Energy Policy 188 (2024) 114051

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

Recommendations for a future-proof electricity market design in Europe in light of the 2021-23 energy crisis

Michael G. Pollitt[a,*], Nils-Henrik M. von der Fehr[b], Bert Willems[c], Catherine Banet[b], Chloé Le Coq[d], Chi Kong Chyong[e]

[a] Centre on Regulation in Europe, Belgium, and University of Cambridge, United Kingdom
[b] Centre on Regulation in Europe, Belgium, and University of Oslo, Norway
[c] Centre on Regulation in Europe, Université Catholique de Louvain, Belgium, Tilburg University, The Netherlands, and Toulouse School of Economics, France
[d] Centre on Regulation in Europe, University Paris-Panthéon-Assas (CRED), France, and Stockholm School of Economics (SITE), Sweden
[e] Centre on Regulation in Europe, Belgium, and Columbia University, United States

ARTICLE INFO

JEL classification:
Q48
K32
L50
L94

Keywords:
Electricity market design
Energy crisis
Retail electricity
Wholesale electricity

ABSTRACT

In this paper, we discuss electricity market design in Europe in light of the 2021-23 energy crisis, drawing on several of our Centre on Regulation in Europe (CERRE) reports. We outline the relevant theoretical background with respect to wholesale electricity markets, retail electricity markets, excess profits regulation, renewables support schemes and emergency interventions. We next outline the responses of the European Union, France, Norway, the Netherlands and Great Britain to the crisis. This allows us to make a number of recommendations about the future design of the electricity market in the light of theory and recent experience. These include a role for long-term contracts, the extension of the single market, the place for increased price granularity, appropriate energy taxation and the necessity of better monitoring of National Energy and Climate Plans to ensure adequate aggregate investment.

1. Introduction

Wholesale gas and electricity prices sharply increased due to the European economy's faster-than-expected recovery from COVID-19 and the Russian invasion of Ukraine in February 2022. Notably, the wholesale gas prices (at the Dutch TTF hub) rose from 21.6 euros per MWh in January 2021 to 239.9 euros per MWh in August 2022.[1] Similarly, the wholesale electricity prices (at the German spot price) surged from 43.8 Euros per MWh on 1 May 2021 to 699.4 Euros per MWh on 26 August 2022.[2] These wholesale price increases have significantly impacted retail prices between the first half of 2021 and the second half of 2022, with household gas prices rising by 78% and household electricity prices by 29% (Eurostat).[3] Non-household consumers also faced substantial price hikes, experiencing a striking 253% increase in gas prices and a 59% surge in electricity prices.[4]

These price increases occurred despite the implementation of substantial fiscal interventions by all EU Member States, Norway and the UK, amounting to 651 billion Euros since August 2021.[5] Most countries have reduced consumer energy taxes, implemented retail price regulations, and organised transfers to support vulnerable groups and businesses. However, due to the unique institutional contexts of each country, the impact of these measures has varied.

In this paper, we examine the major issues for electricity market design revealed by the 2021-23 energy crisis in Europe, which led to unprecedented market intervention at the national and European levels. While the market design was rapidly singled out as one of the contributors to the depth of the energy crisis, we should distinguish between issues with the current market design and the requirements for future

* Corresponding author.
E-mail addresses: m.pollitt@jbs.cam.ac.uk (M.G. Pollitt), nhfehr@econ.uio.no (N.-H.M. von der Fehr), bert.willems@uclouvain.be (B. Willems), catherine.banet@jus.uio.no (C. Banet), chloe.lecoq@hhs.se (C. Le Coq), kc3634@columbia.edu (C.K. Chyong).

1 https://tradingeconomics.com/commodity/eu-natural-gas.
2 https://tradingeconomics.com/germany/electricity-price.
3 Source: Eurostat Band D2 All taxes and levies included gas price per kWh; Eurostat Band DC All taxes and levies included electricity price.
4 Source: Eurostat Band I3 All taxes and levies included gas price per kWh; Eurostat Band IC All taxes and levies included electricity price.
5 As calculated by Sgaravatti et al. (2021) updated to 26 June 2023. Though it is worth noting that the outturn costs could be somewhat lower than budgeted.

https://doi.org/10.1016/j.enpol.2024.114051
Received 28 June 2023; Received in revised form 5 February 2024; Accepted 23 February 2024
Available online 16 March 2024

market design in a net zero energy system (as foreseen in the EU Clean Energy Package of 2019).[6]

We draw on a number of reports that we have written for the Centre on Regulation in Europe (CERRE) looking at the future electricity market design in light of the transition to net zero (Chyong and Pollitt, 2018; von der Fehr et al., 2022; Pollitt et al., 2022a,b). We update some of our earlier conclusions given the European Commission's market design proposals of 14 March 2023 (European Commission 2023; a,b,c).

Section 2 provides a brief overview of the theoretical background relevant to the operation of electricity markets, profits taxation, support mechanism for renewables, and emergency interventions. In Section 3, we explore how the EU and specific nations, including France, Norway, the Netherlands and Great Britain, responded to the crisis, with a focus on the retail market and energy profits taxation. Section 4 collects key recommendations for the future development of the European electricity market. Section 5 briefly concludes.

2. Theoretical background to energy prices

2.1. Wholesale market design

The theoretical framework for electricity market design encompasses wholesale and retail electricity markets (see an overview in FTI, 2023; Chyong and Pollitt, 2018; Chyong et al., 2019). Wholesale electricity markets deliver a market price based on a supply curve that involves stacking the generating units in order of competitive bids reflecting their marginal costs. These costs include expenses related to fuel, carbon permits, and taxes. The wholesale market price is set at the point where the supply curve intersects the demand curve and fluctuates in real time due to factors such as generation plant availability, fuel and carbon costs, and shifts in demand.

The European wholesale electricity market is a flagship EU single market project (see Pollitt, 2019) which has seen increasing market integration between formerly national electricity markets. A large multinational market allows for more competition, more stable prices, sharing of reserves and better management of national shocks. It is increasingly beneficial as the electricity system transitions to low-carbon generation based on northern Europe's wind and southern Europe's solar resources. Future extensions of the single market to include the UK (again!), Morocco, Switzerland, Ukraine, etc., can only be mutually beneficial.

In the EU, there has been impressive integration of national wholesale markets into a single market platform, which can resolve day-ahead, multi-zonal wholesale prices to reflect transmission constraints between zones and supply and demand within zones. Higher gas prices translate directly into higher electricity prices because gas-fired power plants are often the most expensive to meet demand. Gas, coal and carbon prices tend to move together in times of gas shortage because higher gas prices cause gas-to-coal fuel switching among power generators, which drives up carbon prices due to the higher carbon content of coal vs gas. Thus, gas, coal and carbon prices rose during the European energy crisis, jointly contributing to higher power prices.[7]

The theory of well-functioning markets involves paying the same price for identical units of consumption. Thus, in the short-term wholesale power market, renewable and fossil power should be paid the same so as not to distort incentives to supply in real-time. The point is that all power participates in the short-term wholesale market. Keay and Robinson (2017) suggested a two short-run market approach, where renewable and fossil fuel electricity prices would be cleared in two separate markets. The demand curve in the renewable market would be adjusted to the available renewable supply, ensuring a wholesale electricity price unaffected by fossil fuel prices. Residual market demand would determine the electricity price in the fossil fuel generation market. This price would be affected by fossil fuel prices, as per existing wholesale markets. However, this approach ignores that short-run dispatch of power plants should be based on their short-run cost. A single price signal provides the best incentives to generators to make accurate forecasts, provide flexibility and be available in the right locations; and for consumers to adjust their demand, and provide flexibility.

The EU power market has around 60 price zones reflecting national or sub-national transmission constraints. Transmission constraints increase as renewables are added to the European power system. This has raised the issue of whether more zones or, indeed, a nodal pricing system (based on US-style locational marginal pricing – LMPs) should be introduced (see Bohn et al., 1984; Pollitt, 2023). This would better manage real-time flows on the transmission system at the cost of differentiating wholesale prices across potentially 1000s of nodes on the transmission system. The advantage is that this would reflect short-term congestion costs and provide better signals to the location of supply and demand. The disadvantage is that it would create a lot of price volatility and would not necessarily promote building the necessary extra transmission capacity.[8] It would also take years to implement given the need to switch from self-to central-dispatch of power plants and to introduce a compensation mechanism for the initial (significant) redistribution of revenues (among generators and between generators and consumers) that a move to nodal pricing would cause.[9]

One ongoing issue with any wide area single market is free-riding on the capacity provision of others, especially where the wide area market underprices this capacity provision by not pricing-in all externalities. Building a new generation and network is politically costly due to the need to overcome local opposition based on the national interest and (and because of) the direct national costs (e.g. socializing network expansion costs). This means that it is possible that some countries will not contribute their fair share of effort to decarbonise the European electricity system. This suggests a need for monitoring and coordination of whether the national actions of individual countries will collectively deliver on ambitious climate targets (which all European single-market countries have signed up to).

Before the crisis, several wholesale market design issues were actively debated (see Chyong and Pollitt, 2018). The key was whether competitive wholesale markets would be undermined by the continuing roll-out of 'zero' marginal cost variable renewable electricity generation (VRE) such as wind and solar.[10] Driving down market prices seemed to reduce short-run wholesale markets' role in determining longer-run contract prices, financing new investments and determining when generation plants closed. Instead, governments were using renewable support schemes and capacity markets – which pay for the availability of capacity, not energy - to support new and existing investments to join and stay on the system.[11]

Chyong and Pollitt, 2018 document three critical issues for future market design in the light of more VRE. First, long-term contracting plays a role in supporting the role of renewables and other low-carbon generators. This emphasises the importance of longer-term contract

[6] For more details, see: https://energy.ec.europa.eu/topics/energy-strategy/clean-energy-all-europeans-package_en.

[7] See IEA (2022, chapter 2) for a discussion of the impact of the energy crisis on energy and carbon markets.

