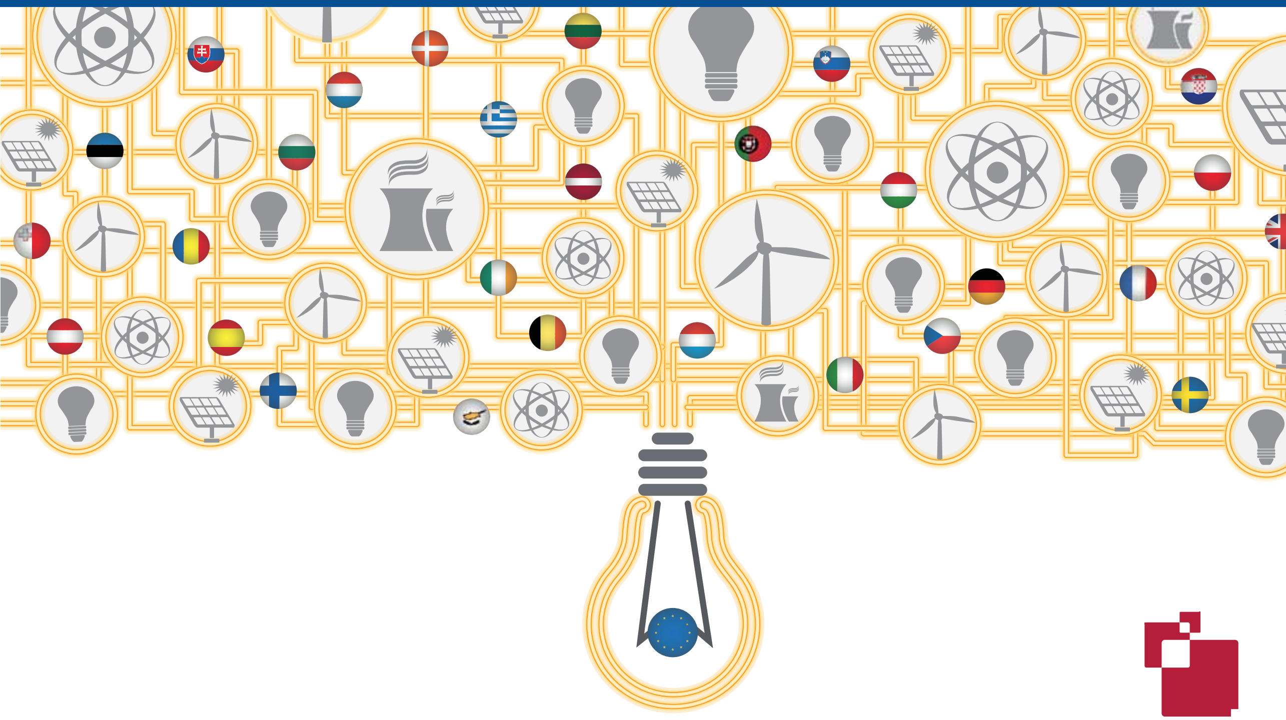
Electricity without borders: a plan to make the internal market work

BY GEORG ZACHMANN



BRUEGEL BLUEPRINT 20

Electricity without borders: a plan to make the internal market work

BY GEORG ZACHMANN

BRUEGEL BLUEPRINT SERIES

BRUEGEL BLUEPRINT SERIES
Volume XX

Electricity without borders: a plan to make the internal market work

Georg Zachmann

Editor: Stephen Gardner
Production: Michael T. Harrington
Cover: Jean-Yves Verdu

BRUEGEL
33, rue de la Charité
1210 Brussels, Belgium
www.bruegel.org

ISBN: 978-90-78910-31-2

Contents

About the author

Georg Zachmann has been a Bruegel research fellow on Energy and Climate Change since September 2009. At Bruegel he has worked on the European electricity market, energy system decarbonisation, European renewables policy and green growth. Prior to Bruegel, he worked at the German Ministry of Finance, the German Institute for Economic Research in Berlin and the energy think tank LARSEN in Paris. He holds a doctoral degree from the Technical University Dresden and a diploma in economics from the Humboldt University Berlin.

Acknowledgement

This Blueprint is based on the report *Modern and extended European energy infrastructure, to meet the Union's energy policy objectives of competitiveness, sustainability and security of supply*, which was prepared at the request of the European Added Value Unit, Directorate for Impact Assessment and European Added Value, within the Directorate General for Internal Policies of the General Secretariat of the European Parliament. The author gratefully acknowledges excellent research assistance from Michele Peruzzi, Alice Gambarin and Valeria Cipollone in the preparation of this volume, and would also like to thank Sebastian Siebers for valuable input.

Executive summary

The completion of the European energy market will help to deliver on all three of the European Union's energy policy targets – security, sustainability and competitiveness. There has been progress, and the cross-border electricity exchanges that have gradually developed over the last century have resulted in substantial cost savings and security-of-supply improvements. Nevertheless, the vision needed for a truly European energy market is lacking. A bolder blueprint is required to overcome the physical and administrative barriers to cross-border trade in electricity. This is what this report provides.

Extending and deepening the internal electricity market is beneficial

A comprehensive quantification of the benefits of a genuine internal electricity market does not exist. However, empirical case studies and simulations suggest that additional integration steps – such as integrating balancing and reserve markets – promise significant yet unexploited benefits. The competition-enhancing effects of market integration are also not yet fully exploited. Furthermore, the infrastructure for cross-border electricity exchanges is increasingly a bottleneck. The cost of using major cross-border transmission lines increased by more than 10 percent between 2012 and 2013 to about €1 billion.

Consequently, there are significant benefits to be had from extending the internal electricity markets by integrating all electricity market segments and deepening it by removing administrative and physical barriers to cross-border electricity exchanges.

Benefits depend on who integrates and how integration is organised

We find that the benefits strongly depend on the systems' characteristics and the approach taken to integration:

- First, substantial efficiency gains of international electricity trade can already be reaped at limited levels of interconnection (5 percent). As the benefits of resolving

the very last transmission constraints are very small, the optimal level of transmission investment will not require an unconstrained network.
- Second, 'shallow market integration,' which only targets optimised usage of the existing system, provides significantly lower benefits than 'deep market integration,' which allows for a reconfiguration of the joint power plant fleet including mutual dependence.
- Third, the benefits of market integration increase with the capacity of renewables. If renewable electricity generation capacities are doubled from current levels the efficiencies increase disproportionally. Consequently, the ambitious European renewables targets will justify greater cross-border transmission capacity.
- Fourth, distant countries with high shares of uncorrelated renewables benefit most from market integration. Limiting market integration to regions with similar renewables production patterns means missing out on substantial trading benefits.
- Fifth, there are significant redistributive effects when countries' power plant fleets are optimised in an integrated way. The balance between consumers and producers is shifted, certain power plants become redundant and countries become mutually dependent. Depending on the level of integration, different generation technologies are preferable.

Market integration requires political intervention for four reasons:

- First, electricity networks are a natural monopoly that requires public intervention to produce socially desirable results.
- Second, the actions of individual market participants have significant externalities that affect all other participants. Because those externalities cannot be dealt with (internalised) by vertical integration, public intervention is necessary to achieve socially desirable sector structures.
- Third, in EU member states very different market arrangements have emerged. Those arrangements are *a priori* largely incompatible across borders and trading thus requires interfaces, which are highly complex because of the need to make different energy products seamlessly tradable between more than 30 incompatible markets. The solution to this – harmonised rules – has significant redistributive effects for market participants. Public intervention is required to strike stable arrangements.
- Fourth, energy is a strongly politicised product in all countries. Consequently, self-organisation of cross-border markets is politically constrained.

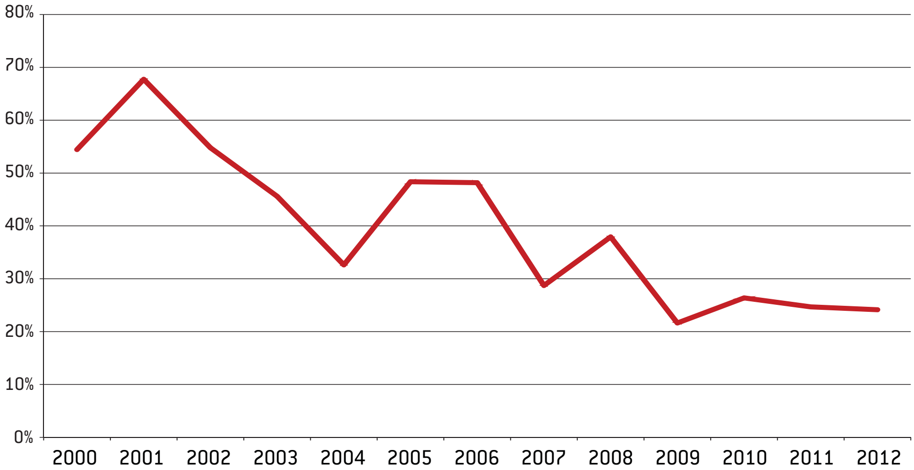
Quantifying the infrastructure need

There are numerous exercises quantifying the future need for energy infrastructure in Europe. The infrastructure needs they predict differ markedly because the 'optimal network' depends strongly on the assumptions made. These assumptions imply societal choices: How are the different objectives of network investments weighted? How will energy demand develop? Which technologies does the model include? How will the cost and availability of these technologies develop? Consequently, the process used to determine the 'optimal network' is more important than the numerical outcomes of individual studies.

Market design not adapted to the changing environment

The liberalisation of electricity generation and retail businesses, and the long-term shift in the generation structure towards variable renewables, is changing the electricity market environment. The value of electricity is more and more determined by factors such as capacity, ancillary services, location and 'greenness', which are remunerated through national schemes. At the same time the value of the component traded at European level – wholesale electricity and emission allowances – has decreased sharply (for an illustration, see Figure 1 for Germany).

Figure 1: Share of wholesale prices in price paid for electricity by industrial users in Germany



Source: Bruegel based on IEA and EEX.

Thus, the incentives for investment in the electricity system are becoming more and more driven by national administrative choices. The EU 'Target Model' that should be implemented by 2014 does not address the issue of establishing European markets for capacity, ancillary services, location and 'greenness'. Consequently, the system under which these services are remunerated will matter more for an investor/operator than the location at which they could be economically provided.

Current infrastructure planning does not target European welfare maximisation

Most transmission line investments in Europe continue to be based on national plans, that target domestic welfare maximisation or network cost minimisation, and are funded by domestic network users. This model fails in the international or cross-border context because both domestic and cross-border transmission lines cause significant spillovers onto neighbouring countries' networks that are not properly addressed in national plans.

As a consequence, cross-border transmission capacity has not been substantially increased in the past five years. Previous European schemes lacked the system-wide overview and were either underfunded or too short-term. The European Union infrastructure package[1] is intended to deliver more cross-border electricity transmission. The cross-border cost-allocation method that it foresees could become quite powerful – but for the time being is only concentrated on a limited number of politically-selected individual projects.

Overall, network planning continues to be driven by the transmission system operators (TSOs), which monopolise the information about the technical details of the energy system, but which have incentives that are not necessarily aligned with societal objectives. The EU infrastructure package is an extension of the current system of national-welfare centred regulations, a system which does not target the optimisation of the EU electricity network, and as such is inconsistent with a truly single market.

Proposal

The most straightforward European single energy market design would entail a European system operator regulated by a single European regulator. This would ensure the predictable development of rules for the entire EU, significantly reducing regulatory uncertainty for electricity sector investments. But such a first-best market design is

1. http://ec.europa.eu/energy/infrastructure/strategy/2020_en.htm.

unlikely to be politically realistic in the European context for three reasons. First, the necessary changes compared to the current situation are substantial and would produce significant redistributive effects. Second, a European solution would deprive member states of the ability to manage their energy systems nationally. And third, a single European solution might fall short of being well-tailored to consumers' preferences, which differ substantially across the EU.

To nevertheless reap significant benefits from an integrated European electricity market, we propose the following blueprint:

1. First, we suggest adding a European system-management layer to complement national operation centres and help them to better exchange information about the status of the system, expected changes and planned modifications. The ultimate aim should be to transfer the day-to-day responsibility for the safe and economic operation of the system to the European control centre. To further increase efficiency, electricity prices should be allowed to differ between all network points between and within countries. This would enable throughput of electricity through national and international lines to be safely increased without any major investments in infrastructure.

2. Second, to ensure the consistency of national network plans and to ensure that they contribute to providing the infrastructure for a functioning single market, the role of the European ten year network development plan (TYNDP) needs to be upgraded by obliging national regulators to only approve projects planned at European level unless they can prove that deviations are beneficial. This boosted role of the TYNDP would need to be underpinned by resolving the issues of conflicting interests and information asymmetry. Therefore, the network planning process should be opened to all affected stakeholders (generators, network owners and operators, consumers, residents and others) and enable the European Agency for the Cooperation of Energy Regulators (ACER) to act as a welfare-maximising referee. An ultimate political decision by the European Parliament on the entire plan will open a negotiation process around selecting alternatives and agreeing compensation. This ensures that all stakeholders have an interest in guaranteeing a certain degree of balance of interest in the earlier stages. In fact, transparent planning, early stakeholder involvement and democratic legitimisation are well suited for minimising as much as possible local opposition to new lines.

3. Third, sharing the cost of network investments in Europe is a critical issue. One reason is that so far even the most sophisticated models have been unable to

identify the individual long-term net benefit in an uncertain environment. A workable compromise to finance new network investments would consist of three components: (i) all easily attributable cost should be levied on the responsible party; (ii) all network users that sit at nodes that are expected to receive more imports through a line extension should be obliged to pay a share of the line extension cost through their network charges; (iii) the rest of the cost is socialised to all consumers. Such a cost-distribution scheme will involve some intra-European redistribution from the well-developed countries (infrastructure-wise) to those that are catching up. However, such a scheme would perform this redistribution in a much more efficient way than the Connecting Europe Facility's *ad-hoc* disbursements to politically chosen projects, because it would provide the infrastructure that is really needed.

1 EU energy policy targets: security of supply, sustainability, competitiveness

EU energy policy strives to deliver on the 'magic triangle' consisting of security, sustainability and competitiveness of energy supplies. In the context of network infrastructure, **security** has two main aspects. First, Europe should have sufficient infrastructure to ensure that it can reliably acquire energy to meet its needs. In order to prevent import disruptions (in particular for natural gas) and to reduce the price-setting power of foreign suppliers, Europe is committed to build and maintain a diversified portfolio of physical import channels (pipelines, LNG terminals). Second, the internal aspect of network security is the ability to safely deliver energy to where it is needed. In terms of electricity this involves mainly the stability of the electricity system with respect to individual incidents[2] – but also the minimisation of local supply disruptions[3]. For natural gas, internal network security also requires a robust internal network that is able to compensate for supply disruptions caused by the cutting-off of specific external supplies.

Sustainability in terms of network infrastructure is more difficult to define. One aspect of sustainability is the provision of the network required for the integration of sustainable energy sources, in particular renewables. This is a challenge because some of these newly developed sources will be in poorly connected regions, such as

2. For example, the n-1 criterion as for example defined in the Network Code on Operational Security by ENTSO-E foresees that the electricity system should be able to withstand the failure of an individual component, ie no individual component should cause systemic failure if it fails.
3. Completely preventing supply disruptions is not economically sensible as the cost of the back-up systems needed to achieve the target far exceed the cost of minor disruptions. National preferences for the security-versus-cost trade-off differ.

wind power in northern Scotland. In addition, the intermittent nature of renewable electricity sources such as solar and wind requires exchanges of energy across wide areas to efficiently balance regional shortages.

In terms of **competitiveness**, network infrastructure has to maintain a trade-off. Network infrastructure has an economic cost that has to be borne by energy consumers. However, network infrastructure also enables cost savings by allowing access to the cheapest energy sources.

2 The cost of non-Europe

In a world without transaction costs more centralisation always increases efficiency. Any cooperating group of countries faces essentially a trade-off between two opposite forces: the economies of scale that can be achieved by enlarging the market, and the heterogeneity of the participants' preferences. Economies of scale foster the creation of ever larger markets, while the costs of mediation between different needs prevent unions of countries from growing too large. The larger the number or the more heterogeneous the countries' preferences, the more likely it is that the transaction costs of mediation outweigh the benefits achievable through the integrated market[4]

This also holds for the energy sector, in which preferences, resource allocation and historic path dependencies have resulted in very heterogeneous energy systems. However, efficiencies from cooperation between energy sectors are substantial.

Efficiencies arise from the cross-border coordination of the use of existing assets (static efficiency), and from the cross-border coordinated development of the asset structure (dynamic efficiency). One example of a static efficiency is the monetary gain from replacing, at a given hour, electricity produced in an expensive gas turbine on one side of the border by electricity produced by wind turbines on the other side of the border. Dynamic efficiency would arise from building only one gas turbine to balance both systems instead of two turbines on either side of the border. In this section we present evidence of the benefits of integration based on historic evidence, a literature survey, a simulation exercise and recent data on cross-border trade.

2.1 Many benefits of integration have already been reaped

European energy market integration is a continuous process that reaches back almost a century. In a dry winter following a hot summer in 1921-22, the reduction of Italian hydroelectric production was partly compensated for by imports from Switzerland that were made available as France exported electricity from coal-fired plants to

4. Altomonte and Nava (2006).

Switzerland[5]. Because of the large potential gains, cross-border electricity trade continued throughout the protectionist inter-war period.

Table 1: Cross-border lines in north-west Europe in 1949

From/to	AT	BE	DK	FR	NL	NO	CH
FR		1x65kV					2x60kV
		1x70kV					1x70kV
							1x125kV
							4x150kV
IT	1x130kV			1x70kV			1x130kV
				1x150kV			1x140kV
							1x150kV
NL		1x220kV					
SE			1x50kV			1x80kV	
DE	2x220kV	1x220kV		1x110kV	1x220kV		3x110kV
	9x110kV			1x150kV			1x220kV
				2x220kV			

Source: OEEC (1950, p.52-55) quoted by Lagendijk (2008).

Table 2: Cross-border lines in north-west Europe in 2011

From/to	AT	BE	DK	FR	NL	NO	CH
FR		3x380kV					5x220kV
		3x220kV					6x380kV
IT	1x220kV			1x110kV			1x110kV
				1x220kV			5x220kV
				3x380kV			5x380kV
NL		4x380kV					
SE			2x110kV			2x110kV	
			2x380kV			1x220kV	
						4x380kV	
DE	20x110kV		1x110kV	2x220kV	6x380kV		5x220kV
	11x220kV		2x220kV	3x380kV			7x380kV
	2x380kV		3x380kV				

Source: ENTSO-E Statistical Yearbook 2011.

5. Lagendijk (2008, p39).

Before the second world war, most lines were intended to pool resources by connecting very different systems. One striking example was the connections between France and Switzerland that served to bring electricity generated from French thermal plants to Switzerland during off-peak hours in return for electricity produced in flexible Swiss hydro-plants during peak hours (the same was done between Germany and Austria). These transactions allowed both countries to maintain complementary fuel mixes and were commercially beneficial to both sides. During and after the second world war, the energy sectors in most European countries became owned or at least largely controlled by their respective governments[6]. Since the 1950s, cooperation between national energy sectors in Europe (within the two political blocs) was strengthened[7]. Both the eastern and western blocs moved from individually controlled cross-border lines to synchronisation of their respective systems. An international alternate-current system requires that all power plants connected to the joint network inject power in a synchronised way. In the west, synchronisation happened in 1957.

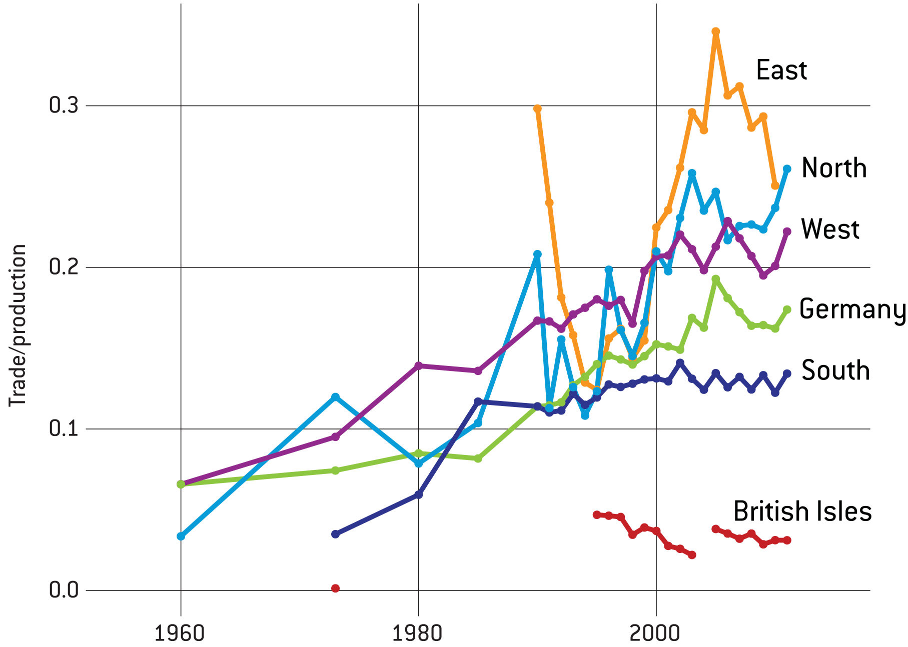
In 1959, the exchange of electricity, which had been strongly regulated since the protectionist inter-war period, became liberalised allowing national energy companies to more flexibly engage in corresponding transactions. The primary target of this removal of physical and administrative barriers more than 50 years ago was to increase security of supply by allowing electricity imports/exports at short notice. Significant investments in a strong and internationally meshed high-voltage network (see Tables 1 and 2) allowed increasing electricity exchanges between countries. Interestingly, between 1949 and 2011 the relative strength of bilateral connections was largely maintained and only one previously unconnected country-pair (Germany-Denmark) was connected.

The structure of national monopolies exchanging electricity on a bilateral basis continued until the early 1990s. By then it became apparent that integrated monopolies were not sufficiently incentivised to cut costs and improve service quality. In the international electricity trade for example, it was by no means ensured that the dispatch (ie the decision about how much electricity each power plant has to produce) in the joint network was minimising cost. Even though most integrated companies tried to switch on only the cheapest plants in their respective countries in order to meet

6. Examples are the nationalisation in the UK in 1947 and in France in 1946, the Energiewirtschaftsgesetz of 1935 in Germany that created regional monopolies, and the 1946 decision in Sweden to give the state-owned Vattenfall a monopoly over the national grid (see Heddenhausen, 2007).
7. The United Nations Economic Commission for Europe even proposed joint ownership of high-voltage power-lines in 1947, but this was rejected by European states (Lagendijk 2008, p130f).

demand, cheaper plants in neighbouring countries often remained idle because optimisation was a national matter.

