Energy Security and Energy Connectivity in the Context of ASEAN Energy Market Integration

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Executive Summary

Key observations

- The absence of consensus meant that the EU encountered continuous difficulties in enforcing laws relating to energy market integration, despite the fact that the EU has significant legal authority in the field of the internal market.
- A combination of complexity of network industries, the political nature of energy, and market power concentration slowed down further EU efforts to create internal electricity and gas markets.
- Nevertheless, with the adoption of the so-called Third Internal Market Package in 2009, 20 years after the start of liberalisation, significant progress was achieved, at least in Western and Central Europe.
- Gas is now traded on hubs where prices are set by supply and demand, and electricity markets are linked so that power can freely flow across borders.
- The policy-driven rapid expansion of renewable energy sources in the electricity sector as a response to climate change is threatening to undermine the past success of the electricity market liberalisation.

Policy implications

- Liberalising electricity and gas markets requires a political consensus among all major stakeholders.
- Liberalisation necessitates that companies are largely independent from national governments; EU member states have adopted different approaches.
- Successful liberalisation is greatly helped by relative homogeneity of the countries involved in respect of, for example, fuel mix, import dependence, ownership structures, and economic policy.
- The rapid expansion of renewables in the electricity sector poses new challenges to electricity market regulation and will require a considerable reform on how EU electricity markets work to date.

1. Introduction

The creation of the internal market for energy has been one of the most ambitious, yet also controversial undertakings of the European Union (EU). Started as early as 1988, significant progress has been achieved, notably in the area of crude oil and oil products, public procurement and even the convergence of energy tax rates. More difficult proved to be electricity and natural gas markets. More than 25 years after the objective to complete the internal electricity and gas markets has been formulated, much work remains to be done. Within the Energy Union document[1], the completion of internal electricity and gas markets is one of the 5 dimensions of the EU energy strategy. Energy Union can be seen as the final push to complete the internal energy market.

This article will take stock of the past and current efforts of EU liberalisation of electricity and gas markets. It will describe its motivation, the applied methods but also the – specific EU – institutional context. A particular focus will be put on infrastructure policy before we examine the new challenges, which arise as a result of the EU and global decarbonisation agenda.

2. Energy in the EU

2.1 The EU energy situation

In 2013, according to the European Environment Agency (EEA) the total energy consumption of the European Union was as follows: 33% petroleum, 23% natural gas, 17% coal, 14% nuclear, 12% renewables and 1% waste[2]. The European Union as a whole and all member states except Denmark are net energy importers. In 2012, 53% of the EU's energy needs were imported. This represents a 40% increase since the 1980s when liberalisation started. The dependency rate is highest for crude oil with 88%, followed by natural gas (66%) and coal (42%). Russia tops the table as the biggest supplier for all three fuels. Natural gas imports are highly concentrated; more than three quarters (77 %) of the EU-28's imports of natural gas in 2012 came from Russia, Norway or Algeria. Most of the Central and Eastern European member states depend on Russia as the main or in some cases, sole supplier for natural gas. Overall the Russian share of EU imports is typically somewhat above 30% with recently strong yearly variations as a result of market dynamics and weather variations.[3]

As a net importer, the EU has traditionally attached high importance to energy demand management through energy efficiency and conservation.

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[1] European Commission, Energy Union Package, COM(201580) of 25.02.2015; see also: Egenhofer, C., F. Genoese and A. Dimitrova, *Making most of Energy Union*. CEPS Commentary, February 2015

[2] European Commission, *EU Energy in Figures, Statistical Pocket Book 2015*.

[3] Up to the subsequent Russia-Ukraine crises Russia has been a reliable and relatively cheap supplier, causing few fears on security of supply. Except for oil during the oil crises, supply concerns or disruptions have been related to domestic events, typically related to strikes of coal miners and blockades of refineries by truckers or electricity black and brown outs as a result of system failure. With the first Russia-Ukraine crisis in 2006 however, gas supply disruptions have become a concern for the EU and member states.

High energy prices compared to other regions have made Europe's industry among the least energy-intensive as a result of specialisation in non-energy-intensive goods and energy-efficient production. High European energy prices were offset by high efficiency and specialisation in higher added value goods resulting in moderate energy costs, keeping European industry competitive[4].

