Determining Optimal Interconnection Capacity on the Basis of Hourly Demand and Supply Functions of Electricity

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ABSTRACT

Interconnections for cross-border electricity trade improve price convergence and welfare. Increased production from variable renewables however implies higher levels of optimal interconnection capacity than in the past. Rather than using scenario building to determine new optimal levels of interconnection capacity, this paper presents a new methodology for Cost-Benefit Analysis (CBA) based on empirical market data, using the French-German electricity trade as an example. Employing a very fine dataset of hourly supply and demand curves (aggregated auction curves) from the EPEX Spot market, it constructs net export (NEC) and net import demand curves (NIDC) for both countries. This allows assessing hourly welfare impacts for incremental capacity and, summed over the year, the annual welfare benefits for each discrete increase in interconnection capacity. Confronting benefits with the annualised costs of increasing interconnection capacity determines the socially optimal increase in interconnection capacity between France and Germany on the basis of empirical market micro-data.

Keywords: Electricity Interconnections, Variable Renewables, Optimal Infrastructure Provision, Hourly Net Export and Import Demand Curves, Cost-Benefit Analysis

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1. INTRODUCTION

Interconnections for cross-border electricity flows are at the heart of the project to create a common European electricity market. Interconnections allow exporting electricity from countries with relatively lower costs of production to those with relatively higher costs thus increasing economic efficiency. In the process, prices in the high cost country will fall and prices in the low cost country will rise thus increasing the combined producer and consumer surplus in both countries.[1] The process will come to an end only when either prices in both countries are equalized or when the available interconnection capacity is saturated.

1. A net gain in welfare is ensured by the possibility of arbitrage. If the gains of the winners from increased trading were not larger than the losses of the losers, it would be profitable for consumers in the exporting low-price country to buy back the electricity sold abroad. Conversely, it would be profitable for the producers in the importing high-price country to sell electricity at less than the new equilibrium price.

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The challenge for regulators and electricity policymakers is to determine the optimal amount of interconnection capacity. Constructing cross-border capacity is costly. Installing interconnection capacity up to a level at which it would never be saturated, yielding zero benefits at the margin, would constitute inefficient over-investment. Optimal investment will take place up to the point where the marginal welfare increase equals the marginal cost of adding interconnection capacity. Determining the socially optimal interconnection capacity is the subject of this article.

Expanding cross-border interconnection in an economically optimal manner has become more critical in recent years due to the large-scale deployment of variable renewables energies (VRE), i.e., wind and solar PV. Due to their dependence on a varying meteorology, wind and solar generation tends to be concentrated during a limited number of hours, during which large amounts of low cost electricity flood the European electricity system. As the wind blows and the sun shines only during a limited number of hours, VRE production is highly correlated, both spatially and temporally. Annual VRE production is concentrated during hours with favourable meteorology. The result is an increasing number of hours with high VRE production, which implies more frequent saturation of interconnection infrastructure and, in consequence, price divergence with concomitant welfare losses (see Keppler *et al.*, 2016). The optimal amount of interconnection infrastructure will *ceteris paribus* be higher in the presence of VRE than in their absence.

The objective of the European Union (EU) to increase the overall share of renewable energy sources to 20% by 2020 (27% by 2030) implies for the electricity sector a share of more than 30% (40% by 2030) from renewable sources, much of it from wind and solar PV. Already, generation from wind and solar PV has risen in the EU from 7.6% in 2010 to 14.4% in 2014 (ENTSO-E, 2014). For interconnection capacity provision, more important than the share of electricity, which reflects average annual production, is the installed VRE capacity, which determines peak production during favorable hours. The latter, for instance, has risen in Germany from 6 GW for wind and 0.1 GW for solar in 2002 to 39 GW for wind and 38 GW for solar in 2014 (BMU, 2016).

In the presence of such dramatic changes in the generation mix, the question of what constitutes the socially optimal level of optimal interconnection capacity poses itself with new urgency. Given its importance, there exists a large and growing literature on the subject. A first general reference is the paper by Brunekreeft, Neuhoff and Newbery, which carefully discusses four key policy issues in optimal infrastructure provision – locational marginal pricing, congestion management, merchant provision of interconnection capacity and optimising incentives for TSOs (Brunekreeft *et al*., 2005). Optimising TSO incentives falls outside of the scope of this paper, which assumes that the objective function of TSOs is the maximisation of the social surplus but has been discussed, for instance in Léautier (2003), Joskow (2008) and Glachant *et al*. (2012). Congestion management has become less of an empirical issue in the European context since the introduction in 2010 of flow-based market coupling, which optimises the use of existing interconnection with the help of a combined order book and implicit trans-border capacity allocation. The benefits of market coupling and implicit pricing had been pointed out early by Ehrenmann and Smeers (2003), Joskow (2003) and Turvey (2006). The questions posed by locational marginal pricing and the merchant provision of interconnection capacity are remarkably similar and are at the heart also of this paper: in competitive electricity markets with marginal congestion cost pricing, the private provision of transport capacity will *not* ensure the social optimum. The key reason is that in the absence of being able to differentiate prices, investors are unable to capture the totality of the social surplus (see Joskow and Tirole (2005) and de Jong and Hakvoort (2006)).

Despite the rich literature on interconnection investment, there exists little empirical work in the vein of the present article. Wherever quantitative welfare analysis has been undertaken, it is based on *ex ante* scenario modelling rather than on *ex post* empirical analysis based on market data. In terms of the underlying research issue, this paper nevertheless belongs to the literature on the welfare analysis of investment in interconnection capacity. Work by Malaguzzi Valeri (2009) on the UK-Ireland border, Schroder *et al*. (2010) on the link between Germany and the Nordpool region, Schaber *et al*. (2012) on the regions of ENTSO-E plus several off-shore grids, Lynch *et al*. (2012) on Northern Europe and Spiecker *et al*. (2013) on the EU-27 countries, all modelled the contribution of greater levels of interconnection capacity on reducing the cost of integrating variable wind-power. The impact on welfare is straightforward: as interconnection capacity increases, congestion recedes and price convergence between adjacent regions improves, bringing increased welfare in its wake.

Despite this shared interest in the welfare implications of interconnection provision, the present paper distinguishes itself due to its use of empirical electricity market data and its objective to use this data to answer the normative question of what constitutes a welfare-maximising level of interconnection capacity. In this approach, optimal interconnection capacity is endogenously determined as a function of the existing generation mixes in the two countries. These generation mixes may not be the least cost mixes but are considered to be determined by autonomous policy decisions. This is different in linear optimisation models such as the one presented in Lynch *et al.* (2012), where optimal investment in interconnection and generation capacity are determined jointly.

The methodology and results of this paper should be seen as complementary to the *Ten-Year Network Development Plan* (TYNDP) developed by the European Network of Transmission System Operators for Electricity (ENTSO-E, 2016), which also aims at determining welfare maximising levels of interconnection capacity. The TYNDP 2016 foresees investments of € 150 billion for transnational interconnection capacity in Europe to double by 2030 in order to achieve the European target of each country achieving an interconnection capacity corresponding to 10% of its peak demand. Among the 200 individual projects listed, priority is given to those that improve the links with the electricity "peninsulas" of the British Isles, Iberia, Italy and the Baltic States. The interconnection capacity between Great Britain and the Continent is thus to increase from currently 2.5 GW to 10 GW in 2030.[2] Interconnection capacity between Spain and France is set to increase from 2.5 GW to at least 9 GW and between Northern Italy and the rest of Europe from currently 8.5 GW to 13.5 GW (ENTSO-E, 2016, 1.12).

Desired future interconnection capacity is determined through a forward-looking scenario analysis centring on cost minimisation and economic welfare but including security of supply, VRE integration, reducing transmission losses and CO_2 emissions, technical resilience and flexibility as additional criteria (ENSO-E, 2015). Optimal interconnection capacities are determined through an iterative modelling process, in which different exogenously given levels of capacity are combined with detailed generation dispatch modelling benefitting from a high level of technical details on parameters such as reserve requirements, ramp rates, minimum up-and-down-times and start-up costs. The TYNDP benefits from extensive consultation with experts, TSOs and other stakeholders and its road-map for European network development enjoys broad support. Nevertheless, the Cost-Benefit Analysis (CBA) it proposes lacks any explicit feedback with the actual production and consumption decisions of the actors in European electricity markets. This is where the present research comes in, which provides a complementary methodology for the assessment of optimal interconnection capacity.

