An assessment of the European electricity market reform options and a pragmatic proposal

March 2023

This report has been prepared by J.P. Chaves, R. Cossent, T. Gómez San Román, P. Linares, and M. Rivier. We would like to thank, without implicating, the very helpful comments received from Luiz Barroso and Gabriel Cunha, Christian Egenhofer, William Hogan, Paul Joskow, Juan Luis López Cardenete, Karsten Neuhoff, David Newbery, Michael Pollitt, Alberto Pototschnig, David Robinson, Tim Schittekatte, Richard Schmalensee, Peter Sweatman, Jorge Vasconcelos, and our colleagues at IIT.

CONTENTS

In time of desolation never to make a change; but to be firm and constant in the resolutions and determination in which one was the day preceding such desolation, or in the determination in which he was in the preceding consolation.

St. Ignatius of Loyola, Spiritual Exercises

The current energy crisis and its impact on electricity markets

The unlawful invasion of Ukraine by Russia and the associated disruptions in gas supply to Europe have contributed to and exacerbated a trend that started in the summer of 2021, the increase in natural gas prices particularly in Europe. This in turn has resulted in very high electricity prices in the European electricity market, given that natural gas combined cycles are typically the marginal electricity production technology (that is, the highest variable cost required to supply demand), and therefore the one that sets the price that all demand pays and all supply receives.

These very high prices are hurting consumers across Europe when not hedged against them with long-term contracts, and also producing very high profits for infra-marginal technologies (that is, those cheaper than natural gas combined cycles), such as renewables or nuclear, again, when not engaged in long-term contracts.

European governments, in coordination with the European Commission, have been implementing different measures to protect consumers and to regulate the profits of producers, with different levels of success, particularly in terms of addressing the underlying cause of this energy crisis: the scarcity of natural gas.

But, in addition to these emergency measures, several parties have argued that a deep reform of the European electricity market is needed. Indeed, these calls for reform are not new: the increasing share of variable renewables (such as wind or solar photovoltaics) in electricity markets and its impact on the market has been a concern for many academics and practitioners for many years, who have been discussing and formulating different proposals to make the electricity market signals compatible with the energy transition and with an efficient operation and investment (a recommended reading list would include Pérez-Arriaga et al, 2016; Neuhoff et al, 2016; Newbery et al, 2017; Joskow, 2019; Batlle et al, 2021; Barroso et al, 2021; Pollitt, 2021; Gruenspecht et al, 2022; Schmalensee, 2022; or Pollitt et al, 2022). Now, this discussion has been brought again to the fore, although with not necessarily the same objectives: the problems identified for systems with large share of renewables, and the time frames involved, are not the same as those currently experienced under the natural gas crisis. Therefore, the solutions devised may not be the same either.

In this paper, we look at the alternatives proposed for the reform of the European electricity market, analysing their advantages and disadvantages, and we put forward a specific proposal for the reform. We focus mostly on measures directed at the wholesale generation market, although we also propose some changes that we believe will also be needed at the retail level. Emergency measures to tackle the current energy crisis, which are not necessarily consistent with the long-term reform and should definitely not determine the long-term design of the European electricity market, are very briefly assessed in an annex, including their compatibility with this long-term reform.

Is the European electricity market delivering?

As mentioned earlier, many have argued that the European electricity market is not doing its job, either under the current natural gas crisis, or along the energy transition. Comments like "the electricity market is not fit for purpose", or "the market is broken", have been highlighted in recent discussions. Others (including ACER, the European Agency for the Cooperation of Energy Regulators), have defended the virtues of the current market design. Who is right and who is wrong?

Answering correctly this question requires defining what the market is. To some, the electricity market is synonymous with the wholesale, spot day-ahead market. However, that is not true (or at least should not be): the electricity market is where buyers and sellers meet to exchange electricity, and this is not only in the day-ahead market. Electricity is also exchanged in the wholesale market through medium to longer-term financial or physical bilateral contracts (such as Power Purchase Agreements, PPAs, base or peak load forward contracts, etc.), or in the retail market. It is exchanged in the short term (day-ahead, or even in shorter periods, e.g. in ancillary service markets), but also in the long term, e.g. with futures contracts.

Each of these exchanges plays a certain role. Day-ahead markets should provide efficient short-term operation signals, whereas long-term contracts or markets provide price stability and give the investment signals required to deploy additional renewable and firm power. Wholesale markets decide the right mix of generation and storage technologies and demand response, whereas retail markets translate this mix into the electricity services required by final consumers.

However, the current situation of the electricity market in Europe is biased towards short-term, wholesale signals, something which the current energy crisis has made even more visible. There are several reasons for this (see e.g. Rodilla and Batlle, 2012), mostly related to the limited role of the demand, to the increasing long-term uncertainty, or sometimes even due to regulation[1]. As a result, and as may be seen in the following figure, only some countries in Europe show reasonable liquidity in long-term markets.

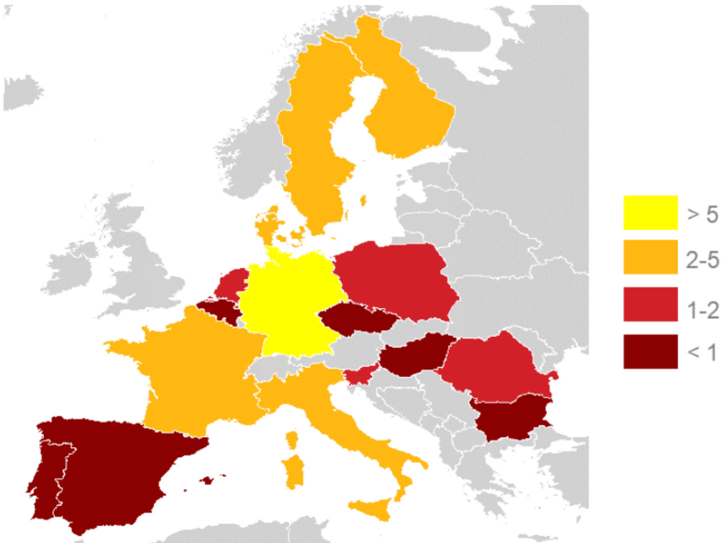


Figure 1.- Churn rate *(a measure of liquidity) in long-term markets (ACER, 2022)*

Moreover, even in those countries with reasonable liquidity, the term of the contracts is typically limited to 2-3 years, which is clearly insufficient to provide investment signals in the electricity market, particularly for capital-intensive technologies such as renewables or storage.

So maybe the problem is that we are asking too much of the day-ahead market. Indeed, most commentators (see e.g. Pérez-Arriaga et al, 2016; Newbery, 2016; Batlle et al 2021; or Hogan 2022) agree that relying only on the current day-ahead market to provide the right investment signals is not appropriate for the energy transition: the short-term market price will be too low in a decarbonized electricity system to cover the cost of renewables due to many real-life issues[2].

Interestingly, this is contrary to what is happening under the current energy crisis, with very high prices coming from the day-ahead market. This may be a harbinger of the times to come: along the energy transition, short-term price volatility will significantly increase compared to current markets, with very high prices in scarcity hours and very low prices in most hours. We

---

[1] For example, limitations to the permanence requirements in retail contracts that try to promote competition.

[2] In theory, in a truly competitive and ideal market, with active demand ready to pay for non-supplied energy, the short-term price should be enough, and additional payments should only be required if renewable targets go beyond the economically-efficient level (Gerres et al, 2019). Alas, real markets are quite different from theoretical ones: among others, we may find cost reductions for renewables, risk aversion, lumpiness of investments, lack of hedging instruments, regulatory interventions…

will also observe the oscillatory patterns characteristic of all markets, with short-term prices either above or below the long-term price.