Greenhouse gas emissions in 2012 were down by 19% compared to 1990, keeping the EU on track to meet its 20% reduction objective by 2020. Although reductions are a result of policies, they have been 'helped' by the fall of economic activity following the world economic crisis. There is also some windfall effect as a result of the economic contraction of the former GDR and the member states from Central and Eastern Europe. Due to an effective policy renewables have been growing very fast and are expected to reach the target of 20% in total primary energy in 2020. In 2013, it has been above 13% of total final energy consumption, up from 8% in 2007.

2.2 EU energy policy

EU energy policy, as most EU policies, features supranational as well as intergovernmental elements, depending on the specific area of action. For example, at the onset of the "European project" there has been a common "EU policy" for coal (European Coal and Steel Community 'ECSC') and nuclear energy (Euratom), while later on and outside these two sectors energy policies have largely been confined to essentially voluntary intergovernmental co-operation. Such voluntary co-operation typically mean decisions based on the lowest common denominator, except in times of crisis. As a result, typical energy policy areas such as choices about the fuel mix and (by extension) geopolitics by and large are left to member states. This has resulted in a very low degree of convergence between the fuel mixes notably in the power sector and to a varying degree of diversification of the gas import portfolio.

In this situation, policy at the EU level has mainly focused on building an internal market for electricity and gas and horizontal measures to moderate demand and to promote indigenous sources including renewables. In the domain of the internal market, the EU decides by majority voting. The EU's Lisbon Treaty entering into force in 2009 has not affected the constitutional situation as it yet again confirmed member states' relative freedom of choice of their energy mix.

In addition to internal market, energy policy initiatives have often been driven by climate and environmental concerns where the constitutional situation is different. Since the 1980s, the EU has significant legal authority, notably the possibility to take decisions by (qualified) majority. Much of the EU's energy policy decisions, including energy efficiency or renewables have been based on legal bases stemming from the environment and climate change. Pursuing energy policy goals via the environment has been facilitated by the EU-wide consensus on the importance attached to addressing climate change preceding the 1997 Kyoto Protocol. This is evidenced in the EU's so-called 2007-09 Energy and Climate Change[5] Package, which established a 20% greenhouse gas reduction target, a 20% energy efficiency improvement and a 20% renewables production goal all by 2020. These targets are currently being updated for

[4] European Commission, "Energy Economic Developments in Europe", *European Economy*, 1/2014, DG ECFIN

[5] Often also referred to as 20-20-20 by 2020 Package.

the 2020-2030 period. On 23/24 October 2014 the European Council decided on a new set of targets for 2030 ("2030 Framework for climate and energy policy"), including a 40% greenhouse gas reduction, a minimum 27% renewables and a minimum 27% efficiency target, in the meantime also completed by an interconnector target[6].

3. The EU's internal market for electricity and gas: motivation and method

The drivers for the creation of an internal energy market, including notably for electricity and gas have been both legal/constitutional and economic.

- The creation of an internal market guaranteeing the freedom of movement and establishment for goods, services, capital and persons is one of the most fundamental objectives of the EU and therefore is a legal obligation under the Treaty.
- The economic justification of the internal electricity and gas markets is based on two arguments: (i) increased competition in order to lower costs and (ii) scale to enhance security of supply. The European Commission has frequently argued that a unified EU (electricity and gas) market would be intrinsically more secure than the individual member countries' markets. A larger market, served by a wider and well-interconnected networks, which receives electricity or gas supplies from a larger number of actors, may be expected to be more stable than a combination of national markets and often, small countries. A resilient market is also a tool to provide solidarity among member states, which has become a guiding principle with the Lisbon Treaty – entering into force in 2009[7]. An integrated market is more efficient in allocating resources across Europe than strictly nationally organised – and often small – markets. It would provide a pan-European investment signal.

3.1 The beginnings

Although the creation of an internal market is one of the tools of European integration[8], for many years, progress was slow. A fundamental change occurred in the 1980s with a reform of the EU Treaty through the so-called Single European Act to take force in 1986. This has been followed up by the so-called Delors White Paper, which set out an ambitious programme to complete the single or internal market by 1992. However energy was neither part of the Single European Act, nor the White Paper. It was only as late as 1988 that the creation of an internal energy market was actively pursued after it became evident that energy markets were deeply affected by internal market legislation. Key areas of legislation included public procurement, which, despite a delay, soon had to be applied to the energy sector. Tax harmonisation and environment legislation also affected the sector. But the most important was the active application of the hitherto dormant competition rules (e.g. the then Art. 90 and competition rules 85, 86) to utilities for the first time. Still, it took nine years, until 1996, to reach an

[6] The European Council of October 2014 agreed to arrive at a 15% interconnection target, meaning that each member state should have interconnections to the tune of 15% of electricity consumption.