Figure 2: International trade (imports plus exports) over production

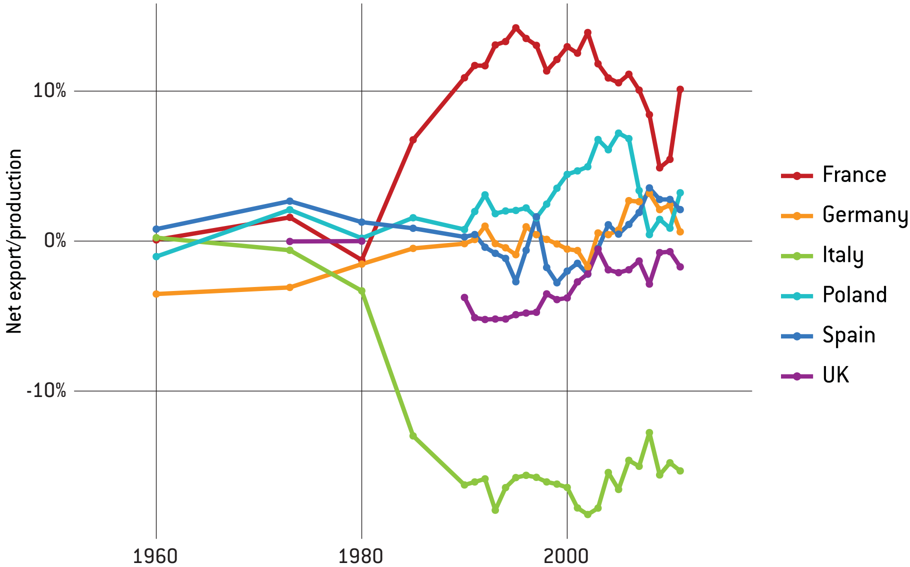


Source: Bruegel based on IEA Electricity Information 2001, 2005, 2011; Eurostat, World Bank, Lagendijk (2008).
Note: West = Austria, Belgium, France, Luxembourg, Netherlands; East = Czech Republic, Estonia, Hungary, Poland, Romania, Slovakia, Slovenia; South = Greece, Italy, Portugal, Spain; North = Denmark, Finland, Norway, Sweden; British Isles = United Kingdom, Ireland.

To overcome these inefficiencies, the European Union initiated a major project to liberalise and integrate the European electricity market. This project consisted of regulating the network business and establishing competition between generators within and between countries. As a result, electricity started to more regularly flow from low-cost countries to high-cost countries, leading to increasing and more volatile net trading positions (see Figure 2). At the time of writing, the European Union is finalising this project to integrate the energy wholesale markets. The administrative rules that will complete the integration of the market should be implemented by 2014.

In summary, electricity market integration in Europe has been a continuous process that started long before the existence of the European Union with its single market

Figure 3: Annual net exports by selected countries



Source: Bruegel based on IEA Electricity Information 2001, 2005, 2011; Eurostat, World Bank, Lagendijk (2008).

project, or even the European Communities. This confirms the huge benefits of cross-border cooperation in the electricity sector, but it also indicates that major benefits were reaped long before the EU was created. The question we will address will therefore not be what the cost of non-cooperation is, but what benefits can be reaped by extending cooperation even further.

2.2 Literature survey

Table 3 identifies the main competition and integration related benefits of the single market for energy in terms of the impact on the use of existing assets ('static') and/or investment decisions ('dynamic').

Table 3: Categorisation of benefits

	Static	Dynamic
Competition	- Reduced mark-ups - Improved operation	- Less investment withholding - Improved investment decisions
Integration	- Cross-border optimisation of operation	- Cross-border optimisation of investment decisions - Cross-border optimisation of company structures (M&A) - better use of local resources

Source: Bruegel.

But the effects of competition and integration cannot be easily analysed in isolation. Competition is impossible in small-scale energy systems because there are significant effects of scale and scope in energy companies. Consequently, in small-scale systems only one or two companies might have an optimal size – markedly reducing the scope for competition. On the other hand, integrating systems that feature non-market based allocation of goods is difficult because the value of the exchanged service cannot be easily determined. In which direction should electricity, for example, be traded if it is unclear on which side of the border it is more valuable? Thus, competition and integration are largely intertwined.

Benefits from integration

Efficiencies in electricity trade can *inter alia* arise from the benefits of exchanging differences in resource endowments in different countries (trading intermittent-versus-hydro resources), the possibility to maintain more diversified portfolios of power-plants across larger areas and the reduced need for reserves in larger zones (the reserve need for thermal units increases with the square root of total capacity).

A number of empirical studies find a positive relationship between integration and productive efficiency. Bergman (2003), for instance, uses the creation of a single Nordic market for electricity as a case study to illustrate that competition induces substantial productivity increases in the power industry. This is mainly suggested by the increase by more than 15 percent since 1996 of the production of electricity in Sweden, while generation capacity has been slightly reduced. Moreover, in connection with the restructuring of the network and retailing segments of the industry, personnel and other costs have been heavily reduced.

Numerous recent studies have analysed the effects of integration on the different segments of the electricity market:

- Gerbaulet *et al* (2012) investigate four scenarios of different tertiary reserve market cooperation (currently purely nationally organised in Germany). Results point towards overall system costs reduced by about 10 percent in the case of one unified tertiary reserve market called 'Germalpina' (German, Swiss and Austrian markets), which is preferable compared to all possible bilateral arrangements.

- Haucap *et al* (2012) analyse the German reserve power market, which in recent years has gone through major regulatory changes – including the better coordination of the four sub-national markets. Haucap *et al* find that the reforms were successful in reducing minute reserve power prices[8], leading to substantial cost savings for the transmission system operators.

- Abbasy *et al* (2009) find that integration of the Dutch, Nordic and German balancing markets has the potential to reduce the costs of balancing[9]. The total annual balancing cost before balancing market integration is about €180 million per year (corresponding to no interconnection available), and drops below €100 million per year when 10 percent of interconnection capacity is available for balancing. This means a balancing cost reduction of about €80 million per year.

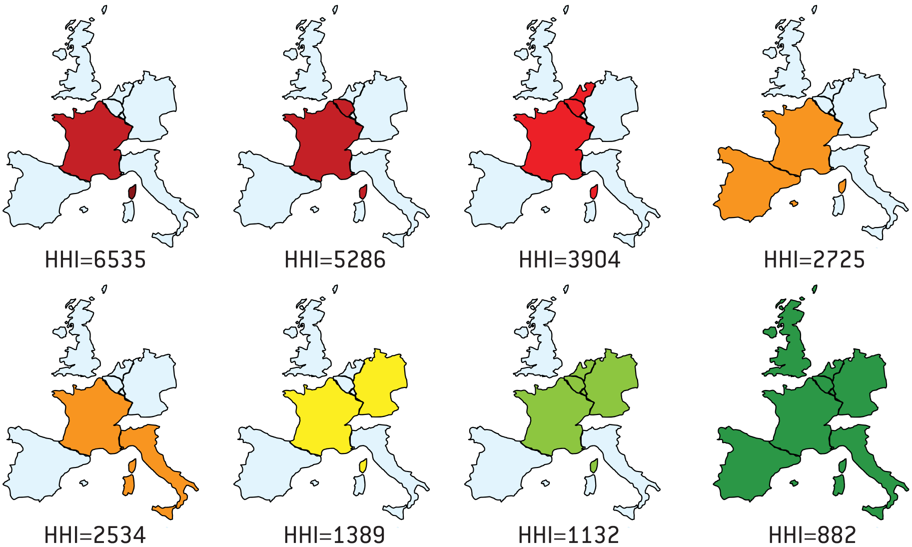
- Mansur and White (2012) indicate that employing a more centralised market design that is only possible in unified trading areas substantially improved overall market efficiency, and that the efficiency gains far exceeded implementation costs. Indeed, they find that adopting the organised regional market design produced efficiency gains of over US$160 million annually, substantially exceeding the (one-time) US$40 million implementation cost. These efficiency gains arise from supply-side allocative efficiency improvements and from superior information aggregation about congestion externalities, enabling the organised market to support greater trade.

8. Minute reserve power (MRP) is power acquired by the system operators from generators and large consumers to increase or reduce power production/consumption on a given day at short notice (<15min). Two types of MRP have to be distinguished: incremental (positive) reserve power and decremental (negative) reserve power. While the former is used when the demand for electricity exceeds the supply of electricity, the latter is needed when more electricity is generated than consumed.
9. For example, when the balancing markets of two areas are integrated, negative imbalances in one area can be offset by positive imbalances in another area without requiring expensive power plants to be switched on.

Benefits from competition

Extending the national market to an international market reduces the market power of individual players. As Figure 4 shows, the concentration of the generation sector in France drops drastically when it forms a joint market with its neighbours. Full integration could essentially lead to an unconcentrated market.

Figure 4: Concentration indicator for generation companies for different market configurations



Source: Bruegel based on companies' capacities reported in their 2012 annual reports, and total capacities reported by national regulators. Note: the reported Herfindahl-Hirschman-Index (HHI) is the sum of the squared market shares of all major electricity producers in the included countries. In US competition law, an HHI below 1500 indicates an unconcentrated market, an HHI between 1500 and 2500 indicates a moderately concentrated market and an HHI above 2500 indicates a highly concentrated market. Colours range from green (least concentration) to red (greatest level of concentration).

More competition in theory leads to increased production and lower prices, and creates incentives for more efficient operation and investment. Hence social welfare increases because less market power is exercised (lower mark-ups on prices) and costs are controlled more aggressively.

Zarnic (2010b) indicates that the price-cost margin, which he uses as a proxy for the mark-ups on the electricity price demanded by generators with market power, has declined as a result of EU-wide liberalisation efforts, but the mark-up applied by incumbent firms is on average still greater than theoretical models would predict under effective economic integration. The average price-cost margin is estimated at almost 45 percent for the largest consolidated firms, but has declined due to EU-wide liberalisation efforts by about 2 percent each year since 2003 for those firms. The results show that price-cost margins are negatively associated with better functioning of wholesale and retail markets, but better market access has not led to competitive market outcomes (ie mark-ups close to zero) because of prevailing market concentration and insufficient unbundling of transmission and distribution channels. Zarnic (2010b) suggests that an increase in market concentration of 10 percentage points is equivalent to an increase in the average price-cost margin of 0.7 percent.

Several empirical studies focus on the efficiencies brought about by increasing competition in energy markets. These efficiencies are realised mainly through better usage of inputs, such as labour, and through significant cost reductions. Shanefelter (2008) considers improvements in productive efficiency that can result from a movement from a regulated framework to one that allows for market-based incentives for industry participants. She finds that merchant owners of divested generation assets employ significantly fewer people, but that the payroll per employee is not significantly different from what workers at utility-owned plants are paid. As a result, the new merchant owners of these plants have significantly lower aggregate payroll expenses (-32 percent). Decomposing the effect into a merchant effect and a divestiture effect, she finds that merchant ownership is the primary driver of these results. Similarly, Fabrizio *et al* (2007) adopt the agency model for their study and this suggests that firms may not minimise costs in less-competitive or regulated environments. The study finds that the division of the utility company faced with competition, ie the generating sector, responded with a reduction in costs, while other sectors and companies not faced with competition did not. The results suggest statistically and economically significant declines in input use associated with regulatory restructuring. The results also suggest modest medium-term efficiency benefits from replacing regulated monopoly with a market-based industry structure.

However this efficiency enhancement also affects capital usage. Davis and Wolfram (2012) argue that the deregulation and consolidation of nuclear generators in the US are associated with a 10 percent increase in operating efficiency, achieved primarily by reducing the frequency and duration of reactor outages. At average wholesale prices, the value of this increased efficiency is approximately US$2.5 billion annually for the 103 United States nuclear reactors. Ten years earlier, Hiebert (2002) also found evidence that plant efficiencies are associated with capacity utilisation of the plant and also with the number of plants under utility management. He also found that regulatory restructuring activity in certain US states is associated with improvements in plant operating performance. Nevertheless, this productivity improvement does not affect all types of firms in the same way. Zarnic (2010a) finds that productivity gains of European electricity firms deriving from reforms implemented in the last decade are associated with high-productivity firms close to the technology frontier (ie firms able to transform inputs to outputs efficiently), while no significant impact is found for the laggards (ie firms that still need technological catch-up).

The empirical results of the reviewed studies are summarised in Table 15 in the Appendix.

2.3 Simulation

The following simulation is not a representation of the European market but should illustrate the value of market integration via a stylised example.

We show the benefits of coupling two markets by considering two imaginary countries, Zone A and Zone B, for a period of one year. Each of the two countries has its own supply and demand profile. The two countries can be described by their power plant configuration, by the profile of the renewables feed-in, and by their demand profiles. In terms of power plants we categorise the existing plants in the two countries into four groups: (i) intermittent renewables (wind, solar), (ii) nuclear, (iii) coal and (iv) gas. Table 4 details the data we used, and our *ad-hoc* assumptions on the fixed and variable costs[10]

Table 4: Assumptions used for static simulation

	Capacity, Zone A (MW)	Capacity, Zone B (MW)	Fixed cost in €/MW/y	Variable cost in €/MWh
Renewables	23,000	13,000	120,000	0
Nuclear	5,500	3,900	190,000	10
Coal	7,100	22,600	100,000	21
Gas	7,600	10,600	40,000	35

10. Data on the installed capacity for different power sources, the vertical network load and the wind and solar feed-in for Zone A and Zone B correspond to the 8,784 hours of the year 2012 in the German zones served by Amprion and TenneT, respectively. We do this for reasons of completeness and availability. For fixed and variable costs, we use the values reported in Delarue *et al* (2011).

It should be noted that the supply of renewables and the vertical network load are not constant over time, but random. We use realistic data for both (see Figure 5). Since the two countries are neighbours, there is a high level of correlation of their renewables feed-in patterns and vertical network loads. In fact, the renewables feed-in shows a correlation of 67 percent between the two countries. Also, the 100 hours with the lowest renewables feed-in in Zone A coincide with 6 hours that are among the 100 hours with the lowest renewables feed-in in Zone B[11]. The vertical network load is also highly correlated at 78 percent, and 40 hours are among the 100 hours with the highest load in both countries. Most importantly, the hours with the highest residual load – that is the load that needs to be served after all variable renewable supplies were already used – strongly coincide. As both countries would need the remaining resources at the same time reserve sharing between these directly neighbouring countries might have limited benefits.

Table 5: Coincidence of hours with minimum renewables feed-in and hours with maximum load in 2012 for Zones A and B

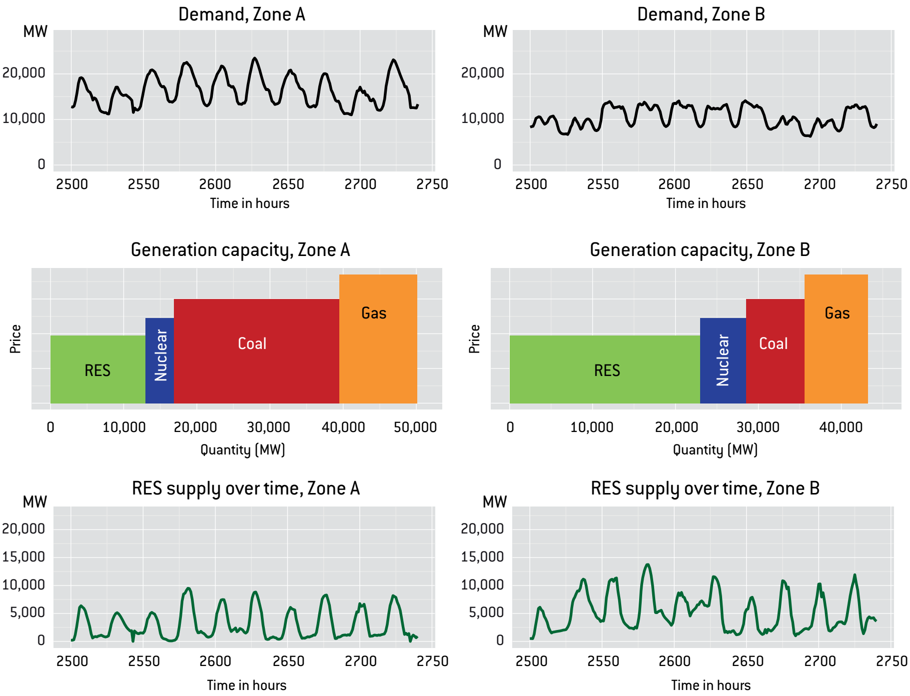
	top 10h	top 50h	top 100h	top 200h	correlation
Renewables (min)	-	1	6	24	67%
• wind (min)	5	23	36	110	77%
• solar (min)	6	32	66	139	98%
Load (max)	-	8	40	121	78%
Residual load (max)	-	8	27	53	74%

We will analyse three cases. The first is a no-trade case that consists of the optimal schedule of the existing power plants when the two countries are isolated. In the second case, up to five percent of the total generation capacity in the smaller zone can be traded between zones, ie maximum transmission capacity is assumed to be 2160 MW. In the third case we assume unlimited transmission capacity between the two countries[12].

Installing five percent transmission capacity between the two countries allows reducing the total system cost in the two countries by 0.9 percent (see Table 6). This cost saving is achieved as at some occasions more expensive plants in one country can be replaced by imports from cheaper plants in the other country. Unlimited transmission capacity reduces the system cost by one additional percentage point.

11. For solar and wind energy considered separately, the number of hours that are among the 1000 hours with the highest load in both countries is 865 and 578, respectively. Solar also shows very high correlation between the two countries, at almost 98 percent. Wind has a 76.5 percent correlation.
12. Imported electricity is assumed to have an additional variable cost of €0.1/MWh

Figure 5: Graphical representation of the data



Source: Bruegel.

This indicates that almost half of the trading opportunities are already physically possible with only five percent transmission capacity.

Table 6: System cost under different scenarios

	No integration	5% transmission	Full integration
Total costs	100	99.1	98.1
Avg Price, Zone A €/MWh	20.95	20.97	19.92
Avg Price, Zone B €/MWh	14.35	16.39	19.88

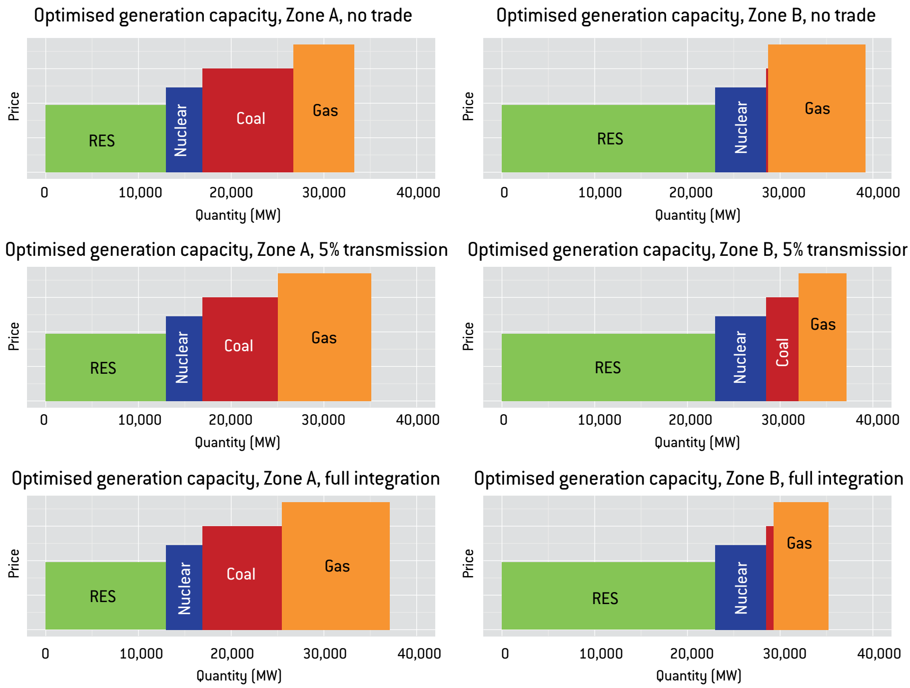
Source: Bruegel.

Up to this point we have considered static efficiency, ie the countries optimise their generating costs given their current power plant fleet. We now move to an analysis of the effects of dynamic efficiency: the two countries are allowed to optimise their fossil power-plant fleets[13]. Again, we consider three scenarios: no-trade, reduced transmission capacity, full-trade. We find that the efficiencies of trade increase when countries can reconfigure their plant fleets from two fleets that are optimal in a national setting to an arrangement that is optimal in a joint setting (Table 7). Given the renewables and nuclear capacities and the load and renewables patterns in the two countries, jointly optimising the investment and operation of the coal and gas power plant fleet allows the cost to be reduced by 1.1 percent if transmission capacity is limited, and by 2.5 percent if transmission capacity is unlimited. Figure 6 shows that in the analysed case the cost reduction is not due to a reduced total capacity but to a shift in production technologies (more coal at limited transmission and more gas at full integration) and a shift in production location (more generation in Zone B). A shift from gas capacities to coal capacities implies a shift from variable to fixed cost. An investor would build a capital-intensive coal-fired plant instead of a gas-fired plant with higher variable cost when the plant can be ensured to run at least 4286 hours per year[14]. In Zone A the coal generation capacity that can be guaranteed to run at least 4286 hours increases when five percent transmission capacity become available as then occasionally coal-generated electricity can be exported to Zone B where it replaces electricity generated by gas-fired plants. This makes more coal plants in Zone A competitive. At full integration, foreign oversupply situations shifts the balance towards gas-fired plants, as more often domestic demand can be met by domestic and foreign baseload generation (renewables and nuclear) alone. In short, the high correlation of both, volatile demand and volatile renewables feed-in, does not allow for substantive reserve-sharing[15] between the two countries. But a better adapted supply portfolio and more optimal scheduling of plants allows total cost savings up to 2.5 percent in a fully integrated market.

Interestingly, when we double the assumed renewables capacity in each country, the cost-reducing effect of joint optimisation increases significantly. At full integration, almost five percent of the total-system cost can be saved when the coal and gas power-plant fleet is not individually but jointly optimised.

13. We modify the data by increasing by 10 percent the vertical network load when it reaches its peak value. Also, we impose a €200,000/MWh cost for every MWh of unfulfilled demand. This makes sure that the system has a 10 percent reserve margin at all times.
14. As 4286h x €35/h + €40,000 ≈ 4286h x €21/h + €100,000.
15. Here we underestimate the reserve sharing potential, as reserves are not only required for backing-up renewables and high-load situations but also for insuring the system against stochastic plant and line failures. According to the law of large numbers, corresponding reserve needs grow less than proportionally with the system size (see Anderson, 2006). For example, when nine equally-sized systems with a reserve margin of 21 percent are joined, the reseve margin in each country might be reduced by one third to 14 percent without loss of security of supply.