2. This does not include interconnections between Ireland and Great Britain, nor the direct link between Ireland and the Continent. Entso-E has also issued a statement that current network expansion plans shall not be affected by Brexit.

An Economic Approach Based on Empirical Electricity Market Data

The present paper calculates the annual consumer and producer surpluses for different levels of additional interconnection capacity at the French-German border on the basis of detailed hourly supply and demand data from the EPEX Spot Day-ahead electricity market.[3] The available data on consumer preferences and supplier cost is used first to estimate supply and demand functions and then to establish net export supply and import demand curves in the spirit of Spiecker *et al*. (2013) for both countries. This allows the estimation of consumer and producer surplus for each hour for different increments of additional capacity. Summing the hourly surplus over the year and confronting the resulting combined annual welfare gain with the annualized cost of additional infrastructure allows determining the economically optimal, *i.e.*, welfare maximising, amount of interconnection capacity that should be added to the already existing infrastructure between France and Germany. The hourly data on market supply and demand functions, indispensable to establish meaningful estimates of consumer and producer surpluses, was so far unavailable for economic research. Using hourly offer and supply curves to assess the shifts in equilibrium resulting from increasing infrastructure capacity was first suggested in an unpublished paper by Phan (2014). Phan and Roques (2015) subsequently used hourly offer and supply curves to study the propagation of price changes.

The current article thus presents a new methodology providing a point estimate for 2014. However, estimates for optimal infrastructure will differ with different levels of VRE production in different years due to changes in weather patterns. Annual production levels alone will thus not allow establishing a precise quantitative link of VRE production with infrastructure needs. This is why the authors are working on follow-up research estimating the causal link between VRE production and implied infrastructure needs on an hourly basis, which would allow estimating a causal link independent of annual changes in weather patterns.

The data and methodology employed in this paper are straightforward and the results replicable.[4] There exists nevertheless the limitation that the optimal interconnection capacity between France and Germany is determined exclusively on the basis of French and German supply and demand data. While France and Germany are, their largest respective trading partners, they trade also with Austria Belgium, the Czech Republic, Denmark, Italy, the Netherlands, Poland, Switzerland and the United Kingdom. A complete analysis would have had to take into account also hourly supply and demand data from each of these countries. The switch towards the flow-based allocation of interconnection capacity since March 2015 would further require taking into account trilateral trade flows. However, data on hourly supply and demand curves for individual hours was available only for France, Germany and Switzerland.[5]

While the authors encourage the adoption of the proposed methodology at the European level with more complete data, they are confident that the results would not change substantially. The principal reason for this confidence is that there exists a precise benchmark for unlimited multi-lateral trading including all trading partners of France and Germany, which can be directly compared to the equivalent metric established in this research. This metric is the price of electricity calculated by EPEX Spot since 2010 under the assumption of unlimited interconnection capacity at all borders,

3. This data is currently not publicly available but proprietary to EPEX Spot. However, EPEX Spot has always been forthcoming in making electricity market data available to academic researchers. Requests will however be dealt with on a one-by-one basis.

4. The source code used for the estimation can be made available to researchers upon request.

5. Adding Switzerland as the only third-party country would have reduced rather than increased the transparency of the results.

the European Electricity Index (ELIX), on the basis of the aggregated supply and demand functions of all countries of the Central Western Europe (CWE) platform. The ELIX thus constitutes a hypothetical European maximum efficiency price.

For comparison purposes, this research established for each hour the *bilateral* maximum efficiency price on the basis of French and German supply and demand, i.e., the price that would result if bilateral interconnection capacity was unlimited. Comparing hour by hour the ELIX with the bilateral maximum efficiency price provides a good indicator of the importance of including third countries in the analysis. The comparison shows that the difference amounted on average to € 2.13 per MWh (see Section 4 below for more detailed statistical analysis). This modest divergence between optimal bilateral and multilateral prices implies that the bilateral producer and consumer surplus calculations provide indeed meaningful indications for the optimal provision of bilateral interconnection capacity.

Enlarging the Methodological Tool-Box for Optimal Infrastructure Assessment

This article presents an approach focussed on economic welfare and based on empirical market data complementary to the broader approach pursued in TYNDP 2016, which includes also technical, environmental and social impact (see ENTSO-E (2015)). Clearly, the development of networks for electricity systems takes place in a complex world with overlapping political priorities of which maximizing the economic surplus is only one. Authors such as de Nooij also argue that dynamic efficiency benefits through increased competition and security of supply improvements in a broader "social cost benefit analysis (SCBA)" add to the static economic efficiency improvements calculated here (de Nooij (2012), p. 161). Impacts on investment are one example, as added interconnection capacity and the convergence of electricity prices will improve conditions in the former low-cost country and make them less attractive in the former high-cost country. These dynamic effects, just like non-economic benefits, are, however, very difficult to quantify as they depend on qualitative and political judgements. In keeping with existing research on the economic benefits of interconnection capacity, this paper also does not take into account the costs and benefits of alternative instruments. On a technical level, it is now possible to replicate some of the static efficiency gains, dynamic gains or security of supply improvements of added interconnections through increased flexibility provision by means of storage, demand response or local auto-consumption. The economic case for such alternative instruments remains to be made. In any case, economic comparisons between different technical measures would have to begin with individual assessments such as the one proposed here.

Economic Cost-Benefit analysis thus remains the basis for informed decision-making. This does not impede real-world decision-making to take additional criteria into account. Like all empirical research, the present analysis is inevitably backward-looking, while the TYNDP develops forward-looking scenarios for 2020 and 2030. Again, both approaches have their uses. Ideally, future development plans will take the methodology and results provided here into account to refine their forward-looking scenarios in specific policy-oriented contexts.

While this paper thus establishes a quantitative estimate for a lower bound of optimal additional interconnection capacity, its principal contribution is methodological by making use of the detailed hourly demand and supply curves of the EPEX Spot electricity market. Complementing electricity market simulations with empirical and econometric research is also all the more important in the light of recent developments in electricity markets. Economically speaking, electricity is less and less the homogenous good scenario modelling presupposes. The variability of renewable production in conjunction with emerging phenomena such as auto-consumption and demand response makes explicit modelling of the objective functions that determine the dispatch of power suppliers more difficult than only a few years ago. This requires dispatchable producers to vary their output frequently and with steep gradients, which increases the importance of ramping constraints that are notoriously hard to model. All of this requires new forms of empirical calibration, especially on the demand side. An important part of the value added of this research consists in extracting the economic information contained in 8 760 demand functions of each country, in addition to the same number of supply functions, of the Franco-German day-ahead market.

In addition, the economic value of providing ancillary services to the system such as primary, secondary or tertiary reserves has increased considerably while the value of simple electricity provision has fallen. The falling market price of electricity is readily verified. Average electricity prices in the German/Austrian market were € 32 per MWh in 2015, more than 50% off their peak of € 67 in 2007 (see http://www.epexspot.com/en/market-data/). Assessing the increasing economic value of ancillary services is more difficult but anecdotal information points into the direction that market participants increasingly modify their behaviour according to developments in short-term markets. One indicative example is continuous Intraday trading in France, where volumes have risen between 2007 and 2015 from 232 GWh to 339 GWh and prices from € 17 to € 33 per MWh (*ibid*.). Due to data constraints, also this paper only uses data from the day-ahead market, which remains a valid proxy for forward markets. However, while most scenario exercises completely disregard developments in the shorter-term Intraday, balancing and ancillary services markets as well as ramping constraints, empirical investigations such as this one take such changes into account at least in a partial and implicit manner, through their impact on the real day-ahead market. Once comparable data on short-term markets becomes available, it will improve the precision also of this analysis. However, their direct impact, as opposed to the indirect impact through the day-ahead market, on optimal interconnection provision is limited. While volatility in shorter-term markets is higher, which *ceteris paribus* would imply higher optimal levels of interconnection, volumes are still about two orders of magnitude lower. In other words, it is still decided in the day-ahead market whether an interconnection is congested or not.