Now, it is important to remark that too-low or too-high prices in the day-ahead market are not necessarily undesirable: if they correctly account for the underlying cost of production (the opportunity costs), they are actually sending the efficient signal to the agents about how much to produce and consume in the next day. If prices are very high, showing scarcity, consumers will have incentives to reduce their demand (e.g. investing in energy efficiency) and producers would increase supply, mitigating this scarcity. If prices are very low, that means that there is too much generation in the system compared to demand. Short-term prices also help regulate the efficient use of storage[3]: when prices are low, storage is incentivised, while high prices signal the need to discharge the electricity stored into the system. For this to work correctly, all technologies must bid their short-term variable (or opportunity) cost (which in the case of storage is the cost of the expensive technology avoided by using the electricity stored).

The problem is when these signals are not efficient, that is, when the market is not able to adjust at the speed required, mainly due to barriers to entry or exit, or to market or behavioural failures, leading either to not incentivizing the right type of investment (or demand response), or to providing permanent extraordinary profits or losses to existing assets. The first priority should be always to try to remove those barriers and failures rather than resorting to other more controversial measures such as trying to capture these extra-profits or subsidise those extraordinary losses[4]. As an example, removing barriers to entry includes opening markets to new resources – such as demand-side resources or new storage technologies – that can compete with incumbent technologies.

It is particularly important to correctly diagnose the reasons that prevent this adjustment, in order not to fail in the design of the corrective measures. This is the issue that market reform proposals try to address, and to which we will look at in the following section.

But before moving forward, let us comment briefly on other problems identified in current electricity markets, and which should also be considered in a potential electricity market reform.

First, markets by themselves do not account for the environmental impacts of electricity generation, transport and use, that is, environmental externalities. A correct allocation of resources by the market requires the internalization of these externalities. In Europe, the Emissions Trading System (EU ETS) ensures that a carbon price is incorporated into the

[3] Note that demand management, that is, shifting consumption in time, is also a type of storage.

[4] For example, we may remark that grid access, which is out of the scope of this paper, may also create extraordinary rents, if not allocated competitively: if grid access is a scarce resource, it should be auctioned.

generation of electricity. However, other externalities, such as those related to NOx emissions, or to non-emission-related impacts, are arguably not efficiently internalized.

Second, the exercise of market power may also distort the efficient allocation of resources. The economies of scale related to some of the activities of electricity generation and transport make them prone to the existence of large operators, sometimes with the capacity to exert market power (particularly in those regions with smaller markets or fewer interconnections), as shown in several instances across Europe. Competition authorities in Europe have among their functions the monitoring and supervision of electricity markets.

Finally, markets cannot ensure fairness in the allocation of resources, as has become evident in two major problems: energy poverty and the phase-out of coal. High electricity prices damage particularly the poorest consumers, which typically devote larger shares of their budget to electricity expenses. The energy transition may also hurt fossil-based economies and regions, which will need help to adapt to new economic activities.

All these issues, although out of the scope of these notes, should be addressed by a comprehensive electricity market reform if we want to achieve a clean, efficient, affordable and fair electricity system in Europe.

Alternatives for the current European electricity market design

As stated in the previous section, the major challenge that the European electricity market faces is to reconcile short-term efficient operation signals with long-term efficient investments under non-perfect conditions. There are basically two "pure" approaches to this, plus some mixed ones – indeed, probably the right approach lies somewhere in the middle, as argued by Perez-Arriaga and Linares (2008). Here we will describe them very briefly, and also in probably too-simplistic terms. Readers interested in understanding better the alternatives and implications of the regulation of power systems may check Pérez-Arriaga (2013).

On one side, we would have the "regulated" or "centralized-planning" approach[5] by which the regulator would decide the amount and type of investments required, and then private (or public) agents would compete (e.g. through auctions) for building and operating these investments. This approach was termed by Demsetz (1968) as "competition for the market".

These investments would be remunerated at a fixed price per MWh produced (including some incentives to operate efficiently), which would ideally be set so that investors receive a reasonable rate of return. This remuneration would be provided through different contracts adjusted to the different technologies (e.g., contracts for differences, reliability options, etc.). This would ensure that there would be no windfall profits in situations like the current one, and that there is no "cannibalization" of income for renewable energy sources when they

[5] We describe here the "modern" regulated approach, which typically includes some competitive elements.

become a significant share of the system. The regulator would be the single buyer for these contracts.

Under this approach, efficient operation and trade signals would be ensured by maintaining a spot market in which all power plants would bid their variable (or opportunity) cost. Alternatively, as proposed by some, the system operator would take care of the efficient dispatch of nuclear or hydro if there is a risk of market power.

On the other extreme, we would have the "decentralized" or "market-based" approach, which argues that what we need is more markets to complement the day-ahead one. Better and more developed forward markets, as well as capacity markets which incentivize investments in flexible backup resources, would be needed.

In theory, both approaches should be equivalent: both centrally-planned systems and perfectly competitive markets are able to achieve an efficient allocation of resources, under the required conditions. In practice, however, these conditions are almost never met, so there are significant differences between the two alternatives.

What are the problems with the "regulated" approach? Here we just list them. Interested readers may look for more details in the corresponding annex:

- Significant risk of overinvestment (and the corresponding cost)
- Slower substitution of inefficient technologies
- Inefficient allocation of risk, from investors to consumers (through the regulator)
- Some technologies, like hydro, are very difficult to contract, due to the variability in volume
- If some private resources (hydro or storage in particular) are operated by the system operator, this may result in legal issues (as in South America)
- In Europe, having Member States decide installed capacities intensifies their influence on the single market (which explains the reluctance of the European Commission to discuss capacity markets)
- Transferring existing power plants, built under a deregulated system, back into a regulated one, presents many challenges (mostly legal)
- A technology-centered approach like this reduces incentives to innovative uses of technologies and energy services
- Demand is largely absent or passive in this scheme, with the regulator assuming its role. Given that decarbonization will rely significantly on many demand technologies, this presents the risk of missing significant and interesting opportunities
- In principle, distributed generation would be hard to accommodate under this approach
- Finally, a relevant challenge is how to make compatible a regulated wholesale system with a liberalized retail one

A "market-based" approach would avoid many of these problems, but would also feature its own. Do note that the fact that the list is shorter does not mean that the problems are less serious:

- As mentioned earlier, many issues prevent an efficient development of long-term markets
- Under certain situations, some agents may have market power and exercise it, increasing prices
- Due to technical or political reasons, some past investments may receive permanent extraordinary rents if there are barriers to entry; or windfall losses if exit is not possible
- Markets may be slow to adjust, due to many reasons, creating excessive rents or insufficient remuneration for different technologies

To try to solve some of these shortcomings of both "pure" approaches, some proposals have been put forward that try to combine them to some extent. The most relevant of those is the "split markets" or "dual procurement" idea first proposed by Robinson and Keay (2017), and further promoted by IRENA (2022) and others. Under this approach, there would be two physically-separated[6] electricity markets: one for renewable producers, which would provide energy as available, and another for flexible ones, which would provide the required backup. In the original proposal, consumers would decide how much they would demand from each market, although in others the renewable market demand would be decided by the regulator. The system operator would be in charge of the efficient dispatch and the coordination of the markets.

The problem we see with this proposal is that it brings additional complexity, without necessarily improving the outcomes compared to the "purer", and simpler approaches. For example, under the regulated approach with appropriately designed contracts for differences, renewables would be remunerated very similarly to a split market, while still being able to participate in the short-term/flexible market and hence receive efficient operation signals (such as very low prices when there is excessive supply), which would not be possible in the split market proposal. Under the split market approach there are also other potentially complex issues to solve:

- How is remuneration decided in the renewables market? If cannibalization is to be avoided, producers must receive their average cost, but this requires a long-term market, or mandatory long-term contracts or auctions (as in the pure approaches).
- If demand has several barriers to participating effectively in the current market, will it be easier with two? As a consequence, if demand is not active enough, who decides how much energy and backup is needed?
- Would the backup market (essentially an energy-only market) provide for the reliability needed in the long term?
- Which will be the price used for efficient trade between electricity markets? How to exchange renewable energy without short-term prices?
- How much do we lose by preventing renewables from supplying flexibility to the system?