Figure 6: Energy support for Zones A and B, with optimisation and varying levels of trade



Source: Bruegel.

Table 7: Total system costs with optimal capacities under current and high RES penetration, with varying level of market integration

	No integration	5% transmission	Full integration
Current renewables	100	98.9	97.5
High renewables	100	97.5	95.4

Source: Bruegel.

Our analysis provides a lower bound for potential efficiency gains because the cost of the technology is similar in the two countries and because both consumption and the renewables feed-in are highly correlated between Zones A and B. To illustrate the benefits of connecting more distant geographic regions, we repeat the analysis with a stylised example modelled using 2012 data from Germany and Spain[16].

Table 8: Data used for static simulation

	Capacity, Germany (MW)	Capacity, Spain (MW)
Renewables	58,400	28,800
Nuclear	12,100	7,850
Coal	44,400	11,250
Gas	23,200	25,800

Source: Bruegel based on data from www.bmwi.de and www.ree.es.

The two countries have quite different renewable generation profiles. Table 9 shows that the correlation of renewables feed-in in both countries is only 18 percent. Among the 100 hours with the lowest renewables feed-in in Germany, none are among the 100 with the lowest renewables feed-in in Spain. This is mainly due to the low correlation of wind in the two countries. By way of contrast, network load and solar power have a much higher correlation, as is to be expected since daylight hours are only marginally delayed in Spain and also peak-demand hours almost coincide.

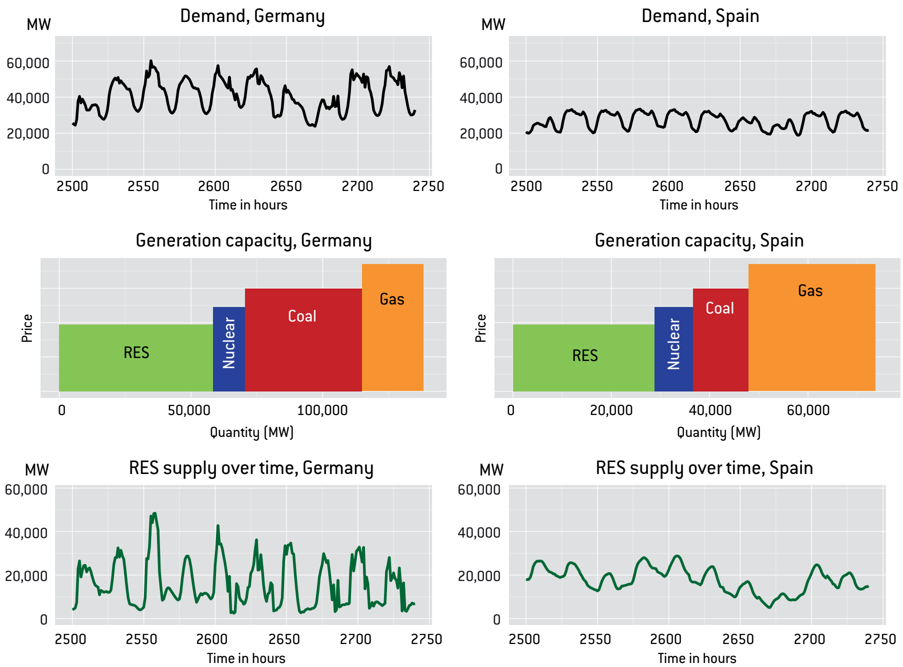
Table 9: Coincidence of hours with minimum renewables feed-in and hours with maximum load in 2012 for Germany and Spain

	top 10h	top 50h	top 100h	top 200h	correlation
Renewables (min)	-	-	-	2	18%
• **wind (min)**	-	-	-	3	2%
• **solar (min)**	-	12	20	50	86%
Load (max)	-	4	19	43	80%
Residual load (max)	-	6	14	31	59%

The trading of electricity between Spain and Germany generates efficiencies from the use of existing plants amounting to 0.7 percent, lower than that generated between Zone A and Zone B (1.9 percent), which have very similar demand and supply patterns. This counter-intuitive result – one would have expected that trading is more beneficial between countries with less correlated demand and supply patterns – is due to the

16. Data on the installed capacity for different power sources, the vertical network load and the wind and solar feed-in for Germany and Spain correspond to 8,724 of the 8,784 hours of the year 2012. For fixed and variable costs, we use the values reported in Delarue *et al* (2011).

Figure 7: Graphical representation of the data



Source: Bruegel.

substantial excess capacities in both Germany and Spain in 2012[17], and to the fact that Zones A and B have quite complementary generation structures, making trade between them particularly beneficial[18]. Consequently, trade between two self-sufficient countries that maintain their initial power-plant fleet provides comparatively limited benefits in terms of total system cost. Nevertheless, integration has substantial redistributive effects with electricity prices[19] in Spain dropping dramatically (-17 percent) with increasing integration. Hence, Spanish consumers gain while Spanish producers are worse off.

17. German maximum generation capacity excluding (including) RES represents 216 percent (307 percent) of its 2012 peak load. Spanish maximum generation capacity (including) RES represents 182 percent (253 percent) of its 2012 peak load.
18. Zone A has 21 percent renewables capacity while Zone B has 35 percent renewables capacity.
19. Assuming a fully competitive wholesale market, electricity prices can be calculated as the average of the hourly marginal cost. Remaining price differentials at full integration come from a €0.1/MWh penalty for imported electricity.

Table 10: System cost under different scenarios

	No integration	5% transmission	Full integration
Total costs	100	99.5	99.3
Avg Price, Germany €/MWh	19.46	19.95	20.25
Avg Price, Spain €/MWh	24.32	21.99	20.28

Source: Bruegel.

When we allow Spain and Germany to re-optimise their power-plant fleets, we obtain efficiencies similar to those we found for Zones A and B at limited transmission (1 percent total system cost savings), and slightly lower efficiencies from full integration compared to the Zone A-Zone B case (1.6 percent total system cost savings) (Figure 8). However, when the capacity of renewable generation is doubled in both countries, the greater heterogeneity of Germany and Spain results in significantly higher trading effects. If both systems were fully integrated, system cost would drop by as much as 6.5 percent compared to the no-integration scenario (for the two neighbouring countries these efficiencies only amounted to 4.6 percent).

Table 11: Total system costs with optimal capacities under current and high RES penetration, with varying level of market integration

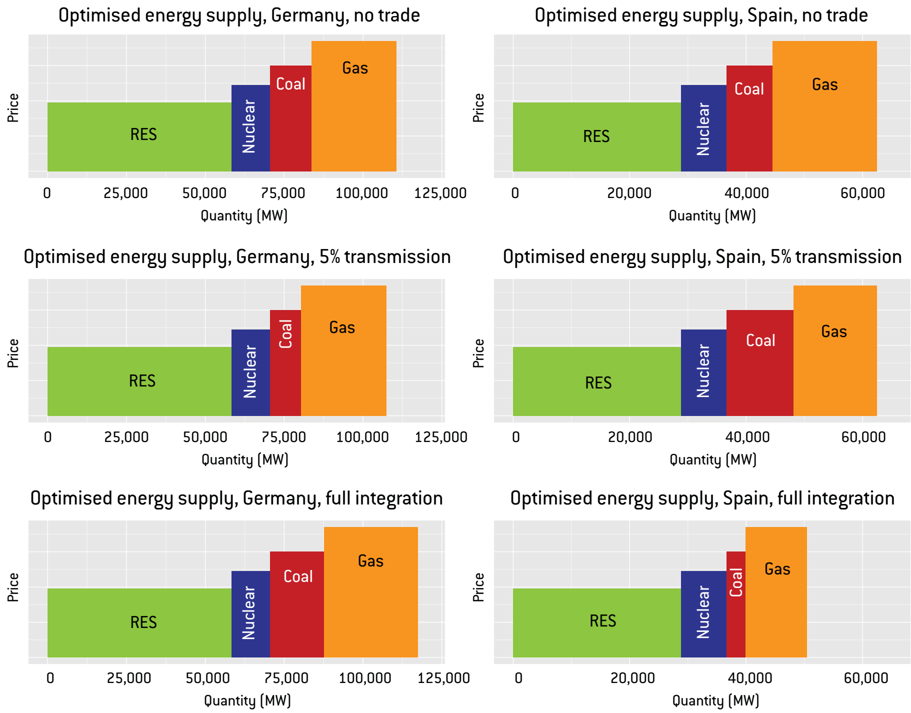
	No integration	5% transmission	Full integration
Current renewables	100	99	98.4
High renewables	100	95.1	93.5

Source: Bruegel.

Our analysis provides a rough indication of the possible efficiency gains of different levels of integration for different country settings. Four findings from the simulations can be highlighted:

- First, substantial efficiency gains from international electricity trade can already be obtained at limited levels of interconnection. In general, about half of the efficiency that would be achieved through full integration can be obtained when interconnection capacity is limited to 5 percent of the smaller country's consumption.
- Second, efficiencies arising from market integration increase with the capacity of renewables. If renewable-electricity generation capacities are doubled from current levels, the benefits of integrating countries increase disproportionally.
- Third, distant countries with high shares of uncorrelated renewables benefit most

Figure 8: Energy supply for the two countries, with optimisation and varying levels of trade



Source: Bruegel.

from market integration. Hence, limiting market integration to regions with similar renewables production patterns potentially means missing out on substantial trading benefits.

- Fourth, we note that there are important redistributive effects when power-plant fleets are jointly optimised. Electricity prices decline much more strongly than system costs when markets become integrated, indicating a shift from producer to consumer surplus in the two cases we analysed. Obviously, joint optimisation implies that at least some consumers in one country occasionally have to rely on production in the other country. Also, power-plant fleet re-optimisation does not only imply a reduction in total capacity, but also a shift in technologies and location of the plants, which in the real world are likely to belong to different owners. We demonstrate that these effects are complex, depending, for example, on the level of integration of the different technologies chosen.

2.4 Bottom-up quantification

In this section, we evaluate empirically the benefits of a truly European electricity market. The electricity sector's annual turnover of €420 billion represents more than 3 percent of European GDP[20]. Correspondingly, small efficiency gains in the electricity sector represent significant absolute efficiencies.

Extrapolating the efficiencies identified in the literature survey to the EU27 market would correspond to €11 billion of payroll cost savings[21] and to €289 million per year of balancing cost savings (corresponding to a 10 percent total interconnection capacity)[22]. In addition, the literature on full market integration shows that promising results can be secured when moving from a national towards a full-integration scenario; simple extrapolation of these results to the EU27 level gives a reduction in the total system cost of €6 billion[23]. Deregulating and consolidating electricity markets in the US led to an increase in nuclear operating efficiency; the corresponding value for the EU would be €2.35 billion annually[24]. Market reforms in the electricity sector have been shown to be successful in reducing minute reserve power prices and leading to substantial cost savings for the transmission system operators (TSOs); the estimated effect on Europe amounts to €4.7 billion annual cost savings in the MRP markets[25].

20. The turnover is calculated based on 3086 TWh net electricity generation times an average final sales price of €0.136 /kWh divided by EU GDP of €12,900 billion (all data from Eurostat for 2012).
21. Eurostat reports data on average personnel cost only. Personnel costs are the total remuneration payable by an employer to an employee for work carried out. This is divided by the number of employees (paid workers), which includes part-time workers, seasonal workers, etc, but excludes persons on long-term leave. As we are interested in total payroll costs, we multiplied €43,000 (average personnel cost) times the 800,000 employees in the sector (source Eurelectric) and obtain €34 billion (payroll cost in electricity generation in the EU in 2012); 32 percent – the efficiency gain identified by Shanefelter (2008) – of this is €11 billion.
22. Abbasy *et al* (2009) estimate €80 million balancing cost savings per year (corresponding to a 10 percent total interconnection capacity) for the Netherlands, Nordic Region and Germany. As these countries jointly represent 27.7 percent of total EU gross electricity generation, the corresponding effect on EU27 would be €289 million balancing cost savings.
23. Gerbauleta (2012) estimate a total system cost reduction of €10 million per month, and a re-dispatch cost decrease of €0.2 million/month. The study focuses on the region including Germany, Austria and Switzerland, which jointly represent 20.6 percent of total gross electricity generation; the corresponding effect on the EU27 would therefore amount respectively to €48 million and €0.97 million in total and re-dispatch cost savings.
24. Davis and Wofram (2012) estimate the value of this increased efficiency at approximately $2.5 billion annually in the US nuclear power market (in 2012, €1.95 billion). The most recent data on nuclear power plants in Europe and the US report an installed electric net capacity of 122 GWe and 101 GWe respectively (http://www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-world-wide.htm and http://www.euronuclear.org/info/encyclopedia/n/nuclear-power-plant-europe.htm). Therefore the effect scaled up to EU level would be €2.35 billion.
25. Haucap *et al* (2012) estimate €1950 million and €1400 million cost savings respectively for incremental and decremental MRP in Germany's market for 46 months. As Germany represents 18.6 percent of the total gross electricity generation, the corresponding effect on the EU27 would be €4.7 billion cost savings per year.

Evidence suggests that adopting an organised market design in the US produced efficiency gains – efficiency improvements in Europe on a similar scale would amount to about €700 million annually[26].

All reported values for extrapolations to the EU level are purely indicative, because the conditions are entirely different for the individual empirical cases and for the EU as a whole. Furthermore, some of the benefits might overlap and other potential benefits are not considered. Consequently we refrain from providing an estimated total for potential efficiencies.

Another way to approach the benefits of integration is to analyse market participants' willingness to pay for cross-border lines. Suppose there are two geographical areas, and each generates electricity up to a certain quantity. With a perfect connection between the two areas, market forces would drive the price to the same level. Instead, if there is limited interconnection capacity, the prices in the two areas will in general be different. Thus, TSOs can extract a rent by exploiting the price difference between two areas, selling interconnection capacity through auctions.

Europe is characterised by a multiplicity of electricity price areas and by an imperfect interconnection between them. It is therefore possible for TSOs to collect congestion rents. More than €1.6 billion in congestion rents was obtained by TSOs in Europe in the period 2006-2009 (Supponen, 2012).

CASC (Capacity Allocating Service Company, www.casc.eu) is the central auction office for cross-border transmission capacity, and runs yearly, monthly and daily auctions, coordinating TSOs in 10 European countries.

Figures 9 and 10 report the values of the transactions (allocated capacity x price) of the yearly and monthly[27] auctions[28]. Compared to 2012, 2013 saw an overall increase in the value of the transactions. While in 2012 the value of transactions in CASC

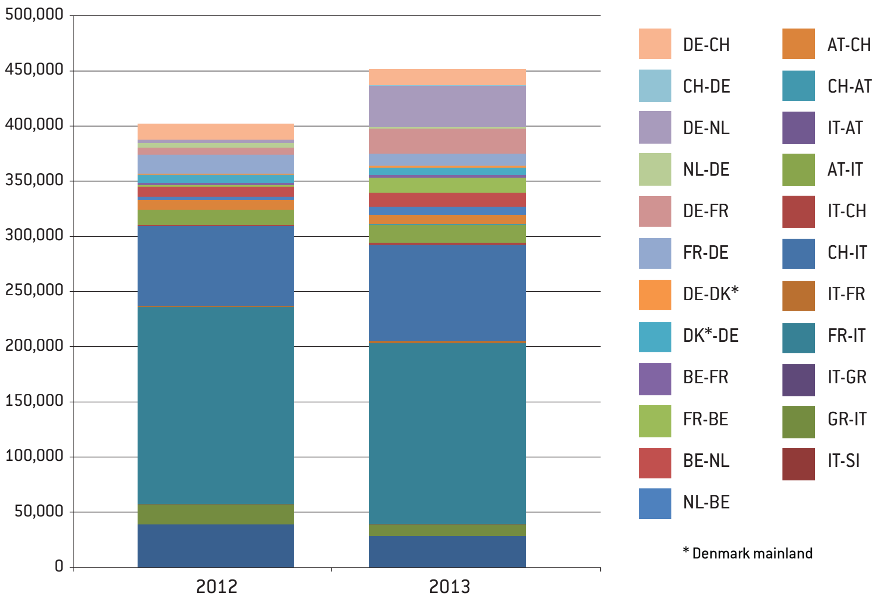
26. Mansur and White (2012) show that an organised market design resulted in increased efficiency gains of $163 billion in an eastern US region that switched from a bilateral to an auction market design. The electricity market in question, PJM Interconnection, as of summer 2009, had installed generating capacity of 167,326 megawatts, which amounts to 19.7 percent of the EU27 total electricity installed capacity. Therefore, scaling to the European case, the efficiency gains from trade would amount to €690 million.
27. Complete data for monthly auctions spans the period April 2011 to April 2013, since some countries joined CASC in 2011.
28. It should be noted that the data analysed here only includes yearly and monthly auctions. Daily auctions are not included.

countries was about €750 million, the first four months of 2013 indicate an annual value of more than €900 million.

Most of this stems from the auction of annual transmission capacity usage rights. Traders valued the right to use the interconnectors in 2013 by more than 10 percent more than in 2012, with an increase in the corresponding auction revenue from €400 million to €450 million.

Countries in northern-central Europe led this growth[29]: the value of the transactions, in fact, almost doubled for them. This increase in value was largely due to an increase in prices; the auctioned interconnection capacity only grew by about 2.5 percent. This increased willingness to pay for interconnection indicates an increasing demand for transmission lines.

Figure 9: Results of annual interconnector auctions in € thousands

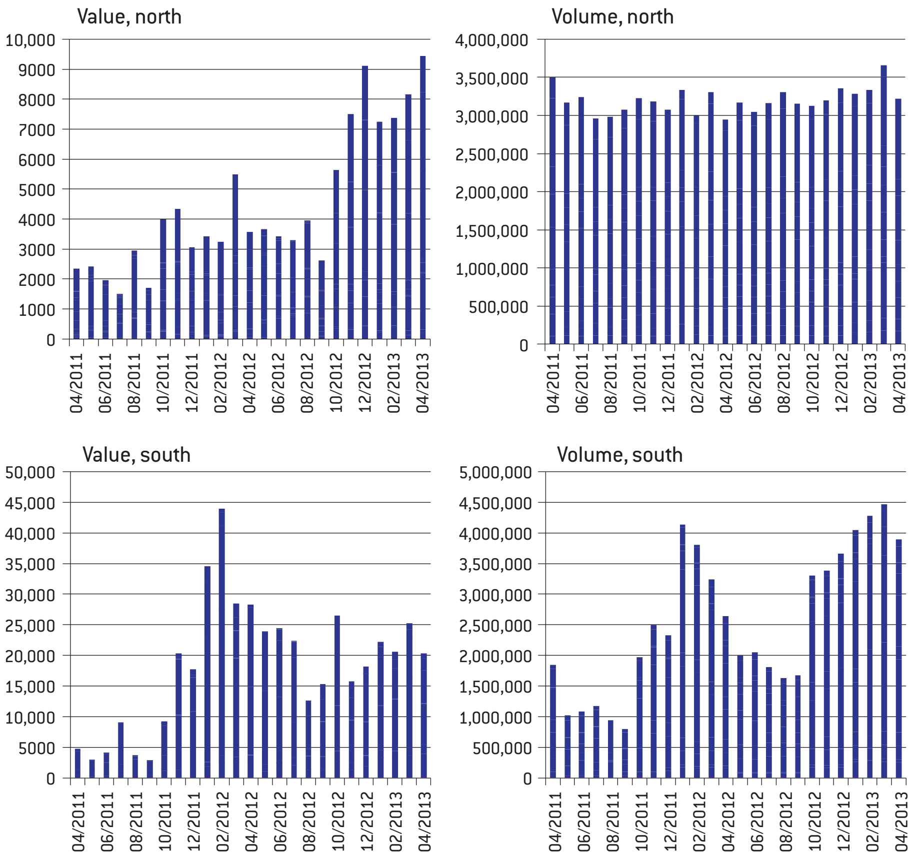


Source: CASC.

29. Countries in central-north Europe show an increase in the transacted value starting from the final quarter of 2012. There is some degree of seasonality in the monthly transacted value, especially for the Belgium-to-Netherlands connection, which is more active during the summer months, and the Germany-to-Switzerland connection, more active during winter. This seasonality of the transacted value is probably because of seasonal variations in prices in the two price areas.

In southern European countries, meanwhile, the picture is more stable: the value of the transactions fell by 4 percent in 2013 compared to 2012, and the interconnection capacity sold was essentially the same (+0.6 percent) – reflecting a recession-induced reduction in electricity consumption.

Figure 10: Results of monthly interconnector auctions in € thousands



Source: CASC. Note: 'North' refers to interconnector auctions between Germany and Switzerland, the Netherlands, France and Denmark; and between Belgium, France and the Netherlands; 'south', refers to interconnector auctions between Austria, Swizerland and Italy; and between Italy, France, Greece and Slovenia.

The total value of interconnector usage could also serve as an upper bound for the economic value of doubling the interconnector capacity. At a 10 percent interest rate, merchant investors would be unwilling to spend more than €9 billion (10 x €900 million, ie the estimated value of transactions in CASC countries in 2013) on doubling the capacity of the cross-border lines under consideration[30].

BOX 1: DOES INTEGRATION REDUCE PRICES?[31]

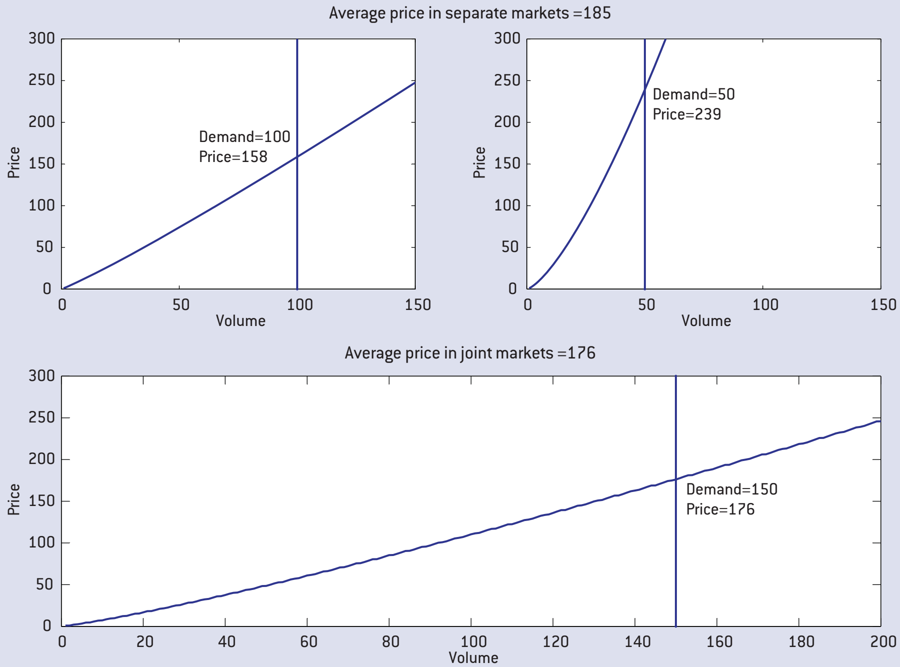
Market coupling is one of the key policies for achieving the EU single electricity market. The European Commission Internal Market Communication praises the price-reducing effects of market integration: *"Market opening, increased cross-border trade and market integration, and stronger competition E are keeping energy prices in check"* (European Commission, 2012, p4).