The structural changes that have taken place in electricity markets during a very short period thus add pertinence to the sort of empirical research proposed here. In combination with the large amount of relevant new data on detailed demand and supply function that was hitherto unavailable for economic research, this article thus presents an additional methodology for determining optimal interconnection capacity. The remainder of the paper is organized as follows. Section 2 briefly presents the context of German-French electricity trade as part of the transition to a unified European electricity market. Section 3 provides a detailed description of the data used, the methodology employed and the model that was developed. Section 4 presents the results in terms of the optimal amounts of additional infrastructure capacity required to maximise the combined surplus in the French and German electricity markets. Section 5 concludes.

2. THE CONTEXT OF FRENCH-GERMAN ELECTRICITY TRADE

Both France and Germany are actively engaged in the pan-European electricity trade. Traditionally, France is a net exporter during the summer time and a net importer during winter time due to the specificity of having a relatively high share of electric heating. Germany's exports and imports depend primarily on the availability of surplus power from its of wind and solar PV capacity which stood at 77 GW in 2014 (BMU, 2016). While France is overall Europe's largest electricity

Table 1: The Convergence between French and German Electricity Prices (GWh) (Percentage of hours with price differences of less than € 0.1)

	2011	2012	2013	2014
Convergence Rate	74.05%	68.49%	47.61%	58.73%

Source: Keppler et al. (2016) and own calculations.

exporter, Germany is the only country with which it maintains a negative trade balance. In 2014, Germany exported 77.1 TWh of which 9.9 TWh went to France, which imported a total of 15 TWh. France exported 84.5 TWh, of which 4.0 TWh went to Germany, which imported a total of 40.4 TWh (http://ec.europa.eu/eurostat, http://clients.rte-france.com).

These electricity flows pass through a total of 2.6 GW of interconnection capacity from France to Germany and of 3.6 GW from Germany to France. There has been no investment in new interconnection capacity between France and Germany in recent years. The surprising difference in the available capacity for the two directions, France-Germany or Germany-France, is due to physical constraints on the national upstream and downstream networks to which the interconnections are connected. Potential flows from France to Germany are thus smaller than flows from Germany to France due to the limited capacity of the intra-German transport lines in particular in the Rhine-Ruhr area.[6]

The capacities indicated are commercial capacities that can be acquired by commercial auctions with appropriate adjustments, decided upon by the TSOs of both countries for safety margins to ensure network security. In particular, Germany's energy supply has significantly changed over the last few years due the rapid deployment of new capacities of wind and solar PV with a variable production profile. The maximum daily solar and wind-combined production in 2014 was thus 580 GWh on 31 January, while the minimum was only 22 GWh on 16 January, which corresponds to factor of 30. For comparison, Germany's average daily power consumption was 1 435 TWh and that of France 1 274 TWh (www.rte-france.com). Germany's hourly maximum load of wind and solar PV combined was 41 GW on 14 April, whereas the minimum hourly load is equal to zero (Fraunhofer ISE, 2016). Such high variations require flexibility responses, one of which is constituted by interconnections with neighbouring countries.

In the presence of limited interconnection capacity, the variability of wind and solar PV impacts the convergence of electricity prices. From the point of view of welfare economics, price convergence between countries is desirable as it maximizes the combined surplus of the two countries. However, prices between France and Germany *diverged* in recent years due to the rapid development of VRE in Germany coupled with constant bilateral interconnection capacities (see Table 1). This development was dampened but not overcome by the introduction of market coupling, allowing for more efficient allocation of available interconnection capacity (see Keppler *et al.*, 2016).

While the convergence rate increased somewhat again in 2014, this was a year of exceptionally low wind production. In either case, prices converge as long as interconnection capacity is available, and power can circulate freely between all neighbouring countries and, in particular, directly between Germany and France. However, during hours when export demand due to massive German VRE production exceeds available interconnection capacity, prices diverge. In an economic

6. Germany is currently investing heavily in its national transmission grid, in particular along its Western border (Bundesnetzagentur, 2018). By 2025, current bottlenecks are likely to be alleviated. Calculations in Sections 3 and 4 have thus been performed on the basis of the assumption that interconnections are unconstrained by national bottlenecks in both directions.

perspective, such price divergence translates into welfare losses, which could have been avoided if more substantial interconnection capacities had been available. The article concluded that "the significant increase in the production of variable renewables that Europe has witnessed in recent years requires a new look at European power market integration. It poses, in particular the question of … what is the socially optimal level of physical infrastructure provision of both at the national and the European level." This paper takes its starting point from this observation.

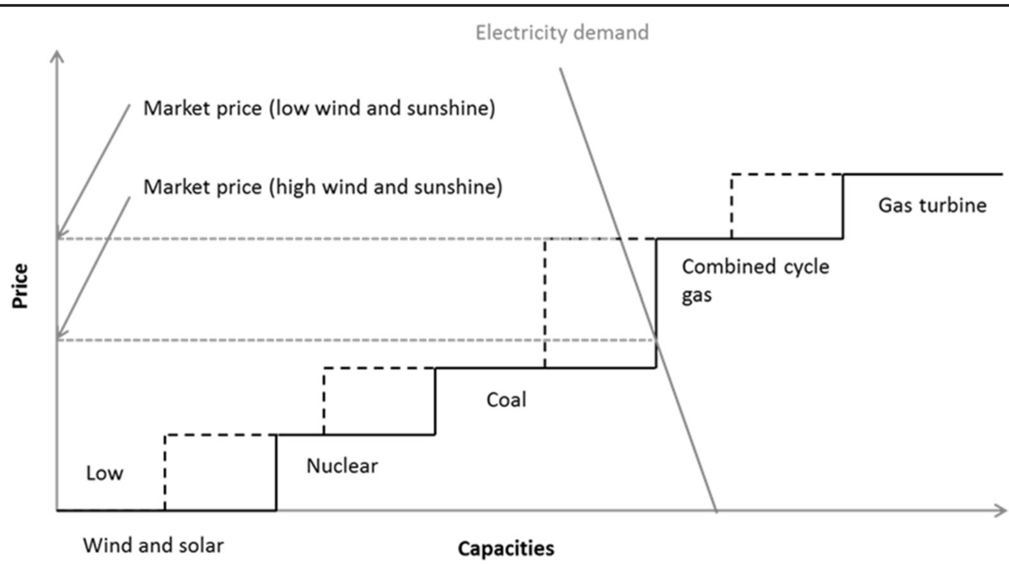
3. DATA, METHODOLOGY AND THE CALCULATION OF CONSUMER AND PRODUCER SURPLUS

As far as exchanges on organized multilateral markets with transparent price formation are concerned, electricity trading between France and Germany takes place on the EPEX Spot and EEX exchanges. As discussed, while short-term and ancillary markets are becoming gradually more important, the hourly Day-ahead market remains for the time being the most relevant reference for the price of electricity.

Electricity generation technologies vary by their costs structures and are dispatched according to the increasing order of their variable costs. These variable costs form a bidding or merit order curve that consists of a set of stacked quantity-cost tuples, which is equivalent to the short-term supply curve in the electricity. In the presence of electricity produced by wind or solar PV at zero short-run marginal costs, the merit curve shifts to the right (see Figure 1). With unchanged demand, technologies with lower variable costs will be selected at the margin and prices will fall.

Electricity trading on EPEX Spot handles the respective export supply and import demand curves of two countries jointly, establishing an *overall* merit order and demand curve, a process known as "market coupling". Market coupling implies implicit rather than explicit auctioning of cross-border transport capacity, *i.e.*, exporters and importers obtain the necessary cross-border capacity automatically with their bids on the power exchange. Despite the efficiency gains due to market coupling, due to the costs of providing interconnection capacity, some limited price divergence remains the norm rather than the exception.

