The EU Internal Electricity Market: Done Forever?

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Abstract. Taking a quarter-century to build Europe's internal market for electricity may seem an incredibly long journey. The aim of achieving a Europe-wide market might be reached, but it has involved – and continues to involve – a process subject to many adverse dynamics. The EU internal market may derail greatly in the coming years from the effects of a massive push for renewables, as well as a growing decentralization of the production-consumption loop. Moreover, a serious concern is the risk of a definitive fragmentation of the European electricity market due to uncoordinated national policy initiatives with respect to, for example, renewable support and capacity payments.

Keywords. EU internal market, power sector reform, market design, renewable integration

1. Introduction

It took us a while to build an EU internal market for electricity. According to the Single European Act strategy of Commission President Jacques Delors, signed in 1986, it should have been implemented back in … 1992 – but that turned out to be only the first chapter of a 25-year, and still ongoing, process.

The liberalization of the electricity sector started in the UK, followed by Norway, from the premise that while networks are natural monopolies that require regulatory control, generation and trade are potentially competitive activities. The reform of this sector was built on several pillars, including the unbundling of monopolistic activities, the introduction of competition in wholesale markets, the gradual extension of competition to the retail level, and incentive regulation à la *RPI-X* of network services. The European liberalization process had been set out to simultaneously target two goals: first, to achieve competitive prices through the game of market forces; second, to establish a unified energy market and thus contribute to the "ever closer Union" that will also be conducive to ensuring secure energy supplies.

Much has been achieved since the early 1990s. Wholesale and retail markets are now open, and the eligibility of customers is mandatory in the EU, with a general increase in the choice of suppliers and tariffs and more competitive pricing [1]. Consumers can respond to price signals by changing their supplier or by adapting their consumption behavior. Innovative business models evolve in retail markets. Incentive regulation has brought the costs of grid operators down. Even though there are still significant differences among Member States in terms of electricity generation structure and concentration of generating companies and suppliers, in general, we no longer have a patchwork of closed national energy systems, each with a national-only company controlling the entire electricity sector [2]. However, certain anti-market arrangements, such as ill-designed regulated end-user prices or insufficient unbundling of distribution and retail activities, still prevail in many countries.

EU officials claim that a first version of this European-wide power market should work by 2015[1] – while we also know that this market is only going to implement the "old" goal of 1996; that is, of the first EU Internal Electricity Market Directive.[2] Thus, one may wonder whether this will be the end of the journey, or just a coffee break. The EU's internal electricity market is already seriously challenged by two waves of disruptive innovations – the renewable energy sources and the smartening of the energy-system's interactions. It is also challenged by exogenous shocks like the economic and financial crises, the Fukushima accident, or the flooding of cheap gas and cheap coal as a consequence of the US shale gas revolution. Accordingly, the goal of building a cohesive set of market arrangements in the EU cannot stop today or tomorrow, and we already know that what we need will be of a different nature than in the 1990s. This paper argues that existing regulation – once fully implemented – adds up to a "European market" even though many market arrangements differ from the perfect textbook case [3], [4] (Section 2). However, since the initial power sector reform draft has neither been conceived for systems with a massive penetration of intermittent renewables, nor for a decentralization of the production–consumption loop, we need to revisit regulatory practices in the whole spectrum of market and

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network arrangements (Section 3). This obvious need to adapt market design and regulation to "unforeseen" developments, however, is not the only challenge. What is currently becoming a growing concern is the risk of a deep fragmentation of the European electricity market due to uncoordinated national policy initiatives in the areas of support of low-carbon generation technologies and possible capacity payments (Section 4).

2. Europe's Single Electricity Market: Done by 2015?

Taking a quarter-century (from 1990 to 2015) to build Europe's internal market for electricity may seem an incredibly long journey, as well as an example of the EU's inability to accomplish serious industry reforms. But we should remember that no other "federal-style" government of a major country (such as the US, Canada, Brazil, Russia, India or China) has achieved an internal, continent-wide, open market for electricity so far.