[6] Note that we do not include in this category different approaches on contracting (e.g. CfDs mandatory for RES), since those would fit in a single market structure as presented in the regulated or market approaches.

- Where would hydro bid? In the renewable or the flexible market? The same applies to biomass, hybrid installations, solar thermoelectric, virtual power plants, or storage.

There have also been other ideas proposed, although they only address specific issues:

- Auctions for inframarginal energy (which must be mandatory to remove the opportunity cost of bidding in the spot market).
  Similar in many aspects to the split market idea, or to mandatory CfDs for inframarginal technologies, it has an additional problem: if only covering a part of the market, what demand would benefit from the lower prices under a liberalized retail market?
- Public entities (Great British Energy, L'Energètica).
  Public generation or retail companies have always existed (indeed, in some European countries municipal retailers are very common). However, by themselves they are not able to change the allocation of revenues in the market, although sometimes they may overcome trust or transparency issues.
- Public management of hydro.
  A solution sometimes mentioned to prevent market power or windfall profits for hydro, public management by itself would not change the operation of hydro in the market (unless there is a risk of market power), since hydro should still be operated according to opportunity costs, for the water to be used in the optimal way for the system. Therefore, the revenues obtained by the owners would not change. And indeed, as mentioned earlier, it may give rise to serious legal problems.

A pragmatic proposal for the reform of the European electricity market

Our proposal is based on the following diagnosis of the alternatives described above:

- Markets are typically better than regulators at retrieving information and allocating risks, and promoting innovation;
- A well-functioning short-term market is essential to provide efficient operation and cross-border exchange signals;
- Active demand participation is lacking, particularly in the long-term;
- Market power needs to be prevented as much as possible, both in the wholesale and retail markets; and creating European-scale markets reduces these risks;
- Governments or regulators have a role in creating markets for emerging technologies, in protecting vulnerable consumers, in representing passive consumers, or in regulating situations created by barriers to entry or exit (if not able to remove them first);

Accordingly, we propose:

- To maintain the short-term market, but improve some of its elements (temporal and geographical granularity, bid formats and market algorithms, local flexibility markets);

- To promote long-term markets to enable consumers to benefit from more stable and cheaper prices. This may be done with standardized, technology-neutral, European-scale products, such as Contracts for Differences or Reliability Options;
- To introduce efficient mechanisms for protecting vulnerable consumers, such as Affordability Options;
- To develop European trading platforms for primary and secondary long-term markets;
- To ensure that the retail market is compatible with the generation market reform, and that it provides the required level of competition and signals for an efficient behaviour of demand.

In the following we provide further explanations for each of these elements, without actually getting into implementation details, which of course will be necessary. These details shall be developed once the basic mechanisms are agreed upon. In this regard, it must be noted that the proposal, for the sake of simplicity, does not enter into the locational dimension of the instruments proposed. That should not be understood as implicitly assuming a copper plate for the European system: instruments must reflect that there is no copper plate.

Market fundamentals

Our proposal is based on two pillars: first, all generation technologies and demand resources may compete to offer valuable services to the system (energy, firmness, reliability, adequacy, flexibility, etc.) if technically possible; the value for the power system is not given by technologies, but by the capabilities to provide specific services.

Second, price signals (both market derived or regulatorily fixed) must be as efficient as possible to incentive the right operation and investment both in generation, storage, networks and demand.

Based on these two pillars, we also propose some additional market design elements:

Short-term markets should be made as granular as possible, both temporally and geographically. Day-ahead, intra-day and balancing markets have been harmonized over the last 10 years through common and coordinated European structure and trading platforms, and are being constantly improved (e.g. currently increasing their temporal granularity). These markets are still essential, or even more needed, to price and provide investment signals in generation, demand or storage, to procure the required flexibility for an efficient and secure renewable electricity system.

Improvements in bid formats and market algorithms which would improve the allocation efficiency, etc. (see Herrero et al, 2018; MCSC, 2022), and increases in geographical granularity are needed. These present institutional and computational challenges, but may be increasingly necessary, and some analysis has already started (ENTSO-E, 2022). In this regard, the debate about nodal pricing, although always controversial in Europe, should certainly be brought back, as proposed by Eicke and Schittekatte (2022) or Neuhoff et al (2023).

Local flexibility markets must also be developed to address problems in distribution grids. Demand participation in these markets should be not only allowed, but also encouraged.

Increasing coordination between TSOs and DSOs is required to guarantee the optimal use of resources and maintain the security of the overall system (see e.g. Lind et al, 2019).

However, short-term markets are not enough: they must be complemented with long-term markets, largely absent up to now, and which may require some regulatory intervention. Joskow has termed this as "hybrid markets". Long-term (5-10 yr) markets are needed to finance investment in variable renewable technologies (PV and wind), energy efficiency, or seasonal storage technologies to ensure system adequacy.

In addition, these markets will provide price stability for demand, which would be otherwise subject to an increasingly volatile short-term market along the energy transition. In this regard, the expected price volatility in the long-term should be lower, given the high-CAPEX, low-OPEX structure of the predominant technologies of the future electricity system; but prices may be very volatile while gas plays a significant role. Long-term contracts, if mandatory, would also reduce the incentive to exert market power in the short-term market (see e.g. Liski and Montero, 2006).

Now, the challenge is how to make these long-term markets happen. The reform should act on the supply and the demand. ACER (2022) has already identified the need to look for mechanisms to increase access to private PPAs to smaller players in the market; to explore the introduction of market makers in long-term markets; to integrate long-term national markets and cross-border transmission rights trading; to revise the guarantees required in long-term contracts; and even consider centralized long-term auctions to complement markets. Here we elaborate on some of these aspects.

Market instruments

First, we need European-wide standardized products and trading platforms for long-term markets. Ideally, these products will combine physical delivery with financial compromises, as already done in Latin America, New England, Ireland or Italy. As mentioned earlier, they should not be restricted to specific technologies, but open to all that may provide the services demanded. We believe that the main instruments should include:

- Contracts for Differences to deliver energy and protect producers and consumer from short-term volatility;
- Reliability Options to ensure system adequacy;
- Affordability Options to protect vulnerable consumers against persistently high prices

These instruments are further described below.

a) Contracts for differences

Contracts for differences (CfDs) have already been used as instruments to promote renewable energy. These long-term contracts (two-sided options) provide a stable remuneration to sellers (producers) and price stability to buyers (consumers), by defining a volume of energy to be paid for, a contracted or strike price, and a reference market where the price and quantity differences would be settled. Therefore, they prevent windfall profits or losses.

Under these contracts, producers sell their electricity in the reference market, usually the day-ahead market, and receives (or pays, if negative) the difference between the strike price and the reference market price. To avoid distortions in the market, the volume contracted should have an ex-ante profile, settled by deviations with respect to prices and volumes traded in the reference short-term market (see Newbery, 2023; Schittekatte and Batlle, 2023; or Barquín et al, 2017). Thus, they may also provide efficient operation signals.

Although these contracts have typically been used by regulators to promote a predetermined amount of renewables, if standardized they could be easily used and traded as decentralized instruments (such as PPAs[7]) for most technologies. As in future markets, standardized periods for trading considering daily, weekly and seasonal differences can be defined. Do note, however, that using these contracts for hydro may be very difficult in some regions, since the annual volume to be contracted may be very uncertain: therefore, they may not be able to cover all of hydro production.

It is also important to remark that CfDs do not need to be centrally auctioned or "regulated"[8], and indeed should not cover all demand[9] (in order not to crowd-out private contracts and encounter the problems mentioned above for regulated systems). However, a certain amount of regulatory-backed, centralized CfDs may still be desirable, as a market making instrument and also to provide variation in the risk profile of these contracts[10].

Standardized long-term CfDs and cross-border capacity trading, implemented in European platforms similarly to what exists today for day-ahead or intraday markets are key elements in the required market reform.

b) Reliability options

Reliability options have been proposed as a key instrument to ensure system adequacy[11] particularly in a system mainly dominated by renewable energy. First proposed by Vázquez et al (2002), these are long-term contracts based on call options that the buyer can exercise

[7] Note that here we do not reserve the CfD denomination only for centrally-auctioned contracts: these can also be (and indeed are) used for private transactions.

