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Power Crisis in the EU 3.0: Proposals to Complete Long-Term Markets

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Power crisis in the EU 3.0: Proposals to complete long-term markets

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Abstract

On the January 23, 2023, the European Commission launched a public consultation on the reform of the EU's electricity market design. Here we provide our perspective. We assume that the decision to intervene in the market, and the depth of the intervention, belongs to the political sphere. The scope of this paper is limited to a discussion of the implications that the different measures under considerations might have. We start by focusing on the revenue cap mandated through the European Council Regulation published on the October 6, 2022. We discuss that, while there are worse tools, certain implementation difficulties with the revenue cap lead to the conclusion that it is not advisable to keep it in place as a permanent feature of the market design. Further, we argue that the issue that has led to the current financial hardship is an incomplete long-term power market. In that regard, we recommend the introduction of a market maker obligation to improve liquidity in forward markets. We discuss complementary proposals that aim at completing the long-term market while fulfilling the two main objectives of the reform: facilitating the entry of renewable energy sources (RES) at the lowest system cost and limiting the impact of sustained high prices on end users' bills. We explain why these two different objectives are less related than often thought, since they concern different groups of stakeholders with radically different risk profiles, i.e., newly connecting RES units and existing generators. Regarding the former, we argue that even if currently RES costs decrease near or below grid parity, there are still very sound arguments to keep auctions for government-backed long-term contracts in place. Contract design is important and should be reviewed to remove distortion while limiting increases in investment risk. Regarding the latter, we recommend affordability options as the best suited tool to prevent end-user bills from exceeding reasonable levels.

A brief version of this paper can be found as [a 6-page Research Commentary \(CEEPR RC 2023-02\)](#)

Previously, we published two papers on power market interventions as a response to the EU energy crisis:

- Batlle, C., Schittekatte, T., and Knittel C.R., 2022a. Power price crisis in the EU: Unveiling current policy responses and proposing a balanced regulatory remedy, CEEPR 04/2022 and MITEI WP 2022-02. February 2022. <https://cutt.ly/83zli9q>
- Batlle, C., Schittekatte, T., and Knittel, C.R., 2022b. Power price crisis in the EU 2.0+: Desperate times call for desperate measures. MITEI WP 2022-03. March 2022. <https://cutt.ly/v3zlove>

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Contents

1. Introduction: The current call for electricity market design reform in the EU	1
1.1 <i>What happened?</i>	1
1.2 <i>How did policy makers react?</i>	1
1.3 <i>Why reform the EU power market design?</i>	2
1.4 <i>Regulation, not policy</i>	3
2. A brief evaluation of the existing EU power market design	4
2.1 <i>Spot markets doing their job</i>	5
2.2 <i>Long-term markets never really did</i>	6
3. Interventions in wholesale power markets	7
3.1 <i>Which interventions minimally interfere with the efficient short-run dispatch?</i>	7
3.2 <i>How to distribute the revenue from any intervention without distorting saving incentives</i>	11
4. A power market reform: How to “complete” the market design?	12
4.1 <i>Two different problems that cannot be tackled with a single tool</i>	12
4.2 <i>Investment risk management</i>	13
4.3 <i>Lack of adequate hedging of end users against periods of sustained high prices</i>	16
5. The counterparty of the long-term hedges	19
6. Long-term contracts for new RES	21
6.1 <i>Auctions to enhance competition for accessing the network</i>	21
6.2 <i>Long-term hedge contract design for newly connecting RES: Well-designed CfDs</i>	22
7. Long-term contracts for existing generation	26
7.1 <i>Negotiated long-term contracts</i>	27
7.2 <i>Price regulation: Explicit, implicit, permanent revenue cap, and price cap</i>	27
7.3 <i>Procurement of AOs</i>	29
8. Conclusions and policy recommendations	31
Bibliography	33
Appendix A: A product to address affordability concerns: Affordability options	38

1. Introduction: The current call for electricity market design reform in the EU

1.1 What happened?

Since the end of the summer 2021, Europe's energy prices have reached sustained, unprecedented, and largely unexpected high levels, raising a vivid debate across the European Union (EU). The current energy crisis is first and foremost a natural gas crisis. However, as reference day-ahead electricity markets reflect the system marginal (opportunity) cost of generation, often set by gas-fired plants, electricity prices have also attained sustained high levels. Figure 1 shows monthly averaged day-ahead electricity prices from the start of 2021 until the end of 2022 for a selection of European countries. The price dynamics have not been homogeneous across countries, due to the diverse levels of gas dependency, cross-border interconnections, and national interventions in the spot market (most notoriously in Spain and Portugal since June 15, 2022, see e.g., Euronews 2022).

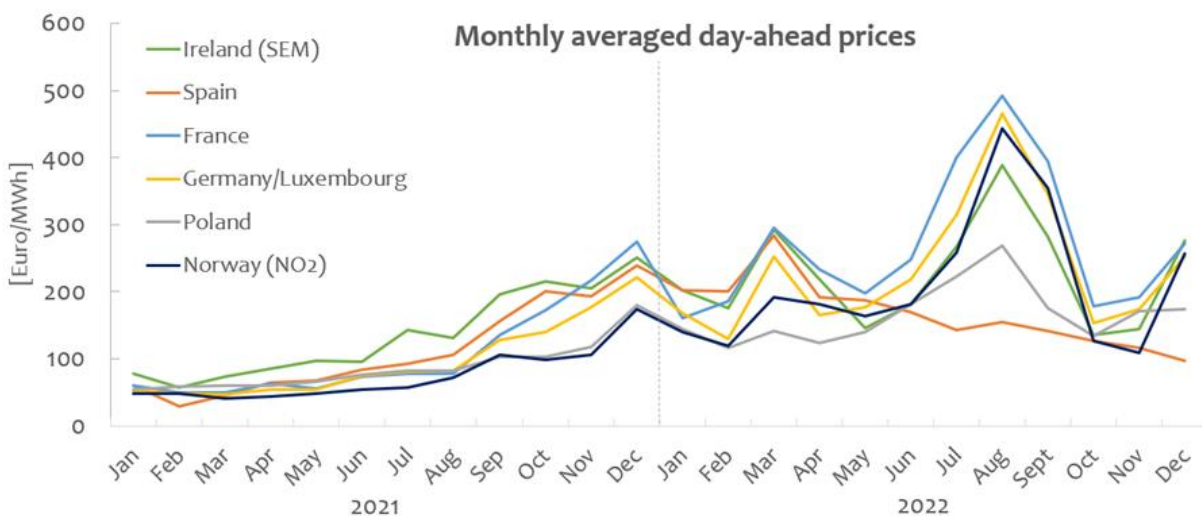


Figure 1: Monthly averaged day-ahead prices for six bidding zones 2021-2022. Based on ENTSO-E (2022).

1.2 How did policy makers react?

Since the onset of the crisis, governments in the EU have spent billions of euros, often representing several percentage points of their national GDP, to shield consumers and industry from high prices. Figure 2 provides an overview. Even when considering such substantial public support, many end users are still facing energy affordability issues (at the time of this writing, February 2023).

An important lesson of the ongoing energy crisis is that although it is a gas crisis, the current regulatory power market compound has proven to be fragile for political interference. The European Commission (EC) initially defended the functioning of the power market but after the Ukraine invasion gradually allowed Member States to intervene (EC 2022a). We discussed these policy responses and interventions in two earlier publications (Batlle et al. 2022a; 2022b). An important milestone occurred on October 6, 2022, when the European Council (2022) finally adopted the regulation on an emergency intervention to address high energy prices. A centerpiece of that regulation is the introduction of a cap for the market revenues set at a maximum of €180/MWh for inframarginal electricity generators, such as renewables, nuclear, and coal. The mandatory cap on revenues would cover all market

timeframes and would apply across the EU from December 1, 2022 to June 30, 2023. We discuss the revenue cap in more detail in Section 3 of this paper.

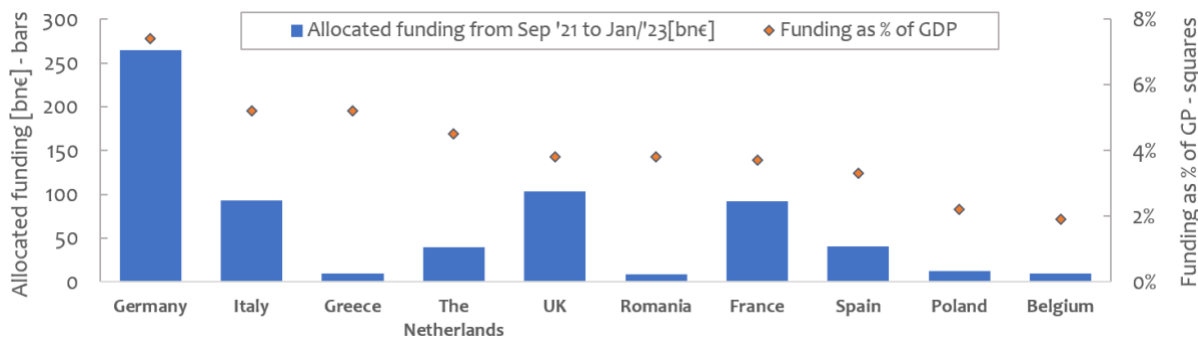


Figure 2: Government earmarked and allocated funding to shield households and industry from high energy prices for the ten most populated countries in EU+UK (Sept.'21-Jan.'23). Last updated 02/13/23. Based on data from Breugel (2023).

Maybe even more important than any temporary intervention in the spot market (even though few temporary measures are truly temporary) is that in the meantime, the Commission started working on its own assessment of the existing power market design. On January 23, 2023, the Commission launched a public consultation on the reform of the EU’s electricity market design (EC 2023a). A proposal for a market reform is expected to be presented in early spring 2023. The proposal has the alleged aim “to decouple electricity prices from the effects of gas prices” (EC 2022b).

Recently, radical calls to overthrow the regulatory compound, which has been gradually built up over the past two decades or more, have been gaining traction. Examples are the so-called “Greek proposal” and variants that in one way or another argue in favor of different ways of “splitting the market” (Although, at least for us, it is not always clear how this approach can be implemented in practice. We briefly come back to these proposals in Section 7.2).

1.3 Why reform the EU power market design?

Before discussing any sort of market reform, it is worth starting by pointing at the actual reason behind the current urgency to change the regulatory compound: (Marginal) energy prices have reached sustained and never expected high levels, and there are reasons to think that it is not necessarily going to be an exceptional situation. In this new reality, the variable costs of an important share of the existing and upcoming capital-intensive fleet, e.g., nuclear, hydro, and renewables, are significantly lower than the marginal spot clearing price. On the one hand, looking backwards, several policy makers and academics blame the already existing investments of “unfairly” making too large profits. It is argued that the relevant investors could have never dreamt of the current price levels when they risked their capital at the time of initially financing the projects (or later by acquiring the shares that gave them the right to collect any future returns).³ On the other hand, looking forward, the investment costs for (intermittent) renewable energy sources (RES) have been significantly reduced much earlier than expected and investment in RES appears now as the by far cheaper alternative.

In economic terms, there is an increasingly widespread perception that long-term marginal generation costs, signaled now by renewable technologies, are and very likely will be for quite some time well

³ For some reason, the unexpected large profits for gas-fired generators holding medium- to long-term gas supply contracts at pre-crisis conditions have been less under the radar of the political action.

below short-term marginal prices often set by gas-fired generators.⁴ In an extremely theoretical market context with strictly zero entry barriers, the current crisis would be nothing less than a great opportunity. Strictly zero entry barriers imply full connection access, manageable investment risks, and, related to this, the willingness to competitively engage in long-term contracts from both the supply and demand side. Under these conditions, from today to tomorrow, thousands of renewable megawatts would connect. Since there would be a severe risk for new entrants of what now has been called cannibalization, they would necessarily have to rely on some sort of long-term commitments with end users. The massively entering renewables would quickly bring overall price levels down by selling their currently below-market-price energy, considering not only their operating costs but also capital expenditures and a reasonable rate of return. It is in this context in which the open (and like any other marginal) market framework, which has been in force for the last two decades, is severely questioned. But the market framework is a compound of many interrelated mechanisms, and the fact that the current market outcomes might deviate from what politicians would desire does not mean that all its building blocks are malfunctioning.

In any case, we need to face the facts: The desired (by many) “market reform” goes beyond the design of the market mechanisms. Looking forward, there is nothing particularly new on auctioning some sort of long-term contracts for new entrants (RES) with the whole system as counterparty. It is a framework that has already been a common practice in Europe (and in many other jurisdictions) for years. Such development has not led to the questioning of the rest of the market compound. The most groundbreaking aspiration of (at least some) Member States governments is to regulate/limit the income of already installed generating units and to discretionally subsidize end-user prices. Even discriminating among the different categories of customers at will, either via direct subsidies or by providing some end users with priority access to the contracts resulting from past and/or future RES auctions.

