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Abstract

Cross-Border Trade in Electricity and the Development of Renewables-Based Electric Power: Lessons from Europe

by

Heymi Bahar and Jehan Sauvage

The uptake of renewable energy (RE) has been identified by a number of governments as a primary means for mitigating CO_2 emissions from the electricity sector, and for making the transition to a low-carbon economy. The electric power output of some RE technologies, however, including those based on intermittent wind and solar energy, can vary considerably over short periods of time and thereby introduce instability into the electricity system. The risk of instability increases with higher shares of intermittent power sources connected to the electrical grid. Different means have been used to deal with this intermittency problem. Cross-border trade in electricity appears to be one of them since it enables countries to gain access to a more diversified portfolio of plants, producing over a wider geographic area. Preliminary results from an examination of the European electricity market confirm the importance of cross-border electricity trade in increasing the effective capacity factor of intermittent plants in the context of a growing share of intermittent renewables in the power sector. There are a number of policy issues that must first be addressed though, with some financial and administrative incentives provided to variable RE technologies discouraging RE producers from fully participating in electricity market operations and exerting downward pressure on wholesale electricity prices. The positive contribution that cross-border trade in electricity can make to address the variability problem not only depends on addressing challenges that renewable-energy technologies pose to electricity markets, but also necessitates the existence of an efficient cross-border electricity trading regime. Addressing those regulatory and administrative measures that are inhibiting growth in cross-border trade and the smooth operation of regional electricity markets would therefore help increase the potential for trade in electricity to facilitate growth in renewable energy.

JEL classification: F18, L94, L98, Q42, Q56.

Keywords: Trade, environment, electricity markets, renewable energy, trade barriers.

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Abbreviations

BRIC	Brazil, Russia, India and China
BRP	Balancing responsible party
CCGT	Combined cycle gas turbine
CES	Constant elasticity of substitution
CHP	Combined-heat and power
CWE	CENTRAL West Europe
ECF	Effective capacity factor
ENTSO-E	European Network of Transmission System Operators for Electricity
HS	Harmonized Commodity Description and Coding System
HVAC	High-voltage alternating current
HVDC	High-voltage direct current
IEA	INTERNATIONAL Energy Agency
ITC	inter-TSO compensation
MW	Megawatt (10^9 Watts)
MWh	Megawatt hour
NEC	Net export curve
NTC	Net transfer capacity
OECD	Organisation for Economic Co-operation and Development
OTC	Over-the-counter
PV	Photovoltaic
PX	Power exchange
RE	Renewable energy
RES	Renewable energy source
RET	Renewable-energy target
RPS	Renewable portfolio standard
TPA	Third-party access
TSO	Transmission-system operator
TWh	Terawatt hour
UCPTE	Union for the Co-ordination of Production and Transmission of Electricity

Executive Summary

The uptake of renewable energy (RE) has been identified by a number of governments as a primary means for mitigating CO_2 emissions from the electricity sector, and for making the transition to a low-carbon economy. Governments have introduced ambitious targets, both binding and non-binding, in order to increase the share of RE in their energy portfolio. Although on a life-cycle basis RE technologies have low CO_2 emissions relative to fossil fuels, their levelised cost of electricity can often be higher than that for technologies based on fossil fuels. Accordingly, RE-based electricity technologies have benefitted from various financial support schemes, administrative privileges, and special regulatory regimes.

In 2010, RE contributed approximately 19.7% of global electricity supply (of which 16.2% came from hydroelectric power plants) while coal, natural gas, and oil together provided about 65%. Many studies have estimated that the global technical potential of RE can meet a significant amount of electricity demand in many countries. The increasing deployment of some RE technologies has, however, posed a number of technical, economic, and regulatory challenges.

The electric power output of some RE sources, including those based on intermittent wind and solar energy, can vary considerably over short periods of time due to changing meteorological conditions. The risk of instability increases with higher shares of intermittent power sources connected to the electrical grid. Different means have been used to deal with this intermittency problem. Cross-border trade in electricity appears to be one of them since it enables countries to gain access to a more diversified portfolio of plants, producing over a wider geographic area. Flexible power plants — e.g. combined cycle gas, new-generation coal, and large hydroelectric plants — are particularly important given that they can increase or decrease their output easily and quickly in order to keep the overall system balanced at all times. However, this flexibility often involves additional costs, which are usually transferred to electricity ratepayers in the form of additional charges related to renewable energy. On the other hand, under some circumstances, intermittent renewables deployed across a wider geographical area may actually serve to balance the power variability that can arise from dispatchable plants or sudden increases in demand in interconnected countries. Cross-border trade in electricity can thus enable countries to gain access to more flexible power plants (both conventional and renewable such as hydropower, geothermal, and biomass) located in a wider geographical area, which can then reduce the costs of balancing power stemming from increasing RE penetration. To the extent that it does help dampen variability, increased trade could therefore allow greater penetration of intermittent renewable-energy power plants.

Preliminary results from an examination of the European electricity market confirm the importance of cross-border electricity trade in increasing the effective capacity factor of intermittent plants in the context of a growing share of intermittent renewables in the power sector. Thus, electricity trade is expected to become an increasingly important strategy to meet countries' RE goals.

However, financial and administrative incentives provided to variable RE technologies — e.g. feed-in tariffs, green certificates, special imbalance settlement regimes, priority of dispatch — are complicating matters. Many of these incentives or privileges discourage RE producers from fully participating in electricity market operations, something which has a substantial influence on cross-border power exchanges. Due to their low marginal cost and the financial incentives they attract, variable renewables exert downward pressure on wholesale electricity prices in the short run, thus making more flexible plants (which are crucial for the balancing of the overall system) unprofitable and pushing them out of the power market. Yet increasing the penetration of variable RE requires more rather than less flexible generating capacity in order to help keep the power system balanced at all times. Optimal integration of variable RE technologies into national and international electricity markets is therefore crucial if the full economic and environmental advantages of these energy sources are to be fully realised.

The positive contribution that cross-border trade in electricity can make to address the variability problem not only depends on addressing challenges that renewable-energy technologies pose to electricity markets, but also necessitates the existence of an efficient cross-border electricity trading regime. Cross-border trade in electricity requires co-operation and co-ordination among interconnected countries as most electricity markets remain designed nationally with country-specific rules and regulations. Yet it is these regulatory and administrative measures that are in some areas inhibiting growth in cross-border trade and the smooth operation of regional electricity markets. Addressing those general trade barriers would therefore help increase the potential for cross-border trade in electricity, thereby facilitating higher shares of variable RE in the electricity grid.

Both renewable-energy incentives and non-harmonised cross-border trading regimes can affect competition in electricity sales between interconnected countries. This hampers countries from reaping the benefits of trade both in general and in the context of dealing with the variability problem, though the competition effect will usually vary depending on the level, design and type of incentives provided.

Introduction

The uptake of renewable energy (RE) has been identified by a number of governments as a primary means for mitigating CO_2 emissions from the electricity sector, and making the transition to a low-carbon economy. In 2010, RE contributed approximately 19.7% of global electricity supply (of which 16.2% came from hydroelectric power plants) while coal, natural gas, and oil together provided about 65%.

Medium-term national targets for shares of renewable-energy supply typically range from 5% to 30% of total electricity production (REN21, 2010), usually by the year 2020. A key component of the European Energy Strategy is its target of achieving a 20% share of renewable energy by 2020. Chile unveiled its goal of obtaining 20% of its energy from renewable sources by 2020 during the climate-change summit of Copenhagen in 2009. China aims to raise the proportion of its energy coming from non-fossil energy resources (including nuclear power) to 11.4% by 2015. Since the Fukushima Daiichi nuclear disaster in 2011, Japan has engaged in the development of new strategies in relation to energy and the environment, one aim of which is to increase the country's deployment of RE sources. In this context, Japan introduced a new feed-in tariff policy in July 2012. And while renewable energy currently contributes 2.4% of primary energy needs in Korea, the country's long-term vision foresees the RE's contribution increasing to 11% by 2030. More than 25 U.S. states have established renewable-energy targets for their electricity sectors, and California and Texas both have renewable portfolio standards (RPS).[1] Similarly, Canada has adopted nine provincial renewable-energy targets (RETs).[2]

The electricity industry is one of the major contributors to global CO_2 emissions. In 2008, power plants fired by coal, natural gas and oil products generated more than two-thirds of the world's electricity. In the OECD area, thanks to government support, the share of low or zero-emissions RE-based power generation in the electricity sector increased from 15.1% in 2005 to 17.3% in 2009 (IEA, 2012). Although hydroelectric power still accounts for the majority of RE-based power generation, its share has declined since 2005, from 81% in 2005 to 72.7% in 2009. Meanwhile, over the same period, the generating resources powered by wind and solar energy experienced, respectively, more than a doubling and an almost fivefold growth since 2005 (IEA, 2011a). Under the IEA's outlook scenario for 2035, renewables-based electricity is expected to triple, representing 44% of the growth in total electricity generation. Wind and hydroelectric power would each contribute approximately one-third of the growth, followed by biomass-fuelled plants and solar PVs.

RE targets are often combined with financial incentive measures since the levelised (i.e. full) cost of electricity for RE technologies is often higher than for conventional (fossil-fuel) technologies, though some RE technologies are already competitive in particular regions or locations. Despite continued progress in reducing costs, it is expected that many technologies will still need incentives to compete with non-renewable-based electricity. The IEA estimates that subsidies to renewables-based

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1.   The US federal government does not have mandatory renewable-energy targets for electricity, but it does support the growth of renewable-energy industries through subsidies, tax exemptions, and other financial support measures.

2.   Canada does not have a national target since electricity supply there falls primarily under provincial jurisdiction.

electricity, excluding large hydro, totalled about USD 64 billion in 2011, and expects these subsidies to increase further to around USD 170 billion by 2035 (IEA 2012).

The intermittency of some of the most important renewable-energy sources present considerable technical challenges for utilities wishing to source more of their electricity from renewable energy. The resulting variability in electricity output can introduce instability into the system as the share of electricity from these sources increases (Moselle et al., 2010). In order to be able to increase the share of electricity generated by variable power sources in an electricity grid, a parallel increase is needed in its ability to respond flexibly to system demands. Such flexibility can be introduced by improving load management, making greater use of energy-storage systems (e.g. pumped hydro), by achieving a geographic and technological diversification of variable energy sources, and by trading with other electricity grids (OECD, 2011).

Trade in electricity, considering both cross-border trade, and trade between regions within countries, appears to be one way of addressing the problems created by having significant shares of variable generating capacity feed in to the electricity system. Trade can allow countries to make better use of their available resources by balancing demand and supply variations. Short-term balancing of variable electricity output remains a significant challenge both in terms of its high cost and the physical risk it entails. Cross-border trade in electricity can help countries reduce their balancing costs, which in turn can enable more penetration of variable renewables into the grid. Thus, trade could support governments' efforts to reach their renewable-energy targets at lower cost. There are, however, numerous barriers to trade in electricity that need to be better understood, some of which have particular implications for renewable energy.

To the extent that it does help dampen variability in electricity output, increased trade could therefore allow for greater penetration of variable renewable-energy-based power plants. The degree to which it can play such a role depends on geography and on the interconnectivity of grids. But even countries that currently have no high-voltage electricity transmission lines connecting them to a neighbouring country may at some time in the future consider building such interconnectors. The bipolar ±450 kV direct-current NorNed underwater transmission line, recently built between Norway and the Netherlands, is as much as 580 kilometres long. Consideration is even being given to the idea of building a 1000-km interconnection between Iceland and the UK. If 1000 km marks the maximum length for an undersea cable, then only New Zealand (approximately 1500 km from Australia at the closest landfalls) is truly isolated among OECD countries.

In addition to physical constraints, regulatory and administrative issues can also hinder international and inter-regional trade in electricity. The liberalisation of the power industry in many OECD countries has created national electricity markets with often country-specific rules and regulations. Efficient cross-border trade in electricity requires harmonisation of rules across interconnected electricity markets. Only with such integration can the full benefits of cross-border power exchanges be reaped.