There are many good reasons why Europe has been so slow with the liberalization of its electricity sector, as discussed in-depth in [5]. This market project aimed to open up national monopolies' territories to foreigners, which of course was a radical project that inevitably triggered huge and fierce opposition. Second, there was no wave of disruptive technological innovation – unlike in the case of telecoms – to challenge the incumbent energy giants. Third, electricity is a difficult product to trade, as it requires hundreds of technical, legal and economic rules and standards to be agreed upon before it can become tradable. Electricity is, after all, not more than a coordinated flow of electrons inside the millions of metallic wires of a gigantic, interconnected network. Therefore, for decades electricity was considered to be a typical "anti-market" product, best suited to natural or franchised monopolies. In fact, it has been the revolution in the information communications technology (ICT) sector that has enabled new market arrangements in the electricity industry. New ICT gave us the tools to register every move of electricity generators and consumers alike – thereby allowing one generator and one consumer to trade bilaterally in a market, in parallel to the electron flow variations. The fourth reason is that the various national arrangements that were historically developed between industry players and public authorities cannot be easily merged at the EU level into a common scheme of interoperable markets.

Several successive packages have then been needed in order to get (almost) all EU countries to implement compatible market arrangements. These include the European Commission's three energy packages (adopted in 1996, 2003 and 2009, respectively), with the third[3] calling for the effective unbundling of generation and supply interests from the network, and increased transparency of retail markets. It also includes the establishment of the Agency for the Cooperation of Energy Regulators (ACER) in order to ensure effective coordination among national regulatory authorities, and to make decisions on cross-border issues. Moreover, it incorporates the establishment of the European Network for Transmission System Operators (ENTSO-E), which pushes all grid operators to cooperate and to develop common commercial and technical codes and security standards.

In addition, a supplementary Infrastructure Package[4] (adopted in 2013) defines rules to identify "projects of common interest" (PCIs); that is, infrastructure projects that will help Member States to physically integrate their energy markets and to enable the power grid to cope with increasing amounts of electricity generated from intermittent renewable energy sources within a number of key trans-European energy corridors and areas.

The building blocks for the internal electricity market are laid out in the third energy package. If today we ask ourselves whether these existing arrangements – once fully implemented – add up to a "European market," the answer is yes. Whereas in the old times, trade across borders of areas controlled by different transmission system operators (TSOs) was mostly guided by security, rather than economic considerations [6], today we have a set of national, day-ahead wholesale markets that are mostly connected by implicit access given to physical interconnections from the trade floor. Any bid accepted in an exchange is simultaneously taken into account by the other exchanges, and by the TSOs that manage the interconnections in between. Whenever there is significant congestion in the network, the European market splits into smaller regional or national markets until the congestion ends. Second, we have more and more intraday and "real-time" arrangements by which offers of capacity and energy services also cross the borders of electrical zones. Third, the network is itself becoming more and more Europeanized. New grid operation codes are being conceived at the EU level, and a common strategic planning of the EU grid is taking place under the "Ten Year Network Development Plans" adopted bi-annually by ENTSO-E. The set of PCIs is also meant to better adapt our infrastructures to the internal market's needs.

Having said all this, it is nevertheless true that many anti-market arrangements still survive in too many European countries. At the *wholesale level*, byzantine market arrangements can add up to a "re-regulated access regime," not only in France and Spain but also in the UK, in light of its new nuclear power program [7]. At the *retail level*, national governments have typically been reluctant to eliminate regulated end-user tariffs [8], [9], though these tariffs discourage consumers from searching for alternative suppliers and, even more consequentially, might prevent their exposure to more elaborate price signals. Unfair competition arises if these tariffs are not even aligned with wholesale prices, and instead establish values that are deliberately below the minimum levels needed to cover the cost of energy (plus the regulated charges, which also include network tariffs, subsidies to renewables, or taxes). This may result in billions of euros of "tariff deficits," as has notably been the case in Spain [10]. Moreover, insufficient unbundling of distribution companies can be a serious obstacle to competition [11], [12], provided that DSOs shall act as "entry gates to retail markets […] making them an important influence on the level of competition as well" [13].

The degree of market liberalization and competition still varies significantly across the EU, and there is broad consensus that there is "room for more competition in power markets" [14]. Energy markets in general are perceived not to be very transparent or sufficiently open for new entrants, including demand-side service providers [15], while prices have significantly converged due to market coupling. However, inter-regionally there remains significant scope for further market integration [1]. National distortions have significant effects, but they cannot entirely block the internal market's functioning. Nevertheless, however imperfect the EU's internal market may be, there can be no doubt that we are now very near to the European-wide market target set in 1986.

3. Europe's Single Electricity Market: Also Done Forever?

It is far from guaranteed that this internal market for energy will work forever. The many national compromises that have been realigned and harmonized in successive EU compromises dealt with the past, and aimed to open up an EU market as conceived in the 1990s. However, many unforeseen but dramatic changes have happened during the past 20 years; these shifts from the initial power reform draft are not at the periphery of the system, but rather at its core. Their actual number is heavily debated. Let's say five to seven.