[7] In the absence of an integrated gas market each members state, many of them small were responsible for signing gas import contracts, often from a single supplier, e.g. Gazprom. In an integrated market where gas flows freely, imports are contracted by pan-European companies, which serve the whole EU market. 80% of the gas is traded at gas hubs.

[8] The others have been economic and Monetary Union and common policies and activities.

agreement on electricity. Not surprisingly, the resulting Directive (96/92/EC) remained cautious and competition was slow to take off.

The framework set by the first electricity and gas directives of 1996 and 1998[9] fixed a minimum level of competition at member state level by way of agreed common rules while progressively bringing down barriers to cross-border trade. It was expected that the cross-border market dynamics would unleash competitive forces, which would quickly remove the last remaining barriers to the functioning of a fully competitive and integrated European market.

The first electricity directive of 1996 concentrated on full liberalisation of generation and introduced a six-year phased-in freedom for all large and medium-sized companies to choose their supplier as well as the freedom to construct lines. Access to the grid was tackled by unbundling[10] the accounts of integrated companies and by promulgating a number of different access rules to be implemented by member states that should guarantee non-discriminatory access. The 1998 gas directive chose the same approach in principle, but with two modifications: first, the transition period was to be ten years to accommodate long-term investment needs, and second, the unbundling provisions were lighter to avoid undermining EU companies' bargaining powers with non-EU suppliers. The gas directive allowed each power generator to choose its own supplier.

While the first electricity and gas directives constituted considerable progress, many weaknesses persisted; a lack of effective unrestricted and non-discriminatory third-party access to networks due to vertical integration, weak regulatory function, high and increasing concentration (and market power), limited or non-existent competition in the small consumer segment and generally, insufficient liquidity in wholesale markets and response of prices to supply and demand conditions, including network capacity.

Many of the issues in the electricity markets could also be found in the gas markets. There were problems with access and high access charges and the independence of transmission systems operators (TSOs). There were concerns about a lack of transparency over the publication of infrastructure capacity able to dispatch both cross-border and domestic transits, and also in relation to capacity reservation procedures. Rules that governed network balancing were sometimes seen as being too stringent, to the point that they hindered the development of market competition, while at the same time they did not reflect the costs incurred. More generally, gas import levels and cross-border trade were seen as not satisfactory, with the existing incumbents dominating domestic markets and wholesale prices. Gas trading hubs were slow to develop.

The shortcomings have been tackled by the second legislative package by 2003, which amended the electricity and gas directives. Essential changes were to allow all consumers to choose their supplier.

3.2 The "Third Package"

[9] 96/92/EC and 98/30/EC, respectively.

[10] Unbundling describes the separation of energy supply and generation from the operation of transmission networks.

To address the shortcomings of the first and second package, the European Union adopted what became known as the Third Package. It was adopted in 2009 and entered into force in 2011. It aimed at improving the functioning of the market and resolve structural problem, notably related to unbundling and the independence and capacity or regulator. Practically, it consisted of

- Fully unbundling energy suppliers from network operators,
- Strengthening the independence of regulators,
- Establishing the Agency for the Cooperation of Energy Regulators (ACER),
- Improving cross-border cooperation between transmission system operators and the creation of European Networks of Transmission System Operators (ENTSO-E and ENTSO-G), and finally
- Increased transparency in retail markets to benefit consumers.[11]

Most important were the rules on unbundling, the regulatory agencies and co-operation of Transmissions Systems Operators.

The Directive foresees either full ownership unbundling in case of integrated companies or the creation of an independent System Operator where all important decisions are taken independently of the parent company.

Independence of regulators from both industry interests and government should from now on be guaranteed by creating an own legal entity with authority over their own and sufficient budget, supplied by national governments. Following the Third Package, regulators can issue binding decisions to companies on the member state level and impose penalties in case of non-compliance. They have far-reaching access to data from generators to network operators, and other companies. Finally, regulators from different EU countries are asked to cooperate with each other to promote competition, the opening-up of the market, and an efficient and secure energy network system. However, co-operation is slow to develop.

