The Energy Transition: An Industrial Economics Perspective

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Abstract

Addressing climate change requires full decarbonization of our economies. Whether this objective is achieved at least cost for society hinges on good policy design. In turn, this calls for a thorough understanding of firms' and consumers' incentives in the presence of asymmetric information, the determinants of strategic interaction, and the impact of market design and market structure on the intensity of competition. Industrial Economics thus has much to contribute towards a successful Energy Transition, while benefiting from the exciting research opportunities it brings. In this paper, I survey some of the recent developments in this area. My focus is on the power sector, and in particular, on the regulatory and market design challenges triggered by the expansion of intermittent renewables with almost zero marginal costs. I conclude with some questions that merit further research.

Keywords: carbon emissions, energy, competition, market power, market design, auctions, investment, dynamic pricing, storage.

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1 Introduction

Energy is embodied in all goods and services. If such energy is generated through the combustion of fossil fuels it generates carbon emissions, which are the leading cause of climate change. The mounting evidence in this regard (IPCC, 2018) has prompted governments around the globe to put in place policies aimed at achieving the Energy Transition, i.e., pathways to fully decarbonize their economies.[1] This process will require heavy investments in low carbon assets and energy efficiency in order to substitute fossil-fuels with renewables while reducing the energy needs. Likewise, new market rules and regulatory arrangements will be needed to make this process happen.

One can analyze the Energy Transition from a myriad of perspectives. In this paper, my focus will be on the Energy Transition in the power sector, and I will approach it from an Industrial Economics perspective. Relative to other approaches, Industrial Economics recognizes the relevance of incentives in the presence of asymmetric information, the determinants of strategic interaction, and the impact of market design and market structure on the intensity of competition (Tirole, 1988; Laffont and Tirole, 1993). "*Wholesale markets for electricity are inherently incomplete and imperfectly competitive*," as Wilson (2002) has described them, which explains why Industrial Economics has played a prominent role in the recent literature analyzing the options for decarbonizing the power sector. In this paper I survey some of such contributions.[2]

The Energy Transition in the Power Sector. Among all the sectors involved in the Energy Transition, the power sector will bear a significant burden of the overall emissions reductions. Given its unique ability to transform renewable energy into electricity, it

[1] Climate objectives are at the top of the policy agenda in Europe, in the US, and in several countries in Asia. In 2019, the European Commission launched the European Green Deal, i.e., a 1 Trillion Euro plan to fully decarbonize the European economy by 2050 (European Commission, 2019). This has been stressed in its Recovery Fund, which heavily relies on the climate agenda as part of its economic stimulus package after the COVID-19 crisis. At the time of writing this paper, US president-elect Joe Biden's plan is to also achieve carbon neutrality by 2050, with a 90% carbon-free electricity sector by 2035. And China has committed to decarbonizing its economy by 2060.

[2] Inevitably, lack of space obliges me to omit some relevant topics and contributions. Notably, I do not cover important issues such as energy efficiency (Allcott and Greenstone, 2012), transmission and market integration (Newbery, Strbac, et al., 2013), or the impact of carbon pricing (Fabra and Reguant, 2014), among others.

can contribute to decarbonizing other polluting sectors in which electricity is used as a substitute for fossil fuels (notably, transportation through the deployment of electric vehicles and hydrogen cars; or buildings through the deployment of electric heat pumps). Technology breakthroughs are making this easier. Over the last decade, there have been massive reductions in the costs of wind and solar investments, which have now become competitive *viz à viz* the conventional energy sources (coal, gas and nuclear).[3] These trends imply that the costs of generating power in a 90% carbon-free market will be 10% lower than in a 55% carbon-free market (Goldman School of Public Policy, 2020).[4]

In several countries, renewables already represent more than one third of total electricity generation, and they are expected to become the main source for power generation by 2030.[5] However, the rapid expansion of intermittent renewables with almost zero marginal costs is bringing new challenges for the performance of electricity markets under their current design. As Joskow (2019) puts it: *'These developments raise profound questions about whether the current market designs can be adapted to provide good long-term price signals to support investment in an efficient portfolio of generating capacity and storage consistent with public policy goals.'* Industrial Economics can greatly contribute to addressing these fundamental questions by identifying the regulatory and market-based solutions that minimize the costs of decarbonizing the power sector, which is a necessary condition for decarbonizing the whole economy.

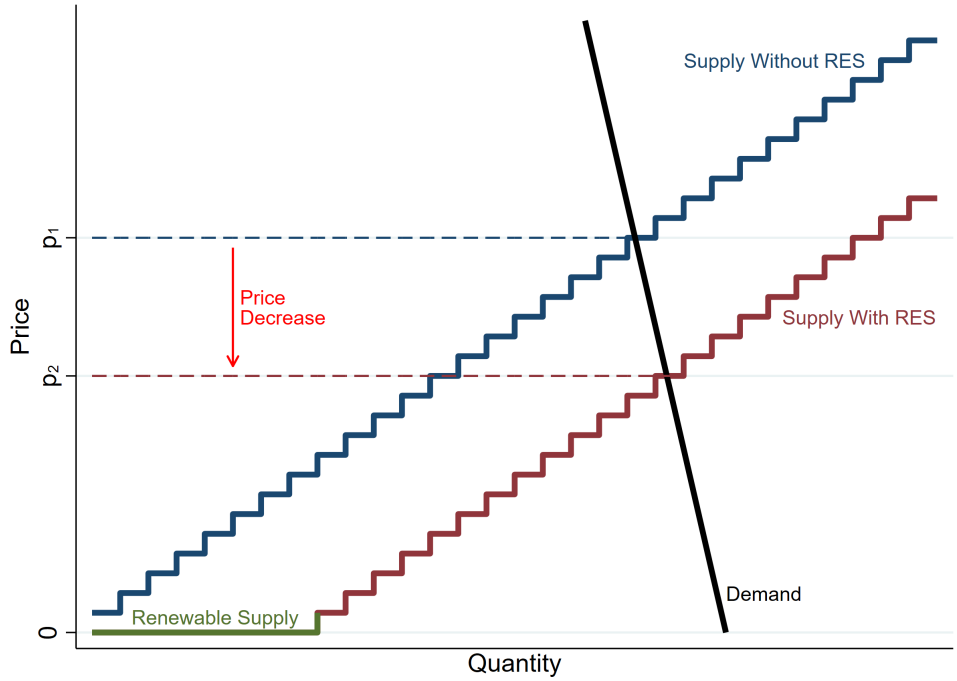
In this paper I classify the main challenges faced by current and future electricity markets in three blocks. First, the understanding of how competition takes place in renewable-dominated electricity markets is a prerequisite for designing market rules that

[3] According to IRENA (2020), *"New solar and wind projects are undercutting the cheapest and least sustainable of existing coal-fired power plants"*. Costs reductions for energy storage – which is needed to address the intermittency of renewables – have also been impressive; further cost reductions are nevertheless needed to make it cost-effective (BloombergNEF, 2020).

[4] However, it is important to stress that whether these projected cost savings are actually realized depends on whether the investments actually take place, which in turn depends on the policies implemented. Likewise, such policies will also determine whether the projected cost savings are passed on to final consumers, which is a necessary condition to incentivize an electricity-based strategy to decarbonize the rest of the economy.

[5] For instance, according to Eurostat (2020), the average share of energy from renewable sources in gross electricity consumption in the European Union in 2019 was 34.1%, with some countries already exceeding 50% (notably, the Nordic countries, but also Denmark, Portugal, Albania, Austria, etc.). In the US, renewables made up to 26.2% of global electricity generation in 2018.

Figure 1: The price-depressing effects of renewables under perfect competition



Notes: This figure depicts market-clearing in electricity markets, with and without renewables (RES). Renewables' supply at zero marginal costs pushes the aggregate supply curve outward, leading to lower market-clearing prices.

provide the correct incentives for firms to invest in renewables and to price them efficiently. Investments in renewables are costly, as they involve large capital upfront costs. However, once in place, renewables have almost zero marginal costs of production. For this reason, an increase in renewable generation shifts the aggregate supply function to the right, leading to a price-depressing effect, as illustrated in Figure 1.

The scale of this effect depends on several factors, including the energy mix and the market structure. Both factors will determine the intensity of competition among renewables and the change in the conventional energy sources' decisions in response to the expansion of renewables (Acemoglu, Kakhbod, and Ozdaglar, 2017; Fabra and Llobet, 2019; Bushnell and Novan, 2018). In Section 2 of this paper, I survey some of the main contributions that shed light on these issues.

Second, the analyses of competition in wholesale electricity markets with large shares of renewable energy lead to another important conclusion: the average market price cap-

tured by renewables will fall below their average costs. The reason is that, at times when the supply of renewables exceeds total demand, the short-run electricity market prices will converge towards the (almost zero) marginal costs of renewables.[6] To provide long-term signals that support future investments, it will be important to rely on mechanisms, other than short-run electricity markets, to determine payments for renewables without distorting the choice of locations and their efficient use once the investments have taken place. Not surprisingly, auctions for renewable investments are rapidly expanding worldwide (IRENA, 2019). Design features of such auctions - including, among others, the product that is auctioned off (e.g., either energy or capacity), the winning projects' price exposure, or the set of technologies that are allowed to compete - are key determinants of the auctions' success. In Section 3, I discuss the implications of such choices through the lens of recent contributions in this area.