Common sense would indeed suggest that in competitive markets the average price of two market zones will be equal or lower when they are coupled than when they are separate. In fact, coupling should lead to lower average prices for typical electricity markets (increasing marginal cost on the supply side and price-inelastic demand). The intuitive reason is that the most expensive MWh in the expensive country might be replaced by switching on one additional MWh in the cheaper country. As the marginal cost increases, the switched-off MWh will be disproportionally more expensive than the switched on MWh. In our example (Figure 11), in the first market 10 MWh with a marginal cost of €158-€176 is switched on while 10 MWh with a marginal cost of €176-€239 is switched off. Thus average prices decrease from €185 to €176 per MWh.

When there are only few companies with market power, this effect is amplified by the increase in the number of players in the joint market. The increased competition in the joint setting will drive down prices compared to the separate market setting. In our example (Figure 12) coupling two monopolistic markets (with similar cost curves) to one duopolistic market drives down the average price by 7 percent.

30. Typically, investors would be willing to spend much less as the price differentials between countries – and consequently the arbitrage value of the lines – decreases with increasing interconnector capacity.
31. This box draws to a great extent on Zachmann (2012).

Figure 11: Market coupling with well-behaving cost functions under perfect competition

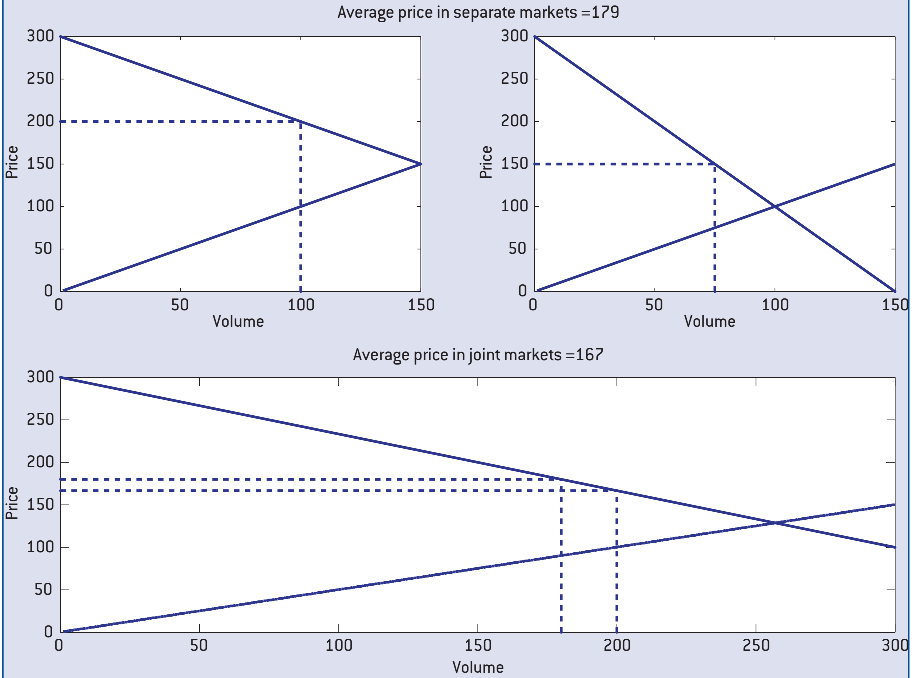


Market 1:
Marginal Cost = Volume$^{(1.1)}$
Demand = 100

Market 2:
Marginal Cost = Volume$^{(1.4)}$
Demand = 50

Source: Bruegel.

Figure 12: Market coupling with well-behaving cost functions under imperfect competition



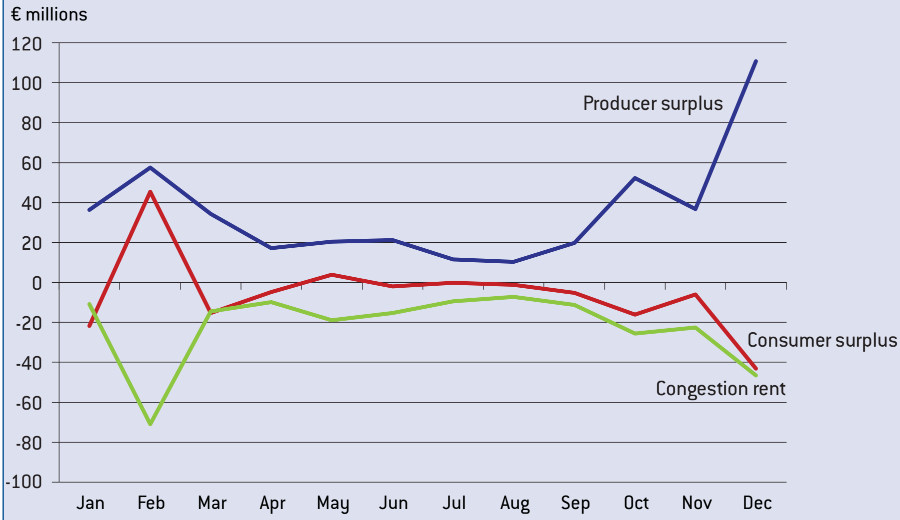
<u>Market 1</u>:
Cost = ½*Volume^2
Demand = 300-Volume

<u>Market 2</u>:
Cost = ½*Volume^2
Demand = 300-2xVolume

Source: Bruegel.

However, this ideal result does not hold in all real-world situations. In 2012, market coupling in central-western Europe caused average prices to rise. Higher prices and lower total generation costs increased producer surplus by €428 million, while the consumer surplus decreased by €67 million. After subtracting the reduction in congestion rent of €263 million, the net welfare effect was €98 million in 2012 – still significantly positive (Figure 13).

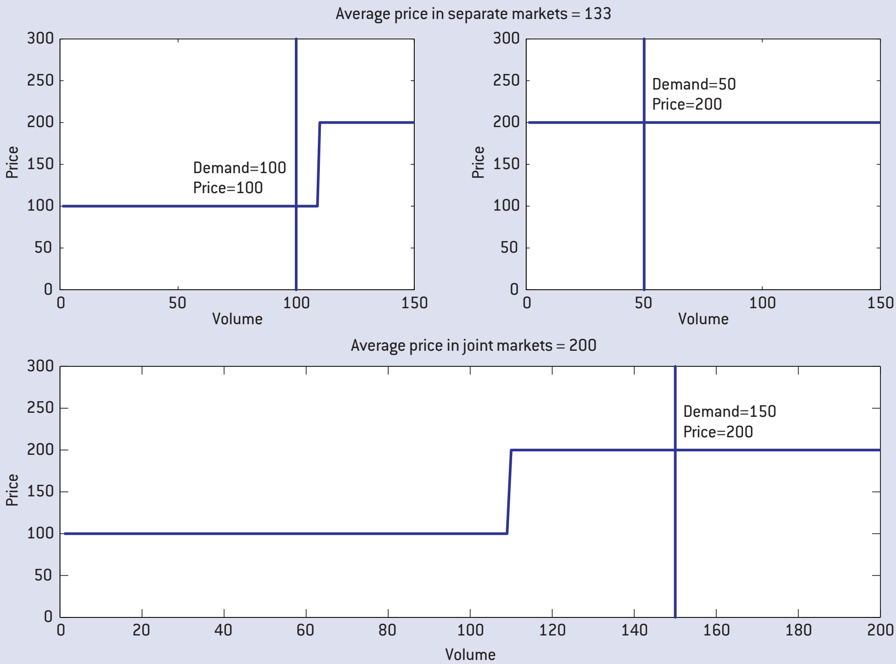
Figure 13: Producer and consumer surplus and congestion rent



Source: http://www.epexspot.com/de/Marktkopplung/dokumentation_cwe

But why can market coupling – counter intuitively – increase prices? One explanation is that the price might converge to a higher price when a low-price zone is forced to accept higher prices as a consequence of coupling (Figure 14). If, for example, the electricity price in Germany is set by coal-fired power plants (€50) and by nuclear plants in France (€0), coupling both markets might increase the price above the average of €25. This would, for example, happen if there was no additional nuclear plant in France available to meet high demand. In this situation all French and German nuclear and renewables capacity would run, but to meet the joint Franco-German demand some German coal plants would need to run as well, and these expensive units would set the joint price.

Figure 14: Market coupling with non-linear cost functions under perfect competition



Source: Bruegel.:

3 Why does the single market not self-organise?

There are four main reasons why public intervention is necessary to design an efficient European energy market:

First, the gas and electricity sector is confronted with the fact that one part of the value chain is a **natural monopoly** that requires public intervention to produce socially desirable results. Because the different parts of the energy value chain are firmly interlinked, network regulation strongly affects the generation, storage and consumption segments.

Second, the electricity sector is a very complex construct. The actions of individual market participants have significant **externalities** that affect all other participants. Because those externalities cannot be dealt with (internalised) by vertical integration, public intervention is necessary to achieve socially desirable sector structures.

Third, in the EU member states, very different market arrangements have emerged. Those arrangements are *a priori* largely **incompatible** across borders and trading thus requires interfaces. The complexity of interfaces designed to make different energy products seamlessly tradable between more than 30 incompatible markets is huge. The solution to this – harmonising rules – however, entails significant redistributive effects between market participants. Thus public intervention is required to strike stable arrangements.

And fourth, energy is a strongly **politicised** product in all countries. Consequently, self-organisation of cross-border markets is politically constrained.

The following sub-sections discuss these issues in more detail.

3.1 The network is a natural monopoly

Energy networks are natural monopolies. That is, building a second network to compete with an existing one would neither be beneficial from a company nor a societal perspective. Consequently, in all EU countries, electricity networks are regional monopolies. So that this market power is not abused, TSOs are not free to set network tariffs. In most EU countries, regulators try to ensure that the income of TSOs only slightly exceeds the operational and capital expenditure.

This tariff-setting power of regulators is also used to indirectly incentivise the natural monopoly to invest in innovation, quality improvements, cost reductions and line extensions. To deal with this complex question, very heterogeneous national regulatory arrangements have emerged. To isolate the natural monopoly from the competitive part of the sector, European legislation limits joint control over generation and transmission assets ('unbundling')[32].

3.2 System nature of the energy sector

Electricity systems are made up of a great variety of interlinked generation, transmission and storage assets. The assets are partly complementary (power plants need to be connected to transmission lines), and partly substitutes (a power plant supplying local demand might be replaced by a transmission line that brings electricity from elsewhere). Individual decisions have an impact on all other participants in the system (the 'system nature' of the electricity sector). The physical features of electricity require a high degree of interaction between all parts of the electricity-sector value chain. Changing one part of the system has immediate consequences for the entire system. Adding one transmission line might result in the overloading of another, and a new power plant might require network extensions hundreds of kilometres away. Networks cannot be evaluated in isolation: many benefits of network extension can be equally well or better secured by changes at other levels of the value chain. Better coordination, demand response, energy efficiency and generation management can relieve congestion, increase reliability and mitigate market power.

The fact that electricity networks have to be seen as a part of a system implies a chicken-and-egg problem for generation, storage, transmission and load investments. A generation investment might only make sense if it is properly integrated into the

32. Three admissible 'unbundling' regimes are defined in Directive 2009/72/EC.

transmission grid. However, as long as there is no generation, there is no need for investment in transmission.

Because of the European 'unbundling' requirements, the externalities we have described cannot be dealt with (internalised) by vertical integration. Thus, further public intervention is necessary to define the responsibilities of the different parties.

3.3 Incompatible sector arrangements and locked-in national interests

Investment in transmission would be a lot easier if all major stakeholders had the same preferences. However, investor interests diverge and partly conflict. Electricity generators in zones with low prices would like to be connected to higher-price zones in order to export. Such connections would also be appreciated by the consumers in the zones with high prices. Meanwhile, generators in high-price zones would prefer to prevent cheap imports, and consumers in low-price zones do not want to compete with other customers for low-price electricity. The picture is even more complicated in zones with different seasonal price patterns. For example, storage operators prefer connections to zones with high price volatility because this allows them to buy at low prices and sell high. Consumers residing close to the storage capacity, however, are not fond of 'importing' higher volatility through a new line connecting to a zone with extreme price volatility.

TSOs – the owners and operators of national transmission infrastructure[33] – also have complex preferences. They live from the regulated tariffs they charge to the users of their infrastructure. If regulators grant them the right to recover high rates of return on their transmission investments, they would prefer to overbuild the network ('gold plating'). Overbuilding the network means abundant capacity and peace of mind in terms of network operation. However, low regulated rates of return and the possibility to be reimbursed for costs resulting from managing an insufficient network might incentivise a TSO to delay investment. Additionally, TSOs might find that placing restrictions on cross-border flows is a cheap way to ensure national system security. Furthermore, if the TSO is still partly integrated with a generation company, the incentives for the generation side of the business (eg enabling exports, preventing imports) might spill-over to the preferences of the TSO (Supponen, 2011).

National energy regulators are typically biased towards short-term tariff reductions

33. Some TSOs operate in multiple countries (eg the Dutch TSO TenneT owns a central German TSO), others only in part of a country (eg the German TSO Amprion operates only in the western part of Germany).

(Meeus *et al*, 2006). Hence, they often prefer tariff reductions over investment in transmission. Their task is to maximise the welfare of national network users, and, as such, they have no incentive to consider the positive cross-border spillovers of their decisions. Regulators risk being captured by interest groups (eg generators in importing zones).

Another group of stakeholders[34] is local residents, who often dislike new transmission lines in their backyards. A study commissioned by the European Commission has identified local opposition as one of the main obstacles to transmission system investment[35].

Diverging stakeholder interests are amplified by the differing availability of information to different parties. The TSO has the best information on the cost of operating existing transmission lines and constructing new ones, while the generators/storage operators possess the best information on their own costs and extension plans. Consumers[36] have the best view of their future consumption. Stakeholders cannot rely on the information provided by other stakeholders because it might be distorted for strategic reasons. For example, a TSO might indicate that it will construct an additional cross-border line in order to discourage an investment in additional power plants in the high-price country. Hence the price differential persists and the TSO can maintain its congestion rent (the income from auctioning transmission capacity).

Market arrangements in different countries are largely determined by the pre-existing energy system. Because sector rules are typically designed to favour incumbents, reforms often reinforce the specialisation pattern of the physical electricity system For example, a country that features a dominant nuclear generator is likely to develop rules that favours sources that are complementary to nuclear (hydro-storage) and discourage sources that compete with it (lignite, variable renewables).

Consequently, EU member states have developed market designs that implicitly support their local producers, consumers and transmission companies. Because of the different starting points these systems have become largely incompatible between countries. Making even individual segments compatible is difficult because changing

34. The interests of other stakeholder groups such as traders and power exchanges are not discussed here, although their business models (providing a national trading platform, arbitraging price-differential) are not always helped by more transmission investment.
35. Roland Berger (2011b, p9): *"Project developers identify public opposition as a key problem"*.
36. This includes large industrial consumers as well as electricity suppliers that typically monitor the demand patterns of their final customers.

even seemingly minor aspects of the market design produces losers. One example is moving the gate closure – ie the time by which traders must notify the market operator of their supply and demand curves – forward to harmonise two systems and allow more information on renewables to be taken into account in the scheduling of conventional plants. This would leave less time for transmission system operators to optimise the dispatch and might reduce the need for balancing, and typical providers of balancing power (gas turbines) and transmission system operators might lose out.

3.4 National energy policies

Conflicting interests are not restricted to individual stakeholders. Countries also have different preferences. Low-cost producers such as Norway might, for industrial and social policy purposes, want to restrain energy exports in order to restrict prices, while other countries strive to increase their exports. Transit countries know that if they build too many transmission lines, the price differential between the country it imports from and the country to which it exports will decrease such that the total arbitrage rent (volume times buy price minus sell price) decreases. Thus, transit countries might want just enough international interconnection to maximise their rents. Due to the highly volatile national demand and supply position, the optimal transmission level for a country is difficult to establish analytically. Hence, national preferences with respect to individual projects are strongly driven by the advocating power of stakeholder groups.

On a political level, countries prefer to keep control of energy policy and are thus sceptical about increasing the levels of coordination and harmonisation. Therefore, they retain the operation and extension of the transmission system as an issue at national level. As a consequence, the rules for incentivising transmission investments are different in the different EU member states. National network extension plans are not regularly exchanged, and developments in the power plant fleet are not communicated to neighbouring TSOs. As a consequence, national energy strategies might be inconsistent – for example all Nordic countries plan to increase their energy exports – and internal network investments are ill-coordinated across borders.

4 Quantification of the infrastructure investment need

There are diverse motives for extending and reinforcing the transmission network. Additional power lines might help the integration of renewables and produce implicit environmental benefits by, for example, allowing well-connected wind-turbines to replace generation from polluting conventional power plants. Other reinforcements increase the reliability and operational flexibility of the transmission system or reduce congestion, dispatch costs and losses. Furthermore, network investment that allows more electricity to be transmitted to certain areas can substitute investment in generation or storage in import-constrained areas ('load pockets'). Finally, a substantial benefit of transmission reinforcement is its mitigating effect on local market power, exercised by generators in load pockets (Awad *et al*, 2006). The diversity of the motivations makes it difficult to establish the total investment needed for the most cost-effective network development. Thus, determining the optimal infrastructure need is a challenging exercise that crucially depends on a number of assumptions.

(1) The most important issue is to identify what should be optimised by the infrastructure investment. Possible objectives are minimising the short-term system cost, minimising congestion, minimising system losses, minimising electricity prices, maximising expected welfare in each member state individually, or maximising expected European welfare. Each objective would imply different 'optimal' network layouts, investment volumes and distribution of benefits between the affected stakeholders. For example, minimising the national system operation cost might lead to the overbuilding of domestic lines and a reduction in cross-border capacity. In a high-cost country this might benefit producers (which would have less competition from imports) to the detriment of consumers. By contrast, a strategy to maximise European welfare might strengthen cross-border links but might not entail connecting

certain remote uneconomic renewable sources. Choices about the objectives of network investment are thus highly political.

(2) The second important determinant of an optimal infrastructure is the development of energy demand in the coming decades, though it is difficult to make assumptions about this. The definition of the 'optimal network' might change significantly depending on the expected demand at a certain network point. If for example a large aluminium smelter (1000 MW) is established in the south of Germany instead of the north, an extension of electricity lines between the Czech Republic and southern Germany might become beneficial to accommodate the increased loop-flows.

(3) A third important decision is which technical approaches to consider when optimising the network investments. Excluding some options might lead to significantly higher deployment of higher-cost options. To give one example, if one does not allow for demand side management in network planning, the optimal transmission network will need to be significantly stronger. Consequently, optimising the system by only planning high-voltage cables is likely to be excessively expensive.

(4) A related element is the cost assumptions made about the different options. If, for example, only the cost of the physical hardware of high-voltage lines is taken into account, they will always appear the cheapest solution. However, if the costs of getting approval, buying rights of way, compensating residents and so on are also taken into account, the cost of a new transmission line might exceed the cost of strengthening existing corridors (eg through high temperature cables) or making changes to other parts of the value chain (eg curtailing exceptional wind peaks).

(5) A fifth determinant of which network investments are 'optimal' is the assumed market design. Research has shown that moving from the current sub-optimal market coupling of large national zones, to centrally optimising dispatch via nodal pricing (different prices at each node of the network depending on the physical network) can increase transmission capacity by up to 30 percent[37]. Hence, the optimal network extension under an advanced market design might differ greatly from the network that would be optimal if dispatch continues to be based on overlapping national and European rules and markets.

A number of studies have tried to estimate the need in terms of required finance and physical infrastructure need. The assumptions differ markedly and so do the results.

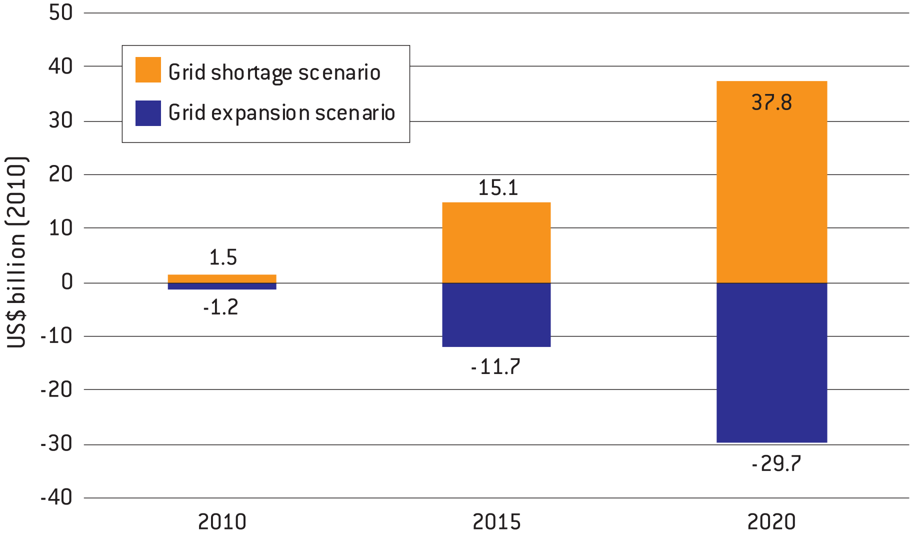
37. See Neuhoff (2011).