[8] Unless used to subsidise emerging technologies.

[9] Schittekatte and Batlle (2023) argue that mandatory CfDs linked to grid access improves the coordination of the generation and transmission capacity expansion problem. Neuhoff et al (2023) in turn defend regulated CfDs, with an also regulated access to this pool of affordable energy.

[10] In this regard, it should be mentioned that information problems are less severe for wind and solar PV projects (see Neuhoff et al, 2016)

[11] As has been shown by some systems with large hydro shares, energy-only markets are not able to provide adequacy in the medium and long-term.

when the market price exceeds the strike price, which is used as the indicator of scarcity in the market (and should be set above the most expensive variable generation cost in the system).

Several reference markets (and strike prices) may be used: for example, the day-ahead market for firm power, or the balancing market for flexible power. Interestingly, this instrument not only provides a signal for investment, but also a price cap for the contracted volume (the strike price) and hence insurance for those consumers affected.

These options are auctioned among those agents willing to supply energy (or withdraw demand) at the given strike price (independently of the technology used, as long as technically possible, and of course including storage), and allocated to those who offer the lowest premium (or option price). Non-compliance with the option must of course be materially penalized, and physical coverage may also be required as in Latin America.

The auctions may be run on a centralized basis (through market or system operators) or on a decentralized approach, requiring all retailers to buy a certain amount, with the possibility to opt-out of them, which brings a more efficient allocation, by avoiding spending in reliability if some consumers do not value it[12] (although, in this case, free-riding should be prevented with an adequate allocation of the costs of the reliability).

The centralized approach is more transparent and less prone to market power as shown by Batlle et al (2010), so a combination in which retailers submit their needs and the MOs/SOs carry out a centralized auction would be particularly interesting.

In this regard, it should be remarked that with a common European electricity market (and hence interconnected prices) reliability options can only be implemented at a European, coordinated scale, if distortions in the common market are to be avoided[13].

For more details, see Brito et al (2022), Batlle et al (2021), or Batlle and Perez-Arriaga (2008).

c) Affordability options

These are long-term contracts that ensure affordable prices for a group of consumers (typically vulnerable ones, but not necessarily). Instead of avoiding price spikes related to scarcity, these contracts provide reasonable average prices. They can be implemented through Asian call options[14], with a strike price that would represent the limit of an affordable price. If dealing

[12] Either because their demand is flexible enough, or because they have already independently invested in storage or firm power options.

[13] Which is not that different from a strategic reserve triggered by a certain price, as proposed by Neuhoff et al (2023).

[14] Compared to a CfD, these options present some advantages (Schittekatte and Batlle, 2023) particularly when applied to existing generators. The main one is that its goal is not to secure revenues, but to protect against high bills, not to fix them, hence keeping as much as possible short-term signals.

with vulnerable consumers these options should be contracted (auctioned) by the regulator for the energy required by vulnerable consumers. Given that, under typical conditions, the volume should not be significant, and that the consumers affected can be clearly identified, these contracts should not interfere with the rest of the market. For some illustrative examples and an extended explanation see Batlle et al (2022).

European standard products and platforms

As mentioned earlier, for these products to be exchanged efficiently and competitively, and to prevent undue interferences of countries in the single market, we need European-standard products and platforms. Accessing all possibilities at the European level (of course accounting for limitations due to reduced interconnections) helps reduce the risk of market power in regional markets (or countries).

According to our first pillar, these products and platforms would not be technology-specific, but open to all resources, including generation, storage and demand that can deliver services and value to the system. For example, storage might cover most of its revenues in the short-term markets, but could complement them with reliability options[15]. This also promotes innovation in developing new technologies or improving or combining existing ones to provide the services required.

We also need to extend the European cross-zonal capacity allocation platform by the Joint Allocation Office (JAO) to products covering the time horizon needed (5-10 years). And, more importantly, address the current problem related to the guarantees required by long-term contracts.

Guarantees for long-term contracts

As has been experienced in the current gas prices, the guarantees required by long-term contracts, which lie under the MiFID II regulation, are clearly excessive, since buyers must account for a liability equal to the difference between contracted prices and short-term prices (which may be very high). These liabilities cannot be assumed by many suppliers or consumers, and are therefore limiting the development of long-term contracts. An alternative would be to move to a scheme similar to REMIT supervision, by which suppliers would need to submit all contracted quantities to the regulator.

Mandatory elements for long-term contracts

But creating and standardizing these products is not enough if there is no demand for them (as has been shown in the past). Therefore, incentives are needed to create a demand for these products, without falling into the problems of a regulator-only demand (as in the regulated approach). We propose that all retailers or large consumers must be required to contract a

[15] This of course depends on the type of storage; and also on the characteristics of the system. In systems with large oscillation in hydro, for example, reliability options may become more relevant. See e.g. Valentín et al (2023).

minimum amount of these products in public, centralized auctions to provide liquidity and transparency[16].

If there is a risk of market power[17] (for example, in regions with little interconnection), producers should also be required to provide a mandated amount of capacity for these regions, or become market makers (requiring them to buy and sell in the market at a given spread, which would also help creating demand and increasing liquidity).

These obligations may be phased out eventually once there is sufficient independent demand for these products and if there is no risk of market power.

Additionally, if long-term products are contracted via auctions, secondary markets in which long-term positions may be traded will also be required to incentivize the participation of demand in long-term markets. As an example, ACER has proposed that all CfDs resulting from state-organized RES auctions should be sold in forward markets to increase their liquidity.

Retail markets

Finally, all these reforms must be consistent with the competition in the retail market, and with the efficient signals required by final consumers for their short-term decisions and investments in energy efficiency or flexibility. These signals might also include different reliability values, so different products might be offered to consumers depending on their flexibility.

In this regard, it must be mentioned that not all long-term contracts provide the same space for a healthy retail market. For example, a contract-for-differences that covers all real consumption leaves very little space for retail, whereas reliability options create much more room for retailers.

To ensure a fair competition in the retail market, market maker obligations on incumbent vertically integrated firms may be used (Schittekatte and Batlle, 2023), as well as more transparent contracting platforms. Also, the regulator must not distort this competition by introducing regulated tariffs for all consumers which may compete or even crowd-out retailers.

[16] If there is some volume contracted directly by the regulator, then these contracts must be passed on to retailers or large consumers.

[17] This is evidently not an easy risk to determine, moreover given that, in the electricity sector, market power does not depend only on market shares (as measured typically with the HHI index). European-wide rules or methodologies to determine this risk would be welcome in this respect to prevent unequal and market-distorting solutions. It is interesting to note that, for example, the Single Electricity Market of Ireland already has a mandated contract (Directed Contract) in place to mitigate market power in their region.

In addition, and to achieve an efficient participation of demand, efficient signals must be sent to final consumers, following the principles set and extensively described in e.g. Perez-Arriaga et al (2016):

- Electricity prices and network charges must be temporally and geographically differentiated, also to ensure an efficient deployment of the grid and distributed generation. Volumetric or increasing block tariffs or postage-stamp charges may result in inefficient decisions, without providing a more equitable distribution (see e.g. Ito, 2014)
- Network charges must be based on incremental network costs.
- Residual charges or policy costs should be allocated on a non-distortionary and equitable basis (e.g. based on property values).
- Vulnerable consumers must be protected effectively, through affordability options or energy checks, financed from the public budget.

The role of governments/regulators

As mentioned earlier, our proposal acknowledges that, besides from setting up the right market frameworks and trading platforms, governments or regulators may have an active role to play when markets do not deliver efficient or fair outcomes.

First, governments should provide guidance along the energy transition, through indicative planning, and also supporting emerging technologies that may play a role in this transition. An example would be jump-starting investments in storage technologies when the market presents excessive uncertainties for private investors. The existence of a limited amount of government-backed CfDs may also help diversify risk portfolios or facilitate access to financing.