1.4 Regulation, not policy

The decision to enforce these sorts of measures does not correspond to the regulatory but to the political sphere. At this stage, we explicitly avoid taking a position in favor of or against the implementation of measures of this nature. It is not at all an easy political decision to make, and we are far from having sufficiently sound criteria to take a position or to recommend acting in one way or another. The aim of this paper is to carefully assess the least harmful ways to design certain measures, in case the decision is to go in this direction. This paper consists of six more sections and a conclusion. In Section 2, we provide a brief evaluation of what elements of the market design worked and what did not work. In Section 3, we provide a discussion of the current interventions in the power market with a specific focus on the revenue cap. In Section 4, we identify what we consider to be the two key issues with the current market compound, and we explain why we think that they cannot be addressed with one tool: investment risk management and a lack of adequate hedging of end users against periods of sustained high prices. The two different objectives engage different groups of stakeholders with very different risk profiles, i.e., newly connecting generating units and existing generators, and require different regulatory solutions. We discuss these two separately, respectively in Section 6 and

⁴ It is not the first time that this is a factor behind a significant regulatory reform in the energy sector. Back in the early nineties, the fact that the long-run marginal cost of the by-then-new technology (combined-cycle gas plants) was perceived to be lower than the existing generation technologies at that time was undoubtedly one of the factors that pushed policy makers to introduce the major restructuring that led to the market framework that is in force today.

7. Before doing so, we highlight a key factor common to both mechanisms in Section 5: the end users on behalf of whom the regulator purchases long-term contracts. We end with a conclusion.

2. A brief evaluation of the existing EU power market design

On June 8, 2022, Ursula von der Leyen, President of the European Commission, responded to the questions of the European Parliament after her initial speech on the energy crisis (European Parliament 2022). To the surprise of many, she made the following statements:

*Electricity prices and energy prices are skyrocketing and we are doing a lot on it. We have issued a toolbox that many of our member states are using **that is taxing the windfall profits** and subsidizing thus the vulnerable households and the vulnerable businesses.*

*But we also acknowledge that **this is a short-term relief** that will not really change something in the structure of the market and **what is the problem is the structure of the market.***

We still have an electricity market that is designed in a way like it was necessary 20 years ago when we started to bring in the renewables so it is the renewables that go in first, at that time much more expensive, and later on comes the other energy topics like for example oil or gas or nuclear or coal and the one that comes last, the most expensive, is defining the price.

*Today the market is completely different. It is the renewables that are the most cost effective and the cheapest ones and they come in and then **at the very end comes in gas, the most expensive, but it defines the whole price.***

***This market system does not work anymore. We have to reform it.** We have to adapt it to the new realities of dominant renewables.*

*This is the task that the commission has taken over now. This is not trivial; **this is a huge reform.** It will take time. It has to be well thought through, but we need to step forward to adapt our electricity market to the modern conditions.*

When stating “the problem is the structure of the market (...) we have to reform it,” it is worth questioning what is meant by the “structure of the market” or “this market system,” taking into account that, for instance, some Member States have introduced:

- different sorts of capacity remuneration mechanisms (CRMs)
- auctions in which RES are offered long-term contracts (with diverse formats and risk profiles)
- alternative ways to subsidize RES deployment
- different sorts of regulated default tariffs for some categories of end users,
- consumer access to electricity provided by the state-owned utility at a price below market price levels
- ...

Considering this reality, is it possible to talk about a common market structure, system, or design in the EU? While there is no doubt that there are some common elements, the diversity of “market structures” is so large, that it is not obvious to guess which specific elements of the electricity market design are supposed to have not worked properly.

Next, we first remind what we think has worked, and after what did not. We argue that, although some changes would still be more than advisable, in general terms, spot markets do what they are supposed to do, while long-term markets never did.

2.1 Spot markets doing their job

The short-term market mechanism has a “coordinating role” and does its job: revealing the actual opportunity cost of electricity supply (prices reflect the scarcity of resources). Spot price signals lead to the commitment of least-cost resources, the efficient organization of cross-border trade, and, if end-user tariffs would be properly designed, the possibility for end users to optimize their consumption patterns. Importantly, due to the successful coupling of the day-ahead (and intraday) market, the so-called Single Day-Ahead Market Coupling (SDAC), billions of euros are saved each year in the EU (ACER 2022). The EU has the biggest power market in the world in terms of geographically covered consumption, which is a tremendous achievement. Any change in the day-ahead price setting risks foregoing these important benefits. We provide some more theoretical background to marginal pricing in spot markets in Box 1.

Box 1: Some more background to marginal pricing in spot markets for power

The main idea behind marginal pricing is that when satisfying the demand for electricity, a watt-hour produced by one generation technology is indistinguishable from a watt-hour generated by another technology. Under the assumption that market power is absent, no seller has an incentive to sell their watt-hour under the cost of production of the marginal unit. Hence, the price for each watt-hour delivered at a particular location shall be priced the same in real time. Any deviation from this principle (“the rule of one clearing price”) will lead to uneconomical decisions on the supply side, demand side, and the usage of cross-border interconnectors.⁵ Even though trading volumes in spot markets are often not very high, highly traded longer-term contracts reflect expectations of the spot market prices. As such, inefficient spot prices “propagate” along the sequence of markets and lead to significant additional costs. In the longer run, the evolution of marginal prices should also indicate which technologies are most valuable to add to the existing resource mix.

Marginal pricing is not unique to the power sector, but the standard approach in all commodity markets, such as gas, oil, coal, copper, or grain. A complexity that is specific to the electricity sector is that electricity is not (or hardly) storable, at least not yet in many jurisdictions. This implies that short-term trade directly determines production. This is less the case for other commodities, such as gas, coal, and oil, which can more easily be stored and transported. Considering this reality, one could argue that efficient pricing is (even) more crucial for electricity than for these other commodities. Marginal pricing is in place in the spot markets everywhere in the world where the power sector is liberalized: Europe, the United States, the majority of Latin-America, and Oceania (see e.g., Glachant et al. 2021).

Even though often disputed (for flawed reasons), in a future with a higher penetration of near zero-marginal cost renewables, marginal pricing becomes even more important than what it has already been to date, to coordinate increasingly volatile supply, increasingly controllable demand, storage, and the grid flows. Marginal pricing, based on open bidding, is the only suitable way to reveal marginal operating costs or opportunity costs in the case of demand response and storage (for an elaboration, see e.g., Hogan 2022). Obviously European spot power market design can and should be gradually improved (for a complete overview see Meeus 2020). Examples are more locational prices, bidding

⁵ Professor Ross Baldick (2009) of the University of Texas at Austin also wrote a brilliant explanation of the very basics of the rule of one clearing price.

formats, the removal of portfolio-based BRPs, and scarcity pricing (see, respectively, Eicke and Schittekatte 2022, Herrero et al. 2020, Neuhoff et al. 2016, Papavasiliou 2020). However, none of these gradual improvements has a direct link to the current high prices. In case the key element of the existing short-term market design (i.e., marginal pricing) is substituted by some alternative⁶, additional inefficiencies would be introduced leading to the need for complex regulatory patches and, almost unavoidably, increased costs in the longer run.

2.2 Long-term markets never really did

We pointed in our earlier work (Batlle et al. 2022a; 2022b) at the malfunctioning (or even “non-functioning”) of long-term markets. Certainly, the issue is not a lack of standardized products or organized markets. Power exchanges have offered different sorts of long-term contracts for years already. The issue is the lack of liquidity for electricity price hedges beyond two years. For example, the volumes and contracts negotiated in the EEX German Power Future, with more than 20 years of existence and by far the most liquid in the EU, are insignificant beyond two years forward. This is even more acute in the case of the French Power Futures. The affordability issues that some consumers are facing today are a direct consequence of insufficient hedging. The conclusions of the European Agency for Energy Regulators’ final assessment of the EU wholesale electricity market design, published in April 2022, were also largely aligned in this respect (ACER 2022). The malfunctioning of long-term markets is undisputed and has been a concern for years without any advances along these lines.

In case of perfect information, full economic rationality, and the absence of entry barriers, consumers in need would have naturally hedged themselves not to bear the risk of a period of sustained high prices. Indeed, those consumers for which the energy price levels experienced in the last months turn to be a dangerous hazard (by no means the vast majority of the European consumers) would have paid a market premium to those parties capable of better managing this risk. Assuming a perfectly competitive long-term market, both parties would have been better off. However, in practice, it is largely demonstrated that many consumers do not perceive this need⁷ and significant barriers to the procurement of long-term hedging products (>2y) exist. An important reason for the lack of offers of long-term contracts is that vertically integrated utilities with a fully diversified generation portfolio and a wide consumer base have little incentive to offer long-term hedges. Why would these companies be willing to offer long-term hedges to competing retailers, instead of allowing their own retail branch to benefit from this natural hedge?

The immense bill shock that European energy consumers have witnessed for the last year and a half could be the last straw to convince those who kept on arguing that long-term markets for electricity could ever “naturally” work. In summary, the main reasons behind the power market incompleteness (not at all being a new topic of research⁸) that lead to the need for some sort of market reform are:

⁶ At the onset of the energy crisis a lot of discussion was raised around the possibility of substituting marginal pricing (“pay-as-cleared”) with pay-as-bid. This is definitely a bad idea, and in the meantime, the discussions have moved beyond that point.

⁷ A quick look at the current energy policy debate allows to confirm that end users were not wrong when ignoring the need for long-term hedges, implicitly trusting on interventions from national governments as we are currently witnessing.

⁸ See e.g., Willems and Morbee (2008), Rodilla and Batlle (2012), Joskow (2013), Cramton et al. (2013), Henriot and Glachant (2014), Simshauser et al. (2015), Newbery (2016), Batlle et al. (2021), and Simshauser (2021).

i) lack of demand-side participation in long-term markets, partly due to transaction costs but mainly due to the trust in governmental intervention in times of stress (confirmed soon after the crisis started).

ii) vertical integration between generation and retail, combined with an asymmetric distribution of diversified generation portfolios.

Any proposal for the improvement of the existing regulatory compound should be focused on complementing the long-term market rather than making any radical change to the short-term market. However, as we are currently in a situation where sufficient hedges for the consumer-side have been lacking, governments have opted to intervene in the short-term power market. We first discuss these interventions in the next section. After, we lay out in Sections 4-7 how we think the market should be completed to reduce the risk of costly interventions having to repeat themselves in the future.

3. Interventions in wholesale power markets

Given current affordability concerns, governments have opted to intervene in the power sector to directly or indirectly reduce bills for end consumers. We take this fact as a given. The questions that are most relevant for us are two-fold:

1. Which interventions minimally interfere with the efficient short-run dispatch?
2. How to distribute the revenue from any intervention in a way that minimally distorts incentives for consumers to save energy?

We divide this section up according to these two key questions.

3.1 Which interventions minimally interfere with the efficient short-run dispatch?

This subsection is divided into two parts. First, we identify three groups of interventions. Second, we focus on one of these groups: interventions in the revenues of inframarginal generators.

Three groups of interventions in the power sector

We distinguish three groups of interventions in the power sector, ordered from most to least interfering in the short-term dispatch: i) administrative alteration of spot-market price-formation processes (e.g., acting directly on the price resulting from the market clearing, e.g. via the determination of some sort of cap or artificially reducing the bids in the market of some technologies, as is the case of the so-called Iberian exception), ii) limits to the revenue of inframarginal generating units, or iii) to the profit of all generators (i.e., windfall profit taxes).

In our previous publication (Batlle et al. 2022b) we explained the detrimental secondary effects of interventions that directly impact the price setting in spot markets (flawed incentives on the supply and demand side, as well as cross-border trade distortions). But unfortunately, these latter are seemingly the most implementable interventions from a legal perspective, while the introduction of less-distortive windfall taxes—in case well-designed—seems not legally feasible, at least not at the EU-level. The reason being that a windfall profit tax is a fiscal measure that goes beyond the legal compound of a specific sector or commodity market intervention. But a thorough discussion of the legal hurdles lies beyond our expertise. Besides the legal obstacles, another perceived issue with windfall profit taxes is that they do not help moderating inflation. The reason being that the windfall

profit taxes are not directly transferred to electricity consumers to lower their bills but are first collected by the government (i.e., it is not straightforward that they can automatically be turned into a rebate for electricity bills). The issue here is not the claw-back instrument, i.e., a windfall profit tax or a revenue cap, but the methodology to determine the impact of electricity costs on inflation.

The decision published by the European Council (2022) on October 6, 2022, after a proposal by the Commission, was to implement a revenue cap for inframarginal generating units. Such intervention lies in the middle in terms of introducing risks with regards to interference with the short-run dispatch and legal feasibility. The idea seems to be that a well-designed intervention in the revenues of inframarginal generators can mimic a windfall profit tax, but it is far from clear, even after examining the decision in much detail, how such a revenue cap would actually work (e.g., How should it be calculated? Should an estimation of the generation costs of each technology be made? If so, how?).

Also, a practical (and major) implementation difficulty with any intervention in the revenues of inframarginal generators is that a share of future production could already have been financially committed forward before the introduction of the revenue cap. Or it could be subject to long-lasting renewable support schemes, which often are shielded from significant short-term market price deviations. An additional complication is that hedging contracts do not necessarily match one-on-one with the production of an individual generation unit, as the common practice is portfolio hedging (for ones that have diversified portfolios). Such complications that come with the implementation of a revenue cap (and others, since for instance long-term gas contracts previously signed should also be considered) require that all market parties expose all of their contracts and trades, which is a procedure that makes the implementation of some form of a revenue cap not entirely impossible but quite burdensome to say the least.