And third, because renewable energies are not always available, their expansion has been traditionally associated with the need to build back-up capacity to avoid disruptions in energy supply. However, more efficient solutions to cope with renewables' intermittency may come from either the demand side (e.g., by using dynamic prices to induce a shift in consumption towards hours with high renewables' production), or from the supply side (e.g., through storage). Both can help mitigate the need to maintain excess capacity. In particular, demand response mechanisms can induce load shifting from high-price periods (i.e., those with high demand/low renewables) to low-price periods (low demand/high renewables). Storage technologies can also help address renewables' intermittency by allowing storage during periods with abundant renewables' generation, and release during periods when renewables are scarce. However, some pending issues merit further research. On the one hand, even though there are strong theoretical arguments in favour of dynamic pricing (Borenstein, 2002; Borenstein and Holland, 2005), the experimental literature has shown that active demand response is not likely in the absence of enabling technologies (Harding and Sexton, 2017), a result that has recently been confirmed empirically (Fabra,

[6] Besides these low-price episodes, there will also be instances of high prices. However, these will tend to occur precisely when renewables are not available. Hence, there will be a wedge between average market prices and the market prices captured by renewables.

Rapson, et al., 2021). Regarding storage, not only do their costs remain high, but market power can also create distortions for the efficient operation and investment in storage facilities (Andrés-Cerezo and Fabra, 2020). On the other hand, both options are very complementary with the renewables' expansion, as renewables will likely enlarge cost and price volatility which will in turn enhance the social and private benefits of demand response and storage. In Section 4, I review these issues with the aim of identifying policy options to enhance the effectiveness of demand response and storage as complements for the renewables' expansion.

2 Market Impacts of Renewables

That renewable energies possess unique features which are not shared by conventional generation technologies is beyond dispute. Not only are they able to produce carbon-free electricity but also, importantly for market design, they do so at almost zero marginal costs. Furthermore, unlike conventional technologies, the availability of renewables depends on weather conditions, which have seasonal (e.g., timing of sunset and sunrise) and stochastic components (e.g., whether it is cloudy, or not).[7] These differences imply that renewables change the economics of electricity markets in fundamental ways. Issues such as investment incentives and security of supply or competition among intermittent zero marginal cost resources have to be re-assessed. An emerging literature has tried to assess, both theoretically as well as empirically, the impacts of renewables on wholesale electricity markets.

Given the still greater weight of conventional technologies in the energy mix, it is not surprising that the economic analysis to date has largely focused on the performance of electricity markets with no renewables (Green and Newbery, 1992; Fehr and Harbord, 1993; Fabra, Fehr, and Harbord, 2006). These approaches are still well suited to analyze market performance as long as the amount of renewables is small. Essentially,

[7] This mostly applies to the quantitatively more relevant renewable technologies, such as wind and solar photovoltaics. However, there are some exceptions. For instance, biomass is closer to conventional technologies in that its marginal costs are strictly positive and its availability is not subject to weather conditions.

if the marginal output (i.e., once renewables have been subtracted from total demand) is served by conventional technologies, renewables simply affect the amount of firms' infra-marginal output. Matters become different, however, in the presence of large amounts of renewables, given that their availability changes across time in ways that cannot always be accurately forescasted or even observed. The implications of these issues are discussed below.

2.1 A primer on wholesale electricity markets

Let me start by briefly describing some stylized features of electricity market design. Electricity wholesale markets are well-defined institutions with a set of well-specified rules that map firms' prices and quantity offers into market prices and outputs. Most wholesale electricity markets are organized through a series of sequential auctions, of which the day-ahead market is the most relevant one. The day-ahead market is typically structured as a uniform-price auction, in which generators submit 'price-quantity' bids specifying the minimum prices at which they are willing to produce the corresponding quantities. Similarly, consumers submit the maximum prices at which they are willing to buy the various quantities. The auctioneer, or market operator, aggregates the supply and demand bids to construct the market supply and demand curves for each hour. The intersection between the two determines the equilibrium market price, as well as the units that will be called to produce: namely, those that are willing to produce at prices that are equal to or below the market price.

The various technologies are called to produce in increasing bid order (in industry parlance, in "merit-order"), regardless of their investment or fixed costs. Therefore, as demand changes over time, different types of plant, with different marginal and fixed costs, are dispatched to meet it. Because renewable energies have low marginal costs, they are optimally dispatched first, either until demand is met or until their available capacities are exhausted. The residual demand (if any) is satisfied by the conventional power plants (coal-fired and/or gas-fired power plants), as their marginal costs are significantly higher relative to the low marginal costs of renewable generation. Under competitive conditions,

reservoir hydroelectric power and pumped storage capacity are also used to meet the peaks of demand, which is when their value is the highest. Furthermore, because of their flexibility to start-up or ramp-up or down, some plants (typically, coal, gas or hydro units) are particularly well-suited to provide provide flexibility, helping to equate demand and supply at all times, at all nodes of the network. Changes in demand affect the resulting market-clearing prices and the production patterns of the various technologies over time.

2.2 Renewables in perfectly competitive markets

In this context, the simplest approach for analyzing the market impact of renewables is to assume perfect competition. In this case, renewables simply push out the supply curve, displacing expensive conventional generation and thus leading to lower prices, as shown in Figure 1.[8] This effect, labeled as the "merit order effect", has been used as one of the arguments when advocating for renewable energy support.[9] For instance, with German data, Sensfuß, Ragwitz, and Genoese (2008) concluded that *'the volume of the merit-order effect exceeds the volume of the net support payments for renewable electricity generation.'*[10] While the impact of renewable electricity expansion on power market prices has broadly benefited consumers, it has also put some electricity companies in financial distress (Bushnell and Novan, 2018; Benatia, 2020). The question of whether these producers should be given additional support to remain available is the subject of an intense policy debate around the need for and effects of 'capacity mechanisms' (Fabra, 2018; Llobet and Padilla, 2018).

However, while renewables indeed depress market prices, the assumption of perfect competition biases the quantification of the price-depressing effects of renewables. Indeed, under imperfect competition, the shift in the aggregate supply function need not be

[8] Several papers have measured the environmental implications of the expansion in renewables as they replace other polluting sources. For instance, see Cullen (2013), Novan (2015), and Gowrisankaran, Reynolds, and Samano (2016).

[9] Bushnell and Novan (2018) argue that the price effects are not uniform across hours of the day. For instance, in California, the expansion of solar photovoltaics is depressing prices at mid-day, while it is leading to price increases around the sunset as several conventional resources are leaving the market for lack of profitability.

[10] Also with German data, Cludius et al. (2014) estimate that, for each additional GWh of renewables, the electricity price in the day-ahead German market was reduced by 11-13 Euros/MWh in the period 2008-2016.

parallel to the shift in the marginal cost curve as (i) renewables might also affect the bidding behaviour of other market players and (ii) renewables themselves might not have incentives to bid at marginal cost. Therefore, the scale of the price-depressing effect really depends on what the new market equilibrium looks like, which in turn depends on the new market game that is being played.[11]

2.3 Introducing imperfect competition

Acemoglu, Kakhbod, and Ozdaglar (2017) provide one of the first analysis of the strategic effects triggered by renewables. They assume Cournot competition between a fringe of renewable-only producers and a set of strategic firms that own both conventional technologies as well as a fraction of the renewable assets. In line with the conventional wisdom, they find that an increase in the availability of renewable resources pushes equilibrium market prices down. However, they show that the merit-order effect is partially mitigated by the Cournot incentives, which induce the strategic players to withhold more output in response to an increase in renewables. In the extreme case in which all the renewable assets are in the hands of the strategic players, the increase in renewables' availability is fully offset by the withholding of conventional output, allowing firms to avoid any price-depressing effect. However, because Acemoglu, Kakhbod, and Ozdaglar (2017) assume that there is only a small amount of renewables (in the sense that that they are never marginal), their model cannot capture the nature of strategic interaction in future electricity markets when most (if not all) production will come from renewable sources. Simply put, if strategic producers are not able to counteract the price-depressing effect of renewables by withholding their conventional output, will they be able to exercise market power, and if so, how?

[11] As explained in the next section, this price-depressing effect also depends on the pricing scheme renewables are subject to. The papers reviewed in this section assume that renewables are paid at market prices, while it is also common for renewables to be paid at fixed-price contracts.

2.4 A new competitive paradigm in renewables-only markets

Analyzing competition in renewables-only markets is the focus of recent work by Fabra and Llobet (2019). They point at a fundamental difference between conventional and renewable energies. In line with the existing literature on electricity auctions, they argue that competition among conventional technologies is better analyzed using models in which capacities are common knowledge but production costs might be private information (Holmberg and Wolak, 2018). In contrast, they stress that competition among renewables should rather be analyzed under the assumptions of complete cost information but privately known capacities. The reason is that the production costs of renewables are known to be almost equal to zero, while their availability depends on local weather conditions. Furthermore, the information gathered at the plants' sites allows firms to forecast their own plants' availability better than that of their rivals. This is confirmed by the evidence reported in Fabra and Llobet (2019), using proprietary data gathered from six renewable power plants for which they observe their private hourly forecasts and actual production, for a two-year period. They also collected publicly available information (i.e., the forecasts computed by the System Operator and the one-day ahead weather predictions at the most disaggregated local level available). Table 1 compares the forecast errors when using only publicly available information, versus when also using private information. Notably, in the latter case, the R-squared improves from 0.52 to 0.83 and the impact of the public forecast on the prediction, while still statistically significant, becomes economically small.