In order to help the different national regulators cooperate the EU established the independent Agency for the Cooperation of Energy Regulators (ACER), located in Ljubliana/Slovenia. It is not comparable with a national regulator, such as for example in the UK. Instead it should be seen as an attempt to bundle all competencies related to cross-border trade, which is in EU philosophy an original EU task. All other regulatory competencies remain with national regulators in line with the subsidiary principle[12]. By Europeanising cross-border competencies within one agency, the EU attempted to i) reinforce the European Commission's role as the responsible body for undertaking negotiations with third countries, ii) affirm the independence of regulatory authorities from both the European Commission and member states, iii) reduce complexity of the current system, and iv) bundle technical expertise within EU bodies. The main advantage was that it could be implemented within the then existing Treaty as well as the then forthcoming Lisbon Treaty. The EU Treaties require that the delegation of powers to independent agencies must be limited to implementing powers clearly defined and entirely supervised by the delegating institution on the basis of specific and objective criteria. Put

[11] For a more detailed analysis, see for example the Florence School of Regulation: http://fsr-encyclopedia.eui.eu/the-third-energy-package-2009/

[12] The subsidiarity principle stipulates that the EU action is appropriate only if an objective cannot be sufficiently achieved by member states. In addition, EU intervention must be proportional to the objective to be achieved.

differently, this means that delegation cannot concern discretionary powers involving a margin of political judgement, unless they are set up by the EU Treaty itself, by 'quasi constitutional law' itself.

Given that networks in the past have been and still are developed according to national, member states' interests, a particular focus has been co-operation and integration of (national) Transmissions Systems Operators (TSOs). This is attempted through the creation of European Networks of Transmission Systems Operators[13], for both electricity and gas: ENTSO-E and ENTSO-G. Their task is to develop standards and draft network codes – later to be formally adopted in EU legislative processes – to help harmonise the flow of electricity and gas across different transmission systems as well as to coordinate the planning of new network investments and monitor the development of new transmission capabilities. This includes publishing a Europe-wide 10 year investment plan to help identify investment gaps every two years.

This focus on TSOs has led to a surprising development; the creation of multinational network companies such as Elia and Tennet, which own assets in several member states. On the downside, there is an unresolved conflict of interests, as ENTSO-E and ENTSO-G are responsible for network planning, while at the same time, their member companies will build and operate the assets they have been planning.

A notable development is that small consumers such as households have shown very little interest in retail market liberalisation. Savings from changing suppliers are generally seen as too small and transactions costs too high to motivate consumers to switch.

3.3 Coupling national markets to create a single EU market

Cross-border cooperation and competition is most advanced in the power sector. The EU blueprint for creating an internal electricity market foresees that national power markets (at wholesale level) should be coupled. Implicitly, this means that the EU is pursuing a zonal pricing approach, not a nodal pricing approach. In most cases, price zones are currently defined by national borders, with some notable exceptions: In the Nordic markets and in Italy, there are sub-zones to reflect internal (domestic) grid congestion, while Germany, Austria and Luxembourg represent a unified market and there is a single wholesale electricity price for these three countries.

Market coupling has successfully been implemented for day-ahead markets, while much work remains to be done for intraday and balancing power markets. Essentially, coupling means that generators do not have to decide whether to offer their production capacity to the domestic or a neighbouring market. Instead, electricity should freely flow from regions with high prices to regions with low prices. To this end, the various national market operators (power exchanges) combine all demand orders and supply offers. Afterwards, the available cross-border transmission capacity is allocated in such a way that the overall costs to consumers are minimised. Thus physical transmission rights are allocated implicitly. As of June 2015, this approach has been implemented in most EU member states.

In the current framework, transmission rights must be used day-ahead or will otherwise be released to the day-ahead market-coupling algorithm (use-it-or-sell-it principle). It is currently not possible to keep these transmission rights for transactions in the intra-day market, while for balancing power markets they may be reserved under specific circumstances[14]. Moreover, bilateral agreements exist to allow for some cross-border intraday trading.

