas has increased the running costs of gas-fired plants, the technology that is on the margin when the market is tight. Since generators always have the option of selling in the spot market, any increase in the price in the spot market tends to be transmitted to the bilateral market, and *vice versa*, and therefore the increase in cost is driving up prices in the entire market.

Changes to the composition of the generation park may also affect the merit order and hence prices. In recent years, large amounts of renewables have come onto the market. They have the characteristics of base load, with very low running costs and correspondingly high capacity costs and have consequently taken their place at the bottom of the merit order; wind and solar farms produce whenever they can. This has had two important effects: on the one hand, renewables have reduced the running time of other types of generation, **especially** thermal technologies based on hydrocarbons, and hence made them less profitable, sometimes to the extent of pushing them out of the market. On the other hand, whenever renewables constitute the marginal technology, prices are very low.

So far, we have only seen relatively few instances when demand may be covered entirely by renewables (e.g., in Denmark and Germany), but this will be much more frequent as the amount of renewable generation increases. In a **net zero** world, we are likely to see **extended periods of time** in which **prices are very low**, intercepted by **periods** in which **prices raise to high levels** to remunerate peak-load technologies (e.g., gas), that are required to compensate for lack of wind or sun or cover peak demand. The price swings will be **moderated by the presence of storage** facilities, such as pumped storage and batteries.

The bilateral market (which is typically for longer-term contracts) and the day-ahead market are complemented by other markets that allow for continuous adjustment of positions and overall market balance. In the **intra-day market**, market participants can trade up to only a few minutes before actual delivery. In the **balancing market**, where market participants offer to deviate from their generation (or consumption) plans, the system operator could adjust generation (and consumption) to ensure that there is always complete physical balance.

In other words, the peculiarities of electricity alluded to above, which necessitates a range of different contracts, especially in the time dimension, means that generators (and consumers) have the opportunity to trade on different marketplaces. Under ideal conditions, arbitrage and competition ensure that prices are equalised across markets. However, since generators (and consumers) differ in their ability to provide services – particularly with respect to adjusting plans on short notice – **efficiency may not always be ensured**. Much effort has gone into the development of measures to reduce the risk that market participants do not use market power to distort prices within or across markets, most notably the **Regulation on Wholesale Market Integrity and Transparency (REMIT)** that came into force in 2011 and for which ACER has main responsibility.

The fact that the different marketplaces are closely, if not perfectly, interrelated, means that any attempt at influencing the price in one market is likely to spill over into the others. Moreover, attempts to control the price in one marketplace will move trade between this market and the others; for instance, an **attempt to reduce or cap prices on the day-ahead** spot market, is likely to **shift trade from this market to the bilateral** or "over-the-counter" **marketplaces**.

Gradually, markets across Europe have been integrated – or, more precisely, **coupled** – allowing for trade between different areas.[21] Specifically, day-ahead markets are cleared simultaneously across

[21] See Pollitt (2019) for an account of the history of the European single market in electricity, including the evolution of cross-border trade.

Europe, thereby ensuring that interconnectors are efficiently utilised, and prices are brought as closely together as possible. This ensures that electricity is supplied from the cheapest sources and consumed where it has the highest value, thereby maximising value added across Europe.
The integration of electricity markets should be seen as the realisation of the more general idea of the "**single market**", whereby gains from trade can and will be realised across Europe, in this case for electricity (and gas). The facilitation of cross-border trade has been accompanied by rules to ensure that competition, both within and across markets, is effective, i.e., a 'level playing field', to maximise overall gains.[22]

A consequence of the integration of different areas is that **events in one area will have an impact in other areas** also. For example, when generation is reduced in a certain area for one reason or another, imports from other areas may partly or wholly make up for the difference. A recent example is how the unavailability of nuclear capacity in France has made the country go from being a net exporter to a net importer of electricity. Other examples include low water in Norway, cold winters in Northern Europe and high temperatures in Southern Europe. As such, integration acts as a form of shared insurance that makes each part of the market more resilient to shocks, whether of domestic or external origin. The single market area ensures the security of its constituent parts against energy threats to one Member State, such as the cutting of electricity exports to Finland from Russia and Russian gas exports to Poland.

The fact that the transmission networks in general, and interconnectors in particular, have **bottlenecks** means that it is not compatible with complete price equalisation across Europe. Prices will be lower in areas where there is surplus supply (and hence export to neighbouring areas) than in areas where there is surplus demand (and hence import from neighbouring areas). These price differences, which reflect **lack of transmission capacity**, may occur both within and between countries. They provide a signal of the value of reducing or removing bottlenecks. The signals have led to large increases in interconnector capacities, for example between Norway and the EU and between the UK and other European countries.[23]

While market manipulation and market-power abuse has been a recurring topic in European electricity markets, it seems that the general view among industry experts is that these markets perform quite well and have delivered what they were supposed to. Even during the present tumultuous times, the price mechanism has ensured that **rationing was avoided** (this is not to suggest that the consequences for those who have felt the implications of high prices are not severe).

Risk and hedging

When most physical trade takes place on a day-to-day basis in markets where prices fluctuate, market participants are subject to price risk. In the current market design, market participants are assumed

[22] Challenges associated with market integration, and how they may be resolved, are discussed in von der Fehr (2017).

[23] Ensuring efficient investment in interconnectors meets with many challenges; for a recent analysis and references to other literature, see Crampes and von der Fehr (forthcoming).

to handle this risk themselves. The idea is that they know best, both their ability to withstand risk and how much they are willing to pay to hedge against it.

Hedging takes place both through bilateral contracts and through financial markets. In the bilateral market, parties are free to negotiate any form of contract they see fit, including its duration and indexation of price. Bilateral contracts may have quite long durations, of five years or more.

The financial marketplaces offer standardised products, such as futures and options, with different durations. These products may provide hedging against variations in the spot price in any given market or against price differences between different price areas. Duration is typically relatively short; it is rare that standardised financial contracts for electricity have a duration of more than five years.

By having access to a wide selection of contracts and marketplaces, market participants can choose not only the amount, but also the type of hedging they prefer. In practice, we see **different hedging strategies** both across types of market participants and across different parts of Europe, presumably reflecting different needs. While most generators and energy-intensive industries tend to be fully, or almost fully, hedged, many smaller businesses do not hedge at all. Among household consumers, there are remarkably large differences in the extent of hedging across Europe, as we have documented in our companion report on retail markets.

It remains an **open question how well the markets for risk hedging actually work** and hence **whether the current market design does provide sufficient hedging opportunities**, especially for generators who must undertake investment in plants with a long lifetime. Financial markets evolve freely, responding to the needs of market participants, and hence one would expect the availability of products to reflect demand. The fact that financial markets do not offer contracts of very long duration may therefore simply suggest that there is limited appetite to pay for such contracts. Also, bilateral contracts, often of quite long durations, are common in parts of Europe, for instance in the Nordic region, suggesting that they will be available when there is a need for them.

Critics will respond that the lack of **long-term contracts** reflect a market failure, rather than a lack of demand. The liquidity of financial markets was affected by the tightening of financial regulations following the financial crises (and, of course, in the current turmoil many have become more reluctant to trade in what is seen as highly uncertain assets). In particular, the requirements on market participants in financial marketplaces means that they will only be of interest to generators and large consumers of electricity (as well as traders with sufficient financial resources). Also, bilateral contracts are mostly of interest to generators and large consumers of electricity. To enter into such contract, volumes have to be sufficiently large and time horizons sufficiently long.

The current energy crisis has revealed that **many suppliers were not well hedged** against a rise in wholesale prices. These suppliers had instead relied on buying in the wholesale spot market even when offering retail contracts to their customers of duration of a year or more. The reason these suppliers did not hedge their positions may of course be that their experience was that hedging was unnecessarily expensive; after all, hedging comes at a cost. However, it may also be that since their

customers are free to move after their contracts are expired, or indeed before that, if their contracts allow (maybe at a modest penalty), **suppliers may have been reluctant to commit** to long-term purchases. In jurisdictions where customers are allowed to switch suppliers at short notice, suppliers will naturally be unwilling to enter long-term contracts.

It should also be emphasised that while hedging reduces the exposure to price swings – particularly in periods of high prices – they do not protect against prices being high for a long time. Prices in long-term contracts reflect expectations of future average prices, and hence prices will only be low if future prices are expected to be low.

Moreover, in periods of high uncertainty – such as right now – it may well be worth waiting for a reduction in uncertainty. Currently, long-term contracts are offered only at relatively high prices, reflecting the huge uncertainty about how the market will develop, and so the cost of reducing risk is very high. Instead of locking into a certain, but high, price now, it may be better to pay the current high price and wait for a reduction in prices of long-term contracts.

Investment and technology

Just as decisions on generation are decentralised, so are decisions on whether to invest in new generation capacity, including both the size of the plant and its technology. It is the **individual company who decides** how much and in what they want to invest. This is notwithstanding the fact that investments are **heavily dependent on government intervention** (see below).

Investment incentives depend on market prices, in particular the premium between market prices and variable or running costs. This is illustrated in Figure 2, which builds on Figure 1 above and shows the capacity premium in three different circumstances.

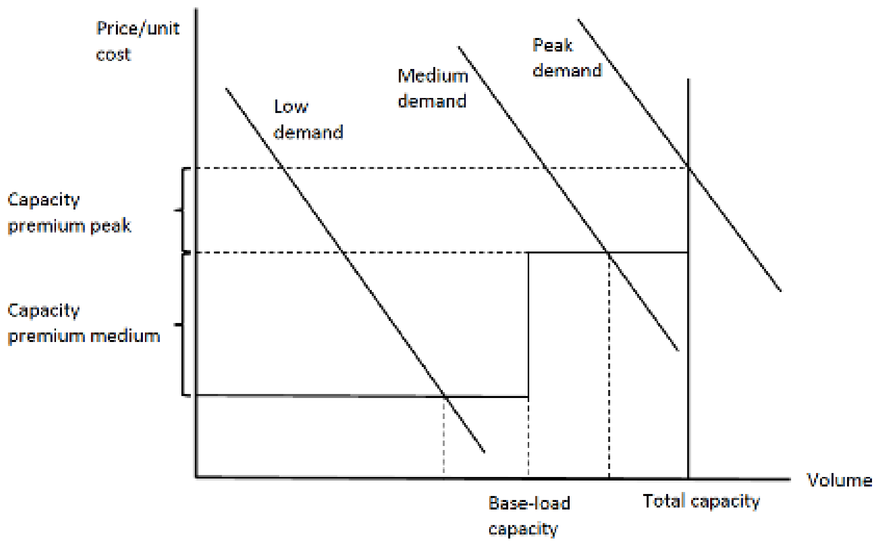


Figure 2: Capacity premium

In low-demand periods, the market is cleared at a price that equals running costs, and hence there is no capacity premium for either technology. In medium-demand periods, when the price is set by the peak-load technology, the market is cleared at a price that exceeds the running cost of the base-load technology. Consequently, the base-load technology receives a capacity premium, in the figure denoted "Capacity premium medium". In peak-demand periods, when price must be set so high that demand does not exceed total capacity, price exceeds the running costs of both technologies (reflecting instead willingness to pay or value of lost load). The peak-load technology receives what in the figure is denoted "Capacity premium peak", while the base-load technology receives the sum of the "Capacity premium peak" and the "Capacity premium medium". The fact that the base-load technology receives capacity premia more often and of a larger magnitude than the peak-load technology, reflects the higher capacity costs of the former technology, and so ensures there is incentive to invest in both technologies.

This model is clearly extremely simplistic. For example, it does not consider that there are many different generation technologies and that both demand and available capacity varies in a (partly) unpredictable or stochastic manner. However, the main insight, that capacity investment incentives arising from the market requires that prices exceed running costs, which mostly occur when the market is relatively "tight", is robust. Over time and on average, **in a well-functioning market, the capacity premia will reflect capacity costs of relevant generation technologies**.[24]

More specifically, a well-functioning market ensures that long run profitability of generators will reflect normal returns on capital (considering industry specific risks). If prices go up, and profitability with it, new capacity will be attracted to the market and push prices and profitability down again. Similarly, in periods of low prices and low profitability, generation will be taken off the market, thereby pushing prices back up. There may of course be periods of both unusually high or low profitability, but over time neither excess nor deficient profit levels can be sustained.

As such, the current spike in electricity prices rewards installed investment in generation. Curbing prices (or taxing the resulting profits) will not only reduce the reward to installed capacity but may also reduce incentives to invest in new capacity if investors fear that similar interventions will take place whenever prices spike in the future. However, one could reasonably argue that the current spike is not only extreme, but also unprecedented, and that measures taken in such unique circumstances do not set a precedent for future, more normal events.

Investment does not only depend on expected profitability, but also on risk. Generation capacity is generally long lived, sometimes with very long lifetimes, and hence subject to considerable risk, especially concerning future prices. This risk drives up the cost of capital and hence undermines investment incentives. As explained above, generators can hedge at least some of this risk, either by

[24] The conditions for this result are strict, but not entirely unreasonable; they includes free movement of prices (no effective price caps) and free entry of new capacity. Classic references to the theory are Boiteux (1960) and Turvey (1968); see also Crew and Kleindorfer (1976).

bilateral contracting or in financial markets, or a combination of the two. In many parts of Europe, for example in the Nordic region, investment is undertaken entirely on this basis (admittedly with some government support, see below). However, this may not always be possible, especially where a large part of demand is unwilling or unable to enter long-term contracts.

While investment in generation depends on price levels (and the risk associated with these), Investment in hydro reservoirs, pumped storage, batteries, and hydrogen facilities depend on intertemporal price differences (and the associated risk). These capacities derive their profits from drawing electricity from the system (or not producing, in the case of reservoirs) when prices are low and injecting electricity into the system when prices are high. The profitability of these investments is therefore highly dependent on the extent to which prices vary over time. As explained above, when large quantities of wind and solar capacity comes on the market, prices are expected to vary more, increasing the profitability of technologies that benefit from price variation. Of course, such investment will also depend on the extent to which investors can hedge their risk, in this case by contracts related to differences in prices over time.

In practice, investment does not depend only on incentives arising from the wholesale market; **investment in generation is to a considerable extent regulated**, both directly and indirectly.

Investment requires approval of relevant government authorities (typically many different ones, representing both local and national interests). The approval may not only depend on where the new plant is built, but also upon its capacity and generation technology. As such, investors face real constraints on their investment decisions. This is true also of disinvestment or capacity reductions; governments sometimes intervene to take capacity off the market, such as has been the case with nuclear generation capacity in Germany and Sweden.

Moreover, governments regulate investment indirectly, through various economic incentives. These indirect means of regulating investment are sometimes general, available to all of generation. The so-called capacity mechanisms, which in one way or another pay generators for making capacity available, are often of this type. Others are directed at encouraging specific technologies, typically renewable energy. These measures have taken the form of guaranteed prices (**feed-in tariffs**), subsidies to output (green certificates) and investment contributions. In addition, the Emissions Trading Scheme (ETS), which puts a price on carbon emissions, discourages thermal generation based on coal, gas, and other petroleum products.

Increasingly, governments have also regulated investment directly by **procurement of specific types of generation capacity**. These procurement contracts are often offered through auctions, in which participants compete on how much they require (or are willing to pay) to enter contracts.

As a result of active intervention by government authorities, the current (and future) configuration of generation capacity is not so much a result of market forces as of deliberate government plans. This is true both for the size of the overall capacity, as well as for the technological composition of the generation park.

Consequently, electricity prices have been driven down to levels where purely market-based investment is not profitable (this is of course not true at the moment, where prices are at levels where, should they last, almost any investment would be profitable). Consequently, if the ambitious climate and energy targets are to be achieved, **government support will be required** for the necessary investment to be forthcoming.

In the longer run, as installed capacity approaches the end of its subsidy period, and as the cost of renewable generation becomes competitive, unsubsidised renewable generation is expected to be dominant. Whether this will require **further development of long-term contractual arrangements is an open, important question**. Specifically, investment in large-scale and long-lived projects, such as nuclear and offshore wind, may well require better hedging opportunities than is currently available to investors. **Whether this should be offered by governments** underwriting specific investments (which would require acceptance under state-aid rules), or **whether there is a need for developing markets for long-term contracts, needs careful consideration.**

Infrastructure and regulation

While generation and supply are based on decentralised decisions and subject to competition, networks, and other infrastructure, including system operation, are not. They are vested in companies which hold a monopoly right to operate, and often own, the relevant part of the infrastructure.

These monopolies are consequently subject to strict regulation. This concerns their day-to-day operations, but especially their investment decisions. New lines and other network elements need acceptance from the relevant authorities. When lines cross from one jurisdiction to another, they are subject to approval from both sides of the border.

The strict rules and regulations concerning infrastructure, and the considerable opposition with which new infrastructure is often met, has meant that building new infrastructure has become difficult. This is particularly true for cross-border interconnectors, where there may also be difficulties in reaching agreements on the financing of investments (Crampes and von der Fehr, forthcoming). Cross-border offshore projects, which may also act as interconnectors, and consequently raises a range of regulatory questions, is a point in case. Such **obstacles may have important implications also for future investment in generation and the ability to achieve a single market** for electricity (and gas).

At the European level, The Council of European Energy Regulators (CEER) provides a forum for cooperation and exchange of best practice between national regulators. Moreover, The EU Agency for the Cooperation of Energy Regulators (ACER) has been given the task of fostering integration and completion of the European internal energy market for both electricity and gas. Regarding infrastructure, the European Network of Transmission System Operators for Electricity (ENTSO-E) every two years presents a 10-year plan on how to develop the power grid (a similar plan for gas infrastructure is provided by ENTSO-G). The plan is the basis for selection of Projects of Common Interest, which are eligible to receive public funds.

While these institutions are clearly important, it is still the case that development of the internal market is to a large extent dependent on decisions taken at the national level.