Second, governments may need to protect vulnerable consumers, or represent the interests of those consumers not active enough as to participate in long-term markets. As mentioned earlier, this can be done directly, or by requiring retailers to assume these obligations towards these consumers, always taking care not to cannibalise active demand.

Regulators may also intervene if there are significant barriers to entry in some markets, or if windfall losses put at risk the security of the system.

Finally, although out of the scope of this note, a more active involvement of governments may also be needed for network expansion decisions (see e.g. Vasconcelos, 2022), especially in regional interconnections, as it represents a powerful instrument to enlarge the competitive pressure for all technologies, reduce market power and boost a European harmonisation of electricity trading mechanisms and prices.

Conclusions

Following St. Ignatius' quote at the beginning of this document, we believe that the reform of the European electricity market should be carefully thought over, given the many implications of the different proposals on efficiency, equity, administrative complexity, and the need to succeed in the energy transition. In particular, we should not haste to remove the short-term electricity market model that Europe has built over many years. As with the Chesterton fence, this market performs a critical task and removing it might create more problems than sometimes argued.

That of course, does not mean delaying the reform: indeed, and using the second part of St. Ignatius' quote, the impacts of the current crisis could have been minimized if the reforms that many experts have been proposing for many years would have been already implemented.

In this paper we have reviewed two stylized options for this reform, their advantages and disadvantages. Interestingly, one conclusion of this review is that many of the instruments proposed by both are very similar: contracts for differences or reliability options feature prominently in all proposals. Where do the differences lie then?

The major difference is in who makes the decisions about future capacity: a centralized regulator, or decentralized market agents. Having the regulator decide the amount of capacity to be built or the energy to be contracted allocates the risk of uncertain outcomes on final, passive consumers, instead of placing it in the hands of the market agents, which should be the ones with better information. In addition, it increases the possibility of regulatory capture and overinvestment; reduces the incentive to innovate and renovate technologies; and is not able to exploit the heterogeneity of demand. Finally, it places in the hands of member states a large instrument to influence the European single electricity market.

A second relevant difference between the current proposals is whether to consider technologies or services as the object of markets. Differentiating among technologies, and not among services, unnecessarily constrains the range of options available to provide an affordable and reliable electricity service and deters innovation.

This is why we argue that a decentralized, European market-based approach to the reform, in which all technologies are allowed to provide any service technologically feasible in transparent, European-wide platforms, would be superior to the regulated, centralized, technology-specific, one. If carefully designed, and protected against market power, it can overcome many of its problems, while avoiding the inherent disadvantages of a centralized approach. By incentivizing the participation of demand in all areas and promoting innovation, while providing certainty to investors, this proposal ensures an efficient energy transition and, as the European Commission demands, puts citizens (and their decentralized demands) at the center of the transformation.

References

ACER (2022). ACER's Final Assessment of the EU Wholesale Electricity Market Design, April 2022, available at: www.acer.europa.eu.

Amundsen, E.S., C. Andersen, J.G. Sannarnes (1992). Rent taxes on Norwegian hydropower generation. *The Energy Journal* 13: 97-116.

Banfi, S., M. Filippini, A. Mueller (2005). An estimation of the Swiss hydropower rent. *Energy Policy* 33: 927-937.

Barroso, L., F.D. Muñoz, B. Bezerra, H. Rudnick, G. Cunha (2021). Zero-marginal-cost electricity market designs. *IEEE Power and Energy Magazine*, Jan/Feb 2021, 64-73

Batlle, C., I. J. Pérez-Arriaga (2008). Design criteria for implementing a capacity mechanism in deregulated electricity markets. *Utility Policy*, 16: 184–193.

Batlle, C., P. Rodilla, P. Mastropietro (2021). Markets for efficient decarbonization: revisiting market regulation and design. *IEEE Power and Energy Magazine,* 19: 20 - 28.

Batlle, C., T. Schittekatte, C. Knittel (2022) Power price crisis in the EU: Unveiling current policy responses and proposing a balanced regulatory remedy. MIT CEEPR WP-2022-004.

Batlle, C.; Barroso, L. A., I. J. Pérez-Arriaga (2010). The changing role of the State in the expansion of electricity supply in Latin America. *Energy Policy*, 38: 7152–7160.

Barquín, J., P. Rodilla, R. Cossent, C. Batlle (2017). Obtaining best value for money in res auctions: a capacity-based with an embedded menu of contracts approach. Working Paper IIT-17-177A.

Brito-Pereira, P., P. Mastropietro, P. Rodilla, L.A. Barroso, C. Batlle. (2022). Adjusting the aim of capacity mechanisms: future-proof reliability metrics and firm supply calculations. *Energy Policy*, 164: 112891-1 - 112891-13.

Chaves-Ávila, J.P.; Troncia, M.; Herding, L.; Morell, N.; Valarezo, O.; Kessels, K.; Delnooz, A.; Vanschoenwinkel, J.; Villar, J.; Budke, J.; et al. (2021). EUniversal: D5.1 Identification of Relevant Market Mechanisms for the Procurement of Flexibility Needs and Grid Services. Available at: https://euniversal.eu/wp-content/uploads/2021/02/EUniversal_D5.1.pdf.

Chiappinelli, O., K. Neuhoff (2020). Time-consistent carbon pricing: The role of carbon contracts for differences. DIW Discussion Papers No 1859.

Demsetz, H. (1968). Why Regulate Utilities? *Journal of Law and Economics* 11:55-65.

Eicke, A., T. Schittekatte (2022). Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate.

ENTSO-E (2022). Report on the Locational Marginal Pricing Study of the Bidding Zone Review Process ENTSO-E Mission Statement..

Gerres, T., J.P. Chaves, F. Martín, M. Rivier, R. Cossent, A. Sánchez, T. Gómez (2019). Rethinking the electricity market design: remuneration mechanisms to reach high RES shares. Results from a Spanish case study. *Energy Policy*, 129: 1320 - 1330.

Gruenspecht, H.K., H. Pfeifenberger, P.L. Joskow, R. Schmalensee (2022). Electricity sector policy reforms to support efficient decarbonization. MIT CEEPR WP-2022-008.

Herrero, I, P. Rodilla, C. Batlle (2018). Enhancing intraday price signals in U.S. ISO markets for a better integration of variable energy resources. *The Energy Journal*, 39: 141 – 165.

Hogan, W.W. (2022). Electricity market design and zero-marginal cost generation. *Current Sustainable/Renewable Energy Reports*, 9: 15-26.

IRENA (2022). RE-organising power systems for the transition. International Renewable Energy Agency.

Ito, K. (2014). Do consumers respond to marginal or average price? Evidence from nonlinear electricity pricing. *American Economic Review*, 104: 537-63.

Joskow, Paul L (2019). Challenges for Wholesale Electricity Markets with Intermittent Renewable Generation at Scale: the US Experience. *Oxford Review of Economic Policy* 35(2): 291–331.

Linares, P., S. Isoard (2001). Effects of energy markets de/re-regulation onto EU's technology portfolio: conventional and emerging technologies. Report EUR 19829 EN. European Communities.

Lind, L., R. Cossent, J.P. Chaves, T. Gómez (2019). Transmission and distribution coordination in power systems with high shares of Distributed Energy Resources providing balancing and congestion management services. *Wiley Interdisciplinary Reviews-Energy and Environment*, 8: e357-1 - e357-19.

Liski, M., J. P. Montero (2006). Forward trading and collusion in oligopoly. *Journal of Economic Theory*, 131: 212-230.

MCSC (2022), Market Coupling Steering Committee, 7th June 2022, available at: https://www.entsoe.eu/events/2022/06/07/first-market-coupling-consultative-group-meeting/

Newbery, D. (2005). Why tax energy? Towards a more rational policy. *The Energy Journal* 26: 1-39.

Newbery, D. (2016). Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors. *Energy Policy*, 94: 401-410.