What we now live in in the EU does not fall under the former "common market – yes; common energy policy – never" motto that framed the European policy for 20 years from 1986. We now stand in a common energy policy frame designed at the EU level in 2007, when the European Council decided in Berlin to go for it. To this end, in 2009, a set of Directives, which are well-known today as the "20-20-20 climate and energy package," was approved.[5] Parallel to this, a wave of "smart" innovations, such as advanced electricity meters, automation and remote-control technologies, et cetera, is growing. You might end up with an internal market headache: the energy policy frame did move, and key technologies are moving as well.

2.1 Today's Generation Mix Split into Two Contrasting Sets of Generators

In the early 1990s, we were pretty sure that most of the "steam for markets for power" was there. At that time, generation did not seem like any type of natural monopoly, except in very rare cases where the size of the market was too small to duplicate the existing generation facility (pocket market). Free entry in generation, free choice of the fuel or primary resource, of the technology and of the plant size (if not the location) should act to break the old world of chartered territories for incumbent generation self-planning. This belief is heavily questioned today.

Rising environmental concerns and associated market failures have led to a renewed public involvement in the power sector. Renewables are pushed in the electricity sector from outside the market. Both wind and solar PV energy run at the speed of their feed-in tariffs, or similar forms of deployment subsidies (see, e.g., [16], [17], [18]). Germany, for instance, is already deploying renewable generation to "a spectacular – and destabilizing – extent" [19]. The country doubled its renewable generation capacity within five years, increasing it from less than 40 GW in 2008, to more than 80 GW today. With virtually no barriers for entering the electrical system, renewables enjoy considerable advantages: they have always guaranteed access to existing consumption, whereas conventional thermal generation has only had access to the residual demand. In some EU countries, renewables also have the right to connect to the grid, and the grid owner has a duty to invest accordingly [20].

Over time, a significant proportion of Europe's thermal power plants are selling less and less energy while providing more and more "flexible capacity" for the electrical system. Some countries, like the UK and France, are looking at bridging this power generation revenue gap by reorganizing their national market's capacity arrangements. Obviously enough, this might well break up the EU's internal market, as some thermal generators would still be paid only for the energy they can sell, while others would get both energy revenues and a national capacity payment.[6] A similar disruption might come from a national "energy price floor option" given to privileged generators (as new nuclear in the UK). Of course, and on the contrary, a harmonized enough frame for a long-term price guarantee might literally rejuvenate the wholesale power market.

Even if capacity-splitting of the market did not occur, the present wholesale market might well undergo profound changes under the pressure of the growing share occupied by renewables. Large amounts of energy generated by renewables that enter the wholesale market greatly depress the market price. The variable cost of generating electricity with renewables is low, and a competitive energy market uses the variable cost of marginal power generation to price the market as a whole. That price can then easily drop close to zero if the market is flooded by renewable energy. It can even fall below zero into negative prices, as has regularly been observed within, for example, the German market area [21]. Some thermal generators in such situations prefer to pay for the right to keep their plants running, as thermal plants may face difficulties when reducing their output (they have to contend with huge output start-up costs, and other dynamics).

But in depressed conditions of this sort, how could the wholesale day-ahead market, which is the strongest backbone of the EU internal market, maintain its central position in the chain of electricity market arrangements that stretches from futures to real-time? The renewables, pushed by feed-in tariffs, largely locate their generation structure change in the realm of a public authority. The renewable priority of dispatch both reduces the market size remaining for non-renewable generators, and breaks the price trend at which they can make money or break even. Hence, the generation set is deeply fractured into two opposite sets of generators: on the one hand "new" generators that bear no significant risk for capacity, volume or price, thanks to, for instance, feed-in tariffs/premiums and priority dispatch, and on the other hand the "conventional" generators bearing a significantly increased uncertainty, and a foreseeable depressed future.

2.2. Unpredictable Impacts of Technological Shocks on Available Set and Relative Cost of Generation Technologies

The current EU Energy Roadmap scenarios [22] are built on a menu of essentially known technologies. They have also been criticized as relying on outdated cost assumptions for different low-carbon technologies [23]. Of course, 2050 is 37 years from now and, looking back 40 years ago, no oil crises had yet occurred, European energy markets had only national structures, and electricity generation from renewable sources was mainly restricted to some hydro power. In 2050, the energy system will probably be extremely different from what it is today. Composing an adequate portfolio of generation technologies encompasses a very long-term scope, which is not only about looking ahead towards the 2050 decarbonization horizon, but also anticipating technological lock-ins that might persist even beyond that point in time (see also [24]).