Fabra and Llobet (2019) build an auction model that reflects this new competitive paradigm and apply it to understanding competition in 100% renewables markets.[12] In particular, they solve a uniform-price auction among two firms with privately known capacities. Firms compete by submitting a price-quantity pair, indicating the minimum price at which they are willing to produce up to the corresponding quantity. Prices are implicitly capped at the marginal costs of the conventional technologies, as raising the

[12] Admittedly, their model abstracts from other ingredients that will play a key role in these markets, such as demand response and storage. I devote attention to these issues in Section 4 of this survey.

Variables	(1) No Private Info.	(2) With Private Info.
Public forecast	0.582***	0.070***
	(0.035)	(0.021)
Private forecast		0.657***
		(0.008)
Observations	36,671	36,671
R-squared	0.520	0.826
Standard deviation of the error	.18	.11

Table 1: Forecast errors of wind plants' availability using public information only, versus public and private information

Note: The dependent variable is the plant's hourly production normalized by its nameplate capacity. Both regressions include weather data (temperature, wind speed and atmospheric pressure) as well as plant, hour and date fixed effects. Robust standard errors are in parentheses. Significance are levels indicated by: *** p<0.01, ** p<0.05, * p<0.1. Source: Fabra and Llobet (2019).

bid above that level would displace renewables with conventional output.

They show that the unique (symmetric) Bayesian Nash equilibrium of the game depends on the relationship between a single firm's maximum capacity and total demand. Consider first the case in which the former is lower than the latter, thereby implying that firms are always pivotal (i.e., regardless of their prices and capacity realizations, they always produce a positive quantity). In this case, in equilibrium, firms always choose an output equal to their realized capacity, but exercise market power by adding a mark-up above their marginal cost, which is decreasing in the firm's available capacity. In particular, in the duopoly case, at the symmetric Bayesian Nash equilibrium, a firm with realized capacity k_i offers it at a price given by, for $i = 1, 2$ and $i \neq j$,

$$b^*(k_i) = c + (P - c) \exp\left(-\omega(k_i)\right), \tag{1}$$

where c and P denote their own marginal cost and that of the conventional technologies, respectively. The function $\omega(k_i)$ is given by

$$\omega(k_i) = \int_{\underline{k}}^{k_i} \frac{(2k - \theta)g(k)}{\int_k^{\overline{k}} (\theta - k_j) g(k_j) dk_j} dk, \tag{2}$$

where θ denotes (inelastic) market demand and $g(k)$ represents the density of capacity realizations, which take values in the interval $[\underline{k}, \overline{k}]$.

This optimal price offer reflects a standard price-quantity trade-off which is common in oligopoly games. First, conditional on bidding above its rival, a firm is better off increasing its price offer in order to set a higher market price – this is the *price effect*, which is captured by the denominator in expression (2). However, the firm would rather bid below its rival in order to sell more – this is the *quantity effect*, which is captured by the numerator in expression (2). While the price effect is independent of the firm's size, the quantity effect is not. Indeed, a firm that has a large capacity is more eager to bid lower prices as the output gain from undercutting the rival and selling at capacity is larger. Figure 2 shows the equilibrium price and quantity offers as a function of a firm's realized capacity.

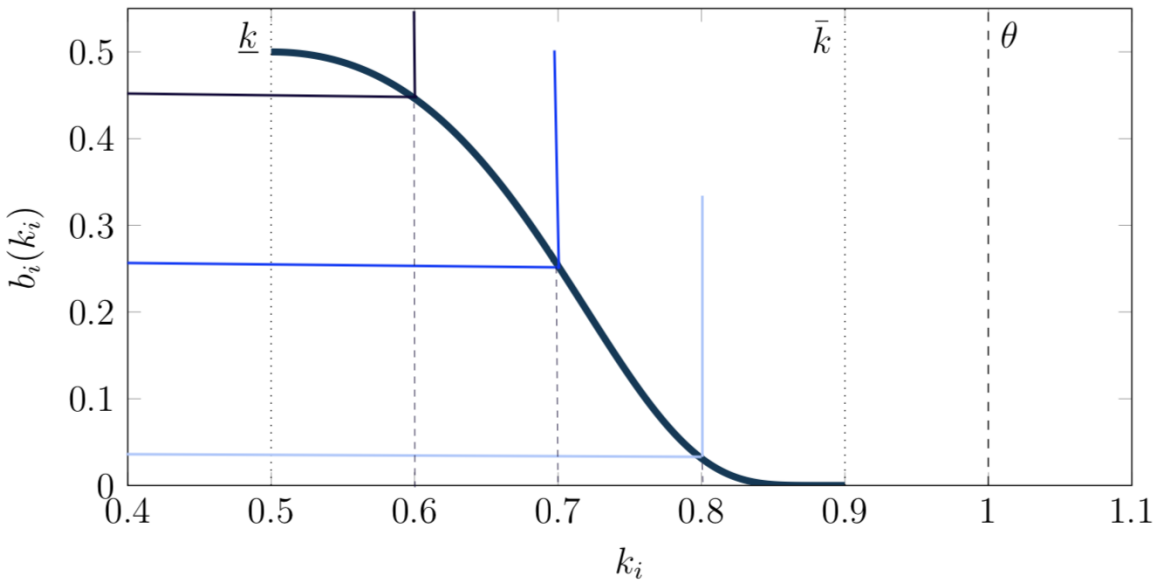
Relative to when capacity realizations are low, high capacity realizations push firms' supply functions outwards and downwards,[13] which reduces market prices. Through this channel, renewables' intermittency gives rise to price volatility. However, in contrast to what is often claimed, this is not due to renewables' intermittency *per se*, but rather to renewables' intermittency coupled with market power (a perfectly competitive market would result in prices equal to zero marginal costs and no price volatility).

Consider now the remaining case in which, with some probability, a firm has enough capacity to fully serve demand alone. Whenever this is the case, in equilibrium, the firm bids at marginal cost but withholds capacity in order to avoid driving the market price down to that level. While the resulting expected market price is above marginal cost, the realized market prices might fall down to marginal cost if the capacities of both firms happened to exceed total demand. The incidence of zero-price events grows larger the more renewable capacity is deployed. As a consequence, average equilibrium prices smoothly converge towards marginal costs.

While these pro-competitive effects should be welcome, they naturally raise a key

[13] Note that in the case in which costs are private information, supply functions only shift up and down (Holmberg and Wolak, 2018). Hence, in models in which capacities rather than costs are private information, prices are more elastic to the shocks, giving rise to smoother price changes.

Figure 2: Equilibrium price offer



Notes: This figure depicts the equilibrium price offer 1 as a function of a firm's realized capacity k_i when it is distributed uniformly in the interval $[0.5, 0.9]$, with demand equal to 1, and the marginal costs of conventional generation equal to 0.5. The optimal price curve starts at 0.5 for the lowest possible capacity realization, and decreases in k_i until it takes the value 0 at the higher possible capacity realization. These prices anchor the optimal supply curves, at the corresponding capacity realization and optimal price offer, as shown by the blue lines in the figure. Source: Fabra and Llobet (2019).

question, which brings us immediately to the topic of the next section. Would firms be willing to invest in renewables if they expect that the market might not cover their high fixed costs? Is it possible to enhance, through market design, the long-term price signal so as to induce firms to invest in renewables and thus comply with the environmental targets?

3 Incentives to Invest in Renewables

Until very recently, the rationale for granting support to renewables was based on two grounds: their positive environmental and learning-by-doing externalities (Borenstein, 2012a; Newbery, 20180), coupled with their higher average costs relative to the conventional technologies. However, major technology breakthroughs have pushed the costs of renewables to a similar range of, and in some cases even below, the costs of

conventional technologies (IRENA, 2020). Yet, this cost advantage does not imply that such investments will necessarily take place. The problem, which was already highlighted in the previous section, is at the heart of the Classical Theory of Regulation: whenever marginal costs are below their average costs, efficient pricing does not allow firms to break even. While future electricity markets will certainly depict price volatility, with low and high price episodes, renewables will tend to capture the lower tail of the price distribution because of the price-depressing effect discussed earlier. The uncertainty over the future prices captured by renewables exacerbates this issue by adding risk premia to the costs of financing the high capital cost investments. The question is how to design the policy instruments so as to achieve investments in renewables at least cost for society.

Worldwide, regulators are increasingly adopting a solution is reminiscent of Demsetz (1968)'s seminal work: rather than relying on short-run price signals or on price regulation,[14] renewable investors are now called to compete to access the market through auctions of long-term, legally enforceable, contracts that reduce electricity market price risk. In line with Weitzman (1974), the success of auctions relative to price regulation is probably explained by the severe degree of asymmetric information faced by regulators in a setting of rapidly falling costs.

Auctions have appealing properties. Competition among investors prior to carrying out the investments has the potential of driving prices down to the average costs of the best available technologies, thus allowing firms to break even and consumers to benefit from the renewables' cost reductions. Furthermore, the possibility of entering into long-term contracts prior to carrying out the investment should reduce investors' risk-premia, facilitate access to credit, and promote entry, ultimately benefiting consumers through more vigorous competition and lower prices.