Further, several companies are also vertically integrated and might quickly argue to have previously signed long-term contracts between their generation and retail arms at price levels under the revenue cap. What matters in that case when looking for “excess revenues” is the final rate at which the retail arm charges retail consumers. However, even if the final rate at which the retail arm charges retail consumers equals the revenue cap or below, not necessarily all issues are solved. For example, a cap on revenues for generators, as implemented in Spain, very much disadvantages “independent” retailers. Vertically integrated incumbents holding diversified portfolios with a balanced generation/retail position can perfectly afford a cap at a level below market prices (in the Spanish case, the “virtual” revenue cap is set at around 67€/MWh, while according to [omie.es](https://www.omie.es), the average market price in 2022 was 167€/MWh). These companies see their income capped indeed. But at least they can sell via their retailers to end users at a price equal or below the cap without much additional complication. Generation is paid at the cap, the retail arm sells at the cap. But independent retailers without the natural hedge of a portfolio whose cost is aligned with the market prices can hardly compete. They cannot sell to retail customers at prices above the cap as that would make them uncompetitive in the retail market. But they have a much higher risk for having to procure at least part of their energy in the market at higher prices, especially when considering the crisis is lasting longer than the length of most long-term contracts available at its onset. The solution would be to enter into a new contract with a generator. But which generator with a diversified portfolio is going to be willing to be the counterparty at a price that would render independent retailers competitive? The ones that can are direct competitors of the independent retailers. Why should we expect that they would do it?

Implementation of a revenue cap: Interference in the short-term dispatch

While there are worse instruments, beyond the high risk of negatively impacting retail competition, it is not straightforward to implement a revenue cap that does not interfere with the short-term dispatch, leading to additional costs (e.g., burning more gas while the main goal is to reduce gas consumption) and, in the extreme, to security of supply issues. We cannot provide a full-fledged guidance on how to implement a revenue cap in the least harmful way, as it goes beyond the scope of this paper. However, here we discuss some of the main identified issues.

A revenue cap affects two key decision-making processes relevant for an optimal dispatch: the generation plant management “inter-time periods” (ideally guided by the right price arbitrage incentives, leading to production in those hours in which the value for the overall system is larger) and across markets “intra-time periods” (e.g., selling energy/capacity in day-ahead, intraday, or balancing markets). The actual cost for the system caused by these distortions depends on technology characteristics: It is most acute when it affects units that are flexible and have a limited production over a long horizon, such as hydro plants with reservoirs, but it can also be relevant for e.g., maintenance schedules of coal, nuclear, and renewable units.

The worst-case implementation of a revenue cap would imply making a generation unit subject to the revenue cap that renders the owner of the plant completely indifferent from the level of the spot prices above the level of the cap. The contractual equivalent of such implementation would be the introduction of a sort of call option not linked to a predefined quantity and settled based on the entire volume actually sold per individual generator unit, per short-term market segment (day-ahead, intraday, or balancing), and per relevant market time unit. The strike price of the call option would be the level of the cap. A simple example of what could happen is the following: Imagine a coal unit that needs to schedule maintenance in the next months. The maintenance cost can be different depending on when it is actually completed. In a well-functioning market, this decision depends on the balance between these costs and the market prices, which determines the revenues while at the same time reflects the value of the generation at each moment. If subject to a revenue cap, the plant owner completely disregards the fact that there are hours/periods in which hourly day-ahead prices are a lot higher than other periods (as long as the prices are constantly at least equal to the cap). A similar example, but even more difficult to manage, can be made up with a hydro unit with a limited reservoir having to decide when to produce or when to save the water for production at a later point in time.

Also, under such an implementation of the revenue cap, market parties would have no or at least a strongly reduced incentive to trade part of their energy in the balancing market, a key tool to keep the system secure. One possibility, as also mentioned in Art. 4.a of Regulation 2022/1854 of the Council, is to exempt revenues from balancing (or redispatch) from the revenue cap. However, it would have the counter effect of providing generators with the incentive of offering more balancing energy than what would be optimal for the system. Moreover, it would open the floor to potential and harmful trading strategies: If flexible units are kept aside from trading before the balancing timeframe, what could happen is that those units might not be used to trade out imbalances with other market parties in the intraday market. This, in its turn, would have the effect of increasing the total system imbalances and the need for balancing energy, thus working in favor of those “withholding capacity” to provide balancing energy. Such a strategy, while not necessarily in conflict with market rules, would lead to higher system costs and potential risk of supply security. In short, in case a revenue cap is introduced,

completely exempting the balancing timeframe does not seem to be a good idea.⁹ In case the balancing market is also subject to the revenue cap, another strategy that could occur is that flexible units would aim to provide “passive balancing,” i.e., willingly being imbalanced in the opposite direction of the system and, as such, earning from the imbalance settlement mechanisms. Such a strategy, while in “normal times” being helpful to reduce balancing costs, could lead to severe issues if suddenly pursued at larger scale. However, such a strategy would be very risky for a market party and therefore less likely to be pursued.¹⁰

To find a more resilient solution that avoids the issues discussed above is very complicated, but there are (at least) four important design parameters of the revenue cap that can mitigate them: i) the frequency of the settlement to calculate the “excess revenue,” ii) whether the revenue cap is applied to the aggregate sales over all markets or individual sales per market segment, iii) whether the revenue cap is applied at unit-level or portfolio-level, and iv) the proportion of revenue above the level of the cap that must be returned to the government. Unfortunately, there is again a trade-off; less interference in the dispatch will typically lead to less “excess revenues” that are captured for the same level of the revenue cap. We discuss each design parameter one by one.

i) A settlement based on the price of sold electricity averaged over a period that is longer than the market time unit (typically one hour for spot markets) will generally lead to less distortions; market parties will be more inclined to produce at the hours with highest prices.¹¹ A longer settlement also allows for a more even-level playing field between sales in spot markets and sales via long-term contract, for which the price is by definition an average over a longer period. In other words, an hourly settlement might skew incentives to contract more via long-term contracts compared to a situation without an intervention.

ii) Treating the sales per short-term market segment (day-ahead, intraday, balancing) separately when calculating the amount of “excess revenue” can distort the arbitrage between these markets. It seems more appropriate to treat these sales (and purchases) in aggregate (including or not sales from long-term contracts).

iii) Calculating the excess revenues per unit will typically be more distortive than over a portfolio. However, the calculation over a portfolio, while also being easier to implement, would critically favor larger players. Also, in the national implementations of the revenue cap, often different levels per cap are chosen per technology. The reason being that some sort of “reasonable return” is calculated which might differ per technology, as costs also differ. Such implementation would indeed require

⁹ In case the revenues per market segment are separately settled, a compromise could be to leave more “excess revenues” with market operators when sold in the balancing market versus the day-ahead market (e.g., 90% of the “excess revenues” being captured for the day-ahead market and 70% when sold in the balancing market).

¹⁰ Another issue with the revenue cap is that while revenues from selling electricity are reduced, the imbalance price would reflect the actual value of that imbalance. Thus, the imbalance price would be very high at moments the system is short, as well as the market party. Such high prices give the adequate signal to not deteriorate the system imbalance but can also lead to financial pressure on market parties that deal with frequent hard-to-control imbalances. Due to the introduction of a revenue cap, high market revenues do not make up for this risk anymore.

¹¹ Unless prices are very high every hour, the difference is minimal. Also, imagine that the revenue cap would be settled per month. In that case, often it is straightforward to anticipate if the revenue cap is going to be active or not in, for example, the last week. If affirmative, price signals will have little value. This issue can be mitigated by not capturing the entire amount of revenue above the cap as discussed later.

calculating the “excess revenues” per unit or at least on aggregate per technology and not per portfolio.

iv) Not capturing the entire amount of revenue above the cap also provides improved incentives with regards to dispatch efficiency, both in terms of less interference of the optimal dispatch over time as well as over the different market segments. This is true since production during hours or sale in particular markets when the price (and thus the value for the system) is very high will be encouraged because at least a fraction of the revenue can be kept by the market parties. Art. 4.b of Regulation 2022/1854 states that the cap on market revenues only applies to 90% of the market revenues exceeding the cap. Advanced schemes can be thought out; however, not having a full passthrough of the entire marginal signal will always lead to cases where the dispatch is distorted to some extent.

In summary, the potential gravity of the distortions created by a revenue cap is a function of technology characteristics. There is a trade-off between reducing distortions and maximizing the capturing of “excess revenues.” A combination of having a settlement period for the determination of the “excess revenues” beyond the market time unit, aggregating sales (at least in short-term markets, potentially also long-term contracts), aggregating units, and not capturing the entire revenues in excess of the cap would be recommended to avoid costly interference in the short-run dispatch and additional security of supply risk. Table i provides a summary.

Table i. A revenue cap mechanism and risk for interference in the short-run dispatch

	<i>High risk for interference</i>	<i>Lower risk for interference</i>
<i>Settlement frequency of the “excess revenue” calculation</i>	Per market time unit (e.g., hourly in the day-ahead market)	Longer than the market time unit, e.g., monthly (at least for short-term markets)
<i>Aggregated or separate sales per short-term market segment (day-ahead, intraday, balancing)</i>	Separate per market segment	Aggregated per market segment (possibly including long-term contracts)
<i>Calculation per unit or portfolio</i>	Per unit	Per portfolio
<i>Amount of excess revenue captured above the cap</i>	100%	Less than 100 %, e.g., 90% (can be lower for balancing but not too low)

3.2 How to distribute the revenue from any intervention without distorting saving incentives

An intervention in the market price setting impacts all end users and requires direct accompaniment by demand reduction measures as the marginal price signal is artificially reduced, leading to a reduction in savings incentives. Interventions in the revenue and income of generators—when well-designed—impact the marginal price signal to a lesser extent. A major advantage is that interventions in revenue and income allow a differentiation in support among end users, which is crucial as not everyone needs support.

Using the income from interventions to reduce the average price in euro for each kWh consumed is a very bad idea. It reduces incentives to save energy. A better idea is to use the income to write lump-sum checks or subsidize a minimum level of consumption, while keeping the exposure to spot prices for consumption levels beyond that threshold. The latter is called inclined block rates in the academic literature and have been recently introduced in e.g., Austria, the Netherlands, and Germany (Euractive

2022; Independent 2022; Reuters 2022a). A rationale for choosing inclined block rates over checks can be to protect households against inflicting rationing measures that are too strong on themselves, for instance causing longer-run health impacts.

The determination of the volume of subsidized electricity is an important question. In that regard, we would rather advocate to let the subsidized volume depend on socio-economic parameters (e.g., income, household-size, weather-related variables) than on historical consumption. Another question is how to price subsidized non-consumed energy. In case the subsidized volume is small relative to the consumption, this is not an issue. However, if the subsidized volume is not much different from the actual historical consumption (such as the 2900 kWh uniformly applied for all households in Austria), paying back the marginal (market) price might incentivize even more savings. However, such approach could also lead to windfalls for some consumers to whom too much subsidized electricity was allocated due to an imperfect allocation formula. An example is a household that did a recent major investment in energy efficiency or PV panels, or the owners of a house which are absent for a prolonged period. Especially for the energy poor, another alternative would be to use the income from the revenue cap to subsidize energy efficiency, or even a solar panel, rather than lowering the bill. The former has a more lasting impact.

4. A power market reform: How to “complete” the market design?

In the meantime, the Commission has started working on its own assessment of the existing power market design. A proposal for a market reform is expected to be presented in early Spring 2023. The proposal has the aim “to decouple electricity prices from the effects of gas prices” (EC 2022b). At the time of writing, the public consultation on the reform of the EU’s electricity market design is open (EC 2023). It will be closed on the February 13, 2023.

In the following sections we provide our perspective on the call for reform. We explore different power market design elements that the ongoing energy crisis has evidenced as much needed to complement the long-term market. We divide this section into three parts. First, we identify—what we consider—the two key issues with the current market compound, and we explain why we think that they cannot be addressed with one tool. After, we discuss each of these issues separately. First, the investment risk management. After, the lack of adequate hedging of end users against periods of sustained high prices.

4.1 Two different problems that cannot be tackled with a single tool

As discussed in Section 2.2, the main reasons behind the power market incompleteness that led to the need for some sort of “market reform” are:

- i) lack of demand-side participation in long-term markets, partly due to transaction costs, but mainly due to the trust in governmental intervention in times of stress (confirmed soon after the crisis started), and
- ii) vertical integration between generation and retail, combined with an asymmetric distribution of diversified generation portfolios.

These factors have led to two major problems that need to be finally tackled:

a) the inability of (particularly new) investors in generation to efficiently manage long-term uncertainties and risks linked to technology learning curves, entry barriers for access, and rapidly changing policy agendas, and

b) a lack of adequate hedging of end users against periods of sustained high prices.

At this stage, it is of no use to persist in the same (costly) mistake of suggesting “cosmetic” solutions that do not address the actual reasons behind these problems. A proactive regulatory intervention is needed to complete the market in a way that i) long-term risks, especially for RES investment, can be more efficiently managed and ii) political unrest, when for justified reasons prices are high, can be mitigated. However, these two main objectives of the reform are in practice less related than many might think. In the short- to medium-term, we cannot expect that new RES alone can solve the affordability concern. For at least a decade, the total volume of new RES electricity production is going to have a relatively limited impact on final bills. But moreover, as penetration increases, the hours of RES production are expected to increasingly decorrelate from high-priced spot hours, which is most acute for solar PV. There is no one solution that fits all. And as is well known in the regulatory field, trying to address two problems of different natures with one instrument nearly unavoidably leads to inefficiencies.