Newbery, D.M., M. Pollitt, R. Ritz, and W. Strielkowski (2017). Market design for a high renewables European electricity system. EPRG Working Paper 1711, at https://www.eprg.group.cam.ac.uk/wp-content/uploads/2017/06/1711-Text.pdf

Newbery, D. (2023). Efficient Renewable Electricity Support: Designing an Incentive-compatible Support Scheme. *The Energy Journal*, 44: pre-press.

Neuhoff, K., S. Wolter, S. Schwenen (2016). Power markets with renewables: new perspectives for the European target model. *The Energy Journal,* 37 (SI2): 23-28

Neuhoff, K. (2022). Defining gas price limits and gas saving targets for a large-scale gas supply interruption. EPRG Working Paper 2212, June 2022.

Neuhoff, K., J. Richstein, M. Kröger (2023). Reacting to changing paradigms: how and why to reform electricity markets. DIW Politikberatung kompakt 189..

Pérez-Arriaga, J.I. and P. Linares (2008). Markets vs. Regulation: A Role for Indicative Energy Planning. *The Energy Journal*, Special Issue. The Future of Electricity: Papers in Honor of David Newbery, 149-164.

Pérez-Arriaga, J.I. (2013). *Regulation of the Power Sector*. Springer.

Pérez-Arriaga I. J. et al. (2016). Utility of the Future: An MIT Energy Initiative response to an industry in transition Report.

Pollitt, M. (2021). The future design of the electricity market. In Glachant, J-M., P.L. Joskow, and M. Pollitt (eds). Handbook on Electricity Markets. Edward Elgar.

Pollitt, M., N.H. von der Fehr, B. Willems, C. Banet, C. Le Coq, D. Navia, A.R. Bennato (2022). Recommendations for a future-proof electricity market design. Centre on Regulation in Europe.

Robinson, D., M. Keay (2017). The decarbonized electricity system of the future: the "two market" approach. Energy Insight 14. The Oxford Institute for Energy Studies.

Rodilla, P., C. Batlle (2012). Security of supply at the generation level: problem analysis. *Energy Policy*, 40: 177-185.

Schittekatte, T., C. Batlle (2023). Calls of an electricity market reform in the EU: Don't shoot the messenger. MIT CEEPR RC 2023-02.

Schmalensee, R. (2022). Competitive energy storage and the duck curve. *The Energy Journal*, 43: 1-16

Valentín, J.J., J.P. Chaves, P. Linares, A. Ramos (2023). How much storage does the energy transition need? Mimeo.

Vasconcelos, J. (2022). EU Electricity Reform. NEWES, New Energy Solutions.

Vázquez, C.; Rivier, M., I. J. Pérez-Arriaga (2002). A market approach to long-term security of supply. *IEEE Transactions on Power Systems*, 17(2): 349357.

Annex I. The problems of regulated and deregulated approaches

In the main section of the text we just listed the major problems of each of the “pure” approaches to the electricity market design. Here we elaborate more on them.

For the centralized approach:

Significant risk of overinvestment and the corresponding cost, paid by the consumers, which have no say in the matter

Companies regulated through a rate-of-return approach, as would be the case, tend to overinvest in order to increase profits (this is known as the Averch-Johnson effect). Although in most proposals it is the regulator who decides the amount of investment, companies have a clear incentive to capture the regulator and promote inefficient overinvestment.

Regulatory capture can also affect the price of the contracts awarded, either directly (in the case of existing power plants, see below; or with capacity payments) or indirectly through reserve prices in auctions for new power. In this regard, the asymmetry of information about investment costs (which are known much better by promoters than by regulators) plays again against the interests of consumers.

The regulators may have a much more biased idea of the most efficient long-term mix of technologies. It is not possible for the regulator to address and internalize all technological and economic factors that condition investment decision-making as “markets”, involving thousands of agents do.

Slower substitution of inefficient technologies

As pointed out e.g. in Linares and Isoard (2001), moving back to an average-cost scheme also reduces the incentives to substitute older technologies with new, more efficient ones, since the sunk cost disappears. Therefore, the incentive to innovate and bring forward new, more efficient decarbonized technologies (and pass on the lower costs to consumers) is reduced.

Inefficient allocation of risk, from investors to consumers (through the regulator)

A regulated system typically reduces the risk for investors. This has been argued by some as “allowing for an efficient transfer of risk – from the more risk-averse side (i.e. the private investors) to the less risk-averse side (i.e. the regulator on behalf of all consumers)”. However, the reality is that the regulator is usually very risk averse, moreover considering that the cost of that risk aversion will be paid for by consumers. Therefore, it is questionable whether transferring the investment risk from producers to consumers actually allocates this risk efficiently.

Some technologies, like hydro, are very difficult to contract, due to the variability in volume. Also, if some private resources (hydro or storage in particular) are operated by the system operation, this may result in legal issues (as in South America)

Systems with a significant share of hydro also present problems under regulated systems, as shown repeatedly in South America (e.g. Barroso et al, 2021). First, engaging in Contracts for Differences (CfD) with hydro is very difficult because the volume contracted is uncertain, and sometimes very variable. Second, if the operation of hydropower plants is left to the system operator, the South American experience shows a significant risk of engaging in legal battles over the "right" operation of hydro and its ensuing revenues.

In Europe, having Member States decide installed capacities intensifies their influence on the single market (which explains the reluctance of the European Commission to discuss capacity markets)

National decisions about capacity have a large influence on an integrated market such as the European one, and in fact, national decisions about nuclear or renewables, or capacity remuneration mechanisms have already affected European markets (which explains the reluctance of the European Commission to approve them). A regulated system in which national regulators decide all the capacity installed intensifies and make more evident these influences.

Transferring existing power plants, built under a deregulated system, back into a regulated one, presents many challenges (mostly legal). The non-contestable technology argument may provide some relief in some cases, but not in others

A technology-centered approach like this reduces incentives to innovative uses of technologies and energy services

This approach is based on the assumption that electricity generation technologies are very different, and therefore should be regulated specifically based on their characteristics, which must be well known in advance by the regulator. But what if this is not true? Actually, what matters is not the technology itself, but the services it provides to the system: firm power, flexibility, load-following capability or compatibility with demand profiles, locational value…Adapting the regulation to all these characteristics, in a dynamic way (to account for potential improvements of the technology) seems a very complex task, and may leave out interesting innovations such as Virtual Power Plants, hybrid renewable plants, new storage technologies, etc. Remunerating technologies as such does not provide incentives either for these technologies to offer additional services.

Demand is largely absent or passive in this scheme, with the regulator assuming its role.

If regulators decide the amount of power to be installed, they will also need to determine the amount of energy efficiency that will be undertaken, or how flexible can demand be. Given the less-than-perfect information available, this will probably result in larger costs, and lower efficiency of the system, as well as a lack of consideration for heterogeneous consumers.

Additionally, given that decarbonization will rely significantly on many demand technologies (e.g. electrification of industrial demand, electric vehicles, etc), this presents the risk of missing significant opportunities if demand does not have the right incentives to change.

In principle, distributed generation would be hard to accommodate under this approach, which would open a loophole. How would investment in distributed generation be decided? Would it be subject to the same auctioning process, or decided in a decentralized way? Would it be subject to contracts?

Finally, a relevant challenge is how to make compatible a regulated wholesale system with a liberalized retail one.

If all generation is contracted with the regulator, how can consumers choose their supply under free competition? Do note that, under certain circumstances, a single buyer scheme like the one underlying the regulated system may improve the competition in the retail market, by providing electricity to all retailers under the same conditions and avoiding market power, but in turn does not allow retailers to buy directly in the market and choose their own supply strategies.

For the market-based approach:

Many issues prevent an efficient development of long-term markets

Long-term contracts have always been possible, but demand was not there. There are many reasons for this (see e.g. Rodilla and Batlle, 2012), but in the end, if there is no demand, how can we have well-functioning long-term markets?