Figure 1: Shifts in the Merit Curve Due to VRE with Zero Short-run Marginal Costs



Presentation of the Data

All data used in this study is hourly data, in order to take into account intraday variations of variable production. The precise data sets used were:

- The EPEX Spot market auction prices for the market zones of France and Germany/ Austria;
- The ELIX price for each hour (EPEX Spot data);
- The EPEX Spot auction aggregated demand and supply curves in the market zones of France and Germany/Austria;
- The import and export capacities for interconnection between France and Germany provided by RTE.

The basic idea is to calculate the hourly variations in consumer and producer surplus as a function of different levels of added interconnection capacity. Let CS_i be the consumer surplus and PS_i the producer surplus at each hour i, D_i the quantity demanded at each price p_i, S_i the corresponding supply and IC the available interconnection capacity and it holds that

$$CS_i = \int_0^{qi} \mathrm{D}_i(p_i)\mathrm{dq} - p_i(\mathrm{IC})^* q_i(\mathrm{IC})$$

$$PS_i = -\int_0^{qi} \mathrm{S}_i(p_i)\mathrm{dq} + p_i(\mathrm{IC})^* q_i(\mathrm{IC})$$

On the basis of the hourly demand and supply curves (aggregated auction curves) in the French and German electricity markets it is possible to calculate the prices and respective welfare surplus *that would have prevailed at different levels of interconnection capacity*.

The aggregated auction curves provide the price and quantity information for all bids in the French and the German market. The specific format in which they are provided can be seen in Table 2. Offer bids are marked "sell", demand bids (not represented), are marked "buy".

Table 2: Example of an Auction Aggregated Supply Curve (Price in Euros/MWh and Volumes in MWh)

Date	Week	Week Day	Hour	Price	Volume	Sale/Purchase
12/31/2014	1	3	1	-500.00	5,702	Sell
12/31/2014	1	3	1	-499.00	5,712	Sell
12/31/2014	1	3	1	-498.90	5,742	Sell
12/31/2014	1	3	1	-498.00	5,742	Sell
12/31/2014	1	3	1	-497.90	5,742	Sell
12/31/2014	1	3	1	-200.10	5,743	Sell
12/31/2014	1	3	1	-200.00	6,115	Sell
12/31/2014	1	3	1	-180.50	6,115	Sell
12/31/2014	1	3	1	-180.00	6,140	Sell
12/31/2014	1	3	1	-150.10	6,140	Sell
12/31/2014	1	3	1	-150.00	6,180	Sell
12/31/2014	1	3	1	-49.98	6,180	Sell
12/31/2014	1	3	1	-49.90	6,274	Sell
12/31/2014	1	3	1	-10.00	6,274	Sell
12/31/2014	1	3	1	-5.00	6,275	Sell

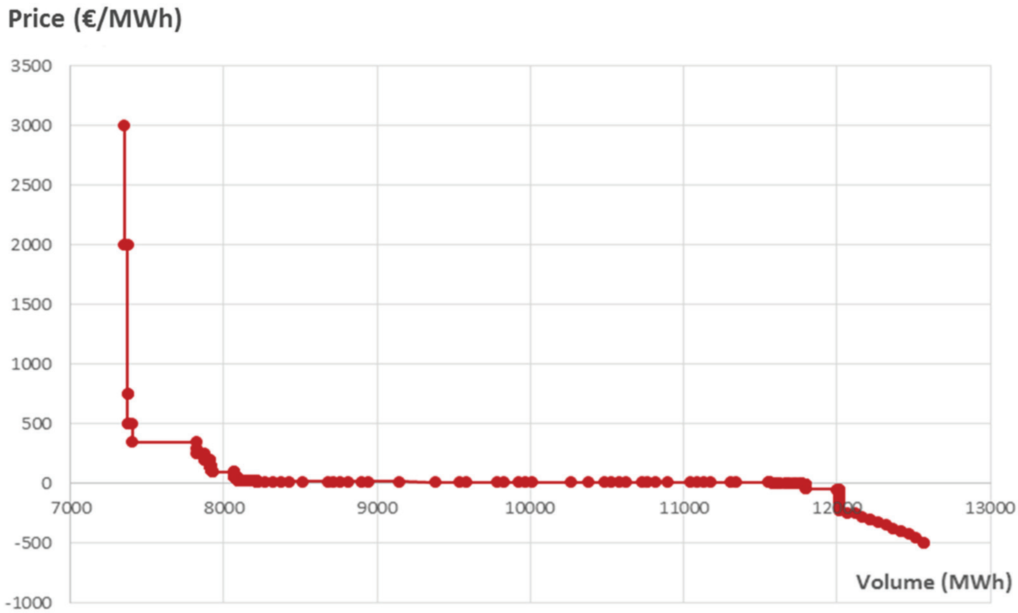
Source: www.epexspot.com

Taken together, these bids form demand and supply curves for each hour of the year. Figures 2 and 3 show examples for demand and supply curves in the French market.

An Overview of the Methodology: Working with NECs and NIDCs

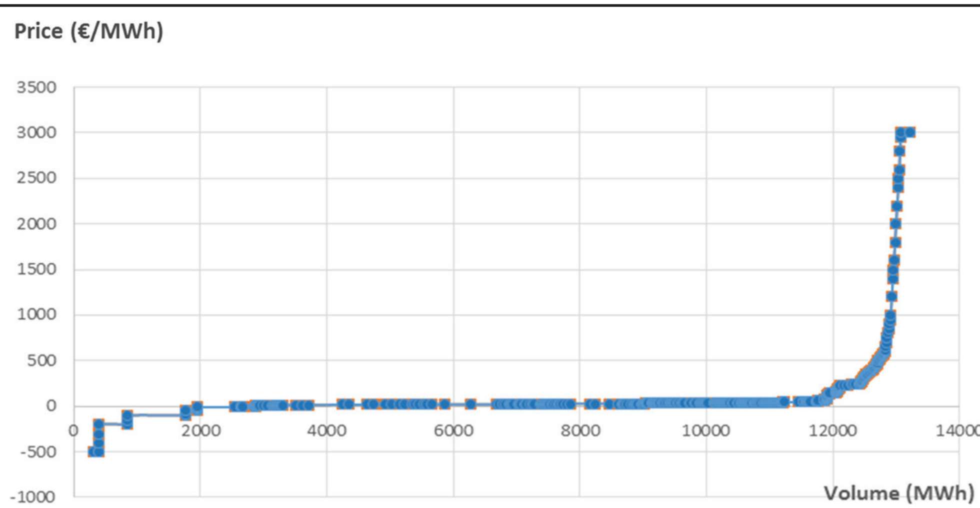
Figure 4 synthesizes the methodology employed. On the basis of the hourly offer and supply curves from the EPEX Spot day-ahead market as well as from the observed exchanges between France and Germany, net export curves (NEC) and net import demand curves (NIDC) for both

Figure 2: Example of a Demand Curve in the French Market (3 June 2014, Hour 7)



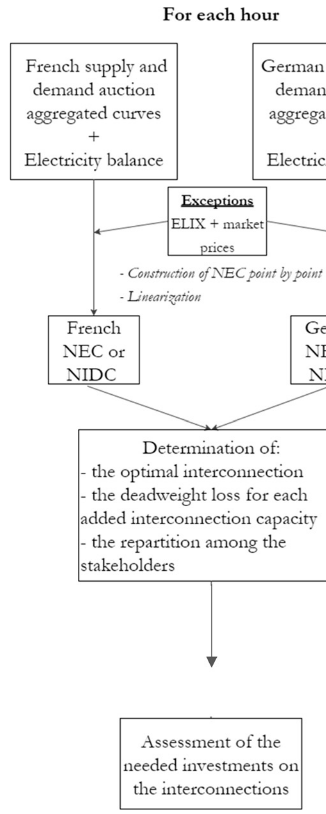
Source: www.epexspot.com

Figure 3: Example of a Supply Curve in the French Market (20 May 2014, Hour 8)



Source: www.epexspot.com

Figure 4: Synthesis of the Methodology



countries were constructed. To this purpose the offer and demand curves are linearized by means of ordinary least square (OLS) regressions. In order to be able to treat the vast amount of data, a number of small adjustments for extreme outliers and corrupted results were applied (see below).