SECTION 2: A DISCUSSION OF SUGGESTED INTERVENTIONS

What proposals have been made for dealing with the crisis at the wholesale level?

We will examine a number of proposals that have been made for dealing with the electricity crisis at the wholesale level. We look at the proposals from **ACER, Great Britain, Greece, Spain** and the **European Commission** as these are either implemented or well documented. The first three of these proposals also seek to address wider questions of future market design of the electricity market on the path to net zero, as well as seeking to reduce prices in the near term. The final three are discussed in both their short- and long-term context. A number of companies and trade bodies (e.g. EnergyUK[25]) have also made statements on what they think should be done about electricity market arrangements; we comment on some of these below.

Although the topic is covered in section 3, this paper's core focus is not on proposals that have been made that apply to just the gas market. These include a cap on the Russian gas price[26] or indeed on all imported gas[27]. This is not an electricity market measure. However, price caps on prices paid for international commodity prices look unlikely to be sustainable. Other suggested reforms to wholesale gas pricing include the replacement of new LNG import benchmark price for natural gas to replace the use of the TTF wholesale gas price[28], or the introduction of a price corridor without a fixed cap with friendly gas partners[29]. Some Member States have also been calling for joint purchasing of natural gas at EU level to attempt to reduce prices, possibly via the newly established (2022) EU energy platform[30].

ACER

The Agency for the Cooperation of Energy Regulators published its 'final' assessment on EU wholesale market design in April 2022. A summary of its recommendations is contained in the figure below.

[25] See https://www.energy-uk.org.uk/index.php/media-and-campaigns/press-releases/526-2022/8286-energy-uk-backs-scheme-to-reduce-power-costs.html

[26] See https://www.reuters.com/world/europe/eu-energy-chief-calls-price-cap-russian-gas-2022-09-29/

[27] See https://www.politico.eu/wp-content/uploads/2022/09/28/Gas-Price-Cap.pdf

[28] See https://uk.investing.com/news/commodities-news/eu-wants-new-transaction-based-lng-benchmark-in-bid-to-calm-prices-2766763

[29] See https://uk.movies.yahoo.com/eu-try-price-corridor-rein-184335783.html

[30] See https://www.euractiv.com/section/energy/news/berlin-makes-u-turn-backs-joint-gas-purchasing-at-eu-level/

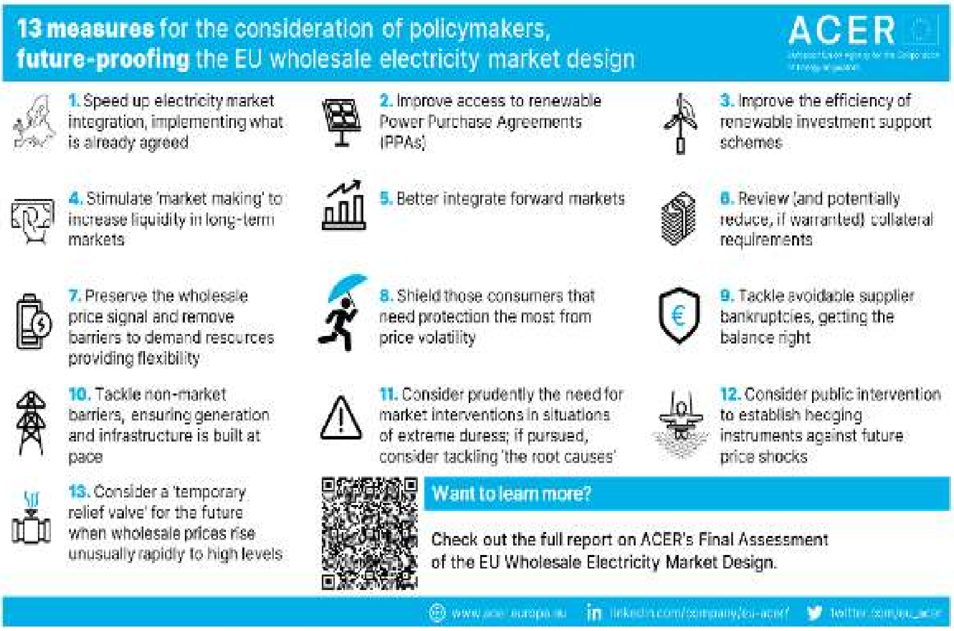


Figure 3: ACER Summary of Future Proofing Measures[31]

ACER's basic starting point is that the single market in electricity is something worth preserving and completing. It makes **13 recommendations** on 'future-proofing' market design. We can group some of the recommendations. For instance, the recommendations to 'speed up electricity market integration' (1), 'stimulate 'market making' to increase liquidity in long-term markets' (4), 'better integrate forward markets' (5) and 'preserve the wholesale price signal and remove barriers to demand resources providing flexibility, are all **objectives of current policy and a part of the current design** (or design intention) of the wholesale electricity market. These are sensible. Completion of the current market is estimated to bring benefits of the order 1-2% of the current wholesale price across Europe (see Newbery et al., 2016), especially if extended to ancillary service markets.

Recommendations on renewable support schemes are not strictly about market design, but about **how renewable support is integrated into the operation of the market**. 'Improve access to renewable Power Purchase Agreements (PPAs)' (2) would allow consumers to lock in lower renewable prices as part of their demand. This happens in some countries where long-term PPAs have been adopted by government renewable support schemes and where, if the strike price of the PPA is below the market price, revenue is recycled to the customer (e.g., Great Britain)[32]. 'Improve the efficiency of renewable investment support schemes' (3) would reduce the long run cost of renewable support. Examples of this would include moving to **auction-based procurement of renewables**, rather than paying fixed prices, or indeed moving to a **European system of renewable support**, where a given country could meet its renewable obligations with renewables in another country. This might give northern European countries access to solar resources in the south and southern countries access to offshore

[31] Source: ACER (2022, p.7)

[32] For more detail on how the UK scheme works, see https://www.lowcarboncontracts.uk/contracts-for-difference

wind resources in the north. The inefficiency of nationally based renewable support schemes was estimated to have cost Europe $100bn by 2014 (WEF, 2015, p.14). Neither of these recommendations is a quick fix for the current crisis but is certainly very sensible at any time.[33]

The nature of competition is addressed by three of the recommendations. Thus 'review (and potentially reduce if warranted) collateral requirements' (6) could improve entry into wholesale and ancillary service markets if small competitors are prevented from entering due to collateral requirements. 'Shield those consumers that need price protection the most from price volatility' (8) and 'Tackle avoidable supplier bankruptcies, getting the balance right' (9) are not strictly about the wholesale market. (8) This is really a **retail question**. For (9), the point is that a competitive wholesale market relies on active competition on the buyer side of the market. None of these recommendations seems likely to influence the price by much, but lower collateral for wholesale market entrants, protecting 'vulnerable' customers and encouraging 'sustainable' competition in the market are **sensible objectives for energy regulators** at any time.

'Tackle non-market barriers, ensuring generation and infrastructure is built at pace' (10) is a good idea, but hardly a measure that will address the crisis in the short-term. However, perhaps now is a good time to get **proposals blocked in planning through the planning system**.

The final three recommendations seek to stabilise the price against future price shocks. 'Consider prudently the need for market interventions in situations of extreme duress, if pursued, consider tackling 'the root causes'' (11) is a call to **make only limited interventions in the wholesale market** itself. If the root cause is high gas prices, then this concentrates on how wholesale electricity prices can be decoupled from high gas prices. It is not clear how this sits with 'Consider public intervention to establish hedging instruments against future price shocks' (12), which is reminiscent of the California power crisis of 2001-2002, where the State of California did eventually enter into long-term contracts for power in order to reduce the price in the wholesale market (see Sweeney, 2002). 'Consider a 'temporary relief valve' for the future when wholesale prices rise unusually rapidly to high levels' (13) suggests that regulators could step in to cap the price (or suspend trading) when wholesale prices behave in this way. It is not clear whether this sort of measure can be left to national regulators or the European Commission itself.

Overall, this is a jumble of recommendations, several of which are not really about market design per se. There is nothing particularly concrete or implementable and few are under the control of the EU itself. It is perhaps not surprising that ACER do not recommend any radical departures from a European single electricity market policy that has been decades in the making. It is **worth emphasising the benefits of the single market**, because a sensible European response relies on maintaining access

[33] Indeed, if such a scheme had been put in place at the time of the first renewable electricity directive (Directive 2001/77/EC), the cumulative benefits might have been substantial in terms of both lower costs for consumers (across Europe) and higher quantities of renewables in aggregate.

to the European maximising total generation available and shared demand response, with the benefits of this being relatively larger for periphery countries.

Great Britain

The Department of Business, Energy and Industrial Strategy in the UK announced a comprehensive **Review of Electricity Market Arrangements (REMA)** in July 2022 (BEIS, 2022). This is summarised in Figure 4.

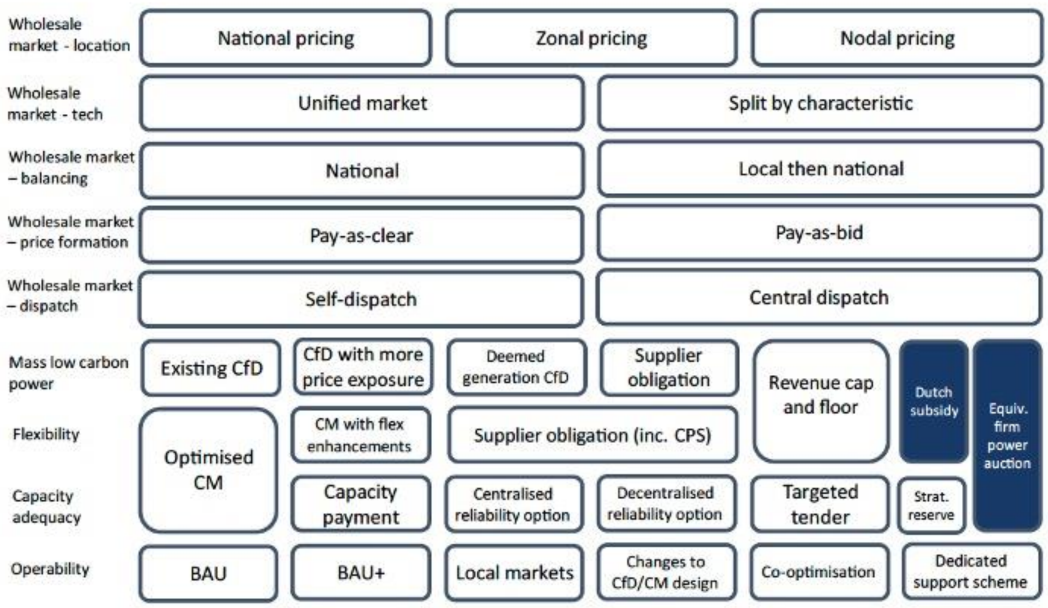


Figure 4 : Review of Electricity Market Arrangements[34]

REMA seeks to address the muted locational investment and operational price signals in the wholesale price, the limited temporal signals for flexibility, low wholesale market liquidity and not making efficient use of all the assets on the system (p.41-42). REMA will make recommendations based on five criteria: least cost, deliverability, investor confidence, whole system flexibility and adaptability. The review does this in the context of wanting to keep the cost of capital down to finance the energy transition at reasonable cost. The figure shows the areas being examined by the review.

The first consideration (Row 1) is whether the GB wholesale market should provide **locational signals** for investment and operational decisions. This would involve moving away from a single national price and splitting the GB market by zones or nodes, with prices varying by location and according to transmission constrained capacity. The introduction of a locational wholesale market typically lowers prices in zones or at nodes where there was excess local generation relative to local demand, in the presence of transmission constraint on electricity export; but higher wholesale prices where local

[34] Source: BEIS (2022, p.109).

demand was higher than local generation, in conditions where there was a transmission constraint on electricity import. In GB, this is expected to result in higher wholesale prices in the south than the north and more price volatility between and within regions[35]. The experience from other jurisdiction where price zones exist is that prices can be substantially different (e.g., between North Norway (Zone NO4) and Southern Norway (Zone NO1))[36]. The need for more accurate price signals to support flexibility and more efficient system operation and development has been emphasised by the GB System Operator, NG ESO (2022). This points to problems with rising constraint payments to renewable generators in export-constrained areas of the network, illustrating the need to adequately incentivise demand flexibility and storage[37]. It also notes that current price signals for the efficient use of the existing network infrastructure (in administrative use-of-system charges) are both complicated to understand, forecast and relatively weak.

The second consideration (Row 2) is whether the different generation technologies should effectively trade in different markets which could clear at different prices. A number of **two-markets approaches** have been recommended, but one (from Keay and Robinson, 2017) suggests that there could be a separate market for intermittent power and for dispatchable power. Thus, wind and solar would be in the intermittent power market and some customers would be happy to buy power from this market (flexible demand customers). Gas turbines would be in the dispatchable power market and available when needed and customers who wanted such power could buy from this market. Under current circumstances the price might be lower in the first market than in the second. Individual customers could buy from both markets to satisfy their demand. There is a related two-markets suggestion that there should be a Green Power Pool (from Grubb and Drummond, 2018) separate from the current power market. In Grubb and Drummond's variant, renewable energy only would face a separate long-term contract market price with demand being directed at bulk industrial sectors, among others.

The **two-markets idea is a confused one because it conflates several different things**: namely long-term contracting for part of demand and short-term market price determination. Thus, while long-term contracting for low carbon generation might yield lower prices, two short-term markets does not make a lot of sense. This is because it is a **form of market segmentation** which **arbitrarily separates generators** who in theory provide the same product. Most of the time kWhs from different generators are identical. No rational renewable generator would want a lower price for its product if it could sell in the dispatchable power market at a higher price. A simple way to arbitrage this would be to simply combine renewables with a gas turbine or with a battery within a portfolio and sell dispatchable power. Indeed, Keay and Robinson suggest that a **group of generators could choose which market they were in** (including nuclear, biomass and storage), further ensuring that such arbitrage would take place. To the extent that forcing the system to have two markets and then incentivising costly arbitrage incurs real additional costs to meet market qualification rules and operate two markets. The

[35] See Energy Systems Catapult (2022, p.9).
[36] See https://euenergy.live (Accessed 1 October 2022).
[37] See https://www.nationalgrideso.com/document/266576/download

net result would be to **raise system costs and prices** relative to the current single market price arrangement.

The well-meaning intention of such a suggestion is to use a **two-market solution to capture the resource rent arising from renewables and give it to electricity consumers**. As such, it has the potential to **sacrifice market efficiency to tax resource rents**. The aim of such a redesign is to capture the resource rent of a favourable technology (arising from the availability of free wind or sun at a particular location), without the need to pay the owner of the technology the rent which arises in an efficient market at the market clearing price which is currently set by the price of gas used to generate electricity in a gas turbine.

Another issue with the two-market approach is that while it aims to capture the resource rent that may be present in electricity, an increase in inefficiency which inadvertently drives up the demand in the gas market creates more resource rent there. There is in fact a **'two rent' problem**. Given that most gas in most European countries is almost wholly imported, national attempts to capture electricity resource rents may backfire if they increase rents (for foreign owners) on imported gas.

The point is that we have other ways to do this which maintain market efficiency and limit resource rents. The most obvious is the **auction for large-scale low carbon generation**, particularly for wind and solar resources, or for nuclear power. These result in government locking in low prices for some part of the total national generation. Any positive surplus arising from selling this at the market price – such as might arise when fossil fuel prices are high – can then be captured by the government and used to reduce electricity bills. This is precisely what happens with the **CfD auctions in the UK**, where the Low Carbon Contracts Company receives the difference between the market price and the CfD strike price and uses this to reduce the levies paid by consumers for low carbon power. Other mechanisms, such as profits taxes and auctions for the seabed (and the right to build offshore wind facilities) are additional ways in which resource rent arising from renewables can be taxed.

Auctions for low carbon generation are a good idea if they do reduce the long-term cost of procuring generation capacity that would have been required anyway (via both more competitive procurement and lower financing costs). They are part of what Roques and Finon (2017) identify as the emergence of 'hybrid market regime' where the electricity market combines competition in the market (via conventional power markets) with competition for the market (overseen by the government) in the areas of low carbon generation and reserve capacity. However, it is important to point out that over the long-term the **aggregate benefits** of this to consumers **depend on the correct identification of both the quantity and type of procurement by the government**, which historically has been cumulatively poor in some countries, including the UK[38]. An alternative future with investments being left to be guided by **longer run market signals** could result in less overcapacity and cheaper types of generation.

[38] See Pryke (1982) on the woeful record of the CEGB.

The third, fourth and fifth rows refer to the specifics of market price determination within balancing and energy markets. Balancing markets could be cleared locally (a form of locational pricing, discussed above) or nationally as now (Row 3). Energy markets could switch from pay as clear to pay as bid (Row 4). Pay as bid is thought to produce slightly lower on average market clearing prices, as bids are shaved lower to increase the probability of being dispatched (Krishna, 2009). However, auction theory says this is less efficient because it might lead to costlier producers being dispatched above cheaper ones (due to bid shaving mistakes), raising overall system costs. A move from **self-dispatch**, as now, to **central dispatch** would see the system operator dispatching plants in price merit order directly based on the short-term market, rather than based on self-declaration of the desire to be dispatched.

Central dispatch is thought to be marginally more efficient because the system operator makes use of all available bid information to dispatch, while under self-dispatch generators must correctly predict their own costs relative to the costs of others and the overall likely market clearly price (and cannot see others' bids), given that profits depend on the actions of others some of which may not be well informed. Analyses of US markets suggests operational cost savings of the other 2-3% of generation operational costs from central dispatch relative to self-dispatch (see Sioshansi et al., 2008), though this is disputable given that such a calculation assumes that system operators know the real time costs of each generator (in particular their real time fuel cost and ramping costs), whereas self-dispatch makes better use of the private information known to a given generator about its own costs of generation in real time. Indeed, in 2016, the Competition and Markets Authority, having looked at central vs self-dispatch in Great Britain, concluded that 'Nor have we found evidence of systematic technical inefficiency arising from self-dispatch' (see CMA, 2016, p.10).