It is also possible to obtain long-term transmission rights explicitly. This can be useful to contract cross-border deliveries of electricity for a period longer than one day. Moreover, it gives market participants the possibility to hedge themselves against congestion costs. One shortcoming, however has been that transmission rights on national borders can only provide hedging opportunities between two price areas, not on a regional or even EU level.

3.4 Implementation, enforcement and governance

As indicated earlier, the EU features supranational as well as intergovernmental elements, depending on the specific area. This is also true for energy. While energy policy in the narrow sense, for example choices of the fuel mix is a member state competence and therefore subject to unanimous decision, other areas such as the internal market (including energy) or the environment (including climate change), are subject to qualified majority voting. While voting is used very seldom, the very fact that the possibility of a country being outvoted exists, has a disciplining effect; countries are more open to compromise. In areas where unanimity is required, controversial decisions tend to be adopted only in times of crises such as that involving the Euro.

Nevertheless, there is an implicit understanding that the EU does not adopt measures which would put a member state government under pressure. Therefore, there is significant opportunity for member states to bargain very hard. Very often this results in transition periods, differing options offered to member states or straightforward exemptions. In reality, this means that a particular subject is subject to recurrent changes. In the field of the internal electricity and gas markets, there have been two changes to the original decisions, in the form of 3 packages with a fourth one in the making, the proposal and then decision on 'electricity market design'.

When it comes to enforcement the situation is different. If member states do not implement legislation which has been adopted, the European Commission can bring them to court within 4 months. The difficulty is that in many cases a possible breach of EU law can be hard to identify. Given the fact that member states have very different legal systems and traditions, let alone the more than 20 official languages, the EU typically leaves considerable discretion to member states when implementing legislation.

Again different is competition law, which covers state aid such as illegal subsidies and anti-trust measures. Here, enforcement is entrusted to the European Commission. In this field the European Commission can act without member state consent.

4. Infrastructure policy

[14] The network code on 'electricity balancing' allows for reserving transmission capacity for balancing markets subject to cost-benefit analysis.

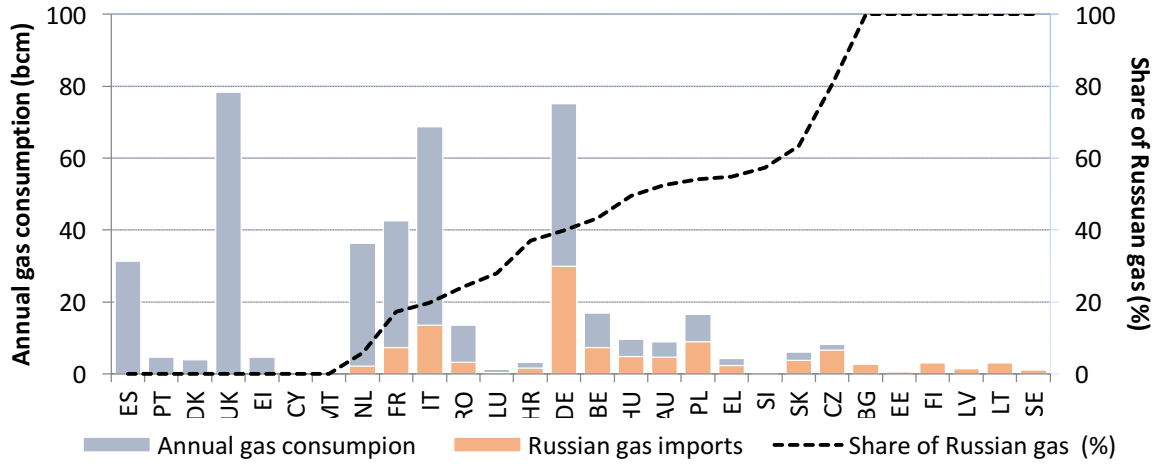
The European Commission estimates that for both electricity and gas €200 billion are needed until 2020 to complete the internal market for electricity and gas but also to guarantee security of supply. Planning is based on the rolling so-called '10-Year Network Development Plan' (10YNDP) compiled by the EU electricity and gas TSO associations, ENTSO-E and ENTSO-G, respectively. Execution of the projects is done by member states according to national laws and regulations such as those relating to permitting and other issues. Financing in most cases is private, although supported by member state funds. The EU contribution is small and is currently limited to roughly 3% of the total amount required.