Net Export Curves (NEC) and Net Import Demand Curves (NIDC) are convenient tools for assessing the welfare gains from increased electricity trading. Net Exports (NE) and Net Imports (NI) are defined as the difference between local supply and demand, depending on whether the latter exceeds or falls short of the former. If P* is the equilibrium price at which local supply and demand are balanced and no further trading takes place, NE is a positive quantity for all prices higher than P* and NI a positive quantity for all prices lower than P*:

$$NE(p) = S(p) - D(p) \forall P \geq P^*$$

$$NI(p) = D(p) - S(p) \forall P \leq P^*.$$

The Net Export Curve (NEC) and the Import Demand Curve (NIDC) indicate the market price for each amount of exports and imports. One can thus also infer from the NEC (NIDC) the price changes for each additional MWh exported (imported).

Combining the aggregated auction curves of the EPEX auctions with the observed demand and supply of France and Germany, NEC and NIDC curves were constructed for each of the 8760 hours of the year. The amount of data is about 600 Mo per year and was treated with the statistics Software R.

Table 3: Statistics for Outliers Eliminated from the Construction of NECs and NIDCs

	2014
Mean of percentage of outliers excluded for each hour	4.12%
Maximum percentage of the points excluded at each hour	31.7%
Minimum percentage of the points excluded at each hour	0.51%
Standard deviation of percentage of excluded points	1.75%

First, aggregated auction curves were linearized concentrating on the affine parts and eliminating extreme outliers. Working with linear supply and demand curves is the only operationally feasible option. There is also good reason to believe that outliers do not provide economically relevant information as trading never takes place at such extreme values. Very high or very low prices, for instance, are quoted for bids that are inserted into the 24-hour bidding forms only for completeness sake but are not intended to be actually executed.

Given this premise, working with a very good fit for the overwhelming majority of quotes was preferable to working with a mediocre fit for the totality of quotes. The criterion to eliminate outliers was to exclude all points outside a 3-sigma band around the mean price of the hourly data set. This yielded the results in Table 3:

Second, the linearized demand and supply curves from the hourly auction were confronted with the observed values for the domestic supply and demand in each country. The difference between demand and supply curves from the EPEX Spot auctions and observed domestic demand and supply provides for each price the desired quantities for export and import. The only thing that stops these desired quantities to be realised and reach full price convergence are limitations in interconnection capacity.

One thus obtains:

- o The desired net exports for the exporting country, i.e., the difference between potential supply and domestic demand; this provides the net export curve (NEC).
- o The desired net imports for the importing country, i.e. the difference between desired demand and domestic supply; this provides the net import demand curve (NIDC).

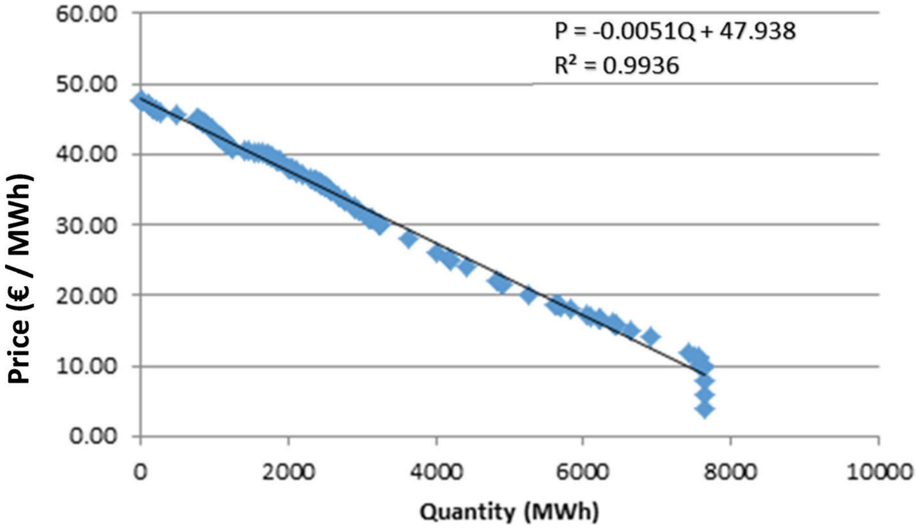
Figures 5 and Figure 6 show examples for a French net import demand curve (NIDC) and a German net export curve (NEC).

A certain number of further adjustments to the results of the econometric regressions for specific hours became necessary as completeness of the data was a prerequisite for the necessary automation process. Such adjustments were applied in two cases:

- o If there existed a significant difference, more than €10, between the real equilibrium price reported for France and Germany provided by EPEX and the equilibrium price resulting from the linear regressions of the model.
- o If there existed a significant difference, more than €15, between the ELIX price and the unconstrained equilibrium price with unlimited interconnection capacity predicted by the model.

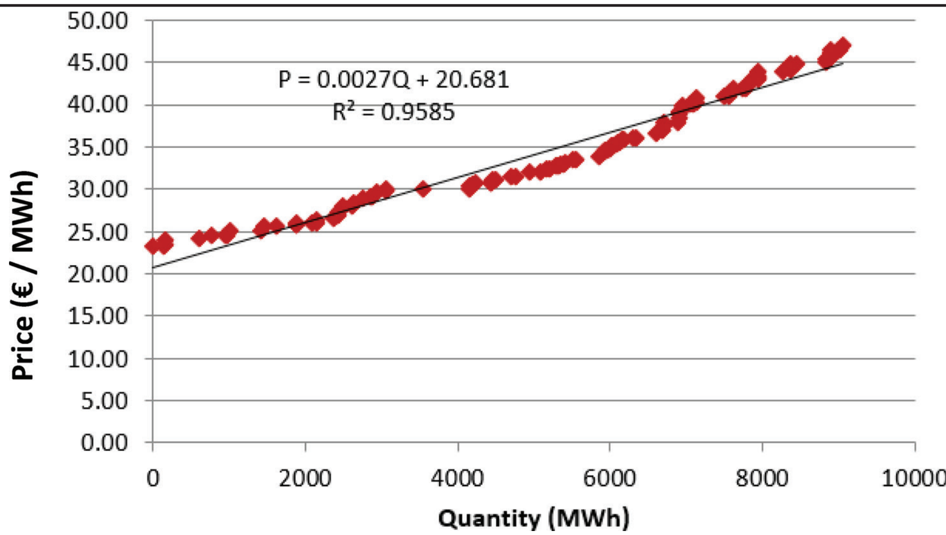
In both cases, exchanges with third countries that were not included in the model are the obvious explanation for such divergences. The amounts chosen reflect the arbitrage between maintaining completeness of data and the need to exclude individual data points clearly determined by

Figure 5: A French Net Import Demand Curve (NIDC)



Source: www.epexspot.com and www.rte-france.fr

Figure 6: A German Net Export Curve (NEC)



Source: www.epexspot.com and www.rte-france.fr

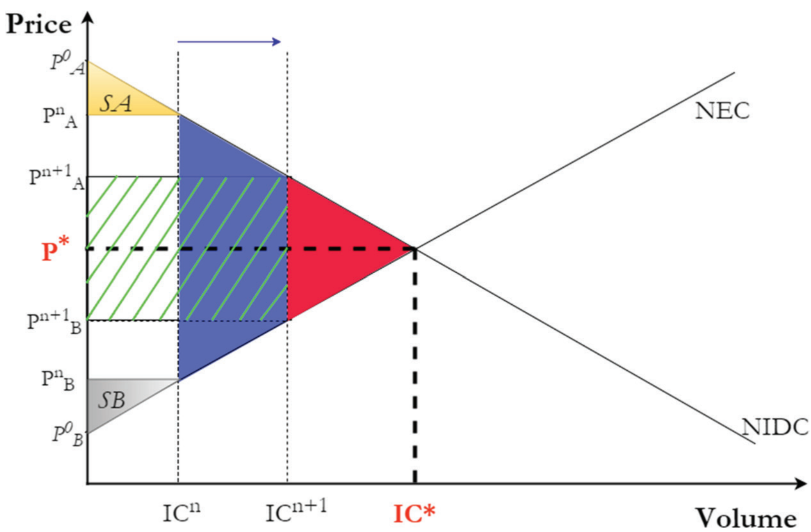
factors outside the model. In these cases, the linear regressions of the reported supply and demand curves were rejected and NECs and NIDCs were constructed on the basis of the reported equilibrium values for national prices and the ELIX. These provide neutral results included only to satisfy the completeness requirements of the automation process. The share of thus adjusted hourly values out of a total of 8 760 hours per year was less than 1.5% (see Table 4).