The present paper first discusses the development of renewable-based electric power and the variability problem that characterises some renewable-energy technologies. It then highlights the importance of cross-border trade in electricity as a way to deal with this variability problem by focusing on wind power-plant productivity. Results of a simulation based on the European market are shown to assess both the past contribution of electricity trade to wind-plants' productivity, and the marginal impact that facilitated international trade can have under three different scenarios: business-as-usual, facilitated cross-border electricity trade, and autarky. The paper then explains the impact that

variable renewables have on cross-border trade in electricity, focussing on renewable-energy incentive measures and their implications for wholesale electricity prices and for flexible power plants. It then examines regulatory and administrative impediments to trade in electricity in general, considering that the majority of the electricity traded across borders is generated using non-renewable resources. The paper also includes a case study on the Nordic Electricity Market (Annex E). The aim of this case study is to illustrate some of the concepts and issues discussed in the paper. It highlights the co-operation that took place over many years among Nordic countries to increase cross-border trade in electricity by reducing trade barriers. It then explains the impact of variable renewables on cross-border trade, focussing on the integration of wind power plants and on the possible integration of green electricity certificates market.

Variability – an issue for some renewable-energy technologies

The electricity output from certain renewable-energy technologies is both stable and flexible. Hydro-electric power plants can provide reliable and clean electricity according to seasonal changes in water level. Hydro-electric plants with big reservoirs (and pumped-hydro) can also store massive amounts of power to be used when necessary. The predominant technology, pumped-hydro storage, which involves pumping water uphill into the reservoir at off-peak times and then releasing it when needed, can prove very flexible. Some other renewable-energy plants, such as those powered using biomass and geothermal energy, can also provide reliable electricity.

By contrast, some renewable-energy technologies, such as wind turbines and PV solar plants, represent significant challenges for transmission-system operators (TSOs) because their output is intermittent — i.e. it varies in response to changing meteorological conditions, and is difficult to forecast (Figure 1).[3] In many OECD countries, electricity markets are finding it challenging to accommodate high growth in intermittent power sources, spurred by the ambitious goals that have been set for renewable-energy deployment.

Traditionally, power generation has followed load or consumption patterns. In other words, TSOs could predict supply and adjust it more accurately in response to forecasted demand. Although demand varied throughout the year, the week and the day, these variations have remained mostly foreseeable. The large-scale deployment of wind and solar power sources[4] and the intermittency this entails has, however, added to demand variations (Figure 2). Wind power plants and PV solar systems generate electricity only when there is enough wind blowing or adequate sun shining. This variability poses several challenges to the electricity system.

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3. The output variations in these technologies are not seasonal but rather have variability even within an hour.

4. Mostly increasing penetration of wind and solar. Other renewable energy technologies such as hydro-electric, biomass, geothermal are not variable.

Figure 1. Hourly onshore wind-power output in Spain (2009)
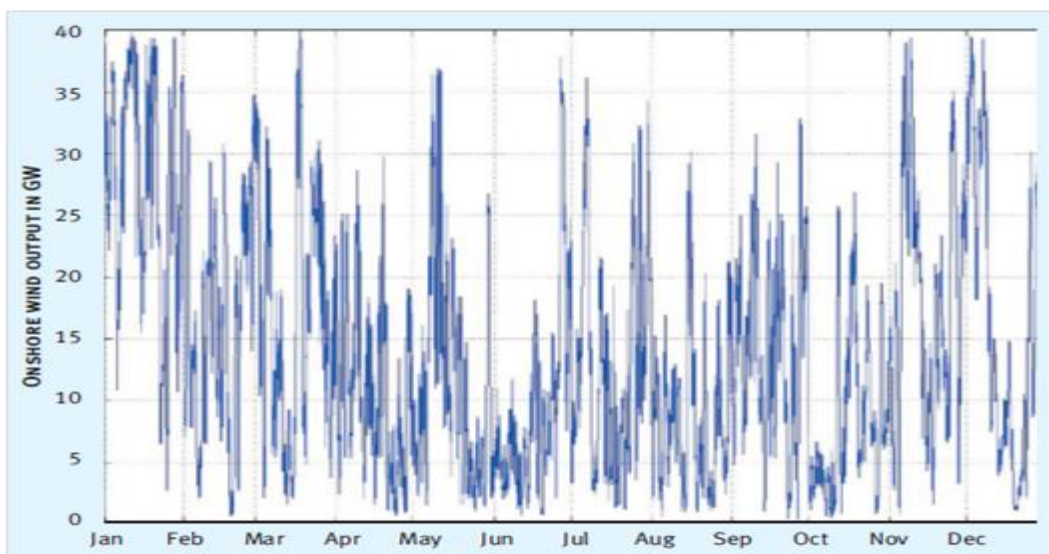
Source: European Wind Energy Association.

Figure 2. Effect of 35% variable renewables in the West Connect of the United States
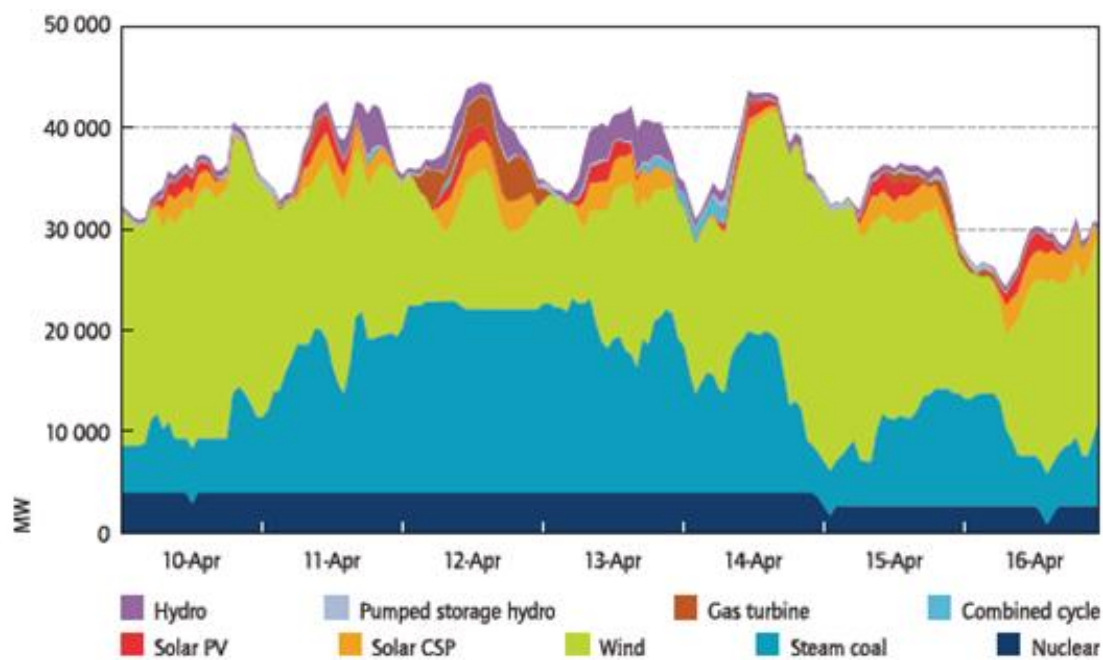
Source: IEA (2011c).

In order to be able to increase the share of electricity generated from variable power sources in an electricity grid, a parallel increase is needed in the grid's ability to respond flexibly to system demands. Such flexibility can be introduced by improving load management, making greater use of energy-storage systems (e.g. pumped hydro), by achieving a geographic and technological diversification of variable energy sources, and by trading with other electricity grids (OECD, 2011).

In addition to support measures, the greater penetration of intermittent renewables in electricity grids entails additional costs of integration. TSOs have to ensure that supply and demand are continuously in balance throughout the system. If supply is not available to meet demand, the whole system may crash, precipitating black-outs. Thus, the system operator must always be ready to make up for any shortfalls or absorb any excesses brought by variable renewables.[5] TSOs usually balance the system by ordering various plants to ramp their output up and down when needed. The level of flexibility of these plants depends, however, on their respective technologies. Some plants (simple-cycle gas or diesel turbines, and hydroelectric plants with big reservoirs) can respond to variations immediately while others (some coal and biomass powered plants, and certain hydroelectric plants and combined-cycle gas plants) need an hour to ramp up or decrease their output. Power output from solar PV plants can cycle from zero to maximum capacity in a matter of seconds, introducing the possibility in reliably sunny locations of using them as load-controlling resources.

Cross-border trade in electricity as a way of dealing with the variability problem

Cross-border trade in electricity can enable countries to gain access to more flexible power plants located in a wider geographical area, which can then reduce the costs of balancing power due to increased RE power output. However, under some circumstances,[6] intermittent renewables deployed across a wider geographical area may actually serve to balance the power variances that can arise from conventional plants or sudden increases in demand in interconnected countries. To the extent that it does help grids to better respond to short-term load variability, increased trade could therefore allow greater penetration of intermittent renewable-energy-based power plants and a more efficient utilisation of conventional ones.

In a companion paper to this one (OECD, 2012), the effects of different market conditions on the productivity of intermittent renewable power plants are assessed using an econometric model of wind-based power generation. Based on a review of the literature, the paper assumes that the effective productivity of wind plants (*ECF*)[7] is a function of grid flexibility and transmission capacity, as well as wind speed. Transmission capacity is defined as the length of installed transmission lines with voltages of 330 kV or greater. Grid flexibility includes measures of dispatchable power

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5. System operators have different spare capacities that they can use in the emergency situations mentioned above. System operators buy and sell power in order to keep the system working at all times.

6. When meteorological conditions are favourable, intermittent renewables may produce surplus electricity that can be traded across borders.

7. Defined as the annual quantity of power dispatched from plants of a certain technology into the network relative to total installed generation capacity of that specific technology at the country level.

capacity, energy storage, and international trade. The model focuses on wind since it is the most deployed, variable, and unpredictable energy source among intermittent renewables. This analysis is, however, of broader relevance since it also applies to solar photovoltaic and marine energy sources.[8]

International trade in electricity can allow for greater productivity of the intermittent renewable power-plant stock by increasing system flexibility through the following channels:

- Greater spatial dispersion and portfolio diversification of intermittent renewable sources. If intermittency is increasingly less correlated across renewable type and space, then this will help smooth supply.

- Greater access to dispatchable sources (e.g. gas turbines or hydroelectric plants) located in other countries or regions. This allows countries to draw upon electricity sources that can be ramped up and down relatively quickly and at low cost.

- Greater access to storage facilities (pumped hydro and advanced energy storage) located in other countries or regions. This allows for balancing over time, as countries store electricity generated in periods of excess supply to be used in periods of excess demand.

- Greater potential for demand-smoothing across different time zones. Since peak demand is likely to vary across time zones, electricity trade between countries at different longitudes can help smooth the demand curve.

The empirical impact of those various factors on wind-farm productivity has been estimated using data from 1990 to 2009 covering 31 OECD countries.[9] The findings confirm that, although effective capacity factor (*ECF*) depends largely on environmental factors (e.g. the annual wind resources in a given country), it is also significantly affected by the other explanatory variables present in the model. For example, dispatchable generation and grid transmission capacity have significant and positive estimated effects on *ECF* (and of rather similar magnitude). The marginal effect of cross-border electricity trade is also found to be significant and positive, though of a lower magnitude than dispatchable generation and transmission capacity.

The impact that electricity trade has on the productivity of wind plants may, however, be expected to vary with the existing share of wind capacity in the grid (e.g. for very low levels of installed wind capacity, power systems may be assumed to have sufficient slack and, as such, to allow for maximum use of wind farms). This possibility has been tested through the estimation of a second model, which looks at the interaction between the explanatory variables and the penetration of wind capacity. Estimation is performed on both the global sample of 31 OECD countries and on a subset of European countries. Comparing the results, it is found that the influence of electricity trade on *ECF* is significant only at higher levels of penetration, and is of considerably greater significance for the subsample of European countries.[10]

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8.   It should be noted that some marine energy sources (i.e. tidal and wave energy) are in general more predictable than wind and solar technologies.

9.   The full description of the model can be found in OECD (2012).

10.   Cross-border trade in electricity is greater among OECD European countries than in other OECD regions, and some European countries (e.g. Denmark and Germany) are known to use it

The last step of the analysis consists of a simulation based on the previous estimates. Three cases are successively considered: business-as-usual, facilitated cross-border electricity trade, and autarky (i.e. absence of trade). The aim is to assess both the past contribution of electricity trade to wind plants' productivity, and the marginal impact of facilitated international trade through larger cross-border transmission capacities or better-integrated power markets.