[8] Note that in zonal markets, price volatility exists in the balancing markets. With a zonal market design, system operators can have strong incentive to build network capacity to reduce counter-trading costs for congestion inside zones.

[9] See FTI Consulting (2023) for a recent analysis of its potential impact in Great Britain.

[10] In the spirit of Rifkin (2015).

[11] See also Finon and Roques (2013) who suggest a more radical change the market design with harmonised European-wide capacity mechanism, a reform of the renewable electricity supply (RES) policy support mechanism and a larger role for the government.

markets against short-run markets and the potential for a disconnect between short-run prices, long-term prices and investment. Second, is the role of wholesale non-energy markets in supporting a VRE-dominated system. Such ancillary markets in electricity provide frequency response, reactive power, reserves and constraint management.[12] VRE increases the need for all four of these services. A particular emphasis has been on capacity markets, which form part of the longer-term reserves market. These involve paying flexible generators to be available to support the system during individual hours when VRE might not be able to meet demand.[13] Third, the role of carbon pricing (and high fossil fuel prices) in providing high enough average prices to support wholesale prices to a level where the first two issues are less critical. Modelling can help show that as long as gas plus carbon prices are high enough, wholesale prices might allow investment in VRE to occur without price support from government-backed long-term contracts. This last point suggests that wholesale markets might require the least adaption when gas plus carbon prices are high, as seen in the European energy crisis.

2.2. Retail market design

Retail electricity markets were a work in progress before the energy crisis. Retailers are often selling power at a fixed price for a fixed period and can be considered as selling a bundle of products: electrical energy and a financial hedge limiting the impact of real-time power prices on consumers (though not in Norway; see below). They also have to add on network charges, system operation costs, taxes, other charges (e.g. for government renewables' policies) and their margin (see Chyong and Pollitt, 2018). While some large industrial customers are on retail contracts that expose them to fluctuations in wholesale prices, most customers are not exposed directly to wholesale prices. Many industrial and commercial customers might be on one-to three-year contracts that fix prices for that period. Those prices reflect expectations of wholesale prices, and retailers buy longer-term contracts from generators to limit their direct exposure to real-time wholesale prices (often facilitated by ownership integration between generators and retailers). The financial hedging function of retailers puts them in the category of selling a financial product with a potentially substantial failure risk in the face of a significant rise in wholesale prices.[14] Hence, there is a need for appropriate regulation regarding the financial position of suppliers, which could include stress-testing and setting minimum forward hedging requirements. Individual households do not have the incentives and information to monitor the financial stability of their retailer, which can lead to too much risk taking by retailers. In many countries the cost of such retailer bankruptcies are (partially) socialized, for instance by reallocating consumers to new suppliers and therefore leading to overall higher energy prices. Otherwise, retail customers are fully exposed to the risk that their supplier might fail. All consumers are then liable to pay the costs of any insurance scheme which charges the generality of customers to cover the costs of failed retailers.

Prior to 2021, around half of EU countries still had regulated residential prices, which offered a capped price to these customers based on a benchmark formula of expected retailer costs (Pollitt, 2019). Households that chose competitive contracts typically signed contracts that fixed their prices for a year. EU bodies frequently lamented the failure to eliminate regulated retail tariffs across Europe.[15] In that sense, progress with an effective retail market design across Europe was less impressive than in wholesale markets. This was in spite of the creation of very significant pan-European energy companies doing generation and retail. During the crisis, as discussed below, governments intervened directly in retail markets to prescribe the maximum prices that retailers could charge. This had the impact of substantially reducing incentives to switch retail suppliers and reducing the number of retail offers.[16]

Before the crisis, a key issue in retail markets was how to encourage a more active demand side whereby smaller consumers would be encouraged to invest in their generation, storage ('prosumagers') and active demand response in the face of the increasing importance of intermittent renewables. More VRE on the system gives rise to incentives to match demand to supply rather than vice versa. As Pollitt (2021) discusses, there are two limiting approaches to doing this: one is greater use of granular pricing in retail tariffs, which signals system costs directly to customers, and the other is more use of control algorithms and pro-response default settings, which adjust the quantity of consumption in line with pre-agreed consumer tolerances. Either approach involves incentivising smaller consumers to respond actively or passively to underlying real-time system costs. So few smaller customers have historically signed up for dynamic tariffs because the absolute benefit of doing so was so small.[17]

2.3. Excess profits in the electricity system

Wholesale and retail electricity markets were heavily regulated because of worries about companies' ability to gain excess profits. In wholesale markets, the issue is that demand is very inelastic in the short run. When supply is tight (e.g. due to high demand or low VRE), pivotal generators can substantially raise prices by reducing their available supply. This was a key feature of the California electricity crisis of 2001-2 (Sweeney, 2002). This is why governments impose price caps in wholesale markets and also have incentives to introduce capacity markets to increase available generation during periods when prices might otherwise be vulnerable to anti-competitive behaviour by pivotal generators. In retail markets, the issue has been that smaller consumers are often reluctant to change suppliers and can end up being on a much less competitively priced tariff than customers who actively switch to the cheapest supplier. In such circumstances, retail markets can be characterised by profitable incumbents with inactive customers and a fringe of poorly capitalised entrants who essentially engage in hit-and-run entry, often exploiting short-run falls in wholesale prices to gain customers quickly. These entrants subsequently raise their tariffs or default if wholesale prices rise (the GB example illustrates this below).

While these excess profitability issues do exist in electricity markets, there is a general backdrop of the additional subsidised renewables gradually reducing the profitability of fossil fuel generators and active switching and price regulation limiting retailers' profitability (see Pollitt, 2019).

Assuming that the crisis created opportunities for excess profits, the issue is how to (re-)capture them to benefit consumers/citizens. Economic theory says the best way to do this is by directly taxing excess profits.[18] Capping generator bids or revenue is an indirect way of doing this, which may reduce their incentives to supply, raising prices for consumers and giving profits to other generators and retailers. Excess profits taxes can be recycled back to consumers directly or indirectly (by subsequently paying for the fiscal cost of bill support).

[12] See Pollitt and Anaya (2021) for a discussion.

[13] Capacity markets often have higher activation prices than shorter term reserve markets, to leave room for private contracting in this longer time frame. Capacity markets also play a role in reducing market power, as discussed in 2.3, and Fabra (2018).

[14] See Ofgem (2023) for a discussion of the issues around financial resilience of energy retailers.

[15] See for example ACER/CEER (2020, p.10-11).

[16] https://www.cer.eu/sites/default/files/EC_ZM_retailenergy_19.4.23.pdf.

[17] The challenging nature of dynamic tariff business models is discussed in Richter and Pollitt (2018).

[18] For a good introduction to both the theory and the experience of excess profits taxes, see Hebous et al. (2022).

2.4. Renewable support schemes and locational rents

Renewable support and carbon pricing mechanisms raise excess profitability issues. If sold in the wholesale market, low carbon generation benefits from increases in carbon and fossil fuel prices if these drive up the wholesale price. In extreme cases, this can be considered excess profit if these investments were supported for an initial period by higher customer prices (e.g. early wind projects) or taxpayer funding (e.g. nuclear power plants), in the expectation of no subsequent excess profits.

Renewable support design has traditionally been about offering higher support prices to renewables than the market price. This has led to fixed prices (feed-in tariffs) or contracts for differences (CfDs) (see Mozelle et al., 2010). CfDs set a strike price, which can offer a one or two-way hedge against fluctuating wholesale power prices. A one-way hedge pays the generator if the wholesale price is below the strike price and lets them keep any price above the strike price. A two-way hedge pays the government counterparty the difference between the higher wholesale price and the strike price. The government counterparty may then pay/charge the consumer or the taxpayer the net payment/receipt.

The preferred support mechanism for renewables in Europe is now a procurement auction,[19] which locks in a price for a fixed period. It is important to note that this has several theoretical little-discussed features (see Zhang and Pollitt, 2023). First, if contracts are location-specific they transfer any positional rent to the CfD counterparty. This means the government is taxing the positional rent in the CfD auction and distributing it to those who benefit from the CfD counterparty. Second, for offshore wind projects, upfront charges for using the seabed get priced into CfDs and are recovered from customers who pay for electricity. Third, when the CfD term is up (or if the CfD is one-way), the positional rent transfers to the generator. Given technological and policy uncertainty, and the high discount rate investors might use, the initial auction bids are unlikely to fully reflect future long-term windfall profits. The taxation of renewable generators and the nature of CfD design involve important distributional issues as VRE becomes more important.[20]

Retail tariff models can help stabilise bills by allocating the benefits (and costs) of CfD contracts among consumers or specific consumer groups. Currently, government CfD contracted generation tends to be allocated proportionally to all consumers. However, in the future, it could be allocated to smaller consumers who cannot contract directly with renewable generators.

The crisis has raised important issues as to whether low-carbon generation, which is beyond its initial subsidised fixed price period, should be allowed to earn fossil fuel price-related rents; whether CfDs should be designed to be two-way; whether the CfD counterparty should always pay any surplus to the consumer; and whether seabed charges (i.e. payments by offshore wind developers for the right to use the seabed) should be fixed or vary with electricity prices.

2.5. Emergency intervention principles

According to optimal taxation theory, consumer support in the face of a price shock is best administered through the regular tax and welfare system rather than in line with energy consumption.[21] This would imply that governments should prioritise the development of integrated welfare and energy data systems that deliver effective and timely financial support to consumers. This approach avoids blanket subsidies and allows quick and targeted payments.

However, other considerations suggest price interventions are likely when bills rise significantly. Behavioural economics and evidence suggest the importance of reducing price-related stress, especially for the vulnerable.[22] Political reality says governments cannot just worry about the poorest consumers already on benefits. In addition, administrative simplicity, suggests that support is most quickly and easily given through the electricity bill, either in terms of additional credit or a unit price reduction.

However, there are some important principles in intervening directly in energy bills.