These adjustments permitted to establish a complete and workable set of NEC and NIDC curves for calculating the welfare implications of the stepwise provision of additional interconnection capacity. The linear coefficient of correlation R^2 for the estimation of NECs and NIDCs for 2014, excluding the outliers, is above 0.90.

Table 4: Number of Rejected Hourly Estimations

	2014
Total number of hours	8760
Divergence with reported real equilibrium prices	88
Divergence with ELIX	29
Divergence with reported prices and ELIX	11

Figure 7: Welfare Impacts Due to Additional Interconnection Capacity



The Welfare Benefits of Providing Additional Interconnection Capacity: Basic Concepts

Following Spiecker et al (2013), a simple two-country linear model is used to analyse how added interconnection capacity increases social welfare and how those gains are distributed among consumers, producers and TSOs. Consider two countries A and B, which in autarky have different equilibrium prices, P_A^0 and P_B^0, due to differences in generation costs. Country B (A) with lower (higher) costs is a potential exporter (importer), with $P_B^0 \leq P_A^0$. Adding interconnection capacity allows electricity to flow from B to A, causing prices to converge, increasing social welfare in the process. The resulting welfare gain from electricity trading can be interpreted as a reduction in the deadweight loss, i.e., the opportunity cost of mutually beneficial trades that were not made due to limited interconnection capacity. Maximizing social welfare is equivalent to minimizing this deadweight loss (see Figure 7).

Improving social welfare, however, implies a trade-off with the private earnings of the operator of the interconnection. Constrained capacity and the resulting price differences during congestion hours generate an income for the TSOs, referred to as the congestion rent (CR). The congestion rent is then the product of the price gap and the electricity traded:

$$CR = (P_A - P_B) \times Q_{IC}.$$

Increasing interconnection capacity between the two countries enables an increase in trade that corresponds in Figure 7 to a move from IC_n to IC_{n+1}. In low-cost country B producers thus face higher demand and in high-cost country A consumers can buy additional electricity at lower prices. This causes prices to converge, as they increase in country B and decrease in country A. The blue-coloured area represents the newly available advantageous trades made possible by new interconnection capacity and the associated gains in consumer and producer surplus. For each increment of added interconnection capacity, the surplus resulting from these new trades can be split into three different components:

- The additional consumer surplus in importing country A (SA in Figure 7);
- The additional producer surplus in exporting country B (SB in Figure 7);
- The reduction in the congestion rent which is shared, by assumption, equitably between the TSOs of the two countries.

As indicated earlier, interconnection capacity is costly and some remaining congestion is thus socially optimal. This implies also at the optimum the existence of a residual deadweight loss (in red in Figure 7) as well as a congestion rent (in striped green).

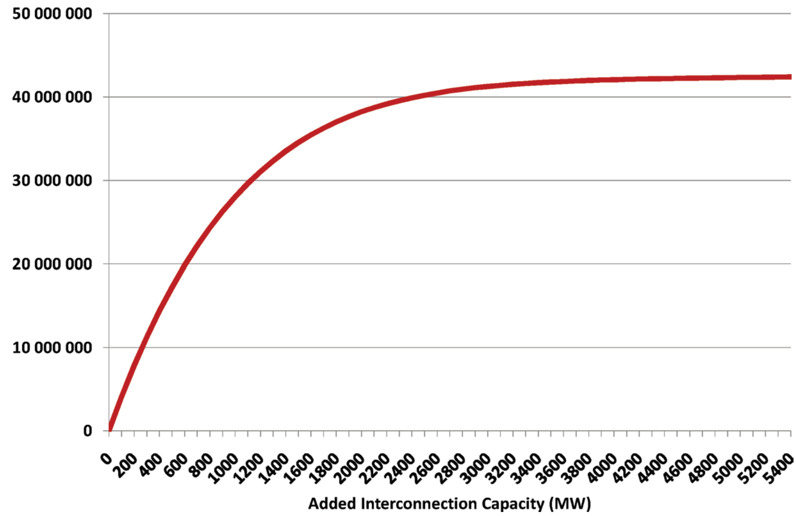
4. RESULTS: DETERMINING THE OPTIMAL INVESTMENT IN ADDITIONAL INTERCONNECTION CAPACITY

On the basis of the NECs and NIDCs constructed with the help of the aggregated auction curves, for each hour welfare changes were calculated as a function of step-wise incremental increases in interconnection capacity. Summing the combined welfare increases on the producer and the consumer side over the 8 760 hours of the year provides the annual increase in welfare for each step increase of interconnection capacity. This benefit in welfare terms is confronted with the annual cost of augmenting interconnection capacity. The point of equality between marginal costs and benefits indicates the socially optimal increase in interconnection capacity.

Estimating the NECs and the NIDCs for each of the 24 hours of the 365 days of the year also allows the determination of a no-congestion interconnection capacity that would ensure full price convergence between the two countries at the no-congestion price. This no-congestion price for the French-German market was compared to the ELIX that takes into account all markets to which France and Germany are connected. As expected, the mean of the difference between the full convergence price and the ELIX is positive. A larger number of participant countries will always allow for lower prices and more efficient outcomes than trading arrangements within a more constrained set of participants.

The full convergence interconnection capacity modelled varies strongly hour by hour. Ensuring complete convergence at all times would require the extremely high added capacity of 28.6 GW, which is clearly suboptimal given the associated costs. Cost-benefit analysis must thus determine the optimal level of investment in added interconnection capacity that maximises net benefits over the year 2014. Results for a specific year must be seen in perspective, as the weather and thus demand and supply can change significantly from year to year. While 2014 was, in terms of renewable production an average year, the quantitative results provided remain limited to that year. At this point, the primary purpose of this paper remains to show that using microdata of real economic behaviour generates relevant results. For a more definitive quantitative assessment, two options exist: first, the use of multi-year data to allow for averaging and the determination of trends; second, the econometric analysis of the link between VRE production and interconnection needs based on

Figure 8: Annual Welfare Increases as a Function of Different Levels of Additional Interconnection Capacity between France and Germany (Euros, 2014 Data)



hourly data. In particular, the second option holds promise and is currently being explored by the authors. Neither option precludes the use of traditional scenario analysis as a complementary tool.

The benefits of added capacity are calculated by first determining on the basis of the linearized NECs and NIDCs the prices in France and in Germany for each increment of interconnection capacity in every single hour. This allows subsequently the calculation of consumer surplus, producer surplus and congestion rent, which together yield the net gain of social benefits, again at the hourly level, for each increment in infrastructure capacity. For each hour, capacity is added until prices converge completely. Figure 8 shows the welfare benefits in function of the level of added interconnection capacity.

As one would expect, the function is increasing and convex. Up to the point of capacity where prices converge at all hours, adding interconnection capacity always increases the social surplus albeit at progressively smaller increments.

Assessing the Cost Side

Determining the optimum level of additional interconnection capacity requires the equalisation of marginal benefits with marginal costs at the optimum. Specific data for the cost of additional interconnection capacity between France and Germany is unfortunately unavailable. However, Schaber *et al*. (2012), Lynn (2012), Bahrman and Johnson (2007), the *2016 TYNDP* (ENTSO-E (2016b) and, in particular, the detailed report by Parsons Brinckerhoff (2012) contain some information on investment costs for interconnection projects. For this exercise, we computed the cost (C_{IC}) of a 400 kV AC interconnection line between France and Germany with a length of 50 km and a power factor of 80% once as an overhead line (OHL) and once as a direct-buried line (DBL). Based on Parsons Brinckerhoff (2012), total investment costs were set at € 24 348 per MW for the OHL and € 111 652 per MW for the DBL. The discount rate was assumed to be 6% and the lifetime 40 years.