A simulation is drawn using relevant data from the IEA's *World Energy Outlook 2011* (IEA, 2011b) in order to assess the effects on European power markets of implementing the EU's plans for 2020. The —Basline Scenario‖ assumes that electricity trade will grow in line with electricity generation. While the —Autrky Scenario‖ considers trade to linearly phase out by 2020, the opposite trend is considered in the —Tade Enhancement Scenario‖ (Figure 3). Although the extent of electricity trade is assumed to double in Europe in the latter scenario, it is not the case at country levels. Instead, it increases by a fixed amount equals to the weighted average of the variable TRADE at the EU level.

Figures 3 to 5 show results from the simulation under different assumptions concerning international trade in electricity. The simulation shows that electricity trade might become an increasingly important strategy to meet RE objectives. Figure 5 shows the relative additional costs of (or benefits from) meeting the objectives for renewable energy under each scenario, which are computed as the additional investment in wind projects required to reach the Baseline Scenario's wind-power penetration targets.

Figure 3. Effective capacity factor in the EU
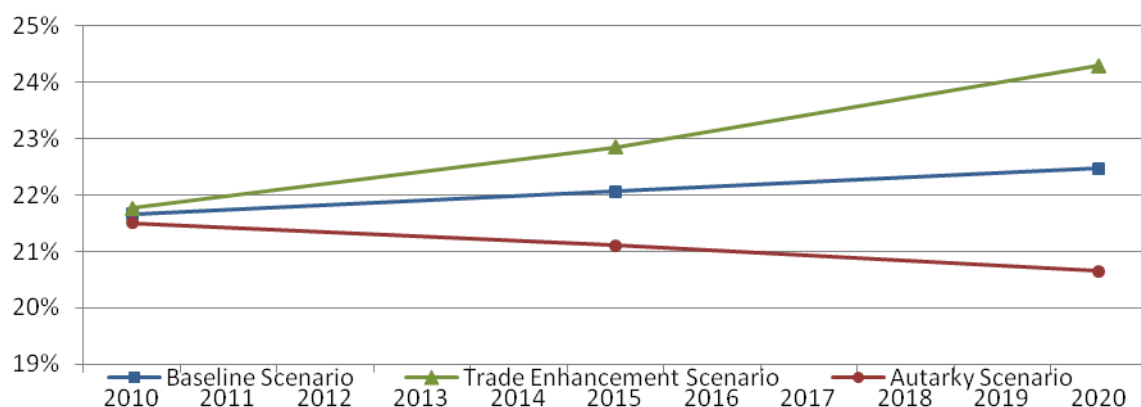
Notes: The "Baseline Scenario" assumes that electricity trade will grow in line with electricity generation. While the "Autarky Scenario" considers trade to linearly phase out by 2020, the opposite trend is considered in the "Trade Enhancement Scenario". Although the extent of electricity trade is assumed to double in Europe in the latter scenario, it is not the case at country levels. Instead, it increases by a fixed amount equals to the weighted average of the variable TRADE at the EU level in the Baseline Scenario.

Source: OECD (2012).

as a means to deal with the intermittency of their renewable power sources, particularly wind energy.

Figure 4. Share of wind power relative to total power generated in the EU
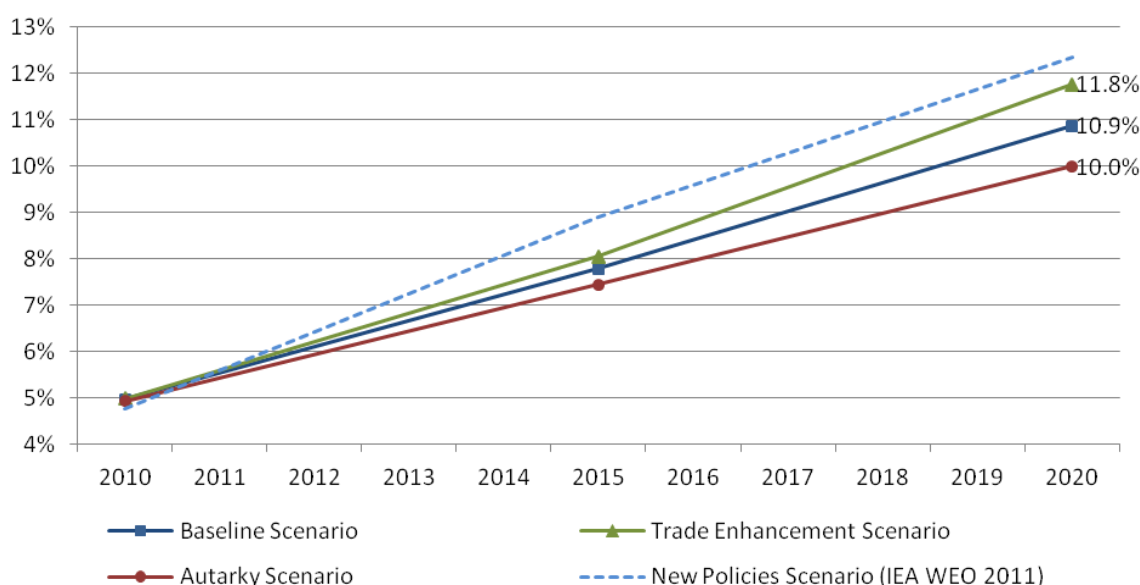
Notes: With a particular focus on 21 European countries, this simulation draws on estimates from model (E3) and is calibrated with relevant data from the International Energy Agency's World Energy Outlook 2011 and ABS Energy Research's Transmission & Distribution database. The constant average annual growth rate for total electricity generation in the European Union under the "New Policies Scenario" (IEA, 2011b) is used to project electricity generation by country through 2020. Annual targets for the share of installed wind generation capacity relative to total generation capacity (i.e. wind capacity penetration) are imposed at the EU level using data from the "New Policies Scenario". National objectives are set accordingly with EU targets and current domestic wind generation capacity levels.
Source: OECD (2012).

Figure 5. Relative additional cost of restrained cross-border electricity trade within the EU
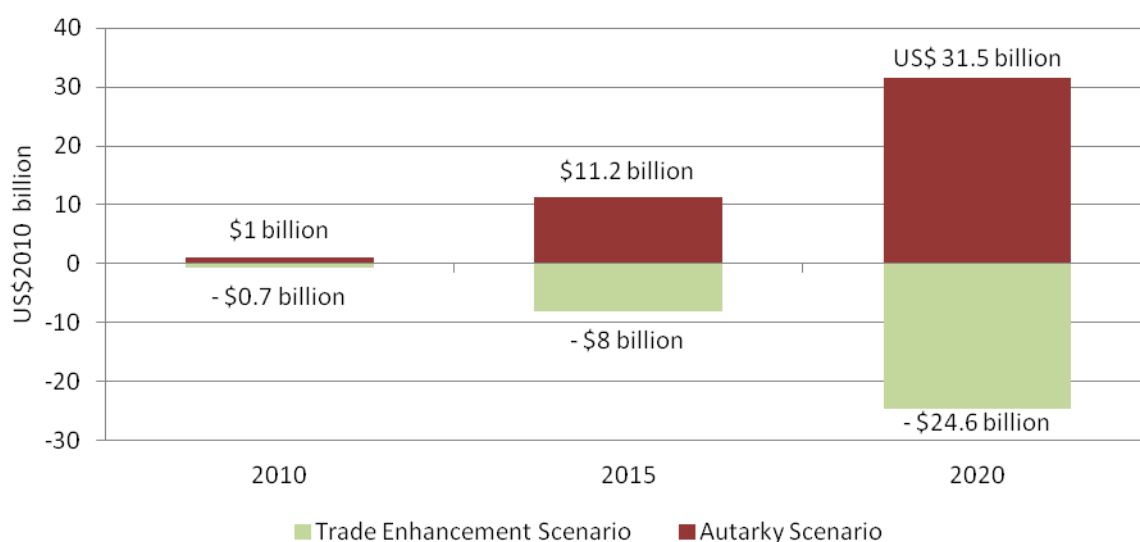
Notes: The "Baseline Scenario" assumes that electricity trade will grow in line with electricity generation. While the "Autarky Scenario" considers trade to linearly phase out until 2020, the opposite trend is considered in the "Trade Enhancement Scenario". Although the extent of electricity trade is assumed to double in Europe in the latter scenario, it is not the case at country levels. Instead, it increases by a fixed amount equals to the weighted average of the variable TRADE at the EU level in the Baseline Scenario.
Source: OECD (2012).

These results further confirm the importance of cross-border electricity trade in increasing the effective capacity factor of intermittent plants in the context of an increasing penetration of intermittent renewables. The simulation is, however, based on coefficients and trends at the European level, and different outcomes might obtain in other regions.

Although cross-border trade in electricity bears some potential for helping deal with the variability problem of intermittent renewables, the impacts that the latter can have on electricity markets have raised several issues that further complicate their integration into the grid. The direct and indirect impacts that these issues may have on cross-border exchanges are then discussed.

The impacts of renewables on cross-border trade in electricity

While cross-border trade in electricity can help countries deal with power-supply variability, incentive measures and other privileges provided to intermittent renewables sometimes interfere with trade by distorting price formation in electricity markets (see Annex B for an explanation of price formation in electricity markets). Relative prices are the main drivers of cross-border trade in electricity, something which has to do with the information that power prices convey about countries' resource endowments, geographical situations, and national skills. Capital investment is also crucial for trade since it permits countries to be interconnected. When two electricity systems are interconnected, it is expected in a competitive market that electricity will be transmitted from the low-price zone to the high-price zone (see Annexes 2 and 3 for a detailed explanation of the drivers of cross-border trade). Hence, distortions in the formation of electricity prices can have direct and indirect impacts on cross-border trade in electricity.

While the various support measures encouraging the deployment of intermittent renewables have an impact on wholesale electricity prices, and thus on cross-border trade, direct and indirect forms of support provided to other electricity-generating technologies can also distort price formation in electricity markets. In many OECD countries, the generation of electricity from fossil fuels has been encouraged in various ways. Although this paper is essentially focussed on intermittent renewable-energy sources, it also recognises that support to fossil fuels can distort wholesale electricity prices to varying degrees depending on the level and type of support provided.[11]

The importance of relative prices in cross-border exchanges

To assess the impact that price differentials have on the cross-border trade of electricity, the authors have constructed a small partial-equilibrium model of trade where countries are differentiated by market size (total demand) and the productivity of their power generators. These differences in size and productivity in turn translate into price differences that result in low-price countries exporting electricity to high-price countries. It is, however, assumed that exporters face trade costs when sending electricity to a neighbouring country. As explained above and later in the paper, trade costs are frictions

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11. Various measures supporting the use of fossil fuels in electricity generation can be found in OECD countries and are documented in the OECD's *Inventory of Estimated Budgetary Support and Tax Expenditures for Fossil Fuels* (www.oecd.org/iea-oecd-ffss). Examples include: feed-in tariffs for fossil-fuel-based electricity generation, market-based support for domestic coal, targeted excise-tax exemptions and reliefs, etc. See OECD (2013).

that have the effect of creating a wedge, which prevents prices from converging fully between a set of trading partners. Annex C describes the model in depth and provides further details on its empirical application.

Using data obtained from various industry sources, an empirical version of the model is applied to several European countries.[12] Because of data constraints, trade costs are here restricted to the narrower net transmission capacity between countries. In spite of this limitation, regression analysis nevertheless provides valuable information on the impacts that prices and net transfer capacity have on trade flows in a European context. Table 1 shows some of the econometric results obtained from the sample described in Annex D using the final equation derived in Annex C.

Table 1. The impact of price differences and net transfer capacity on cross-border trade

	(1)	**(2)**	**(3)**	**(4)**
Change in log of weighted relative prices	1.092*** (8.31)	1.092*** (7.43)	1.092*** (3.69)	1.092*** (4.98)
Change in log of relative net transfer capacity	0.486*** (3.13)	0.486** (2.53)	0.486* (1.96)	0.486** (1.99)
Constant	-0.0306 (-0.07)	-0.0306 (-0.40)	-0.0306 (-0.36)	-0.0306 (-0.42)
Observations	1201	1201	1201	1201
Adjusted R-squared	0.050	0.050	0.050	0.107

Notes: See Annex C for more details. Standard errors are in parentheses and asterisks denote the level of statistical significance (*** at the 1% level, ** at the 5% level, and * at the 10% level). The dependent variable is the percentage change in bilateral exports of electricity from country i to country j relative to total electricity demand in country i. All equations have time dummies and are estimated in first differences. Equation (2) also uses "White-robust" standard errors. Equation (3) clusters standard errors by country pair. Equation (4) clusters standard errors by reporting country and by partner country as in Cameron et al. (2006).