On one hand, unforeseen technological shocks can eliminate technology options. For instance, a "2050 bridging role" was given to nuclear energy in the first version of the German energy strategy in late 2010, whereas one year later the country announced a nuclear phase-out until 2022, as a response to the Fukushima accident.

On the other hand, unforeseen technological revolutions can also add new or cheaper means of generation and decarbonization. For instance, whereas the International Energy Agency in its World Energy Outlook 2007 (at the time when the 20-20-20 strategy was adopted by the European Council) predicted a moderate growth for US gas production, four years later the World Energy Outlook 2011 was centered around a possible "golden age of gas." Assuming that the US will become a large-scale exporter of cheap gas, and that it is possible to replicate their experience in other parts of the world (from the UK to Poland or Ukraine; from India to China), the availability of cheap gas in the market would allow for a certain degree of decarbonization at low cost (or even net benefits – one should decarbonize to make more money in the market). The "rational" price of carbon might then fall extremely low under the push of shale gas as a market-based decarbonization technology. Hence, cheap gas may not only substitute *dirty* coal, but also *expensive* renewables.

Certainly, technological developments, shocks and revolutions can have important, unpredictable impacts on the available set and relative cost of generation technologies.[7] How can innovation in the field of low-carbon technologies be sufficiently stimulated in a scenario involving decarbonization at a very low cost, and thus resulting in the lack of a strong carbon price signal? How will this interact with the market and network arrangements that we use in the EU as our common market model or network operation frame?

2.3. Transition From "Centralized Top-Down" Towards "Distributed Local" Electricity Systems

We observe changes in the generation mix, not only in the form of a shift from conventional fossil fuels towards renewables, but also in the form of a shift from centralized towards decentralized resources. More mature technologies for local renewable generation, decreased investment costs thereof, and ambitious national support schemes have led to the significant market penetration of distributed generation (DG) in many EU countries. An important share of renewable energy is no longer fed into the transmission grid, but at distribution grid level. In Germany, for instance, "in many places, the DG output of distribution networks already exceeds local load, sometimes by multiple times" [25].

Furthermore, distributed storage might soon become viable at all voltage levels and in significant amounts, thereby becoming a critical component of the grid of the future [26], [27]. Likewise, the use of electric vehicles charging from local grids, and possibly also being able to inject power back into it, is expected to grow (see, e.g., [28], [29]). In addition, recent innovations in metering and communication devices enable active demand response and enhanced distribution automation. Whereas at the beginning of the liberalization process demand response was considered only interesting for large, typically industrial, customers (Stephen Littlechild is one of the very few having always advocated for retail competition and demand response), technological advances today also make this concept appealing for residential consumers (see, e.g., [30], [31]).[8] Demand will become "as important as supply" [32]. Millions of smart consumers already are, or might soon be, producers of electricity themselves, thanks to solar PV panels. This is famously turning these consumers into "prosumers," and it may therefore have a significant impact on both the offer and demand sides of these fast-changing segments of energy markets.

This newly emerging broad range of "distributed energy resources" [33] – be it distributed generation, local storage, electric vehicles or demand response –also has the potential to drive significant changes in the planning and operation of the power systems. Traditional power systems were designed to transport electricity top-down, from generation connected to the transmission level to end consumers connected at distribution grids. Moreover, the distribution grid was designed accordingly, such that there were no significant bottlenecks or congestion. In contrast, today's distribution systems are challenged by new features, such as increased volatility of net demand and peak demand fluctuations, as well as reverse flows from the distribution to the transmission grid in times of local generation exceeding local demand. It also increases the feasibility and the likelihood of having energy and power trades at the local level, *du jamais vu*.

All these changes bring challenges for electricity distribution system operators (DSOs) and their regulation alike, ranging from increasing uncertainty in distribution grid flows to the necessary integration of new business models into retail markets. As we can already see, the distribution grids might become the new core of the EU internal market. The key question we should ask, from a market policy point of view, is how they will operate, and how they will be regulated and monitored? Should we avoid a situation in which several thousands of DSOs throughout Europe cause the fragmentation at a national and sub-national level of the existing EU internal market by spontaneously diverging through a myriad of different rules and arrangements? Nobody yet knows how the corresponding new services, whether communication-related or energy-related, as well as new markets that are immediately responsive to retail demand, will evolve.