Roland Berger's report (2011a) analyses the EU's 2010-20 energy transmission investment needs. Their figures show that distribution and transmission together will require around €600 billion during 2010-20, of which approximately €200 billion will be devoted to improving transmission infrastructure. Most of this investment will involve electricity transmission (65 percent), while the remaining 35 percent will go to natural gas transmission. According to the European Commission, approximately 50 percent of the €200 billion of planned transmission investment is at risk of not being realised because of delays in permitting procedures and general difficulties in access to finance and lack of adequate risk-mitigation mechanisms. The same report also compares past and future planned TSO investments; the average annual TSO investment for electricity projects during 2005-09 was around €5.8 billion, while the forecast annual amount for 2010-20 is €9.8 billion, an increase of nearly 70 percent. Europe's electricity TSOs have pursued very different investment strategies in the past. During 2005-09, investment in energy transmission infrastructure was focused on western Europe (Austria, Belgium, Germany, France, Ireland, Luxembourg, the Netherlands and the UK), where the average annual investment amounted to €3.2 billion. This region also expects to see the largest relative increase during 2010-20 (+94 percent compared to the 2005-09 average annual investment amount).

The European Energy Infrastructure Priorities report (European Commission, 2010a) argues that, since the electricity sector is expected to face increasing demand in the future and since the electricity generation mix is changing, with less generation from fossil fuels and more electricity from renewable and variable energy sources, large-scale investments are needed at a level not seen in past decades. The study quantifies the infrastructure investment needs for electricity from 2011-20 as follows: €70 billion for transmission infrastructure, €32 billion for offshore grid infrastructure and €40 billion for smart grid infrastructure. As a result, the total investment need is €142 billion for electricity (while the total system costs are estimated to be about €1000 billion).

A 2013 OECD working paper (Benatia *et al*, 2013) compares two different grid development scenarios and shows that, in a grid expansion scenario, that is characterised by a 20 percent increase in transmission capacity, the cost of meeting renewables objectives would be almost $68 billion lower than under the grid shortage scenario (Figure 15). In addition, if domestic grids are well-reinforced, the average Effective Capacity Factor in the EU might strongly increase compared to both the baseline and the grid shortage scenario.

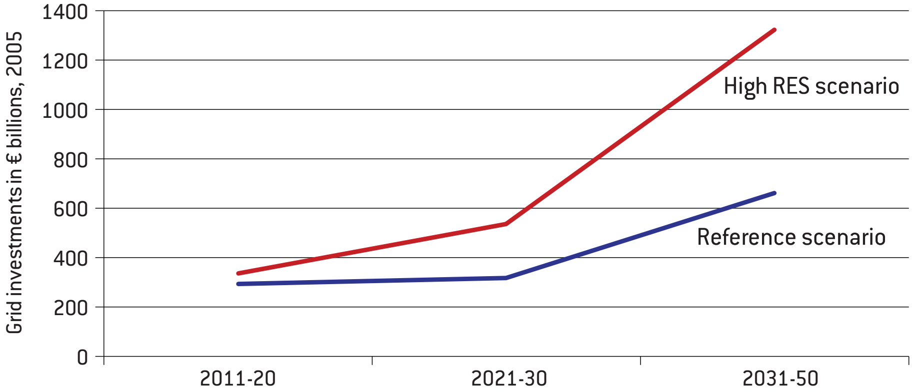
Figure 15: Additional investment in wind turbines required to reach the EU 2020 target



Source: Benatia *et al* (2013).

The European Commission's Energy Roadmap 2050 (European Commission, 2011a) also refers to several policy scenarios. The reference scenario yields the lowest investment requirements, while the traditional-technology scenarios converge to a slightly higher investment level both by 2030 and 2050. A clear-cut result is provided by the renewable scenario (with a 75 percent share of RES in final energy consumption), especially during the 2031-50 period. Indeed, infrastructure requirements reach €1323 billion (Figure 16). The 'High RES' scenario gives a total grid investment cost for 2011-50 of approximately €2195 billion, which implies an increase in infrastructure requirements of about 73 percent compared to the reference scenario.

Figure 16: The EU's grid investment needs

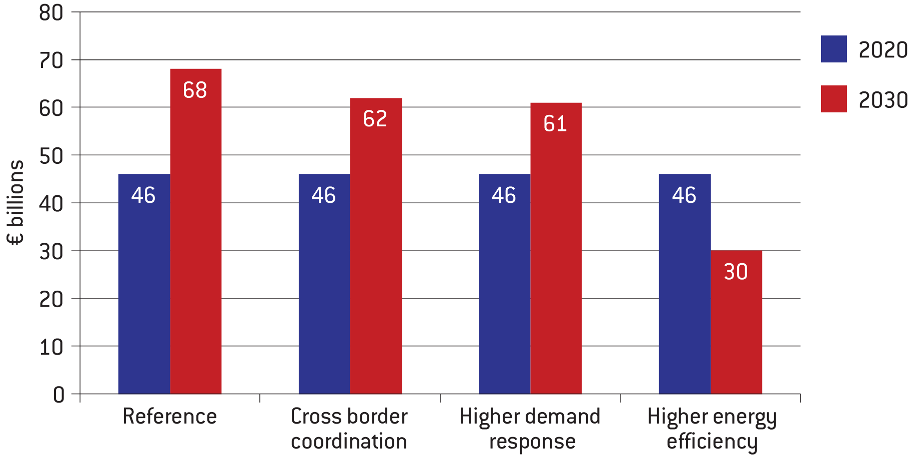


Source: European Commission (2011b).

The ENTSO-E Ten Year Network Development Plan 2012 (TYNDP, ENTSO-E, 2012) gives an overview of all grid development activities in the ENTSO-E region. The expected grid investment for all projects of pan-European significance in the next ten years varies by country, with Germany spending the most at €30.1 billion, according to the TYNDP. The total investment cost within the whole ENTSO-E perimeter is estimated to be around €104 billion (€23-28 billion during the period 2010-14, according to ENTSO-E TYNDP, 2010). Presently, the European transmission network consists of approximately 305,000 km of routes. Completing the projects of pan-European significance will lead to refurbishment of about 9,000 km of existing assets and building of 43,200 km of new assets in the long-term, increasing the total length of the network by 17 percent over the next ten years (of which 76 percent will be overhead, and 24 percent underground or subsea). It is estimated that moving from the currently limited Net Transfer Capacities (NTCs) to greater NTCs once projects of pan-European significance are implemented will alleviate total annual generation operational costs by about 5 percent. For the higher generation costs that can be expected by 2020, this represents about €5 billion.

The European Climate Foundation's (ECF) study (2011) shows that the share of transmission expansion investment in the overall energy system cost will be comparatively low during the next decade, ie €46 billion out of €2273 billion in 2020, and €68 billion out of €3277 billion in 2030 (Figure 17). The investment required for both generation and transmission are substantially reduced if there is cross-border coordination, higher demand response and greater energy efficiency. Transmission costs reduce by up to 56 percent, from €68 to €30 billion, with a high level of energy efficiency.

Figure 17: Transmission costs under different scenarios



Source: ECF (2011).

Rebours *et al* (2010) argue that an increase in cross-border capacity between France and its neighbours by 7 GW would have an annual cost of about €380 million and a benefit of €980 million – a net benefit of about €600 million. According to the authors, this corresponds to the optimal reinforcement, because only increasing the capacity by 5 GW would lead to benefits worth €200 million less, while increasing the capacity by 10 GW leads to costs that are more than €200 million higher.

Von Hirschhausen (2012) discusses various estimates of the investment need, finding both a high variance among estimates, and that the financing of generation investment is the real challenge. Von Hirschhausen (2012) argues that the issue is not over- or underinvestment in the European electricity sector as such, but that different development paths have different implications for generation and transmission infrastructure, and consequently for financing. In that context, a positive, differentiated analysis seems more appropriate than a normative request for more investment. Last but not least, the investment needs must be assessed in the light of the political and institutional scenario that is expected to occur. In a 'Europe centralised' scenario, there is ample room for pan-European electricity networks, which become less relevant in a 'national approaches' scenario. Furthermore, he argues that more complete consideration of 'transaction cost' would lead to significantly higher cost assumptions for networks.

To sum up, the definition of the optimal network depends strongly on the assumptions that are made. This is the main reason why different studies produce significantly diverging results on investment needs and the economic consequences of investment choices. This implies that the process used to reach a certain result is more important than the resulting outcome.

The Spanish example might serve as a cautionary tale. Between 2008 and 2010, Spanish spending on electricity transmission infrastructure increased by 18 percent to €865 million and even exceeded German spending in 2010. It is now becoming obvious that Spanish consumers must pay for a network that is excessive for their needs for the foreseeable future.

5 Evaluating the current approach to the internal market

There are two main building blocks for the internal market: the market design and the provisioning of physical infrastructure. In this section, we describe current and foreseen approaches to both and provide a critical evaluation with respect to the internal market.

5.1 Market design

Current approach

Electricity is not a simple product that is produced, exchanged and consumed. A number of factors must be taken into account in trading electricity. Key determinants of the value of the electricity service are (in simplified terms):

- **The volume of electricity:** This is the most straightforward component, typically measured in megawatt hours (MWh) at the wholesale level and kilowatt hours (kWh) at the retail level.
- **The location of delivery**: Like any product or service, electricity only has a value when delivered to the customer. Consequently, electricity is more expensive in countries in which it is more difficult to produce and cannot easily be imported. However, for administrative reasons, electricity has within most European countries (the Nordic countries and Italy being exemptions) the same price at the wholesale level at each location.
- **Speed of delivery**: Electricity travels at the speed of light. But, facilities to produce or consume it need time and sometimes fuel to ramp-up or ramp-down. Consequently, the more immediate the delivery requirement, the more expensive electricity typically is. To schedule deliveries using the latest

available information on likely demand and supply (eg from renewable sources), a sequence of markets is established: a long-term forward market for annual or monthly deliveries that typically covers the largest volumes; a day-ahead market that largely determines the scheduling of power plants with low variable costs and long ramping times (eg nuclear and lignite plants); an intraday market that responds to changes in supply and demand, leading to the rescheduling of power plants with short-to-medium ramping times (eg gas turbines); and a balancing market in which very short-term deviations from the initially-planned schedule are exchanged.

- **The ability to stabilise the system**: This entails (i) maintenance of the balance between generation and demand using turbine speed generators (Primary Control), (ii) maintenance of exchanges with other control areas at the programmed levels and returning the frequency to its set value in case of a major frequency deviation, thus restoring primary control reserve (Secondary Control), (iii) restoration of an adequate secondary control reserve (Tertiary Control), (iv) starting operating and delivering power without assistance from the electric system (Black-start Capability) and (v) injecting or withdrawing reactive power to keep system voltage within prescribed levels at specific nodes (Reactive Power). These five services are typically referred to as ancillary services.
- **The availability to meet demand (' supply adequacy')**: There is a value in being sure that electricity is delivered when needed. Such insurance can theoretically be provided by outbidding competing consumers for a given limited supply in the long-term markets. The resulting high prices would encourage the necessary investments and ensure supply adequacy. In markets with high regulatory risk and administrative barriers this mechanism might not provide the optimal level of supply[38]. Consequently, other mechanisms/markets to remunerate market participants for their contribution to supply adequacy are being considered/implemented in the EU and elsewhere.
- **The 'technology externality' of electricity**: Installing new technologies implies technological and organisational improvements. The initially high cost of deploying a not-fully mature technology can translate into valuable learning, both for technology providers and the entire system that has to accommodate new technology. This is relevant, for example, for the deployment of new renewable generation technologies, new storage technologies and smart grids.

38. There is a longstanding academic and political debate about the need for capacity mechanisms. See for example the public consultation on generation adequacy, capacity mechanisms and the internal market in electricity: http://ec.europa.eu/energy/gas_electricity/consultations/20130207_generation_adequacy_en.htm

- **The carbon content of electricity**: The CO2 emissions linked to power production are an externality that can be either dealt with by differently valuing 'dirty' electricity compared to 'clean' electricity, or by treating pollution directly (through taxes, pollution permits or regulation). As the EU has chosen to set up an emissions trading system that covers the power sector, the 'cleanness' of electricity is priced outside the electricity service.

The different parts of the electricity value chain produce and consume different combinations of these determinants. For example, nuclear power plants provide at their location capacity and reactive power and can hence either provide secondary reserve or produce electricity and reactive current on long or short notice (day ahead, intraday). To a limited degree, nuclear plants are also able to provide frequency and voltage control as well as balancing services. Wind turbines by contrast only provide stochastic capacity contributions. When the wind blows they will produce electricity and, if correspondingly equipped, reactive current and downward balancing.

For each of these elements, different remuneration schemes can be set up. Within EU member states, these schemes differ significantly. So far, only the market for emission allowances is completely harmonised in the EU. At the wholesale level, the value of a megawatt hour of electricity is determined in national markets that are internationally coupled by a seemingly stable but arguably inefficiently interface – market coupling. In the intraday, reserve and balancing segments that are essential for remunerating the speed of delivery, some countries rely on the system operators and some on bilateral trading, while others are about to introduce organised markets – but cross-border trading is still limited. The same holds true for 'ancillary services'. More complex market arrangements have emerged in some countries, but corresponding products are rarely sourced in neighbouring countries.

Finally, most countries do not have markets for 'technology externality', 'supply adequacy' and 'location', which implies that these determinants are at most implicitly exchanged across borders. These determinants are provided administratively in member states based on national preferences. For example, to remunerate the 'technology externality', each EU country has adopted a different set of policies, including green certificates, feed-in tariffs, obligations, direct subsidies, preferential grid access regulations and tax breaks. The actual size of the different support schemes for renewables is difficult to assess because they often mix fiscal (direct support), para-fiscal (for example compulsory apportionments collected by network operators) and non-fiscal (regulatory) instruments. The numbers that the European Commission's Directorate-General for Competition collects on state aid for environmental protection hint at large divergences in the structure and size of support provided to renewables by different EU countries. In 2009, such state aid amounted to 1.1 percent of GDP on average in the EU. But it was 2.4 percent of GDP in Germany and only 0.12 percent of GDP in Italy. Such differences are economically inefficient because they lead to different prices for the same product (electricity produced from renewable sources) within the EU[39]. Thus, the European Commission has been pushing for transferability of renewable energy achievements. Such transferability – for example through an obligation for any member-state's support scheme to accept foreign 'green' electricity – should quickly lead to the harmonisation of support schemes and prices for renewable energy, and a single market for electricity generated from renewable sources. However, the Commission has so far failed to push through plans to achieve such transferability – because the fragmentation of Europe's renewables market reflects the political preferences of EU member states. Countries would rather reduce their dependence on imported energy and support their home-grown renewables industries than subsidise renewable energy production in another member state.

Between 2005 and 2010 Germany deployed about 9 gigawatts (GW) of wind turbines and 14 GW of solar panels, amounting to about 18 percent of total installed electricity generation capacity. The success of renewable energy support schemes will create new challenges for other parts of the electricity sector. The observed wind energy forecast errors for Germany in 2012, for example, imply that sometimes up to 6000 MW of additional capacities have to be switched on in the intraday market while at other times up to 10,000 MW have to be switched off (Figure 18). In 2012, in more than 1000 hours, more than 2000 MW needed to be switched on, and in more than 400 hours, more than 2000 MW needed to be switched off. This implies an increasing need for adequately remunerating intra-day deliveries, balancing, 'location' and ancillary services.

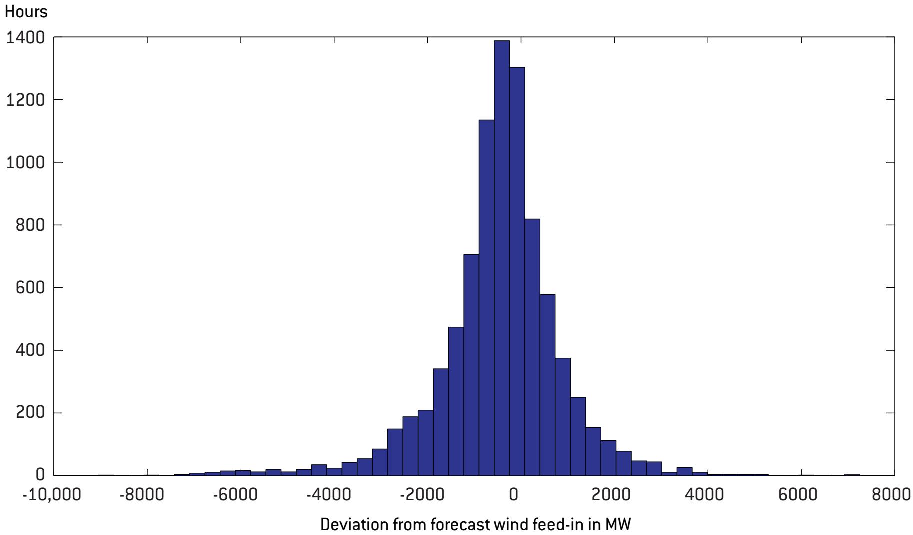
In the long-term, 'supply adequacy' might be one of the most serious elements. The EU is on course to meet its 2020 renewables target and it is now discussing renewables targets for 2030. By 2050, Europeans hope to get all their power from renewable or carbon-free sources. This transition will change the nature of the power sector. Unlike

39. A European market for renewables deployment could make significantly better use of natural resources. For example, if the 32.3 GW of subsidised German solar power had been installed in Greece, the value of the additional electricity generated because of the 50 percent higher level of sunshine would have been around €600 million in 2013 (Greece has an annual solar return of about 1500 kWh/kWp while Germany only has 1000 kWh/kWp and the baseload electricity price in Germany is currently about €38/MWh).

fossil fuels, the input (or variable) costs of wind and solar power are zero. That means that wind and solar power installations typically run irrespective of the electricity price. As the penetration of renewables in EU power markets increases, conventional power plants are often idle, and median wholesale electricity prices drop. Yet some conventional plants are still needed when a cloudy, low-wind period coincides with high electricity demand. However, in the current system, coal and gas-fired plants will close unless they can recover their fixed costs by charging very high prices in the few hours they are needed. To date there is no consensus on whether such a system of highly volatile prices (very low prices when renewables are sufficient to meet demand and very high prices if they are not) is politically sustainable and sufficient to incentivise the provision of back-up capacity needed to run the system securely. Member states are thus contemplating alternative mechanisms to make it worthwhile for power companies to provide back-up capacity. Discussions at the time of writing indicate that such incentives are likely to be non-market based[40] and will vary from one country to another.

40. The strategic reserve discussed in Germany, for example, foresees that a small number of plants that fulfil the selection criteria can bid to become reserve providers (see BDEW, 2013).

Figure 18: Day-ahead wind forecast errors in Germany in 2012 in MW



Source: Bruegel based on TenneT, Amprion, 50Hertz and TransnetBW

Performance

The integration of west-European day-ahead electricity wholesale markets has been the biggest success so far of the single energy market policy. Already the possibility to reserve transmission capacities through auctions has allowed better cross-border trade leading to partial price convergence between countries[41] (Zachmann, 2008). The market coupling introduced between Belgium, France and the Netherlands in 2006; Belgium, France, the Netherlands, Germany and Luxembourg in 2010; Italy and Slovenia in 2011; and some direct current links (Germany-Sweden, Norway-Netherlands, Poland and Sweden) have substantially reduced price discrepancies between countries. For example, the frequency of hours with identical wholesale prices on both sides of the German-Dutch border increased from 12 percent in 2010 to 87 percent in 2011, when coupling was introduced[42].

For other market segments, performance depends on the region-specific arrangements. Cross-border balancing and intraday markets have worked quite well in the

41. 59 percent of the studied hourly pairs of national wholesale electricity prices in 2002-06 converged.
42. ACER Press Release (ACER- PR-02-12) (CEER- PR-07-12).

Nordic countries since 1999. Cross-border exchanges are significant and the market is liquid even though it only corresponds to one percent of the turnover of the day-ahead market. The system began trading activities in Germany in 2006-07. A joint intraday market was launched by the Dutch, Belgian and Nordic power exchange in 2012, but volumes are still very small. In other regions, for example between Poland and Germany, no structured cross-border trade is possible in the intraday market.

The value of location of electricity deliveries is largely remunerated in the day-ahead and the intraday/balancing market in the Nordic countries. There, bringing electricity to supply-constrained parts of the country is providing higher revenues. For example, in April 2013, bringing electricity from central Sweden (€43.91 /MWh) to the connected Norwegian region of Trondheim (€46.37 /MWh) was about 5 percent more beneficial than bringing it to the likewise connected Norwegian region of Tromso (€44.48 /MWh). In the highly meshed continental European grid, such intra-country differentiation of electricity prices is not employed. Hence, bringing additional electricity to north Germany – where it is often excessively available due to the concentration of wind power in this region – has the same value as bringing it to south Germany, where it is scarce when the sun does not shine on the Bavarian solar panels.

Finally, ancillary services, 'greenness' and adequacy/capacity are currently not traded across borders. Table 12 shows that the parts of the electricity sector that are currently becoming more important are not internationally exchanged. Moreover, the economic benefits of a European market for these parts of the sector are particularly significant. Consequently, the cost of 'non-Europe' is increasing.

Table 12: Determinants of the value of the electricity service and how its allocation is organised

	Nationally administered provision	Purely National market arrangement	National market arrangement with an interface for imports/exports	European market	Expected change in Importance
Frequency and voltage control					+
Other Ancillary services[43]					
Balancing			Nordic+		+
Intraday delivery of electricity			Nordic+		+
Day-ahead and term delivery of electricity					-
Supply Adequacy					+
Location			Nordic		+
'Greenness'		Quotas			+
Emissions				ETS	

Source: Bruegel. Note: shaded cells indicate how allocation of the service is typically organised.

Furthermore, the different elements of the electricity supply system obviously interact. For example, (i) a country with a market for supply adequacy will typically see lower prices during hours with extremely high demand than a country without such a market – as the peak capacity in the first case is already remunerated through the capacity mechanism, (2) if international intraday trading is not possible because interconnectors cannot be nominated within the day, patterns of international day-ahead trading change, (3) if renewables are supported with feed-in tariffs negative wholesale day-ahead market prices might appear and (4) if providing electricity to a specific location where supply is constrained is not remunerated by the market, other administrative instruments to ensure adequate supply need to be devised.

43. Such as Transmission Must Run Service, Load Shed Scheme Service and Black Start Service.

Consequently, even if some parts of the market design are harmonised across borders, one cannot speak of a functioning single market for this, because inconsistencies in the trading of other aspects are spilling-over to the harmonised segment.

Ongoing progress

Inconsistencies in the design of national markets have been acknowledged at the European level. The European Commission has concluded that more top-down guidance in the form of a 'Target Model' is desirable. In 2009, European regulators and stakeholders finalised the Target Model. The preparation of framework guidelines (and eventually 'network codes', that deal with technical issues such as the allocation of cross-border transmission capacity or the requirements for generators) based on the Target Model started in early 2010. In simple terms, the process foresees that the Agency for the Coordination of European Regulators will develop four framework guidelines on capacity allocation and congestion management, network connection, system operation and balancing. Based on these, the European Network of Transmission System Operators will develop European network codes. These European codes should cover all provisions that are relevant for cross-border trade. After these codes are (possibly amended and) approved by the regulator, they will become binding. The current draft codes, at time of writing, indicate that they are in fact guidelines with a lot of flexibility on how they are transposed into the individual member states network codes. For example, Article 24 of the draft network code on capacity allocation and congestion management allows member states to maintain the current model of capacity calculation based on a simplified representation of the network, or to move to a model based on the true physical representation.