Local energy or balancing markets, cleared at each grid supply point are a possibility (as discussed in Pownall et al., 2021). Local markets are a form of incomplete locational marginal pricing, which effectively does the same thing at a higher-level granularity while also allowing direct competition between generators in the absence of network constraints.

A striking feature of these suggestions on specifics of market price determination within balancing and energy markets is that they are **small changes to existing market design,** which individually will not make much difference to average energy prices. Indeed, the reason they have not been implemented is because their overall efficiency is questionable at best. They **may however be sensible incremental improvements** to market design on the road to net zero (see Pollitt and Chyong, 2018).

A sixth consideration is around **how renewables should be contracted for and their price regulated**. The current CfD auction scheme involves simply purchasing all of the output of the project at the auction market clearing strike price over a fixed period (usually 15 years). This could be changed to an equivalent firm power auction where capacity market and CfD markets are combined on the basis of their equivalent firm power (adjusting for intermittency), or a deemed output CfD auction where the strike price is paid on a fixed amount of output, which would encourage locating renewables where subsidies would be paid out more quickly. The revenue of renewable generators could be subject to cap and floors to reduce excess profits in return for guaranteed minimum revenue. While a Dutch Subsidy has bidders in low carbon auctions bidding based on their cost of carbon abatement rather than low carbon electricity. This would allow low non-zero carbon sources to compete with zero carbon sources.

None of these approaches seem likely to significantly, if at all, increase overall efficiency in the electricity sector, relative to the current CfD auctions. Equivalent firm power, by combining two currently separately priced attributes in one auction, is unlikely to improve efficiency. Deemed renewables might be useful for guaranteeing the total quantity of money received for a project, but not the time over which it is received, so seems to replace one sort of uncertainty with another. The Dutch subsidy scheme does what a carbon market does and does not focus on what a CfD auction does, which is procure a given amount of low carbon capacity at least cost (and hence promote low carbon technology roll out).

The trade association for the electricity and gas supply industry in the UK, EnergyUK, recently came out in favour of converting nuclear and renewables to voluntary long-term contracts, citing work by the UKERC[39]. This work[40] had calculated the voluntary CfDs for nuclear and renewables could reduce current costs by up to £22.4bn per annum, though this looks like an over-estimate[41]. As UKERC point out this is a high-end figure and seems unlikely to be realised in full, as nuclear plants near the end of their lifetime are unlikely to want to sign such contracts. It also includes biomass, where the price of biomass has risen sharply recently. The UK Prime Minister announced in September 2022 that there would be a move to convert existing low carbon contracts to CfDs.[42] We discuss the economics of such voluntary long-term contracts below.

Greece

The Greek government presented a non-paper proposal on power market design on 22 July 2022 (Council of the European Union, 2022a). This again proposed a **two-market solution** (similar to Keay and Robinson, 2017). They proposed a segmented market consisting of: (a) CfDs based on total levelized cost for nuclear, renewables and hydro ('when available market') and (b) fossil fuel, peak hydro, demand response and electricity storage ('on demand market') They suggested that high efficiency co-generation should also be included in the 'when available market'. 'When available resources' would submit volume-based bids in a mandatory day-ahead wholesale market and be paid their CfD prices. The day ahead market then clears based on clearing the net load with the on-demand bids. Intra-day and balancing markets are proposed to be unaffected and continue as now. Consumers then pay the weighted sum of the CfDs and the net demand market prices.

This proposal imposes new contracts on existing low carbon sources not currently covered by CfDs or feed in tariffs. It also introduces an arbitrary distinction between the two markets and the **ability to**

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[39] https://www.energy-uk.org.uk/index.php/media-and-campaigns/press-releases/526-2022/8286-energy-uk-backs-scheme-to-reduce-power-costs.html

[40] Gross et al. (2022).

[41] To get to £22.4bn, the authors have to assume that biomass fuel prices do not adjust in line with fossil fuel prices.

[42] https://www.gov.uk/government/publications/energy-bills-support/energy-bills-support-factsheet-8-september-2022

arbitrage through the purchase of storage or through withdrawal from the day-ahead market and selling in the balancing market. Maurier et al. (2022), offer a good critique of the Greek proposal. CfDs, written on behalf of customers alone are what deliver the lower retail prices, so it is not clear why a new and inefficient market design (as we explain above) is needed. They also point out that the mandatory inclusion of the when available segment reduces dispatch signals for this segment, ends market-based renewables and raises legality issues with the arbitrary imposition of CfDs. A further suggestion that this blunts demand side incentives is not strictly correct, because that depends on the nature of the retail tariff that they faced.

It is worth noting that Greece has introduced a series of national interventions to address the crisis, one of which involves a temporary 90% tax on domestic power firms.[43]

Spain

In May 2022 the Spanish government adopted a novel direct intervention in the operation of the wholesale power market (see von der Fehr et al., 2022). This **paid gas-fired power plant generators a subsidy** equal to the difference between the day ahead natural gas price in Spain and EUR 40 / MWh (initially). This effectively capped the gas cost at EUR 40 / MWh. By law, generators must use this price in calculating their offers in the European market coupling algorithm. Given limited interconnection with France (and Portugal), this has resulted in lower wholesale power prices in Spain, though prices are still very high in the wholesale market.[44] This may be because gas fired power plants in Spain are not setting the marginal price of electricity, possibly more expensive demand response is. For instance, if industrial consumers are deciding to reduce their electricity demand by increasing direct combustion of gas, which they could otherwise sell at the unregulated market price of gas, demand response bids would still reflect wholesale gas prices. Thus the fundamental shortage of gas would still be manifesting itself in electricity prices.

This approach does not change the existing market design and it is a way of reducing the rent being extracted by low-cost generators. However, it is **very inefficient**. By subsidising the use of gas in electricity production it **increases the demand** for gas by encouraging substitution away from coal and biomass and renewables with storage and it also drives up the demand for electricity. Given that it pushes up the demand for gas, it increases the cost of gas to other users, such as industrial users of gas. It **exacerbates Europe's overall supply crunch** and creates a **cross-border trade distortion** due to the fact that the cost of gas for power generation is substantially different in France and Spain. The policy is also very **costly**, as the government has picked up the bill for more gas than would otherwise be used at a higher price. As a policy for reducing low carbon rents, this is an unusually distortionary one and not a model for any other country (or Europe as a whole) to follow. If this policy were followed across Europe, we would see demand for gas for power surge across Europe at a time when it should

[43] https://www.reuters.com/article/greece-energy-profit-idUKL5N2X31R2
[44] https://www.surinenglish.com/spain/domestic-electricity-bills-20220823173417-nt.html

be reduced[45]. This intervention, approved by the European Commission, does not make sense for the wider European energy market. It is a political decision to appease an individual member state. If this happened across Europe it **would worsen the gas supply crunch and push up gas prices even further**, distorting relative electricity and gas prices across Europe.

Clearly, **interventions to limit costs to marginal bidders in the electricity market do not make sense in the long-term on the path to net zero**. They do however highlight an important point that proper oversight of marginal bids in any power market is important, because it does directly impact on the market price. This was an important lesson from the Californian electricity crisis of 2000-2001 (see Sweeney, 2002), and highlights the **potential role for market monitoring of marginal bids**. One of the disputed elements of market pricing in California was the existence of a soft price cap, which capped wholesale bids up to the cap and then was pay as bid beyond the cap. This can be a way to limit both market power and the negative externality of high marginal bids. The impact of this on market efficiency is negative (see Vossler et al. 2009), but the distributional consequences could be positive.

European Commission

In September 2022 the European Commission proposed 'an emergency intervention to address high energy prices' which is 'time-limited'. A further agreement was reached on September 30, 2022 (see Council of the European Union, 2022b). This consisted of several important elements:

1. A target **reduction in total electricity demand of 10%**, with a target **5%** reduction in electricity consumption during **peak hours** during the period 1 December 2022 to 31 March 2023 (member states must identify peak hours representing at least 10% of all hours over this period). This is relative to a reference period of the five years beginning November 2017 to March 2018.

2. '**A cap on market revenues from infra-marginal generation technologies'** (p.5). This would include renewables, nuclear and lignite.[46] The proposed cap is 180 Euros / MWh but may be adjusted depending on the generation technology. This cap would be applied to 'realised revenue' and would apply to all revenues whether they occurred under long-term contract or from participation in short run markets.

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[45] For a good discussion of the need to reduce gas consumption across Europe this winter and how to achieve it, see Bachmann et al. (2022).

[46] The full list of technologies included in the cap are: '(a) wind energy;
(b) solar energy (solar thermal and solar photovoltaic);
(c) geothermal energy;
(d) hydropower without reservoir excluding pumped hydropower without reservoir;
(e) biomass fuel (solid or gaseous biomass fuels), excluding bio-methane;
(f) waste;
(g) nuclear energy;
(h) lignite;
(i) crude oil and other oil petroleum products;.
(j) peat.'

3. A **temporary solidarity contribution** based on taxable surplus profits made in the fiscal year 2022 and/or 2023). This would be made on crude petroleum, natural gas, coal, and refinery companies. This would contribute to a fund at the European Union level. Only profits more than 20% higher than the level of the four years from 2018 would be subject to additional taxation (p.28). The minimum tax rate would be 33% on these additional profits, though higher tax rates could be applied. The tax rate would be applied to 2022 or 2023 profits.

4. Revenues from the cap and solidarity contributions are required to be **recycled to household and industrial customers**.

While there is agreement that demand reduction is necessary, there is no suggestion about how it is going to be achieved. Pollitt et al. (2022) advocate the use of **rising block tariffs** to reflect high marginal prices to customers and help incentivise demand reduction. It is also unclear what the point of the 5% peak demand reduction target is, when the primary objective should be to reduce total demand for gas. If the 10% average target is achieved, it is likely the peak 5% target would be redundant, given that even bigger off-peak reductions would be required if demand is not reduced by 10% in peak hours. The cap on market revenues is a market design feature. However, it is not a straightforward bid cap, as the cap is on 'realised revenue'. It will not be easy to police and a bid cap would have been a simpler measure, albeit more inefficient. The solidarity contribution is a 'voluntary' temporary tax measure, combined with a requirement to recycle the revenue to consumers.

Although sensible, none of these measures directly impact the design of the wholesale market. and they are **aimed at relieving pressure on household and industrial consumers in retail markets**.

Overall observations on suggested changes to market design

Wholesale fossil fuel prices have provoked renewed interest in market design. Some suggested design changes to the operation of current electricity markets are sensible but even in aggregate they do not offer the likelihood of significant reductions in prices. Indeed, it is unclear as to whether any of them could be implemented quickly. **Continuing with the single electricity market agenda looks just as promising and more important for periphery countries and shared energy security**.

Not surprisingly, the suggested changes to market design, motivated by how far we are currently along the way to net zero and the reality of a gas supply crisis, are not that radical. Fundamental changes to future market design can however be contemplated. For example, **internet style 'rationing' of electricity** in real time to reflect the availability of intermittent renewables and the physics of the system. This would supplement price signals with pre-set algorithmic allocation of electricity to prioritised loads (see Pollitt, 2021).

Many of the sensible suggestions for reform that we discuss above will only reduce prices in the longer term. There are few market-based design improvements which deliver anything other than marginal changes to average prices. Even the introduction of locational marginal pricing will not reduce average prices by much, even if some locational prices will fall. What remains true is that **extension and deepening of existing markets can increase efficiency and reduce prices**, even if the absolute reduction is only of the order 2-3%. This is sobering in the light of the very large rises in wholesale prices we have seen.

Two surprising observations are that, despite the European Commission's efforts and sensible recent proposals for electricity and gas demand reduction, **more detailed work has not been done at national level across Europe to prioritise actual demand reduction for electricity and gas**, and that **completion of the single market** to protect periphery countries in both electricity and gas is not being further accelerated. A worst-case scenario is that individual countries restrict flows across interconnectors this winter and that we see a breakdown or breakup of the single market in energy. The failure to coordinate a large demand reduction may mean that distorted demand signals will worsen the crisis in certain countries and put unnecessary pressure on the single market.

Markets are largely working as might be predicted given the large underlying rise in the price of gas and market efficiency seems to be being maintained. However, markets do not merely exist to be efficient in many jurisdictions, where they should be seen to achieve wider societal goals, such as perceived fairness. Markets work by raising prices in times of scarcity. This has created revenue streams for some and leaving some market parties exposed to unhedged high prices or some customers unable to pay. This is generally **acceptable if it occurs for short periods, but it clearly cannot continue if large groups of household and industrial consumers cannot afford to pay**. One large energy supplier suggested 50% of all households would struggle with energy bills in the UK this winter.[47] European energy poverty is also expected to increase relative to when it was last measured in 2019.[48]

A **frequently suggested change is for governments to sign longer-term contracts with generators on behalf of customers** (i.e., increase hedging)[49]. This parallels the idea that retailers might agree limit price rises now in return for recovering losses in future years as a form of long run energy pricing. The idea of signing lower price contracts at a time of high short run prices is attractive, but it is less attractive when short run prices come down. The point about this sort of contracting to reduce bills now is **whether it is efficient because it effectively borrows money at a high cost of capital from private energy firms**. **Direct government subsidy** (funded by taxpayers or borrowing) to bills would be **more efficient and deliver the same bill reduction** now at a lower long-term financial cost. For instance, at a BBB corporate bond rate for a utility of 5.33% vs. a government bond rate of 3.64%, delivering one year of bill reduction and paying it back over 20 years, it is 32% cheaper for the government to fund it. To put it another way, **the government can reduce the bill by 46% more for the same amount of future repayment, by using government borrowing**. This is relative to the case where the government signs an efficient long run contract.

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[47] https://www.bbc.co.uk/news/business-62643934
[48] See for example: https://edition.cnn.com/2021/09/30/business/europe-energy-poverty/index.html
[49] See for example Batlle et al. (2022).

The **available size of the inframarginal rent from low carbon generation, accruing to generators, is likely much smaller than is being suggested**. Renewable power only makes up 30% of electricity in Europe and much low carbon generation is already sold under lower-price, long-term contracts, from which consumers are benefitting[50]. Meanwhile most retail businesses are integrated with generators and are selling power at below wholesale prices.

There have been several versions of a 'two-market' solution, as we discussed above. The UK's REMA explicitly raises it, based on earlier suggestions. The Greek approach also suggests it. Such an approach produces two prices: a marginal price and an infra-marginal one. The central aim of the two-market solution is to price marginal gas-fired power plants at a different price to infra-marginal plants, such as nuclear and renewables. This can be done in the long-term market or in short run markets. In the short run market it could involve a price cap on the bids of low carbon generators. We argue above that **long-term markets already offer a form of a two-market solution, via long-term auctions for renewables**. **Two markets in the short run raises difficult issues whereby market efficiency is likely to be reduced, potentially substantially**. In the short run, the marginal cost of extra low-carbon output from a given facility can be high and this should be priced.

These costs are especially important with respect to cross-border flows within Europe, whereby consumers in importing countries won't distinguish between imports based on low-carbon sources or gas and will see higher prices if lower carbon facilities in exporting countries lower their output due to receiving a lower price. We are already seeing the effect higher prices are having in life-extending existing nuclear facilities (e.g., in Germany).

An issue in suggestions for changes to market design is that they neglect the macroeconomic aspects of energy markets. This crisis is about more than simply what is happening in the energy sector. Indeed, microeconomics and macroeconomics may be in conflict in the energy sector. While high prices are a sensible response to market scarcity, high prices for a basic commodity which contribute to significant inflation mean that prices may need to be capped and some form of rationing put in place to avoid setting off a wage-price spiral which reduces GDP beyond the initial price shock. High prices which are outside the normal range of prices require some **tough political decisions to be taken on how to ration energy, of which rationing by price is one solution (and not the preferred one globally).**

Similarly, **suggested changes to market design generally ignore the question of the structure and ownership of the electricity sector**. Under the single market this has been characterised by private ownership (or international ownership outside of home markets) and horizontal and vertical disintegration of utility firms within countries. Changes to current ownership arrangements are being proposed or happening in some jurisdictions (e.g., renationalisation). Nationalisation of electricity

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[50] See https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-october-2022-31-december-2022. This shows a £23 per household credit to consumer bills due to negative CfDs for the consumer price cap latest period.

generation is one way to capture the resource rents and to make it easier to redistribute back to electricity consumers. However, this if this policy seeks to use a change of ownership to address the problem of redistribution this can be better addressed by the appropriate use of the tax and benefit system and price regulation. These mechanisms can target profits and electricity prices directly. Nationalisation of energy resources raises its own issues, such as the reduction of incentives to efficiency which motivated the global drive towards privatisation of energy assets in the 1980s and 1990s (Megginson and Netter, 2001).

A final point is that **many of the proposals for changing market design mix up sensible long-term market design for net zero with interventions in the current market design driven by the nature of the war economy**[51]. Sensible long-term design suggestions will take time to have an effect, whereas short run market interventions will not be sensible in the longer term. Being clear about the timeframe of suggested interventions and their likely impacts is important. Doing things quickly in a war time situation is not necessarily conducive to good longer-run solutions and, perhaps equally, extreme short run measures may make it difficult to get back to policies which are sensible for the longer run. **A more careful consideration of short- and long run perspectives might be helpful.**

In a war economy, as Maynard Keynes pointed out in 1940 (Keynes, 1940), rationing – in the form of suspension of the normal operation of markets – can be necessary to control inflation and maintain post-war purchasing power (as supply improves) to manage the macroeconomy and voter expectations of fairness, which become more, not less, important.

[51] See Pollitt (2022).