First, support should be exceptional and temporary. Rich countries have spent years telling poor countries about the importance of cost-reflective energy prices and the need to stop subsidising fossil fuel consumption to revert to prolonged periods of subsidising energy use.[23]

Second, at least for EU member states, price interventions need to be harmonised when they affect energy-related trade. It is distortionary of trade in energy-intensive goods if countries subsidise energy consumption to a substantially differential extent. The overall effect of major interventions can increase European wholesale electricity market demand and distort intra-European trade.

Third, the same welfare effect can be achieved with less cost and more demand response if energy prices remain cost-reflective at the margin.[24] A good way to do this is to give a fixed block of subsidy of a certain number of units of electricity rather than subsidising all units. This can either take the form of a fixed per unit amount of subsidy for a given number of units or a price cap on the first block of consumption. This number of subsidised units could be fixed per consumer or could be a percentage of their previous consumption.

3. What did governments do in response to the electricity crisis? Observations on national and European Union responses

This section looks at how the European Union (EU) and four national governments responded to the energy crisis, particularly concerning electricity. The four national governments illustrate a range of responses, from blanket price intervention to more targeted interventions.

3.1. European Union

The EU adopted emergency measures in response to the crisis in an EU Council Regulation on 6 October 2022 (Council of European Union, 2022a). These included 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 had to identify peak hours representing at least 10% of all hours over this period) and 'a cap on market revenues from infra-marginal generation technologies' (p.5). The cap included renewables, nuclear and lignite. The proposed cap was 180 Euros/MWh but could be adjusted depending on the generation technology. This cap was to be applied to 'realised revenue'. There was also 'a temporary solidarity contribution' based on taxable surplus profits made in the fiscal year 2022 and/or 2023. This was to be made on crude petroleum, natural gas, coal, and refinery companies. This would contribute to a fund at the EU level. Only profits more than 20% higher than the level of the four years from 2018 were subject to additional taxation. The minimum tax rate was 33% on these additional profits, though higher tax rates could be

[19] Following DIRECTIVE (EU) 2018/2001 OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL of 11 December 2018 on the promotion of the use of energy from renewable sources.

[20] Extracting the resource rents of oil profits is typically also not organized by a one-off auction for a drilling permit, but consists revenue sharing and taxation arrangements for the lifetime of the field. See Rowland (1980).

[21] For a nice summary see: https://www.imf.org/en/Blogs/Articles/2011/05/10/food-and-fuel-subsidies.

[22] For a review of the literature, see Van Ooij et al. (2023).

[23] https://www.iea.org/topics/energy-subsidies#.

[24] See Pollitt et al. (2022c) for a comment on the UK's poorly targeted intervention.

applied. The tax rate would be applied to 2022 or 2023 profits. Revenues from the cap and solidarity contributions had to be recycled to household and industrial customers.

In March 2023, the European Commission published its Electricity Market Design Proposals 14/03/23, proposing changes to the Electricity Directive, Electricity Regulation and the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT) (see European Commission, 2023a,b,c). The suggested changes included giving consumers access to multiple contracts, including a fixed price contract, and access to a rising block tariff. There was also to be better protection from supplier failure and the extension of regulated retail prices in times of emergency. Member states needed to encourage a power purchase agreement (PPA) market, and all public support for new non-fossil fuel generation should be subject to a two-way CfD. The Commission also proposed more use of capacity markets and the development of national flexibility markets for demand response and storage. There were to be enhanced market transparency rules under REMIT. The detailed implementation of much of the above is delegated to member states.

Future emergency intervention on retail prices is subject to three conditions. [1] 'Very high prices in wholesale electricity markets at least two and a half times the average price during the previous five years occur which are expected to continue for at least six months. [2]. Sharp increases in electricity retail prices of at least 70% occur, which are expected to continue for at least six months. [3]. The wider economy is negatively affected by increased electricity prices' (European Commission, 2023c, p.89). The nature of the emergency regulated tariff interventions should introduce rising block tariffs with a two-tier approach and restrict regulated prices to 80% of the median consumption for households and to 70% of historical consumption for small and medium-sized enterprises (SMEs).

3.2. France

The French government was among the first EU member states to introduce cap-regulated gas and electricity tariffs, as early as October 2021. These caps limited the increase to a maximum of +4%.[25]

Furthermore, the French government implemented measures directly targeted at the retail electricity market. First, the electricity consumption tax was removed, reducing it from 22.50 euros to 50 cents per MWh. Secondly, the government extended the obligation of the incumbent electricity provider, EDF, to supply alternative suppliers at a fixed price. The volume of this obligation was increased by 20%. In addition, low-income households were granted exceptional energy cheques ranging from €100 to €200.

The impact of the crisis on the French retail market was relatively limited, primarily for consumers and small businesses. This was mainly due to the implementation of an extensive tariff shield policy. However, it was not until early 2022 that the private sector and local authorities (often locked in with a variable pricing contract) began to benefit from a subsidy scheme to compensate for their much higher energy bills. This scheme covered approximately 25%–35% of the total bill increase (Rüdinger, 2023).

In November 2023, the government announced the continued implementation of its energy support policy, involving the maintenance of the existing price cap for certain consumers or an increase in bill coverage from 50% to 75%, as compared to the measures applied in 2023, specifically for small businesses and medium-sized enterprises.

A brief cost-benefit analysis reveals the various trade-offs associated with governmental intervention. This intervention yielded evident benefits, including a direct and immediate impact on the purchasing power of French consumers, a low general inflation rate (initially), and minimal bankruptcies among alternative electricity suppliers competing with the incumbent EDF. However, it is essential to acknowledge that these measures also incurred direct and indirect costs.

The estimated cost of the French government's intervention amounted to €100 billion from the end of 2021 to 2023, compared to the €150 billion public expenditure allocated during the COVID-19 crisis (La Tribune, 2022). Additionally, introducing a cap delayed the demand response to scarcity-related prices. This measure is often viewed as inequitable due to the absence of a threshold based on energy consumption levels. In addition, the attractive regulated electricity tariff decreased competition within the retail electricity market. Reports indicate that alternative electricity suppliers consistently lost household consumers to the incumbent EDF's advantage throughout 2022 (CRE, 2023). The French government announced it would completely renationalise EDF in July 2022 (which has now happened). Ultimately, government intervention has not improved the company's financial credibility. There are significant concerns surrounding the feasibility of its nuclear investment strategy.

By contrast, the effects of the French government intervention appear to have had a lesser impact on the gas market despite having a similar market structure characterised by one incumbent company, Engie, and a few alternative suppliers. This disparity can be attributed to several factors, such as over half of the households having fixed-price contracts and Engie not being subjected to any "selling obligation" like EDF. This has resulted in fewer cases of price or competition distortion compared to the retail electricity market.

3.3. Norway

The Norwegian retail electricity market has been resilient because it continued to operate as usual, and suppliers generally did not experience serious financial difficulties. The main reason for this is that over 95 per cent of consumers (households and industry) are on spot- or variable-price contracts – with retail prices linked to wholesale prices – and for these, suppliers bear no real price risk. Contractual terms are not regulated, and there are no price caps. Consequently, public debate and political concern concentrated on high consumer prices.

By June 2022, there were more than 100 companies active in retailing. The five largest suppliers have a combined market share of 65 per cent. Generation is almost totally hydro-based and mostly owned by local and central governments. The rise in price was, therefore, linked, by some, to an (unjustified) tax increase. The government responded by halving the electricity tax and introducing a general refund to all households of 80 per cent of wholesale energy prices in excess of 7 euro cents (support for industrial consumers has been small and essentially limited to subsidised loans for energy efficiency investments). The support scheme has had some odd results, including some consumers experiencing negative energy bills. Also, by keeping prices down, there has been limited demand response among households.

With the budget for 2023, the government adjusted the support scheme to effectively put a cap of 7 euro cents on the hourly price paid by household consumers (all consumers are on hourly meters).[26] The support scheme was also extended through 2024. Given expectations for the development of electricity prices, it now seems an open question whether it will be politically possible to revise or remove the support scheme and whether effectively capping (or subsidising) household electricity prices may become a permanent feature of the Norwegian electricity retail market.

3.4. The Netherlands

The Dutch retail electricity market has been relatively resilient

[25] Since January 2023, the increase in the price of gas and electricity is limited to 15%. The government has decided to maintain the electricity tariff shield until 2025, but the gas tariff shield ended in December 2023.

[26] See https://www.regjeringen.no/no/tema/energi/regjeringens-stromtiltak/id2900232/?expand=factbox2900261.

during the crisis, but consumers bore the brunt of high energy prices. The social cost of bankruptcies has been limited. Six suppliers went bankrupt, covering 2% of households. There were no supply interruptions, but households were reallocated to new suppliers at higher market-conforming rates. Liquidity in the retail market dried up, especially for long-term fixed-price contracts. More and more consumers transferred to variable-price contracts and full exposure to wholesale prices. This is partially due to regulations limiting the penalty for early termination of contracts, which makes it too risky for suppliers to offer fixed-price contracts.[27]

Initially, there was an income support scheme which focused on the poorest households and kept incentives intact. 10% of the poorest households received €800 from local governments, and a general tax credit was worth €265. High wholesale energy prices led to a reduction of the energy tax that is earmarked for supporting Renewable Energy Sources (€160). On top of that, VAT was reduced (by an average of €290).