Under certain situations, some agents may have market power and use it, increasing prices

Market power, either due to high concentration; or to the ownership of flexible technologies such as hydro or gas which typically set prices, combined with the ownership of inframarginal technologies which benefit from the mark-up, is always a concern in power systems, both in wholesale and retail markets.

Technical or political reasons may create permanent extraordinary profits or losses

Profits and losses are inherent to market approaches as a reflection of the risk borne by the competitive agents. However, market-based systems may give rise to windfall profits and windfall losses for existing assets. Sometimes these windfalls may be sending the efficient signal, either for additional investment, or for phasing them out, but in the case when technical or political reasons create barriers to entry for new investments, or barriers to exit for existing ones, this signal may not be efficient anymore. This being said and even if this issue may have some theoretical support, this does not seem really to be a concern at the European level at this moment. However, since some proposals have insistently raised it, we deal with this issue in Annex II.

Annex II: Dealing with permanent extraordinary rents or losses for existing assets

Due to technical, political or social reasons, or a mix of them, some barriers to entry may exist which may create long-lasting extraordinary rents for some existing assets; or barriers to exit may result in permanent extraordinary losses. The (lack of) speed of market adjustments may also create temporary inefficiencies in market signals. In those cases, some kind of regulatory intervention might be warranted, since these extraordinary profits or losses will not be efficient in incentivising new investment, or in closing existing ones[18].

Do note that these interventions should be justified in efficiency terms, and not derived from the incentive for regulatory capture of rents also present in dynamic markets (e.g. Chiappinelli and Neuhoff, 2020). Note also that we are focusing here on the structural reform of the European electricity market and not on temporary measures to face emergency situations as that derived from the Ukrainian war (which are commented in Annex III). In this regard, these potential interventions would incur in significant legal risks, as well as increase regulatory uncertainty. Both aspects are critical for deploying the large investments required by the energy transition, and would be hopefully minimized for new entrants in our market design proposal. In addition, the existence of long-lasting extraordinary rents is not an easy one to prove in practice and cannot therefore be taken for granted. A European-coordinated approach, solidly grounded on state-aid guidelines to avoid market distortions and unfair competition, and with a clear and rigorous methodology, would help in this regard.

This being said, if a solid case is made, according to a sound European methodology, for the existence of permanent extraordinary rents, and for the need to remove them, the typical options would be a windfall tax or a Contract for Differences. The latter may present lower legal risks, but there is a clear difficulty in finding the right price for the contract, probably resulting either in overpaying, particularly in high-price times like these, or underpaying and hence not covering the actual production costs. One possibility to reduce this difficulty would be to auction these contracts publicly (e.g. in the same platforms as other long-term contracts), with a reserve price. Another one, put forward by Schittekatte and Batlle (2023) would be to auction these assets under Affordability Options (with reserve prices to maximize competitive pressure, and once emergency situations are over), with non-vulnerable consumers able to opt-in and participate in the auction. This would also help protect consumers against future crises.

However, affordability options would not protect generators against extraordinary losses, which would arise if they need to operate (e.g. to keep security of supply) in spite of not receiving sufficient revenues. In those cases, the revenue required should come from the

[18] Note that these extraordinary rents or losses, and the potential inefficiency of investment signals, will correspond to specific technologies or assets, independently of the fact that these assets may obtain their revenues from different markets for providing energy, capacity or additional ancillary services.

relevant reliability market (if the asset receives no revenues from this market, it means that it is not required for security of supply, so it should close).

However, if the assets receiving extraordinary rents are reservoir-based hydropower plants, the situation is more complex. As mentioned earlier, CfD or affordability options are difficult to implement, since production (and hence contracted volumes) may be highly variable. In addition, it is essential that these plants capture the short term price signal to maximize the efficiency of the use of the water. Having these power plants operated by an independent entity, as mentioned before, would not be able to eliminate extraordinary rents (only reduce the possibility of market power, if any). The only option would be to capture the extraordinary rents, if they exist, either by auctioning hydro concessions (which may be a problem given the long lifetime of these, typically 50-75 years), or by setting flexible resource rent taxes (see e.g. Amundsen et al, 1992; or Banfi et al, 2005), which present serious legal risks.

Our conclusion is that, given all the legal and technical complexities and potential disputes associated with adjusting these rents or losses, the first priority in this regard should be to try to remove the potential or existing barriers and market failures creating the extraordinary rents or losses, rather than resorting to regulatory solutions for them. Indeed, in the framework of the European structural market reform addressed in these notes, those potential regulatory actions may not be necessarily warranted beyond the temporary and emergency measures already adopted to face the Ukranian war’s price crisis.

Annex III. An assessment of the different emergency measures proposed

We only assess briefly the emergency measures proposed to address the current energy crisis. Although high energy prices may reappear along the energy transition (e.g. as a result of the lack of investment in fossil fuels), we believe that these measures should have a short horizon (an emergency one), and should not determine or precondition the long-term design of the European electricity market. Also, hopefully the reforms proposed in the main text will reduce the exposure to high prices and increase security of supply, hence reducing the need to use this type of measures.

We should start our assessment by stating that there is no single good solution to the energy crisis (although some combinations may give reasonable results). This is because the two problems they try to solve are difficult to reconcile: saving natural gas and reducing consumer prices.

Therefore, we assess the effectiveness of the measures proposed on these two fronts, plus some other important outcomes: economic transeuropean flows, investment, border trade, efficient operation, windfall profits, legal risks, administrative complexity, impact on previous contracts, fiscal burden, and fairness.

The measures we consider are briefly described below. It should be noted that in most cases our description is too simple.

A cap on gas prices

The European Commission has proposed an administrative cap on gas prices. This avoids messing with the electricity market, and addresses the source of high prices. It also maintains the competition between gas demands. However, it is very difficult to implement, unless also requiring the gas TSOs to buy all gas in Europe, as proposed by Neuhoff (2022). In addition, it reduces the saving signal, so it should also be accompanied by mandatory savings targets to prevent shortages in the market if the cap is too tight. If not implemented as proposed by Neuhoff, it would need a compensation for importers, to be paid for by windfall taxes. Managing existing contracts would also be complex. Finally, a low price of gas in the electricity market might send the wrong signals for the interannual operation of hydro, and for cross-border trade (which would be subsidised).

A cap on electricity prices

A cap on the bids for the power market could also be set, to minimise the impact of high gas prices on electricity prices. However, if not compensated (see the Iberian exception), this would result in a severe shortage of electricity, since high-cost producers would not bid. In addition, the lower prices would incentive exports. This is not a viable measure.

A cap on gas for electricity production (the Iberian exception)

In order to reduce electricity prices in a viable way, the bids from gas power plants can also be capped, and then these producers would be compensated through a charge to consumers. This is what the Iberian market has implemented, with a positive impact on prices, which have been reduced between 10 and 20%, depending on the contribution of gas power plants to the mix. However, the measure has induced a significant increase in gas consumption (against the savings required to fight against the crisis), and also in several cross-subsidies (to countries outside this regulation, which now benefit from the lower electricity price; and also between regulated and non-regulated consumers). It also affects previous contracts by changing the reference price. If implemented across Europe, it would generate distributive flows between consumers in different countries, depending on their generation mixes.

Windfall taxes

This can be implemented through actual windfall taxes, or implementing a cost-of-service regulation which would achieve the same goal: that producers are remunerated based on their average cost, not on the marginal price in the market. It would reduce prices, at the cost of increasing consumption; but would maintain market signals for cross-border trade and efficient operation. The major problem is how to determine correctly average cost, when dealing with private resources (with a large incentive for regulatory capture). In addition, there is a large legal risk, since investments made under competition would see their revenues reduced. Regulatory uncertainty would also increase, which is not good for new investments.

A cap on inframarginal technologies

A similar measure to the windfall tax, but simpler to implement, since instead of determining the average cost of each technology, a uniform cap would be implemented. The disadvantages are the same as before, but in addition it creates differences (and cross-subsidies) among Member States if the share of inframarginal technologies in the mix is different.