SECTION 3: THE ENERGY CRISIS, NET ZERO, AND ELECTRICITY MARKET DESIGN

Section 1 presented the European standard model of electricity markets. It showed that with a uniform pricing model, the inframarginal rents of power plants are essential to pay for the investment costs of generators. In a market without entry barriers, in expectation infra-marginal rents are equal to the investment costs of the firms and provide a fair return on their capital.

In this section we look at how **two new elements impact the standard electricity market model**: the **energy crisis** due to the war in Ukraine and the **increased share of renewable energy production** in the generation mix under net zero.

The current energy crisis

The reduction of gas supply in the last year is unprecedented, was political in nature, and was not foreseen by market players.[52] It has given the European energy sector characteristics of a 'war economy': uncertainty in the market has increased,[53] the liquidity of long-term contracting has reduced,[54] and compulsory rationing demand this winter is a real possibility. The high energy prices create hardship for consumers and industries alike and has considerable macro-economic effects. **Considering those circumstances, exceptional temporary measures might be justified**.

The energy crisis has led to higher fossil fuel and ETS prices. This raised electricity prices as illustrated in Figure 3. In a uniform price auction, it is optimal for generators without market power to submit bids which reflect their marginal costs. So, the bid functions in the graph represents the marginal costs of producers. As natural gas is the marginal technology, it sets the wholesale electricity price at p_{crisis} which is higher than the price that would have arisen in a situation without an international crisis, p_{norm}. The market process guarantees short-term efficiency: the electricity price represents the willingness to pay (WTP) of consumers for the marginal unit and all generators with marginal cost (MC) below the spot price are producing. Consequently, the production is produced at the least cost. The **high electricity price provides strong incentives for consumers to reduce demand and for generators to be available**.

The high electricity prices *strongly increase the inframarginal rents* for technologies that do not rely on fossil fuels (nuclear, hydro, wind and solar) if generators would only sell in the spot market. Those short-term profits contribute towards paying for the capital cost of those firms but are likely to be higher than what an investor might have accounted for even in its most optimistic investment

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[52] The price for monthly baseload future contracts for delivery on April 2022, was 43 EUR / MWh in April 2011, while the price settled at ca. 165 EUR / MWh (source: tradingview.com)

[53] On top of geopolitical risk there is also regulatory risk. Market participants are expecting the governments to intervene in wholesale gas and power markets and are therefore reluctant to conclude any new contracts.

[54] Representatives of the German industry report (VEA) that there are very few suppliers in the forward market and municipal utility association TIRANEL indicates that few retailers have contracted energy for 2023. https://www.montelnews.com/news/1348157/german-industry-struggles-to-find-energy-suppliers--lobby

scenario. The green area in Figure 3 represents the additional inframarginal rents on top of the rents that the firms would have collected in a 'standard' market situation.[55] In mid-August 2022, the forward price for German baseload power for delivery in 2023 was around EUR 500 /MWh, which is a magnitude larger than "normal" prices. It could be argued that taking away additional rents in such unexpected and extreme situations does not affect long-term investment incentives, as firms may correctly understand the exceptionality of the current situation. Note that defining 'standard' market rents is not straightforward, as it is a stochastic variable (corresponding to profitable and less profitable years) and requires determining the counterfactual market outcome without major international conflict. [56]

In practice, most generators sell a large fraction of their production on long-term contracts with a fixed price to retailers or large industrial consumers. Hence, for the duration of those contracts, the inframarginal rents do not accrue to the producers but lower in the value chain.

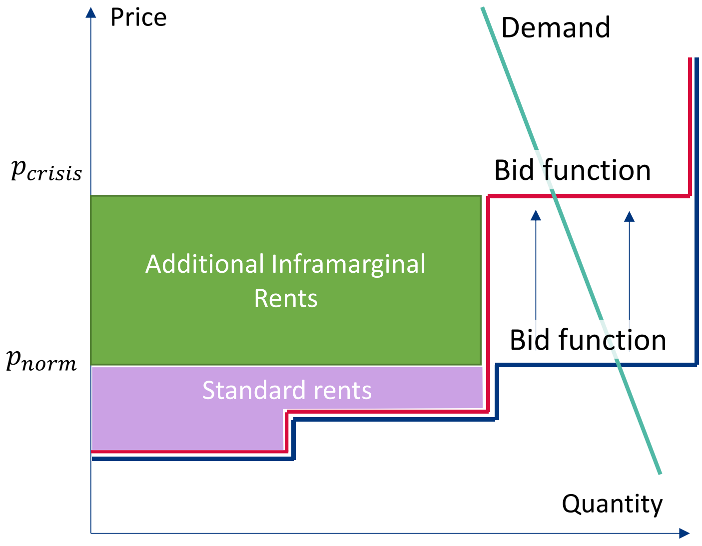

Figure 5: The effect of the energy crisis on wholesale energy prices and inframarginal rents, for a generator that would only sell in the spot market.

Renewable energy sources

The levelized costs of renewable energy sources (RES) have decreased sharply in recent decades. RES have become (almost) cost-competitive with conventional generation technologies. IRENA (2022) reports that in 2021, 73% of newly commissioned utility-scale renewable generation capacity has costs of electricity lower than the cheapest fuel-fired option in the G20. For onshore wind this is number is

[55] Note that the graph is not drawn on scale for clarity reasons.

[56] The IEA (2022) mentions excess profits of up to EUR 200 billion in 2022 in the EU for electricity generation using gas, coal, nuclear, hydropower and other renewables. It is, however, not obvious how those numbers were obtained.

even 96%. RES support schemes are therefore expected to phase out. Hence, new RES will rely solely on market revenue to recoup investment costs. How does this impact the current market model?[57]

Volatility

The phase out of conventional generation and the growing share of RES in the generation mix will make **electricity prices more volatile**. This is because RES production is intermittent with low marginal and high investment cost. In the long run those high investment costs need to be recuperated in a small number of hours with small production levels and high prices. Those more volatile prices provide incentives for storage operators and demand flexibility providers. Indeed, they rely on intertemporal arbitrage opportunities to make money.

The higher volatility also **incentivises market participants to sign more long-term contracts**. The parties to those contracts are typically firms with offsetting or imperfect correlated risk profiles. For instance, generators and retailers, or intermittent producers and storage providers. Consumers will typically sign contracts that hedge against those short-term shocks, make some money providing flexibility themselves, and end up paying an electricity bill corresponding to the long run average system cost.[58] They are likely to remain exposed to medium run energy price movements.[59] Therefore, the introduction of additional renewable energy does not pose a problem for the market design *as such*, although **market outcomes will be different**: **more volatile pricing, larger role for ancillary services markets, and more contracting and hedging**.

Hedging and merchant investments

Many current RES investments in Europe rely on government support which provide long-term price guarantees and low risk for investors. Hence banks are often willing to provide debt funding for those projects, and capital costs are often very low. As subsidies are being phased out, renewable energy producers must rely more on market-based contracts to manage their risks. Those contracts often take the form of **Power Purchasing Agreements (PPAs).**

A PPA for renewable energy is, in its most basic format, a long-term contract which guarantees a fixed price to a renewable energy producer for its total production. A PPA might be physical (where the energy is taken by the buyer of the contract) or financial (a virtual PPA), where the buyer receives the difference between the spot price and the contract price when it is positive, or pays the difference when it is negative.[60] The buyer of a corporate PPA could be large industrial consumers or a retailer,

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[57] The 2018 CERRE market design report (Pollitt and Chyong, 2018) studies the effect of further integration of renewable energy on the wholesale power markets and the consequences for different types of power plants, and whether market design need to be adjusted. Market based investments in RES are possible from 2025 onwards in a high carbon and high fuel price scenario.

[58] The 2022 CERRE report on retail market design (von der Fehr, et al., 2022) highlights that regulation where consumers can terminate a fixed-price contract early without paying a penalty is detrimental for the development of those fixed-price contracts for households.

[59] Prices in dry years with low hydro production and cold winters leading to higher demand will be higher. Those prices are likely to be reflected in consumer prices, as contracts are typically limited from 1 to 3 years.

[60] A financial PPA requires a sufficiently liquid spot market. A financial PPA is sometimes also called a Contract for Differences or a fix-for-floating-swap.

which would like to hedge their energy prices in the long run and would like to reach their sustainability targets. Sometimes also the government might sign a long-term PPA contract.

The global market for corporate PPAs has been increasing rapidly, especially in the USA. Development in Europe is lower because the volume of subsidised RES remains high, but 8.8 GW deals were signed in 2021 (Stet,2022 and Bloomberg 2022). Development of the PPA market was strong in the Nordic countries, Spain, the Netherlands, and Germany. One of the hurdles for the development of the PPA market in Europe is the **lack of contract standardisation, large price volatility in the short-term, and the important swings** in recent average power prices due to Covid and the Ukraine energy crisis. (Stet, 2022).

Corporate PPAs are leaving **more risk to investors** than the support schemes provided by the government in the past.[61] This **increases the capital cost**, as investors can rely less on bank financing and need to use more equity. However, as markets become more mature, lenders might become more comfortable with rolling-over **shorter duration PPA contracts**, and **innovation is likely to reduce total capital expenditure**, which will reduce total risk exposure (Ryszka, 2020). **Merchant investment** in RES, based on corporate PPAs and project funding can therefore play an important role in the future, but those investments are likely to be complemented with **portfolio-based investments strategies** by larger integrated utilities, who manage most of their risk in-house.

Compared with a standard base-load futures contract, a corporate PPA-contract is riskier for the buyer of the energy. The production of RES is intermittent, which creates shaping risk: the buyer needs to balance its consumption profile with the RES production output by buying and selling on the short-term market. RES output is also negatively correlated with the electricity price, which creates price capture risk. PPA prices are therefore often lower than the forward prices. To handle those risks, RES investors might contractually agree to build battery storage as part of their PPA. It could also be that a third party, typically a utility, is involved to managing those additional risks.[62] We expect **this type of risk management to become more important** in the future.

Scarcity rents

One issue with renewable energy resources is the **scarcity of suitable building locations**.[63] For instance, hydro power plants depend on the availability of water and geographical height differences. Hence, owners of the hydro plants earn scarcity rents based on those natural resources, which the

[61] Ryszka (2020) identifies several reasons why risks are higher: The demand for long-term contracts is limited. It is 10-15 years for large industrial users, less than 10 years for ICT sectors, and covers less than the full life-time of the investments. Counter party risk for smaller entities with lower credit rating is too large. Contracts cover less than the full capacity to reduce risk exposure.

[62] Those contracts are often called sleeved PPAs. Specific contracting conditions and definitions might differ between utilities.

[63] Scarcity rents become more relevant for renewable energy, but they have been studies extensively for fossil fuel extraction and large hydro power plants. Baunsgaard, T. (2001) highlights different fiscal regimes for mineral extraction and design considerations: higher corporate income tax, resource rent tax, royalties, rental fees and bonuses, auctions for exploration right, production sharing and state equity.

government might want to take away for equity reasons.[64] Those rents could be captured by taxing the owners, by organising a market for the scare resource (auctioning of a building permit for the hydro power plant location), or public ownership of the resource. Figure 6 illustrates the idea of scarcity rents for a hydropower plant. The expected inframarginal rents that companies receive in normal market situations pay for the capital costs of the investments, but cover more than that for hydropower plants, who obtain a scarcity rent. This scarcity rent reflects the economic value of the water in the reservoirs that nature provided for free.

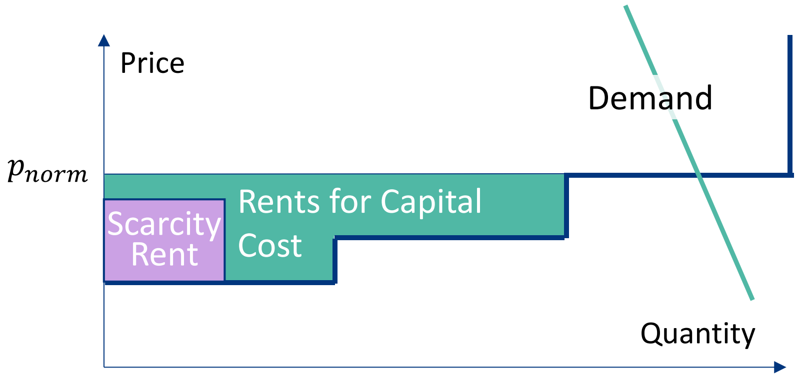

Figure 6: The expected normal inframarginal rents pay for the capital cost of the generators, but also provide scarcity rents to the owner of scarce hydro locations.

Those scarcity rents do not only exist for hydro plants, but also for other renewable energy sources. High wind speed sites, close to the transmission network and away from built-up areas are far and between and are a scarce resource. A wind farm at such a site has lower long run average costs than in other sites, as nature provides more freely available energy.

In the current regime, where RES still depend on support schemes, those scarcity rents are taken away by differentiating support based on the characteristics of the resource. For instance, onshore and offshore wind energy receive different levels of support. When support schemes will be phased out, we need a **mechanism similar to that of existing hydropower plants,** to address scarcity rents also for **windfarms and photovoltaics**.

Taxing the scarcity rents of all RES, will however affect long-term efficiency if the long run supply of good site locations is elastic. In that case, there is a trade-off between extracting rents and investment

[64] Taxing scarcity rents of RES is often motivated by equity concerns, but they can also be motivated as a way to make markets more competitive. By handicapping firms with good sites, competition becomes more intense, and exercise of market power decreases. However, this comes at a cost as not always the firm with the lowest cost that wins the auction.

efficiency.[65] Figure 7 shows the effect of a scarcity tax for onshore, offshore wind and hydro on long-term investments.

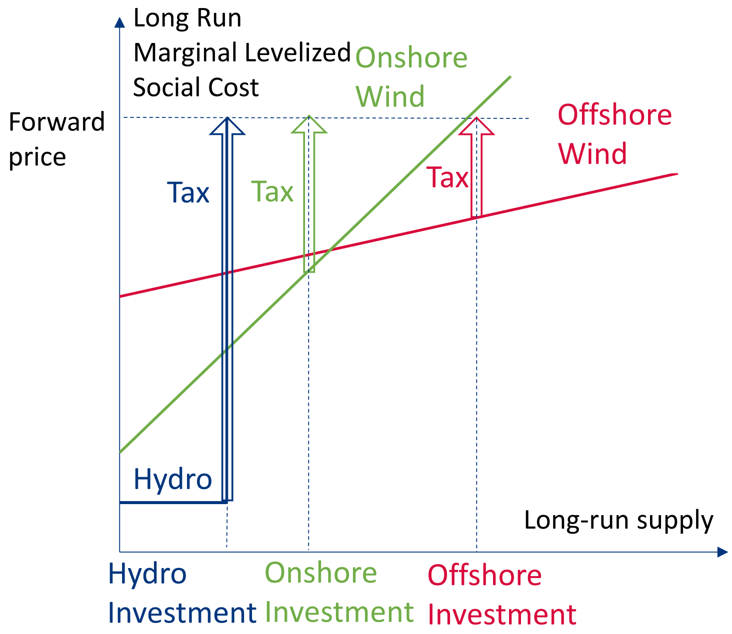

Figure 7: Effect of taxing scarcity rent of onshore and offshore wind energy on long run supply.

The curves represent the long run marginal levelised social cost of different technologies as a function of investment levels. Hence the curves include capital cost and the environmental costs. If offshore wind supply is more elastic than onshore, the optimal scarcity tax will be lower for offshore than for onshore wind power.

Note that long-term supply of wind power is likely to be more elastic than of hydro power, and that the optimal scarcity taxes are therefore likely smaller.

Instead of a scarcity tax, we could use *regulated* long-term PPA at prices below the forward price for electricity. See Figure 6: by locking-in a low price for the electricity produced by RES power plants, the scarcity rents can be collected. The scarcity rents then have to be reallocated to the market for instance by auctioning off the PPAs to potential consumers or grandfathering them to energy users proportional to their energy consumption.

Figure 7 also shows that some inframarginal scarcity rents will remain with the RES producers if the PPA price is uniform for all power plants within a given technology class.

[65] The outcome of this trade-off depends on the relative weight the social planner puts on equity and efficiency and the availability of other policy instruments to address equity concerns. Rowland (1980) describes how in the UK the Petroleum Revenue Tax is distortive towards smaller less productive oil fields, and leads to inefficiencies.

The size of the scarcity rents is expected to increase, as capital expenditure is dropping, electricity and carbon prices will increase and the total size of RES market will increase as well, but it is **hard to find reliable estimates**.[66] An indication of the size scarcity rents are the differences of the Levelized Cost of Electricity (LCOE) across technologies. IRENA (2022) reports LCOE of 0.033 USD/kWh for onshore and 0.075 USD/KWh for offshore wind. If in the current cost structures both technologies would be active without a support schemes, then onshore wind would earn a ca. 130% scarcity premium. IRENA also reports that capacity factors for new onshore wind production in Germany in 2021 is 28% while it is 43% in Spain, so there are significant differences in the quality of onshore locations as well.

If the government did not address the scarcity rents, then those rents could end up with project developers, landowners, or even turbine manufacturer or the network operator, depending on their respective bargaining power. Bargaining power by the landowners would for instance be reflected in higher land prices. **If the government wants to extract the RES scarcity rents, it is important that it commits early whom it wants to "tax"**, the landowner, or the project developer, and **creates well-defined property rights**, so that its policy is correctly reflected in land prices.