Hence, we deem it important to face both objectives separately. On one side, focus on designing centralized auctions for long-term contracts for new RES entrants. On the other side, develop mechanisms to provide end users in true need with hedges against future sustained high price events. The natural counterparties of end users for such hedges are not new entrants, but generation companies owning large and diversified portfolios.

4.2 Investment risk management

An incomplete forward market has led to difficulties for market parties to efficiently manage risk when investing in new generation. This problem was being addressed in most jurisdictions already before the crisis started. In this subsection, we first start with a discussion of existing tools, Capacity Remuneration Mechanisms (CRMs) and RES support mechanisms. After, we discuss a Market Maker Obligation (MMO) as a complementary approach to improve investment risk management.

CRMs and RES support mechanisms

The issue that power markets have significant entry barriers and are far from being complete has already been recognized for a long time and has led to complements to the energy-only market idea that was developed decades ago (Joskow 2022). Since the implementation of electricity markets worldwide, first via the design of stranded cost mechanisms with claw-back clauses, and then through different sorts of subsidization tools (mainly) for non-emitting technologies as well as via Capacity Remuneration Mechanisms (CRMs) in some contexts, policy makers have intervened with the expectation to guarantee at least a “reasonable” floor on the income of the generation capacity deemed necessary. These complements are forms of (mostly) centrally managed, promoted long-term contracts.

For instance, the main objective of CRMs is to complete the market by reducing uncertainty in future revenue streams of resources that are deemed necessary to continuously guarantee a sufficient level of resource adequacy. CRMs can increase revenue certainty for new investments (needed to make

that investment happen) or solidify future revenue streams of existing generators to avoid their retirement. Many different types of CRMs exist, under diverse denominations and different design elements, such as capacity payments, capacity markets, strategic reserves, reliability options, and other. None of these mechanisms lead to a (significant) transfer of income from the generators to consumers at times of sustained high spot prices. One could argue that some generators received CRM support that has currently shown to be excessive but clawing back such support would imply a retroactive action and set a dangerous precedent. It is important to remind us that the objective of CRMs was not to guarantee capped prices, but adequacy and availability (Mastropietro et al. 2017). For instance, the original objective of reliability options was to use the strike price of the call option as the threshold evidencing a scarcity situation in which those generators that are rewarded with the CRM payment are expected to be producing. Reliability options transfer income from the sellers of those options (typically generators) to the central buyer (on behalf of the system), but, for good reasons when thinking about the goal of a CRM, their strike price is high, and the settlement frequency is hourly. Hence, reliability options protect against (hopefully infrequent) very high prices but not against high bills, as discussed in more depth in Appendix A.

CRMs are expected to remain an important complement to power markets in the future; however, in the current European context, capacity is not the problem—no blackouts or rolling brownouts are witnessed. However, there is still a lot of work to do to improve the design of these mechanisms. Examples of main open questions are leveling the playing field for different resource types to participate (RES, demand response, storage), the design of the reliability commitment, and the definition of the so-called firm capacity. Although this discussion is of utmost importance, particularly in the current context in which the whole regulatory compound is under review, we deem it out of the scope of this document.¹²

The aim of support schemes for RES, besides covering investment costs that could not be recovered via short-term market prices, is to provide revenue certainty for new investments in carbon-free generation technologies to reduce project financing costs. RES support schemes are not designed to protect against affordability issues. However, in the current context in which RES's average costs are below the level set by short-term prices, some types of RES support partially do. Once again, it is important to remind that the hedge resulting from these mechanisms is linked to the price “seen” by RES (the one that the mechanism aims at helping), not to the price end users do pay. And moreover, this spread (the difference between, for example, the solar PV price and the market price) in the absence of adequate storage is going to be increasingly high.

We briefly discuss two different examples: feed-in premia (or green certificates) and contracts-for-differences (CfDs):

i) Feed-in premia (and all sorts of green certificates) will not lead to a net income that can be transferred to end users, as they represent a payment on top of sales in the spot market (or via privately agreed long-term contracts). Again, one can argue that some RES generators receiving feed-in premia (or green certificates) on top of the already very high spot prices is excessive, but clawing back such support would imply a retroactive action and set a dangerous and costly-for-the-future precedent.

¹² For a recent overview, see the book by Hancher et al. (2022).

ii) Under CfDs, RES generators sell their production in the spot market and receive/pay the difference between the pre-agreed strike price in the contract and a reference price (in most cases, the hourly spot price, but it can also be a “technology price” or a reference plant price, see a more in-depth discussion in Section 6.2). Currently, mainly due to strike price levels that are typically under the average spot prices, income is transferred to the CfD counterparty, thus (depending on the tariff regulation) benefitting end users.

While originally the level of the feed-in premia or strike prices in CfDs (or alike) were mostly administratively determined, centralized tenders for long-term contracts in which developers are competing for contracts by bidding in their required price are currently widespread in Europe (AURES II 2023), as well as worldwide (IRENA 2015). Beyond continuing to gradually improve the design of these mechanisms and the relevant contract formats, we do not see any need for a fundamental change or “reform” at this point in time. As discussed in more depth in Section 6.1, we agree with Neuhoﬀ et al. (2022a;2022b) in that, even if RES costs decrease near or below grid parity, there are still very sound arguments to keep auctions for government-backed long-term contracts in place. As discussed in depth in Section 6.2, at this stage, we deem the emphasis should be on finding the most adequate contract format that balances investment support and short-term economic dispatch, and medium- to long-term planning efficiency. This discussion was also already active before the crisis started.¹³ Finally, what has gained momentum recently, now that these government-backed contracts are in the money, is the intention of some Member States to discriminate in favor of certain categories of end users (industrials or residential customers) by turning them, rather than the entire end-user base, into the sole counterparties of the RES contracts. We discuss the allocation methodologies of the settlement of contracts procured on behalf of end users in more depth in Section 5.

Market maker obligation for incumbents

A “market maker” is a firm that stands ready to buy or sell a financial derivative at publicly quoted prices (U.S. Securities and Exchange Commission 2022). Market makers quote two prices, bid (buy) and ask (sell) prices, on a given pair, thus creating liquidity and speeding transactions in the market, when sellers cannot find buyers or vice versa.¹⁴ They commit to accepting trades at these prices within certain restrictions and obtain remuneration on the difference between these prices—the so-called spread. In some cases, the role of market maker can be granted in an auction, in which the potential candidates can ask for a fixed remuneration to develop the role. Considering that market makers assume the risk of open positions, it is advisable to assign this role to market agents owning deep and balanced positions in the market, capable of assuming any trade or quickly finding a counterparty willing to offset each operation for a fee below the predetermined spread.

An MMO is an especially relevant solution to mitigate the competitive advantage with respect to risk management of vertically integrated firms with diversified generation portfolios. Market makers are not new in electricity markets. For instance, in 2014 the Secure and Promote (S&P) MMO was introduced by Ofgem in the Great Britain (GB) market, placing the obligation on the six largest vertically integrated companies at its time of introduction. The mechanism was later suspended in 2019, among other alleged reasons because at least four of the six utilities that assumed the market

¹³ See e.g., Cochran et al. (2012), Purkus et al. (2015), Huntington et al. (2017), Barquín et al. (2017), and Newbery (2017).

¹⁴ The rationale of the measure is that if a market agent with sufficient size (at both ends, generation and retail) is asking a certain price to sell a relatively small part of its future output (for example, 60 €/MWh for a baseload contract), it should be equally willing to buy the same amount at a lower price (say 55 €/MWh).

maker role divested their generation assets (it is not clear that the MMO had any impact on the decision made by the firms). As reflected in the responses to the open letter in which Ofgem discussed its decision (Ofgem 2019), there was a consensus among all the large companies against the mechanism; but not surprisingly, a good number of small companies argued in favor of it.

This mechanism has even been proposed as a tool to improve the functioning of balancing markets in Europe, in which flexibility resources are traditionally largely concentrated, see Batlle et al. (2007). Certainly, as with any other solution, the design details make a key difference. Examples of choices that need to be made are how to assign the responsibility, how to determine the bid-offer spread, what maximum volumes should market makers be obliged to cover, etc. Anyhow, we consider the introduction of a market maker for long-term electricity futures (>3 years) a rather straightforward and not disruptive measure to carefully explore.

4.3 Lack of adequate hedging of end users against periods of sustained high prices

The lack of safeguards, revealed by the crisis, has led to a severe economy-wide affordability problem for the EU. And, obviously, high and unhedged prices have also led to generators' profits being largely above expectations, both for policy makers and the market parties themselves. The regulatory objective in this context is the provision of long-term hedges for end users in need to guarantee affordability, while keeping short-term incentives for efficient consumption intact.

New RES entrants via centralized auctions for government-backed CfDs can slowly soften the medium-to long-term volatility of certain categories of end users' prices. But, as discussed before, this solution can only be very partial. Unfortunately, in the absence of abundant storage, not just short-term but also seasonal storage, the average market price that consumers pay will increasingly diverge from the average price that new renewables perceive in the market (see Box 2 below). In this context, owning a large and, maybe even more important, fully diversified generation portfolio provides incumbents with an unbeatable competitive advantage in both the generation and retail market. Why would these generators be willing to offer long-term hedges to competing retailers, instead of allowing their own retail branch to benefit from this natural hedge?

Box 2: Residential bill prices and solar income divergence

Already nowadays, when there is still an extremely significant amount of renewable (wind and solar) to be installed in the coming years, it is possible to easily illustrate the already well-known mismatch between hourly spot power prices, residential demand, and solar PV output. We provide an example in Figure 3.

The mismatch is not just between daily profiles: Monthly values also are differently affected by seasonality; indeed, they are far from being positively correlated. But as we argue above, this mismatch, particularly the one between the monthly bills of low-voltage end users and solar PV income (or market value of solar PV production) is unavoidably going to increase as penetration of solar PV grows, as established in the EU National Energy and Climate Plans (NECP) (EC 2023b). To illustrate this phenomenon, we developed a long-term simulation of the future functioning of the power market in Spain. We consider the generation (and storage) capacity expansion scenario depicted by the Spanish NECP, simulated the future hourly economic dispatch and calculated the corresponding spot market prices for the period 2024-2030.

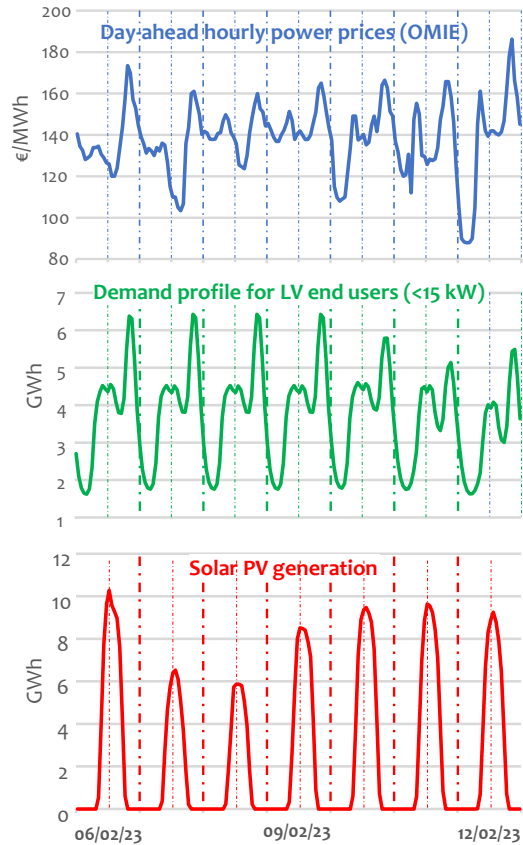


Figure 3: Hourly spot prices, low-voltage consumers demand and solar PV generation from February 6 to 12, 2023 in the Spanish system (data collected from omie.es and ree.es)

The simulation allows us to compare the future evolution of i) the monthly income to be received by a solar PV panel of 1500 kWp of capacity (by just multiplying the expected hourly production of the panels times the hourly prices obtained from the detailed system simulation), and ii) the total monthly energy payments to be made by low-voltage end users (idem, by just multiplying the estimated demand of these consumers¹⁵ times the hourly prices).

Figure 4 and 5 below show for years 2024, 2026, 2028, and 2030: i) on the left, the monthly payments of low-voltage consumers, and ii) on the right, the monthly income of the solar installation.

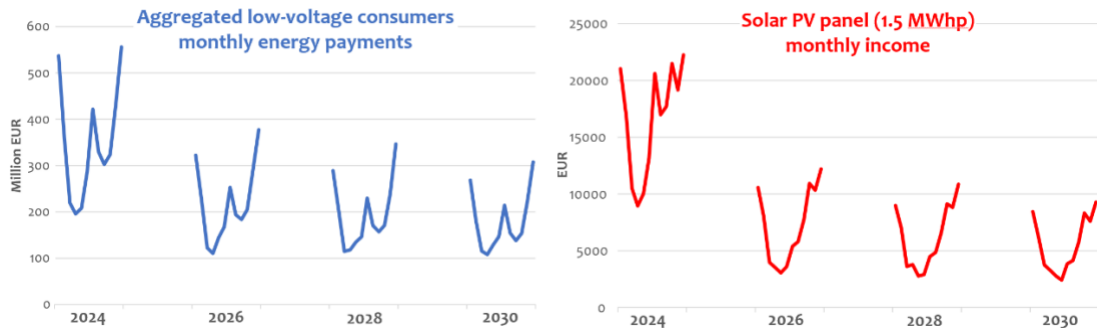


Figure 4: Evolution of (left) low-voltage energy payments and (right) solar PV income per month

First, it can be observed that for 2024 it is expected that there will still be some remnants of the energy crisis, and thus prices and income will remain high. For the other three years, we assume in our simulation that gas prices return to “normal” price levels.