2.4. Network Neutrality

Considering network neutrality as another important "unforeseen" shift from the initial power reform draft may be controversial, though it should not be, because it is actually a major departure. As natural monopolies, networks had to be detached from market operations, remaining neutral vis-à-vis the fuel mix, and cost-based with respect to hosting generation capacity. The main positive outcome expected from the networks in the liberalization process was a reduction of their costs to their bones, à la RPI-X formula [34]. However, transmission, as well as distribution, grids, are now seen as the vanguard of a significant shift of the whole industry towards new business models.

2.4.1. Transmission Grid and TSO Regulation

Challenges accompanying the connection and integration of large-scale renewable energy sources are manifold. First, we observe an increasingly unbalanced regional distribution of supply and demand. As a consequence, the transmission grid needs to be reinforced – within countries, but also via extended interconnection capacities – to be able to transport electricity from its sources to its sinks. Second, we expect an increasing share of remote generation, outside of the present European core grid. New lines need to be built to connect, for instance, offshore wind parks, or one day solar power plants in Northern Africa. Furthermore, the economic features of these new resources may presumably be different (different timing of investment and construction; and, technically, different load-following, production ramping and dispatch firmness profiles). The proper development and operation of networks, far from staying neutral, will strongly interact with the new users and new usages of transmission services. For the following three decades, the Commission estimates investments in transmission network infrastructures in the range of €100–200 billion [35].

The Infrastructure Package could help to identify key infrastructure projects. A methodology for cost-benefit analyses is currently developed in order to facilitate the selection of such PCIs (see also [36]). Nevertheless, serious challenges for investors, grid operators and regulators remain. Regulation affects firms' investment behavior by altering the allocation of risk among shareholders and customers [37]. Whereas under traditional rate-of-return regulation much of the risk is shifted to the customers, and investments are thus encouraged, incentive regulation, in contrast, may discourage investments. Moreover, how to mobilize the required funding, given that, under the current evolution of transmission tariffs, only half of planned investments could be financed [38]?[9] How should grid costs be allocated, considering that the way we designed grid tariffs for our past priorities cannot stand forever, and that, instead, new grid tariffs have to be aligned with the new system needs (see also, e.g., [39], [40])?

2.4.2. Distribution Grid and DSO Regulation

For high amounts of distributed energy resources (DER), the total costs of business-as-usual management of distribution networks is likely to increase in most systems. Substantial future investments are also required to properly connect all of these new DER to the distribution networks, to enable the system to deal with increased volatility of net demand and peak demand fluctuations, and to set up an ICT infrastructure that empowers DSOs to employ DER for their daily grid operations. DER offer a new set of instruments for grid operation, and thereby a tool for DSOs to perform their tasks of electricity distribution. DER also allow for an *active distribution system management*, and have the potential to decrease the total costs of DSOs compared to not relying on these new resources in local system management (see, e.g., [41], [42]).

As discussed in-depth in [43] and [33], the use of DER in distribution grid management can decrease OPEX compared to a business-as-usual treatment of these resources. In contrast, how the use of DER will impact CAPEX is not obvious. Integrating DER into grid operation procedures can decrease CAPEX in the longer run, if grid investments can be deferred. For instance, relying on DER to solve local congestion can postpone investments in new lines (CAPEX hence being substituted for OPEX). On the other hand, in the short-run, significant expenditures for investments in grids and ICT infrastructures supporting grid monitoring and automation are needed upfront. New types of assets being part of a smart grid infrastructure will reflect in new types of CAPEX. A challenging task for regulators, therefore, remains to design a sound regulation that efficiently incentivizes DSOs to engage in active system management, and thus takes account of the changing OPEX and CAPEX structures, and of trade-offs among them.

Finally, grid operators are much more than “simple regulated infrastructure monopolies” (like bridges or roads are), for which it might suffice that regulation primarily aims to decrease their costs. Instead, grid operators are becoming important market facilitators who shall favor all welfare-enhancing business models under any future market development. Both transmission and distribution grids are supposed to become smarter platforms for deeper market interactions. A regulatory challenge, therefore, lies in incentivizing grid operators to deploy innovative solutions and operating procedures. As discussed in [44], evidence suggests that past reforms in the power sector have led to a decline in R&D expenditures. Even if a certain part reflects inefficiency in expenditures before the reform process, short-term profitability may be further improved by reducing expenses in research and innovation.