Source: OECD based on industry data (see Annex D).

The results indicate that changes in relative prices do have a significant and positive impact on cross-border trade expressed as a share of total electricity demand. Changes in relative net transfer capacity[13] also seem to have a positive impact, though the coefficient on the second variable suggests that their impact is less than half that of differences in relative prices. The results therefore suggest that price differentials in interconnected electricity markets are the main drivers of cross-border trade in electricity. Interconnectors are, however, required for cross-border exchanges to take place in the first place, so that insufficient net transfer capacity can prove an important technical barrier to trade. One would therefore expect this capacity to have a bigger impact on trade than prices do. However, this supposition proves generally not validated since price

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12.   See Annex D for a complete description of the data. The sample comprises Austria, Belgium, France, Germany, Greece, Italy, the Netherlands, Poland, Portugal, Slovenia, Spain, and Switzerland, and covers the years 2004-11.

13.   Relative net transfer capacity is here defined as the net capacity of interconnectors relative to the exporting country's total net electricity supply.

differentials in liberalised electricity markets remain the main driving force for countries to either establish a new interconnector, or to increase the capacity of existing interconnectors.[14]

The impact of intermittent renewables on wholesale electricity prices

The marginal generating cost for most sources of renewable energy, except for biomass-fired power plants, is close to zero. In **merit order dispatch** (Annex A), wind and solar power plants are thus near the bottom of the supply curve. Wind, solar and nuclear power plants all enter the bid curve at the lowest level due to their low marginal costs, followed by CHP, natural-gas and coal plants (Figure 6). This can result in lower power prices in wholesale markets depending on the level of penetration of low-marginal-cost renewables. If electricity trading happens to be based on the system's marginal price, which is usually the case in most countries, the very low marginal costs of intermittent renewables can then significantly reduce wholesale market prices. Several empirical studies conducted by Neubarth, Bode and Groscurth, Munksgaard and Morthorst for countries having high penetrations of intermittent renewables (e.g. Germany, Spain, and Denmark) have concluded that this merit-order effect on wholesale electricity prices can be significant at times of high wind and radiation.[15] Figure 6 summarises the shift that occurs in the merit-order dispatch when the share of wind-generated power is high. It implies that the revenues of generators, including those using renewable energy, will be lower if they trade their energy on the wholesale market (Klessmann et al., 2008). In that sense, wholesale electricity prices tend to be lower during periods of high wind and solar output (Annexes 1 and 2).

Not only do renewable-energy-based power plants exert downward pressure on wholesale electricity prices, but they can even generate negative prices (Figure 7) in markets where regulatory authorities allow them. With greater penetration of renewables, a combination of factors such as high power output from low-marginal-cost renewables and low demand in a given hour or dispatch period can lead to negative wholesale prices.

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14.   The Netherlands and Norway decided to build a new interconnector (the longest in Europe) in 2005 though both countries were already inter-connected through other national grids. The main driver for the Netherlands to make this significant investment was to gain access to cheap hydro-electricity from Norway.

15.   Discussions on wholesale price-reducing effects and on their economic interpretation are still ongoing in many countries. The German Federal Ministry of Environmental Affairs conducted a study in 2007 to calculate the merit-order effect of intermittent renewables. The study simulated the wholesale electricity market with and without intermittent renewables. The resulting average power-price differential amounted to EUR 7.73 per MWh, and the total amount of the merit-order effect was thus reported to be EUR 4.98 billion while the total support for renewables amounted to EUR 3.3 billion. Several other studies have criticized this simulation's use of a static approach and its assumption that a power system without any RES-E would have had exactly the same installed capacity mix as the reference case. In addition to that, the 2007 study ignored the dynamics of cross-border trade in electricity. Sensitivities concerning capacity adaptation and a discussion on cost savings versus rent redistribution are provided in Sensfuss et al. (2008), which confirmed the price-reducing effect of intermittent renewables. The debate is still ongoing on the economic interpretation of the merit-order effect. Many studies have attempted to analyse the long-term economic impacts of greater penetration of intermittent renewables on wholesale electricity prices. However, analysis from a dynamic perspective remains a significant challenge.

A negative price simply means that generators, rather than consumers, pay for the electricity fed to the grid. This situation arises for two reasons. First, the output of power-generating technologies cannot be quickly reduced in reaction to an unexpected and sudden drop in demand. As a result, it makes more sense for such generators to keep their plants running by bidding in negative prices, since it is still cheaper to pay somebody to take the electricity than to stop the plant and start it again shortly afterwards. Second, financial incentives for renewable-energy technologies encourage generators using these technologies to produce even if market prices happen to be low or negative. Renewable-energy producers that are eligible for financial incentives will thus continue to produce as long as the negative price level is no greater in absolute terms than the subsidy level.

Figure 6. Change in wholesale electricity price with increasing wind penetration
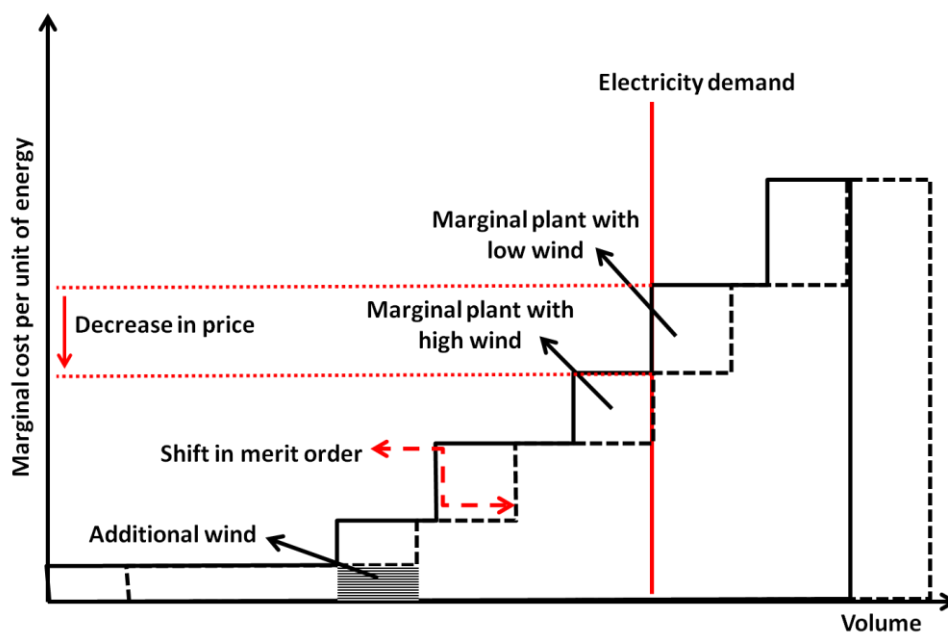
Figure 7. Frequency of negative prices in Germany from 2008 through [May] 2012

Year	Total hours	Hours with negative prices	%
2008	8,783	15	0.17
2009	8,759	71	0.81
2010	8,759	12	0.14
2011	8,759	15	0.17
2012	336	14	4.17
2008-12	35,396	127	0.36

Source: OECD based on EPEX.

The different ways in which markets in each country deal with negative prices can lead to artificial differences in wholesale prices between trading partners. These artificial differences may have possible cross-border trade implications, considering that electricity flows respond to price differentials on both sides of the interconnection, and that the

deployment of renewable-energy technologies is expected to increase the frequency of negative prices, and thus market distortions. If two interconnected countries have different approaches for dealing with negative prices (e.g. if one country allows negative prices to happen but the other does not), electricity can flow in the opposite direction to actual demand. Furthermore, if two markets are coupled, negative prices could also lead to a situation where no electricity is being traded across an interconnector despite there being differences in prices (CEER, 2011).

Renewable-energy incentive measures and their impact on wholesale electricity prices

The design of support measures for renewable-energy technologies has an impact on price developments in wholesale markets. Support measures that are independent of electricity markets, such as feed-in tariffs (and to a lesser extent premiums), may influence wholesale market prices in ways that are different from market-based incentives such as green certificates. The remuneration provided via fixed feed-in tariffs is usually independent from actual electricity prices since generators receive a fixed-price per kWh of electricity generated regardless of price fluctuations in wholesale markets. In other words, generators of electricity from renewable-energy sources do not have any incentive to bid in the wholesale market because they will receive the fixed-price for the electricity they produce regardless of the wholesale price. Although renewable-energy generators receiving a fixed feed-in tariff do not directly participate in the electricity market themselves, their energy is nevertheless bought and sold usually by TSOs or other market participants. These indirect transactions in wholesale markets can influence spot prices as mentioned above.

Where market-based incentive schemes are used, renewable-energy generators are fully or partly exposed to market prices. They usually bid in the wholesale electricity market along with all other generators, and receive the market price for the electricity they generate in addition to the value of green certificates or premiums. Although these schemes may increase investment risk for investors due to price volatility in both the electricity and the green-certificate markets, and thus may have an impact on the deployment of renewable-energy technologies, they facilitate the integration of renewables into wholesale electricity markets. A fixed feed-in tariff does not entail any price risk, whereas both quota obligations and a premium support scheme involve a market-price risk since relevant generators have to sell their output directly either in the electricity market or through bilateral contracts.

In addition to financial incentives, electricity generators operating intermittent renewable-energy assets are entitled to other privileges. One of the most important privileges given to them is the priority of dispatch. In many countries, TSOs are expected to give priority to non-dispatchable renewables in the electricity dispatch order unless they threaten transmission-system security.[16] Second, renewable-energy generators in many countries are not exposed to imbalance-settlement regimes, which means that renewables are not penalised if they do not feed electricity to the grid as scheduled.[17]

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16.   Usually, TSOs are allowed to curtail variable renewable-energy plants in emergency situations to keep the grid balanced.

17.   Intermittent renewables can also run surpluses instead of deficits depending on meteorological conditions.

Feed-in tariffs are usually combined with a priority dispatch requirement. Considering that a generator's revenue is dependent both on prices and volumes sold, renewable-energy producers that benefit from both a feed-in tariff and a priority dispatch regime are at an advantage since they face neither price nor volume risks. Contrary to what happens in a priority-dispatch regime, generators operating under a quota or a premium scheme have to find counterparties to sell their production, either through bilateral long-term contracts or in the wholesale market. Hence, there is always the risk that a plant does not manage to sell its total production and thus loses revenue. However, because the marginal cost of renewable-energy-based plants is generally low, this kind of situation rarely arises.

Differences in renewable-energy support schemes may have different impacts on wholesale prices in interconnected countries. Wholesale electricity prices may not fully reflect the supply and demand conditions in a given market, but would still be distorted to varying degrees depending on the support schemes and special privileges granted to renewables. In that sense, these distortions may create further inefficiencies in cross-border electricity exchanges since they can make some countries more competitive based on the level and the type of incentive provided. Considering that the penetration level of renewables is highly dependent on the level and the type of support, countries with high penetration of renewables will face artificially lower wholesale electricity prices, and may thus be more competitive in cross-border trade in the long-term.

Impact of decreasing wholesale electricity prices on flexible plants

Declining wholesale electricity prices directly affect the profitability of non-renewable plants and investors' expected return on investment. The low marginal costs, financial incentives, and privileges provided to renewables result in fewer operating hours for conventional plants. This combination of fewer operating hours and lower wholesale electricity prices contributes additional uncertainty for future investments in conventional power generation, which are crucial in balancing intermittent renewables when the wind is not blowing or the sun is not shining enough. Countries with a high share of intermittent renewables are already experiencing significant reductions in the number of hours that their conventional plants operate. For instance, the operating hours of coal and CCGT plants in Spain declined by around 70% and 50% respectively between 2004 and 2010 (Figure 8).

If sufficient revenues cannot be recovered in the energy market to support new investment or to keep existing capacity operational, a fallback solution may be necessary in the form of capacity payments. Capacity-payment mechanisms or remunerations are generally based on the concept of a two-part price, with one set of revenues paying for energy on a MWh basis and another rewarding the capacity needed on an installed-capacity basis.[18] In other words, these mechanisms, in general, aim at rewarding the availability of certain plants in addition to their output. Liberalisation processes in electricity markets have, however, been initiated to reduce economic inefficiencies in the system by, among other means, preventing over-investment in generating capacity. Some capacity-payment methods (depending on their particular design) can lead to such inefficiencies and market distortions. In that sense, countries may want to analyse the various impacts that capacity payments can have before implementing them.