A major shortcoming is the fact that the 10-Year Network Development Plans are largely a bottom-up exercise where member states and often regional and local governments promote their national priorities based on their national needs, interests and politics, with limited consideration for the EU perspective or the market. As a result, member states pursue their national priorities, which does not necessarily mean that these match European ones. This is aggravated by the unresolved conflict of interests between the TSOs, which at the same time are responsible for network planning and building and operating the projects they have been conceiving. Most European member states, which tend to be densely populated, face difficulties concerning the social acceptability of infrastructure projects. This is generally seen as the biggest obstacle to the construction of new electricity and gas infrastructure.

As a result, natural gas markets and infrastructure are unequally developed within different regions of the EU, often depending on historical developments. For instance, the markets of the Baltic States are isolated and not connected to gas hubs in Central Western Europe, which are generally considered as competitive and liquid markets. The size of these Central Western markets – more than 80% of total EU gas consumption – also makes it easier to attract new suppliers of natural gas. The situation in South Eastern Europe is similar to the Baltic states: connectivity to other parts of Europe remains low, thus forcing, for example, Romania and Bulgaria to rely on (limited) domestic production and imports from Russia. These states are also the most vulnerable to supply disruptions.

In 2012, five member states were 100% dependent on natural gas imports from Russia: Latvia, Lithuania, Estonia, Bulgaria and Finland (see Figure 1).

Figure 1: Russian gas in the total gas consumption of the EU-28 (2012 data)



Sources: own data, based on BP, U.S. Energy Information Administration, International Energy Agency

Power markets face similar challenges of fragmentation as gas markets. As in the gas sector, missing infrastructure is a key reason for fragmentation. Increasingly, there is a need for new electricity interconnectors to accommodate an increasing level of intermittent renewables but progress is very slow.

5. New challenges

The EU electricity market has been developed as so-called energy market only (EOM). At the core is the day-ahead market, which produces a uniform, non-discriminatory, market price for each hour of the day as a result of the intersection of all offers and bids. This price is set by the variable production costs of the marginal power plant, that is the last power plant needed to satisfy electricity demand. All generators receive the same price irrespective of their variable production costs. As a result, generation units with variable production costs below the market price receive a so-called 'infra-marginal rent'. This margin – typically referred to as gross margin – is used to cover fixed operation and maintenance (O&M) costs as well as to recover investment costs. Thus availability is implicitly remunerated through infra-marginal rents.

If market prices were always equal to the variable production costs of the marginal plant, this plant would not even be able to cover its fixed O&M costs, let alone recover its investment costs. This is why so-called 'scarcity prices' are required to let an energy-only market function properly.[15] Such price increases are expected to occur when supply struggles to meet demand, for example when consumption peaks, when production from intermittent renewable sources is low or when there are large, rapid swings in demand or supply. During these hours, the price would rise above variable production costs of the marginal plant and thus offer a so-called 'scarcity rent' to all resources in the market. These additional revenues are needed to fully recover both fixed O&M and investment costs.

An energy-only market attracts investment in new capacity, therefore, through either direct or indirect reliance[16] on scarcity prices. Unexpected policy interventions, erroneous demand expectations and long lead times for planning and building new capacity lead to boom and bust cycles, with times of overcapacity alternating with times of scarce capacity. When there is overcapacity, scarcity prices are not going to occur, simply because supply is always well above demand, which signals that there is no need for new capacity.[17]