In 2023, the income support scheme was replaced with a price cap for all households for their first tranche of consumption, similar to a block tariff. The government would refund retailers based on the difference between the price cap and the retail rate. The goal of the price cap was to provide a broader measure to address the cost-of-living crisis. Limiting the volume for which the price cap applies could make the measure progressive. In relative terms, poorer households would benefit more. It would also keep marginal incentives intact for households consuming more than the regulated volume. There have been some well-founded concerns that the mechanism reduced competition in the retail market, as retailers benefitted from setting high retail prices as the government compensates them based on their market rates. Consumers only have had limited incentives to shop for the lowest prices. Another problem was that the volume covered by the cap was set relatively high, so 70% of consumers were fully covered by the price cap.[28] The government introduced a gross profit margin limit to ensure that retailers did not profit too much. Haan and Schinkel (2023) give some anecdotal evidence that competition was reduced: the variance in retail prices increased, and the subsequent drop in wholesale gas prices did not lead to an equivalent reduction in retail rates. They also argue for alternative measures, price discounts instead of fixed retail price caps so switching incentives remain intact, and compensation that is not directly linked to a retailer's prices. By the end of 2023, the price cap was binding for only 7% of the households and it was abolished by January 1, 2024. The cost for taxpayers was 4.3bn euros or about 0.45% of GDP, much lower than the original budgeted 23.5bn euros.[29]

The regulator and legislator announced that they would tighten the regulation of suppliers' risk. However, it is recognised that regulation could stifle innovation by restricting business models and limiting entry if new requirements are hard to meet for small retailers. There is no consensus yet on whether a guarantee fund needs to be established to compensate consumers of bankrupt suppliers, as it could reduce consumers' incentives to monitor the quality of retailers.[30]

3.5. Great Britain

The impact of the crisis on the Great Britain (GB) energy retail market (electricity and gas) has been profound, with the exit of most pre-existing new entrant competitors in the household market (the number of household suppliers dropped from 49 in June 2021 to 22 in April 2023). This was due to a combination of a six-month lagging regulator-calculated price cap, which kept prices below cost as wholesale prices were rising, leaving no room for competition between suppliers based on being able to undercut the price cap. This raised questions as to how often the price cap should be reset, and the extent to which forward-looking prices should be incorporated in the calculation of the price cap. Financial regulation and the bankruptcy regime for suppliers have been found to be lacking. Many suppliers were poorly capitalised with inadequate hedging of fixed-price annual retail contracts with monthly wholesale contracts.

The government initially gave generous targeted direct financial support to households for energy bills of up to £1200 per household for at least 25 per cent of households, covering most of the expected (to May 22) bill rise. This maintained strong incentives for energy efficiency and investment in renewables by not distorting consumer energy-saving incentives or corporate incentives to invest in electricity and gas supply sectors.

However, faced with a steep rise on 1 October 2022 in the regulator calculated price cap, the government capped electricity and gas bills for the typical household to £2500 with the Energy Price Guarantee (EPG),[31] significantly below the regulator cap level of £3549.[32] The price would have risen again on 1 January 2023 to £4279 in the absence of the EPG, which continued to bind until 1 July 2023. The announced regulator price cap then dropped to £2074 due to falling wholesale prices. The retail market, therefore, restarted in July 2023, albeit with significantly fewer companies than pre-crisis, and monthly switching rates have increased substantially. The pre-crisis price cap (April to September 2021) was £1138. A similar Energy Bill Support (EBS) scheme was introduced for businesses simultaneously as the EPG. The overall cost of the fiscal support under the EPG and EBS is estimated at £35bn in addition to the direct income payments.[33] The EPG was raised to £3000 p.a. on 1 July 2023 and remains in effect until 31 March 2024.[34]

One interesting retail electricity innovation was trialled during the crisis. Octopus Energy (a supplier) and NG ESO (the system operator) designed a Demand Flexibility Service (DFS) product which notifies consumers a day ahead of stress periods during which reductions in their normal consumption are rewarded with per kWh payments of roughly 5 or 10 times the normal retail rate. 1 million households registered to participate, and the trial generated an average of an 18 per cent demand reduction among those participating.[35]

A significant initial failing of the UK approach was not merging energy support payments with a two-block tariff design. This would have had the desired income effect, reduced calculated inflation, and adequately reflected wholesale prices in the marginal cost of energy. As it was, marginal unit prices through the 2022-23 winter were significantly (c.25%) below calculated wholesale prices.[36]

Stephen Littlechild, one of the architects of the UK electricity reform and an advocate for competitive retail energy markets, raised the

[27] New regulation increased the penalty for early termination and from June 2023, long-term contracts are available again. See: Roos van Riel. (15 mei 2023). Energieleveranciers gaan weer vaste contracten aanbieden, dankzij nieuwe regel ACM. FD.nl.

[28] For a more in depth discussion, see Haan and Schinkel (2023). They indicate there are also pro-competitive effects if too generous government compensation gives retailers an incentive to increase market shares.

[29] Yvonne Hofs, (27 december 2023). Kosten voor prijsplafond op energie vallen vele malen lager uit dan kabinet eerder had berekend. De Volkskrant.nl.

[30] See Lavrijssen and de Vries (2022) on the role of ACM in regulating retailers' risk.

[31] For a discussion, see Pollitt et al. (2022c).

[32] For details of the energy price cap calculations, see: https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-july-2023-30-september-2023 See Model - Default Tariff Cap Level v1.18.

[33] https://obr.uk/docs/dlm_uploads/OBR-EFO-March-2023_Web_Accessible.pdf#page=62.

[34] See Bolton (2024).

[35] See Centre for Net Zero (2023).

[36] See Pollitt (2023) for a discussion.

question of whether the UK will ever return to a competitive retail market for small consumers (Littlechild, 2022). He noted that the price cap was introduced as a temporary measure but that its operation had effectively ended retail competition and led to many bankruptcies, a view endorsed by the National Audit Office (NAO, 2022).

4. Recommendations for electricity market design

In light of the theory and evidence above, we develop a number of recommendations for the future development of electricity markets in Europe. These relate to wholesale markets, retail markets, excess profits, renewables support and emergency intervention principles in Section 2 and are informed by the experiences at the EU and national levels discussed in Section 3.

4.1. Wholesale market recommendations

4.1.1. Recommendation 1: A role for long-term contracts

The energy crisis has fuelled the debate we noted above regarding the role of long-term contracting in generation markets. Specifically, the crisis has highlighted the lack of contracting between generators and retailers for more than one year, leading to a scarcity of long-term retail contracts for consumers (i.e. low long-term contract liquidity). Most customers are reluctant to contract for energy for longer than this due to uncertainty about their long-term energy demand and the price of energy, in the face of energy being a low share of their total expenditure. In addition, long-term hedging is expensive relative to self-insurance and, therefore, unattractive to most, especially given that the government closely monitors the fairness of energy prices (therefore offering a form of insurance). However, this unwillingness of consumers to contract for years ahead versus the need to finance long-term generation and network investments is oft-lamented. It leads to calls for the government to step in and contract in the long term on behalf of consumers. For instance, Gross et al. (2022) suggested switching all low-carbon generators in the UK to long-term contracts. However, this solution is not without its challenges.

Long-term contracts serve as a hedging mechanism, protecting against sudden sharp price spikes. However, entering into such contracts during the peak of the crisis is unlikely to be advantageous. Fixed-price contracts were signed amid the 2001 California power crisis, leading to significant losses for the State of California when prices eventually declined.[37] It is important to recognise that signing fixed-price contracts does not guarantee low prices over the long term. Long-term contracts should be allocated in a way consistent with competition rules. Otherwise, they may foreclose competition.

Nevertheless, there are compelling arguments in favour of signing some long-term price hedging contracts for generation in normal times, as they can provide price stability and certainty to electricity consumers. In addition, a long-term contract signed with new generators is likely to lower the cost of capital faced by investors in generation and, hence, secure lower average prices.

As a result, multi-year power purchase agreements (PPAs) can finance new investments in low-carbon generation. These PPAs can involve various types of 'customer' counterparties, including large energy users who opt for 'corporate' PPAs, retailers who purchase PPAs on behalf of their stable customer base, and governments seeking to support the financing of low-carbon generation.

These PPA contracts have been established between large industrial users and individual wind farms, government counterparties, and new low-carbon generators. Such contracts are often two-way contracts for difference (CfD), wherein the agreement specifies a strike price. This strike price results in payments to generators if the wholesale price is below the strike price and payments to the CfD counterparty (the government, customer or retailer) if the price is above the strike price.[38]

Using auctions for long-term PPAs for new generations combined with existing short-run power markets can lead to a desirable hybrid market arrangement,[39] with competition *for* the market in combination with competition *in* the market.

Legal barriers to corporate PPAs have stemmed from certain national legislation. The restrictions or constraints on the conclusion of PPAs are primarily related to: third-party ownership of on-site renewable installations; signature of direct contracts between generators and off-takers; the number of buyers per installation or the number of suppliers per metering point; the relationship to renewable support schemes; the transfer of guarantees of origin to the off-taker; and cross-border PPAs.[40] As a first step to removing these barriers, the Renewable Energy Directive (EU) 2018/2001 contained some facilitating provisions that could be further reinforced.[41] The European Commission also published a non-legally binding guidance document as part of the REpowerEU Plan in May 2022.[42] If the EU wants to support government-backed PPAs specifically and facilitate their approval under state aid rules, it should clarify the acceptable design features of these agreements in the state aid guidelines for climate, environmental protection and energy.

As part of its 2023 proposal for reforming electricity market design, the Commission has recommended using PPAs as above. It made observations on which types of PPAs have worked, but it should not recommend using a standard PPA contract to cover a fixed proportion of all national output. This is because to do so would expose the EU to a correlated risk in terms of concentrating a large amount of generation in a contract of specified length, contract terms and risk profile. However, The EU has recommended that all new publicly supported generations be contracted via a two-way CfD (EC, 2023, a,c).

Whether and to what extent EU Member States provide long-term government-backed financial PPAs should be left to their discretion under the subsidiarity principle. It should, in theory, depend on the preferences of individual Member States, but to ensure a minimum level-playing field between companies in Europe, national legislation could further facilitate PPAs. This could happen without unnecessarily harmonising the exact nature of the PPAs facilitated. The EU's proposal on CfDs does not rule out merchant contracting for low-carbon generation but does potentially rule out further contractual innovation in government contracting. Thankfully, it has not ruled on the signing of retrospective PPAs with existing generators because this is simply a way of smoothing payments at private sector discount rates (which generators will use in calculating acceptable payment schedules). This will not make fiscal sense for most European states (who could finance equivalent direct electricity bill support at lower fiscal cost) and, therefore, should be a matter of national preferences.

In addition, corporate and retailer PPAs seem to be socially desirable options. At least for companies that are long-lived and can commit to, say, 15 years of purchasing the output of their generation counterparty (e.g. Amazon, Microsoft) and also for large incumbent retailers with relatively stable customer bases. Secondary markets for PPAs and additional risk regulation for retailers will likely grow this market.