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18. These plants do not receive direct financial assistance for the installed capacity. Yet, they receive additional payments for their available capacity at a particular time.

Figure 8. Operating hours of coal and gas plants in Spain
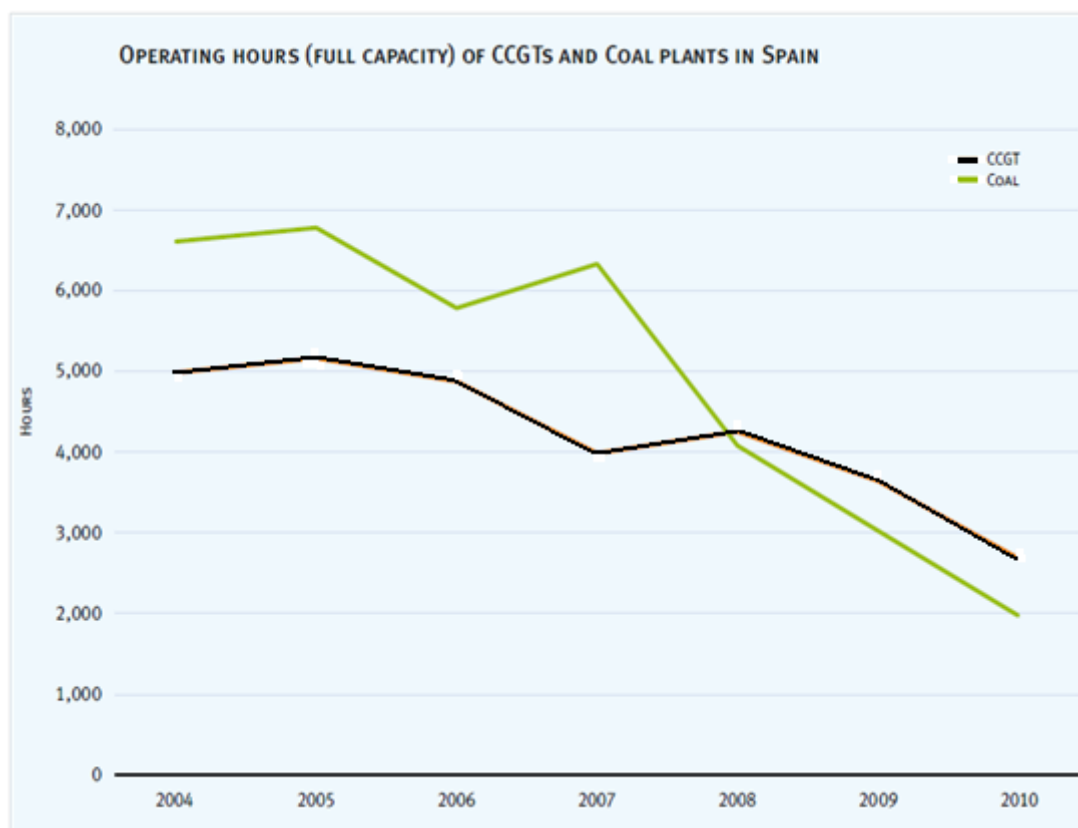
Notes: The impact of the economic downturn on the operating hours of coal and gas plants is limited because although electricity demand slightly declined between 2008 and 2009, it recovered in 2010 growing 3.2% annually. However, as shown in the figure above, the operating hours for coal and gas plants continued to fall significantly even though electricity demand increased during the same period. The main reason for this decoupling is the increasing deployment of wind and solar power plants, which have displaced some of the older power plants.

Source: Eurelectric (2011).

If capacity payments are designed based solely on national considerations, they may end up having cross-border implications as well. Capacity payments usually imply more involvement of energy regulators and TSOs in decisions regarding the availability and operation of generating plants eligible for these payments. Thus, some countries may impose discriminatory network-access arrangements for those plants receiving capacity payments. It is also expected that balancing-market prices in countries that provide capacity payments (to flexible power plants) would be lower than in countries that remunerate electricity generators only for the electricity generated. Consequently, TSOs may be tempted to procure balancing capacity from the market with the lowest balancing price, which may be in another country. This would lead to the migration of reserves and ancillary services to neighbouring countries.

Other possible cross-border implications of renewable-energy support schemes

Theoretically, the most cost-effective way to reach RE targets is to install RE generation where it will provide the most low-carbon electricity to the grid at least cost. Usually, one would expect the efficient development of RE to be highly correlated with natural-resource abundance in a given country. However, the experience to date shows that RE investors' decisions are often based not only on natural-resource endowments, but also on the level and type of incentive provided. Thus, countries that do not have particularly high wind or solar potential can have the highest installed capacity for these technologies. Some variable renewable-energy technologies, especially wind and solar power plants, may therefore be located in certain specific areas or countries where RE support[19] is the highest, which can in turn lead to unexpected cross-border flows to other countries' networks during periods of high wind or solar radiation. These additional cross-border flows can easily congest interconnectors and neighbouring countries' grids, thereby diminishing the spare cross-border capacity available to market participants to tackle the variability problem.

Need for a better integration of intermittent renewables in electricity markets

In order to deal with the variable-output problem of some renewables, countries need to have an appropriate amount of flexible generation at hand. Flexible generation can come either from other renewable-energy sources (hydroelectric and geothermal plants) or from conventional technologies (such as combined-cycle gas, new-generation coal plants), or from electricity-storage assets, such as pumped hydro. Naturally, hydroelectric power plants are constructed where there is a suitable source of hydro power,[20] while there are fewer limitations on where other flexible power-generating plants can be built. Thus, flexible generation is usually spread over a wide geographic area. On the contrary, intermittent power sources are usually concentrated in specific regions where the natural resource in question is relatively abundant. Cross-border trade in electricity can play an important role by encouraging the efficient usage of flexible and intermittent generation across connected countries.

Special market arrangements for renewables and their impact on cross-border trade

Gate-closure times

A gate-closure time is the final moment at which market players are able to trade electricity or inform TSOs of their final position before the real-time dispatching of electricity occurs. It marks the closure of market actions in a forward, day-ahead or intraday timeframe (Annex B).

The main challenge for TSOs and generators of variable electricity is to predict the latter's exact production of electricity the day before actual delivery. Because generation from intermittent renewables varies according to uncertain meteorological conditions,

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19. Here, RE support does not only include financial incentives such as feed-in tariffs, premiums or green certificates, but also encompasses the efficiency and transparency of administrative procedures, which are crucial to gaining RE investors' confidence. Other considerations, such as the cost of capital, also have a bearing on investors' decisions and may thus influence the location of RE plants.

20. Japan already has a seawater-based pumped storage system and several other countries are looking into possibilities of building reservoirs for pumped-hydro storage near their coasts and using seawater.

errors in day-ahead predictions are common. In that sense, gate-closure times that are closer to real-time may ease the integration of intermittent generating assets.

Intraday auctions are already possible in some OECD countries (see Annex B for a detailed explanation of intraday auctions). These auctions allow market participants to review their positions before electricity is dispatched. The design of auctions is important for intermittent power plants since gate-closure times may differ between neighbouring countries. The time elapsed between the closure of a forward market and real-time delivery can vary significantly (see Table 2). Several studies show that going from an hourly market to a ten-minute market would bring a reduction in balancing costs of about 30% to 40% (IEA, 2011a). However, the rules and design of intraday auctions still differ considerably across many interconnected OECD and non-OECD countries.

Table 2. Gate-closure times before the delivery of electricity

Austria	15 minutes before delivery
Belgium	60 minutes before delivery
Czech Republic	3 hours before delivery
Denmark	45 minutes before delivery
Finland	60 minutes before delivery
France	60 minutes before delivery
Germany	15 minutes before delivery
Hungary	3 hours before delivery
Italy	4 gate closure times during the day
Netherlands	2 hours before delivery
Norway	60 minutes before delivery
Poland	60 minutes before delivery
Portugal	6 gate closure times during the day
Spain	6 gate closure times during the day
Sweden	60 minutes before delivery
Switzerland	45 minutes before delivery
United Kingdom	60 minutes before delivery

Source: EPEX, EEX, Nordpool, OTE, PXCE.

Cross-border capacity allocation

The cross-border allocation of interconnector capacity is usually auctioned off yearly, monthly and day-ahead. Only a few country pairs have established some intraday allocation of cross-border capacity. Intraday cross-border allocations can be helpful for generators to respond to cross-border balancing needs, especially those caused by variable renewables. Such allocations can also allow unexpected surplus generated by variable renewables to be traded across borders.

As noted above, intermittent power can be difficult to predict at the day-ahead stage but becomes more (if imperfectly) predictable closer to real-time. This raises the question of how to treat significant proportions of variable output when all physical capacity is allocated at the day-ahead stage. Adjustments to the use of capacity would be possible intraday, but only if there is enough spare cross-border capacity (Annex B).

Balancing obligations

Electricity cannot be easily stored, and in order to ensure the security and quality of the supply in the system, its provision must equal demand at all times (Annex A). Traditionally, the amount of balancing energy, or reserve, provided by controllable thermal or hydroelectric power plants has been sized to balance variations in demand or has involved forced outages of the largest production unit.

In many OECD countries, intermittent generators do not have balancing responsibility. TSOs are instead responsible for balancing output from variable renewables, and this implies an additional cost imposed on the system (Figure 9). In order to keep the electricity system firm, TSOs ask the more costly generators to keep their plants turned on, or already scheduled generators to stop their generation. In countries where variable renewable-energy generators are exempt from the balancing regime, parties responsible for the balancing thus have to balance the system at a greater expense. Generators in some countries may therefore face higher balancing-price risks than others, depending on the special balancing regime for renewables in place in these countries. These different approaches can have implications for cross-border trade in electricity, especially if trade is important for balancing renewables.

As highlighted by European energy regulators (CEER, 2011):

"Where RES is exempt from balancing in one country the balancing responsible party may be forced to export the resulting imbalances across to neighbouring countries (i.e. the contracted import or export across the interconnector is not met). Because of the contractual agreements in place to import or export a certain amount of electricity across the interconnector, compensation is likely to be in place for the party who finds itself out of balance because of the actions taken by the responsible balancing party."

Balancing costs depend on many factors such as the share of variable renewable-energy plants connected to the grid, the availability of flexible power plants in the energy mix, the weather forecast for wind and solar plants, and electricity market structure (IEA, 2011a).

Furthermore, greater electricity-market integration could reduce the costs of integrating variable power into the grid. Indeed, making adjacent markets compatible through cross-border allocation methods that are closer to real-time would enable TSOs and market players to gain access to a larger market in which to achieve balance. Cross-border trade in electricity over shorter timeframes remains, however, an important market-design challenge for countries, something that is discussed in the following section.

Impediments to cross-border trade in electricity

Having shown that cross-border trade can play an important role in dealing with the variability challenge, and having summarised the impacts that renewables have on electricity markets and on cross-border trade, this section now looks at the impediments to electricity trade in general. Once electricity is generated, it becomes hard to differentiate between what has been produced using renewable and non-renewable energy resources. Indeed, considering the share of renewables in the electricity mix in OECD countries (ranging from 1-25%), it would appear that the majority of the electricity traded across borders is generated using non-renewable resources. In that sense, even if the

challenges that renewables pose are overcome, other impediments to cross-border trade in electricity may still create frictions.