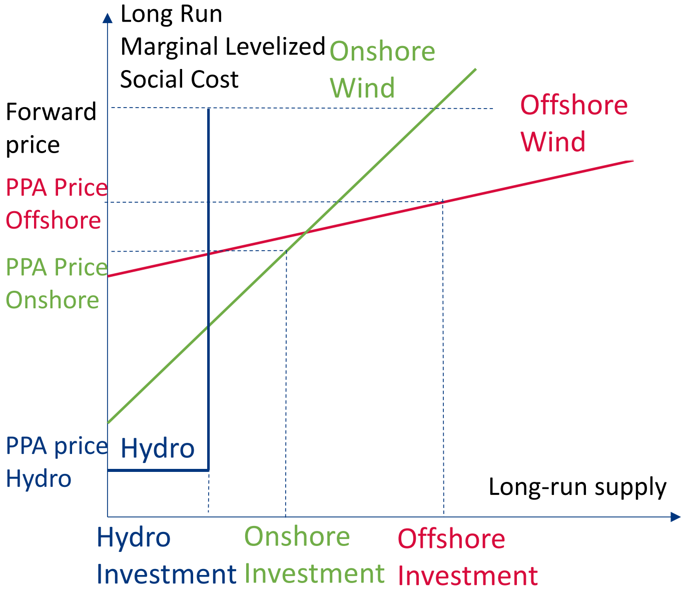

Figure 8: PPA prices below forward prices for electricity to extract scarcity rents of RES producers.

[66] Gross et al. (2022) estimate that CfD contracts for wind, solar, biomass and nuclear power could reduce UK energy bills up to £22.4 billion per year. However, this estimate seems to cover not only resource scarcity rents, but also windfall profits due to the energy crisis, and inefficiencies in the ROC pricing.

In **some proposals for new market designs, RES will not be subject to a scarcity tax but instead RES scarcity rents are intended to be extracted through a change *in spot market design***. RES is treated differently than conventional generation and receives a lower payment. We argue below that it **does not make sense to organize the spot market for such a purpose**.

Many RES producers would like the government to keep on providing long-term price security, by signing government backed PPA agreements with them. Those PPAs can also be used to extract the scarcity rents of RES, by setting a PPA price which is lower that the corresponding forward price, but this is not the only way of doing so. It is important to **distinguish those two functions of PPA: hedging and extracting scarcity rents.**[67]

Potential short-term market interventions

In this section, we discuss four proposals for short run market interventions: A **windfall profit tax on inframarginal generation**, a **subsidy for gas-fired power plants combined with a bid cap**, a **price cap on gas imports** and a **switch from a uniform price to a pay-as-bid auction**. The first three measures keep the current market design intact and rely mainly on taxation and subsidies to change market outcomes, while the third one changes the market design.

Those four types of proposals are representative of the policy proposals that are currently being discussed (and which were reviewed in Section 2). For instance, the windfall profit tax targets the inframarginal rents of the RES and nuclear generation, in case those exists, and could be implemented as a tax, cap on auction revenues, or a regulated contract for differences. Those implementations have their benefits and drawbacks, some of which we mention in the text below.

Winfall profit tax

The windfall profit tax proposal is a temporary tax on part of the infra-marginal profits of firms who do not use fossil fuels. In this text we will use the more neutral terminology of a **crisis tax** (See Figure 7). The crisis tax reduces the profits of nuclear, wind and solar producers, but does not affect the electricity price. The **incentives for consumers to reduce energy consumption therefore remain intact**. This is one of the advantages of a crisis tax. The money that is collected by the crisis tax can be used to compensate vulnerable consumers for the higher electricity price.

[67] The government could also insure RES producers against price capture risk, shaping risk, ancillary service costs, and network congestion costs. This could also justify a lower PPA price.

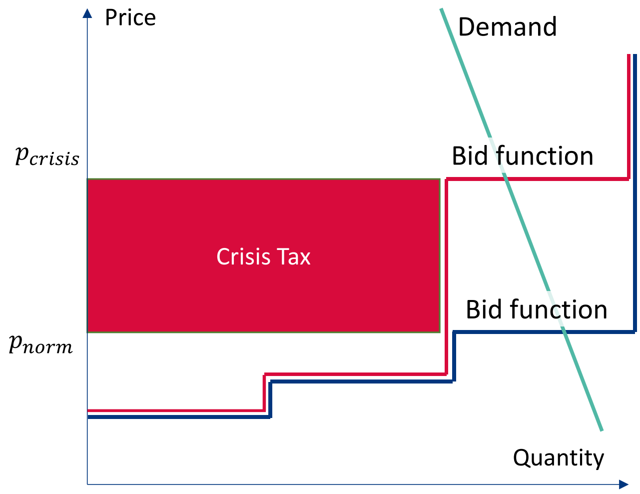

Figure 9: Crisis tax on the extra inframarginal rents of non-fossil fuel-based generation.

The **main arguments in favour of a crisis tax are political**. Higher fossil fuel prices have considerable redistributive aspects which increase the profitability of some assets, while reducing those of others. This is seen as a politically undesirable outcome which needs to be corrected.[68]

The **main objection** against taxing the increased value of assets is that it **punishes past actions or investments that are helping us today to reduce the impact of the energy crisis**.[69] It hollows out property rights and lowers incentives for future investments but could possible also hinder short-term emergency investments. Imposing the crisis tax also implies some arbitrariness. Wind turbines and nuclear power plants selling in the spot market are more profitable with higher electricity prices, but other assets, such as rooftop solar and fuel-efficient cars increase in value as well. Based on practical considerations and voter sentiment, policy makers are likely to exclude some assets from a crisis tax (for instance fuel-efficient cars) but to include others (a baseload plant).

To **reduce the impact of a crisis tax on future investment incentives, governments might negotiate long-term deals with energy producers**. In return for paying a crisis tax now, long-term commitments are made that guarantee future income or reduce future risks for producers. For instance, the government could take over some of the risk of nuclear waste or sign long-term contracts under a capacity remuneration mechanism. If those commitments are budget neutral for the firm, the government is in effect taxing firms today, in return for higher profits in the future. Hence, the government is relying on energy firms as an indirect way to borrow funds against the future and relax today's budget constraints, instead of going to the capital market. Those **kinds of long-term measures are often untransparent and have a higher implied capital cost than government bonds**.[70]

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[68] A crisis tax will also reduce the burden on the government's budget of social measures to address energy poverty.

[69] Even though extra RES do not have a large effect on electricity prices as long as those are set by marginal gas plants, each unit of RES production translates one-to-one in a reduction of gas imports. It reallocates rents from foreign exporters to domestic producers.

[70] In order to end the California energy crisis, the government signed long-term contracts at high prices.

A second objection against a crisis tax, is that is it **not easy to identify who is benefiting from an energy price shock,** as this depends on the long-term contracts that firms have signed. A nuclear power plant who sells energy under a long-term contract for a fixed price to a paper mill does not make extra profit when the day-ahead price for electricity increases. However, as a result of the contract, the paper mill has lower production costs than its competitors and becomes more profitable.[71] Hence, if we follow the logic of taxing unexpected gains due to the war, the crisis tax should be imposed on the paper-mill, and not on the owner of the nuclear power plant. In practice, with complex value chains and many contractual relations, it is **nearly impossible to determine who finally benefits from local production.**

Note that the **largest windfall profits are in upstream gas and oil production** and not in the power market. Therefore, specific measures in the gas market might be necessary, which are not the focus on this report.

Implementation

A crisis tax can be implemented in many ways. Ideally, it is implemented so that it **does not to distort the short-term incentives of market players**; takes into account **existing contractual relationships**; is **temporary in nature** and specifies under which **conditions** the crisis tax will be automatically abandoned; **leaves sufficient profit to the firm**; and is **not imposed arbitrarily**. Those criteria **might need to be imposed at an EU level**. Note that a crisis tax does not alter the market design or market rules but reallocates revenue streams.

In order for short-term incentives (i.e., operational decisions) to remain intact, the firm should ***on the margin*** **benefit from the high electricity prices**. Increasing production by increasing availability of the power plants or pushing the limits of the power plants should be worth it.

One implementation that satisfied this requirement is to oblige firms to **sell contract for differences (CfDs) for a fixed quantity at a regulatory price**. This regulatory price should reflect some measure of long-term price expectations and still allow the company to recoup its investment costs. This type of mechanism is only necessary if the company did not yet sell its full capacity under a long-term fixed price contract or is subject to a contract for differences.[72] Similarly to the crisis tax, the CfD implementation involves partial appropriation of property rights as lifetime expected profits are affected.

Imposing a **crisis tax ex-post**, based on the historical performance of a firm, does, by design, not alter incentives and could therefore be used retrospectively to finance any crisis intervention.

[71] It could also resell electricity on the wholesale market at a premium.

[72] The imposition of the short-term CFDs has been used in Italy to extract windfall profits.

An implementation which **does not** satisfy the requirement of **keeping incentives intact**, is to tax the firm's revenue in the **day-ahead auction**. The firm will no longer receive the price p_{crisis}, but will be paid p_{norm}. The marginal benefit for increasing availability is now p_{norm}, while the social value is equal to p_{crisis}. In most European markets, generators are not obliged to participate in power exchanges and can trade energy in bilateral contracts instead. This mechanism will therefore only work if firms are prohibited from signing long-term contracts.[73] Bids in most power exchanges are not linked to a particular power plant, as nomination only happens after the market clears. So, implementation is not straightforward. Capping the price inframarginal powerplants receive is one of the policy proposals currently put forward by the European Commission[74], which is equivalent to a revenue tax on inframarginal plants.

To determine the tax level, one would need to **determine the profits that the firm would make in a hypothetical situation without an international conflict in Ukraine**. The firms should obtain sufficient short-term profit to fund its capital cost and give it a risk adjusted return for low price periods. Those profit levels cannot be identified from a cost audit or by observing the market bids (which reflect short-term variable costs only).

Price cap on gas power plants

By imposing a price cap on bids of gas power plants, the wholesale electricity prices and the inframarginal rents will be reduced (See Figure 8). As gas-fired power plants will be required to sell below production cost, they **receive a subsidy** so they can buy gas on the international market. This policy reduces wholesale prices for all consumers and reduces the need for providing targeted income support. The budgetary effect for the government will be limited if the fraction of gas producers is small.

A benefit of the system is that it **might be compatible with bilateral long-term contracts**. Prices in the long-term contracts will reflect the lower price in the spot market. Those forward prices become more predictable which could increase the liquidity of the forward markets.

[73] Prohibiting long-term contracts comes at a large cost as it prevents downstream companies to hedge their risk.
[74] Council of the European Union (2022b).

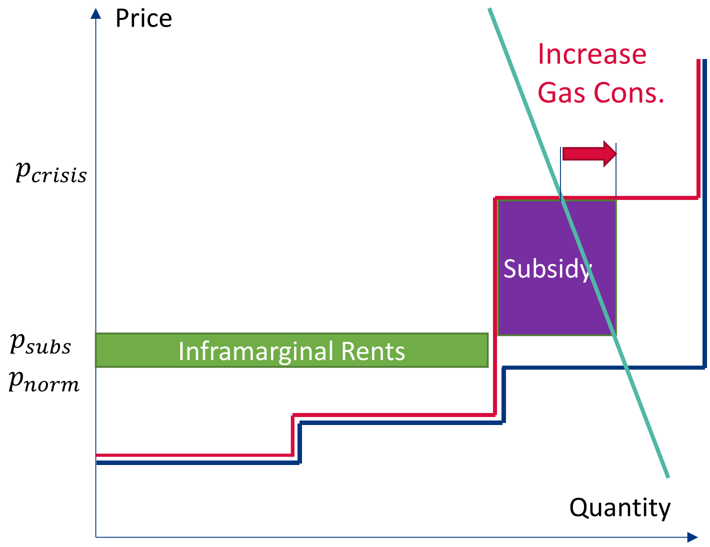

Figure 10: The introduction of a bid cap and a subsidy for natural gas producers lowers electricity prices and increases demand for electricity and gas.

Imposing the bid cap on the wholesale market to drive down energy prices has similar economic effects for the long-term incentives of infra-marginal producers. Although the legal effects on the undermining of property rights might be less obvious, the profits of renewable generation and nuclear energy are reduced. As noted in section 4, it is the generators penalised by this mechanism who may then take legal action. There are signs this is already happening.

A major problem of a bid cap, and the lower electricity prices, is that it **reduces the short-term incentives for energy conservation by consumers and for being available by generators**. It is therefore required that **additional regulatory measures are taken to reduce energy consumption** across the board.

A third problem with the bid cap is that it **requires a subsidy for gas-fired power plants**. Depending on how the scheme is organised (from government funds or not), this can constitute **state-aid**, which provides an unfair advantage to energy-intensive industries. It also **distorts trade flows** between member states, as electricity prices no longer reflect the true social cost, and might violate the rules or spirit of the internal market and free movement of goods. Member states that subsidise their local electricity price will also try to restrict exports to prevent other member states from benefiting from those subsidies.

A fourth problem is that the **subsidy of natural gas will benefit the gas exporting countries**, and it will **drive up the price of gas for other types of usage**. This is illustrated in Figure 9. If the supply of gas is inelastic, the subsidy in the electricity market will lead to inefficient substitution of gas used for heating and industrial production.

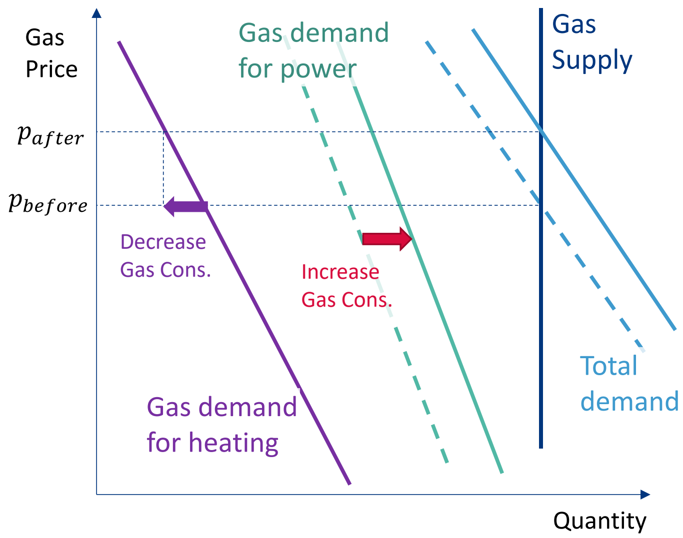

Figure 11: A subsidy for gas-fired producers in the power market will shift the demand function for gas. Assuming that the supply of Russian gas is inelastic, this will lead to an equivalent reduction of gas consumption in other sectors and an increase of the gas price.

A fifth problem is that the **measure is not targeted**. Electricity prices are reduced for rich and poor households and industrial consumers. It increases the price of gas for gas consumers, particularly the industry, and if one country does it, it drives up the price of gas for other countries. A more targeted subsidy scheme could **focus on the most vulnerable consumers**, at a lower overall social cost.

Price cap on gas imports and equivalent measures

The policy discussed in the previous section is one where governments subsidise natural gas for electricity production and imposes a cap on the bids of the gas-fired power plants. This led to an *increase* of European gas demand. An alternative remedy is one where the government puts **a cap on import prices for gas.** This will have opposite effects on the gas market. It corresponds to a ***decrease*** **of European gas demand**, **reduces the rents of energy exporters**, and **will increase electricity prices**, but will **create scarcity rents** that can be redistributed to end-users.

One way to implement the price cap for gas imports is the creation of a **single buyer** who **negotiates long-term contracts** with gas exporters. See Figure 10. This single buyer will drive down the price from $\boldsymbol{p_{before}}$ to $\boldsymbol{p_{cap}}$. In response to the lower prices, **exporters will *reduce* supply**. At the price cap, demand for gas within Europe is larger than supply. In order to efficiently allocate the gas imports to users within the EU the single buyer could **organise an auction**.[75] The resulting auction price for gas within Europe will in equilibrium then be equal to $\boldsymbol{p_{after}}$, when demand and supply meet. Hence the

[75] An alternative to auctioning capacity, would be to ration demand and grandfather capacity to existing users based on historical consumption patterns of current importers. However, as gas remains scares, this provide those importers with windfall profits, which would need to be reallocated using additional regulation. This looks very hard to implement.

internal gas price for consumers within Europe will be **higher than before** the intervention, but the single buyer will **collect a rent** which can be used to **compensate consumers**.

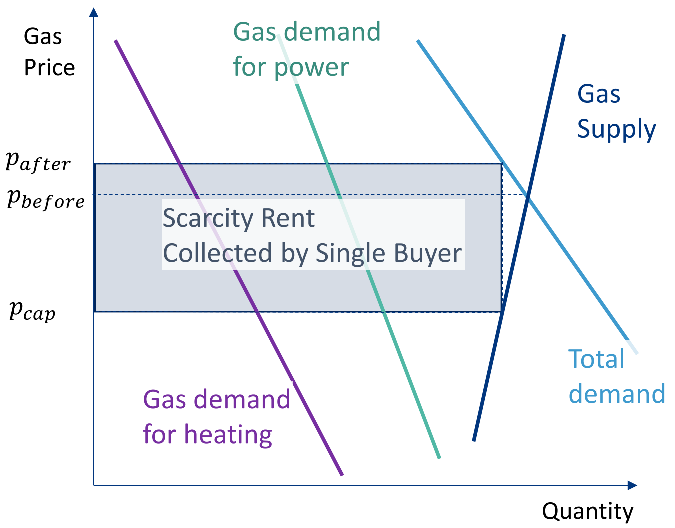

Figure 12: The effect of a price cap on gas markets in a single buyer setting.

It reduces the supply of natural gas and the rents for gas exporters, creates a scarcity rent for the single buyer and leads to higher gas prices within Europe for industrial production, heating and electricity production. The scarcity rents can be used to reallocate rents to end-users. Note that if gas supply were perfectly inelastic, prices would remain unchanged

Instead of a single buyer solution, the EU could also impose an **import tax** which is equal to the difference of the auction price and the price cap, $Tax_{import} = p_{after} - p_{cap}$. The market outcome would be equivalent, but long-term contract commitments would now be made by **individual energy firms**, and not by the single buyer.

Both the single buyer and the import tax solution **might run afoul of international trade rules**. A third equivalent policy measure is to impose a **consumption tax on natural gas**, which is equal to $Tax_{consumption} = p_{after} - p_{cap}$. This is simple to implement at member state level and would allocate the tax benefits to member states. It requires some **coordination between Member States**, in the form of a minimum tax level, so countries do not free ride on each other's effort to lower the import prices.