[37] See Moss (2002) for a critique.

[38] In this paper we consider the two-way CfD contract as a specific type of PPA contract, which is purely financial, and acts like a swap contract based on the output of particular technology or power plant.

[39] See Roques and Finon (2017).

[40] See CEPS and COWI (2019).

[41] Renewable Energy Directive (EU) 2018/2011, Art. 2 (definition of renewables PPAs) and Art.15.8 (Member States' obligation to assess and remove unjustified barriers to renewables PPAs, and to report on the related measures in their national integrated energy and climate plans under Regulation (EU) 2018/1999, Art. 20(b)(10)).

[42] European Commission (2022).

4.1.2. Recommendation 2: European capacity markets need to be better coordinated

The EU has now recommended the greater use of capacity markets, as we mentioned above, in part because a future weather-based energy crisis might require the use of rarely used capacity (e.g. gas, hydrogen or liquid biofuel). However, the design of capacity markets is not straightforward, and many such markets see continuous reforms. So, the debate about whether they are really necessary continues. Higher capacity payments implicitly subsidise the technologies that receive them. This affects the generation mix and the distribution of spot prices. It is important to treat intermittent generation and demand-side flexibility on an equal footing in the capacity market, as those technologies find it harder to provide standardised reliability. Capacity contracts are therefore often adjusted, for instance, with a de-rating factor applied to the nameplate capacity of a generation facility.

A particular issue for European capacity markets is that they can distort cross-border trade in electricity. [43] This is because of the relative attractiveness for given capacity to sell into different capacity markets across interconnectors. Higher market prices, arising from a higher value of lost load (VOLL), will attract capacity. Countries might also free-ride on capacity remuneration schemes made in neighbouring countries or try to restrict energy export from contracted capacity in case of an emergency. The treatment of interconnectors in capacity mechanisms raises issues of the extent to which two connected systems can contract with the same capacity (given that co-incident peaks might be unlikely and capacity events usually have national origins).[44] Bucksteeg et al. (2019) discuss the significant benefits of coordinated capacity market design across Europe. This would seem to leave a role for the European energy regulator (ACER) and for the European Commission to regulate the role of interconnectors in capacity mechanisms.

4.1.3. Recommendation 3: The extension of the single market in electricity (and gas)

A clear lesson from the crisis is that the single European energy market has been a great success in allowing Europe to cope with an externally sustained shock to its energy supply. Germany, in hindsight, pursued a risky policy of reliance on Russian gas. Germany did not sufficiently hedge this risk with adequate LNG import facilities, sufficient gas storage or large amounts of flexible demand. Instead, Germany relied on the single market to help mitigate the energy supply crunch it would otherwise have faced. In line with our earlier observations, this indicates both the value of extending the single market and the need to monitor the extent to which countries that are part of it are free-riding on the security it provides.

The depth and degree of integration of European internal gas and electricity markets helped mitigate the energy shock that Europe has faced. The EU-27 should move to complete and extend the single markets in gas and electricity, for example, by speeding up the provision and use of two-way transfer capacity in gas and electricity.

The bigger the 'European' market, the better. This refers to the external dimension of the EU internal energy market, as EU legislation in this domain is implemented by neighbouring countries to the EU through a series of agreements. For example, Norway (through the European Economic Area Agreement), the UK and Energy Community countries are implementing internal market legislation, contributing to its extension. Thus, removing remaining trade barriers in electricity with these countries is beneficial. The extent to which market design solutions enable cross-border cooperation between EU countries and neighbouring countries should be considered from the start of any market design reform. The EU and third countries, such as the UK and Switzerland, have so far failed to fully integrate their markets, creating the need for legal structures of ultimate dispute resolution that are mutually acceptable. This can be changed. For instance, the renegotiation of the Trade and Co-operation Agreement between the EU and the UK in 2026 provides an upcoming opportunity to extend the single market in electricity to the UK.[45] In practical terms, this would, for instance, include extending the EU's EUPHEMIA market coupling algorithm to include additional countries.

The success of the single market during the crisis suggests that national market design solutions should be compatible overall. While there has been a lot of progress in integrating the day-ahead markets in electrical energy across Europe, there is still more work to be done to integrate capacity and ancillary services markets, as noted above.

When considering emergency measures under Article 122 of the Treaty on the Functioning of the European Union (TFEU),[46] the Commission and Member States should refrain from adopting those that could directly impact the energy markets. A good example of an intervention that should have been prevented in the interests of the single market was the Iberian cap on the gas price for electricity generation.[47] This intervention was an attempt to manipulate short-run power market price formation. It ended up raising gas demand for electricity and distorting power flows between France and Spain during a time of gas scarcity. Its compatibility with state aid market rules is questionable, although the European Commission approved it.

4.1.4. Recommendation 4: A move to a US standard market design with locational marginal prices (LMPs)? Not yet

As we introduced earlier, the single electricity market in Europe is characterised by self-dispatch and zonal pricing. A move towards a US-style standard market design with locational marginal pricing (LMPs) is being debated in the UK as part of a Review of Electricity Market Arrangements (BEIS, 2022).[48]

LMPs or nodal pricing is a proven method of providing short-run pricing signals to the marginal value of injections and withdrawals from the electricity network reflecting line congestion and marginal losses. The overall efficiency benefits of nodal pricing are small (possibly 2% of generator operating costs).[49] Still, it may be valuable in signalling scarcity of transmission capacity in a system characterised by increasingly active distributed energy resources (DERs). This might provide better locational signals for generators, which could reduce transmission investment needs. As prices are aligned with physical constraints, they reduce counter-trading costs for the system operator. Nodal prices are volatile; hence, system operators sell (or allocate) financial transmission rights (FTRs) as hedging instruments, giving the holder the right to receive the volatile congestion revenue, which they might otherwise be exposed to paying.

However, the distributional implications are potentially large for consumers and generators, and the impact on long-run transmission investment is small. The investment impact of exposure to nodal pricing is negative for the energy transition. This is because any large regulatory redistribution of financial value creates uncertainty and defers investment until this is resolved. The academic literature analysing the economic impact of nodal prices in the US is surprisingly thin, with little written about the investment impact. However, the literature suggests that FTR markets are inefficient and result in significant consumer losses[50], which may significantly offset the congestion reduction benefits. This suggests the model is not likely to deliver much benefit in the short run, requires careful design and demands more empirical investigation

[43] See Pollitt (2019).
[44] i.e. what derating factor is assigned to an interconnector.

[45] See Pollitt (2022).
[46] The foundational treaty of the EU. Article 122 allows for proposed exceptions to current rules if 'in particular if severe difficulties arise in the supply of certain products, notably in the area of energy.'
[47] See Patel (2022), Robinson et al. (2023).
[48] See BEIS (2022).
[49] See Wolak (2011).
[50] See Opgrand et al. (2022).

in a European context.

In favour of nodal pricing, the Commission has noted (EC, 2023c, p.107-8) that 'while the current zonal design may provide financial incentives to create congestions in real-time if not well-configured', 'a zonal design hampers the efficient integration of offshore bidding zones and large scale flexible assets and demand response'; 'granular locational signals would help taking appropriate investment decisions (including for hydrogen production)'; and 'a nodal design would strongly simplify the European design, as there would be no need for (i) a bidding zone review; (ii) a capacity calculation methodology; (iii) analysing if this capacity calculation methodology is non-discriminatory; and (iv) a redispatching and cost-sharing methodology' (EC, 2023c, p.107). Against nodal pricing, the Commission noted that it 'risks: potential lack of liquidity in smaller bidding zones, risk of market dominance, and risk of high local prices'; 'locational signals are needed in more short-term markets, e.g. for flexibility for system needs'; 'distributional challenges to societies as prices might differ considerably within countries which could go against political objectives of a country'; and 'transparency on the price formation process risks being significantly reduced (due to complex algorithm)' (EC, 2023c, p.107-8).

The European Commission has decided not to pursue LMPs in its proposals for reforming electricity market design. This view was based on the observation that alternative paths to improved price signals exist, that there would be a long technical implementation time, and that more analysis would be required. This seems a sensible conclusion for now.

4.1.5. Recommendation 5: No to two markets solutions

The energy crisis led to a proposal from the Greek delegation to the European Council[51] for a two-market solution in the day ahead wholesale power market (in line with Keay and Robinson, 2017, above [52]). This involved allowing one clearing price for as available power (including VRE) and one for on-demand power (from fossil fuels). The idea is that this would allow renewable-based power to receive a price decoupled from volatile fossil fuel prices.

This idea is fundamentally flawed, as we discussed above. A lower price for low carbon power will lead to distortionary investment in storage, behind-the-meter use and under-investment in overcoming constraints, running equipment hot, minimising outage time, advancing projects, etc. There is also a problem of how to categorise generators and price arbitrage. Keay and Robinson (2017) suggest that biomass and storage could choose whether they were "on-demand" or "as-available" generators. This would allow them to arbitrage the two prices. Biomass generators face fuel prices for feedstock, which are related to the price of fossil fuels, and are on-demand generators anyway. This reveals an issue with the idea of a separate marginal cost of renewable generators: what is classified as "renewable" determines the marginal price in that market, and hence, it is a manufactured price and subject to political interference.

A policy in this spirit that was implemented during the crisis was the capping of revenue to low-carbon generators (including nuclear and renewables) at 180 Euros per MWh.[53] The motivation was to reduce the windfall profits of low-carbon generators. This attempt to create a lower short-run price for low-carbon generators was mostly non-binding. This differs from signing long-term PPAs at fixed prices, which does not interfere with existing power plants' short-run production incentives. If such two market solutions intend to reduce windfall profits, then better solutions exist, as discussed below.