Figure 9. Balancing cost of integrating intermittent renewables
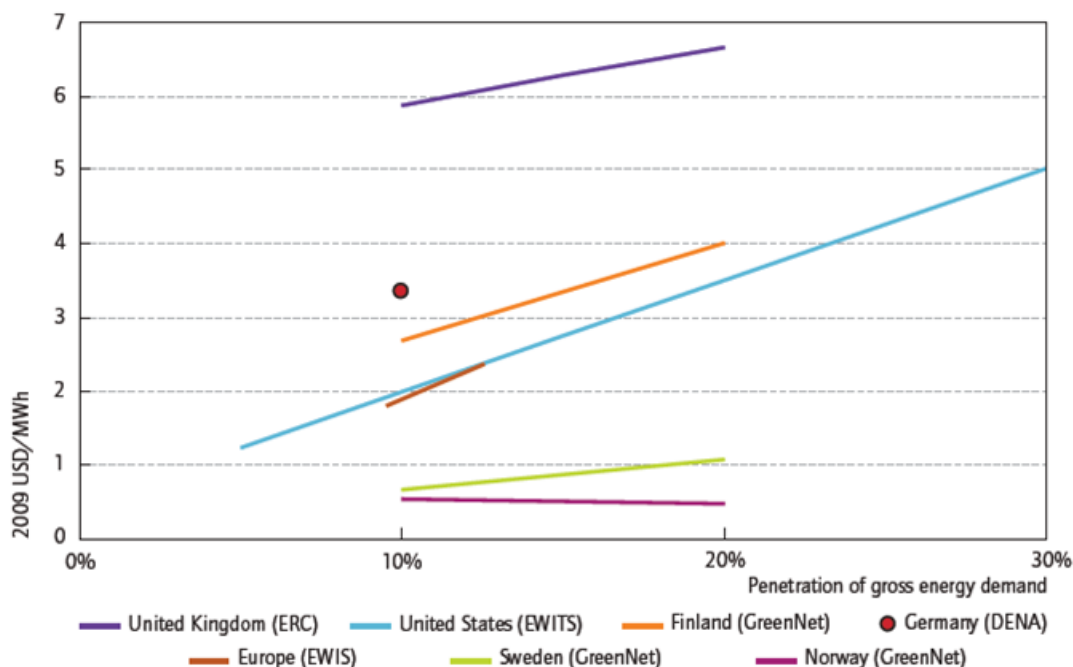
Source: IEA (2011a).

Import tariffs

Electrical energy is considered a good according to the WTO, and attributed the HS code of 271600 by the World Customs Organisation. Only 31 countries in the world apply import tariffs on electrical energy, and those tariffs are generally less than 15% on an *ad valorem* basis. Consequently, import tariffs are not considered an important barrier to cross-border trade in electricity in most regions.

Insufficient interconnectors

Investments in cross-border interconnectors are not absolute requirements for the smooth functioning of a national electricity system. Countries having autonomy in the supply of electricity may choose not to invest in interconnectors. In addition to costs and benefits, politics also plays a role in such decisions (Supponen, 2011). When countries trade electricity, part of one country's consumer surplus is transferred to the producer surplus of the other and vice versa. These distributional changes may accentuate national sensitivities, which can hamper new investments in interconnections.

The net transfer capacities of interconnectors are calculated by TSOs, and usually published twice every year (for summer and winter seasons), taking into account meteorological (mostly temperature) considerations. TSOs also consider the congestion of national transmission lines, security margins, and any planned-down time for maintenance of the interconnectors, among other factors. This capacity is usually

announced bilaterally by the two interconnected countries. The interconnection capacity can be subject to significant seasonal changes over time (Figure 10).

Figure 10. National Transfer Capacities between France and Germany (Winter and Summer)
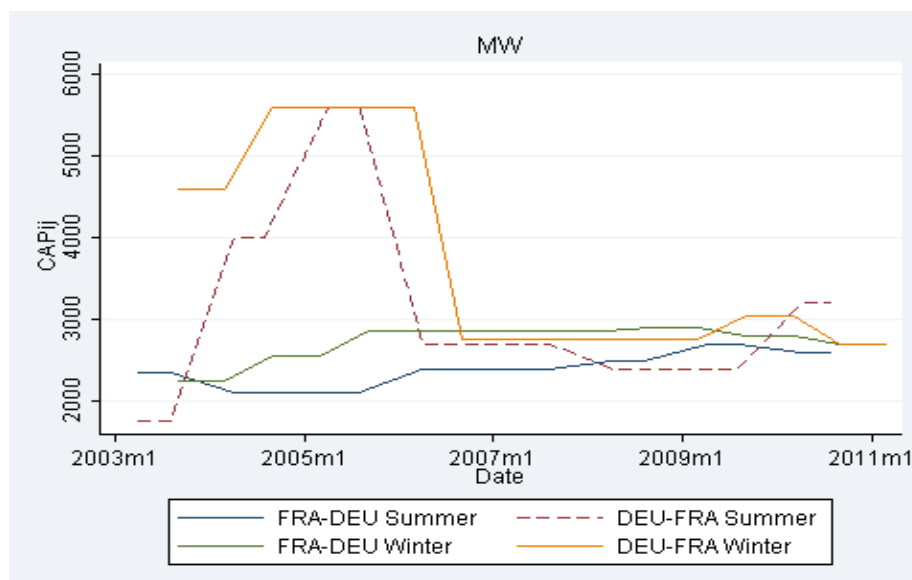
Source: OECD based on data from ENTSO-E.

In Europe, there has not been any significant increase in cross-border electricity transmission capacity in the last decade (Figure 11), though cross-border trade has increased significantly there (Figures 12). The reasons for this increase in trade are twofold. First, electricity consumption has been growing substantially over the period. Second, the liberalisation of electricity markets and the integration process of European electricity markets have facilitated and further encouraged cross-border trade (Annexes 2 and 3). However, the significant increases in cross-border trade in electricity have not necessarily resulted in comparable increases in investments in interconnecting capacity. Although some political and environmental factors might impede such investments (in addition to economic considerations), the data also suggest that interconnectors are being used more efficiently in Europe through various market-integration initiatives.

Figure 11. Net Transfer Capacities in selected European countries
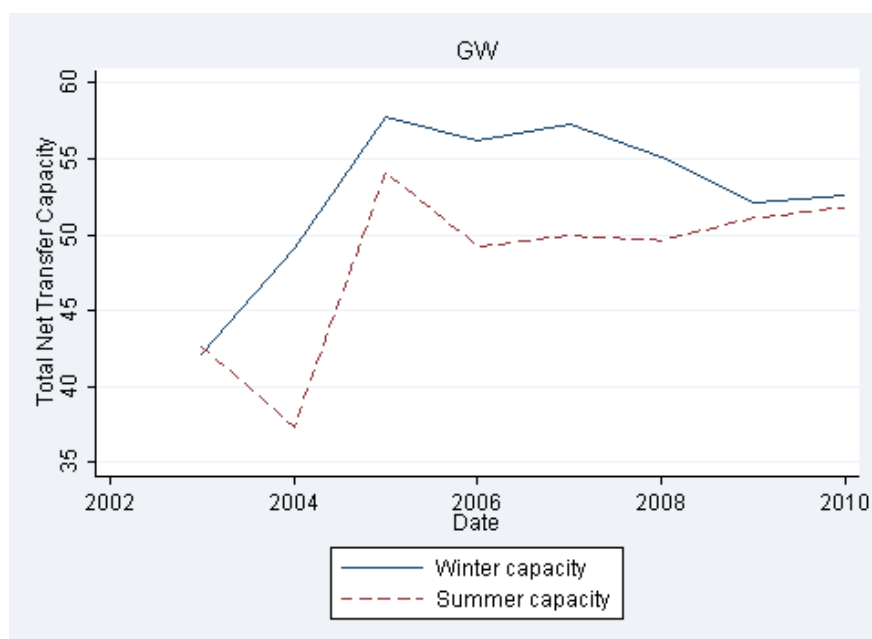
Source: OECD based on data from ENTSO-E.

Figure 12. Cross-border trade in electricity in Europe
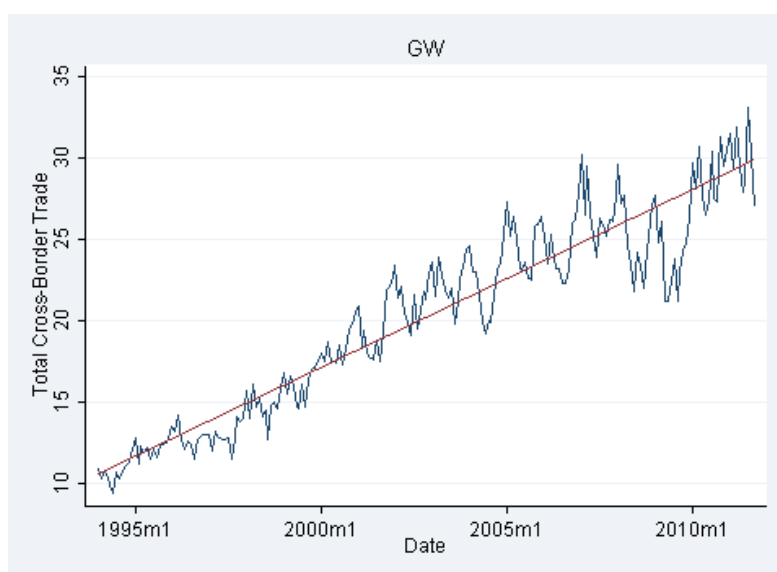
Source: OECD based on data from ENTSO-E.

Market design issues

Historically, TSOs have not designed interconnections between electricity networks with the primary objective of facilitating cross-border trade in electricity. Rather, they have designed their markets independently. Achieving the efficient utilisation of interconnectors' capacity necessitates, however, that interconnected countries harmonise their operating standards. Market participants and energy regulators generally agree that electricity network congestion problems need to be addressed in a non-discriminatory way. This implies that the price for cross-border transmission capacity should be determined through market mechanisms that give correct signals to market participants, and which reflect the opportunity cost of the available capacity (EC, 2001). The opportunity cost could, for example, be determined through a mechanism that reveals potential users' valuation of access to cross-border transmission, i.e. the capacity would be allocated to those users who place most value on the capacity (those who are willing to pay the opportunity cost).

Differences in cross-border allocation methods

There are basically four different methods for allocating available cross-border transmission capacity to market participants. The **first-come-first-served** method requires TSOs to have a co-ordinated schedule for allocating net transfer capacities (NTCs) through bilateral agreements on a regular basis (daily, weekly, monthly or yearly). TSOs normally accept requests until the NTC is fully committed in both directions. With **pro-rata** allocation, TSOs continue to accept requests when demand exceeds available capacity but, having calculated the level of congestion, they then reduce each bid proportionally, so that no congestion remains. By contrast, market-based allocations involve **auctions** conducted either by TSOs or PXs during which each market participant offers a price for the use of cross-border transfer capacity in one direction. There are mainly two auction types. An **explicit auction** is used when the transmission capacity on an interconnector is auctioned off to market participants separately and independently from the marketplaces in which electrical energy itself is being auctioned, while in **implicit auctions** the auctioning of cross-border transmission capacity is included (implicitly) in the auctions of electrical energy in a given power market.

First-come-first-served and pro-rata capacity-allocation methods are not based on users' willingness to pay for cross-border capacity. In both methods, capacity allocation does not guarantee that users who are willing to pay the highest price eventually gain access to cross-border transmission capacity. These methods are, nonetheless, well suited for bilateral trade. On the other hand, they fail to provide an efficient priority mechanism for transactions conducted on daily or real-time PXs, as, in such a case, all the transmission-service requests are submitted almost at the same time, just before market-gate closure time. **Pro-rata allocation** results in a particularly economically inefficient use of the system: everyone is curtailed relative to the amount submitted to the TSOs, and neither participants nor TSOs have an incentive to reduce congestion.

Auctioning can be more efficient than other allocation methods because the bids reflect the value that market participants place on cross-border transmission capacity, so that the highest priority for access is granted to those participants who are willing to pay the highest price. It thus serves to reveal information about market participants. Auctioning allows TSOs to handle constraints for cross-border trading, without providing any physical information other than NTC. To the extent that congestion only exists across borders, its management lies in the hands of market participants. For auctioning to be

economically relevant, however, a minimum number of market players need to be in a position to bid for transmission capacities.

Explicit auctions are considered to be less efficient than implicit auctions since they mean that cross-border capacity is auctioned independent of electricity prices (EC, 2001; ENTSO-E, 2011). The explicit auction suffers from the lag existing between capacity allocation and wholesale energy-market clearance, which creates more uncertainty for market participants since they have to buy cross-border capacity without knowing the relative prices of electricity that will prevail in the respective markets. Many countries use both implicit and explicit auctions. Usually, yearly and monthly allocation of cross-border capacity is done through explicit auctions while daily capacity is allocated through implicit auctions.

Although the efficiency of **implicit auctions** as a method for allocating cross-border capacity is widely accepted, countries cannot easily make the transition to this system due to the differences that exist across electricity markets. These differences make it difficult for countries to apply methods which require a higher level of co-ordination and harmonisation. Liquidity in day-ahead national electricity markets is an important factor that improves the efficiency of implicit auctions.