However, advocating for the use of auctions is not enough. As the experience with

[14] The initial renewable energy roll out was heavily supported by the use of price regulation in the form of Feed-in-Tariffs (FiTs), which established a technology-specific fixed price per unit of renewable energy produced. The first FiTs were introduced in Germany in 1990, but soon became broadly used in Europe. Whereas they succeeded in promoting the early rollout of renewables, they then failed to adjust to the cost reductions. Some countries witnessed a boom in installations exceeding the initial objectives, which added financial pressure to the cost of the renewables' support schemes. Ultimately, the EU Guidelines on State aid for environmental protection and energy 2014-2020 promoted the gradual move from FiTs to competitive bidding processes (European Commission, 2014). See Fabra, Matthes, et al. (2015).

spectrum auctions in Europe demonstrated, auction design is paramount: even seemingly minor differences in auction design can have major consequences for auction performance (Klemperer, 2002). Since there exists cross-country variation in the design of auctions for renewables, it should be possible to provide some empirical evidence on the effects of design choices on auction performance. While to date I am not aware of any such empirical analysis, the recent literature has highlighted some pros and cons of the various options. In the following sections I discuss the trade-offs involved in two key choices: the degree of price exposure and the technological approach.

3.1 Price exposure

As part of the auction design, the regulator has to decide whether to expose renewable investors to the volatility of short-run electricity prices and if so, by how much. On the two extremes, the regulator might decide between full price insurance or full price exposure. To provide full price insurance, the regulator could auction off fixed prices per MWh produced over the lifetime of the plant. Feed-in-Tariffs (FiT) or Contracts-for-Differences (CfDs) serve this purpose. Under FiTs, renewable producers receive a fixed price ($\overline{p}$) for their output (q_i), while under CfDs, producers sell their output at the market price (p) and receive (or pay) the difference between a reference market price ($\hat{p}$) and a strike price ($\overline{p}$) that is set ex-ante (possibly through an auction). Accordingly, a firm's profit under CfDs can be written as $\pi_i = (pq_i - q_i(\hat{p} - \overline{p})$. If the firm sells its output at the reference market, this is equivalent to receiving a FiT, $\pi_i = \overline{p}q_i$.[15]

Instead, to provide full price exposure, the regulator could allow the producer to sell its output in the wholesale market but would provide an additional payment to be determined through the auction. This extra payment could be computed as a function of

[15] This difference implies that, unlike FiTs, CfDs preserve firms' incentives to arbitrage (an issue to which we turn below), given that the financial settlement is not computed as a function of the actual market revenues obtained by the plant. Similar conclusions apply to schemes with sliding feed-in premiums, which are common across Europe, as long as prices in the reference market are above the contract price.

output – for instance, through fixed premia referred to as Feed-in-Premia (FiP) [16] – or as a function of capacity k.[17] Accordingly, using ρ to denote the fixed premium, a firm's profit under FiPs can be written as $\pi_i = (p + \rho)q_i$. Similarly, under a capacity payment s, profits would be $\pi_i = pq_i + sk$.

In between these two extremes, there are hybrid solutions. For instance, producers could receive fixed prices for a shorter period of time and then sell their output at market prices until the end of their lifetime. In this case, the shorter the length of the contract, the greater the investors' price exposure. Similarly, the auctioneer could pay the renewable output at a weighted average of a fixed price (to be determined through the auction) and the short-run market price.

These choices have several implications. For instance, Newbery, Pollitt, et al. (2018) and May and Neuhoff (2017) favor the use of pricing schemes with limited price exposure as a way to de-risk the investments, ultimately bringing down the costs of capital and facilitating the entry of more diverse players.[18] Instead, other authors advocate to expose producers to price risks such that they internalize the economic value of their investments. As shown by Joskow (2011), the cost-based comparison across renewable technologies is inappropriate as it neglects the differences in the values created by the various technologies, which depend on their production profiles, their correlation with the availability of other installed technologies and with demand, as well as on the costs (including emissions costs) of the generation technologies that they replace (Callaway, Fowlie, and McCormick, 2018). For instance, in an electricity market with an already strong solar penetration, an additional unit of solar power may be less valuable than an additional unit of wind, given that their availabilities are negatively correlated. Auction-

[16] This premium can take several forms; it can be a direct payment by the regulator, it can be a tax credit (as the federal Production Tax Credit in the US), or it might derive from the sale of renewable energy credits to electricity providers that are required to procure a proportion of their sales with renewable energy (as the system of Revenue Obligation Certificates (ROCs) in the UK, or the Renewable Portfolio Standard (RPS) in the US). See Newbery (2016) for a description of the ROCs, and Greenstone, McDowell, and Nath (2019) for an analysis of RPS.

[17] In some cases, as it occurred in the 2020 Portuguese auctions, this capacity payment might be negative if firms can only access the market by participating in the auction.

[18] As pointed out by Newbery, Pollitt, et al. (2018), it is more efficient to share the investment risks across the mass of consumers than to concentrate such risk on a small number of companies. For the former, their share of the investment cost is only a small fraction of their total expenditures, while for the latter the investment might represent a high share of their profits.

ing fixed-price contracts (FiTs or CfDs) would select the lowest-cost technology, but this need not be the one providing the most valuable energy. Instead, auctioning contracts with price exposure (FiPs) would select those investors that are able to produce at times when the market price is higher, as these would require a smaller premium to break even.[19].

Ito and Reguant (2016) highlight another benefit of exposing renewable producers to market prices: they are incentivized to arbitrage price differences across sequential markets, which mitigates the dominant firms' market power in the day-ahead market. This effect would not be present if renewables are shielded from market price volatility.

Fabra and Imelda (2020) show that while moving renewable producers from variable to fixed prices limits arbitrage, it also mitigates the incentives of the dominant producers to exercise market power in the first place. The reason is that fixed prices act as a forward contract over the firm's renewable output, thus suggesting that they should have similar market-power mitigating effects (Allaz and Vila, 1993).[20] Fabra and Imelda (2020) label these two countervailing effects as the 'arbitrage effect' and the 'forward-contract' effect.

To illustrate these two effects, let me briefly describe their model. Transactions take place in two sequential markets: a day-ahead market ($m = 1$) and a spot market ($m = 2$). Day-ahead market demand is $D(p_1)$, while $D(p_2) - D(p_1)$ represents unserved demand, which is traded in the spot market. There are two types of firms, a dominant firm (d) and set of fringe firms (f). Both types of firms own wind power plants, with zero marginal costs up to their available capacity $w_i \leq k_i$, where k_i denotes the maximum capacity (i.e., only available in very windy days), $i = d, f$. Furthermore, the dominant firm owns conventional power plants that produce electricity at marginal costs $c > 0$. The dominant firm chooses prices taking into account the output decisions of the fringe firms, which act as price-takers. Let q_{fm} be the quantity offered by the fringe in market $m = 1, 2$, with $q_{f1} + q_{f2} = w_f$ and $q_{fm} \leq k_f$. These conditions reflect two market rules:

[19] However, as discussed later, this approach could give rise to high rents to those technologies that expect to receive high market prices. If these rents are costly, this approach need not be welfare maximizing

[20] Empirically, the market impacts of forward contracts in electricity markets have been analyzed by Bushnell, Mansur, and Saravia (2008) and Fabra and Toro (2005), among others. Theoretically, Dressler (2016) has also noted that fixed prices for renewables play a similar role as forward contracting.

first, firms must be balanced when the spot market closes; and second, they can never offer to produce above their maximum capacity.

Therefore, the dominant firm faces the following residual demands: $q_1(p_1) = D(p_1) - q_{f1}$ in the day-ahead market, and $q_2(p_1, p_2) = D(p_2) - D(p_1) - q_{f2}$ in the spot market. By backward induction, the dominant firm first solves its profit maximizing problem in the spot market,

$$\max_{p_2} \left[p_2 q(p_1, p_2) - c\left(D(p_2) - w_f - w_d\right) \right]. \tag{3}$$

It then solves its profit maximizing in the day-ahead market,

$$\max_{p_1} \left[p_1 q_1(p_1) + p_2^* q_2(p_1, p_2^*) - c\left(D(p_2^*) - w_f - w_d\right) + \pi(w_d) \right], \tag{4}$$

where $\pi(w_d)$ represents the financial settlement for the dominant firm's wind, which equals $(\overline{p} - p_1)w_d$ if wind is paid at a fixed price $\overline{p}$, or ρw_d if wind is paid a fixed premium ρ.

In the spot market, the firm will price above c, while in the day-ahead market, the firm will optimally add a markup over p_2, which represents the opportunity cost of day-ahead sales. This gives rise to a pattern of decreasing prices $p_1^* > p_2^* > c$, which the small renewable producers can exploit through arbitrage. In particular, they can do so by selling $q_{1f} = k_f$ at the high day-ahead price to then undo their long positions by buying $q_{2f} = -(k_f - w_f)$ at the lower spot price. This pushes p_1^* down and p_2^* up, as the increased supply (demand) in the day-ahead (spot) market mitigates (enhances) the dominant firm's market power – this is the 'arbitrage effect' uncovered by Ito and Reguant (2016).

This effect disappears if wind is paid according to fixed prices. Since wind output obtains the same price regardless of where it is sold, fringe producers sell it all in the day-ahead market, $q_{1f} = w_f$ and $q_{2f} = 0$. Instead, fixed prices bring in an additional market power mitigating effect: the dominant firm's incentives to raise the day-ahead market price are diminished as the firm only benefits from an increase in p_1 through its output net of wind, $(D(p_1) - w_f - w_d)$ – this is the 'forward contract effect' uncovered

by Fabra and Imelda (2020).