Regulators also realize that there is more to competition than setting price equal to cost [45], [46]. In this vein, grids may be remunerated for hosting more of the “socially preferred” generation mix, or even to start innovating and running pilots or demonstrations (such as offshore grids). At the end of the day, average grid costs will go up with increased investment costs. The low-cost, market distant and energy mix neutral grid revolution may fade away.

2.5. Market Integrity

A highly concentrated industry structure is detrimental to the development of a functioning and efficient internal energy market. Our initial wisdom was that a “good enough” generation structure is a necessary precondition to market opening: why bother to open markets that are structurally unable to be competitive? This was a key question in the UK in 1990, as it is in France today. Illiquid wholesale markets exposed to dominant market players might not only have negative consequences in terms of potential market power abuse (see, e.g., [47], [48]), but might also delay the transformation of balancing mechanisms into integrated balancing markets, or the development of further interconnection.

However, improving the industry structure has been, and still is, one of the main difficulties in the construction of the internal energy market, as Member States are sovereign in defining their industrial structures [49]. The Commission has no right to intervene, except in cases of major mergers and acquisitions.

Competition should be “at least workable”[10] [50]. The consensus was a magic number of five or more competitors, none of whom has more than 20 percent market share. The Californian crisis with FERC blindly sticking to its Herfindahl–Hirschman concentration index prejudice opened many eyes to other unacceptable deficiencies. [51] showed that more accurate definitions of market power, and more sophisticated econometrics, might be able to identify most of the “new industrial economics” ways in which market power is abused in power markets. In a similar vein, [32] underlined that regulators should stop focusing solely on outcomes, as, for instance, the market share of leading generation companies does not necessarily represent an appropriate measure of the degree of competition.

However, many other doors remained open between market and manipulation. We did learn from the recent financial crisis, and also from the Californian electricity market crisis in the early 2000s, that market power is only one of the many determinants to be considered when attempting to make markets work. In addition, a lack of market transparency not only puts new entrants at a disadvantage, but can also have serious consequences on market functioning. Therefore, with the Regulation on Wholesale Energy Market Integrity and Transparency, (REMIT) the Commission aims to implement binding rules for transparency, and places ACER and national regulatory authorities in a market monitoring role. REMIT is still in its implementation phase. This new Regulation has to prove to be effective. The quality of data collection will be key to its success.

So how to deal with thieves or criminals, like Enron and others in the financial markets (maybe Barclays or JP Morgan in the US) and how should they be deterred from destroying the market from the inside? If we cannot guarantee *ex-ante* transparency and integrity in power markets, how can we rely on these markets to bridge physically (unit commitment, dispatch, capacity allocation and congestion management) and financially (price arbitrage, portfolio and risk management, etc.)? Today we still know more about the "fire alarm" strategy of monitoring (how to assess, *ex-post*, the fairness of actual behaviors in existing markets) and less on the "police patrol" strategy (how to prevent, *ex-ante*, manipulations or crimes). An obvious link between ex-ante and ex-post strategies is how we conceive the definition and the collection of data, the architecture and languages of databases, as well as the screening tools, the market models and the software. Moreover, we have a considerable knowledge about a "country market" monitoring, but have we achieved enough across borders and across markets? Finally, another key issue is how to manage the loop between market monitoring, market investigation and market fixing.

2.6. Market Design

Market players cannot entirely design power markets by themselves, because power markets are structurally incomplete [52], [53]. We saw that market players can easily trade energy until "market gate closure," but they cannot easily trade the corresponding transmission capacity and reserve the availability needed to implement this "ex-ante" energy trade. To alleviate these market difficulties, power markets play the wholesale trade through a series of steps, which mimic the simple offer and demand arrangement of a textbook market situation. Power markets are actually "sequences of markets" from the pre-commitment of plants, day(s) ahead of the real-time balancing of actual injections and withdrawals, via the allocation of transmission capacity and the necessary management of seen and unforeseen congestions.

Making electricity marketable actually means completing the textbook market case with more central coordination, more third party intervention, and market intermediation (see also [54]). If one wants to make electricity homogenous, good, and easier to contract and to trade, at some point the growing gap between the actual physical flows and the notional traded good must be dealt with. The very nature and the right amount of "third party" coordination in power markets is still under discussion after 20 years. We not only disagree on how to design complements or auxiliaries to the market, but also on what to keep free for trade.