While at first sight the illustrations above might give the impression that there is some correlation between the two, a simple further analysis shows that this will not be the case. In Figure 5 we depict the ratio between those two numbers. The ratio of energy bills/solar (RBS) is calculated for each month as the monthly payment of low-voltage consumers (left panel of Figure 4 above) divided by the corresponding monthly income of the solar installation (right panel of Figure 4 above).

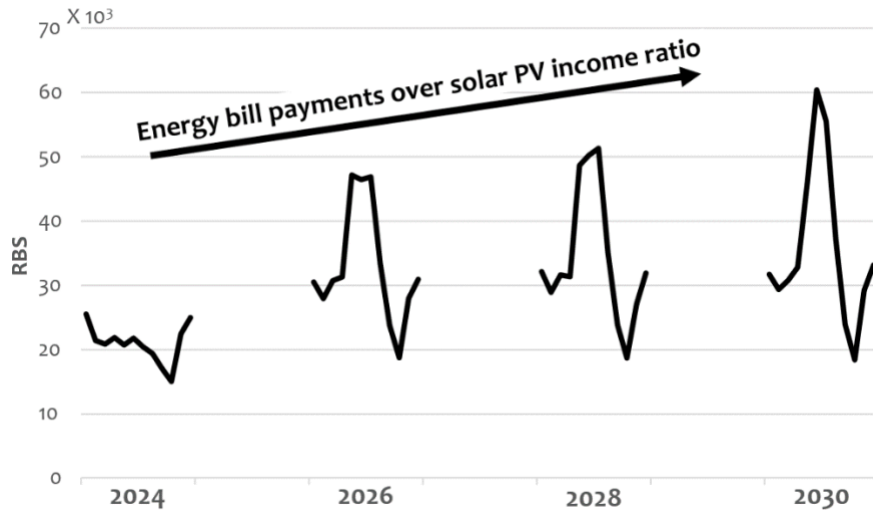


Figure 5: Increasing mismatch between end-user energy payments and solar PV income

The evolution of the ratio, as expected, shows how as solar PV penetration increases, the weight of energy payments for end users increases in a larger proportion of solar PV income. It is also important to bear in mind that the analysis only deals with a single and averaged scenario. A complete scenario analysis exploring the impact of the tails of the probability distribution function would exacerbate this mismatch. It is then evidenced that, as discussed, the price risk profile of new entrants, particularly in the case of solar PV, is not adequate to provide end users with a healthy hedge against periods of sustained high prices.

Apart from a few cases in South America (characterized by relatively large amounts of hydro storage capacity, as e.g., Peru or Brazil—see Barroso et al. (2021) for a discussion) the regulatory mechanisms discussed in the previous subsection are mainly focused on promoting adequate investment on the generation side, and thus they do not necessarily hedge future electricity bills. In the current context, the difficulty for politicians, and in general, the wider population, is to understand how it is possible that some sort of hedge for demand in case prices skyrocket was not equally envisaged. Implicitly trusting governmental protection in case of need (as the EU energy crisis has confirmed), end users have evidenced their relentless insufficient participation in forward markets. The crisis also showed that the same is true for several retailers (although in this case, they can argue that it was not possible for them to hedge their positions beyond the one- to two-years' time frame).

In any case, there is no doubt that the direct impact of the current price levels on the financial health of certain tranches of consumers (not all) is a major issue that needs to be tackled. Beyond that consideration, this scenario of electricity prices reminds us of a higher-order threat: the potential loss of trust (and patience) of the political class (and the mass media) in the whole market compound. The

¹⁵ We avoided modifying the future evolution of customer consumption considering the very likely electrification of heating (currently heating is largely natural gas based). Including these profile patterns would exacerbate the observed divergence, so for illustrative purposes, we preferred to fall short, since even without counting on these changes, the growing mismatch is largely evidenced.

probability of over-reaction after a price shock of this nature, potentially leading to a major step back in the decarbonization process, can no longer be seen as a risk; it is a fact. This has not only been evidenced by the current EU crisis—the market suspension in Australia that nearly led to blackouts in the summer of 2022 can also be taken as another illustrative example, see e.g., Reuters (2022b).

Risk averse governments cannot directly hedge themselves for that risk unless they have a stake in the electricity generation companies and redistribute their inframarginal rents. However, doing so would in some countries imply the (forced) divestment of privately-owned companies. Also, in the EU, except for the case of the NOME regulations in France that was approved by the EU Commission (Creti et al. 2011), the direct redistribution of any rents to electricity consumers would have been a violation of State Aid rules in force until the crisis took place. The only reasonable way to hedge that risk, at least in that context, is to introduce a hedge on behalf of the consumers that are deemed in need of bill protection.

The introduction of such a hedge would be welfare enhancing. The risk for sustained high prices would be transferred from risk averse consumers (and indirectly the risk averse government) to less risk averse market parties who can better manage this risk. The transferred risk would create an incentive for those market parties to hedge themselves by investing in generation assets (e.g., storage with renewables) and/or the purchase of long-term gas contracts possibly “igniting” a chain of long-term hedging contracts, which would lead to a more efficiently functioning power system. So far, the need for generators to hedge themselves against very high gas prices, at least in the middle- to longer-term, has been limited as they can directly pass-through the costs of high gas prices via high electricity prices. This approach would require a significant change of the criteria followed by the EU Commission until very recently, which was a reluctance to approve CRMs and explicitly discouraging long-term energy commitments (not only for electricity but also for natural gas).¹⁶

In the next sections we briefly discuss how the key two matters should be addressed by regulation. We divide the discussion around the procurement of contracts for new RES generators (Section 6), and then with already existing generators (Section 7). We make this division as it aligns with the two identified objectives, i.e., facilitating the entry of new RES at the lowest cost for end users and limiting the impact of high prices on end users’ bills. However, before doing so, we start by highlighting a key factor common to both mechanisms: the end users on behalf of whom the regulator purchases long-term contracts.

5. The counterparty of the long-term hedges

So far, the counterparty in the centralized auctions for CRMs or newly connecting RES has always been (directly or indirectly, at least in the EU) the Government or some categories of consumers via the regulated system charges. The exact allocation methodology of the costs/income of the contracts has been different from one Member State to another.

For RES levies, at least until the crisis started, the lion’s share of the costs was paid by lower voltage connected consumers in most countries, residential and small commercial (for an overview see e.g.,

¹⁶ See for example, De Hauteclocque and Glachant (2009) stating that “the European Commission is taking a dogmatic view on long-term contracts (LTC) and would simply consider them unacceptable when implemented by dominant companies. This can be understood as DG Competition since the early 2000s has publicly and repeatedly voiced strong concerns over the risks of anti-competitive effects inherent in energy LTC.”

CEER (2021)). In the meantime, several governments have reallocated the costs of the existing RES contracts from the electricity bill of those consumers to the state budget, see e.g., Euractive (2021) for the German case. Being the counterparty of RES contracts, in times when RES needed net support to be competitive with other resources, has been a burden. While suddenly, with spot prices reaching unprecedented high levels, being the counterparty has been to some extent a blessing, at least in cases where CfDs were in place (see e.g., Les Echos (2022) for the French case). What has gained momentum, now that these government-backed contracts are in the money, is the intention of some Member States to discriminate in favor of certain categories of end users (industrials or residential customers) by turning them, rather than the entire end-user base, into the sole counterparties of the RES contracts. This is not a new practice in European regulation. For instance, large consumers in Germany were exempted from bearing the burden of RES subsidies. This idea is also further developed by academics such as Grubb et al. (2022), who proposed changes to the existing contract settlement methodology in the UK.

The crisis has made clear that the decision on behalf of which categories of end users to procure long-term contracts is key. This holds for any type of contract procured on behalf of (subsets) of end users, whether it be CfDs for RES, CRM contracts, or contracts with existing generators to limit affordability risk. Once (and for all) determined by policy makers, these end users will not only benefit from the settlement of the contracts, but they will also bear the burden if the contracts end up being out of the money in the future. In what follows, we list what we deem as the important principles with regards to counterparties of the long-term contracts via centralized regulatory-driven auctions.

i) In principle, for the case of the contracts to facilitate penetration of RES, all end users could be the counterparties. All end users benefit from the entry of this new generation as competition increases. But it could also be equally assumed that large-sized consumers can perfectly manage themselves to bilaterally enter into this sort of hedge at wish using corporate power purchase agreements (PPAs). For the case of the purchase of financial instruments to deal with potential affordability issues (procured from existing generation), only those consumers who the regulator considers in true need and are not expected to enter into contracts by themselves should be covered by the contracts.¹⁷ In principle these are the vulnerable consumers, but to avoid future political discomfort, they could be extended to small and middle-size consumers.

ii) The auctions, in both cases (for new RES and existing generators), should be open on a voluntary basis for any type of end user that is not directly considered by the regulator. This would basically imply a sort of centralization of the procurement of standardized PPAs.

iii) In this context, in which auctions are targeting specific categories of end users, it is instrumental to design a transparent methodology to allocate the future settlement of the contracts into the system charges. The pay-outs (which could be a net cost or gain) should not directly interfere with retail contracts but complement it. As discussed in Section 3.2, this can be done by structuring the pay-outs

¹⁷ There is ample experience with centralized auctions for long-term contracts for new and existing generators in hydro-dominant countries in Latin-America (see e.g., Azuala and Barroso (2011)). Latin American hydro-dominant countries are familiar with the occurrence of sudden periods of sustained high prices (during the so-called “El Niño-Southern Oscillation”), as the hydro reservoir levels are a function of multi-annual weather cycles. In that context, it has always been assumed that at least residential demand cannot be expected to sign the long-term contracts that RES investors need to finance their projects. Centralized RES auctions with at least a part of the volumes being bought up by the government on behalf of consumers have been considered as the right instrument.

as lump sums, not as reductions or increases in the volumetric rate paid by end users. Importantly, it must be guaranteed that no future arbitrage should be allowed for those end users. For example, if an end user decides to sign a contract with a different retailer in the market, the link to the contract’s settlement must not change. The introduction of an “exit fee” can be a possible regulatory patch for an end user on whose behalf contracts were concluded but who no longer wants to be covered by these contracts. Inspiration can be found by looking at the power charge indifference adjustment (PCIA), an exit fee charged by California's investor-owned utilities to community choice aggregation and other departing load customers to compensate for electricity generation built or contracted in the past at prices that are now above-market (CPUC 2022).

Anyhow, in such a scenario where the role of the government in long-term contracting further increases, the role of the retailer (of whom hedging is supposedly a key task) will have to be revisited. Further discussions on the future of retail markets in such a scenario go, for the time being, beyond the scope of this paper.

6. Long-term contracts for new RES

The crisis has somehow awoken the demand side. In contrast to the situation before the crisis initiated, particularly among middle- to large-size end users, there is currently some eagerness to sign long-term contracts with new RES entrants. On the other side, developers who were recently granted with access to the network on a first-come-first-serve basis, and can enter the market at short notice, can benefit from their application. At current spot price levels, these RES power plants developers can go merchant or sign lucrative long-term contracts, in most cases collecting a significantly higher income than the levelized cost of energy of their investments. It might take some time for spot price levels to go down, but it is yet to be seen if the pace of connecting renewables can speed up, overcoming administrative issues (permitting and alike), lack or limited availability of physical grid connections, and more recently supply chain bottlenecks (see e.g., the report by Fox et al. (2022)).

Two questions arise when thinking about new entrants as summarized in Table ii: how to deal with the network connection and how to deal with exposure to price risk. In the following subsections we discuss these two questions, and then describe in more detail the possible contract formats.

Table ii. A revenue cap mechanism and risk for interference in the short-run dispatch

	Choices	
<i>Network connection</i>	First-come-first-serve	Auction for access
<i>Exposure to price risk</i>	Merchant	Auction for long-term contract

6.1 Auctions to enhance competition for accessing the network

Regarding the network connection, the lesson learned should be to not grant network access for free anymore—not for any resource, renewable or other (at least not at transmission-level, but it could eventually be considered at the distribution level also). A more adequate mechanism to allocate the scarce connection opportunities is the introduction of auctions for granting network access. This is not a new idea, but it has not been generalized so far. Examples are the auctions of offshore wind sites in Nord Sea countries and the United States (see e.g., Bloomberg (2022)). The ability to auction the right to connect, in the current context, does not only allow for leveraging the benefits of competition

for system access, but also makes it possible for a more efficient coordination of the generation and transmission capacity expansion, which is a major challenge nowadays.