To compare these two effects, it is convenient to write the two first order conditions of the day-ahead market problem (4) side by side, the one for the fixed premium case, equation (5), and the one for the fixed price case, equation (6):

$$D(p_1) - w_f - (k_f - w_f) + (p_1 - p_2^*) \frac{\partial D(p_1)}{\partial p_1} = 0 \tag{5}$$

$$D(p_1) - w_f - w_d + (p_1 - p_2^*) \frac{\partial D(p_1)}{\partial p_1} = 0 \tag{6}$$

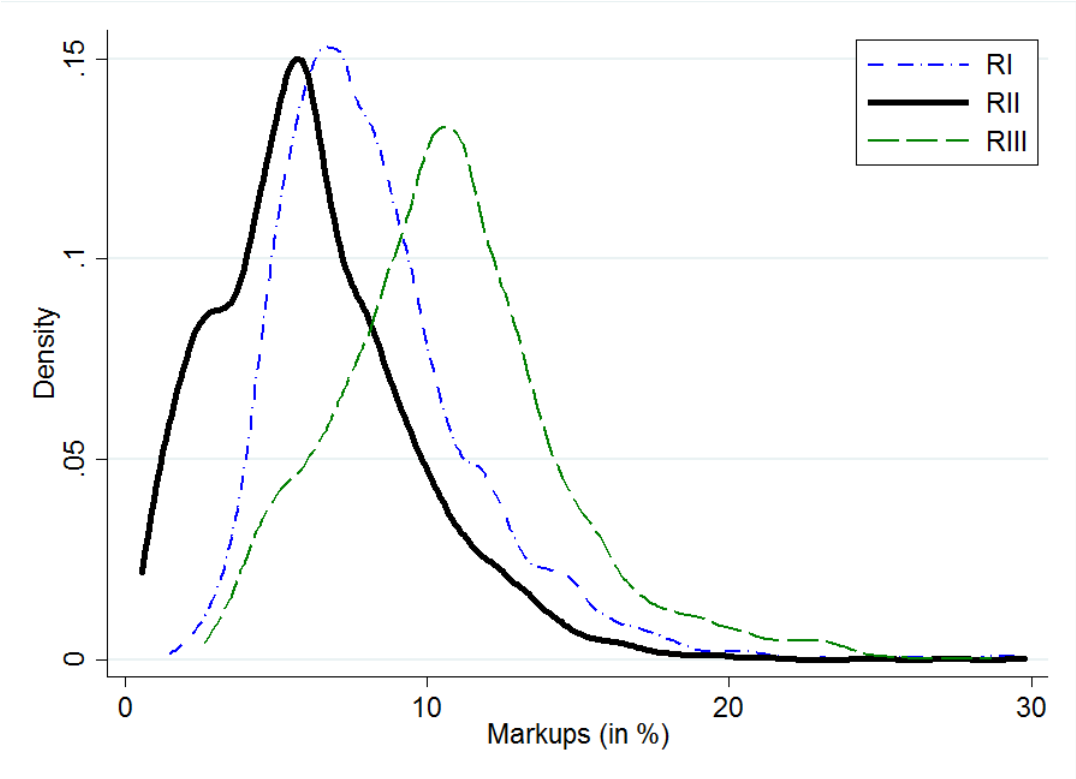
The main difference between these two equations lays in the third term: $-(k_f - w_f)$ in (5) captures the 'arbitrage effect', while $-w_d$ in (6) captures the 'forward contract effect'. Which one of the two dominates depends on the ownership structure of renewables: if it is highly concentrated (fragmented), so that $-w_d$ is relatively large (small), then fixed prices (fixed premia) lead to a stronger market-power mitigating effect. Therefore, fixed prices tend to perform relatively better in markets in which market power concerns are particularly worrisome.

Fabra and Imelda (2020) document that both effects are at play in the Spanish electricity market. To understand which of the two dominates, they leverage on structural estimates to compute firms' mark-ups as a measure of market power. Figure 3 shows the distribution of the estimated firms' price-cost mark-ups when renewables were paid at fixed prices (pricing regime RII) or when they were exposed to market prices (RI and RIII). Results show that paying renewables according to fixed prices mitigated firms' market power as the forward contract effect was stronger than the arbitrage effect. Admittedly, this conclusion need not hold in all markets given that, as mentioned above, whether the arbitrage effect or the forward contract effect dominates depends on the renewables' market structure.

3.2 Technology choices

Another contentious issue is whether all technologies should be allowed to compete within the same auction (technology-neutrality) or whether auctions should be

Figure 3: Distribution of day-ahead markups in the Spanish electricity market



Notes: This figure plots the distributions of the estimated day-ahead markups in the Spanish electricity market, for all firms by pricing regimes, for hours with prices above 25 Euro/MWh. The pricing regimes RI and RIII exposed renewable output to market prices, while RII paid renewable output at a fixed price. Source: Fabra and Imelda (2020).

technology-specific.[21] This question is relevant not only when procuring renewable technologies (e.g., wind and solar), but also when procuring other low-carbon investments (e.g., storage technologies such as electrical batteries versus hydrogen electrolyzers) or when procuring security of supply (e.g., through demand response or back-up generators). Similar issues also arise when deciding the geographical scope of the auctions (i.e., whether auctions are location-specific or not), or when deciding whether all project sizes and firms should be allowed to participate in the same auctions. In between these two extremes, there are hybrid schemes by which some technologies, locations, project sizes or firms would get a handicap to level the playing field ("technology banding").

The choice between a technology-neutral or technology-specific approach involves

[21] For instance, while the European Commission (2014), through its Environmental and Energy Aid Guidelines (EEAG), adopts technology-neutrality as a guiding principle, it also allows Member States to invoke some exemption clauses (e.g., need for diversification, or system's costs and network constraints) in order to approve technology-specific formats. In practice, most European countries resort to technology-specific auctions. The EEAG are currently being revised.

various issues. First, a relevant question is whether the various renewable technologies are truly comparable. As already mentioned, renewable technologies tend to differ in various aspects, giving rise to differences in the economic value they provide. Even if these values could be internalized through a technology-neutral auction that exposed producers to market prices,[22] this would come at the cost of exposing producers to too much price risk. Capital markets are not always willing to lend money under such market risks, and even when they do, they add high risk premia that consumers would end up paying through higher prices. Alternatively, in order to combine both objectives, the regulator could auction fixed prices through technology-specific tenders to de-risk the investments, while taking into account the values of the various technologies when deciding on the amounts to be procured from each. In this sense, the choice between a technology-neutral versus a technology-specific approach is reminiscent of the classical trade-off between market failures versus regulatory failures, which can well be country-specific.

Second, different technologies might be rise to different externalities, e.g., driven by their different stages of maturity (Newbery, 2018).[23] Indeed, over the last 20 years, the costs of solar photovoltaics and wind projects have fallen by 82% and 39%, respectively (IRENA, 2020). Forecasts indicate that the costs of these two technologies will keep on falling but at a slower pace. In contrast, while the costs of the less mature renewable technologies (off-shore wind; wave power; solar thermal; geothermal energy or biomass) are still much higher, the prospects for further cost reductions are promising. Under a fully technology-neutral approach, investors would pick the mature technologies without internalizing the learning externalities triggered by investments in the less mature ones. Uncertainty over the learning spillovers might also make it optimal to diversify support across technologies rather than to concentrate all efforts in the currently cheapest tech-

[22] The contribution of the various technologies to security of supply is not reflected in market prices, and hence could not possibly be internalized through these auctions.

[23] Other externalities include the impacts on rural development and employment or the contribution to security of supply by those renewables that allow for some storage, among others.

nology.[24] This has led some regulators such as the Ofgem, the British regulator, to run auctions separately for "ring-fenced pots", i.e., one for established and another one for emerging technologies (Fabra, Matthes, et al., 2015). An alternative is to run a single auction but in which the less mature technologies are favoured over others; for instance, through technology-banding or through minimum technology quotas.

Last, but not least, the choice between technology-neutral and technology-specific instruments involves a trade-off between efficiency and rent extraction. On the one hand, well-designed technology-neutral approaches are more effective in finding the cheapest technology sources. On the other hand, they may also over-compensate the cheaper sources, thus increasing the costs of procurement. Fabra and Montero (2020) propose a model to capture this trade-off in procurement contexts with multiple technologies.[25] They consider a continuum of agents (i.e., investors) with capacity to supply one unit of some commodity (e.g., green energy) according to different costs and production technologies (e.g., wind or solar). While technologies are observable, their costs are not. The regulator cares about the total quantity invested, but it is indifferent about which technology is adopted (thus abstracting from the other two issues mentioned above – differences in values and learning externalities – so as not to bias the comparison ex-ante). It aims at picking the least cost technologies while also minimizing payments by consumers, given that public funds are costly.

Fabra and Montero (2020) first show that in this context the optimal procurement mechanism is a single auction, with the regulator committing ex-ante to a demand schedule that is contingent on the bids submitted for each technology. This mechanism gives rise to technology-specific prices, a result which is analogous to third-degree price discrimination (Bulow and Roberts, 1989). Furthermore, the quantity allocation across technologies departs from the cost-minimizing solution in order to reduce the costs of

[24] Lehmann and Söderholm (2018) discuss these and other market failures associated with the deployment of renewables. They also discuss how these could be mitigated through the choice of either a technology-neutral or technology-specific approach.

[25] This trade-off has been central to the regulation and public procurement literature (Laffont and Tirole, 1993). Yet, the comparison between technology-neutral versus technology-specific procurement gives rise to new insights relative to the existing literature as the regulatory contract can be made conditional on the technology chosen, which is observable. The distortions do not arise within each each technology, but rather across technologies.

public funds. While this mechanism allows the regulator to overcome the efficiency-rents trade-off, it has never been used in practice (at least not in the context of auctions for renewables). Instead, regulators often rely on simpler policy designs that do not involve bid-contingent schedules, such as pure technology-specific or technology-neutral approaches.