Assuming a nominal discount rate (i) for a regulated entity of 6% and a lifetime (n) of 40 years, this yields the annual annuities (A) per MW for and OHL and a DBL respectively:

$$A_{OHL} = \frac{i * C_{IC}}{1 - \frac{1}{(1+i)^n}} = 1618\,€ / \mathrm{MW} \text{ and } A_{DBL} = \frac{i * C_{IC}}{1 - \frac{1}{(1+i)^n}} = 7\,421\,€ / \mathrm{MW}$$

A 1000 MW interconnection has thus annual capital costs of roughly € 1.6 million if an overhead-line and roughly € 7.4 million if a direct buried line is chosen. While based on the best publicly available data, this calculation contains a number of simplifications, which future refinements may be able to overcome:

- Cost is not necessarily a linear function of capacity;
- Maintenance costs were omitted;
- Discount rates and lifetimes may vary from the ones used above.

More precise analysis would also need to take into account that total physical interconnection capacity is not available in its entirety for the commercial exchanges on which the present analysis is based. Gross interconnection capacity would thus need to be adjusted for the Transmission Reliability Margin (TRM), which is the security margin deducted from the gross physical Interconnection Capacity (IC) to cover unexpected events such as unintended frequency and voltage changes as well as emergency exchanges.

Following the deduction of the TRM, which is partly a function of VRE capacity on both sides of the border, the Net Transfer Capacity (NTC) indicates the capacity available for commercial exchanges. It is composed of the Available Transfer Capacity (ATC) for immediate auctioning, capacity allocated to long-term contracts, as well as capacity withheld for delayed auctioning. For modelling purposes, total NTC would be the relevant metric to assess welfare impacts.

Putting Benefits and Costs Together to Establish Optimal Infrastructure Capacity

The optimal amount of additional interconnection capacity is determined by equating the marginal benefits and the marginal costs established in the two previous sections. Benefits are measured in terms of the total annual welfare benefits due to the more efficient pricing of electricity following increased IC. Annualized investment costs (AIC) are measured for each increment in capacity. It is beneficial to add interconnection capacity as long as the benefit of each increment is greater than its cost.

Total annual benefits (TB) from additional exchanges in electricity between the two countries are a positive function of the added IC exhibiting decreasing returns to scale:

$$TB = f(IC) = \sum_{i=1}^{8760} CS(IC)_i + PS(IC)_i = \sum_{i=1}^{8760} \int_{p_i}^{mu_i} q_i(IC) + \int_{mc_i}^{p_i} q_i(IC)$$

with $f' > 0$ and $f'' < 0$,where mu_i, mc_i, p_i and q_i are marginal utility, marginal cost, price and quantity at hour i.

At any given hour i, consumer and producer surplus are a function of available interconnection capacity (IC). The function is differentiable to the extent that IC can be continuously scaled. The assumption of differentiability is maintained for the mathematical demonstration, while the empirical calculations work with discrete increments. Annualized investment costs (AIC) are a linear function of added interconnection capacity and per unit costs of capacity (k):

$$AIC = g(IC) = k * ICC \;\; with\, g' = k > 0 \, and \; g'' = 0.$$

Total surplus (TS) is maximized as a function of the added interconnection capacity when the difference between total annual benefits (TB) and annualized investment costs (AIC) is maximized

$$Max: TS = h(IC) = TB - AIC = f(IC) - g(IC).$$

At the optimum it holds that

$$\frac{\partial TS}{\partial IC} = \frac{\partial h(IC)}{\partial IC} = \frac{\partial f(IC)}{\partial IC} - \frac{\partial g(IC)}{\partial IC} = 0.$$

This yields

$$\frac{\partial f(IC)}{\partial IC} = \frac{\partial g(IC)}{\partial IC} or\ f'(IC^*) = g'(IC^*) = k.$$

The thus defined point is a maximum due to the fact that over the whole range it holds that

$$h''(IC) = f''(IC) - g''(IC) = f''(IC) + 0 = f''(IC) < 0.$$

At the optimum, the marginal annual benefits in terms of added surplus from trading will be equal to the marginal increase in the annualized investment costs of the added interconnection capacity.

In reality, adding interconnection capacity is not a differentiable function. The optimal additional interconnection capacity (IC*) is thus the largest additional capacity for which it holds that

$$f'(IC) \geq g'(IC) = k.$$

From these calculations it results that the optimal additional level of interconnection between France and Germany on the basis of 2014 data is 2 800 MW for an overhead line and 1 600 MW for a direct-buried line with substantially higher investment costs. With an existing interconnection capacity of 3 600 MW, this implies that the overall optimal interconnection capacity between France and Germany would be 6 400 MW if the chosen option would be an overhead line and 5 200 MW if the chosen option would be a direct-buried line. The additional welfare benefits of trading from this increase would amount to € 41 million for the OHL and to € 36 million for the DBL, while the annualised costs would amount to € 5 million and € 12 million respectively. Annual net benefits would amount to € 36 million for the OHL and to € 24 million for the DBL.

The results are slightly higher than the ones derived at in the 2030 scenario presented in the TYNDP 2016, which indicates a reference transmission capacity of 4 800 MW. It should be kept in mind that the TYNDP works with a higher share of VRE in production, which would suggest *ceteris paribus* an optimum for the French-Germany interconnection higher than the 5 200 MW for an DBL or 6 400 MW for a OHL calculated in this paper on the basis of empirical market data (see Figure 9).

The market-based methodology proposed here thus provides a coherent benchmark of the economic value of interconnection capacity based on market microdata. While several key parameters on the cost side could not be determined with precision, the sensitivity analysis in Table 5 shows that results are robust and stay in a narrow range of possible outcomes.

Distributional Considerations

Added interconnection capacity between France and Germany up to 2 800 MW would bring welfare benefits from increased electricity trading on the basis of 2014 data of € 36 million

Figure 9: Determination of the Optimal Interconnection Capacity between France and Germany (Euros, 2014 Data)

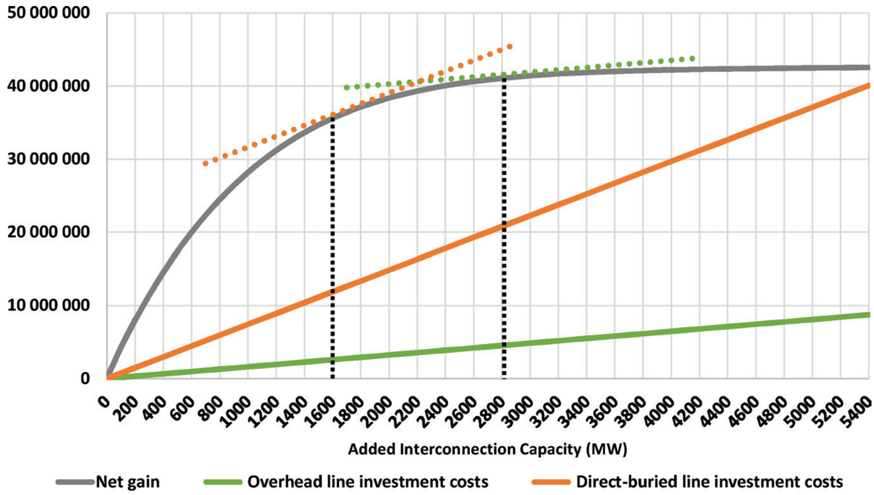


Table 5: Optimal Additional Interconnection Capacity as a Function of Key Cost Parameters (MW, Base Case Highlighted, Length 50 km)

Overhead Line							
Interest Rate	**4%**		**6%**			**8%**	
Years of Lifetime	**25**	**40**	**25**	**40**	**55**	**25**	**40**
Optimal IC Addition	2900	3000	2700	**2800**	2900	2600	2700

Direct-buried Line							
Interest Rate	**4%**		**6%**			**8%**	
Years of Lifetime	**25**	**40**	**25**	**40**	**55**	**25**	**40**
Optimal IC Addition	1700	1900	1500	**1600**	1700	1300	1400

The decisive parameter is clearly the choice between OHL and DBL.

when choosing an OHL and of € 24 million when choosing a DBL. These benefits are shared among French and German consumers and producers as well as the transport system operators through the congestion rent.