We did not really foresee how deeply market trade and market interactions will depend on the market arrangements agreed by policy makers here and there. Even if we bypass more than a decade of wholesale storyboard (see also, e.g., [55], [56], [57]) – such as the UK Pool and New Trading Arrangement, Nord Pool, Germany's dual competing power exchanges, etc. – today we are still discovering how to connect the existing market areas across the existing electrical control zones. Should we "couple" the existing markets within a harmonized nodal frame? Or only with an explicit (or implicit) transmission capacity auctioning? Should we focus only on a day-ahead horizon? Should it then be "flow-based," or with rigid, predetermined, "net transfer capacity"? Should we also couple for intra-day trade? With a few successive windows of price fixing? Or with continuous trading? Should we extend to pooling adjacent markets on their balancing horizon? Through a "loose" common pool of offers from which several system operators may pick up for their needs? Or through a "tight" cross-border common management of all balancing options? Why not then a loose system operator auxiliary (like CORESO), or a more substantial, light, European ISO?

Much effort has been (and still is) made at the European level to develop common rules for grid operation.[11] However, these "Network Codes" are not conceived to develop a deep cooperation among TSOs, as there is a requirement, for instance, to tackle congestion and stability at regional levels, such as in the cases of US Regional Transmission Organizations and RTOs. Even scenarios of grid operation are looked at only in a voluntary frame (like CORESO). In practice, it has proven extremely difficult to ensure an effective development of regional grids, and one may doubt whether the Infrastructure Package will be able to tackle this. Another major flaw of these Network Codes is that they have been conceived for a system with a generation fleet connected to the transmission grid. But what we see today is an increasing penetration of generation, and other local energy resources such as demand response or energy storage capacities, connected to the distribution grid.

Moreover, the European grid frame avoids nodal pricing and financial transmission rights. However, if we wanted to have these two as new operation principles, they would have to be introduced at the European level, otherwise they would lose a significant part of their effectiveness.

4. Conclusions

Building a European internal market for electricity has been a slow process for 25 years, but it is now close to being achieved. We Europeans conceived our internal market arrangements "our way," even though many other ways were, or still are, foreseeable. Europe could for example, have opened up the wholesale market without opening the retail market, or could have made opening the wholesale market mandatory, with a centralized exchange system operating a single price algorithm, just as England and Wales did for more than 10 years.

In the end, building this internal market has been – and should continue to be – a process that is subject to several dynamics. What we now call the EU internal market is in many elements a compromise among all the other national-level compromises. It is far from being a perfect mechanism capable of serving us with everything, regardless of the prevailing conditions. This emerging EU market may suffer greatly in the coming years from a massive increase in renewable energies, or from a deep decentralization of the production-consumption loop. The future, as is already debated in a post-2020 strategy, is far from clear. However, what is clear is that the introduction of new ICT-based technologies could radically modify the economic and physical functioning of the electricity system, and as a result the functioning of the market. What is therefore urgently needed now is "a realistic design for the transition process from today's low-ICT, high-carbon energy system to a high-ICT, low-carbon system of tomorrow" [58]. It would be irresponsible not to ask for renewed regulatory oversight.

What are the main obstacles to be overcome for 2015, 2020, … or even 2030? This is a big agenda in research, and is still open. An ideal power market architecture would build on nodal pricing, financial transmission rights, and long-term energy price guarantees. But we are unable to get it at the moment. In addition, it is also far from clear how one could achieve the required cooperation among Member States.

The need to adapt market design and network regulation to "unforeseen" developments is not the only challenge. What is currently becoming a serious concern is the risk of a re-fragmentation of the European electricity market due to uncoordinated national initiatives. It is true that national diversity has first and foremost been a predictable result of the nature of the compromises made when scoping the first electricity directive. The 2nd and 3rd Packages successfully managed to reduce the scope of this diversity; however, we observe now an again increasing impact of national interventions.

First, diverse renewable support schemes have resulted in a patchwork of effective, but market-distorting, subsidies (see, e.g., [17], [59]). With the exception of a joint support scheme in Norway and Sweden, no use has been made so far of cooperation mechanisms. In contrast, national support, often together with rules on priority grid access and dispatch, was introduced on the grounds of incomplete market opening, an incomplete internalization of the externalities of conventional generation, and immature renewable-energy technologies [14]. However, markets and technologies have evolved since then, and support mechanisms need to be reviewed urgently (see also [60]).