Among these two approaches, maximizing efficiency calls for technology-neutrality, so that the quantities allocated to each technology freely adjust to the cost shocks. However, this may entail leaving exceedingly high rents with the inframarginal technology. Under technology separation, the regulator has an extra degree of freedom as it can distort the quantity allocated to each technology if that helps reducing such rents. The downside is that technology-separation implies committing ex-ante to some quantity allocations, which might give rise to inefficiencies once the cost shocks are realized.[26]

This trade-off is illustrated in Figure 4, which uses data from the Spanish electricity market to depict the cost curves of wind and solar investments. As shown in Figure 4a, the auction price under technology-neutrality is set by a wind project, giving rise to large inframarginal rents for the winning solar projects whose average costs are lower. The regulator could reduce these rents by running two separate auctions, one for solar and one for wind, as shown in Figure 4b. By shifting demand from the solar auction to the wind auction, payments for wind projects would increase but payments for solar projects would decrease by more. Some inefficiencies would arise (some solar projects which are not deployed are cheaper than some of the winning wind projects), but society would be better off because the efficiency loss is offset by the reduced social costs of firms' rents.

If the regulator had complete cost information, the technology-specific solution would clearly dominate the technology-neutral approach given the additional degree of freedom available to the regulator. However, as shown by Fabra and Montero (2020), in the presence of information asymmetries, there does not exist a one-size-fits-all solution

[26] Fabra and Montero (2020) also analyze the optimal design of auctions with technology banding or with minimum technology quotas. They show that a similar trade-off is present. Depending on parameter values, either of the three formats considered (pure technology neutrality or technology separation, or the hybrid schemes with banding or minimum quotas) could dominate the others. Hence, the analysis has to be done on a case-by-case basis.

as the preferred approach depends on model parameters. Within their two-technology model, the welfare difference between the technology-neutral (N) and the technology-specific (S) solutions is given by

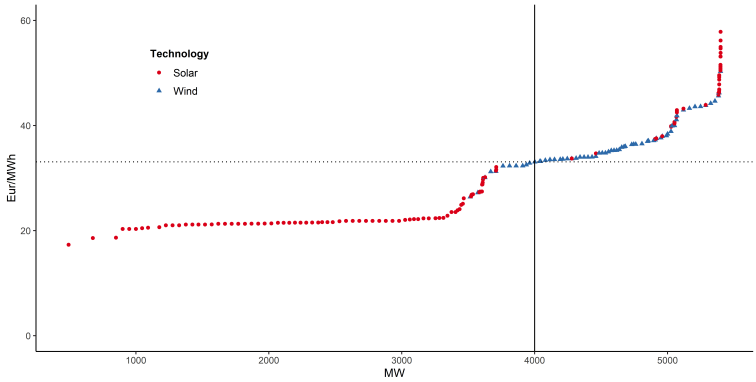
$$W^N - W^S \equiv \Delta W^{NS} = \frac{1}{4C''}\left[2\sigma(1-\rho) - \frac{\lambda^2}{1+2\lambda}(\Delta c)^2\right] > 0, \tag{7}$$

where C'' is the positive slope of marginal costs, σ and ρ represent the variance and correlation of cost shocks across technologies, λ denotes the social cost of public funds, and Δc is the ex-ante cost difference across technologies.

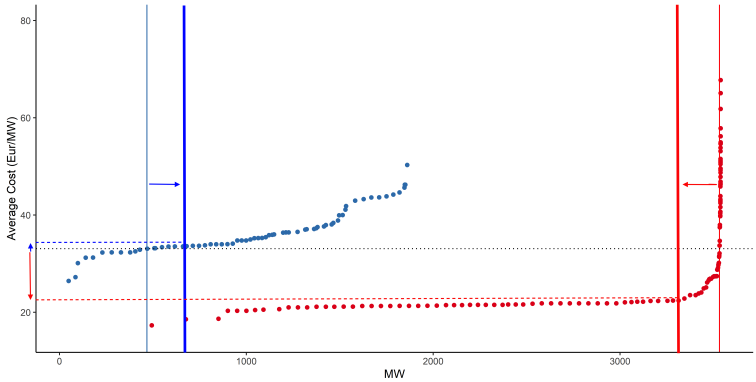
Accordingly, a well-informed regulator ($\sigma = 0$) should always run separate auctions, with the quantities for each technology chosen to balance the minimization of costs and payments. A similar prescription should be followed if the two technologies are subject to perfectly correlated cost shocks ($\rho = 1$), because in this case ex-post cost minimization is no longer an issue. The technology-specific approach should also be preferred if the planner faces large costs of leaving suppliers with high rents, which depends on the amount of over-compensation to the more efficient suppliers, in turn a function of the cost difference across technologies Δc and the shadow cost of public funds λ. In other cases, technology-neutrality would dominate.

Last, an important caveat is in order: designing technology-specific quotas may be quite challenging in practice. Indeed, setting technology quotas optimally has strong informational requirements; and if the regulator gets them wrong ex-post, it cannot blame it on the market. Moreover, the choice of technology quotas might be subject to political pressure by interest groups. It follows that, even in those contexts in which optimal technology separation is preferable, political economy considerations might make it sub-optimal.[27]

[27] Laffont and Tirole (1991)'s seminal work analyzes how the presence of interest groups affects regulatory design.



(a) Technology-Neutral



(b) Technology-Specific

Figure 4: Bidding Results for Different Auction Designs

Notes: These figures display average supply bid curves under the two auction designs. Red dots correspond to solar projects and blue dots to wind projects. Under technology-neutrality (Figure 4a), all projects are ranked in increasing average cost order. Under the technology-specific approach (Figure 4b), projects are ranked separately within each technology. The vertical lines represent how the allocation across technologies is distorted relative to technology-neutrality. Source: Fabra and Montero (2020).

4 Coping with Renewables

The availability of renewable energies depends on weather conditions. Yet, for all nodes of the network, the demand and supply of electricity must be equal at all times to avoid a system's collapse. This is why the intermittency of renewable resources creates a challenge for the smooth functioning of electricity markets. How can security of supply be guaranteed when solar and wind resources are scarce?

The traditional solution has been to build spare capacity. However, not only back-up capacity is costly, but it is also provided by thermal plants, which would jeopardize the objective of achieving zero-carbon power markets. Furthermore, it is not clear whether investors would have incentives to build capacity that is only rarely used, unless they

receive public support (Fabra, 2018). Fortunately however, technology and pricing innovation are paving the way to alternative options: demand response and storage. Given the growing need for counteracting the volatility of renewable energy, an understanding of the scope for demand response and storage to provide such a buffer becomes exceedingly important. I devote this section to reviewing recent developments in this area.

4.1 Dynamic pricing and demand response

The idea that electricity consumers should face the time-varying costs of producing electricity dates back to Boiteux (1964), but has attracted much attention lately, probably prompted by the increased cost volatility brought about by renewables (among others, see: Borenstein, 2002; Borenstein and Holland, 2005; Borenstein, 2005; Joskow, 2012; Joskow and Wolfram, 2012; Ambec and Crampes, 2020). These studies highlight the positive properties of charging retail prices that more closely reflect changes in the costs of producing electricity. Through dynamic prices, consumers face the right incentives to shift consumption from peak hours, when renewables are scarce and production costs are high, to hours of excess capacity when production costs are lower. Long-term benefits include a better use of renewable resources that would otherwise be lost,[28] a reduction in the production capacity needed to meet peak demand and, as a result, a reduction in the cost of meeting electricity needs (Borenstein, 2005; Borenstein and Holland, 2005). Additionally, demand response would contribute to mitigating the incidence of market power (Poletti and Wright, 2020).

Several authors have conducted field experiments to measure demand elasticity and to identify the determinants of demand response.[29] Most experiments demonstrate that consumers respond to time-variant price signals by reducing their consumption in high-

[28] Holland and Mansur (2008) analyze the environmental impacts of Real Time Pricing (RTP). They show that RTP reduces the variance in the quantity of electricity demanded, which can either increase or reduce total emissions depending on the energy mix. If peak demand is met by oil-fired capacity, emissions go up, while the contrary is true if it is mainly met by hydropower. In renewable-dominated markets, the latter effect would likely apply given that the flattening of the demand curve allows to substitute expensive polluting sources with cheap renewables that would otherwise be lost.

[29] Harding and Sexton (2017) provide a comprehensive survey on the experiments that analyze households response to dynamic electricity prices.

price periods (more than by shifting load to low-price periods).[30] However, there are large differences in the estimated elasticities,[31] which are likely explained by differences in the experimental design, the type of time-varying scheme adopted,[32] and the magnitude of the price changes. In some cases, this is compounded by concerns over the external validity of some of the results, given that the subjects participating in the experiments – typically a small number – do so voluntarily. In any event, a robust conclusion from the literature is that differences in the magnitude of the demand response depend critically on the scale of the price increase, the information provided to customers, the lag with which the price increase is announced (Jessoe and Rapson, 2014), the existence of automated control technologies (Bollinger and Hartmann, 2020),[33] and whether consumers are defaulted into time-varying rates or whether they actively opt-in (Fowlie et al., 2021). The experimental literature has also highlighted the role that scarcity of attention (rational or irrational) plays in explaining demand response and tariff choices (Fowlie et al., 2021; Harding and Sexton, 2017).[34]

Despite the large theoretical and experimental literature, there is little conclusive empirical evidence about the effects of dynamic pricing because these policies have not yet been broadly deployed. One potential reason for the slow adoption of dynamic pricing is the fear that an increase in price volatility would harm poorly-informed and/or highly

[30] Jessoe and Rapson (2014) also find that conservation efforts persist outside the critical peak price event window, thus suggesting that these events foster awareness about the possibilities to curb consumption.