Figure 10 provides a breakdown of the distribution of the welfare benefits between French and German producers and consumers as a function of the increase in interconnection capacity. Since during 2014, German exports to France exceeded French exports to Germany, French consumers and German producers would be the main beneficiaries of increased interconnections, while the surplus of German consumers and French producers would decline. Table 6 shows the relevant values for additional increases of 2 800 MW (OHL) and 1 600 (DBL) of interconnection capacity between the two countries.

Figure 10: Consumer and Producer Surplus in France and Germany as a Function of Different Levels of Added Interconnection Capacity (Euros, 2014 Data)

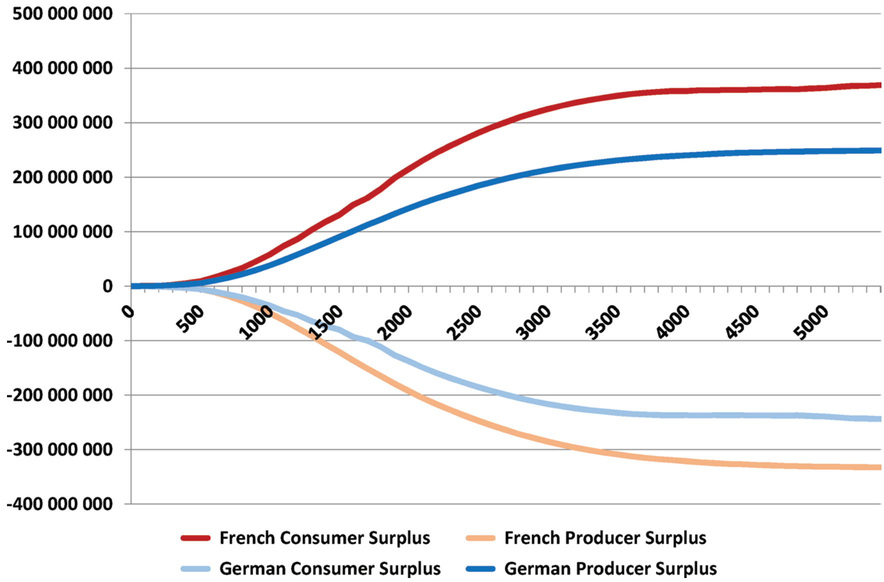


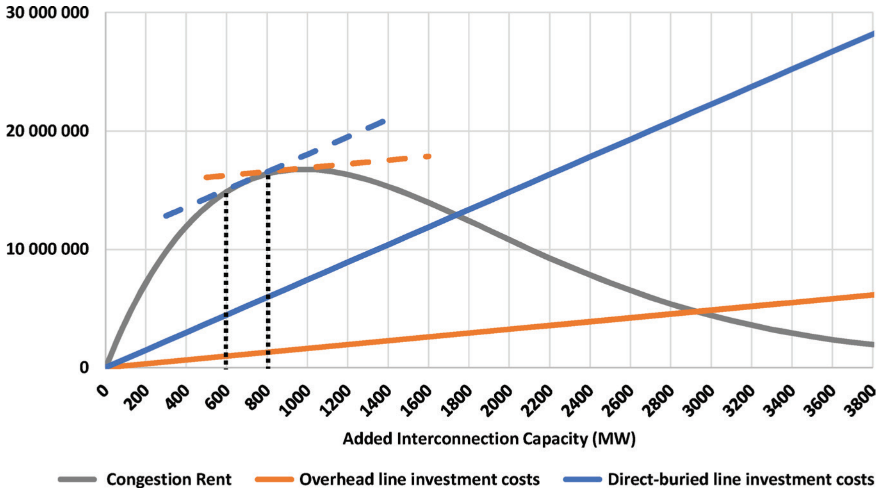
Table 6: Changes in Consumer Surplus, Producer Surplus and Congestion Rent as a Function of an Optimising Increase in Interconnection Capacity (Million Euros, 2014 Data)

	Overhead Line	**Direct-Buried Line**
French Consumers	+310	+149
French Producers	-272	-136
German Consumers	-206	-93
German Producers	+203	+101
Congestion Rent	+5.5	+13
Annual Investment Costs	-4.5	-12
Total Net Benefits	**+36**	**+23**

It is worthwhile to briefly consider the congestion rent separately, as it relates to the regulatory framework that determines optimal infrastructure investments. Figure 11 presents the evolution of the congestion rent for each added increment of interconnection capacity for 2014 data together with the investment costs for an OHL and a DBL.

In a framework where investment decisions in the transport infrastructure are publicly regulated, the normative criterion would be total welfare maximisation and thus an additional investment of 2 800 MW for an OHL and of 1 600 for a DBL would be optimal. However, when TSOs are not publicly regulated, but private enterprises providing merchant power lines to whoever is willing to pay for their use, the optimality criterion would change (de Jong and Hakvoort, 2006). In this case, the relevant criterion is the maximisation of the net congestion rent at the point where the marginal increase in congestion rent is equated to marginal investment costs. At lower capacities, the quantity effect (increasing cross-border exchanges) more than compensates the price effect (reduced price gap).

Figure 11: Congestion Rent as a Function of Different Levels of Added Interconnection Capacity (Euros, 2014 Data)



In this case, the optimal amount of additional infrastructure would only be 800 MW for a OHL and 600 MW for a DBL. The congestion rent would then amount to € 16 million (€ 15 million) with annual investment cost of € 1.3 million (€ 4.5 million), leaving an annual profit to the operator of the merchant power line of € 14.7 million (€ 10.5 million). The peak of the total annual congestion rent, where the marginal private benefit of added capacity is zero, is reached at around 1 000 MW. Privately optimal interconnection capacity is thus considerably lower than the socially optimal one. In the current European context, the above figures highlight the importance of maintaining regulatory frameworks that ensure that the full social benefits of cross-border trades are reflected in the investment decisions on new interconnection capacity

5. CONCLUSION

Interconnections for cross-border electricity flows are at the heart of the project to create a common European electricity market. Interconnections allow exporting electricity from countries with relatively lower costs of production to those with relatively higher costs of production thus increasing economic efficiency and welfare.

Increased capacity from variable renewables such as wind and solar PV in recent years implies higher optimal levels of interconnection capacity, since their production around a limited number of hours per year during which they saturate given levels of capacity happen more frequently than before. The challenge for regulators and electricity policymakers is to determine the optimal amount of interconnection capacity as a function of these new realities.

The present paper proposes a new empirically-based methodology to perform Cost-Benefit analysis for the determination of optimal interconnection capacity, taking the French-German electricity trade as an example. Using a very fine dataset of hourly supply and demand curves from the EPEX Spot day-ahead market, net export curves (NEC) and net import demand curves (NIDC) of both countries were constructed with the help of ordinary least square (OLS) regressions. The NECs and NIDCs then allow determining the increase in welfare for each incremental increase in interconnection capacity hour by hour. Summing the welfare increases over the 8 760 hours of the year yields the total welfare benefits of for each step increase of interconnection capacity. This benefit was confronted with the annual cost of augmenting interconnection capacity. The point of equality between marginal costs and benefits indicated the socially optimal increase in interconnection capacity between France and Germany.

Such empirical analysis in complement to the use of simulation models is becoming increasingly important. While traditional scenario modelling remains indispensable, it increasingly requires empirical verification due to the rapid structural change that European electricity markets are undergoing in the context of the energy transitions under way. As the technical and behavioural parameters of the electricity system change, the econometric verification of scenario results becomes ever more necessary in order to arrive at pertinent conclusions concerning the infrastructure needs required to optimize welfare in electricity markets at the European level.

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