5.1 Renewable energy

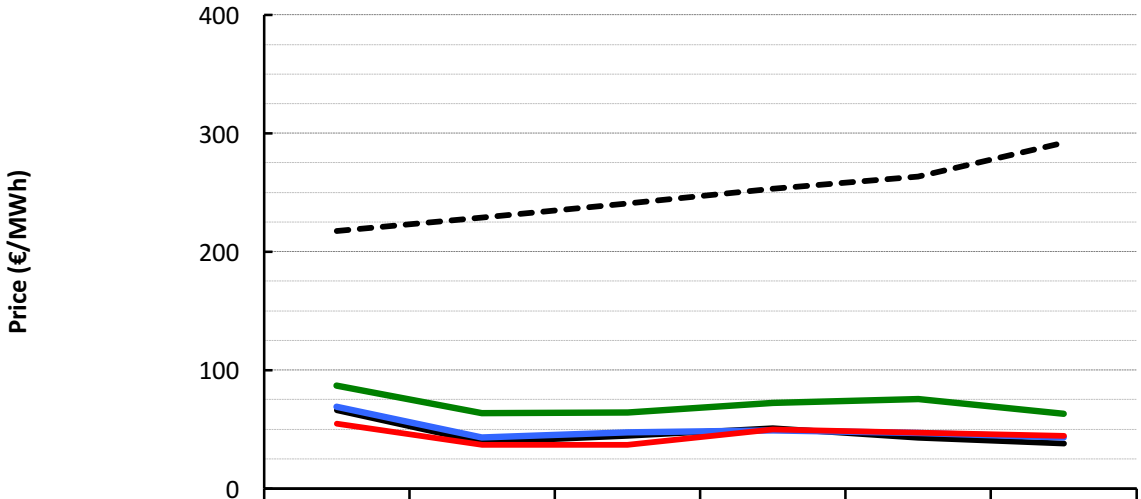
[15] It can be shown that such scarcity prices are needed not just for the marginal production unit but for all units in order to recover fixed and investment costs (see Joskow, 2007). Scarcity prices can only occur if there is no restriction on the bid price. This means generators must be allowed to bid above marginal costs. At the same time, competition authorities must ensure this does not lead to strategic bidding, i.e. exercising market power, (see: Joskow, P. (2007), "Competitive Electricity Markets and Investments in New Generating Capacity", in D. Helm (ed.), The New Energy Paradigm, Oxford: Oxford University Press).

[16] Indirect reliance refers to market participants entering into commercial arrangements with each other in order to hedge their exposure to the price and volume risk.

[17] Scarcity pricing are also suppressed or distorted in energy markets, e.g. through direct public interventions or through system operators (partly) socialising balancing costs.

The very rapid build-up of renewable generation in final energy consumption to 20% and 27% in 2020 and 2030, respectively[18] has created a situation where price signals play an increasingly smaller role.
Renewable energy investment has mostly not been triggered by wholesale price signals based on internal energy market regulation combined with the carbon price signal from the European Emissions Trading System (ETS).[19] To achieve this target, EU member states have primarily relied on dedicated policy instruments to support the deployment of renewables, often feed-in tariffs under long-term contracts. There are two effects of using dedicated support policies.

Figure 2: Retail and wholesale power prices[20] in Germany (DE), France (FR), Spain (ES) and Italy (IT), 2008-2013



	2008	2009	2010	2011	2012	2013
DE, retail	217.2	228.8	240.7	253.0	263.6	292.0
DE, wholesale	65.8	38.9	44.5	51.1	42.6	37.8
FR, wholesale	69.2	43.0	47.5	48.9	46.9	43.2
ES, wholesale	54.4	37.0	37.0	49.9	47.2	44.3
IT, wholesale	87.0	63.7	64.1	72.2	75.5	63.0

DE: Germany; FR: France; ES: Spain; IT: Italy

First, these reduce the demand for electricity generated from conventional sources, resulting in falling wholesale price, and at times even negative prices. Adding supply to an already saturated system will further depress wholesale power prices.

Second, there is more fluctuation of demand for electricity from conventional sources, because

[18] The 20 percent renewables target of total primary energy is most likely met but means that within a short period renewables will constitute some 30-35 % of total electricity production. This situation is likely to continue as the EU has agreed to move to a minimum level of 27% renewables in total primary energy production, which would translate somewhere between 40-50% of renewable energy in the electricity market.

[19] Carbon prices under the ETS have been below 10 EUR/per tonne of CO2 and the ETS and there is little expectation that this situation will change within the next 10 years.

[20] Retail prices for households are shown. Sources: Eurostat, ACER

renewable generation depends to some extent on weather conditions. Decreasing hours of operation of conventional power plants create a need for a different mix of conventional generation technologies, as these do not just differ in their variable production costs but also in their fixed and investment costs. So-called 'base-load' capacity is used to cover the minimum continuous level of electricity demand, as it has relatively low variable but high fixed and investment costs. Consequently, when hours of operation diminish, some base-load is expected being replaced with capacity that has lower fixed costs, natural gas, for example.

The business case for peak-load is challenging because investment costs have to be recovered from a low number of hours of operation. What changes with renewables is that (i) more of these units will be needed and (ii) the exact amount required is subject to greater uncertainty than today due to the weather-dependent availability of renewables. This comes at a time when Europe seems to be entering a situation where overall demand for electricity (even before allowing for renewables) is not growing, and in fact may decline, unless other sectors such as heating or transport are electrified. This represents a radical change for the industry, which for over 100 years was used to steady growth[21].