[51] Council of the European Union (2022b).
[52] Grubb and Drummond (2018) proposed a similar 'green power pool' model in 2018.
[53] https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32022R1854

4.1.6. Recommendation 6: The need for EU monitoring of national planning to ensure adequate aggregate investment

As we introduced above, single markets increase the potential for free-riding on the costly infrastructure investments of others, the costs of which are not fully reflected in prices. The crisis has highlighted that the energy transition is about accelerating the right investment. Past national underinvestment in LNG capacity, gas and electricity storage and interconnection was revealed by the crisis, not to mention the Europe-wide cost of unilateral decisions to close early operational nuclear power plants without planning for adequate replacements. The crisis has also highlighted the need for earlier and greater levels of investment in energy efficiency measures and renewables.

In general, the energy crisis has revealed the lack of coordination in the energy transition among Member States despite being part of the same internal energy market. Here, there is a balance to strike between the Member States' sovereignty over their energy mix and the need for minimum levels of coordination of investments in generation and infrastructure development.

The permitting of renewable electricity supply (RES) and associated network capacity should be prioritised and accompanied by coordination of grid development and consumption scenarios. There is a need for greater regulatory certainty around developing cross-border, hybrid projects involving more than one country. There is still no framework in place as to how these will be treated, and an unreasonable ability of one member state to obstruct mutually beneficial investments.[54]

The EU should better use existing National Energy and Climate Plans[55] to help achieve more coordination between Member States in meeting Europe's energy and climate goals. This should build on the existing requirements under the Governance system of the Energy Union and Climate Action[56] and network development plans (at both the distribution and transmission levels and across gas and electricity). These Plans could be more closely audited as to whether they are being followed and whether they collectively add up to a sensible European energy policy with reasonable burden sharing in the provision of reserve capacity, flexibility and interconnection capacity.

4.2. Retail market recommendations

4.2.1. Recommendation 7: The need for better regulation of retailers to facilitate retail competition

There is a need for more stringent regulations regarding the financial position of suppliers, which should include stress-testing and setting minimum forward hedging requirements. As we discussed, Great Britain and the Netherlands had significant retailer bankruptcies due to the crisis. Consumers need to bear some responsibility for their choice of supplier – otherwise, the door would be wide open to offers that are "too good to be true". However, it is equally important for consumers to enter into a new contract on reasonable terms when warranted. Since financial regulation and customer protection come at a cost, finding the right balance should be a priority for national energy regulators. Good commercial practices corresponding to national circumstances should continue to be the preferred approach, while the suppliers' hedging requirements should be reinforced via harmonised EU legislation.

In the Netherlands, a too-strict cap on the penalties that consumers pay for early contract termination seems to have undermined the market for long-term contracts. With the reworked regulation where the penalty is more market-friendly, the market for long-term contracts has become

[54] Crampes and von der Fehr (2023).
[55] https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en.
[56] See 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.

active again. Contractual terms must, therefore, better balance consumer protection and suppliers' incentives.

4.2.2. Recommendation 8: It is a sensible strategy to have some two-way CfD contracts assigned to consumers

The crisis has revealed the potential future importance of locking in some price insurance for the customer base in advance. This will help dampen future weather or geo-politically induced price rises in electricity prices and reduce the need for government intervention. This can be done by ensuring that support schemes for renewable energy should take the form of two-way contracts, in order to share the diversification benefits with consumers.

As noted in Section 2, retail tariff models can help stabilise bills by allocating the benefits (and costs) of fixed-price long-term contracts among consumers or specific consumer groups. In the case of Great Britain consumers existing CfDs would have resulted in approximately a 2% reduction of the energy bill without the government price cap.[57]

4.2.3. Recommendation 9: The importance of demand-side response and flexibility

A key lesson from the crisis – in line with the path to net zero - is the necessity for electricity demand to become more responsive to supply-side shocks, particularly those arising from fluctuations in the availability of intermittent renewables or hydro-electricity due to weather conditions. In the present case, what was primarily a gas supply disruption was worsened by low water levels in hydro-dams, low wind output, and the unavailability of some French nuclear plants.[58] This highlights the importance of optimising the utilisation of existing power sources and incentivising the development of storage capacity.

There has been some great experimentation to induce a sharper demand response due to the crisis. In Great Britain, the system operator worked with suppliers to create the new Demand Flexibility Service (DFS) mentioned above. However, this illustrates that such products are not default products, are not automated and currently require exceptionally high prices to be worthwhile. This is despite much legislative effort being put into reducing the regulatory barriers to an active demand side (e.g. via support for active consumers, demand aggregators and energy communities within the Clean Energy Package of 2019).

These increased benefits from an active demand side contrasted with the general marginal price suppression of household and non-household prices, which many governments engaged in. This price suppression increased aggregate demand for electricity (and gas), raised wholesale prices and increased the profits of incumbent generators and gas producers. Perkins and Rainaut (2023) estimated that for the UK alone, the cost of the price suppression was to raise total fiscal costs to the government by 20 per cent.[59]

Redesigning the market to get demand down at times of tighter supply greatly affects the price. Steep supply curves are an opportunity where a small reduction in demand disproportionately affects price: a 1 per cent reduction in demand might result in a 10 per cent fall in the wholesale price. More demand flexibility, which reduces high-price periods, might result in a significant fall in average prices.[60] The potential for demand-side response (DSR) is high in the future. While EU-27 peak demand for electricity is estimated to be 752 GW[61] in 2030, potential demand side response is estimated to be 163.8 GW up (22% of peak) and 130.2 GW down (17% of peak), giving a total potential swing of 294 GW (39% of peak).[62] This potential for flexibility includes industrial DSR, battery energy storage, smart charging, vehicle-to-grid, heat pumps, industrial heating, and industrial and district combined heat and power (CHP).

As the DFS product illustrates, there is a need to design markets that unlock this potential for demand-side response flexibility, which is currently untapped, by adjusting ancillary and capacity market rules on demand-side participation. A good example of an area where this is possible is in capacity markets, where currently demand only constitutes 3.3 per cent of available capacity in existing EU capacity mechanisms in 2022; in the US PJM market it is projected to be 4.8 per cent in 2024/25.[63]

4.3. Excess profits and renewable support policy recommendations

4.3.1. Recommendation 10: Energy profits taxes are better than price regulation

Sensible measures to recoup excess generator profits – where these exist – are essential to address concerns about economic justice. In wartime, the requirement for a fair system of taxation is essential, as was recognised by John Maynard Keynes (1940) and John Hicks et al. (1941) during World War Two.

As discussed above, this is best done through non-discriminatory profits taxes, which target 'excessive' aggregate profits and do not blunt incentives to efficient real-time dispatch of power plants. Profits taxes should be targeted on inframarginal rents wherever possible. High profit tax rates are preferable to arbitrary price caps on certain types of generators because they do not blunt marginal incentives to respond to high price periods.

Excess profit taxes can be directly recycled to consumer bills and direct income support to finance bill reductions. This can mitigate the impact of energy prices on inflation, where energy price inflation is calculated on the average prices incurred by consumers, meaning that targeting energy support directly through the bill has an advantage over a separate income support payment. However, excess profits taxes should be imposed for no longer than necessary due to their impact on long-run innovation incentives, particularly towards new entrants.

Windfall taxes have been imposed on oil and gas production and on electricity generation across Europe. As noted above, the EU agreed to a minimum 33 per cent tax rate on supernormal profits for gas, oil, coal and refinery companies in 2022 and 2023 profits.[64] In the UK, oil and gas production has been subjected to a supplementary 35% profits tax until 2028, [65] and electricity generators are currently subject to a 45% supplementary profits tax.[66] These are in addition to normal profits tax rates.

The crisis has, however, revealed some home truths about net zero and energy taxation. First, sector coupling of the type we have seen between gas and electricity prices is not going away in net zero. Distortions in taxes and charges between energy vectors will need to be examined. Direct use of gas should be subject to carbon pricing, as it is

[57] See https://www.ofgem.gov.uk/publications/default-tariff-cap-level-1-july-2023-30-september-2023 See Model - Default Tariff Cap Level v1.18.

[58] See: https://www.iea.org/commentaries/europe-s-energy-crisis-what-factors-drove-the-record-fall-in-natural-gas-demand-in-2022.

[59] This happens because price suppression on the retail side raises demand relative to non-intervention. This higher demand can only be satisfied if the wholesale price is higher than it would otherwise have been under non-intervention.

[60] Source: European Commission (2023c, p.73)https://energy.ec.europa.eu/system/files/2023-03/SWD_2023_58_1_EN_autre_document_travail_service_part1_v6.pdf.

[61] Smart Energy Europe (2022).

[62] Source: European Commission (2023c, p.85)https://energy.ec.europa.eu/system/files/2023-03/SWD_2023_58_1_EN_autre_document_travail_service_part1_v6.pdf.

[63] https://pjm.com/-/media/markets-ops/dsr/2023-demand-response-activity-report.ashx.

[64] https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32022R1854

[65] https://www.gov.uk/government/publications/changes-to-the-energy-oil-and-gas-profits-levy.

[66] https://www.gov.uk/government/publications/electricity-generator-levy.

when used to produce electricity. Low carbon transition charges must be better allocated across energy vectors to avoid distorting technology choices. Heat pumps might eventually become more cost-efficient than gas boilers, but relative electricity and gas taxes are distorted against using heat pumps. Second, significant scarcity rents will be created for those with favourably located low-carbon energy sources. Marginal prices may be high for prolonged periods, and who receives positional rents accruing to renewable generators will be a political issue. Taxing what is a positional rent needs to be thought about more carefully. For instance, site auctions for access to the seabed might be a way to capture rents from merchant offshore wind farms for the government and (technology-specific) auctions for long-term two-way CfDs might capture rents for consumers (see next paragraph). Rents are harder to identify in practice than in theory, and attempts to tax rents may also reduce investment.

4.3.2. Recommendation 11: A role for a two-way CfD auction

The government needs to pay attention to the type of contract offered in the auction, as raised earlier. One-way CfD auctions were more popular than two-way CfD auctions in 2021 among renewable auction support schemes in Europe.[67] Fixed premium FIT auctions that only pay positive premia on top of the market price, leaving consumers exposed to high wholesale prices, were also still popular in 2021.