BOX 2: NATIONAL NETWORK OPERATION IN A SINGLE MARKET[44]

The operation of national or sub-national electricity networks has significant spillover effects onto neighbouring systems. These interdependencies were highlighted by the 2006 blackout in Germany that spilled over as far as the Iberian Peninsula, and by the 2003 blackout in Italy caused by a failure in Switzerland. The tedious searches for the parties responsible for these major incidents are a clear indication of the complexity of the electricity system and its governance.

Different TSOs have drawn different conclusions from the blackouts and the increasing injection of only partly predictable wind and solar power: (1) the Dutch TenneT and the Belgian ELIA tried to improve their capability to deal with cross-border events by merging with German TSOs, (2) several TSOs are installing devices to limit cross-border flows, in order to retain control of their domestic systems[45], (3) groups of TSOs established two regional centres for coordinating electricity system operation. Nevertheless, all systems are still operated nationally and collaboration is limited to ad-hoc initiatives. To prevent black-outs, the inadequacy of the cooperation arrangements for managing the real-time electricity system are currently dealt with by imposing high security margins and by accepting inefficient nationally-focused operational decisions. This ultimately has an impact on the demand for transmission assets (for example, more phase-shifting transformers and fewer cross-border lines).

In addition to this European harmonisation of the network codes, some countries are improving their cooperation on issues such as system operation or day-ahead and intraday market coupling.

In terms of market coupling, for example, the stakeholders in central western European countries are working to introduce 'flow-based market coupling' an algorithm that should allow optimal day-ahead and intraday trading of electricity between countries, given the real physical constraints of the network. Furthermore, initiatives are in place to extend market coupling to an increasing number of countries, eg coupling the Nordic and the central-western region, and coupling the Visegrad4 countries (Czech Republic,

44. This box draws to a great extent on Zachmann (2013, p5).
45. The Netherlands and Belgium have installed phaseshifting transformers that allow the loading of individual transmission lines to be controlled. The transformers can be used to avoid system-destabilising inflows of electricity from Germany (caused by unexpected wind-injections). Poland is also considering this.

Hungary, Poland and Slovakia). Finally, closer cooperation on system operation is institutionalised in regional centres such as Coreso and the TSO Security Cooperation[46].

Shortcomings

The envisaged changes, at the time of writing, to the market framework are insufficient for establishing the internal energy market[47].

First, the harmonisation of rules relevant for cross-border trade is organised as a bottom-up agreement between system operators based on general framework guidelines. These rules will be codified in the form of twelve network codes. Due to the complexity of the electricity sector and the widely differing preferences of stakeholders, a compromise risks providing no more than fairly general direction. In addition, the short timeframe for drafting the network codes – only 12 months were foreseen for completion of the process in time for the 2014 deadline – could give undue influence to the TSOs that have a significant information advantage on to technical issues, and which are responsible for drafting the codes. It is, for example, conceivable that TSOs will shift costly responsibilities for system stability onto network users. The tight political deadline might force ACER and the European institutions (Council, Parliament and Commission), that have to adopt the codes through comitology, to favour speed over thoroughness. Only when the network codes are implemented will we learn how differently they might be interpreted[48]. Consequently, this approach might lead to a wide range of rules in the participating national systems, which is unlikely to bring about workable interfaces at all borders for all dimensions of electricity trade.

Second, network congestion within countries will be dealt with differently from network congestion between countries. This discrimination is necessary to be able to consider countries as single price zones. For example, the price of electricity in the port city Hamburg is the same as in Freiburg in southern Germany even when the 600km transmission line between both cities is congested because of an abundance of power from coastal wind turbines. At the same time, the price in Freiburg might be different from the price in Colmar, 30 kilometres away in France, even when the transmission line between Freiburg and Colmar is not congested. Such a disregard of physical infrastructure, implied by the imposition of country-based price zones, induces an

46. Five major TSOs set up Coreso, a Regional Coordination Service Centre in 2008 in central-western Europe, and eleven TSOs set up the 'TSO Security Cooperation' in central eastern Europe.
47. This section draws to a great extent on Zachmann (2013, p6).
48. See the summary of the public consultation on the network codes in European Commission (2013).

overly conservative calculation of cross-border transmission capacities. The end result is higher-than necessary price differentials between the zones/countries. In addition, planned technical improvements to the existing scheme (NTC-based market coupling) towards a more advanced scheme that takes the physical network better into account (flow-based market coupling) as well as the extension of market coupling to other countries is facing technical difficulties. Market coupling is a system that in principle would ensure that price differentials between countries only arise when no additional transmission capacity can be made available. Already in 2012 the deadline for the start of the arguably more advanced 'flow-based market coupling' in the central-western region (Austria, Benelux, France) had to be postponed from September 2012 to November 2013 at the earliest[49]. Now, the coupling of the Nordic markets with the central-western markets has also been delayed from the beginning of 2013 to November 2013[50].

Third, a more general point: according to the target model, the single electricity market will only provide harmonised signals for the operation of existing assets (including generation, transmission, storage and demand-side response). National markets/regulations will remain pivotal for investment in new assets. Nationally implemented markets for capacity and ancillary services favour the construction of certain technologies in certain countries. In 2012, about 70 percent of newly installed power plants in the EU were renewables (EWEA, 2013). These plants are largely built based on national support schemes and are thus exempted from the single electricity market. If the share of nationally organised electricity sector segments (renewables, capacity mechanisms, ancillary services) continues to increase at the current pace, a 'deep single market' that also drives optimal investment decisions will be unachievable.

Consequently, the target model – even if fully implemented – is unlikely to deliver a fully-fledged single market in which it is irrelevant for the remuneration of a supplier whether it is sited in the same or a different country to its customer.

5.2 Funding, financing and planning of infrastructure

The establishment of sufficient energy infrastructure is the second part of the EU's vision for a single energy market. The Commission has estimated that €142 billion will have to be spent on electricity grids up to 2020. Transmission investment in Europe

49. http://www.epexspot.com/de/presse/news-archive/details/news/CWE_Flow_Based_Market_Coupling_Go_Live_target_date_has_been_shifted
50. http://www.bloomberg.com/news/2013-02-18/northwest-european-power-market-coupling-delayed-to-november.html

need to increase for three reasons: First, investment has dropped to a historic low in the past decade, resulting in some modernisation backlog (see section 4). Second, the massive deployment of renewables will require additional investment in order to adapt the network to the changing location of electricity generation, and to allow for the wide geographic averaging of electricity injections from intermittent sources. And third, in order to develop the single market, sufficient electricity flows across borders need to be enabled.

5.2.1 Current approach

Funding

Most energy infrastructure in Europe is provided at member state level and funded through a 'regulated asset base' model. To incentivise a TSO to construct new transmission infrastructure, the regulator allows the TSO to include all new assets in the regulated asset base if they were part of the investment plan approved by the regulator. The regulator's approval is based on a more-or-less sophisticated cost-benefit analysis[51]. When the approved project is finalised, its capital cost becomes part of the regulated asset base. The TSO can now pass on the higher cost to the network customers. In short, a national regulator approves – based on the welfare of national network users – the investment plan of a national TSO that is then allowed to claim back the capital cost from national network users[52].

For some cross-border projects – such as the sea cables between Norway and the Netherlands – a second funding scheme has been tested. Investors might seek the right to use a transmission line exclusively for some time. They then can earn money by selling line capacity to traders or by using it themselves to transport electricity from a low-price area to a high-price area. This is known as the merchant interconnector approach. This approach suffers from the drawback that the optimal investment for an individual company is less than the socially optimal investment – if the inter-connector is too big, the price difference between the zones collapses and there is no more money to be made through arbitrage. Hence, profit-maximising merchant investors have systematically under-built network extensions. Furthermore, such an approach is not well suited for complex networks.

51. Regulators or governments need to approve all investment projects before they are allowed to be financed via tariffs.
52. In addition, single-purpose lines to connect new users are often funded by the new generation, storage or consumption unit that required the connection.

A third approach has been to contribute public money to politically selected transmission projects. The EU has for example allocated funds for lines with cross-border effects in the framework of the Trans-European Networks for Energy (TEN-E, see discussion under 'Policy performance' in section 5.2.2) and the European Energy Programme for Recovery.

National planning

Currently, network extension in most EU countries is based on decentralised planning. TSOs forecast future power plant fleets and electricity demand in their areas. They deduce from these forecasts the likely need for new lines. National TSOs differ in the degree to which they coordinate with power plant and storage facility investors, administration, regulators, consumers and foreign TSOs. The TSOs will thereby propose projects that are commercially viable for them. For a TSO, a line is viable when it reduces those costs that a TSO is not allowed to fully charge to the customers[53]. Thus, a TSO might be inclined to propose even overly-expensive lines that slightly reduce the TSO's re-dispatch costs as long as the regulator accepts that the TSO can include the investment cost in the regulated asset base. In contrast, a TSO might not be interested in closing a minor gap that prevents substantial increases in international electricity trade when this would result in higher re-dispatch costs. Thus TSOs do not necessarily have an incentive to propose the most cost-effective line. Nevertheless, they are the only body carrying out the planning in all European countries, because no other institution has sufficient technical expertise for this complex task. The regulators largely rely on the information provided by the TSOs when they assess the economics of the individual projects the TSO has proposed. Furthermore, even policy makers and regional authorities typically only consider the projects proposed by the TSOs when deciding on corridors or public co-funding.

European planning

Until 2010, transmission planning was in general an exercise conducted at the level of member states (or transmission zones). Projects with cross-border impacts were of course discussed and adjusted by TSOs, but no joint planning of the networks was carried out. Since 2010 a formal procedure has been put in place to structure these

53. The cost a TSO is allowed to recover from consumers through tariffs differs from country to country and is variable over time. Consequently, starting with the same physical bottleneck, in one country the local TSO might have an incentive to upgrade an existing line, in another the local TSO might prefer to carry out more redispatch, and in a third country it might be most profitable for the local TSO to invest in smart grid solutions. For a discussion on network investment incentives in Europe see von Hirschhausen *et al* (2012).

interactions. TSOs now have to share some of this information with the European Network of Transmission System Operators for Electricity (ENTSO-E) which uses these inputs to build a 10-Year Network Development Plan. This European plan was the first common European network modelling exercise based on massive data gathering and a structured consultation process. Hence it is a big step towards more transparent and more common network planning. The European plan identifies extensions, which affect transfer capabilities between individual TSOs, needed in addition to what the TSOs are planning for themselves. Supponen (2011) summarised the institutional interplay: *"ACER has to give an opinion on the ten year network development plan and to verify that the national plans are coherent with the European ten year plan. If they are not, ACER shall make recommendations to amend either the national plan or the ten year plan. ENTSO-E and the ACER shall monitor the implementation of these plans"*. Based on the ten year network development plan, a number of 'projects of common interest' (PCIs) are identified. These projects (i) are granted preferential treatment in order to speed up the necessary authorisation process, (ii) are funded jointly by the TSOs concerned (ACER can decide on a cost-distribution key if national regulators cannot agree) and (iii) might – when the Connecting Europe Facility is in place – also benefit from European co-financing.

5.2.2 Performance

Recent network extension

While the TSO forecast and the European Commission proposal both foresee significant growth in transmission investment, network developments in the last five years have at best had mixed results (Figures 19-21). Spain has seen a boom (and bust) in terms of extending the size of its high-voltage network, but German investment has remained at its 2007 level for half a decade, and net transfer capacities with neighbouring countries have not increased. Finally, France almost doubled investment in transmission without extending the length of the network. In terms of international transmission lines, France *increased* the capacity of the lines from/to Belgium, Spain and to Germany, *maintained* the capacities from/to Switzerland, England and from Italy and *reduced* the capacities to Italy and from Germany. Overall, the total net transfer capacity to (from) France slightly decreased by 9 percent (1 percent) between 2009 and 2013.

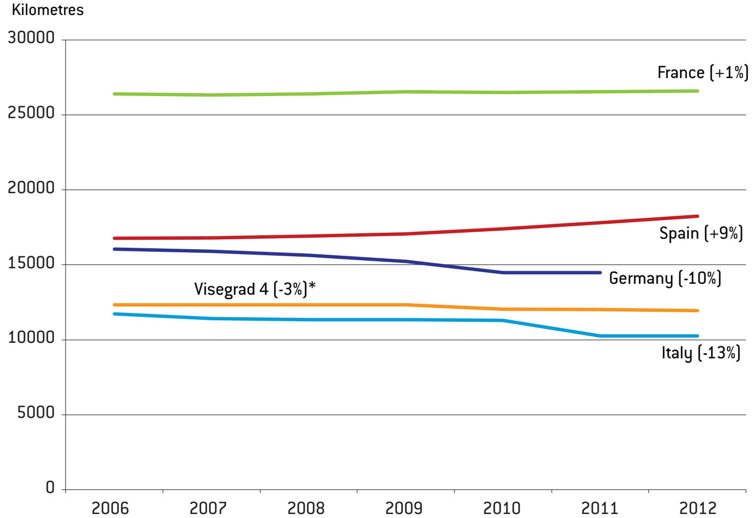
Table 13: Change in annual average net transfer capacity between 2009 and 2013

	Import from France	Export to France
Germany	21%	-29%
England	-6%	-5%
Belgium	8%	19%
Spain	48%	31%
Italy	-39%	-2%
Switzerland	-2%	-2%

Source: RTE (https://clients.rte-france.com/lang/an/clients_producteurs/vie/ntc_annuelles.jsp).

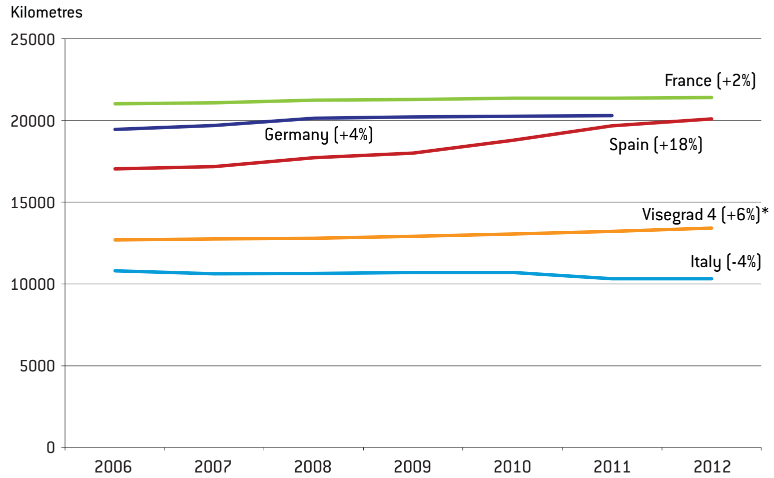
By contrast, transmission investment is on the rise in the United States and China. In China, in 2009 alone, 2078 km of ultra-high voltage transmission lines were added and state investment in the power transmission system was €38.5 billion (Cheung, 2011). In the US, the recent increase in transmission investment is predicted to continue from, currently, about €7 billion per year to €10.5 billion per year.

Figure 19: Length of 22kV circuit in kilometres at the end of the year



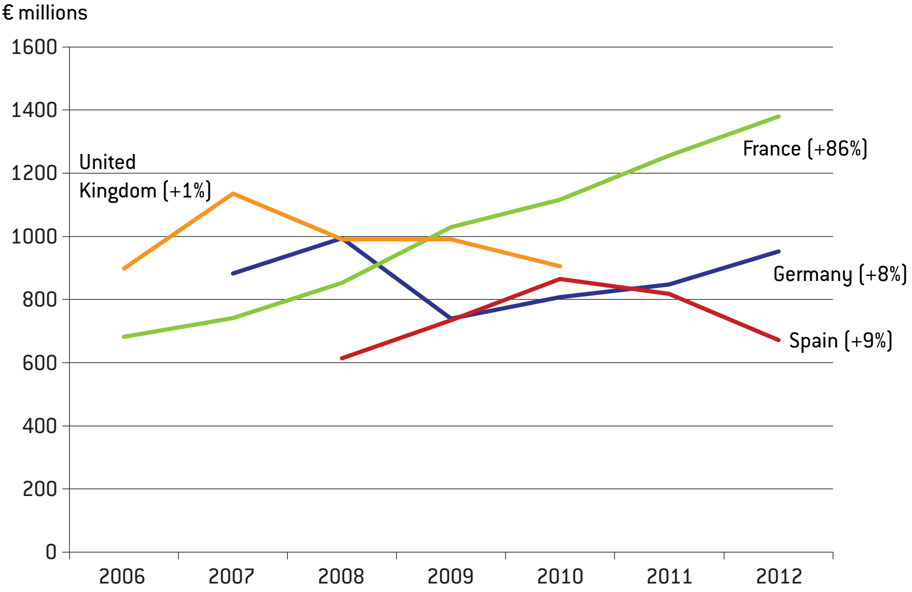
"'Source: ENTSO-E. Note: numbers in brackets indicate change in level of investment during sample period. * Visegrad 4 = Czech Republic, Hungary, Poland and Slovakia.

Figure 20: Length of 400kV circuit in kilometres at the end of the year



Source: ENTSO-E. Note: numbers in brackets indicate change in level of investment during sample period. * Visegrad 4 = Czech Republic, Hungary, Poland and Slovakia.

Figure 21: Investments by TSOs in electricity networks, 2006-12



Source: BNetzA, REE, RTE, Ofgem. Note: numbers in brackets indicate change in level of investment during sample period.

Policy performance

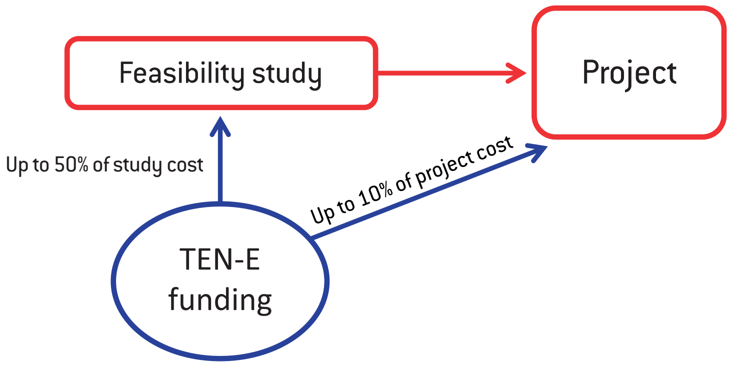
The EU Trans-European Energy Networks (TEN-E) funding programme started in the mid-1990s to push the development of Europe's energy infrastructure, in particular the electricity and gas networks. It was believed that private interests alone were enough to drive the projects forward with no need for strong EU intervention in the implementation phases. A contribution for the initial exploratory phases was deemed sufficient to speed up the process.

Therefore, the TEN-E programme was established to facilitate the initial phases of a project, namely feasibility studies. Since it did not need to cover implementation costs, which make up the bulk of total project costs, the allocated budget for the TEN-E programme was always low and averaged around €20 million annually.

Typically, aid would be given to partially cover the costs of studies, which could then result in the implementation of the project itself. However, only a small percentage of implementation costs could be covered by TEN-E funding (Figure 22). In any case, the first years of operation (before 2001) saw only two out of more than 50 projects receive TEN-E funds for their implementation phases. The TEN-E programme subsequently changed to accommodate the need for more flexible aid, and started to focus increasingly on projects of common interest and their implementation phases. The period 1996-2006 saw 354 applications for funding, of which 211 (60 percent) were approved. Each received €1.3 million on average. The selection was a bottom-up process and left no space for the identification of infrastructure gaps in a top-down manner.

In a 2009 report evaluating the programme in the period 2000-06, 76 percent of the beneficiaries stated that the TEN-E co-funded studies provided little or no help in facilitating the further co-financing of the investment. Also, 78 percent of the beneficiaries believed the study for which they received funding did not further the investment project in other ways. Additionally, almost two thirds of the member states found the TEN-E instruments to be inadequate in steering and guiding the development of the European energy structure. Furthermore, even if 92.6 percent of the studies that were funded between 2004-06 recommended implementation of the project concerned, by the end of 2009, only 48 percent had started, and only 8.7 percent were completed.

Figure 22: TEN-E funding



Source: Bruegel.

Finally, the selection of projects has also been criticised. Proost *et al* (2010) find that many projects do not pass the cost-benefit test and only a few of the economically-justifiable projects would need European subsidies to make them happen.

Table 14: TEN-E budget

in €million

	Budget	Allocated	Allocated yearly	Average allocation
TEN-E 95 99		90.20	18.04	0.79
TEN-E 00-06	148.00	126.20	18.03	1.30

	# Proposals	Funded	% funded
TEN-E 95 99	168	114	67.9%
TEN-E 00-06	186	97	52.2%

Source: Bruegel based on European Commission, 2001, 2004, 2009 and 2010a.

The TEN-E programme aimed to act as a catalyst, and thus play an important role for risky projects and feasibility studies. However, the approach was a bottom-up selection of existing projects. The absence in the TEN-E programme of a top-down approach that could push for the development of the most important infrastructure projects, and the shift in focus towards a low-carbon energy system, led to the development of the TYNDP (2010, 2012).

The European Energy Programme for Recovery (EEPR) was established in mid-2009 to provide financial support to highly strategic projects in the energy sector. It was created not only as means to bolster the completion of the internal energy market and the consequent reduction in greenhouse gas emissions, but also as a means to stimulate economic activity and growth in a time of crisis. The allocated budget was of about €4 billion, of which almost 60 percent was allocated to electricity and gas networks. The remaining funds were for offshore wind and carbon capture and storage. To date, 12 electricity infrastructure projects have been selected and have received €904 million (22.7 percent of the total budget), while 17 gas interconnection projects have received €1285 million[54]. At the time the Commission's 2012 report on the EEPR was written, 30 percent of the projects had been completed, 41 percent were proceeding according

54. Source: Report of the commission on the implementation of the EEPR (2012), http://ec.europa.eu/energy/eepr/doc/com_2012_0445_en.pdf.

to schedule and another 30 percent were behind schedule. Given the long lead times for investment in the energy sector, the substantial success rate of the projects under the EEPR indicates that many of them were funded when already mature. It is hence not unlikely that a number of the projects would have proceeded without the EEPR money.