Moving from uniform price auction to pay-as-bid auction[76]

Most European day-ahead markets use uniform price auctions, where all generators are paid the same price. An alternative would be to use a pay-as-bid-auction, where firms are paid based on the bids they make.

[76] This section is based on recent work by Yu and Willems (2022).

The policy debate on uniform versus pay-as-bid auctions in the electricity sector is not new. It has been discussed during the Californian electricity crisis (FERC, 2000; Sweeney, 2002) and the reform of the England and Wales trading arrangements (OFGEM, 1999). The **economic rationale** for switching to a pay-as-bid auction is **not very strong** and the **policy discussion** is sometimes misguided as it **ignores changes in the bidding** of market participants.

If the bids remained unchanged, the auctioneer collects additional revenue as shown in Figure 11. This revenue could be used to pay to consumers in a lumpsum fashion for instance by a reduction of their network tariffs. Note that in a pay-as-bid auction, generators will not necessarily receive the same price, as prices depend on their own bid.

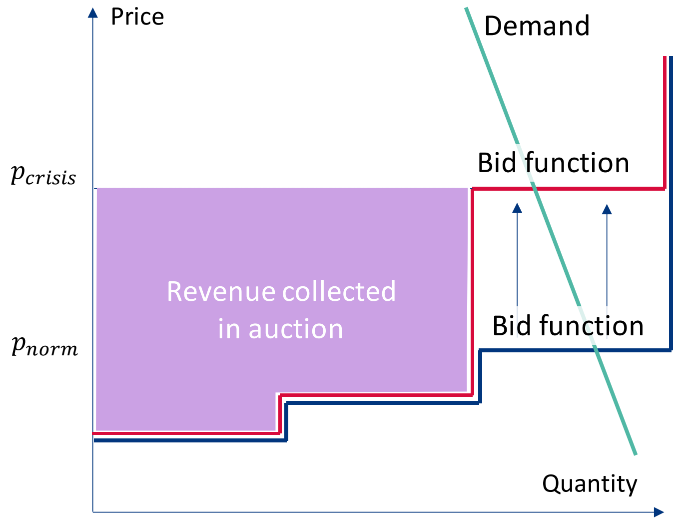

Figure 13: Effect of a change from a uniform price auction to a pay-as-bid auction if bids remain the same (which they will not).

However, Figure 11 is too simplistic, as in a pay-as-bid auction it is no longer optimal for competitive firms to set bids equal to their marginal cost. Firms will maximise their profit by adjusting their bids and include a bid mark-up. This mark-up allows them to make some profit in the short run, which they will use to recoup their investment costs. Hence the effect of going from a uniform price auction to a pay-as-bid auction is not straightforward as firms will **adjust their bidding behaviour**, **short run profits change**, and this **affects long run investment decisions**. It requires long-term models to analyse the overall effect.

If demand is known before firms bid, bidders will adjust their bids, so that their bids reflect the social value of electricity, which is equal to p_{crisis}. The additional revenue collected by the auctioneer will become zero, and the uniform price and the pay-as-bid auction are identical (See Figure 12. Therefore, in this case there is no difference.

However, in the pay-as-bid auction, firms are obliged to make predictions of the equilibrium price p_{crisis} before submitting their bids. If those predictions are wrong, the cheapest technologies might not be selected to produce, and total production efficiency is lower than in the uniform price auction. It may also lead to extra rents for large, better-informed producers,[77] and the cost of making predictions then has to be paid for by end-users (Kahn et al. 2001).

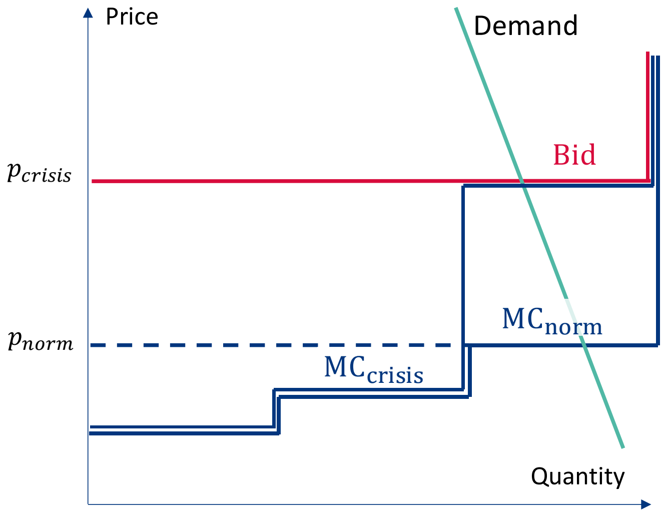

Figure 14: In a pay-as-bid auction with perfect foresight on demand, competitive bidders will increase their bids to the level of the market equilibrium price

If foresight of future demand is imperfect, generators will still set a bid above their marginal cost, but no longer equal to p_{crisis} as there might be a risk that they will not be called upon to produce. Firms will trade-off higher mark-ups versus the probability of being out the market. The bids will look similar to Figure 13. As bids are below p_{crisis}, the auctioneer will collect some revenue that can be recycled and benefit consumers. In the short run, a pay-as-bid option will therefore **benefit consumers with lower energy bills** and will **hurt producers**.

However, the fact that bids are above the marginal cost leads to **efficiency losses if demand is elastic**. Those efficiency losses are highest during low demand periods, as mark-ups are highest in those periods. Hence, a pay-as-bid auction destroys total surplus and is a rather inefficient way to allocate rents from producers to consumers.[78]

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[77] Using agent-based modelling, Bower and Bunn (2001) where bidders develop bidding strategies with an adaptive learning algorithm it is shown that a pay-as-bid auction increases prices. The reason is that firms with a large market share have significant informational advantage.

[78] Several theory papers study the effect of a change towards pay-as-bid auctions. Federico and Rahman (2003), Fabra et al. (2006), and Holmberg (2009) show that in the *short run consumer surplus* increases. Welfare remains constant in Fabra et al. (2006), Holmberg (2009) as they have inelastic demand and therefore rule out deadweight losses. Welfare decreases in Federico and Rahman (2003) who assume elastic demand.

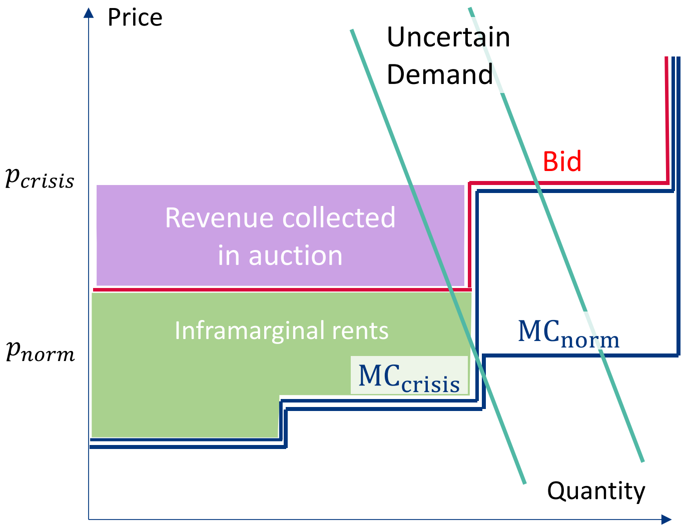

Figure 15: Pay-as-bid auction with uncertain demand.

Generators bid above their marginal cost and obtain some infra-marginal rents. The auctioneer collects some revenue in the auction which can be recycled lower the consumers' energy bills.

In the long run, generators use the inframarginal revenue to recoup their investment costs. As those inframarginal rents are different in the pay-as-bid auction and the uniform price auction, investment decisions will change. The pay-as-bid auction reduces the rents baseload producers collect in the market, and their investment will be reduced. The generation mix will have less baseload capacity and more peak-load capacity, which reduces total surplus. If there are no entry barriers in the market, the long run expected profits of firms are zero, and a reduction of total surplus lowers consumer surplus. Consequently, consumers do not benefit from switching to a pay-as-bid auction in the long run.[79]

Summarising, **pay-as-bid auctions in wholesale spot market are less efficient than uniform price auctions** (price signals distorted for consumers, costly price predictions and scheduling errors). In the **short run they could increase consumer surplus, but in the long run it will hurt consumers**.

In order to address the inefficient short run price signals for consumers under pay-as-bid pricing, some commentators have suggested to use ***pay-as-bid pricing with average bid pricing***, where the consumers pay an energy price that is equal to the average bid submitted by the generators (See Figure 14). As far as we know, this has not been analysed yet, but **first results suggest that it is worse than the "standard"** pay-as-bid pricing.[80]

[79] Fabra et al. (2011), compares investment decisions under pay-as-bid and uniform price auctions with inelastic demand, a single production technology and in a duopoly setting, and finds that consumer surplus increases, total welfare and installed capacity remain constant. Yu and Willems (2022) show that with elastic demand, no entry barriers, and a mixture of generation technologies, total welfare and consumer surplus decrease.

[80] This methodology will lower the price in hours with peak-demand and lead to prices below marginal cost during those periods with high demand. This is inefficient and will lead to extra deadweight losses. During low demand hours, prices are above marginal cost, which is also inefficient, as demand is smaller than economically efficient.

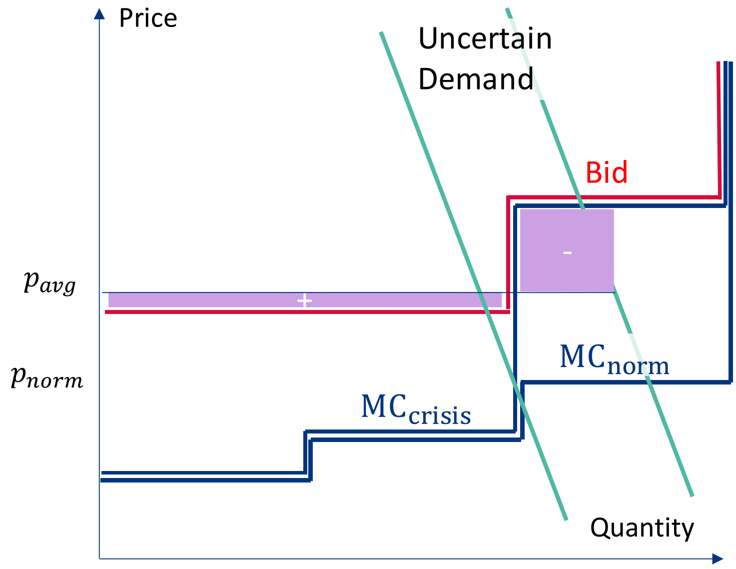

Figure 16. Pay-as-bid pricing with average pricing.

Consumers pay the average price $\boldsymbol{p_{avg}}$ which corresponds to the volume-weighted average bids of the suppliers. The two-coloured areas in the graph have the same size.

General discussion

Spot Prices reflect scarcity

In a liberalised market, day-ahead energy prices tend to converge to the social value of supply and demand, independent of the market design. That is where supply meets demand. This price level provides the correct **short-term incentives**; for energy conservation, storage, demand shifting, plant scheduling, plant availability and congestion management.

The market design of the spot market has only limited impact on average price levels as competitive firms will try to exploit all arbitrage opportunities and **shifting towards pay-as-bid auctions is not advisable**. Empirical evidence of the effects of wholesale market design on market outcomes suggests that the impacts are marginal. Market **outcomes are mainly explained by the market fundamentals**: generation mix, fuel prices, demand levels, horizontal market concentration, the number of long-term contracts and vertical integration.[81]

In the **intermediate future, the electricity spot price will remain to be driven by the natural gas price as marginal technology**. In the longer-run net zero context, it will depend on the cost of a dispatchable backstop or storage technology and could be driven by international hydrogen prices. Trying to

[81] Evidence is provided by Evans and Green (2003) for the UK and Bushnell et al. (2008) for USA.

decouple the electricity *spot price* from the gas *spot price,* does not improve market efficiency and will only create market distortions.

Under the current market design and absent government intervention, future spot prices will reflect, in expectation, the long run average system cost: the long run investment and short run production costs of the portfolio of RES and conventional generation.[82] Hence, forward contracts and PPAs that are based on those spot prices will reflect the long run average system cost and will provide correct investment signals.

The impact of natural gas prices on this average system cost will decrease over time as installed capacity and the capacity factor of gas power plants will reduce. Hence, the **fuel cost becomes a smaller part of the overall system costs and have a smaller impact on forward prices and hence the total energy bill**.[83]

Taxing Scarcity Rents of RES

RES production relies on the availability of natural resources which are unevenly distributed and often scarce. This creates scarcity rents: RES producers in favourable production sites make more money than they need to cover investment costs. **Policymakers might want to take away those scarcity rents. Today, scarcity rents are addressed by differentiating support schemes**: financial support is lower for good RES sites, i.e., sites with higher scarcity rents.

In the future, RES becomes cost competitive and **policy makers might therefore decide to phase out direct support for RES**. **Alternative methods for capturing scarcity rents of good production sites may need to be introduced**. Ideally, rents are captured in a way that does not distort competition and keeps spot price signals intact. **Direct taxation of production assets** (hydro plants) and the **auctioning of permits for using a scarce resource** (oil fields) have been successfully used in the past for this purpose. Those mechanisms might be easily applicable for wind energy, where exogenous parameters like the windspeed are easily observable and auctions for offshore wind sites have been common.

The government does not have full information about the size of the scarcity rents and might instead design markets that incentivise firms to reveal information about the cost of RES production sites. This can be achieved by **creating competition between RES firms in an auction**. Ideally, the auction rules take into account information that the government already obtained before the auction starts and includes additional parameters than price to better screen the cost of RES producers. For those auctions to be of any use in learning about the size of scarcity rents, they **must be organised *before firms invest***, as otherwise investments costs are sunk, and screening becomes impossible. The result of the auction could be the level of the yearly permit price that the RES firm pays for using a location,

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[82] In the past, European governments have heavily subsidized RES production, which absent the Ukrainian war would have led to artificially low carbon and electricity prices.

[83] In order for gas power plants to recoup investments costs with lower capacity factors, electricity prices will need to spike more often. Electricity prices will then be determined by bids offering demand flexibility and storage, and not by the price of natural gas.

or a commitment to deliver power at a specified price under a virtual PPA setting. Both the yearly permit price and the PPA contract have the advantage of keeping short-term incentives intact. The PPA contract provides additional hedging opportunities for the producer and allows the auctioneer to include additional screening parameters in the auction.

Note that any voluntary scheme where RES producers freely choose whether to participate or not, will not be helpful in extracting scarcity rents, as firms will just avoid the mechanism and sell energy in the spot market or via bilateral contracts instead. Hence, the **government will need to require some form of enforcement, either through taxation or an obligation to participate in an auction in order to receive a production permit**.

Note also that adjusting the spot market design is not helpful for learning more about the size of the scarcity rents, as investment costs already sunk. **Decoupling the electricity *spot price* from the gas *spot price,* by creating a hybrid spot market model will therefore only hamper competition and efficiency** without providing additional information.

Improving the market for long-term contracts

We expect that the use of long-term contracts by private parties will *increase* in the long run net zero scenario, due to the higher price volatility, the phasing out of government price guarantees for RES, and stricter regulation of the retailers' risks.

We also ***expect innovation in energy contracts.*** Long-term contracts will need to go beyond standard forward contracts on the day-ahead market. Specific contracts are needed to **target actors with different risk profiles** (retailers, intermittent RES producers, storage operators, aggregators, conventional generators). Balancing contracting positions might require **multilateral contracting**: For instance, a wind farm, a retailer, and a storage operator together might have a lower risk exposure than any two players together. **The risks that need to be hedged will also change**, not only uncertainty in the day-ahead price will matter, but increasingly also balancing costs, regional price differences and congestion costs. The **market for corporate PPA is likely to mature further, but integrated companies with portfolio investments will remain important**.

There are **good arguments for government intervention in the contracting market** such as: **regulating the risk of retailers**,[84] **standardising contracts** to simplify netting of positions, **improving transparency on contract prices and positions**, **contracting on behalf of consumers** to prevent future non-market intervention by the government, **contractual terms of energy imports**, and **provide natural counterparties for some contracts** (e.g. transmission prices with Financial Transmission Rights and ETS policy risks by CO_2 call options).[85] Some markets may also rely on short-term capacity markets

[84] Willems and de Corte (2008) show that regulating the contract positions of retailers and requiring more long-term contracts, does not need to be detrimental for competition.

[85] Some contractual terms for end-consumers contracts are already harmonised by EU law. This means that the EU already has a legal basis for adopting new provisions if so needed. The situation is a bit different on the wholesale market and PPAs.

when spot prices do not fully reflect energy scarcity. However, an **important role remains with private parties**. The market has worked well in providing hedges three to sometimes five years in the future, and it is **unclear whether there are strong economic arguments to regulate hedging beyond this period.**

Whether member states provide long-term hedging, for instance in the form of long-term government backed financial PPA's, should **be left to the subsidiarity principle**, and depends on the preferences of individual Member States. **As long as those policies do not distort the internal market they should be allowed**: the contracts should keep incentives to participate in spot market intact, they do not involve state-aid, and cross-border participation is possible subject to technical constraints.[86]

Taxing Windfall profits

The energy sector currently has some of the **characteristics of a war economy** and skimming the **windfall profits of RES and nuclear generators might be justified for equity reasons**. The best method to skin profits is one that **keeps price incentives on the spot market intact and taxes the inframarginal rents of firms**. Ideally, a crisis tax takes into account existing contractual relationships, is temporary in nature and specifies under which conditions the crisis tax will be automatically abandoned, leaves sufficient profit to the firm, and is not imposed arbitrarily. The revenue collected in a windfall profit scheme is **best used for targeted income support to consumers**. Those criteria might need to be imposed at an EU level. Ex-post taxation of windfall profits can be efficient as it does not distort incentives. Attention should also be given to address **windfall profits in the gas sector**.