The exposure to price risk relates to how the scarce network capacity is auctioned off. As in the current Portuguese auctions (IEA 2020), there are two extreme alternatives: auctioning an annual fee for access or auctioning network access bundled with a long-term contract. In the case of an annual access fee, the choice whether developers want to sell the electricity in the spot market or sign a long-term contract with a private entity is up to them. Even before the crisis was envisioned, incumbents claimed that there was no longer a need for governments to grant RES support in the form of any sort of long-term contracts. The main argument was that the levelized cost of renewables had reached market value levels (S&P Global 2020).

The counterargument for keeping in place the auctions awarding long-term contracts for renewables was that new entrants could not easily find counterparties for the PPAs, or that they are in a significantly worse position than vertically integrated incumbents, who already have direct access to a counterparty thanks to their historically inherited portfolio of rather sticky customers.¹⁸ To that extent, RES auctions for mature technologies gradually became nothing more than a sort of CRM, of which objective was “to complete” the long-term market, reducing financing costs due to risk mitigation and, as such, leveling the playing field between incumbents and often non-vertically integrated new entrants. Important in this regard are also the findings by Neuhoff et al. (2022a), who show that well-designed long-term contracts (particularly CfDs, discussed in Section 6.2) will lead to overall lower financing costs than any alternative and thus lower consumer costs, even with renewables reaching grid parity due to falling investment costs.

Following that reasoning, auctioning rather scarce network access bundled with a long-term contract could lead to higher competitive pressure (new entrants and incumbents both competing). Competition would push the price levels awarded in the long-term contracts closer to the levelized cost of new entrants and thus further away from the market value of their generated electricity. At the same time, the feasibility of massively deploying renewable generation to reach decarbonization targets would not be weakened. Linking the access to the network to a long-term contract for (part of) the produced energy would be nothing but a replication of the South American model, in which the regulator purchases the future energy needs on behalf of residential customers.

In this regulatory context, or even in case the policy decision would be to force all new entrants to participate in these auctions, the key question is what the contract design should be.

6.2 Long-term hedge contract design for newly connecting RES: Well-designed CfDs

In case policy makers can and decide to bundle network access with the signing of a long-term contract, at least at transmission-level, the next big question that arises is what type of contract should be procured. The important consideration is that long-term contracts shall mainly reduce risks for the

¹⁸ Incumbents have always been against this argument claiming that this is not true, that in fact they (their retailers) are offering to enter into these PPAs regularly. Independent investors claim that this is true, but these PPA offers come with a hidden penalty, since there is an evident oligopsony on the demand side. By way of example (similar or more acute cases can be found in other Member States, as e.g., in France or Italy), according to data from the Spanish regulatory authority (CNMC 2022), the three larger energy companies in Spain, Endesa, Iberdrola, and Naturgy,—also the largest investors in new renewables—are the retailers of 80% of the domestic customers, 60% of the SMEs, and almost 80% of the large customers.

project developer, while keeping short-term incentives for efficient operation by exposure to the spot market (at least on the margin).

We focus on intermittent renewables as new entrants, as they represent the bulk of expected newly entering capacity. Discussions on whether and what contracts to bundle for the access of new entrants deploying other technologies, baseload or dispatchable generator, is beyond the scope of this paper but definitely worth further investigation. We discuss different designs of CfDs. CfDs are two-sided (obligations). The advantage of obligations over (one-sided) call options in the context of new investments is that CfDs provide project developers with more revenue certainty. Revenue certainty, at least to a certain extent, is key to lower financing costs which are crucial as these assets are capital-intensive.

The exact designs of these CfDs can widely differ. In abstraction, there are two important design parameters of the CfDs: the volume covered by the contract (as produced or a limited quantity/profile), and the reference price (based on the hourly day-ahead price or longer than hourly, e.g., the monthly averaged day-ahead price weighted accordingly by one specific technology, such as solar PV). Currently, most existing CfDs for renewables are “as produced” in terms of volume and settled based on the hourly day-ahead price. Table 3 provides an overview of the possible choices. For more discussion on specifics, we refer to Schlecht et al. (2022). In what follows, we focus on why “limited quantity” contracts are the preference. The main argument being that these types of CfD contracts can resolve dispatch inefficiencies, which would increasingly be an issue with more RES penetration. We assume that the benefits of keeping efficient incentives intact would largely compensate for a potential limited increase in investment risk (compared to as-produced CfDs). For a more elaborate discussion see e.g., Barquín et al. (2017).

Table iii. High-level design choices for CfDs

#	Volume	Reference price
1	As-produced	Hourly day-ahead price
2		Monthly averaged day-ahead price weighted according to an exogenous metric (e.g., traded volume or reference production profile, i.e., a technology price)
3	Limited quantity	Hourly day-ahead price (or equally the average power price weighted according to the reference power plant’s production profile)

CfDs 1: “As produced” contracts with an hourly day-ahead price

The major advantage of “as produced” contracts are that they limit the risk for the generator. As every MWh sold in the spot market is subject to the CfD, the generator only loses potential revenues by not producing (due to operational issues or alike), but cannot have a net operational loss.¹⁹ The disadvantage of these types of contracts is that they do not expose the generators to the spot price at all (hourly-settled) and, as such, interfere severely with the short-term dispatch.

Indeed, the first type of contract, an CfD settled based on the actual production of a generation unit and the day-ahead price for that hour, makes that unit completely indifferent to the exact timing of its production; the unit is not exposed at all to the spot price, thus has no incentive to coordinate with

¹⁹ Not considering any capital costs and possible imbalance costs.

the wider power system (which for example can lead to overly negative prices).²⁰ This contract is equivalent, at least in terms of incentives, to feed-in tariffs that have been awarded to intermittent RES plants in many EU member states to stimulate their adoption. Imposing such contracts on a subset of generators could also be interpreted as the market being “split” between units that are not covered by this contract and thus exposed (to some extent) to the spot markets and other units that only care about their total volume produced over the period of the contract. In case we managed to understand the proposal of the Greek delegation in the European Council (2022), this type of contract seems like the one they argue resources that “operate when available and not on demand” should be subject to. We touch upon that proposal together with other related proposals in Section 7.2.

Even though the dispatchability of intermittent renewables (wind and solar PV) is very limited, we would argue that it can still be worthwhile to subject these resources to some extent to spot prices. Examples are decisions that must be made about maintenance, curtailment, the provision of downward regulation, etc. In the longer run, in case such contracts would become the norm (which we do not advise), they would also distort investment-related decisions, whether to invest in capabilities for dynamic orientation of solar panels, the exact technical parameterization of a wind farm, or the decision to co-locate a RES plant with storage. Siting decisions would also be distorted. For instance, it might be more valuable from a system’s perspective to locate a wind generator where it produces less energy than it could at other places but with more production at more valuable moments. For more discussion see e.g., Neuhoff et al. (2017), Meus et al. (2021), and Newbery (2023). It goes without saying that subjecting dispatchable generation (e.g., biomass or RES plus a battery) to such contracts would cause more severe interference to the short-term dispatch.

CfDs 2: “As produced” contracts with a more sophisticated reference price

The second type of contract is a slightly more sophisticated alternative for which the volume relevant for the CfD settlement is still directly linked to the generator’s production, but the reference price is based on the day-ahead price averaged over a longer period (e.g., a month) weighted according to an exogenous metric (e.g., a standard solar profile). Under this contract the generator is not isolated from the hourly spot price anymore. The issue is that under these types of contracts the generator’s incentives are to a certain extent distorted as illustrated with a simple example in Box 3. Namely, situations can occur where a unit would have an incentive to stop producing while it would be efficient from a system perspective to produce. An equivalent type of CfD contract is, for example, in place in Great Britain, called baseload CfDs (e.g., for biomass with combined heat and power). In that specific case, the reference price is determined seasonally (LCCC 2022).²¹ If we understand the proposal correctly, the “flexibility contracts” proposed by Fabra (2022) go along the same lines, trying to cover power plants with flexibility in their dispatch, for example, hydropower plants, biomass, or solar thermal.

²⁰ Note that this does not necessarily mean that they are not exposed to imbalance price risk.

²¹ More precisely, the reference prices are calculated using a traded volume weighted average based on forward season data received from the London Energy Brokers’ Association (LEBA).

Box 3: Distortion under an “as produced” CfD based on a reference price determined over a longer period than one hour (e.g., monthly, seasonally, or annually)

With:

- Quantity produced in hour h (q_h)
- Spot price in hour h (p_h)
- Strike price (sp)
- Exogenous reference price in month m (rp_m)
- Marginal cost to produce in hour h (c_h)

The net income in hour h (nic_h)

$$nic_h = q_h \cdot (p_h + sp - (rp_m + c_h))$$

with $sp > 0$, $rp_m > 0$, $c_h > 0$ and p_h any value

The unit will produce if $nic_h \geq 0 \Leftrightarrow p_h + sp - rp_m \geq c_h$

Two cases are relevant:

1/ Efficient dispatch implies that a unit produces if $p_h \geq c_h$

However, when at the same time $p_h < c_h + rp_m - sp$ the unit would not produce while it would be efficient to produce. Hours where $p_h < c_h + rp_m - sp$ holds are medium/low priced hours (but with still higher prices than marginal cost of the unit) within longer periods of on average very high prices (higher than the strike price).

2/ Efficient dispatch implies that a unit does not produce if $p_h < c_h$

However, when at the same time $p_h \geq c_h + rp_m - sp$, the unit would produce when it would be efficient not to produce. Hours when $p_h \geq c_h + rp_m - sp$ holds are, at least typically for RES plants, hours with negative prices (but not too negative) within longer periods of on average low prices (lower than the strike price).

CfDs 3: “Limited quantity” contract

When predetermining the volume of production covered by the contract, i.e., making the volume of production covered by the contract depend on factors that cannot be influenced by the generator subject to the contract, the exposure to the spot price (at least at the margin) is not distorted. The difficulty in this case is the determination of the hourly quantity subject to the contract, which is a function of the technology.

The determination of this volume should not expose the generator to a significant and unmanageable risk. For intermittent renewables, our recommendation would be to link the volume covered by the contract to the actual production of a reference plant of the same technology in the same geographical area during each hour. This method implies that the reference price is not the arithmetic average wholesale spot price, but the weighted average price according to the production profile of the reference plant (which will arguably be lower). This would be nothing but replicating the methodology implemented in the Spanish power system many years ago (Spanish Government

2014).²² The Royal Decree 413/2014 (discussed in Huntington et al. (2017)) put in place a capacity-based support mechanism complemented with ex-post compensations or penalties resulting from the plant's performance compared to a reference plant. This approach, or at least very similar variants/enhancements, were discussed by Barquín et al. (2017); by Newbery (2023), who called it a “yardstick” approach to the determination of the contracted volume; and by Schlecht et al. (2022), who call it a financial CfD. Neuhoff et al. (2022b) refer to the German reference yield model, but as far as we understand, the reference yield model does not impact operational incentives. What it does is introduce a correction factor of the remuneration of different windfarms across the country that lead to a higher valuation of the electricity produced by wind turbines at lower wind sites.²³

An important consequence is that introducing this fixed-quantity contract implies the need for technology-specific auctions as, for example, the reference production profile of a wind resource cannot be compared to a solar resource. This implies thus a larger role of the regulator/government in generation expansion planning. In any case, at this stage, this should be considered a minor issue, since the NECPs in the EU already determined the RES volumes per technology that are expected to be installed in the years to come.

7. Long-term contracts for existing generation

The most groundbreaking aspiration of some Member State governments is not to “fix” the market, but to regulate/limit the income of already installed generating units (beyond the “emergency measures”) and to discretionally subsidize end users’ bills, even discriminating at will among the different customer categories. The final decision to authorize and enforce these sorts of measures does not correspond to the regulatory but to the EU and Member State political sphere.

That being said, after the crisis winds down, it is true that without engaging with a diversified portfolio of existing generation a period of sustained high prices would repeat itself and an affordability concern would likely resurface. As discussed in Section 4.3, there are justifications to proactively better protect certain subsets of end users (by “protect” we want to mean “hedge,” without necessarily subsidizing them; this other dimension exceeds our regulatory scope). But once again, the current objective is to reduce end users’ bills, by putting limits on the profits of existing generation.

In this section, taking the decision to intervene as given, we discuss three ways of engaging (mainly) with existing generation to mitigate affordability concerns: negotiated contracts, different forms of price regulation, and the centralized regulatory-driven procurement of affordability options (AOs) from existing generation. If the policy decision is to contract with existing generation to limit

²² This mechanism was later abandoned in Spain due to difficult-to-explain reasons. The only criticism heard at the time was that it was very complex as 1,200 reference plants had to be defined. But it was done, without leading to meaningful complications. Others argued that, unfortunately, the government at the time preferred an energy-based mechanism, since these mechanisms, although more inefficient, allow calculating and evidencing in a more straightforward way the actual savings linked to every RES MWh produced coming from the governmental auctions (€/MWh than can be compared with average marginal prices, something that cannot be done in the case of capacity-based auctions). Several authors have later discussed and supported that 2014 Spanish mechanism or at least very similar approaches, such as Newbery (2023) and Schlecht et al. (2022).

²³ As pointed out by our colleague Pablo Rodilla, the need for this correction factor is because it is not an auction but an administratively determined price mechanism.

affordability risk, we recommend implementing the last approach as it is by far the least distortive, at least as long as sufficient competition in the auctions can be guaranteed.