The ten year network development plan (TYNDP) is one of the most ambitious projects for European network infrastructure. The plans imply, for the first time, that the European level should be taken into consideration in network planning. The quality of the plans increased significantly between the pilot in 2010, which was merely a collection of national plans, and the plan in 2012 that was based on some top-down analysis. For 2014, ENTSO-E foresees a formal cost-benefit analysis, the formal consideration of projects proposed by parties other than the TSOs and a further increase in stakeholder involvement.

So far, due to the non-binding nature of the plan, its actual implementation has been mixed. The evolution of the status of the individual projects in the 2010 plan reported in the 2012 TYNDP indicates that about half of the projects are delayed. According to this report only 52 percent of the projects proceed as planned, 28 percent are postponed because of delays in the authorisation process, 6 percent are delayed because generators rescheduled their plans and 13 percent are delayed for other reasons.

5.2.3 Ongoing progress

The EU has identified a huge investment gap for energy infrastructure: €400 billion for distribution networks, €140 billion for electricity transmission (€40 billion for smart grids, €70 billion for interconnectors, €30 billion for offshore connections) and €70 billion for gas transmission. Of the transmission investment, they estimate that €60 billion is not commercially viable and €40 billion will not get permission. To close this gap, the Commission proposed in2011 the Energy Infrastructure Package that targets in particular investments in interconnectors.

The corresponding regulation on guidelines for trans-European energy infrastructure[55] was adopted by Parliament and Council on 17 April 2013. The guidelines define a small number of trans-European priority corridors on which European action for energy

55. http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2013:115:0039:01:EN:HTML

infrastructure should primarily focus. For electricity, four corridors are defined[56]. The Commission will identify projects of common interest that are necessary to implement the corridors. These projects will primarily benefit from accelerated permit granting, provisions for cross-border cost-sharing and possibly EU financial assistance.

The time taken to grant permits for projects of common interest should be reduced to less than three and a half years by creating a one-stop-shop to manage the permitting process, ensure preferential treatment in member states and increase transparency and public participation.

To fund these projects of common interest, the regulation obliges the national regulators to grant sufficient returns for the corresponding projects. Probably the most important provision in the regulation is the empowerment of ACER to enforce a sharing of construction costs between the national regulators concerned, in case they find no solution themselves. Finally, the regulation determines the conditions for eligibility of these projects for EU financial assistance. EU funding for this regulation is to be negotiated in the context of the Connecting Europe Facility financing instrument. The Commission has proposed that €9.1 billion be allocated to energy infrastructure in the next multiannual financial framework (2014-2020). On 8 February 2013 the European Council agreed to reduce the amount to €5.1 billion. The European Parliament is expected to finally approve this budget in autumn 2013.

5.2.4 Shortcomings

The regulated asset base' model has proved workable in the national context. However, in the international or cross-border context it fails because both domestic and cross-border transmission lines cause significant spillovers onto neighbouring countries' networks that are not properly considered by national regulators and TSOs. The most

56. Northern Seas offshore grid: integrated offshore electricity grid development and the related interconnectors in the North Sea, the Irish Sea, the English Channel, the Baltic Sea and neighbouring waters to transport electricity from renewable offshore energy sources to centres of consumption and storage and to increase cross-border electricity exchange. North-south electricity interconnections in western Europe: interconnections between member states of the region and with the Mediterranean area including the Iberian peninsula, notably to integrate electricity from renewable energy sources and reinforce internal grid infrastructures to foster market integration in the region. North-south electricity interconnections in central, eastern and south eastern Europe: interconnections and internal lines in north-south and east-west directions to complete the internal market and integrate generation from renewable energy sources. Baltic Energy Market Interconnection Plan for electricity: interconnections between member states in the Baltic region and reinforcing internal grid infrastructures accordingly, to end isolation of the Baltic States and to foster market integration inter alia by working towards the integration of renewable energy in the region.

straightforward problem is that the benefit of a new cross-border line might concentrate in one country, while its cost mainly accrues in another. The regulator in the latter country will not be inclined to approve a corresponding investment plan. The extreme version of this case is that a domestic line in one country to reduce congestion in a neighbouring country would never be approved by the first country's regulator. In addition, cross-border lines – even though they have a net benefit – might, for example, shift welfare from consumers to producers within a country. If regulators focus in their cost-benefit analysis only on consumer welfare, they might be inclined to oppose such projects. As a consequence, network development based on national cost-benefit analysis will not deliver an efficient European electricity network.

Current European planning and funding legislation and practice will not deliver a truly European electricity network, either. The European ten year network development plan is a non-binding proposal by ENTSO-E to the individual TSOs. As the plan is developed by the European transmission system owners and operators, it is likely to focus on projects that are commercially viable for this segment of the industry, even though other projects might be more sensible from a societal point of view. In addition, no stakeholder is legally accountable if the information it transmitted to ENTSO-E, on which the European plan is based, subsequently proves wrong. Hence, the plan cannot ensure synchronisation of the investment decisions of different stakeholders. The lack of accountability for the accuracy of submitted information may allow individual stakeholders to distort or hide information in order to influence the overall European plan. The non-binding nature also casts a degree of doubt over the credibility of the European plan because it may allow individual TSOs to delay investments in certain lines they are not particularly interested in. This uncertainty may discourage generators from coming forward with investments, the profitability of which depends on the realisation of certain lines. Finally, the technical planning and the resulting selection of projects are not transparent. The model and major assumptions are not disclosed. Consequently, challenging the set-up proposed by ENTSO-E is virtually impossible.

The special permitting and funding rules for the projects of common interest – in particular the right of ACER to enforce a compromise on cross-border cost sharing – are a big step in the direction of a more European network infrastructure. However, the focus on a limited number of projects risks ignoring the system nature of the meshed energy network. Consequently, the emphasis might be on building more border crossings rather than investing in the most efficient marginal improvements. In addition, in order to satisfy private or public interests (eg for low or high prices), and as the selection is based on a bottom-up process, only lines with limited impact might be brought forward. Finally, despite detailed criteria, the ultimate choice of projects to be granted 'common interest' status might not be driven by efficiency motives, but by the requirement to disburse the scarce EU budget money 'fairly'.

Consequently, the infrastructure package is unlikely to be a final breakthrough in the development of infrastructure for the single European electricity market.

6 Proposal

Building on our analysis, this section describes a first-best solution for European energy infrastructure investment to meet the EU's energy policy objectives of competitiveness, sustainability and security of supply. However, the first-best solution faces political constraints. For example, any major reform that involves the harmonisation of national schemes will have significant redistributive effects on market participants. Some countries might even be worse-off when introducing a solution that is preferable from the total-welfare perspective. This is amplified by political considerations and different preferences. Thus, we explore the features of a feasible solution to promote truly European energy infrastructure investment.

6.1 A first-best market-based solution

Comprehensive electricity markets are complex. Countries and regions have been able to come up with viable approaches for using existing, and constructing new, parts of the energy system (see Box 3). One first-best market-based solution would consist of:

1) A single regulator overseeing the development of the market design and regulating the tariffs of the natural monopoly part of the business (transmission system operator, transmission system owner, distribution system operator and owner)
2) A regulated independent system operator that optimises the dispatch of the existing units in a cost-minimising way through a transparent mechanism, and that proposes network extensions based on a process that involves all stakeholders.
3) Owners of the transmission system can chose whether they want to build new lines according to the independent operator's plans. If not, alternative infrastructure providers might carry out the projects on regulated terms.
4) A consistent market design that clearly places responsibilities on the different participants, creates the necessary interfaces between them and defines products (for the different components) that can be traded.

In the European context this would imply: European network planning, a single European market design for all aspects, a European system operator and a European regulator.

BOX 3: INTERNATIONAL EXPERIENCE

The United States' transmission systems are operated through a wide spectrum of regional schemes. Some have sophisticated wholesale markets and independent system operators (ISOs), while others possess neither. However, motivations for transmission investment are largely the same as those in Europe: deployment of intermittent renewables (47 GW of wind in 2010), historic investment backlog and regional integration within the US. However, the way the investment needs have been addressed, and the levels of success in addressing them, differs markedly from the EU, and the US has been more successful. In the period 2007-11 a total of 16,000 km of new lines was installed and the volume of investment is increasing.

California ISO (CAISO) is one example of a successful US model. CAISO is responsible for the operation and extension of a large portion of the California grid but the grid hardware itself is owned by the transmission owners (TOs).

Funding: CAISO collects a regulator-approved transmission charge from all consumers connected to the CAISO grid. It retains a grid management charge, and redistributes revenues from the transmission access charge to participating TOs. The tariffs of TOs joining the CAISO grid are transitioned into a grid-wide transmission charge over a 10-year period. CAISO revenues are determined by the regulator.

Operation: CAISO optimises the entire electricity system centrally by setting higher prices in import-constrained parts of the network and lower prices in export-constrained parts.

Planning: CAISO has developed a formalised 23-month transmission planning process, TEAM, which attempts to incorporate five main principles into their planning studies: benefit framework, full network representation, market prices, explicit uncertainty analysis and interactions with other resources. TEAM includes a cost-benefit analysis of investment proposals which uses flexible weighting of the different welfare components, allowing for the assessment of a proposal from the perspectives of different stakeholder groups (Wu *et al*, 2006). The result is a project-submission window in which transmission element proposals (both economically driven and policy-driven) are evaluated, and project sponsors are selected to construct and own the approved elements.

The process has been very successful in incentivising the construction of approved transmission lines. An impressive 87 percent of the transmission lines approved in 2005 had been completed by 2009. Since 1999, transmission investment has increased by 84 percent. A ratepayer organisation claims that this 'success' essentially represents excess transmission being funded through increasing tariffs (since 1999 load has only grown by 9 percent in that time). The organisation asserts that reasonable, and perhaps economic, alternatives (some non-infrastructure) are not being considered. Indeed, the US Department of Energy has begun to look at non-transmission alternatives. From a European perspective the possibility of the oversupply of transmission, and the developing discussion about how to encourage non-transmission alternatives, are a testament to the success of models like CAISO that allow the discourse to be elevated to a higher level.

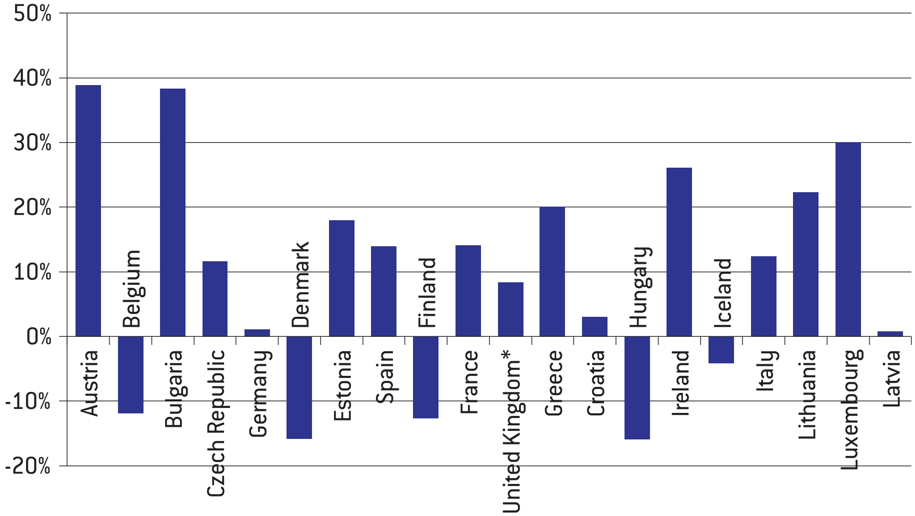
6.2 Political challenges

A first-best market design is likely to be politically unrealistic in the European context for three reasons. First, the necessary changes compared to the current situation are substantial and would produce significant redistributive effects (see the next section). Second, a European solution would deprive member states of the ability to manage their energy systems nationally. And third, a single European solution might fall short of being well-tailored to consumers' preferences, which differ substantially across the EU.

Redistributive effects

A single European market design would result in significant redistributive effects. If, to give an illustrative example, Europe were to introduce the US standard market design, all stakeholders would be affected. The national power exchanges would lose their role of traders for physical products and hence a major share of their current business. The transmission system operators would be reduced to mere owners of the physical infrastructure, while network extension planning and system operation would be transferred to an independent agency. The support for newly installed renewables would need to be reorganised, possibly in a way that is beneficial for some regions with favourable resources and less beneficial for other regions. Consumers in zones with low prices might be faced with increasing prices when better operation of the network allows the export of more of 'their' cheap energy to other zones. And flexible generators might lose some of their value when demand response reduces prices in situations of scarcity. Such redistributive effects for stakeholders translate into redistribution between member states – as each has a different electricity sector to start with. A quantification of these effects is strongly dependent on the details of the final market design and can only be conducted based on substantial modelling. But to give an example of the order of magnitude, we evaluate the impact of a hypothetical European capacity mechanism. If every member state would have to ensure that the remaining margin over the reliable available capacity reaches the European average of 10 percent (Figure 23) by exchanging capacity credits, some member states would be significantly better off, while others would have to pay.

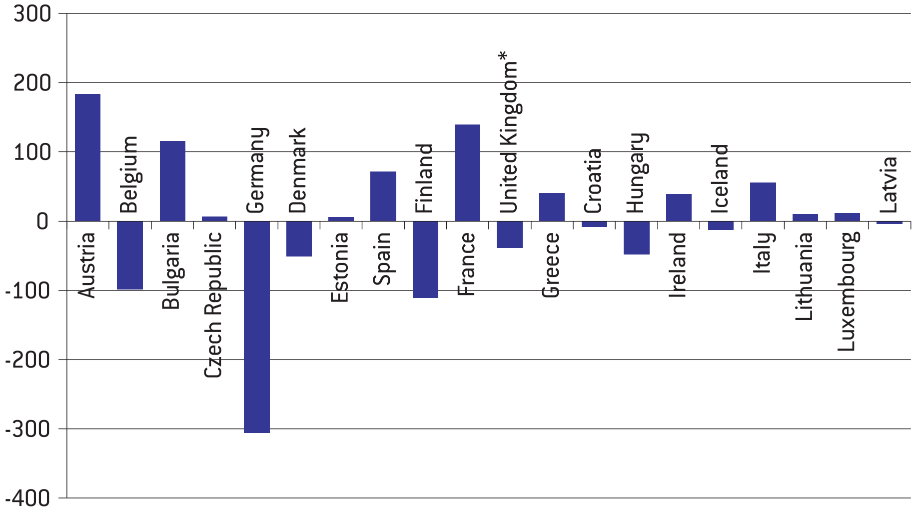
Figure 23: Remaining margin over the reliable available capacity for 2013



Source: ENTSO-E (2013). Note: Countries shown are those for which data is available. * UK data does not include Northern Ireland.

At a price of €100/MW-day[57], the existing French over-capacity could generate – in our purely illustrative example – capacity credits worth €140 million per year while Germany would have to buy credits worth €306 million (Figure 24).

Figure 24: Gains or losses from a simple European capacity mechanism in € millions



Source: Bruegel based on ENTSO-E figures on system adequacy. Note: Countries shown are those for which data is available. * UK data does not include Northern Ireland.

Finally, institutions will also oppose the loss of the powers that they have in the current system. National and sometimes even subnational regulators, power exchanges and even the corresponding mainly national advisory, supervisory and research institutions might perceive themselves to be vulnerable to such dramatic system change.

Perceived loss of sovereignty

In a truly single energy market the scope for national energy policies is significantly reduced. When economic signals in harmonised markets drive investment decisions,

57. This is the order of magnitude observed in the JM Base Residual Auctions in 2013.

member states will find it difficult to ensure that a particular, politically desirable, fuel mix materialises in their country. For example, a harmonised renewables scheme might reduce the number of new solar panels in the north of Europe, while a pure market framework for conventional investments might make new nuclear units uninvestable in Europe[58].

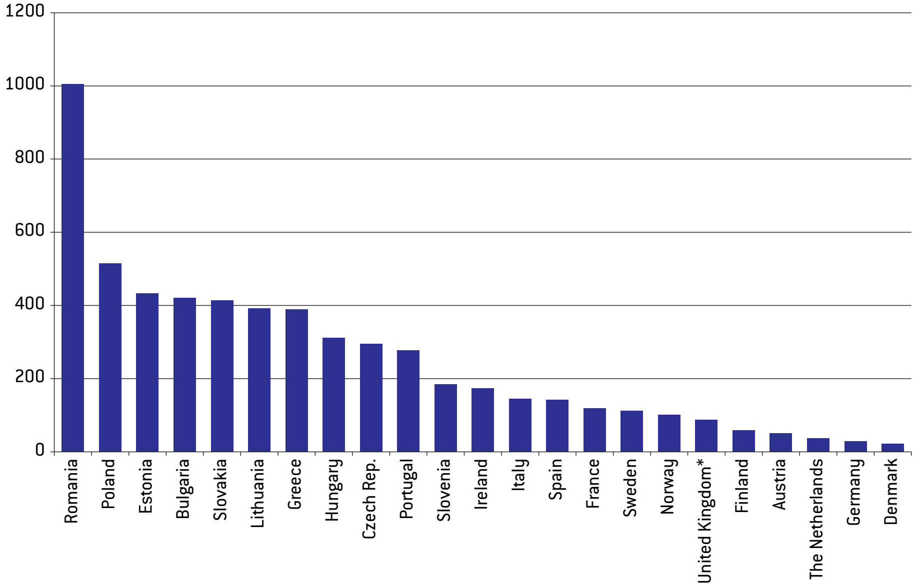
Furthermore, using national market design choices to favour certain market participants for industrial or social policy reasons is not possible in a single market. For example, artificially low network tariffs for customers connected to the high-voltage network – typically energy-intensive customers – at the expense of other domestic consumer groups would then only be possible in a harmonised way at the European level. Likewise, supporting solar panels through preferential network access and exemption from obligations to provide system stabilising services could only be agreed jointly. Finally, subsidising customers in supply-constrained areas by enforcing a unique electricity price per country would be incompatible with the first-best market design.

Different preferences

Harmonising market designs might not only create winners and losers. It might also ignore significant differences in the preferences of national consumers. One illustrative example is security of supply. Some countries attach significantly higher value to an uninterrupted electricity supply than others. One indication is that rich countries in particular develop electricity systems with significantly lower incidence of interruptions than less wealthy EU countries (Figure 25). Hence, hard-wiring a one-size-fits-all level of security of supply runs the risk of not being appropriate for any country.

58. See Lévêque (2013).

Figure 25: Average interruption time (minutes/year) in 2009-10



Source: CEER.

6.3 Properties of a feasible solution

The integrated first-best solution – a single European system operator, regulated by a single regulator, which develops the network in coordination with generators and consumers – appears politically unrealistic because of the redistributive effects, the loss of member-state sovereignty over 'their' electricity systems, the disregard for certain national preferences and the institutional changes it would involve[59].

To nevertheless reap significant benefits from an integrated European electricity market, we propose a blueprint for a European system to fund and incentivise infrastructure development. The approach is fourfold: (1) implement vertical unbundling; (2) add a European system-management layer; (3) establish a stringent planning process; and (4) phase-in European cost-sharing.

59. This section draws on Zachmann (2013).

Implement vertical unbundling

Léautier and Thelen (2009) find that vertical separation is one key-requirement (the other being a well-designed incentive scheme) for reducing network congestion. It is important that transmission system operators should not be concerned with the interests of affiliated generators. The legal basis for this has already been adopted in the third EU energy sector liberalisation package of 2009. Implementation of the unbundling requirements should have been done by 3 March 2012. The European Commission acknowledges that in most member states the unbundling provisions are at the time of writing not fully transposed.

Add a European system management layer

National system operation creates major spillovers onto neighbouring countries, but also affects network investment incentives. Uncoordinated system operation increases the incentives for national operators to close their borders in order to ensure system stability. The straightforward way out of this dilemma is to add a European system-management layer, in other words, centralising and monitoring electricity-system information in real-time. This would enable throughput of electricity through national and international lines to be safely increased without any major investments in infrastructure. This would neither require TSOs to merge nor to be expropriated, nor would it significantly infringe on national sovereignty over the security of national electricity systems. A European control centre would complement national operation centres and help them to better exchange information about the status of the system, expected changes and planned modifications. The ultimate aim should be to transfer the day-to-day responsibility for the safe and economic operation of the system to the European control centre. To further increase efficiency, electricity prices should be allowed to differ between all network points across and within countries. That is, electricity in Hamburg might be cheaper than in Munich on the wholesale market if there is a lot of wind in the North Sea, while the sun is not shining on Bavarian solar panels. This would provide the correct incentive to switch off coal-fired power plants in the north and switch on gas turbines in the south in order not to overcharge the network. In addition, investors in generation (or load) will base their location decisions on these locational price signals. This will reduce congestion over time by creating an incentive for generation/load to move to net electricity deficit/surplus areas.

Establish a stringent planning process

Current approaches to network planning suffer from a number of shortcomings: they essentially reflect the interests of TSOs, which make planning decisions without full information about cross-border impacts; the plans are non-binding, meaning stakeholders are not obliged to comply, and so do not provide the necessary synchronisation of investments in the energy system; the planning process is non-transparent as far as the modelling is concerned; and the planning process is 'technocratic' in the sense that it does not *a priori* take the concerns of residents into account.

Harmonising national network planning rules is administratively difficult and would take many years. To avoid this, the European approach is to use the ten year network development plan (TYNDP) to ensure the consistency of the results of national planning with European objectives. To achieve this, ACER must provide opinions on the consistency of the individual national ten-year plans with the TYNDP. However, the consistency of national plans with European objectives cannot be enforced by ACER or the EU – Regulation 714/2009 explicitly refers to the *"non-binding Community-wide ten-year network development plan"*. Hence, to ensure the consistency of individual national network plans and to ensure that they contribute to providing the infrastructure for a functioning single market, the role of the TYNDP needs to be upgraded. This could be done by obliging national regulators to only approve projects planned at European level unless they can prove that deviations are beneficial.

This boosted role of the TYNDP would need to be underpinned by resolving the issues of conflicting interests and information asymmetry. Two approaches to this are conceivable: first, relying on thorough cross-checking of ENTSO-E proposals by the regulator, or, second, shifting the entire planning process to an independent body.