Subsidising Demand Reduction

One final, somewhat underexplored, policy to address the energy crisis is **demand management that goes beyond initiatives on energy efficiency**. **Industrial consumers could receive a subsidy to temporary shut down production, or households could receive a bonus for reducing consumption**.

This kind of subsidy might be welfare-improving if the wholesale energy price does not reflect the social cost of electricity (for instance because of price caps); when consumers have behavioural biases when choosing consumption levels or buying energy saving equipment; when consumers pay a retail price which does not reflect scarcity at the wholesale level; or when network tariffication and taxation distorts the relative prices of gas and power and self-production versus central generation. There are other market failures in the household sector, such as split incentives between house owners and renters, and financial constraints which hinder investments in new equipment.[87] In the industrial

[86] The current state-aid guidelines might form a starting point; *Guidelines on State aid for climate, environmental protection and energy, 2022*.

[87] A previous CERRE report discusses hurdles to make activate consumers and looks at behavioral nudges, business models, and regulatory changes. It also highlights the importance of aligning incentives. (Giulitetti et al. 2019). Borenstein and Bushnell (2022) show for California that aligning prices for different energy fuels would create significant efficiency gains. Gillingham and Palmer (2014) review the empirical and behavioral literature on whether consumers make the right choices regarding energy savings.

sector, legal limits in the European labour markets might make it hard to furlough personnel and companies might face more than the social cost of a temporary reduction in employment.

SECTION 4: LEGAL ASPECTS OF WHOLESALE ELECTRICITY MARKET (RE)DESIGN

The EU architecture of wholesale market design legislation

Over time and with the adoption of the different energy legislative packages, the content and manner to elaborate EU energy market legislation has evolved. The EU rules have become more detailed, prescriptive, and technical in nature. The rules are also increasingly reflecting elements of **co-regulation**, with a shift marked in the third energy package with a more **decentralised approach** of law making resulting in the adoption of network codes, guidelines and terms and conditions (TCMs), based on the involvement of notably Transmission System Operators (TSOs), Nominated Electricity Market Operators (NEMOs), National Regulatory Authorities (NRAs) and the Agency for the Cooperation of Energy Regulators (ACER).

The EU architecture of wholesale market design legislation can be described as follows.

In primary law, the legal basis for EU action in the field of energy is **Article 194 of the Treaty on the Functioning of the Energy Union (TFEU)**. Some other legal bases, such as Article 114 and 122 TFEU, have also been used in specific circumstances. While Article 194 TFEU remains the primary legal basis for Union energy policy, the **emergency measures enacted at EU level in the gas sector in August 2022 have been based on Article 122 TFEU**.[88] Additional emergency measures in the electricity sector are also expected to be based on Article 122 TFEU. This is a notable legal development that has consequences on the shaping of EU emergency measures. Under Article 122 TFEU, the Council is the one responsible for adopting the EU measures, based on a proposal from the Commission. This leaves the **Council with a large influence** on the choice and the drafting of the EU measures. The European Parliament might possibly be involved in a consultation phase, but this is not required. Article 122 TFEU sets additional requirements for the shaping of the EU measures that must aim to ensure solidarity between the EU Member States (solidarity principle) and be related to a situation of severe difficulties in the supply of certain products, notably within energy.

Moving to EU secondary legislation, the central acts of on electricity market design are the **Electricity Directive**[89] and the **Electricity Regulation**[90]. **Other pieces of secondary legislation** regulate the support to, among others, renewable energy sources,[91] energy efficiency,[92] energy performance in buildings and of appliances, as well as specific trading actors or energy transactions with a focus on

[88] The Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas.

[89] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.

[90] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity

[91] Renewable energy Directive

[92] Energy Efficiency Directive

wholesale market integrity and transparency (notably the REMIT Regulation[93] but also the application of the legislation on market abuse and on financial instruments such as MIFID and MiFIR)[94].

In addition, a third level of legislative acts, increasingly referred to as "**tertiary legislation**"[95] are adopted in the form of delegated acts, implementing act, or acts adopted using regulatory procedure with scrutiny when this still applies. The most relevant market design rules among this tertiary legislation are the **network codes, guidelines and TCMs** previously mentioned. There are four "families" of network codes organised according to their area of focus, i.e. connection, operations, market and cybersecurity. The procedure for the adoption of the network codes, and subsequent guidelines and TCMs, was defined in the 2009 Electricity Regulation and amended in the 2019 Electricity Regulation.

To assist and guide market actors, the European Commission and ACER are also publishing **guidance documents**, of non-binding nature. For example, ACER publishes guidance on the application of Regulation (EU) No 1227/2011 of 25 October 2011 on wholesale energy market integrity and transparency.[96]

As an overall steering mechanism, the different pieces of legislation fall under the wider umbrella of the Governance system of the Energy Union, and the mechanisms defined in Regulation (EU) 2018/1999 of the European Parliament and of the Council of 11 December 2018 on the Governance of the Energy Union and Climate Action (as amended).

The involvement of the different actors in the adoption of wholesale market rules will depend on the nature of the act (e.g., new legislative act or implementing legislation) and its legal basis. The choice of legal basis will influence the voting rules. The adoption of EU measures on energy, internal market, solidarity, taxation policy has different voting procedures and operate under a different share of competence between the EU and Member States. Amending the EU Treaty is not among the options discussed and deemed necessary. Amending or adopting new secondary legislation will be necessary to implement certain of the proposed measures at EU and national level and will require the involvement of the Council and the European Parliament, as co-legislators, under notably Article 194 TFEU. Depending on the legal basis for the act, the adoption procedure may give more competence to the Council such as the move towards grounding EU emergency measures in Article 122 TFEU. When necessary, the European Commission will be responsible for adopting approval decisions of national measures, such as state aid approval decisions. This often happens after a phase of pre-consultation between the Member States that will notify the measure, and the European Commission services. The

[93] Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency (REMIT).

[94] Regulation (EU) No 596/2014 of 16 April 2014 on market abuse (MAR), Directive 2014/65/EU of 15 May 2014 on markets in financial instruments (MiFID II), and Regulation (EU) No 600/2014 of 15 May 2014 on markets in financial instruments (MiFIR).

[95] The term "tertiary legislation" is not used in the EU Treaties, but it is found in the European Union (Withdrawal) Act 2018 in the UK, following Brexit. See Section 3(2)(a).

[96] https://acer.europa.eu/en/remit/Documents/ACER_Guidance_on_REMIT_application_6th_Edition_Final.pdf

European Commission will also be the one adopting non-binding, guidance documents that will comment on the margin of appreciation left to national governments in the adoption of national measures. Finally, much of the details of wholesale market legislation now involves several actors, as for the elaboration of network codes, guidelines and TCMs. Depending on the level of the measure (national, regional or European), and whether the actors agree or not (risk of escalation to ACER) different actors will be involved. Changing these rules will often be subject to a longer timeline. The measures adopted can also be subject to appeal and judicial review, which will further delay their implementation.

The sequencing of regulatory intervention and legislative changes: short-term, mid-term and long-term processes

A central question to the market design legislation today is **whether it is still fit for purpose for the main part** and just needs the adoption of **supplementary mechanisms** to deal with specific, temporary challenges, or if it requires **a broader revision**. There is therefore a need to distinguish between what should be a future-proofed market design under net zero objectives, and the toolbox of temporary measures that can be adopted by governments or market actors in order to respond to short-term disruptions. A main objective of the Clean Energy for All European Package was already to make the European electricity market legislation fit for the clean energy transition.[97] **New actors and services have gained recognition** in the legislation, such as flexibility services, aggregators, energy communities and prosumers, among others. In total volumes at the wholesale level, their **share in the market remains however limited in the short-term**, **but the situation will evolve as more renewables and more flexibility enters the market**. As an additional challenge, a future-proofed marked design should take due count of the need to build the resilience of the energy system to respond to more structural risks, such as more extreme weather conditions or digital threats. This could result, for example, in the insertion of mechanisms that will valorise energy storage as a security of supply measure or further reward flexibility.

Therefore, in the context of the current debate on market design, and when assessing the need to revise EU market design legislation, regulatory intervention can be classified according to **short-term (a), mid-term (b) and long-term (c) processes**.

A first reason for looking at the sequencing of the market measures adopted is that it enables to distinguish between short-term challenges and structural reforms. Short-term measures aim to address a crisis situation and are adopted within the competences given to the responsible authorities, based on existing legal basis. This is exemplified by the publication of the Commission Communication of 13 October 2021 containing a Toolbox for action and support to tackle rising energy prices.[98] These correspond to the measures adopted during Winter 2021-22, and Spring of 2022. Aware that the

[97] European Commission, Communication, "Launching the public consultation process on a new energy market design", COM(2015) 340 final, 15.7.2015; 2019 Electricity Directive, Recital (6).

[98] European Commission, "Tackling rising energy prices: a toolbox for action and support", COM(2021) 660 final, 13.10.2021.

energy price and scarcity situation will last and could escalate, governments started assessing possible mid-term measures before the summer of 2022, to address the risks identified in the previous period. Therefore, **mid-term measures have primarily related to risk management and adjustment to short-term responses**. They could lead to the adoption of new implementation acts, decrees, or temporary emergency legislation. Such has been the case as part of the Save Gas for a Safe Winter Plan[99] and the adoption of Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas. In the long-term, structural reforms would be needed, to either consolidate and enshrine in law temporary solutions, or revise the existing legal framework, following ordinary-legislative procedures.

A second reason for looking at the sequencing of the adoption of market measures is the **legal consequences that short-term and mid-term measures can have on the internal energy market.** Short-term compensation measures to support a specific sector can potentially create a selective advantage for the beneficiary undertakings, a risk of dominant position on a related market or of cross-subsidisation. Several governments have also considered limiting cross-border trade on electricity or gas interconnectors on the grounds of security of energy supply, with the purpose of limiting exports to first preserve domestic energy supply. Limiting export of electricity is likely to result in quantitative restrictions on exports that are prohibited by Article 35 TFEU, except otherwise justified. As highlighted by the Court in its preliminary ruling of 19 September 2020 in Case C-648/18, an **export restriction** aimed at protecting from high electricity prices **would undermine the very principle of the internal market**.[100] The **(re-)introduction of regulated prices** on gas or electricity would also **undermine some central principles of the current market design legislation**, that is based on market-based signals and liberalisation. This is reiterated in the Electricity Directive that stresses that public service obligations in the form of price setting for supply of electricity constitute "a fundamental distortive measure".[101] The **conditions for such price setting intervention should therefore be clearly defined in legislation and its application limited in time** to limit distortive effects. Another impact of regulated prices is that it would also interact negatively with traditional hedging mechanisms; would they be bilateral contracts or through financial instruments. Finally, the pressure put on the European Commission services for a very rapid assessment and approval of state aid measures (short-term intervention measures) could put at risk certain procedural safeguards, as previously illustrated in the Tempus judgment that annulled the state aid approval decision adopted by the European Commission.[102]

[99] Communication from the European Commission, "Save gas for a sage winter", COM(2022) 360 final, 20.07.2022.

[100] Case C-648/18, Autoritatea națională de reglementare în domeniul energiei (ANRE) v Societatea de Producere a Energiei Electrice în Hidrocentrale Hidroelectrica SA, 17 September 2020. Para. 43 reads at follows: "Securing the supply of electricity does not mean securing the supply of electricity at the best price. The purely economic and commercial considerations underlying the national legislation at issue in the main proceedings are not grounds of public security within the meaning of Article 36 TFEU, or requirements relating to the public interest which make it possible to justify quantitative restrictions on exports or measures having equivalent effect. If such considerations were able to justify a prohibition on direct export of electricity, the very principle of the internal market would be undermined."

[101] Electricity Directive, Recital (22), (23), Article 5.2 to 5.5.

[102] Judgment of the General Court (Third Chamber, Extended Composition) of 15 November 2018, in Case T-793/14 Tempus Energy Ltd and Tempus Energy Technology Ltd v European Commission.

A third reason for looking at the sequencing of the measures adopted is the **influence short-term measures will have on ongoing legislative procedures**. Two legislative packages are currently under negotiation, i.e., the Fit for 55 Package of July 2021 and the Hydrogen and Decarbonised Gases Package of November 2021. Such interaction has already been taking place with the objective of speeding up the deployment of renewable energy generation capacity. On 18 May 2022, the European Commission adopted a Recommendation on speeding up permit-grating procedures for renewable energy projects and facilitating PPAs.[103] Although this is a non-legally binding Recommendation, it relates to topics that are currently under negotiations as part of the revision of the Renewable Energy Directive (Fit for 55 Package).

A fourth reason for looking at the sequencing of the national and EU measures adopted, is that it could influence future long-term market design reforms. Some temporary mechanisms developed in a period of crisis could transform into permanent solutions. For now, the **temporary measures adopted by Member States or EU harmonised emergency measures all are limited in time**, until early Spring 2023, to avoid further distortion of competition on the internal market.

Finally, most of the short-term measures, and some mid-term measures, have been adopted at the national level. In order to preserve the integrity of the internal market, the European Commission has quickly published **guidelines** aimed at mapping the different measures that Member States could adopt within the existing framework. So far, the European Commission has adopted three communications in that sense: (1) Energy Prices Toolbox, COM(2021) 660 of 13 October 2021; (2) the Additional guidance for Member States, COM(2022) 108 of 23 March 2022; and (3) the Communication on Short Term Energy Market Interventions and Long Term Improvements to the Electricity Market Design, COM(2022) 236 of 18 May 2022. Mid-term harmonisation measures at EU level have quickly been deemed necessary to avoid the possible negative effects of divergent national approaches, in line with the principles of subsidiarity and proportionality (such as the Council Regulation on coordinated demand-reduction measures for gas).

Short-term measures (Toolbox) (crisis management)

Short-term measures to deal with high energy prices have primarily focused on the retail market, with direct support measures in favour of household consumers.[104]

At the wholesale level, a short-term measure considered has been the **use of congestion revenues** to finance different types of market intervention measures, mostly with the objective of reducing the costs of energy for final customers. The Spanish and Portuguese governments have adopted such a support scheme that involves as one of the two sources of financing of the measure, the use of

[103] Commission Recommendation of 18.5.2022 on speeding up permit-granting procedures for renewable energy projects and facilitating Power Purchase Agreements, C(2022) 3219 final, 18.5.2022.

[104] Retail electricity market measures have been the subject of a separate report by CERRE: N.-H. von der Fehr, C. Banet, C. Le Coq, M. Pollitt and B. Willems, “Retail Energy Markets Under Stress”, CERRE, 2022.

congestion revenues collected by the Spanish TSO on the interconnector to France. Such a measure raises issues under two set of EU rules. First, it has been concluded by the European Commission that the measures constitute state aid in the sense of Article 107(1) TFEU, a conclusion that was not contested by the Spanish and Portuguese governments. In its decision of 8 June 2022, the European Commission approved the scheme on the grounds that it is compatible with the internal market pursuant to Article 107(3)(b) TFEU concerning aids aimed "*to remedy a serious disturbance in the economy of a Member State*". The second relevant legal framework when using congestion revenues is Electricity Regulation. The **use of congestion revenues by TSOs is strictly regulated** in Article 19 of the Electricity Regulation in order to avoid any conflict of interests by TSOs. Indeed, there is a risk that TSOs underinvest in interconnection capacity when this additional interconnection capacity would result in decreased congestion income for them.

Another form for wholesale market intervention has been the **support in favour of fossil fuel power plants to cover part of their fuels fuel costs**, with the intention to see them reducing with bid, as they retain the highest influence in setting wholesale electricity prices, due to the marginal pricing method. This approach was also followed by Spain and Portugal in the previously mentioned scheme, that has been approved by the European Commission in June 2022 under EU state aid rules, specifically Article 107(3)(b) TFEU (serious disturbance in the economy of a Member State).

Mid-term measures (risk management, adjustments)

The mid-term measures identified below relate to proposals for action by Member States, the European Commission or even ACER that could challenge internal market rules or secondary legislation, or that would trigger the adoption of harmonised legislation at EU level.

In order to prepare for disruption, several governments have started the process of **identifying rationing measures and priority order for curtailment of demand among large energy consumers**. This has been rapidly seconded by supporting measures at EU level, with the adoption of Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas. The Regulation defines a voluntary national gas reduction target of 15% from 1 August 2022 to 31 March 2023).[105] This can be supplemented, in case an "EU alert" is activated, by a mandatory demand reduction target.[106] A system similar to the coordinated demand-reduction measures for gas is to be implemented for electricity, building on the same governance structure[107]. In the context of gas, the European Commission has also referred to the possibility of developing rules for "cross-border rationing", but this has not yet been followed by concrete proposals. Adopting **voluntary and possible mandatory demand reduction targets is an approach that resembles other steering mechanisms in EU law,** such as for energy efficiency and the promotion of renewable energy sources. If combined with a market-based approach (e.g. through **tendering of demand reduction**), it also resembles the **system for capacity mechanisms** already in place in several Member States, where demand response

[105] Council Regulation (EU) 2022/1369 of 5 August 2022 on coordinated demand-reduction measures for gas, Article 3.
[106] Ibid, Article 5.
[107] Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices.

can be supported. This would consequently be an approach that Member States are familiar with, requiring monitoring in terms of implementation and enforcement by the Commission. The implementation of national demand reduction measures (both for electricity and gas) would raise questions concerning the possible financial compensation of the undertakings obliged to curtail their demand, which will trigger **state aid rules** as it will result in subsidising demand rationing. Developing rules for "cross-border rationing" at EU level would be a novel approach (so far only raised in the context of gas) that would elevate at the EU level the question of restriction to exports of energy, as discussed above. It would also raise questions as to the legal basis and scope of the measure.