[31] For instance, a meta-analysis of US residential pricing documents elasticities of substitution in the range of 0.07 to 0.24 and own-price elasticities in the range of -0.07 to -0.3 (EPRI, 2012). See Harding and Sexton (2017) for the results of more recent experiments.

[32] The most commonly used schemes are Time of Use (TOU) and Critical Peak Pricing (CPP). TOU rates vary across hours of the day in a pre-determined fashion, while CPP allows the regulator to nominate a finite number of events during the year as critical peaks, and increase prices during those events. Real Time Pricing (RTP) is a more granular form of dynamic pricing, with retail prices reflecting the changing costs of producing electricity.

[33] De Groote and Verboven (2019) analyze a program to promote the adoption of solar photovoltaic systems. They find that households significantly discount the future benefits from the new technology. Applying this finding to the promotion of automated control technologies, it might be preferable to subsidize the upfront costs of such systems rather than to rely on the households' perceived future benefits of the adoption of such technology.

[34] Allcott and Mullainathan (2010) argue that due to behavioural biases, consumers should be "nudged" to make better choices. However, the effects of these nudges are context-specific. For example, Myers and Souza (2020) note that nudges may not work in the absence of direct monetary incentives to the consumers (e.g., if tenants do not pay the energy bills as they are already included in the rent).

price-inelastic consumers.[35]

One of the few empirical papers on dynamic pricing is Fabra, Rapson, et al. (2021)'s study of the Spanish electricity market.[36] Since October 2015, all Spanish households are defaulted into a Real Time Pricing (RTP) scheme by which retail prices change hourly according to changes in wholesale electricity prices. Consumers can access the 24 hourly prices one day ahead at the System Operator's website or app. The default option also comprises a time-invariant access charge, but households have the choice to opt into Time of Use (TOU) access rates that are lower at night. Fabra, Rapson, et al. (2021)'s analysis focuses on households with the default choice, i.e., those who pay a time-invariant network charge plus an hourly RTP.

The purpose of Fabra, Rapson, et al. (2021) is to exploit the hourly price variation to estimate households' short-run price elasticity. Their analysis uses a large dataset of hourly consumption spanning two years for over 2 million Spanish households. The first step of their analysis is to break the positive structural relationship between quantity demanded and prices, for which they use day-ahead forecasts of nation-wide wind generation as an instrument for price. They then estimate, at the individual household level, the response of hourly electricity consumption against the instrumented price, controlling for various time-varying and fixed effects. They also retrieve individual estimates of the RTP treatment effect by comparing the elasticity estimates for consumers on RTP versus a placebo sample of households facing time-invariant rates.

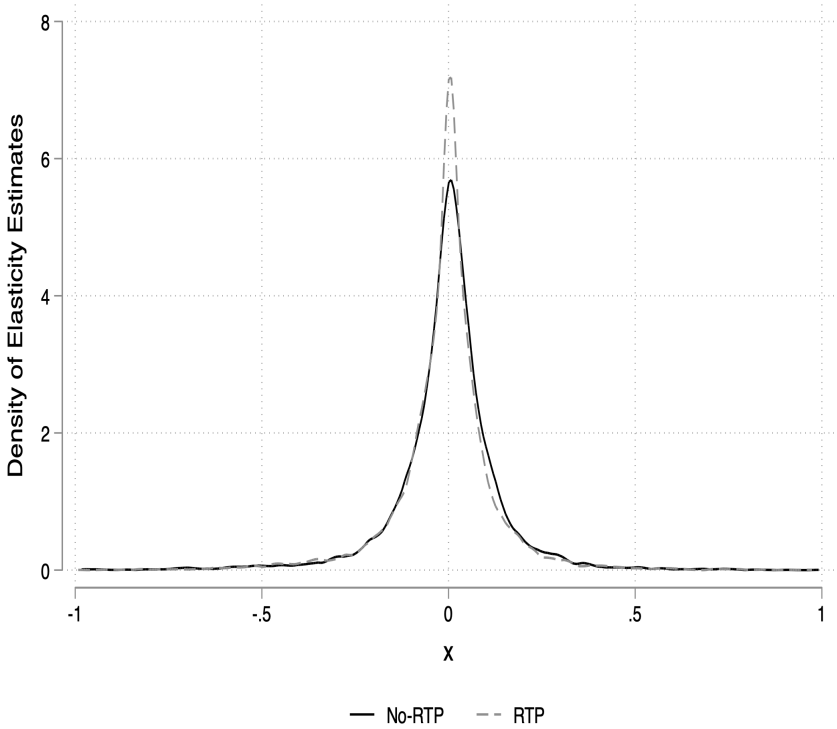
Figure 5 plots the distribution of the estimated short-run price-elasticities for all the households in the sample. The distribution is centered around zero, and there are no significant differences between those households that were exposed to hourly price changes and those that were not.

These results thus suggest that Spanish households do not change their consumption

[35] Wolak (2013) and Joskow and Wolfram (2012) discuss the major political and economic barriers for the implementation of dynamic pricing. Cahana et al. (2021) analyze the distributive implications of RTP in the Spanish context.

[36] Allcott (2011) provides experimental evidence of an opt-in RTP program among 590 households in Chicago. Results show positive but small conservation efforts at high-priced periods. Interestingly, he finds that the average response increased by about two-thirds for households that were provided with small plastic globes that changed colors to indicate high or low prices.

Figure 5: RTP vs No-RTP Elasticities



Notes: The figure shows the density of the estimated individual household short-run price elasticities. The thin (dashed) line represents non-RTP (RTP) consumers. Source: Fabra, Rapson, et al. (2021).

in response to changes in hourly prices, at least in the short-run. Several reasons could potentially explain this finding. First, consumers are in general not aware of the tariffs that they face. This is true in the Spanish case,[37] but it applies more broadly (e.g., Frondel and Kussel (2019) provide evidence of the German case). Second, even if aware, obtaining the price information and acting accordingly is costly in the absence of enabling technologies. Last, the potential savings from demand response are small given that there is little price variation across the day. Hence, it might even be rational not to get informed, not to invest in smart appliances and not to actively respond to price changes if the costs of doing so exceed the gains (which are little, due to limited price variation).

Interestingly, Fabra, Rapson, et al. (2021)'s empirical analysis also reveals that those customers that opted into TOU for the access component tend to concentrate a greater

[37] The Spanish regulator conducted a survey showing that showing that 64% of the Spanish households are unaware of the tariff they are subject to (CNMC, 2019).

fraction of their consumption during the low priced hours as compared to the non-TOU customers, even if they are all facing RTP for the energy component. Clearly, this need not reflect causality, but it is evidence that TOU consumers are aware of the price changes and act accordingly.

Does this mean that we cannot rely on dynamic pricing to facilitate the renewables' expansion? Certainly not. However, it does show that two conditions are needed to make pricing policies effective: not only do they have to provide incentives to shift consumption away from peak times, but also they have to engage consumers so that they can benefit from those incentives. One option would be to rely more on TOU rates, which are more salient and which are known in advance, thus facilitating consumers' response. However, TOU rates do not fully address renewables' intermittency as they are set in advance. While they might work well when price changes are driven by seasonal components (e.g., for solar, the sunrise and the sunset), they are likely inappropriate when price changes are driven by factors which are difficult to predict (e.g., as in the case of wind). The optimal tariffs may have to find a sweet spot between RTP and TOU to strike the right balance between the efficiency and saliency of the price signal. Very likely, the combination of the two would have to evolve with renewables' penetration: on the one hand, the uncertainty of renewables' availability makes TOU less appropriate; on the other, they also enlarge price differences, thus strengthening consumers' incentives to respond to RTP. In any event, it seems appropriate to complement pricing policies with measures to boost consumer awareness, to provide low-cost price and demand information to consumers, and to promote the deployment of devices for automatic demand response.

Beyond the efficiency implications of dynamic pricing, an emerging literature has now started to explore its distributive consequences. Consider for instance the implications of moving from time-invariant rates to dynamic pricing. Under constant price systems, some consumers implicitly subsidize the electricity use of others. For example, a consumer with a flat consumption profile subsidizes a household with similar usage who consumes more during periods of production scarcity (and therefore, higher wholesale prices). Under real-time pricing, if the latter household has no ability to redistribute

consumption away from high-price hours, it will experience a strong increase in its total bill. On the other hand, households that can easily shift consumption across hours of the day, or simply tend to consume more in off-peak periods, will experience bill decreases under RTP. Cahana et al. (2021) analyze this issue in detail in the context of the Spanish electricity market, and find that RTP was slightly progressive (i.e., it benefited the low income households relatively more), thereby ruling out the distributional concerns that might have delayed the adoption of RTP in other countries. The increasing weight of renewables will likely make these effects more relevant by enlarging price differences over time.[38] The distributional consequences of alternative tariff designs is an issue that deserves further attention.

4.2 Storage

Another option to facilitate the integration of intermittent renewable energies is to invest in storage facilities.[39] Storage gives rise to similar benefits as demand response. By storing electricity when renewables' availability is high and releasing it when it is low, storage allows a better use of renewable resources. In addition, by smoothing production over time, storage reduces generation costs and flattens the price curve, which translates into improved production efficiency and lower prices for consumers. Last, because storage improves security of supply, it reduces the need to invest in back-up oil-fired or natural gas generators.