Government PPAs (of which two-way CfDs are a type) have successfully reduced risks and driven down the cost of capital. This has been particularly true for emerging technologies, stand-alone projects and where the retailer or corporate PPAs are not competitive or available in sufficient quantity. Where government PPAs are used, implementing them should ensure that electricity consumers benefit from lower prices when strike prices are below market prices. Well-designed government PPAs significantly improve on older support schemes, such as feed-in tariffs, if they provide incentives for technologies to participate in short-term markets.[68] The UK's Low Carbon Contracts Company (LCCC) provides an example of the legal entity governments can create to act as their CfD counterparty. The LCCC can impose a positive or negative levy on all electricity consumption, reflecting its net payments under its CfD contracts.[69]

4.4. Emergency intervention recommendations

4.4.1. Recommendation 12: Retail emergency measures should be targeted and temporary

As discussed above, regulated retail prices should remain an exceptional and temporary measure to be activated by Member States under specific, harmonised conditions.[70] This is because public intervention in price setting for electricity distorts investment signals in generation, ultimately disempowers consumers and may not be equally available for all Member States due to budgetary constraints. Individual regulatory intervention at the retail level by Member States could also prevent the progressive "alignment of retail markets" envisaged by the European Commission, building on positive outcomes from the wholesale electricity market coupling.[71] To the extent that businesses are also subject to differently regulated tariffs, this must distort trade between European countries. For instance, substantial price support remains in place in France at the beginning of 2024, even though the European Commission has recommended it to be only temporary.

4.4.2. Recommendation 13: Market interventions that have significant pan-European effects need to be regulated

Interventions which increase European wholesale market demand and/or have large detrimental cross-border effects should be prevented. A good example of where this must have been the case was in France, where real electricity prices fell in 2022, increasing European electricity demand significantly relative to a substantial price rise. Therefore, the implementation of EU regulations to reduce gas and electricity demand across Europe during the crisis is a positive development. It is also positive that the Commission has sought to define the wholesale price circumstances under which interventions in the retail market can be justified.[72]

4.4.3. Recommendation 14: Retail market interventions should maintain marginal incentives to cut energy consumption

Higher wholesale prices should be reflected in retail prices at the margin to match supply to demand more efficiently, as mentioned above. The Netherlands and Norway did this among the four countries we looked at, while France and Great Britain did not. This ensures that consumers are strongly incentivised to reduce energy consumption, even when they receive generous bill support. One potential solution is implementing rising block tariffs for electricity at the Member State level. Indeed, the German Gas and Heat Commission (ExpertInnen--Kommission Gas und Warme, 2022) successfully implemented such an approach for German gas prices, and we noted above that this was subsequently done for electricity in The Netherlands.

Retailers should design tariffs that enable customers to mitigate market risks and promote demand flexibility and energy conservation. One potential solution is to encourage (or mandate) the development of retail contracts that offer fixed prices for some energy consumption while maintaining some price variation at the margin. This can be achieved by combining real-time pricing with financial difference payments for a fixed quantity of energy.

4.4.4. Recommendation 15: Accelerating consumer investment in crises is important

The responses to the crisis by the EU and our four example countries focussed on price and profit intervention, with some encouragement to demand reduction. There was relatively little emphasis on promoting more consumer investment in PV, batteries or demand reduction. However, given the prolonged nature of the crisis (nearly two years), the role of active consumers and prosumers in the energy system could have been more significant.

The increased installation of photovoltaic panels, battery storage and electric heating systems (which net saves natural gas) would have partially mitigated the gas crisis. With sufficient encouragement (beyond simply reflecting short run marginal cost), large amounts of installation of these distributed technologies could have been done relatively quickly with beneficial aggregate demand and fiscal effects relative to the very large amount of money that European countries spent subsidising the use of fossil fuels.[73]

[67] Source: European Commission (2023c, p.28)https://energy.ec.europa.eu/system/files/2023-03/SWD_2023_58_1_EN_autre_document_travail_service_part1_v6.pdf.

[68] This requires contracts to be more financial, for instance where output is determined by the typical power plant (and not actual production) and settlement is financial.

[69] https://www.lowcarboncontracts.uk.

[70] The general principle of market-based supply prices is defined in Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market for electricity, Art. 5. Art. 5.3 to 5.10 of the Electricity Directive provides for a possible derogation where Member States can apply public interventions in the price setting for the supply of electricity to energy poor or vulnerable household customers. Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices, Recitals 12, 48, 49 and Articles 12–13.

[71] European Commission (2021, p.15) and Lewis et al. (2021).

[72] See https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX%3A32022R1854

[73] In January 2024, the Dutch government increased the energy tax on gas and lowered the one on electricity in order to accelerate the shift from gas to electricity.

5. Conclusions and policy implications

It is important to remember that a regional war triggered and prolonged the recent gas crisis. It is not an electricity market design crisis. The resulting high gas and carbon prices served as a test for the existing market design. The crisis has brought forward the debate about how to evolve the market design to face net zero.

In this paper, we started by considering the theory relevant to the energy crisis in wholesale markets, retail markets, excess energy profits, renewable support schemes and emergency interventions in energy markets. We briefly reviewed the responses to the crisis from the European Union, France, Netherlands, Norway and Great Britain.

Based on this, we derived several recommendations.

On wholesale electricity markets, we suggested an increased role for long-term contacts; the need for better coordination of capacity markets; the extension of the single market in electricity (and gas); consideration of a move to more granular wholesale market pricing; no to two market solutions; and the need for EU monitoring of national planning to ensure adequate aggregate investment.

On retail electricity markets, we argued for: the need for better financial risk regulation of retailers to facilitate retail competition; that it appears sensible to have some two-way CfD contracts assigned to consumers; the importance of demand side response and flexibility.

On excess profits and renewables support policies, we said that energy profits taxes are better than price regulation and that there is a role for two-way CFD auctions.

Finally, on emergency intervention principles, we suggested: that retail intervention should be targeted and temporary; there should be better regulation of price interventions that have potential pan-European effects; that market interventions should maintain marginal incentives to cut energy consumption; that it is sensible to encourage consumers to invest during energy crises.

Overall, the European electricity market has survived a remarkable stress test. The continent-wide wholesale market proved its worth in maintaining energy security. Retail markets performed less well, being the subject of very costly and often poorly targeted fiscal interventions. However, good lessons appear to have been learned, and some are being actively debated and implemented.

Funding

Centre on Regulation in Europe (CERRE): Electricity Market Design Project 2022.

CRediT authorship contribution statement

Michael G. Pollitt: Writing – review & editing, Writing – original draft, Supervision, Methodology, Formal analysis, Conceptualization. **Nils-Henrik M. von der Fehr:** Writing – review & editing, Writing – original draft, Supervision, Methodology, Formal analysis, Data curation, Conceptualization. **Bert Willems:** Writing – review & editing, Writing – original draft, Methodology, Formal analysis, Data curation, Conceptualization. **Catherine Banet:** Writing – original draft, Formal analysis, Data curation, Conceptualization. **Chloé Le Coq:** Writing – original draft, Conceptualization. **Chi Kong Chyong:** Writing – original draft.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

No data was used for the research described in the article.

Acknowledgements

The authors wish to thank the Centre on Regulation in Europe (CERRE) members and secretariat for their financial and administrative support for the research underlying this paper. This was published in a series of CERRE reports, notably Chyong and Pollitt (2018), von der Fehr et al. (2022), Pollitt et al. (2022a, 2022b). The authors benefitted from a large amount of stakeholder engagement with the European Commission, national regulators and leading energy companies. The views expressed in this paper are those of the authors and should not be taken to be shared with any party with which the authors are associated.

References

ACER/CEER, 2020. ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2019 - Energy Retail and Consumer Protection Volume October 2020. European Union Agency for the Cooperation of Energy Regulators and the Council of European Energy Regulators, BEIS, 2022.

BEIS, 2022. Review of Electricity Market Arrangements: Consultation Document. BEIS, London.

Bohn, R.E., Caramanis, M.C., Schweppe, F.C., 1984. Optimal pricing in electrical networks over space and time. Rand J. Econ. 15 (3), 360–376.

Bolton, P., 2024. *Gas and Electricity Prices during the 'energy Crisis' and beyond*, Research Briefing, 03 January 2024. House of Commons Library.

Bucksteeg, M., Spiecker, S., Weber, C., 2019. Impact of coordinated capacity mechanisms on the European power market. Energy J. 40 (2), 221–264.

Centre for Net Zero, 2023. Insights from the UK's Largest Consumer Energy Flexibility Trail: the Demand Flexibility Service and Octopus Energy Saving Sessions. https://www.centrefornetzero.org/wp-content/uploads/2023/05/Centre-for-Net-Zero-Insights-from-the-UKs-largest-consumer-energy-flexibility-trial-May-2023.pdf.

CEPS, COWI, 2019. Competitiveness of Corporate Sourcing of Renewable Energy, Annex C to Part 2 of the Study on the Competitiveness of the Renewable Energy Sector, Synopsis Report. Online survey and interviews with EU stakeholders, 2019.

Chyong, C.K., Pollitt, M., 2018. Europe's Electricity Market Design: 2030 and beyond. Centre on Regulation in Europe. https://cerre.eu/publications/europes-electricity-market-design-2030-and-beyond/.

Chyong, C.K., Pollitt, M., Cruise, R., 2019. Can wholesale electricity prices support "subsidy-free" generation investment in Europe? EPRG Working Paper 1919. https://www.eprg.group.cam.ac.uk/eprg-working-paper-1919/.

Commission de Régulation de l'Energie, C.R.E., 2023. 'Les marchés de detail de l'électricité et du gaz naturel', *Observatoire des marchés de détail*.

Council of European Union, 2022a. Proposal for a COUNCIL REGULATION on an Emergency Intervention to Address High Energy Prices. Council of the European Union, 30 September 2022.

Council of the European Union, 2022b. Proposal for a Power Market Design in Order to Decouple Electricity Prices from Soaring Gas Prices – Information from the Greek Delegation. Council of the European Union, 22 July 2022.