A parallel approach in the mid-term would be the **implementation of the solidarity mechanisms** defined notably in the Security of Gas Supply Regulation (EU) 2017/1938 and the adoption of the proposed mechanism for voluntary joint procurement of gas strategic stocks (as part of the Gas Directive revision). The **EU Platform** for the common purchase of gas, LNG and hydrogen has had its first meeting already in April 2022. The **exact settings of the joint procurement mechanism are yet to be defined and the effects on competition will need careful assessment**.

Another path for governments would be to further encourage **large energy consumers to conclude bilateral PPAs**, beyond what is referred to in secondary legislation (Renewable Energy Directive, and its current revision). While Member States can facilitate the adoption of PPAs, it would be an **important shift in regulation to require large consumers to conclude such agreements instead of letting them free to choose** their energy purchasers and form of hedging. It could also have reverse effects, based on the contractual arrangements concluded between each party, a matter that government usually do not interact with.

As explained above, there are different types of PPAs, while the focus on EU legislation in the Clean Energy Package has been on supporting the conclusion of corporate renewable energy PPAs to further enable the uptake of renewable energy sources (Art. 15(8) Renewable Energy Directive 2018/2001). This was based on the fact that there are **still some national barriers to corporate renewable PPAs**. In some countries, the legislation does not enable PPAs, where the restrictions or constraints on the conclusion of PPAs are primarily related to restrictions on third party ownership of on-site renewable installations and restrictions on the number of buyers per installation or the number of suppliers per metering point. **By contrast, some other countries have adopted favourable regulatory environments for PPAs**, with the consequence of concentrating the adoption of these PPAs in these countries. Both categories of countries are subject to the same legislation applicable to PPAs, including competition law, internal market, and support schemes to renewables. The legal barriers faced by some companies in concluding corporate renewable PPAs therefore clearly stem from national legislation.

A **more mandatory approach to the conclusion of PPAs would be subject to further EU harmonisation**, as previous national practice around PPAs has been subject to in-depth investigation by the European Commission, such as the in-depth investigation opened on long-term PPAs in Poland in 2005. In this case, the Commission considered that the agreements conferred a state aid to the concerned generators and required Poland to amend its proposed legislation in order to plan the end of PPAs and include a compensation system to the generators in line with the Commission's methodology for analysing State aid linked to stranded costs. Finally, the Commission closed the in-depth investigation in 2007 with a positive decision with certain conditions. A similar case arose in Hungary, where the national authorities notified the Commission in 2004 about the existence of long-term PPAs between the state-owned and monopolistic network operator and certain power generators. The PPAs guarantee a return on investment to the generators and a fixed profit margin. The scheme raised similar questions under the state aid framework. Enabling similar forms of PPAs would therefore require an **assessment under state aid rules** and promoting their adoption at EU level would also require **clarification by the European Commission or the adoption of EU harmonised rules**.

Member States have adopted different forms of financial support measures that will require to be streamlined on the long-term to avoid distortions on the internal market. This could require the further revision of temporary crisis framework for measures involving state aids, with the purpose of better targeting state aid intervention.

The **taxation of windfall profits** by government for the purpose of redistributing tax revenues to final consumers is endorsed by the European Commission and Member States. Greece, Italy, Romania (and the UK outside the EU) have already levied such a tax. A windfall tax is a tax applied to companies that generate a significant increase in their earnings due to circumstances or events for which they are not responsible. The International Energy Agency has estimated that excess profits already amount to EUR 200 billion in 2022.[108] The European Commission has proposed guidance on the introduction of temporary tax measures on windfall profits in its Communication from March 2022[109], followed up by a **proposal for regulation in September, formally adopted by the Council on October 6**.[110] The Commission notably points out that national tax measures on windfall profits would need to be carefully designed to avoid market distortions and to be compatible with state aid rules, while maintaining incentivising additional investment in renewable energy. On its side, the European Parliament has called the European Commission and the Member States to coordinate the design of windfall profit taxation schemes.[111] As Member States retain competence on taxation issues, the European Commission has so far **proposed guidance to streamline national approaches on the matter, but a common approach is progressively defined**. Any harmonised measures on the common design of such a tax measure would require the unanimity of the Member States.

Another type of mid-term measures relates to adjustment to existing market rules. A recent example relates to the price spike incidents that occurred in April in France and in August in the Baltics. Both events triggered the need for an automatic increase of the **harmonised maximum clearing price for**

[108] https://www.iea.org/reports/a-10-point-plan-to-reduce-the-european-unions-reliance-on-russian-natural-gas

[109] European Commission, "REPowerEU: Joint European Action for more affordable, secure and sustainable energy", 8 March 2022, (COM(2022)010), Annex 2.

[110] Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices, 6 October 2022.

[111] European Parliament, Resolution of 19 May 2022 on the social and economic consequences for the EU of the Russian war in Ukraine – reinforcing the EU's capacity to act (2022/2653(RSP)), para. 46.

Single Day-Ahead Coupling (SDAC). Indeed, Europe's single day-ahead electricity market has an automatic maximum price adjustment mechanism in case of high prices. According to the Harmonised Maximum and Minimum Clearing Price (HMMCP) methodology,[112] if prices in any zone reach 60% of the maximum price, it triggers an increase in the maximum price limit five weeks later. As price spikes will probably occur more frequently, there is a **need to limit the frequency of increases of the maximum clearing price in the single day-ahead market**. In that way, consumers and market participants could better adapt their behaviour to the scarcity situation on the market. Therefore, on 2 September 2022, ACER urged a review of the rules on the automatic maximum price adjustment mechanism in the day-ahead electricity market.[113] In order to change the methodology, the NEMOs must first propose an amendment to the HMMCP methodology. NEMO's sent their proposals on 15 September, leaving six months to ACER to reach a decision. In the present case, ACER has indicated that it will complete the procedure within a much shorter framework. In this concrete case, it is the NEMOs that will trigger the start of the revision of the market rules that will be followed-up by ACER and subject to stakeholder consultation.

The current energy scarcity situation has had huge influence on energy price and leads to risk of further price spikes. To prevent this to happen, it is **fundamental that enough cross-border interconnector capacity is made available for trade.** Growing congestion in the European transmission system for electricity has been of increasing concern over time and had already triggered a series of amendments to the Electricity Regulation. This supplements the process of market coupling that started earlier. Of particular importance in Regulation (EU) 2019/943 are the new rules on capacity allocation, the requirements for bidding zone (re)configuration and the obligation for TSOs to provide a minimum cross-border trading capacity. For that purpose, TSOs will be under further scrutiny to make the capacity available at the border, and to implement the rules on the use of congestion revenues defined in the Electricity Regulation.[114] Tools on cross-border congestion management are also defined in the market network codes under Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity calculation and congestion management (CACM), Regulation (EU) 2016/1719 of 26 September 2016 establishing a guideline on forward capacity allocation (FCA) and Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (EB). Further emphasis can be expected on the implementation of existing mechanisms to ensure that a minimum level of capacity for cross-zonal trade is made available. Pursuant to Article 16 (8)(a) of the Electricity Regulation, this minimum level translates into a 70% rule of the net transmission capacity (NTC) after deduction of contingencies (as determined in the CACM guideline). Where the NTC system has already been replaced by flow-based market coupling, the 70% obligation refers to cross-zonal critical network elements Article 16 (8)(b). To sum up, cross-border

[112] Article 41(1) of Commission Regulation (EU) 2015/1222 of 24 July 2015 establishing a guideline on capacity allocation and congestion management (CACM Regulation).

[113] ACER urges a review of the rules on the automatic maximum price adjustment mechanism in the day-ahead electricity market | www.acer.europa.eu; ACER reviews the rules on the automatic price adjustment mechanism in the day-ahead and intraday electricity markets | www.acer.europa.eu

[114] Article 16 (8) of Electricity Regulation prohibits TSOs from limiting the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their bidding zones.

congestion management and the implementation of the different existing tools to ensure it will be under scrutiny in the mid-term.

Long-term measures (reform): alternatives for an improved market design

The current discussion on reform of the market design is oriented towards **two main sets of proposals on: price formation and market behaviour**. While the same categorisation applies to measures proposed for the retail market, the analysis below focuses on the wholesale market.

Price formation

In the REPower EU plan, the European Commission is proposing to strengthen transparency requirements and supervision of transactions in the wholesale market. This follows previous initiatives and will interact with ongoing processes consisting in: review of the CACM Regulation (CACM 2.0)[115], ACER proposal for new governance for Market Coupling Operation (MCO) functions, monitoring of the implementation of the Regulation. The European Commission is also proposing to move towards more integrated forward markets.

The introduction of locational marginal pricing is also among the proposals part of the bidding zone review process, as documented by the ENTSO-E report from June 2022.[116]

Similarly, a future-proofed market design legislation will need to not only **enable the integration into the market of a higher share of RES**, but also ensure that **market rules function with a higher share of RES**. This applies to both RES produced onshore and offshore. The level of ambition is high. The European Commission has announced a target of at least 60 GW of offshore wind installed capacity by 2030, and 300GW by 2050.[117] In the REPowerEU Plan, the European Commission called upon a further acceleration of RES deployment and an increase of the RES target in general to 45% in final energy supply by 2030. In that context, a major question is to know **which market design model will apply to the new generation capacity added offshore, and notably hybrid assets**. Will the common bidding zone model and general rules on management of congestion income apply to hybrid offshore wind assets? This is at least the approach favoured by TSOs and the industry. Whether the EU can push all RES into the lower price of a two-price system is also an important question.

Market behaviour

An important component of future market design reform will be to maintain **regulatory incentives to ensure sufficient investments in renewable generation capacity**, based on the right price signals and with a proportionate return on investment for investors. Therefore, emphasis on **planning,**

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[115] ACER's proposal for reasoned amendments to Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.

[116] ENTSO-E Report on the Locational Marginal Pricing Study of the Bidding Zone Review Process, June 2022. https://www.entsoe.eu/news/2022/06/30/entso-e-publishes-its-report-on-locational-marginal-pricing-study-of-bidding-zone-review-process/

[117] European Commission, An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future, COM(2020) 741 final, 19.11.2020, p.2.

simplification of permitting processes, development of flexibility and new generation capacity is expected to keep an important place in the legislation, supported by the provisions in the revised **Renewable Energy Directive (RED)**. The **EU regime of PPAs will also probably further evolve, most probably as part of the RED** rather than as an element of market design legislation. The reason for that is that the objective of EU harmonised measures on corporate renewable PPAs is to facilitate their adoption and support the further deployment of RES. **The objective is not to harmonise PPAs or regulate PPAs provision but to encourage their uptake**. The drafting of the PPAs will continue to remain an issue for negotiation between parties to the agreement.

However, some flexibility mechanisms enabling the further integration of renewable energy sources into the energy system and to balance the effect of their integration will probably need to be part of market design legislation. This applies to both existing mechanisms, such as the capacity mechanisms, and **new mechanisms such as two-way contracts for differences (CfD).**

The **resilience** of the energy system of the Member States already relies on their integrated energy system. As stated by the European Commission, "*deepening market integration (across all electricity markets) is a no-regret option*".[118] This will continue to be a major element of regulatory intervention, with further regulatory support in favour of coordination of investment decision for the development of smart energy infrastructures and cross-border infrastructures in general. The revision of the TEN-E Regulation already integrates innovation to a larger extent than before in the investment models for elective projects.

[118] European Commission, "Short-Term Energy Market Interventions and Long-Term Improvements to the Electricity Market Design – a course for action", COM(22)236, 18 May 2022.

CONCLUDING THOUGHTS

The current energy crisis has clearly raised questions about the long-term design of the electricity market in situations where unit energy prices will be volatile and high. However, this energy crisis is about much more than market design and clearly about **distributional issues that democratic political systems must address**, guided by national preferences and starting points.

One option is clearly to let the wholesale market continue as now and to help industrial and residential consumers directly through **targeted subsidies** to help with payment of bills. This would have the implication that there would be significant financial incentives to save energy due to being exposed to the impact of high wholesale prices. This approach is not being followed to the same extent by all countries in the European electricity market area, where there are **differing levels of interventions on retail prices directly**, which in turn **increase demand for electricity and raise wholesale electricity** prices.

Two-market solutions to short run pricing are superficially attractive but **raise serious efficiency issues**. Lowering the price of electricity for some types of generation and not others will lower production of the lower-cost electricity and **raise overall electricity production costs**. It will therefore raise the demand for gas generation and hence the price of gas, causing **back-fire by raising rents in the gas sector at the expense of capturing them in the electricity sector**. It may also seriously reduce cross-border trade in electricity. A good example of this in reverse is the recent German decision to extend the life of its nuclear power plants. The economic incentives to take this decision would be substantially reduced in a two-market solution.

Several concluding observations can be made:

First, it is **important not to make changes to market design which are not consistent with good long run operation**, which will be difficult to reverse. The creation of an effective short-term single market in electricity has been a long-running policy objective which has taken two decades to bring about. Net zero modelling tells us clearly that much more, not less, short-term trading of electricity will be necessary to achieve Europe's climate goals while delivering energy security at least cost.

Second, **reducing the demand for gas is key to reducing electricity prices. It is important that gas supplies to Europe are improved, and that European gas demand is reduced**. Policies which indirectly raise gas demand, by subsidising gas consumption (as in Spain) are to be avoided. Encouraging fuel switching away from gas to liquid fuel or alternative gases (such as ammonia) or coal or nuclear is very important.

Third, **reducing electricity demand has a disproportionate effect on prices**. Every 1% reduction in electricity prices, will reduce prices by of the order of 5-10%[119]. This is because short run electricity demand is relatively inelastic. **National campaigns to encourage electricity demand reduction this winter are essential.** There is a lot of excellent international experience of successful campaigns to reduce electricity demand quickly which individual European countries can draw on.[120] For instance: New Zealand reduced electricity demand by 10% in 6 weeks in 2003, in the face of shortage of hydroelectricity[121]; and Tokyo reduced electricity demand by 18% in the summer of 2011, following the Fukushima disaster in March 2011[122].

Fourth, a **consistent suggestion is that low-carbon generation should be moved to long-term fixed price contracts**. While this might be **sensible for new contracts, it is not clearly true for existing projects**. It is important to point out that if this arrangement is voluntary, it simply **moves payment from today to the future at the private rate of interest demanded by low-carbon generators**. It reduces current bills in return for higher future bills and constitutes a loan from the companies to consumers. It **would be cheaper for the government to do this via the tax system**. The signing of **long-term contracts by the state should be matter of national preference**.

Fifth, an **actual reduction in the net present value of the flow of financial payments to low-carbon generation over the longer run will likely involve some sort of appropriation of revenue via increased profits taxes**. This can be done but will come at the potential cost of raising future rates of return demanded by investors on low-carbon generation. This is because there is no agreed definition of "windfall" profits and some inframarginal surplus revenue is required to provide normal returns to individual projects.

Sixth, an **important regulatory question is whether retail prices do reflect wholesale prices. In some countries they apparently do not**. For instance, in the UK, the regulated unit price of electricity for households from 1 October 2022 is only 84% of the forward wholesale price.[123] This is could easily have been altered for standard consumption levels by reducing the daily fixed charge and increasing the unit charge to hit the UK government's Energy Price Guarantee on average bill payments. This would also have improved the distributional impact by reducing bills for lower consumption households, who tend to be poorer. It is important here that **bills are reduced while increasing the marginal price of electricity to reflect expected wholesale electricity prices this winter**. This could be done with a **rising block tariff,** where the final block reflects average expected winter prices. Failure

[119] Labandeira et al. (2017) estimated the short run price elasticity of demand for electricity between 0.1 and 0.2. The UK has observed a 6.1% reduction in industrial demand between June 2019 and June 2022 and a 44% rise in the real manufacturing electricity price excluding CCL (BEIS Statistics, Table 5.5 and Table 3.3.1, September 2022). This gives a raw elasticity of 0.14.

[120] See IEA (2005) and IEA (2011).

[121] See IEA (2005, p.97).

[122] See Kimura, O. and Nishio, K-I. (2016).

[123] See Pollitt et al. (2022).

to price electricity and gas properly this winter to households (and small businesses), will significantly reduce the **productive capacity of European industry**.

Seventh, **regulatory barriers to additional low-carbon generation should be removed**. It is very welcome to see life extension of nuclear power plants being proposed in Belgium and Germany. Even small increases in the availability of low-carbon generation could significantly reduce the impact of gas-fired generation in setting marginal prices in the wholesale market, via **reducing demand for gas and by pushing gas out of the merit order stack.**

Eighth, **distortionary taxes on marginal electricity production should be removed**. There are examples of extra taxes on the use of gas in electricity production, e.g., the carbon price floor in the UK, which can be removed and would directly reduce the wholesale electricity price in Great Britain.[124]

Ninth, **some of the suggestions for electricity market reform are sensible** – such as the completion of the single market, the use of more locational pricing, the implementation of cross-border congestion management rules and the revision of the HMMCP Methodology – but they will not address the magnitude of the energy crisis in the time frame required. Indeed, these suggestions being implemented could be **thought of as the ongoing development of the single market, however accelerating some of them would bring forward their benefits**. Such changes would have to be looked at in the medium run in the context of the road to 2030 and 2050 climate goals.

Finally, **European electricity market solidarity is important**. All countries need to act together to reduce market prices and the Commission should pay attention to **policies which help reduce European demand, improve European supply, reduce European prices and call out policies which export bigger problems to other European countries**. The single market in electricity has been great for promoting European energy integration, reducing overall prices and improving European security of electricity supply. Trade in electricity is net beneficial to all countries, though it benefits some through increased returns to national generators and others through lower prices to electricity consumers. It is essential for the achievement of net zero based on wind and solar resources. **If we undermine the single market in electricity, we threaten European energy supply security and the achievement of net zero.** We should not shoot the messenger of the single market in electricity when the fundamental cause of this crisis is an unforeseen (certainly up to April 2021) precipitant reduction in European pipeline gas supply from Russia.

[124] For a discussion of the carbon price floor, see Hirst (2018).

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