5.2 Reforming the market

The policy-driven rapid expansion of renewable energy has triggered a debate on a comprehensive reform of the EU electricity markets, or as it is called in EU jargon, 'market design[22]'. The European Commission has launched a stakeholder consultation, which closed in early October[23]. The discussion will intensify in autumn 2015 with a legislative proposal to be expected in the course of 2016.

In the meantime, member states have taken action and have introduced new mechanisms to deal with an explicit remuneration for being available or delivering energy in times of system stress in the form of capacity mechanisms. The objective is to ensure parallel streams of revenue to allow the recovery of that portion of their fixed costs that is not recoverable in energy and balancing markets while also reducing the dependency on uncertain scarcity revenues.

Capacity mechanisms have been implemented or are in the process of being implemented in several EU member states, including France, Germany,[24] Italy, Belgium and the UK. They also have a long history in South America and in the US[25], where several states rely on both energy and capacity markets.

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[21] See Genoese & Egenhofer (2015): *Reforming the Market Design of EU Electricity Markets: Addressing the Challenges of a Low-Carbon Power Sector*. CEPS Task Force Report, 27 July 2015.

[22] See Redl et al (2015), Genoese and Egenhofer (2015), Weale (2015).

[23] https://ec.europa.eu/energy/en/consultations/public-consultation-new-energy-market-design

[24] Strictly speaking, there is currently no capacity mechanism in place in Germany. Yet there is a so-called 'grid reserve' ('Netzreserve') to make sure that TSOs have access to sufficient 'redispatch' capacity. Re-dispatch is a measure to resolve internal grid congestion. Since it provides a capacity-based revenue stream for generators, it acts as a kind of de facto capacity mechanism.

[25] See for example Hogan (2015),

5.3 Low-carbon investment

A largely carbon-free power sector by 2050[26] will require considerable investment, some of which will replace carbon-intensive capacity with more flexible, less carbon-intensive forms of power generation. With the drive towards a low-carbon economy, the electricity market will need to make a positive contribution to the successful delivery of these new policy objectives. It is necessary to understand how the low-carbon economy will be brought about, notably what market rules will be required and whether there is a need to adapt the current framework.

Given the weakness of the wholesale price signal, the EU and member states experience a discussion on the role of governments in providing such a long-term price signal. A first element is a strengthening of the EU ETS in order to provide long-term price signal for carbon allowances, which would first serve as market-exit signal for carbon-intensive capacity. In addition, other ideas are currently being discussed for example including,

- Contract-for-Difference related to the electricity price,
- Contract-for-Difference related to the carbon price,
- So-called reliability options,
- Capacity auctions.

From an EU perspective, a key is that they will still need to be tested against their internal market compatibility.

6. Summary & Conclusions

Although the creation of an integrated electricity and gas market is a legal obligation under the EU Treaty, it has been slow to take off. Following several rounds of legislation however the EU is getting close to well-functioning competitive electricity and gas markets. All electricity markets are or soon will be coupled whereby electricity can freely flow across the EU. 80% of all natural gas is traded on gas hubs, with gas-to-gas competition. The remaining 20% is located in Central and Eastern Europe, countries, which have joined the EU late and embarked on liberalisation also somewhat later. A major shortcoming remains the lack of sufficient cross-border infrastructure. Reasons are that infrastructure still remains to be planned and built according to national interests but also public opposition.

The rapid investment in renewable energy supported by dedicated support mechanisms such as long-term feed-in tariffs in the last years has led to a situation where wholesale prices do not allow generators being remunerated for generating electricity. This situation is likely to continue since there is a political agreement and a target to continue building massive new renewable capacity. This is why member states increasingly deviate from an energy market only and complement it by a separate capacity remuneration market. The major future question is how to generate investment signals and in addition give signals that the investment become

[26] According to the EU Energy Roadmap, every decarbonisation scenario will feature a high share of renewables, i.e. at least 64% in 2050, see SEC(2011) 1565 Parts 1 and 2.

low-carbon. Several ideas are currently discussed to achieve this. The likely result is a fundamental transformation of the way the EU electricity markets work today.

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