Differences in gate-closure times

When different electricity markets are not coupled using implicit cross-border capacity allocation, the existence of differences in gate-closure times can cause further inefficiencies. Absent any barriers or frictions, cross-border trade follows price differentials: it flows from low-price zones to high-price zones. However, there are sometimes opposite flows across borders (from high-price areas to low-price areas), which may reveal the existence of inefficiencies in the cross-border trade of electricity. Reverse flows can arise due to differences in gate-closure times in different national electricity markets. The inefficiency of explicit auctions mentioned earlier thus also stems from these gate-closure differences since electricity and cross-border allocation auctions can close at different times. If, for instance, the day-ahead capacity allocation auction ends before the electricity market clears, market participants have to place their bids based on expected market prices, the actual value of which may turn out to be quite different.

Market coupling allows all market participants to place their bids at the same time for different national electricity markets. In other words, in coupled markets both day-ahead and intraday auctions close at the same time. Some studies have indeed shown that market coupling minimises occurrences of opposite flows (Turvey, 2006).

Regulatory issues

Differences in national transmission tariffs

A transmission network is a natural monopoly because of the existence of economies of scale and scope in the delivery of electricity. A monopolistic electricity delivery company could charge prices that are much higher than the actual cost of delivery. Network company revenues from electricity sales are therefore usually regulated to ensure that they do not significantly exceed the cost of delivery. The network company is also mandated to serve all customers, both generators and consumers, according to standards and rules established by the regulatory authorities. Regulated revenues must be

sufficient to allow the recovery of operating and capital costs, including a reasonable rate of return on investments, to ensure the financial viability of the company (Rothwell and Gomez, 2003).

Every country has a different transmission-tariff policy set according to its existing network. One of the main differences is how charges are split between consumers (load) and producers (generators). Some countries implement an injection fee for generators, requiring them to pay a fee for power fed to the grid. Other countries recuperate transmission fees from electricity rate payers. Although the design of these fees falls under the jurisdiction of the corresponding country, it has important implications for cross-border trade. As mentioned above, the main driver of cross-border electricity exchanges are the price differences that exist between interconnected countries. High transmission tariffs for generators in one country may penalise generators in that country compared to neighbouring competitors that pay low or zero transmission tariffs where these are levied on rate payers.[21]

Cross-border fees

Before inter-TSO compensations (ITC) were put in place, cross-border flows were initially subject to transmission fees for both of two interconnected countries. Countries had ―postage stamp fees‖ for transmission pricing. These fees were applied to transport a given amount of electrical energy over the national grid at a fixed price per energy unit, independent of the distance or the voltage level. Since a uniform pro-rata transmission price was charged on all transactions without regard to the location of the buyer and the seller, cross-border traders had to pay two distinct transmission fees. This situation resulted in high trade costs for generators who sent electricity across borders, and was thus abolished in many OECD countries.

Inter-TSO compensation (ITC) methods based on cross-border capacity allocation auctions are considered to minimise trade costs because they are based on market participants‗ willingness to pay for cross-border capacity, if there is congestion. As mentioned above, transmission system operators receive congestion rent as a result of these auctions, and use it to invest in the development of interconnectors. Although the efficiency of this method is well recognised, some countries still levy additional fees on either imports or exports, or both.

Usually countries implement these additional charges for two main reasons. The first motivation is that countries may want to protect incumbent utilities‗ market positions. As cross-border trade in electricity can help improve competition, countries trying to protect their incumbent utilities may be reluctant to lift regulatory barriers. Second, a cross-border flow may have a negative impact on a country‗s national transmission system by congesting its grid. This situation can cause problems if the country‗s grid is weak.

Imbalance settlement regimes

Prior to the actual delivery of electrical power, all market players commit themselves to ensure the scheduled supply and demand (Wibroe et al., 2002). Ensuring the ―scheduled supply‖ means that the producers must generate and that the buyers must purchase the scheduled supplied power. ―Ensuring the scheduled demand‖ indicates that

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21. A distinction may need to be drawn between the formal incidence of a transmission tariff and its actual economic incidence. Assessing the final economic incidence of transmission tariffs is, however, beyond the scope of this paper.

the loads must be consumed and that the sellers must sell the scheduled demanded power. In the event that market players fail to fulfill their commitments, imbalances between the scheduled supply and demand will arise. Market players will then have to pay the costs associated with these imbalances. If the imbalance in a given hour is positive, the balancing responsible party (BRP) is responsible for an excess of generated power; while if this imbalance is negative, the BRP is responsible for a deficit in generated power. Depending on the regulation type and the sign of the imbalance, the BRP pays or receives money from the TSO accordingly.

BRPs are generally all generators or traders of electricity. They are required to submit day-ahead schedules to the system operator that estimate their electricity feed-in or consumption. Schedules can be modified before gate-closure times. The imbalance-settlement rules define the way deviations in generation are priced — i.e. how prices for the balancing service are transformed into imbalance costs for users of balancing services. According to these rules, balancing responsible parties receive payments or have to pay for the imbalance volume of energy. There are two general ways of pricing imbalance settlements. One is single imbalance pricing, whereby a single imbalance price is used regardless of whether the imbalance is positive or negative. The other is dual imbalance pricing, which involves applying different prices to positive imbalance volumes and negative imbalance volumes. Dual imbalance pricing gives a stronger incentive to deliver correct schedules than single imbalance pricing, since generators that do not deliver the scheduled energy face higher charges depending on their level imbalance.

Usually, interconnected countries use different methods to calculate imbalance-settlement prices. Some countries charge penalty (fixed or variable) fees to balancing responsible parties in addition to the normal imbalance price Penalty fees are defined in the balancing market by TSOs and are usually introduced to incentivise balancing-responsible parties to avoid negative imbalances. Penalties are usually larger for short positions than for long ones. In this case, it is expected that imbalance-responsible parties in countries implementing a penalty fee will try to hedge themselves against short positions by purchasing from day-ahead and intraday markets. This situation puts upward pressure on prices in associated markets. If these markets are connected and their electricity markets integrated, one would expect this situation to affect prices in both markets. As a result, if there are exchanges for balancing services, balancing reserves may migrate from countries without penalty to the ones with a penalty.

Administrative and bureaucratic issues

Language barriers

The development of an integrated electricity market composed of different national markets can be supported by the use of one language. The unavailability of official documentation in a common language can create problems for traders. In Europe, traders usually expect to have all documentation in a common language (usually English), not only the ones related to cross-border operations. In interconnected markets, it is important to have all documents — on access rules, licensing requirements, grid and network codes, and application forms — in a common language. Another important barrier may arise if the language used on trading platforms is not spoken by the trading partner(s).

Trading-licence requirements

Some countries may require traders to obtain a license in order to engage in electricity trading. The application process for trading licences varies by country according to the bureaucratic procedures that apply there. This process can take from two weeks to a year depending on documentation requirements and the national authority's speed in processing applications. Usually, traders are allowed to engage in cross-border transactions with their national licences. However, in some cases, national authorities may require traders to obtain another specific licence for cross-border trading.

In some countries, the —Commercial Code" makes the issuing of a license conditional upon a place of establishment in that country. Licenses are only granted to companies with local representation, though usually only a local branch office is required. National authorities may also require a fully-registered company in cases where a local branch is not enough. A requirement for a trading license combined with the obligation for a place of establishment can further cause tax complications for foreign-market entrance.

Transaction fees

In many countries, PXs or dedicated companies run both national and cross-border electricity auctions. Many PXs require an annual participation fee that is either independent of the annual trading volume, or dependent on the number of transactions conducted. High transaction fees can be an entry barrier for small trading companies.

Conclusions and policy implications

RE sources have been playing an important role in decarbonising the electricity industry. Governments in both developed and developing countries have offered generous incentives to RE technologies in order to ensure that they reach the ambitious targets they set for themselves. As a result, more electricity generated from RE sources is now being fed into electricity grids. The majority of existing electricity-grid infrastructure and wholesale markets were designed to accommodate predictable and dispatchable power output from conventional thermal and hydro-electric plants. However, a significant amount of new installed capacity in OECD and emerging countries now consists of solar and wind power plants, which in general benefit most from RE support schemes and whose output is highly variable.

Although current grid infrastructure in many countries can easily handle the low-level penetration of power plants with intermittent output, TSOs in countries where the penetration level is high already face considerable challenges to maintain the stability of their grids, and to keep demand and supply balanced at all times. Although cross-border trade can potentially help countries address the variability problem by giving them access to more flexible plants in a wider geographical area, some incentive measures for intermittent renewable-energy sources can nevertheless generate additional challenges for electricity markets, which in turn can reduce the benefits from cross-border trade in electricity.

In many OECD and non-OECD countries, electricity generators compete to get their electricity dispatched. TSOs try to optimise their portfolio by dispatching electricity from low-cost to high-cost generators until they meet the demand. The logic of cross-border trade in electricity is also based on the competition of generators in different countries, where electricity is expected to flow from low-price to high-price areas provided enough interconnecting capacity exists. Changes in the way that prices are formed in the

wholesale market of one country can therefore have a direct or indirect impact on cross-border trade in electricity. Incentive measures for renewable-energy sources, depending on their design, can also result in electricity market distortions. Non-market-based incentives discourage intermittent renewable-energy generators from participating in electricity markets because they usually receive a fixed payment, which is higher than the wholesale electricity price, for a long-period regardless of market fluctuations. In that sense, it is expected that wholesale price distortions would increase in line with the penetration of intermittent renewables. Countries with high penetration levels of intermittent renewables, which are supported by incentives, already experience lower or negative wholesale prices. This price effect can make these countries' electric power companies more competitive than others when electricity is traded across borders.

Competition effects can vary depending on the level, design, and type of the incentives that are provided. The long-term wholesale-price impacts of renewable-energy incentives have lately been an important topic of discussion among different stakeholders. The advantages and disadvantages of harmonising renewable-energy incentives is a sensitive topic because it involves national interests as well as existing national energy regulations. However, enhanced convergence of renewable- energy support schemes in interconnected countries could address some of the issues related to competition and prices. The harmonisation of RE support measures could also facilitate the trading of renewable energy across borders, which would help countries reach their RE targets (either binding or non-binding) in a more cost-effective way by importing from countries with which they share interconnections.

In addition to financial incentives, special regimes provided to intermittent renewables can also create additional cross-border competition issues. Special imbalance-settlement regimes can discourage generators of renewables from participating in balancing responsibility. This situation can increase the overall cost of balancing, which will be distributed among other generators, thereby increasing their costs. Depending on the imbalance-settlement regimes in place and the level of penetration, generators in some countries may be more competitive than others.

In order to take full advantage of cross-border trade in electricity, regardless of the trade frictions that may arise due to incentive measures, countries need to establish a non-discriminatory trading regime based on co-operation and co-ordination between interconnected countries. The efficient utilisation of available cross-border transmission capacity is highly dependent on the harmonisation of rules and regulations. This requires co-operation on the part of the different stakeholders involved in cross-border transactions. These include energy regulatory agencies, competition authorities, electricity generators, traders, and various ministries.

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Annex A1.

Basics of Electricity Markets

The unique aspects of electricity

There are number of physical properties unique to electricity that have a direct impact on the design and the institutional structure of electricity markets. First, unlike oil or natural gas in a pipeline, **electricity cannot be easily stored**.[1] It must be generated, transmitted, and distributed at the precise moment it is consumed. This means that operators of the electric system have to ensure that supply and demand are continuously in balance throughout the system. If supply is not available to meet demand, the whole system may crash precipitating black-outs. Thus, the system operator must always be ready to make up for any shortfalls or absorb any excesses, regardless of the situation born by generators.[2] In addition to various problems related to not delivering promised power, the increasing number of intermittent renewable technologies penetrating the grid increases uncertainty for system operators. This situation leads to **imbalances in electricity trading** arrangements, including both domestic and cross-border exchanges. These imbalances create a difference between the amounts contracted, and the amounts actually generated by suppliers, and consumed by costumers in real time (Hunt, 2002).