7.1 Negotiated long-term contracts

A very tempting option for short-sighted governments to lower prices in the short run is to hurry and negotiate some sort of long-term contracting with specific generators (e.g., nuclear plants) or incumbents. But the current context of abnormally and sustained high market prices would be the worst moment to enter into such a commitment, and particularly if there is no way (time and manner) to fully open the negotiation to every potential (existing, i.e., already installed or future) counterparty to maximize competition. A bilaterally “negotiated” price, absent from competitive pressures, would necessarily end up being a bad deal for consumers in the medium to long run. The governments could be relieved by seeing a decrease of prices in the short run, but consumers would pay the bill in the middle to long term when prices normalize again.

In the energy sector, there is a long record of these sorts of contracts that later systematically turned into a significant burden for end users. They are included in the category of the so-called legacy contracts, which are currently a big issue in a good number of jurisdictions.

An uncompetitively priced contract is not the only potentially regretful burden of such an approach. Depending on their exact contract design, they might also severely impact the dispatch. For example, contracting all the current output of the nuclear fleet (24/7 production) can imply that in a few years’ time these units have to be considered “must run” even if being uneconomical. This could imply that lots of solar production would have to be spilled.

7.2 Price regulation: Explicit, implicit, permanent revenue cap, and price cap

Here we discuss different types of price regulation that would directly or indirectly impact the revenues from existing generators. All these measures have in common that they, at least to some extent, expropriate future revenues of merchant-invested generators on a permanent basis. Also similarly, they would very likely lead to long-lasting court cases (which can be lost by the regulator) and that in any case, would have a serious impact on the perceived regulatory risk of investment in power generating assets.

First, explicit price regulation means that existing generators are forced into long-term contracts at a regulated price set by the regulator or government. Such “reform” might be an option in countries where the generation portfolio is largely publicly owned (particularly if the utility needs to overcome a difficult financial situation) but obviously would have severe legal consequences in other Member States.²⁴ By directly forcing generators into long-term contracts at regulated rates, their income is regulated. Besides the legal challenges, these imposed contracts are also very hard to design. An example is imposed contracts for reservoir-hydro generators. These generators are flexible in operation, but their future reservoir levels, and thus the total amount of electricity they can produce over a certain timespan, are uncertain. Due to these characteristics, imposed contracts for hydro-generators are extremely complicated to design without introducing costly and potentially even security of supply endangering distortions.

²⁴ When the government signs a long-term contract with a publicly owned company at whatever price is not such an issue for the citizens as, in the end, consumers might end up paying a high price, but taxpayers benefit in a similar proportion.

Second, implicit price regulation is more subtle than explicit price regulation. As forcing generators into long-term contracts might not be a legal option, implicit price regulation tries to do so via another—often (even) more inefficient—“route.” More concretely, implicit price regulation impedes free price formation in the spot market and, as such, tries to indirectly regulate the income of certain market parties. This is where one could imagine (at least if we managed to understand them well) all the proposals regarding a “split market design” coming in (Keay and Robinson 2017, Greek delegation in the European Council 2022, BEIS 2022). These “reforms” propose to introduce different spot prices for different resources. Looking at these proposals from another perspective, one could say that they disallow certain resources from *the* (one and only) spot market and forced them into long-term contracts with regulated prices. The proposals would not only have an impact on existing generation but also on new entrants.

Third, while today there is a perceived political urge to have in place a revenue cap to capture income that can be used to mitigate affordability concerns, making the revenue cap permanent does not seem a good idea. We discussed the difficulties in the exact design of a non-distortive revenue cap in Section 3.1.

Fourth and last, although fortunately they have lost momentum, also “smart” price caps have been proposed in the debate. An example is the “price shock absorber” (see RAP 2022). The idea is that when in a given time period (e.g., a month) the accumulated inframarginal rent for a basket of zero-carbon resources reaches a multiple of their levelized fixed cost resources, a wholesale price cap is introduced. The price cap is set at a level that stops fossil gas generation from setting the wholesale market clearing prices.²⁵ Peaker plants, typical gas-fired generation, which are still required to serve demand at such moments, are eligible for reimbursement of the fuel costs incurred beyond the price cap. When triggered, the “price shock absorber” is a very similar intervention as the currently in place Iberian exception. While such price suppressing mechanisms can be internalized in the future revenue expectations of newly connecting power plants, it would still be a measure affecting the power plants built before its implementation (which could not anticipate its introduction). Maybe more important, while having in place such shock absorbers indeed provide a sort of an “intrinsic hedge,” it introduces the same distortions as the Iberian exception, as discussed in Batlle et al. (2022b): reduced incentives to lower demand; severe dispatch and mid-term planning distortions (particularly for limited-energy plants, such as hydro with reservoir); and issues with the coordination of trade in case it is triggered in one country and not another. In Box 4, we discuss some recent international experiences with similar mechanisms.

Box 4: Some international experiences with “price cap reduction triggers”

In Australia a similar mechanism is in place, i.e., if wholesale prices are too high for too long, a price cap automatically kicks in. More precisely, if the cumulative price of a megawatt per hour of electricity in a state is higher than \$1.359 million over seven consecutive days, the regulator caps the wholesale price at \$300/MWh. In the summer of 2022, the mechanism kicked in and nearly led to a blackout (Guardian 2022, Reuters 2022b). The reason being that high-cost generators withdrew their bids when the price cap was introduced (they would be losing money by generating). To avoid a supply gap, regulators pledged to compensate for any losses—but out-of-the-money generators would have to

²⁵ This is a solution implemented in some Central American markets for many years, under the denomination of “precio de falla” (failure price), a threshold that activates when the most inefficient and thus expensive (fuel-oil or diesel) plants have to be committed.

apply for the make-good payments that would be paid out with (expectedly) several months of delay. Finally, the system became unstable, and the Australian Energy Market Operator (AEMO) suspended the market to take over centralized control until the situation cooled down.

Further, this proposal is similar to the “circuit breaker” that was in place in ERCOT at the time of the Texas freeze in February 2021. The circuit breaker is triggered when the “peaker net margin” reaches a threshold level of \$315,000/MW-year for a natural gas peak generation unit. A key difference with the proposed price shock absorber and the Australian mechanism is that the price cap introduced when the circuit breaker is triggered is typically set to a value between the (very high) value of lost load (VOLL) and the marginal cost of the most expensive generator. Thus, in other words, the circuit breaker merely implies a reduction of VOLL in case demand is setting the price for a substantial amount of time. As such, there is less interference with the dispatch and no side-payments need to be made to avoid a supply gap. However, such implementation makes the mechanism a lot less effective at reaching its objective: providing financial relief for consumers. Namely, at least in ERCOT at the time, when the circuit breaker was triggered, the price cap was set to the maximum of 2,000 \$/MWh or 50 times a natural gas fuel index price (the latter is exactly in place to avoid the need for side payments). However, while the power prices were reaching skyrocketing levels, also the natural gas price was extremely high due to scarcity. This was not anticipated as normally the summer is the period that the power price is mostly under stress in the ERCOT system. Consequently, the “circuit breaker price cap” was higher than the original price cap of 2,000 \$/MWh and thus ineffective. Some authors argued that in such extreme circumstance the level of VOLL should have reduced even if that might have meant the need for out-of-the-market payments (Littlechild and Kiesling 2021). Overall, these sorts of mechanisms, since they end up depending on many variables, are not very contestable (besides being subject to change), and thus difficult to internalize by market agents in their decision-making processes.

7.3 Procurement of AOs

When the crisis calms down, we propose the organization of centralized regulatory-driven auctions for AOs (which can be complementary to a MMO). We provide more background to AOs in Appendix A. The regulator must decide about the volume of AOs to be procured. This decision shall be based on which end users are deemed to (or want to) be protected from sustained high prices and the total volume of production already under existing CfDs. Such an assessment is not very different than e.g., resource adequacy forecasts that regulators perform.

The reference price of the AO is the arithmetic monthly average price for a contracted profile that can be flat or more advanced, e.g., approximating the consumption profile of the protected consumers (possibly considering other hedges already in place). Such parameterization provides a more resilient protection against high bills. The AOs should not be unit specific as the risk would be too high, but any market player can bid (price/quantity pairs) according to its portfolio. To limit regulatory interference in the market and increase competitive pressure, we recommend minimizing the volume of AOs. Also, a reserve (maximum) price shall be considered. This is much needed taking into account that often-diversified electricity generation portfolios are largely concentrated, and as discussed, vertically integrated stakeholders have a natural disincentive to participate in these auctions. As discussed in Section 5, protected end users might be only “standard” vulnerable consumers, i.e., consumers facing energy poverty in normal price scenarios or also a larger share of residential and/or even commercial consumers that would suffer significantly from periods of sustained high prices. End users that are not

by default covered by AOs (e.g., industrial consumers) shall have the right to opt-in and participate in the auction, with the same rights and future obligations.

To enhance the competitiveness of the contracting process, the auction shall be open for all generation technologies, existing and new, and have a sufficient lead time. New generators can be, for example, RES generators that do not enter via the centralized auctions, e.g., wind or solar co-located with a sufficient storage capacity. To ensure that the generators have a natural hedge, they are required to prove that they can honor the option contract. In that regard, having only sufficient generation capacity (in MW) is not enough. Also, proof of being able to deliver the energy is needed (e.g., a long-term gas contract for a gas-fired power plant or a historical production time series for RES plus storage). The exact implementation of these requirements, and possible penalty schemes, need to find a balance between minimizing financial risk for the option buyer and minimum entry barriers for the option sellers.

Why AOs and not CfDs for existing generation? The argument that CfDs lower revenue uncertainty and thus financing costs is irrelevant in the case of existing generators as the investment has already been made. The purpose of this instrument is to protect against high bills, not to fix bills to predefined levels. Hence, options are better suited than obligations. Rather than leading to more stable bills under CfDs, AOs only protect against very high bills and bolster as much as possible the beneficial impact of short-term price signals, particularly under “normal” circumstances.

From another perspective, AOs can be seen as nothing else than merely an elegant way of implementing a revenue cap. However, this sort of revenue cap does not distort and does not necessarily have to come for free or at an administratively set remuneration. The option premium can be determined in an auction. The incurred cost might be worth the avoided hardship and the political turmoil leading to a lot more costly interventions, both in the short run due to distortions and in the long run due to increased regulatory risk. Generators selling AOs can contract or market their production as they want but need to consider their AO contract when doing so.

In case revenues from AOs, revenues from spot or revenues from available contracts in forward markets (in organized exchanges or over-the-counter) do not suffice to keep particular generators online that are deemed vital for system security—a CRM should be in place. This CRM should build in specific performance guarantees to incentivize production to be available when it is of the highest value for the system, on top of the already-in-place incentive to produce at high spot prices that occur during those hours. Such an additional incentive is not inherent in ordinary CfD contracts.

An alternative to a centralized procurement of affordability options by the regulator on behalf of a subset of end users are strengthened (decentralized) hedging requirements for retailers. There are several challenges to doing this. One challenge is the volume risk for retailers as consumers can relatively easily switch from one retailer to another within a horizon much shorter than the required hedging horizon. These issues might be mitigated, but, overall, the coordination of such an approach seems to lead to more complications than a centralized approach. As mentioned before, the regulation of retail markets is definitely another topic that requires scrutiny in a wider discussion around the reform of the regulation of the power sector but goes beyond the scope of this paper.

8. Conclusions and policy recommendations

Although Europe is first and foremost facing a gas crisis, the functionality of the existing electricity market design has been under high political pressure. Market interventions have taken place since the onset of the crisis and are expected to stay in place for quite some time. Also, a more medium to longer term “power market reform” is currently being discussed. Today, long-term marginal costs, signaled by renewables, are and very likely will be for some time well below short-term marginal prices—often set by gas-fired power generators. This gap has led to a political desire to allow for end users to more directly benefit from prices that are more directly aligned with costs. Such a desire implies the reconsideration of power market rules that were considered undisputable until now. We assume that the decision to intervene in the market belongs to the political sphere, so we just focus on discussing the implications that the different measures under considerations might have. An example is our brief analysis of the mandated revenue cap, which we argue is not the worst tool, but definitely not a candidate solution for a permanent market design feature.

In case we want to truly “reform the market,” we first need to analyze what elements of the existing regulatory compound around power markets have worked well and which did not. The crisis did indeed unveil key structural illnesses of electricity markets, but—even though (unrightfully) heavily criticized—spot power market design is not one of them. While it is clear that spot markets can always be improved, they have been doing their job: signaling the opportunity cost to consume power within and between European countries. What has never worked are long-term markets; more precisely, there is a lack of sufficient liquidity for electricity price hedging beyond two years. While this has been a concern for years (long before the crisis started), there has not been any advance along these lines. Hence, any “market reform” should be focused on complementing the long-term market rather than making any change to the short-term market. A first proposal we do is the introduction of a market maker obligation to increase liquidity in forward markets.

Further, we discuss proposals that aim at completing the long-term market while fulfilling the two main objectives of the reform: facilitating the entry of new renewables at the lowest system cost and limiting the impact of sustained high prices on end users’ bills. We argue that these two different objectives are less related than often thought. In the short to medium term, we cannot expect that new RES alone can solve the affordability concern. For at least a decade, the total volume of new RES electricity production is going to have a relatively limited impact on final bills. But moreover, unfortunately, in the absence of abundant storage, not just short-term but also seasonal storage, the market price that consumers pay will increasingly diverge from the price that new renewables perceive in the market. This is an especially acute problem for solar PV. As is well known in the regulatory field, trying to address two problems of different natures with one instrument nearly unavoidably leads to inefficiencies. We discuss how the key two objectives concern different groups of stakeholders with very different risk profiles, i.e., newly connecting generating units and existing generators, and require different regulatory solutions. Again, we focus on the functioning of regulatory tools, the final decision to enforce these sorts of measures does not correspond to the regulatory but to the political sphere.