Crampes, C., von der Fehr, N.H.M., 2023. Decentralised cross-border interconnection. Energy J. 44 (4), 147–169.

European Commission, 2023a. Proposal for a REGULATION of the EUROPEAN PARLIAMENT and of the COUNCIL Amending Regulations (EU) 2019. European Commission, Strasbourg. */943 and (EU) 2019/942 as well as Directives (EU) 2018/2001 and (EU) 2019/944 to improve the Union's electricity market design*, 14.03.23.

European Commission, 2023b. Proposal for a REGULATION of the EUROPEAN PARLIAMENT and of the COUNCIL Amending Regulations (EU) No 1227/2011 and (EU) 2019/942 to Improve the Union's Protection against Market Manipulation in the Wholesale Energy Market. European Commission, Strasbourg, 14.03.23.

European Commission, 2023c. Commission Staff Working Document – Reform of Electricity Market Design, 14.03.23. European Commission, Strasbourg.

European Commission, 2021. Tackling Rising Energy Prices: A Toolbox For Action and Support. COM(2021) 660 final, 13.10.2021.

European Commission, 2022. Commission Staff Working Document, Guidance to Member States on Good Practices to Speed up Permit-Granting Procedures for Renewable Energy Projects and on Facilitating Power Purchase Agreements. SWD, 2022) 149 final, 18.5.2022.

ExpertInnen-Kommission Gas und Warme, 2022. Sicher durch den Winter, Abschlussbericht [Safely through the Winter, Final Report], Berlin, 31.10.22. https://www.bmwk.de/Redaktion/DE/Publikationen/Energie/abschlussbericht.pdf?__blob=publicationFile&v=6.

Fabra, N., 2018. A primer on capacity mechanisms. Energy Econ. 75, 323–335.

Finon, D., Roques, F., 2013. European electricity market reforms: the "visible hand" of public coordination. Economics of Energy & Environmental Policy 2 (2), 107–124.

FTI, Consulting, 2023. London. In: FTI, Consulting, Glachant, J.-M., Joskow, P.L., Pollitt, M.G. (Eds.), Assessment of Locational Wholesale Electricity Market Design Options in GB, October 2023, Handbook on Electricity Markets. Edward Elgar, Cheltenham, 2021.

Gross, R., MacIver, C., Blyth, W., 2022. Can Existing Renewables and Nuclear Help Keep Prices Down Next Winter? the Case for a 'pot Zero' CfD Auction. UKERC Discussion Paper.

Grubb, M., Drummond, P., 2018. UK Industrial Electricity Prices: Competitiveness in a Low Carbon World, Report Commissioned by the Aldersgate Group. UCL Research Report. February 2018.

Haan, M., Schinkel, M.P., 2023. 'Energy price ceilings with partial cover: a Dutch master?'. European Court of Auditors Journal (1), 101–109, 2023.

Hebous, S., Prihardini, D., Vernon, N., 2022. Excess Profit Taxes: Historical Perspective and Contemporary Relevance. IMF Working Paper. WP/22/187.

Hicks, J.R., Hicks, U.K., Rostas, L., 1941. The Taxation of War Wealth. Oxford University Press, Oxford.

IEA, 2022. World Energy Outlook 2022. OECD, Paris.

Keay, M., Robinson, D., 2017. The Decarbonised Electricity System of the Future: the 'Two Market' Approach. The Oxford Institute for Energy Studies.

Keynes, J.M., 1940. How to Pay for the War: A Radical Plan for the Chancellor of the Exchequer. Macmillan and Co. Ltd, London.

La Tribune, 2022. Crise énergétique: l'Etat a dépensé 100 milliards d'euros en trois ans, indique Bruno Le Maire.

Lavrijssen, S., de Vries, F., 2022. Onderzoek naar interpretatie, toereikendheid en toepassing wettelijk kader voor toezicht op energieleveranciers, p. 31. https://www.acm.nl/sites/default/files/documents/onderzoek-interpretatie-toereikendheid-entoepassing-wettelijk-kader-toezicht-op-energieleveranciers.pdf.

Lewis, P., Granroth-Wilding, H., Napolitano, L., Zabala, C., Vékony, A., Felsmann, B., Hirschbichler, F., 2021. European Barriers in Retail Energy Markets Project: Final Report. Publications Office of the European Union, Luxembourg.

Littlechild, S.C., 2022. Discovery, doubt, delusion, ducking, destruction, desperation, diagnosis, discipline, disregarding, direction and decease? Regulation and the evolution of the GB competitive retail energy market, Presentation to EPRG Spring Seminar. https://www.eprg.group.cam.ac.uk/2021-eprg-online-spring-seminar/.

Moss, B., 2002. Can state avoid higher prices incurred under long-term power supply contracts A study of California's situation following its energy crisis. Publ. Contract Law J. 32 (1), 161–196.

Mozelle, B., Padilla, J., Schmalensee, R., 2010. In: Harnessing Renewable Energy In Electric Power Systems. RFF, Earthscan, Washington DC.

National Audit Office, 2022. Report – Value for Money: the Energy Supplier Market, 22 Jun 2022. National Audit Office, London. https://www.nao.org.uk/wp-content/uploads/2022/03/The-energy-supplier-market.pdf.

Ofgem, 2023. Guidance on the Operational Capability and Financial Responsibility Principles, 05 April 2023. Ofgem, London.

Opgrand, J., Preckel, P.V., Gotham, D.J., Liu, A.L., 2022. Price Formation in auctions for financial transmission rights. Energy J. 43 (3), 33–57.

Patel, C., 2022. What lessons can be learned from the Iberian price cap? ICIS, 6 September 2022. https://www.icis.com/explore/resources/news/2022/09/06/10802840/what-lessons-can-be-learned-from-the-iberian-price-cap/.

Perkins, J., Rainaut, C., 2023. The Simple Economics of Energy Prices. https://www.compasslexecon.com/the-analysis/the-simple-economics-of-energy-prices/02-22-2023/.

Pollitt, M.G., 2019. The European single market in electricity: and economic assessment. Rev. Ind. Organ. 55, 63–87.

Pollitt, M.G., 2021. The future design of the electricity market. In: Glachant, J.-M., Joskow, P.L., Pollitt, M.G (Eds.), Handbook on Electricity Markets. Edward Elgar, Cheltenham, pp. 428–442.

Pollitt, M.G., 2022. The further economic consequences of Brexit: energy. Oxf. Rev. Econ. Pol. 38 (1), 165–178.

Pollitt, M.G., 2023. Locational Marginal Prices (LMPs) for Electricity in Europe? the Untold Story. Energy Policy Research Group Working. Paper No.2318.

Pollitt, M., Anaya, K., 2021. Competition in Markets for Ancillary Services? The implications of rising distributed generation. Energy J. 42 (Special issue 1), 1–28.

Pollitt, M.G., von der Fehr, N.-H., Banet, C., Willems, B., 2022a. The European wholesale market: from crisis to net zero. Brussels: Centre on Regulation in Europe. https://cerre.eu/publications/the-european-wholesale-electricity-market-from-crisis-to-net-zero/.

Pollitt, M.G., von der Fehr, N.-H., Willems, B., Banet, C., Le Coq, C., Navia, D., Bennato, A.R., 2022b. Recommendations for a Future Proof Electricity Market Design. Centre on Regulation in Europe. https://cerre.eu/wp-content/uploads/2022/12/CERRE_MarketDesign_Final.pdf.

Pollitt, M.G., Reiner, D.M., Newbery, D.M.G., 2022c. The Energy Price Guarantee: what Principles Should the UK Government Apply in Thinking about How to Implement This? 15 September 2022. https://www.eprg.group.cam.ac.uk/wp-content/uploads/2022/09/EPRG-The-Energy-Price-Guarantee.What-principles-should-the-UK-Government-apply-in-thinking-about-how-to-implement-this-1.pdf.

Rifkin, J., 2015. Zero Marginal Cost Society: the Internet of Things, the Collaborative Commons, and the Eclipse of Capitalism. St Martin's Griffin, New York.

Robinson, D., Arcos-Vargas, A., Tennican, M., Nunez, F., 2023. The Iberian Exception: an Overview of its Effects over its First 100 Days. OIES Paper EL50.

Roques, F., Finon, D., 2017. Adapting electricity markets to decarbonisation and security of supply objectives: toward a hybrid regime? Energy Pol. 105, 584–596.

Rowland, C., 1980. Taxing North Sea oil profits in the UK: special needs and the effects of petroleum revenue tax. Energy Econ. 2 (2), 115–125.

Rüdinger, A., 2023. Exiting the energy crisis: lessons learned from the energy price cap policy in France. Intereconomics 58 (1), 5–9.

Sgaravatti, G., Tagliapietra, S., Trasi, C., Zachmann, G., 2021. 'National policies to shield consumers from rising energy prices'. Bruegel Datasets first published 4 November 2021. https://www.bruegel.org/dataset/national-policies-shield-consumers-rising-energy-prices.

Smart Energy Europe, 2022. Demand-side flexibility in the EU: quantification of benefits in 2030. Smart Energy Europe. https://smarten.eu/wp-content/uploads/2022/09/SmartEN-DSF-benefits-2030-Report_DIGITAL.pdf.

Van Ooij, C., Batenburg, A., Nguyen, N.C., Straver, K., 2023. Energy Poverty: A Science and Policy State of Play. TNO Report 2023 P10119.

von der Fehr, N.-H., Banet, C., Le Coq, C., Pollitt, M., Willems, B., 2022. Retail Energy Markets under Stress – Lessons Learned for the Future of Market Design. Brussels: Centre on Regulation in Europe. https://cerre.eu/publications/retail-energy-markets-under-stress/.

Wolak, F.A., 2011. Measuring the benefits of greater spatial granularity in short-term pricing in wholesale electricity markets. Am. Econ. Rev. 101 (3), 247–252. http://www.jstor.org/stable/29783748.

Zhang, H., Pollitt, M.G., 2023. Comparison of policy instruments in the development process of offshore wind power in North Sea countries. EPRG. Working Paper No.2323.