An exception on the ETS

Some parties have argued that removing temporally the EU ETS would alleviate the cost of electricity. The problem is that, besides from removing the incentive to save gas, the measure would remove the incentive to reduce emissions, and also the remuneration expected by clean technologies which have invested accounting for this carbon price. As with previous measures, by lowering electricity market prices, it would also incentivise exports (and gas consumption).

Single-buyer contracts

A designated single-buyer (might be the market operator) would contract all electricity demanded using monopsony power. For this to work, all producers would be required to enter these contracts. If not, they would always have the option to sell in the wholesale market and hence their opportunity cost would be higher. These contracts could use ex-ante profiles to incentive an efficient operation.

Then, the electricity contracted would be offered by the single-buyer to all retailers, with the geographical or temporal discrimination desired.

This measure would achieve a similar outcome as the windfall tax, but without the complexity of calculating the right tax, and with a lower legal risk. However, there is the risk that, under a high-price emergency, the contracts signed would be probably too expensive, so they should be implemented as a one-side option, so that if gas prices go down, the option is not activated.

Taxes on extraordinary profits

Taxes on extraordinary profits, which can be used to fund some measures to protect consumers (such as lump-sum transfers) present some advantages compared to a windfall tax: they do not affect market prices or signals, hence ensuring the efficiency of operation, trade or savings. The negative impact on investment signals and regulatory uncertainty is also mitigated. They do not affect previous contracts, and legal risks are lower. Of course, they need to be applied to profits, not to revenues…since then they would become windfall taxes.

Reduction of VAT or other taxes

A quite straightforward measure implemented by many countries, a reduction of VAT does reduce prices (and hence the signal for savings), at a fiscal cost (unless redistributed into other products). This measure preserves market prices and efficient signals. However, it may have regressive effects in absolute terms (not in relative ones): larger consumers get a larger subsidy.

Stability options

Already proposed in the main text for vulnerable consumers, it might be applied to a larger share of consumers temporarily.

Regulated tariffs for vulnerable consumers

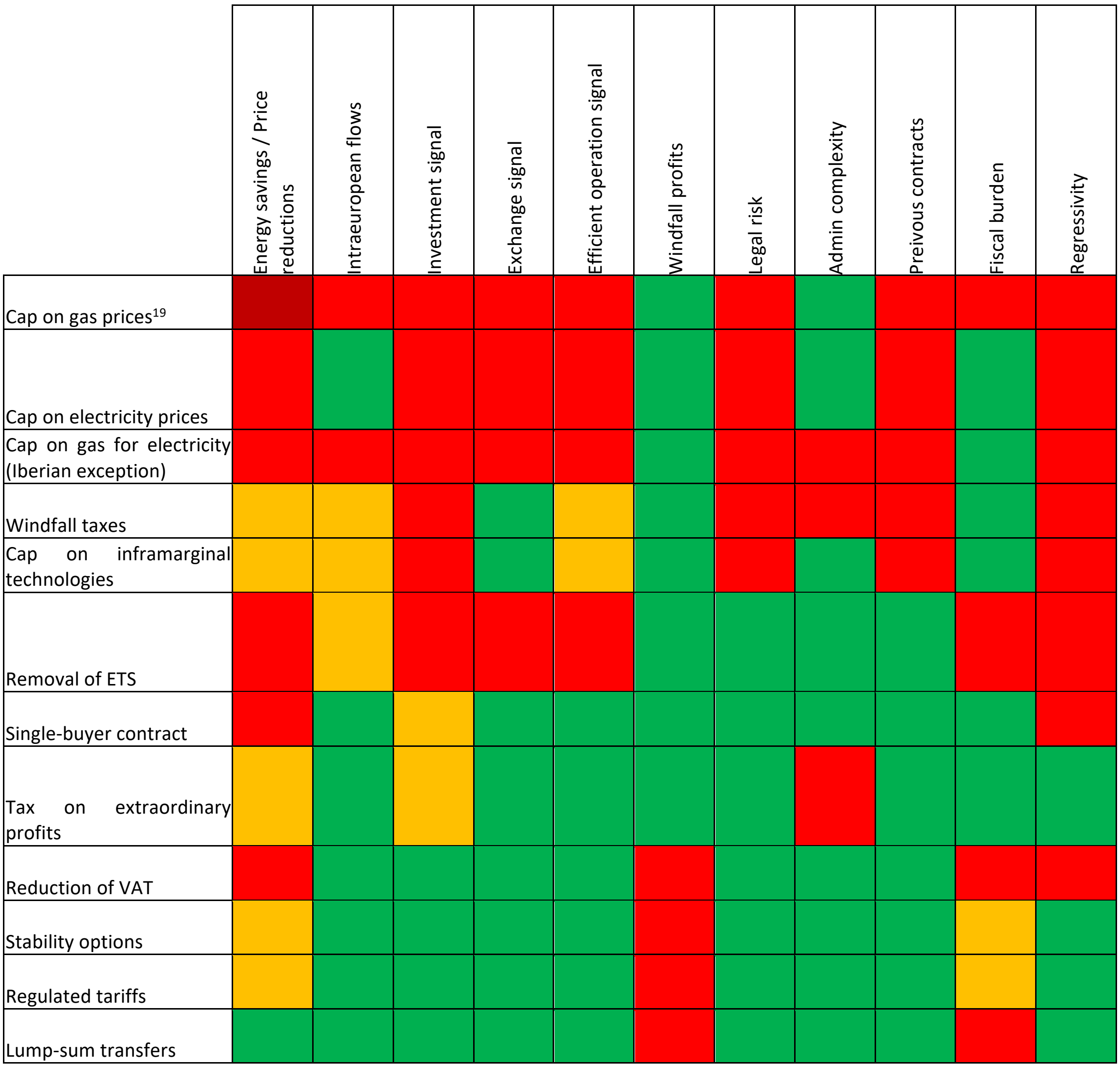
This measure addresses regressivity problems by protecting only a part of the market, those consumers deemed vulnerable. It preserves all efficient market signals, but reduces prices for these consumers. Given that typically the elasticity of demand of these consumers is quite low, negative impacts on savings would be limited. Of course, the subsidy must be funded either by other consumers, or by other sources.

Lump-sum transfers

This is probably the best measure to help consumers without distorting the efficient signals for saving energy, trading electricity, or operating generation technologies. It does not change however windfall profits. And, of course, it must be funded somehow. Depending on how large the number of consumers affected, or the size of the transfer, this can be manageable or not.

The advantages and disadvantages of these measures are shown summarily in the following table. Positive impacts are shown in green, while negative ones are shown in yellow (if mild) or red. As may be seen, there is no single measure that performs well in all aspects, although some look better than others. For example, single-buyer contracts, stability options, or lump-sum transfers are much better than measures like caps or windfall taxes.

Interestingly, if we combine some measures, we might achieve almost all positive effects: for example, a lump-sum transfer funded by a tax on extraordinary profits would be able to reduce the impact of high prices while keeping the marginal signal, and removing extraordinary profits.



[19] The assessment of this measure corresponds to the one put forward by the European Commission, not to Neuhoff's (2022), which are able to prevent some of the problems associated.

Finally, an interesting question is how compatible are these measures with the long-term reform.

Single-buyer contracts would be compatible with the regulated reform (since the regulator is acting as the single buyer). Stability options would also be used in the long-term reform, although typically to protect a smaller group of consumers. Lump-sum transfers could also be used to protect some customers, without interfering with the market.

Caps or windfall taxes, or regulated tariffs, would not be compatible or desirable: indeed, both the regulated and market-based reforms address this through long-term contracts. The removal of the ETS would not be compatible either with the decarbonization signal required by the net-neutrality strategy of the EU.

Finally, potential VAT reductions should be addressed separately, and can be considered neutral for the long-term reform.

Santa Cruz de Marcenado, 26
28015 Madrid
Tel +34 91 542 28 00
Fax + 34 91 542 31 76
secretaria.tecnica@iit.comillas.edu
www.iit.comillas.edu