Second, a number of Member States have introduced, or plan to introduce, separate payments for the market availability of generation capacity. In Germany, for instance, it is justified by the high share of intermittent generation, blowing conventional generation out of the market, and therefore out of money, whereas the UK wants to react to a shortage in overall capacity due to the shutdown of several dirty power plants.

As correctly stressed by the Commission, any public intervention being ill-designed, and lacking a proper coordination at the European level, risks being counterproductive, and can distort the functioning of the internal electricity market [14]. The creation of an EU-wide market has made national markets more interdependent. On one hand, market opening enables the exploitation of synergies and economies of scale; on the other, any public intervention affects prices, and not only domestically. In this vein, national capacity payments can interfere with cross-border trade and competition, as they can close off domestic markets from generation elsewhere in the EU. They also can distort decisions on the location of new generation units and, hence, increase total costs by preventing an optimal use of generation and flexibility across borders.

To conclude, public interventions should not only be properly coordinated within Member States, but also between them in order to minimize costs for consumers and tax payers, and avoid any distortions in competition. Certain situations might call for national solutions; for other situations, the solution might be found in a broader regional, or even EU-wide, context. Two principles are to be respected. First, public intervention must not go beyond what is necessary to respond to existing market failures (*proportionality principle*). Second, any EU involvement must not go beyond what is necessary to achieve the high-level objectives in the EU treaties, except for areas of EU-exclusive competences. EU action should only be taken when it is more effective than actions at a national, regional, or local level (*subsidiarity principle*).

We know that the Commission will use its powers for policing state aids (as recently happened in Germany), and, for instance, for approving national capacity mechanisms, only if the respective Member State devotes funds to improving its interconnections with neighbors [18]. However, this does not reveal whether European competition policy will be the tool that is able to seal the many wounds of EU market arrangements.

Our electricity markets and networks are at the gate of a sea of perils; there is no guarantee that they will sail till the next safe harbor.

Endnotes

1. On 4 February, 2011, the European Council set 2014 as a target year for the completion of the internal market for electricity and gas.
2. Directive 96/92/EC "concerning common rules for the internal market in electricity."
3. Directive 2009/72/EC, "concerning common rules for the internal market in electricity;" Regulation 714/2009, "on conditions for access to the network for cross-border exchanges in electricity;" and Regulation 713/2009, "establishing an Agency for the Cooperation of Energy Regulators."
4. Regulation 347/2013, "on guidelines for trans-European energy infrastructure."
5. In order to achieve the "20-20-20 objectives" (that is, a 20 percent reduction in EU greenhouse gas emissions from 1990 levels; a 20 percent increase in the share of EU energy consumption produced from renewable resources; and at least a 20 percent reduction of EU primary energy use compared with projected levels – all by 2020), this package included a strengthening of existing policy tools, as well as the implementation of new instruments. It mainly stands on three pillars: (a) a revision and strengthening of the EU emissions trading system (Directive 2009/29/EC); (b) an Effort Sharing Agreement governing GHG emissions from sectors not covered by the EU ETS (Decision 406/2009/EC); and (c) binding national targets for renewable energy (Directive 2009/28/EC).
6. See [61] and [62], and references therein, for an elaborate overview of market imperfections that may result in a "missing money" situation, as well as in alternative capacity-mechanism designs.
7. Possible technology paths towards a 2050 (decarbonized) electricity system are also outlined in (for example) [63], [64], [65], [66].
8. Given a positive cost-benefit analysis, at least 80 percent of European households are intended to be equipped with intelligent metering systems by 2020 [67].
9. An interesting proposal is the German *Bürgerdividende*: citizens directly affected by the expansion of the electricity grid will have the opportunity to take a stake in these new assets, with a guaranteed return on investment of up to 5 percent.
10. [50] refers to a market that is "perhaps less perfect than the textbook vision of a competitive market but yet generally free from monopolistic pricing and various forms of collusion and manipulation."
11. The Commission aims to support well-functioning, cross-border wholesale markets. Regarding "capacity allocation and congestion management," requirements for TSOs and power exchanges will be formulated on how to operate the integrated electricity market in the long-term, day-ahead and intraday timeframes by defining rules for, for instance, capacity calculation, bidding zone configuration and capacity allocation. The objectives of other network codes relate to a harmonized system operation regime, including security, control and quality, or the integration of national balancing markets.

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