The investment risk management problem was being addressed in most jurisdictions already before the crisis started via CRMs and centralized auctions for RES. The former must be improved but is not the core issue at stake. Regarding the latter (centralized auctions for RES), we argue that even with decreasing RES investment costs there are still very sound arguments to keep auctions for

government-backed long-term contracts in place. Such centralized auctions for contracts also allow for an improved coordination between generation and network expansion that has been increasingly problematic in the last years, turning network access into a scarce good in many countries. A key issue is the contract design. We advocate for a contract format that resembles a standard contract-for-differences (CfD) but keeps dispatch incentives intact without significantly increasing investment risk. More precisely, we recommend a capacity-based support mechanism complemented with ex-post compensations or penalties resulting from the plant's performance compared to a reference plant. Such a mechanism was implemented in Spain via the Royal Decree 413/2014.

The lack of adequate hedging of end users against periods of sustained high prices was exposed by the crisis. The regulatory objective in such context is the provision of long-term hedges for end users in need to guarantee affordability, while keeping short-term incentives for efficient consumption intact. The best alternative would be to engage the end users in need in some financial long-term hedge. When the crisis calms down, we propose the organization of centralized regulatory-driven auctions for affordability options (AOs).

Why AOs and not CfDs for existing generation? The argument that CfDs lower revenue uncertainty and thus financing costs is irrelevant in the case of existing generators as the investment has already been made. The purpose of this instrument is to protect against high bills, not to fix bills to predefined levels. Hence, options are better suited than obligations. Taking into account that diversified electricity generation portfolios are often highly concentrated, it is important to maximize competitive pressure in these auctions. To do so, besides considering a reserve (maximum) price, we recommend minimizing the volume of AOs to those in true need. The decision about the volume of AOs shall be based on which end users are deemed to (or want to) be protected from sustained high prices and the total volume of production already under existing CfDs. Protected end users might be only "standard" vulnerable consumers, i.e., consumers facing energy poverty in normal price scenarios, or a larger share of residential and/or even commercial consumers that would suffer significantly from periods of sustained high prices. End users that are not by default covered by affordability options (e.g., industrial consumers) shall have the right to opt-in and participate in the auction, with the same rights and future obligations.

Finally, we also underline that the crisis has made clear that the decision on which categories of end users' behalf governments are going to procure long-term contracts is key. This holds for any type of contract procured on behalf of (subsets) of end users, whether CfDs for new RES, CRM contracts, or AOs. Once (and for all) determined by policy makers, these end users will not only benefit from the settlement of the contracts, but they also must bear the burden, in case the contracts end up being out of the money in the future.

Our main aim of this paper is to contribute to the ongoing power market design discussion in the EU. A lot more work is required to further work out the complications and different possible solutions that we sketch. We hope our contribution can at least be that we don't shoot the messenger (the spot market), but rather focus on where we think the way forward lies: a completion of the long-term market while limiting interference with the well-functioning spot markets.

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Appendix A: A product to address affordability concerns: Affordability options

The aim of this regulatory-driven long-term complement is to financially protect during periods of sustained high energy prices some categories of consumers (e.g., those ones considered particularly vulnerable) while, at the same time, not to distort incentives provided by spot markets for both generation and load.

In short, the contract that we describe in this appendix, called affordability option (AOs), introduces a pre-agreed transfer of the gains of generators that are profiting from periods of sustained high prices to consumers suffering from affordability issues. This dynamic is very much the same dynamic any revenue cap is intending to mimic. The big difference is that a revenue cap is *imposed* on generators, while ideally AOs are *procured* from generators. The latter implies that generators can *declare* (or at least agree with) the volume of electricity production that is covered by the contract. Predefining the volume per market time unit that is subject to the contract rather than making the contract cover whatever the volume of electricity produced during a market time unit, makes it possible to keep all marginal incentives fully intact (without transferring uncontrollable risks to generators). The profile contracted can be flat, or a more advanced approach would be that aggregated volume covered by AOs approximates the consumption profile of the consumers that are intended to be protected (possibly subtracted by other complementary hedges already in place). Bill protection does not come for free, as these contracts are procured and not imposed. Consumers pay a fee for this “insurance” (like a regulated RES levy in the bill), while generators exchange part of their uncertain future revenues for a regular payment.

In what follows, we discuss in more detail how three key design choices of affordability options are determined to comply with its original aim: the choice for an option product and not an obligation, the settlement frequency, and the level of the strike price. We also provide a brief discussion on the difference with reliability options and a numerical example.

A.1 Options versus obligations

As the objective is to protect end users from periods of sustained high prices rather than to entirely fix the price paid for electricity under any scenario, the introduction of a financial option is more suitable than an obligation (i.e., a two-sided CfD). It is true that an obligation would also hedge end users in the long run without necessarily minimizing their incentive to respond to short-term signals. However, we consider that an option would be a less intrusive solution, as the electricity bill would remain unaltered during periods of “normal electricity” prices, while the forward contract would have an impact under any price scenario.

A.2 Settlement frequency

The objective of the hedge provided by the affordability options is not to protect consumers from sporadic price spikes, but to prevent that sustained high prices could threaten the financial health of certain categories of end users; what eventually matters for end users are not a few hours of very high prices (which can have a moderate impact on the monthly bill) but months with very high bills. In this regard, an Asian option for which the payoff depends on the average of all prices over a specific period seems to be a suitable product design as opposed to vanilla European or American options, where the payoff is determined at a single expiration date. The most basic is the fixed-strike Asian call option (also known as an average rate). The payoff of this option $C(T)$ can be expressed as $\max(A(0,T) - K, 0)$,

where A denotes the reference price for the period $[0, T]$, and K is the strike price. We propose affordability options to have a monthly fixing to be aligned with typical bill cycles. In addition, by setting the settlement frequency equal to a month, and not, for example, an hour, consumers are still fully incentivized to respond to sudden price spikes, unlocking valuable demand response. A “strip” of affordability options should last sufficiently long; we propose a duration of 5-10 years (respectively, 60 or 120 “bill cycles”). The reference price shall be the arithmetic average wholesale price to protect against affordability issues.

A.3 Level of the strike price

The level of the strike price can be interpreted as the maximum average electricity price that is deemed sustainable over the given settlement period. What that exact price level shall be is at the discretion of the regulator (e.g., a monthly arithmetic average day-ahead electricity price of 100 €/MWh over a month, or alternatively, the weighted average price according to the load profile). Obviously the lower the strike price, the higher the option premium and vice versa.

A.4 Affordability versus reliability options

Affordability options are not to be confused with the already briefly mentioned reliability options that have been introduced to mitigate adequacy concerns in, for example, Colombia, Ireland, and Italy. The idea of affordability options is to induce investment (or retain installed capacity) that is flexible enough to support the power system when it is very tight.²⁶ Moments of high stress are reflected by scarcity prices. This reasoning behind the design of reliability options leads to different design choices: an hourly settlement and a relatively high strike price. Table A.1 shows the interactions between the choices for the settlement frequency and strike prices. Reliability options and affordability options do not exclude each other, but more research is required to analyze their interactions.

Table A.1: Trade-offs and opportunities for the design parameters of the auctioned-off call options and the impact on the cost of the option premium.

	High strike price (e.g., 1,000 €/MWh)	Much lower strike price (e.g., 100 €/MWh)
High frequency settlement (e.g., hourly)	Reliability options in Colombia, Ireland, and Italy: Protection from scarcity prices, exposure to short-term signal for consumers	Constant protection from high prices, limited exposure of short-term signal for consumers
	Ambiguous impact on option premium	High option premium
Low frequency settlement (e.g., monthly)	No protection from scarcity price or sustained high prices, full exposure to short-term price signals for consumers	Affordability options: Protection from sustained high prices, exposure to short-term signal for consumers
	Very low option premium as option is (almost) never exercised	Ambiguous impact on option premium

A.5 A numerical example of the functioning of affordability options

Figure A.1 below provides an illustration of the functioning of affordability options. The left graph shows the hourly prices in the Spanish day-ahead market in 2020 and 2021. Two different abnormal price scenarios are highlighted in different colors. In cyan, January 2021: In the second week of that

²⁶ Note that AOs could also induce new investment in generation that can produce during prolonged periods of sustained high prices, e.g., seasonal storage.

month, a persistent blizzard affected half of the country and led to the occurrence of some hours with high prices. In red, December 2021: a month in the middle of the ongoing energy crisis. The middle and right graphs in Figure A.1 provide larger detail of the prices resulting in these two months. In this example, we use the arithmetic average spot price as the reference price.

If the regulatory decision would have been to hedge, for instance, vulnerable customers with an affordability option at a strike price of e.g., 100€/MWh and a flat load profile, the impact on both cases would have been radically different. In January, even though spot prices were above 100€/MWh 51 times during the month, the average price was 60€/MWh. Therefore, the affordability option would have been out of the money, and it would not have been exercised. Conversely, the average price in December was 239€/MWh, and the electricity bills of vulnerable customers would have been beyond the acceptable range. The option would be exercised, resulting in a pay-out of 139€/MWh. Imagine that on behalf of each vulnerable consumer 300 kWh were contracted per month. In that case, each vulnerable consumer would receive 41.7 euro that month to compensate for the high electricity costs. However, the same customers would still be incentivized to consume more when prices are low and vice versa.

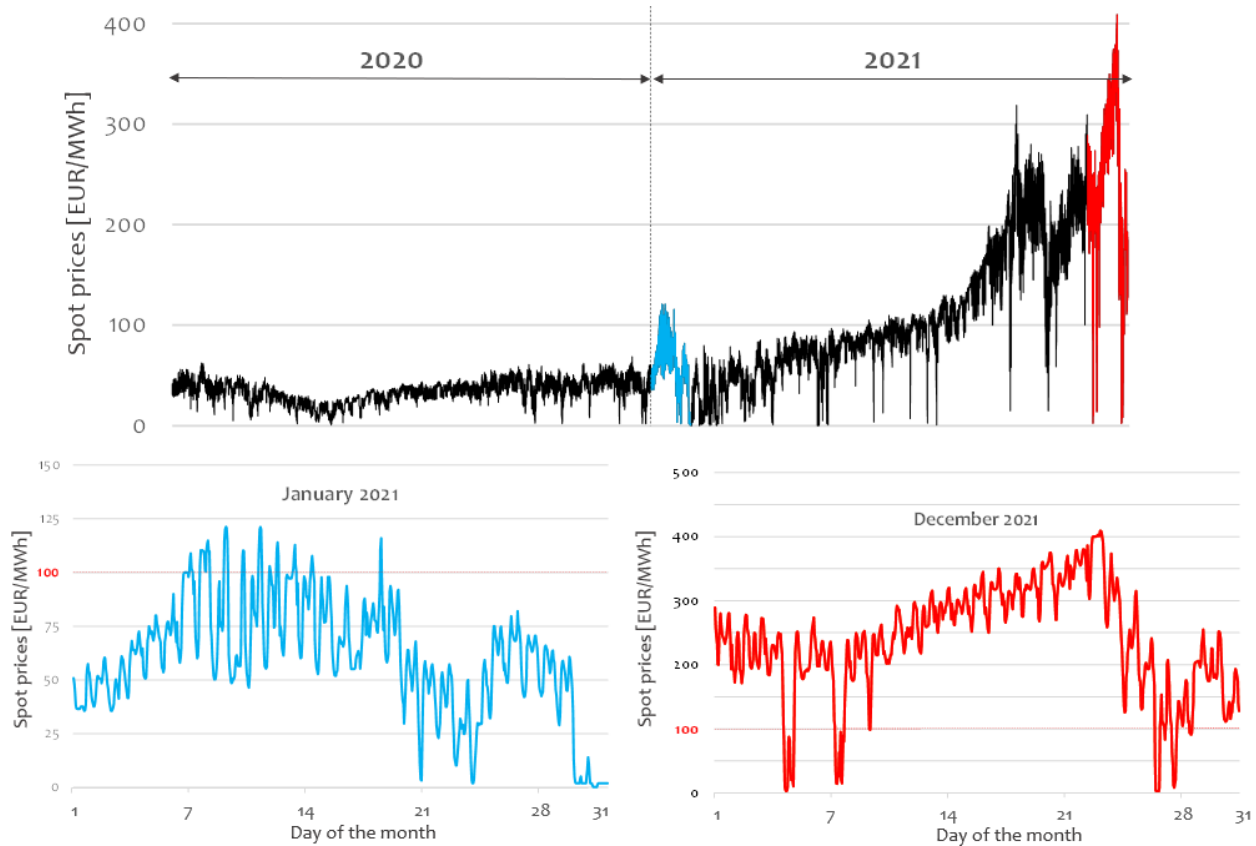


Figure A.1: Day-ahead market prices in Spain in 2020-2021 (top). January 2021 (bottom left). December 2021 (bottom right).

Contact.

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