The potential benefits of electricity storage, coupled with the fact that their costs have declined over the past few years (BloombergNEF, 2020), have created high expec-

[38] See also Borenstein (2007), who computes the hypothetical transfers that a move from TOU to RTP would imply for a set of industrial and commercial customers in Southern California. He concludes that opposition by those customers who are made worse off by the change could make the adoption of RTP difficult unless some compensations are put in place. Borenstein (2012b), Borenstein (2013), and more recently Brolinson (2019), analyze the distributive implications of non-linear pricing, which is often used in order to promote energy conservation.

[39] Another option, which I will not cover here, is to invest in transmission facilities (see Joskow and Tirole, 2000; Joskow and Tirole, 2005). Some of the issues that arise when studying transmission and storage are common. However, there are two main differences. First, the storage capacity allows to 'stock' energy over time, in contrast to the transmission capacity which allows energy to 'flow' at an instant of time from one location to the other. And second, supply and demand shocks at two interconnected locations are typically positively correlated, which limits the ability of transmission facilities to provide as much security of supply as storage.

tations about their future prospects. However, two key questions remain unanswered: do the current market arrangements provide adequate incentives to promote investments in energy storage by the necessary amount? And even if such investments take place, will firms use the storage facilities efficiently?

Under the current market arrangements, storage owners make profits by arbitraging price differences across time. Therefore, similarly to demand response, large price differences are needed to make investments in storage privately profitable. However, since arbitrage results in a flattening of the price curve, such price differences will fade away as more storage comes online, thereby weakening the incentives to invest in storage. Does this imply that such investments are not socially optimal? Not necessarily, given that storage creates positive externalities that the private investors may not fully internalize. This calls for an assessment of the private and social benefits of storage in order to quantify the need (if any) of additional support.

Market power in storage is another reason why social and private incentives may not be aligned. When we analyze the impacts of demand response, we typically assume that consumers take prices as given. The same principle could well apply under consumer-level storage, which is just now starting to develop.[40] However, the same principle need not apply to grid-scale storage, as it is often in the hands of large and vertically integrated companies (particularly so in the case of hydroelectric facilities). This might create distortions in the use of the storage facilities as well as in their investment decisions.

The existing literature on hydropower generation sheds light on some of these issues.[41] Hydropower dams allow water storage that can then be used to generate electricity. From a social point of view, the optimal use of hydro power involves substituting the most expensive generation technologies so as to equalize marginal generation costs

[40] For instance, residential storage linked to rooftop solar installations is growing rapidly in California and Germany, where it is supported by a rebate scheme. The growing prevalence of electric vehicles also raises the possibility of more consumer-level storage in the future.

[41] See Rangel (2008) for a survey of the papers analyzing the competition issues that arise in hydro-dominated electricity markets. For empirical papers, see Kauppi and Liski (2008) on the Nordic electricity market, and McRae and Wolak (2018) and Fioretti and Tamayo (2020) on the Colombian electricity market.

at high demand periods – in industry parlance, this is referred to as 'peak shaving.'[42] While a competitive market would achieve this outcome, an oligopolistic market would not. Indeed, as noted by Bushnell (2003), strategic hydro producers would shift hydro production from peak to off-peak periods in order to avoid depressing market prices when their infra-marginal production is larger (see also García, Reitzes, and Stacchetti, 2001). In other words, rather than equalizing marginal costs, the strategic hydro producers would equalize their marginal revenues, taking into account the price effect on their whole portfolio (see also Newbery, 1990).

Andrés-Cerezo and Fabra (2020) show that a similar result applies to the case of pure energy storage, albeit with some differences. For one reason, whereas hydro management involves allocating an exogenously given amount of output across time (i.e., determined by rainfalls or river flows), energy storage involves four types of intimately linked decisions related to when and how much to charge and discharge. Therefore, understanding the economics of energy storage requires developing new models that take into account charge and discharge decisions, which in turn depend on how much storage capacity firms have chosen to invest in.

Andrés-Cerezo and Fabra (2020) build a simple model to analyze storage decisions in imperfectly competitive markets.[43] Instead of relying on a fully dynamic model, they assume that demand moves deterministically from low to high levels over a compact interval. By ranking demand levels (as in Green and Newbery, 1992) rather than adopting a temporal demand sequence, they can make further progress relative to existing papers

[42] This simple observation applies to settings in which there is no uncertainty regarding water inflows and demand. In the presence of stochastic components, the optimal dispatch of hydro resources solves a dynamic optimization problem that results in the equalization of the expected opportunity costs across time.

[43] Other papers on energy storage have also allowed for market power, but they either take storage capacity as given or do not characterize the equilibrium investment. For an empirical paper using data from the South Australian Electricity Market, see Karaduman (2020). For a simulation analysis of the German market under the Cournot assumption, see Schill and Kemfert (2019). Nasrolahpour et al. (2016) explores storage investment incentives, but only under the assumption of perfect competition. Other recent papers have studied the idiosyncrasies of energy storage and their role in accommodating a greater share of renewables, but this greater complexity comes at the cost of omitting strategic interaction. For instance, Crampes and Moreaux (2010) analyze the complementarity between thermal production and storage, Crampes and Trochet (2019) study the economic properties of different storage technologies, which differ in their capacity and ramping rates, and Ambec and Crampes (2019) study firms' incentives to invest in storage and renewables in perfectly competitive markets.

on storage in comparing equilibrium market outcomes under different market structures.[44] In order to model market power in the generation market, they adopt a dominant firm-fringe model in which generation entails increasing marginal costs. In order to capture the consequences of market power in storage, they consider three cases, with storage facilities in the hands of either competitive owners, an independent storage monopolist, or one that is vertically integrated with the dominant generator. Investment in storage is decided once and for all, followed by competition in the wholesale energy market.

Their analysis reveals that, similarly to the analysis of hydro power, market power in storage leads to a suboptimal use of storage facilities – not only when firms sell the stored amounts (Bushnell, 2003) but also when they buy them. In particular, firms tend to smooth their charge and discharge decisions across time to avoid price increases when buying, or price reductions when selling. Distortions are enlarged in the case of the vertically integrated storage monopolist, which further internalizes the price impacts of storage on its own generation. In turn, the suboptimal use of storage reduces its profitability, leading to under-investment with respect to the social optimum.

In sum, storage, and in particular, storage ownership, is an area in which regulation is still under-developed. In many jurisdictions, storage is considered a generation asset, which essentially bars system operators from owning and operating storage devices due to unbundling restrictions. Andrés-Cerezo and Fabra (2020)'s analysis suggests that regulators should not be concerned about the integration between transmission and storage, which could potentially be positive for security of supply. Rather, they should put the spotlight on vertical integration between generation and storage, as well as on excessive concentration in storage ownership, given that both market structures lead to distorted incentives for storage operation and investment. Whether regulation is developed in one direction or another can have important consequences on the deployment and use of storage facilities, ultimately affecting the overall success of the Energy Transition.

[44] Although the problem is analytically simpler, in the absence of uncertainty, the properties of the comparison across market structures remain as in a fully dynamic problem.

5 Conclusions

The Energy Transition represents one of the key economic and social challenges of our generation. Good policy-making in this area is needed more than ever, because the success of the Energy Transition really hinges on whether it is well designed. At the same time, the Energy Transition provides exciting research opportunities for industrial economists to work on, as many of the key issues are at the heart of Industrial Economics. A thorough understanding of the meaning and relevance of topics such as asymmetric information, competition, incentives, strategic behaviour, market structure or market design, which other approaches omit, will be fundamental for achieving the environmental targets at least cost for society. As Wilson (2002) convincingly argues in his description of the *Architecture of Power Markets*, "game theory and derivative theories of incentives and information [have] expanded economists' tools to include methodologies for predicting how procedural aspects influence participants' strategies and affect overall performance."Such methodologies should be a must-have in the policy markers' Energy Transition toolkit.

In closing, I would like to mention a topic which is attracting much attention in practice but which still is, in my view, under-researched: the contribution of competition policy to the achievement of environmental and climate goals.[45] By promoting competition, competition policy contributes to reducing the costs of the Energy Transition while fostering innovation in energy efficient technologies. But, could it do more? Is there something intrinsically different relative to other types of activities that merits a new approach? This broad question applies to the three areas of competition policy: antitrust, State aid control, and merger control. For instance, how can authorities distinguish firms' attempts to cooperate in order to achieve more environmentally friendly outcomes from those that aim at restricting competition? Which should be the criteria and approaches to (not) allocate public funds to (environmentally harmful) green activities? Which mergers

[45]For instance, this issue is currently under public consultation by the European Commission, and so is the revision of the European Energy and Environmental Aid Guidelines. See also the speech that Competition Commissioner Vestager (2020) has given on this topic. Schinkel and Treuren (2021) provide a critical view on the Green Antitrust movement, and argue that sustainability efforts will come with more, not less, competition.

have the potential to put innovation in sustainability at risk, and if so how should this be embedded into merger control?

An non-exhaustive list of other questions that merit further research includes the following: Which are the incentives for the adoption of energy-efficient technologies and which policies can help promote those technologies? While role can behavioural nudges play? What are the distributional consequences of the various climate and energy policies? How can regulation avoid the pressure from interest groups that could bias the Energy Transition away from the socially efficient path? How can efficiency considerations be reconciled with other social objectives (e.g., promoting a broader participation, including from small investors that cannot benefit from scale economies as much as the large ones)?

Industrial Economics could greatly contribute to the Energy Transition by shedding light on these and related questions. With this survey, I have attempted to set the scene and encourage other researchers to contribute to this highly-policy relevant, and fascinating, field.

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