In the first case, ACER should be requested and authorised to thoroughly check that the TYNDP maximises the welfare of current and future European citizens and that national plans are consistent with the TYNDP. This implies that ACER would not only rely on the modelling results that TSOs use to justify their plans, but would have tools of its own for impartial evaluations. ACER should not resort to consulting proprietary models that are not fully disclosed and that have to be repeatedly procured. Instead, ACER – or another public body – should invest in the capabilities to build, manage and use a European open-source energy model. Based on a substantial upfront investment in a suitable model, ACER would structure a process in which all relevant stakeholders can support ACER by updating the assumptions and the modelling. Individual stakeholders will still have better information on their parts of the electricity system. TSOs will know the network better than any independent network modeller, generators will have a clearer view of their individual plans, large consumers (including distribution system operators) will have more information on their future load, and residents will best be able to evaluate the acceptability of proposed lines. Thereby, ACER's power to approve the TYNDP based on its own modelling results would shift the burden of proof to the stakeholders (including ENTSO-E) in case they disagree with ACER's conclusions. This would give the stakeholders an incentive to disclose private information. In addition, the open-source nature of the model would allow inconsistencies to be identified, and improvements to be proposed. Of course, state-of-the-art could only be ensured by continued investment in the model's capabilities.

In the second case, resolving the issues of conflicting interests and information asymmetry in network planning could also be achieved by building on the significant effort that ENTSO-E has made in developing the TYNDPs. Using the TYNDP expertise would require that its governance structure be made independent from the interests of TSOs. Hence, a dedicated TYNDP governance structure should be developed that is representative of all electricity sector stakeholders (in a membership committee). An executive board that is independent from industry interest should have full operational control. Finally, the by-laws of the institution governing the TYNDP would need to ensure that the model used for planning is made fully transparent and open source.

Irrespective of the model chosen ('cross-checking' or 'independent planning'), it is essential to make both the input from stakeholders and the final plan binding in order to improve the synchronisation of investment. That is, stakeholders that, for strategic or other reasons, deviate *ex post* from their predictions (eg building a power plant or consuming electricity at a certain point of the network) will be liable to claims for damages from other stakeholders.

Finally, planning will not be able to make all stakeholders equally happy. And certain choices that do not affect overall welfare might have substantial redistributive effects. To rectify the distributional consequences, an ultimate political decision by the European Parliament on the entire plan could open a negotiation process around selecting alternatives and agreeing compensation. This need for democratic approval ensures that all stakeholders have an interest in ensuring a maximum degree of balance of interest in the earlier stages. In fact, transparent planning, early stakeholder involvement and democratic legitimisation are well suited for minimising as much as possible local opposition to new lines.

The delivery of the plan would then be left to the TSOs or any other investor willing to deliver individual lines according to the regulated conditions. In case of multiple interests, the national regulator might choose the best value offer.

Phase in European cost-benefit sharing

Cost and benefit sharing is a critical element in the discussions about EU electricity networks. Different stakeholders have diverging interests, and it sounds unnatural to require stakeholders to pay for a transmission line that actually reduces their profits. On the other hand, stakeholders that are the major beneficiaries of a new line should not be able to pass all the cost onto society. Hence, all easily attributable cost should be levied on the responsible party. If new generation requires grid reinforcements, the reinforcements should be largely paid for by the generator (deep connection charges). In this way, the investor has the right incentives to trade-off high locational prices in one place (eg close to consumption centres), with cheap network access in another place (eg in a zone where an old power plant has recently been shut down), and good access to resources in a third place (eg for a wind turbine, a zone with high constant wind).

For all remaining network extensions the question is how to share the cost[60] between network users in different regions. Having all line extensions in Sweden being equally financed by Bulgarian network users seems difficult. Having a Belgian line that is required to accommodate loop-flows caused by inner-German imbalances being paid for only by Belgian network users is not reasonable either.

Based on the assumption that the network development planning process discussed in the previous section delivers an efficient proposal, and that new generators have to pay deep connection charges, we suggest that some redistribution is unavoidable. The reason is that, so far, even the most sophisticated cost-benefit analysis models have been unable to identify the individual long-term net benefit in an uncertain environment. For all infrastructure (eg rail and road), there is some socialisation of the costs of individual projects within the different regions of a country. Therefore, we propose that consumers in all nodes that are expected to receive more imports through

60. It would be sensible to harmonise the allocation of network costs to different types of network users (consumer, generator, storage) across countries. According to Billette de Villemeur and Pineau (2012), trade between different regimes can increase inefficiency. For example, if in some countries only consumers have to pay the entire network cost while in another, all costs are borne by the generators, more generators will move to the first country and more (industrial) consumers to the second country. Hence, more electricity will have to flow between countries and congestion is likely to increase.

a line extension should be obliged to pay a share of the line extension cost through their network charges, while the rest of the cost is socialised to all consumers[61]. Such a cost-distribution scheme will involve some intra-European redistribution from the well-developed countries (infrastructure-wise) to those that are catching up. However, such a scheme would perform this redistribution in a much more efficient way than the Connecting Europe Facility's ad-hoc disbursements to politically chosen projects, because it would provide the infrastructure that is really needed.

6.4 Conclusion

Implementation of this proposal will deliver the infrastructure needed to achieve the European energy policy targets in the field of electricity. It will increase the reliability of the network, enable a truly borderless European electricity market, and facilitate the integration of renewables. If the EU decides to wait for the results of the non-binding plan to materialise in the 2020s, valuable time will have been lost. All approaches involving throwing money at the problem to achieve flagship projects will fail to resolve the complex underlying issues. After three energy sector packages and 20 years of work, the EU possesses many of the key institutions and laws necessary for achieving the single electricity market. In the past, the benefits of a more coordinated system have not been great enough to outweigh the significant political and transaction costs required to achieve such a system. However, recent developments (unbundling, renewables, more trade) have substantially increased the value of greater coordination. It is the right time for the EU to take a bold step towards a borderless electricity infrastructure.

61. If a harmonisation of network tariffs were to be envisaged, this share might also be made time-variant. For example, one might start with 100 percent in the first year and go to 90 percent in the second year and end with zero percent in the tenth year.

References

Abbasy, A., R. A. C. Van der Veen and R. A. Hakvoort (2009) 'Effect of integrating regulating power markets of Northern Europe on total balancing costs', *PowerTech 2009 IEEE Bucharest*: 1-7

ACER Press Release (2012) 'Progress made and challenges ahead for EU gas and electricity market integration', reported by ACER/CEER, Brussels, 29 November

Altomonte, C. and M. Nava (2006) *Economics and Policies of an Enlarged Europe*, Edward Elgar Publishing

Anderson, D. (2006) 'Power System Reserves and Costs with Intermittent Generation', *UK Energy Research Centre Working Paper*

Awad, M., S. Broad, K. E. Casey, J. Chen, A. S. Geevarchese, J. C. Miller, A. J. Perez, A. Y. Sheffrin, M. Zhang, E. Toolson, G. Drayton, A. F. Rahimi, B. F. Hobbs and F. A. Wolak (2006) 'The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Application to Path 26', *Power Engineering Society General Meeting*, IEEE, Ed. Montreal

BDEW (2013) 'Märkte stärken, Versorgung sichern: Konzept für die Umsetzung einer Strategischen Reserve in Deutschland', *Ergebnisbericht des Fachdialogs „Strategische Reserve"*, May

Benatia, D., N. Johnstone and I. Hašcic (2013) 'Effectiveness of Policies and Strategies to Increase the Capacity Utilisation of Intermittent Renewable Power Plants', *OECD Environment Working Papers*

Bergman, L. (2003) 'European Electricity market integration: the Nordic experience', Research Symposium European Electricity Markets, The Hague – September 2003, available at http://www.ecn.nl/fileadmin/ecn/units/bs/Symp_Electricity-markets/c1_2-paper.pdf

Davis, L.W. and C. Wolfram (2012) 'Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power', *Working Paper No. 17341*, NBER

Delarue, E., C. De Jonghe, R. Belmans and W. D'haeseleer (2011) 'Applying portfolio theory to the electricity sector: Energy versus power', *Energy Economics* 33(1): 12-23

De Villemeur, E. B. and P. O. Pineau (2012) 'Regulation and electricity market integration: When trade introduces inefficiencies', *Energy Economics*, 34(2): 529-535

European Commission (2001) *Report from the Commission to the European Parliament, the Council, the Economic and Social Committee and the Committee of the Regions on the implementation of the guidelines for Trans-European Energy Networks in the period 1996-2001*, available at http://ec.europa.eu/prelex/detail_dossier_real.cfm?CL=en&DosId=172182

European Commission (2004) *Mid-Term evaluation of the TEN-E Programme 2000-2006*, available at http://ec.europa.eu/energy/evaluations/doc/2004_ten_e.pdf

European Commission (2009) *Ex-Post Evaluation of the Trans-European Energy Networks (TEN-E) Funding Programme 2000-2006*, available at http://ec.europa.eu/energy/evaluations/doc/2009_ten_e.pdf

European Commission (2010a) *Energy Infrastructure Priorities for 2020 and Beyond – A Blueprint for an Integrated European Energy Network*, COM(2010) 677/4

European Commission (2011a) *Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions. A Roadmap for moving to a competitive low carbon economy in 2050*, COM(2011) 112 final

European Commission (2011b) 'Energy infrastructure investment needs and financing requirements', *Staff Working Paper*, SEC(2011) 755 final

European Commission (2012) *Making the internal energy market work*, COM(2012) 663 final

European Commission (2013) *Commission Decision on the establishment of the annual priority list for the development of network codes and guidelines for 2014*, 2013/442/EU

European Climate Foundation (2011) *Power Perspectives 2030 – On the road to a decarbonised power sector in Europe*, available at http://smartgridsherpa.com/wp-content/uploads/2011/11/PowerPerspectives2030_FullReport1.pdf

ENTSO-E (2010) *Ten-Year Network Development Plan 2010–2020*, available at https://www.entsoe.eu/index.php?id=232

ENTSO-E (2011) *Statistical Yearbook 2011*, available at https://www.entsoe.eu/publications/statistics/statistical-yearbooks/

ENTSO-E (2012) *Ten-Year Network Development Plan 2012*, available at https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2012/

EWEA (2013) *Wind in Power: 2012 European Statistics*, available at www.ewea.org/fileadmin/files/library/publications/statistics/Wind_in_power_annual_statistics_2012.pdf

Fabrizio, K., N. Rose and C. Wolfram (2007) 'Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on U.S. Electric Generation Efficiency', *American Economic Review*, 97(4): 1250-1277

Gerbaulet, C., L. Hankel, L. Laurisch, C. Casimir, L. Lorenz, A. Sander, A. Schröder and A.

Zerrahn (2012) ‘Benefits of Regional Cooperation in Providing Balancing Power’, *Electricity Markets Working Papers*, WP-EM-51

Haucap, J., U. Heimeshoff and D. Jovanovic (2012) ‘Competition in Germany’s minute reserve power market: an econometric analysis’, *DICE Discussion Papers 75*, Heinrich Heine Universität Düsseldorf, Düsseldorf Institute for Competition Economics

Heddenhausen, M. (2007) ‘Privatisations in Europe’s liberalized electricity markets – the cases of the United Kingdom, Sweden, Germany and France’, Research Unit EU Integration, German Institute for International and Security Affairs

Hiebert, L.D. (2002) ‘The Determinants of the Cost Efficiency of Electric Generating Plants: a Stochastic Frontier Approach’, *Southern Economic Journal* 68(4): 935-946

Knittel, C. (2002) ‘Alternative Regulatory Methods and Firm Efficiency: Stochastic Frontier Evidence from the U.S. Electricity Industry’, *The Review of Economics and Statistics* 84(3): 530-540

Lagendijk, V. (2008) *Electrifying Europe - The Power of Europe in the Construction of Electricity Networks*, Amsterdam University Press

Léautier, T. and V. Thelen (2009) ‘Optimal expansion of the power transmission grid: why not?’, *Journal of Regulatory Economics* 36(2): 127-153

Lévêque, F. (2013) ‘Estimating the costs of nuclear power: benchmarks and uncertainties’, *CERNA Working Paper* 13-ME-01

Mansur, E. T. and M. W. White (2012) ‘Market Organization and Efficiency in Electricity Markets’, working paper available at http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.pdf

Meeus, L., K. Purchala, C. D. Esposti, D. Van Hertem and R. Belmans (2006) ‘Regulated Cross-Border Transmission Investment in Europe’, *Transmission and Distribution Conference and Exhibition, 2005/2006 IEEE PES*, pp1285-1290, 21-24 May

Neuhoff, K. (2011) ‘Opening the Electricity Market to Renewable Energy: Making Better Use of the Grid’, *DIW Economic Bulletin* 1/2011: 16-23

Proost, S., F. Dunkerley, S. Van der Loo, N. Adler, J. Bröcker and A. Korzhenevych (2010) ‘Do the Selected Trans European Transport Investments Pass the Cost Benefit Test?’ *Centre for Economic Studies – Discussion papers*, Katholieke Universiteit Leuven

Rebours, Y., M. Trotignon, V. Lavier, T. Derbanne and F. Meslier (2010) ‘How much Electric Interconnection Capacities are Needed within Western Europe?’, *Proceedings of the Conference on European Energy Market 2010*, June

Roland Berger (2011a) *The structuring and financing of energy infrastructure projects, financing gaps and recommendations regarding the new TEN-E financial instrument*, Final Report, European Commission, Directorate-General for Energy, available at http://ec.europa.eu/energy/infrastructure/studies/doc/2011_ten_e_financing_report.pdf

Roland Berger (2011b) *Permitting procedures for energy infrastructure projects in the EU: evaluation and legal recommendations*, Final Report, European Commission, Directorate-General for Energy, available at http://ec.europa.eu/energy/infrastructure/studies/doc/2011_ten_e_permitting_report.pdf

Shanefelter, J. (2008) 'Restructuring, Ownership and Efficiency: The Case of Labor in Electricity Generation', *Center for the Study of Energy Markets Working Paper*, CSEM WP 161, UC Berkeley

Supponen, M. (2011) 'Influence of National and Company Interests on European Electricity Transmission Investments', PhD Thesis, Aalto University, Finland

Supponen, M. (2012) 'Cross-border electricity transmission investments", *EUI Working Paper*, RSCAS 2012/02

Von Hirschhausen, C. (2012) 'Green Electricity Investment in Europe: Development Scenarios for Generation and Transmission Investments', *Working Paper 2012/04*, European Investment Bank

Von Hirschhausen C., S. Ruester, C. Marcantonini, X. He, J. Egerer and J. Glachant (2012) 'EU Involvement in Electricity and Natural Gas Transmission Grid Tarification', *Think Report* Topic 6, available at www.eui.eu/Projects/THINK/Documents/Thinktopic/ThinkTopic6.pdf

Wu, F., F. Zheng and F. Wen (2006) 'Transmission Investment and Expansion Planning in a Restructured Electricity Market', *Energy* vol 31: 954-966

Zachmann, G. (2008) 'Electricity wholesale market prices in Europe: Convergence?' *Energy Economics* 30(4): 1659-1671

Zachmann, G. (2012) 'Market coupling does not lower price', Bruegel blog post, 25 September

Zachmann, G. (2013) 'Electricity infrastructure: More border crossings or a borderless Europe?', *Policy Contribution* 2013/05, Bruegel

Zarnic, Z. (2010a) 'European Electricity Market Reforms: Any Signs of Efficiency Improvements?' *LICOS Discussion Papers 26210*, Centre for Institutions and Economic Performance, Katholieke Universiteit Leuven

Zarnic, Z. (2010b) 'From Liberalization towards Integration: Have Markups of EU Electricity Firms Changed?' *LICOS Discussion Papers 26110*, Centre for Institutions and Economic Performance, Katholieke Universiteit Leuven

Appendix

Table 15: Literature Survey

COMPETITION	
Shanefelter (2008): Restructuring electricity generation industry has improved productive efficiency. In particular, divestitures of generation assets have reduced employment and aggregate payroll expenses.	Dep var: ln(employment) Indep var: divestiture % effect= -42.4% ** Dep var: ln(payroll) Indep var: divestiture % effect= -32.3% **
Fabrizio *et al* (2007): Restructuring electricity generation industry has reduced costs and input use. All IOU (Investor Owned Utilities) plants improved their efficiency relative to Municipal and Federal plants during the late 1980s and early 1990s.	% change in costs per MWh from 90 to 96: -13.5 in restructuring states, -5.1 in non-restructuring states. Dep var: ln(employees) Indep var: Investor Owned Utilities*Restructured coefficient= -0.032 ** Dep var: ln(nonfuel expenses) Indep var: Investor Owned Utilities*Restructured coefficient= -0.095 **
Davis and Wolfram (2012): Deregulating and consolidating electricity markets have led to an increase in operating efficiency, achieved primarily by reducing the frequency and duration of reactor outages. At average wholesale prices the value of this increased efficiency is approximately $2.5 billion annually and implies an annual decrease of 38 million metric tons of carbon dioxide emissions.	Dep var: Nuclear Operating Efficiency Indep var: divestiture % effect= 10.4% ** Dep var: Post-divestiture gains Indep var: - length of outages % effect= -6.4% ** - maximum generation capacity % effect= 2.5% **
Hiebert (2002): Plant efficiencies are associated with capacity utilisation of the plant and the number of plants under utility management. Moreover,	Dep var: Mean Plant Inefficiency Indep var: - capacity utilisation of the plant coefficient (coal)= -1.57***

regulatory restructuring activity in certain states is associated with improvements in plant operating performance	coefficient (gas)= - 5.65*** - number of plants under mgnt of the utility coefficient(coal)= - 0.07*** coefficient (gas)= - 0.06***
Zarnic (2010a): European electricity market reforms have induced improvements in firm efficiency either through productive, allocative or dynamic efficiencies. However these are not uniformly distributed; the closest are the firms to the frontier, the more they are able to improve productivity in response to liberalisation efforts stimulating competition.	Dep var: Solow Residuals Indep var: - Effect of liberalisation coefficient = -0.077** - Liberalisation*Gap to leader coefficient = - 0.004 *** - Liberalisation*Dummy for catch-up firms (Above median) coefficient = 0.01 * - Liberalisation*Dummy for catch-up firms (Above 80th percentile) coefficient = 0.015 **
INTEGRATION	
Bergman (2003): During the 1990s the electricity markets in Norway, Sweden, Finland and Denmark were deregulated and integrated into a single Nordic market for electricity. This paper shows that the electricity market reform has led to quite significant productivity increases.	Suitable data for systematic productivity analysis are not available.
Zarnic (2010b): European electricity market reforms have reduced mark-ups of firms, especially those with subsidiaries. Price-cost margins are negatively associated with better functioning of wholesale and retail markets. The annual decrease in vertical integration negatively affects the mark-ups of consolidated firms.	Average estimated mark-up = 44.6% Dep var: mark-up (for consolidated firms with subsidiaries) Indep var: - Effect of liberalisation coefficient = - 0.018 ** - Effect of cross-border arbitrage Coefficient = - 0.019 ***

Gerbaulet *et al* (2012): The paper examines four scenarios of different tertiary reserve market cooperation; results are promising to lower overall system costs by about 10% in the case of one unified tertiary reserve market called 'Germalpina', which seems to be preferable over the bilateral coalitions. In the scenario of full integration re-dispatch costs decrease by more than 50% compared to the National Scenario.	Total System Cost per month (approximations): 1. National: €85 million 2. Bilateral (Germany and Austria): €79 million 3. Bilateral (Germany and Switzerland): €77 million 4. Germalpina: €75 million ➡ -12% from National to Germalpina Cost of re-dispatch per month (approximations): 1. National: €2.1 million 2. Bilateral (Germany and Austria): €0.4 million 3. Bilateral (Germany and Switzerland): €2 million 4. Germalpina: €0.9 million ➡ - 57% from National to Germalpina
Abbasy *et al* (2009): Integration of regulating power markets of different balancing regions has a potential to reduce the costs of balancing within multinational power markets. This paper investigates this potential by studying the case study of Northern Europe; the Netherlands, the Nordic region and Germany.	Total Balancing Costs (approximations): - 0% Total Interconnection Capacity: €180 million/year - 5% Total Interconnection Capacity: €125 million/year - 10% Total Interconnection Capacity: €100 million/year - 15% Total Interconnection Capacity: €90 million/year
Haucap *et al* (2012): In recent years, a new market design was created by synchronization and inter-connection of the four control areas of German reserve power market. The paper finds that reforms were jointly successful in decreasing MRP prices leading to substantial cost savings for the transmission system operators.	Savings for 46 month: - Market for incremental MRP - €1948 million - Market for decremental MRP €1400 million
Mansur and White (2012): Electricity markets exhibit two forms of organisation: decentralised bilateral trading and centralised auction markets. The empirical evidence indicates that employing an organised market design substantially improved overall market efficiency, and that these efficiency gains far exceeded implementation costs.	Gains from trade ($ million/year) - Bilateral market post 10/2004 (counterfactual) = 150.1 - Organised market post 10/2004 (estimate) = 312.9 - Change in gains from trade ($ million/year) = 162.8 Implementation costs (one-time) - $40 million

About Bruegel

Bruegel is a European think tank devoted to international economics. It started operations in Brussels in 2005 as a Belgian non-profit international organisation supported by European governments and leading corporations. Bruegel seeks to contribute to the quality of economic policymaking in Europe through open, facts-based and policy-relevant research, analysis and discussion.

Bruegel issues a range of publications. The Bruegel Blueprint Series provides comprehensive analysis and policy recommendations on central questions of the moment. Bruegel Policy Briefs provide concise, topical analysis targeted at an audience of executives and policymakers, with an emphasis on concrete policy orientation. Bruegel Policy Contributions are responses to requests by policymakers or public bodies, including testimonies at hearings or responses to public consultation. Bruegel and its researchers also publish working papers, op-eds, collaborative papers with other organisations, and essays.

Bruegel's research is independent and does not represent the views of its board or members. For full details of Bruegel's activities and publications, visit the website at www.bruegel.org.

Electricity without borders:
a plan to make the internal market work

The price paid for electricity by Europe's households and businesses is rising. The completion of the European Union internal energy market in 2014 is supposed to limit this trend. A 'deep' internal energy market would indeed result in significant cost savings. The benefits of integration increase if countries jointly optimise their power plant fleets, and as the share of renewables in the system increases.

However, current policy focuses on one segment of the sector – the wholesale electricity market – and could bring about a hollow victory. Because of the rising share of renewables, factors that affect the cost of energy beyond the pure generation cost become more important. But the provisioning of capacity, flexibility, networks, system stability and renewables continues to be mainly organised nationally. To reap the benefits of the internal electricity market, the remuneration of these components of the system should be organised as part of a comprehensive and consistent European market. This Blueprint sets out a realistic plan that describes how effective European cooperation on network planning, operation and financing can be achieved.

Bruegel is a European think tank devoted to international economics. It is supported by European governments and international corporations. Bruegel's aim is to contribute to the quality of economic policymaking in Europe through open, fact-based and policy-relevant research, analysis and discussion.

ISBN 978-90-78910-31-2
9 789078 910312 > €15

bruegel
33, rue de la Charité, Box 4, 1210 Brussels, Belgium
www.bruegel.org