Second, **electrons flow along the path of least resistance.** Electricity is transported on transmission and distribution wires networked in a complex grid system according to laws of physics. It is impossible to command electricity to take a particular path. If the least resistance path is from one country's transmission system into another's interconnected transmission system, then that is where electrons will flow. If any line reaches its capacity, the system operator must order generators to stop producing. This action is called **congestion management**, which is the main responsibility of system operators to prevent outages from happening.

Third, **electricity travels at the speed of light.**[3] System operators have to manage fluctuating needs, imbalances and congestion. They need to order generators when to start up or when to stop. Any problem in the system also travels quickly, and can cause problems far from its source. Operators need to estimate demand in advance, and schedule generators accordingly. This action is called **scheduling**. After the scheduling,

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1. Pumped-hydro technology is the only economically viable mass storage in the electricity industry. There are other grid-storage technologies, such as large capacitors, which are not yet ready for commercialisation.

2. System operators have different spare capacities that they can use in emergency situations mentioned above. System operators buy and sell power in order to keep the system working at all times.

3. 300 000 000 metres/seconds.

they need to **dispatch** electricity in real time, and check possible demand (and supply) shocks in order to match the supply (and demand). In modern electricity markets, usually, there is a **day-ahead scheduling** both for national and **cross-border electricity flows**.

Fourth, the **electricity network is subject to complex series of physical interactions.** What happens on one part of the system affects conditions on the remote parts of the system. Generators need to produce several outputs,[4] and keep some of the electricity generated as reserve in balancing the frequency, voltage, and stability of the system at all times. These additional activities are called **ancillary services**. These services have an additional cost to system operators depending on the given situation. In order to manage them system operators put a **balancing mechanism** in place in order to tackle these additional physical interactions. The balancing mechanism is a very important tool in cross-border electricity trade to ensure the smooth and secure operation of both countries' systems, especially if variable renewables account for high a share of the electricity mix.

Main physical components of an electric delivery system

An electric delivery system is composed of four main components: **generation, transmission, distribution, and consumption.** The interaction between these components is critical to grasp the logic of cross-border trade in electricity and the role of renewables in electricity markets.

First, **generation** is the production of electricity by power plants in a country. Every power plant has a different levelised cost of electricity generation, which depends roughly on the costs associated with the generation technology, such as capital cost, fuel used, and operation and maintenance costs. In **liberalised competitive electricity markets**, generators compete for getting dispatched. The **marginal cost** of producing electricity is the basis for competition. Renewable-energy technologies, in contrast with conventional technologies that have to pay for fuel, have very low or zero marginal cost. The two most widely installed variable renewable-energy technologies, solar and wind, have no fuel cost. In that sense, they, together with hydro-electric and geothermal power plants, have an advantage in dispatching order.[5]

Generating units are typically scheduled hourly[6] based on least-cost supply and on reliability, operating, locational, and regulatory constraints. Systems operators usually divide generators into three different main categories. First, **base-load plants** (nuclear, coal, gas and oil-fired thermal plants, some hydroelectric plants and CHP plants) usually run twenty-four hours a day since they tend to have low variable costs and limited operational flexibility. Second, **intermediate plants** (combined-cycle gas turbines, single-cycle oil, natural-gas-fired gas turbines, and many hydroelectric plants) are usually dispatched from mid-morning to the evening. These plants are important because their operational flexibility allows them to be ramped up and down quickly, responding to changes in demand and supply. They are especially useful in dealing with changes in output from variable renewables due to meteorological conditions. Third, **peaking plants** operate primarily during times when power consumption peaks. They are flexible but

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4.   Active power, reactive power, fast response.

5.   In competitive dispatching incentive measures do not matter. Plants are dispatched according to their marginal cost of producing electricity.

6.   In some countries, TSOs schedule generators every half-hour instead of every hour.

more expensive than intermediate plants. Peaking plants are usually used for ancillary and balancing services and in emergency situations.

Second, the **transmission system** is the electrical network that connects supply to demand across the grid. The transmission system usually consists of high-voltage electric lines, transformers, switchyards, and transmission substations. The transmission system is usually a **natural monopoly** due to large economies of scale**.** This system is often managed by a centralised operator, also known as the **transmission system operator (TSO)**, which is responsible for managing the actions of generators, within its designated area. TSOs estimate demand in day-ahead, schedule forecasted demand, reserves, other ancillary services, cross-border or regional flows through interconnectors, dispatch electricity, and manage the system in real time. The ownership of TSOs can be public or private (usually called Independent System Operators) depending on the electricity market design.

TSOs are important players in cross-border trade in electricity because they have the authority to calculate available transfer capacities for international exchanges. TSOs announce **net transfer capacity** (NTC) every day for market participants to anticipate and plan their cross-border transactions. NTC values can differ from month to month, or winter to summer, because of power-plant outages and seasonal load changes, and because of the thermal ratings of transmission lines depending on the ambient temperature.[7] The calculation of NTCs has a direct impact on cross-border exchanges because it defines the maximum power that can be transmitted from one grid to the other. In that sense, it is important that NTCs are not defined arbitrarily, something which may cause inefficiencies in cross-border exchanges.

Co-operation and collaboration between two or more TSOs involved in cross-border trade in electricity is important in order to achieve safe and economically efficient electricity exchange. This collaboration can be at different levels, from co-ordination to integration. **Market integration** is the process of progressively harmonising the rules of two or more electricity markets. An **integrated electricity market** will eventually require the harmonisation of all cross-border market rules so that electricity can flow freely in response to price signals. A key challenge of market integration is to find ways of harmonising national and regional rules, which are designed nationally according to the market and regulation structure of a given country, and, eventually, moving to a common approach.

Distribution is the transmission of electricity from high-voltage to low-voltage lines, and finally to end-users. Although the distribution business is important in electricity markets, it is irrelevant for this paper.

Fourth, **consumption** is at the core of the electricity business. As generators represent **the supply**, consumers represent **the demand** for electricity. In general, utilities divide consumption hours between **peak** and **off-peak** hours. Peak hours are usually the periods between 6-7 a.m. and 10-11 p.m., while off-peak hours consist of the remaining part of the day.

Electricity consumers generally face **regulated prices.** Although different pricing strategies are implemented by different utilities during peak and off-peak hours, current technology does not fully enable consumers to respond to hourly changes in electricity

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7.   www.entsoe.eu/fileadmin/user_upload/_library/ntc/entsoe_NTCusersInformation.pdf

prices.[8] In that sense, **demand-response** is very low in electricity markets, leading to an almost perfectly **vertical demand curve** reflecting its inelasticity (Figure A1). Although TSOs are skilled at forecasting demand the day before actual consumption, this forecasted demand is never perfect. Because consumers' responses to prices are limited, TSOs have to balance their system either by ordering more generators to run or to switch off during the day.

Figure A1. Supply and demand in electricity markets
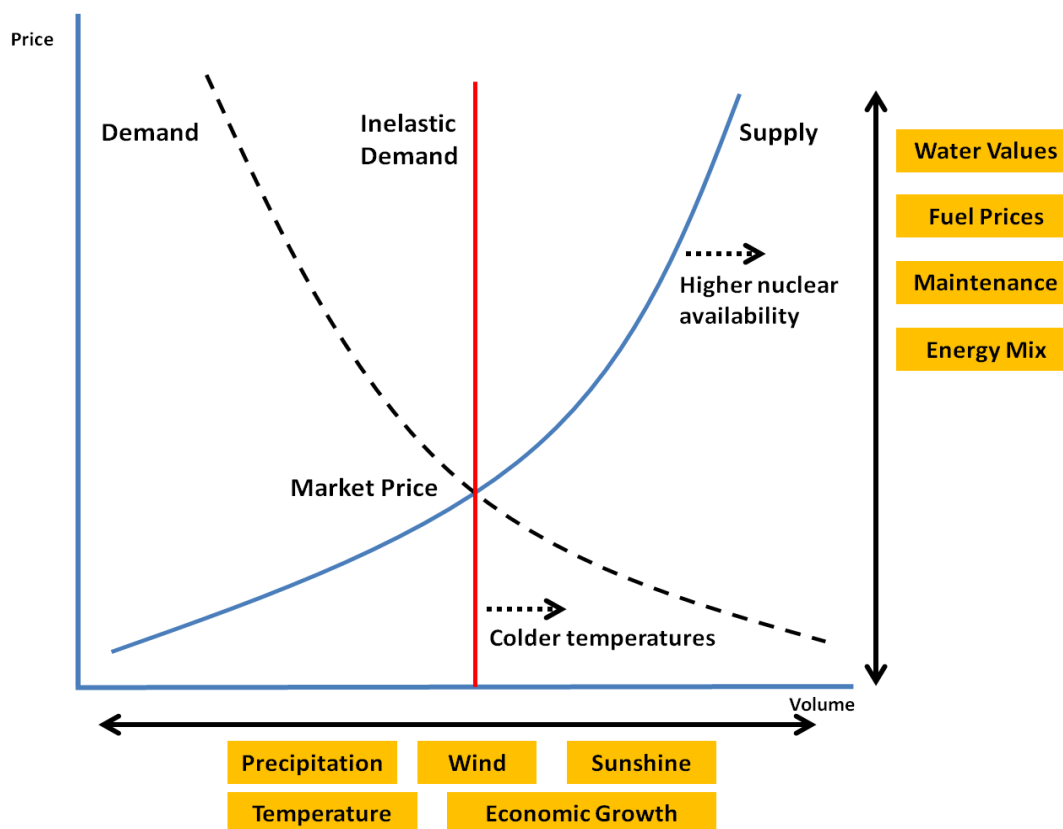
Source: OECD, based on Vattenfall.

Reference

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8.   The technology of smart-metres has been deployed in only a few pilot cities in the world. Smart-metres allow consumers to follow hourly changes in electricity prices, and to respond to these changes by adjusting their consumption.

Annex B.

Liberalisation of Electricity Markets, Competition and the Drivers of Cross-Border Trade in Electricity

Why liberalisation?

Traditionally, the electricity industry has been owned, managed and operated by **vertically-integrated** utility companies, which have been responsible for all the physical components of the electric delivery system, from generation to distribution. In principle, there are many different approaches to liberalising the electricity market, depending on which particular components of the industry are liberalised.

The main motivation behind the liberalisation of the electricity industry is to increase economic efficiency. Inefficient performance of vertically-integrated, publically-owned utility companies and the old regulatory framework have encouraged countries to consider **electricity-market reform**. ⎯Widespread excess generating capacity, unexplained national and international cost differentials (e.g. between plants or between companies), and persistent international (or inter-state) electricity price differentials have implied that there is scope for improvement. Inefficiencies have become more obvious and relevant in the context of slower demand growth and globalisation" (IEA, 2005).

The introduction of competition in different components of the industry can be considered the main benefit of liberalisation, especially in power generation. Historically, significant planning errors led to excess generating capacity and higher costs. Thus, generation was the first target of liberalisation because it offered the largest potential for improvement. Competition puts downward pressure on the profit margins of generators, giving them incentives to reduce costs. As a result of this, **electricity prices under competition tend to be lower.** It is also expected that competition will bring better investment decisions as investors will be exposed to competition.

Competition in wholesale electricity markets

The creation of a **wholesale market** marks an important step in introducing competition in electricity generation. While in a vertically-integrated electricity market, prices are usually set by regulatory agencies or government institutions, the aim in wholesale markets is to set electricity prices through market mechanisms.[1] This requires **equal access** to the transmission system for all generators. Usually, a **bid-based** spot-market pool is designed on the principles of economic dispatch, which sets the stage in the wholesale market for competition among **market participants.** A system operator is required to manage dispatching after the auction. This requires that systems operators be

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1. The existence of a wholesale market does not necessarily mean that electricity prices at the consumer level are unregulated. There are many countries where wholesale electricity prices are defined through an auctioning system while consumers face a fixed regulated price at the retail level.

independent of the existing electric utilities and other market participants in order to ensure equal treatment of all market participants.

Wholesale electricity prices are usually defined **hourly**.[2] System operators forecast demand a day ahead, then generators bid their marginal cost of generating power to the wholesale-market pool. The schedule of generators' costs stacks up to define the generation **merit order** from least to most expensive.[3] This merit order defines the short-run supply curve. In other words, the system operator controls operation of the system to achieve the efficient match of supply and demand based on the preferences of the participants as expressed in the bids. The offer price for the last generator needed to satisfy a given level of demand, the **marginal power plant**, determines the **day-ahead market price** for all the other generators (Figure B1).

Figure B1. Merit order dispatch in electricity markets
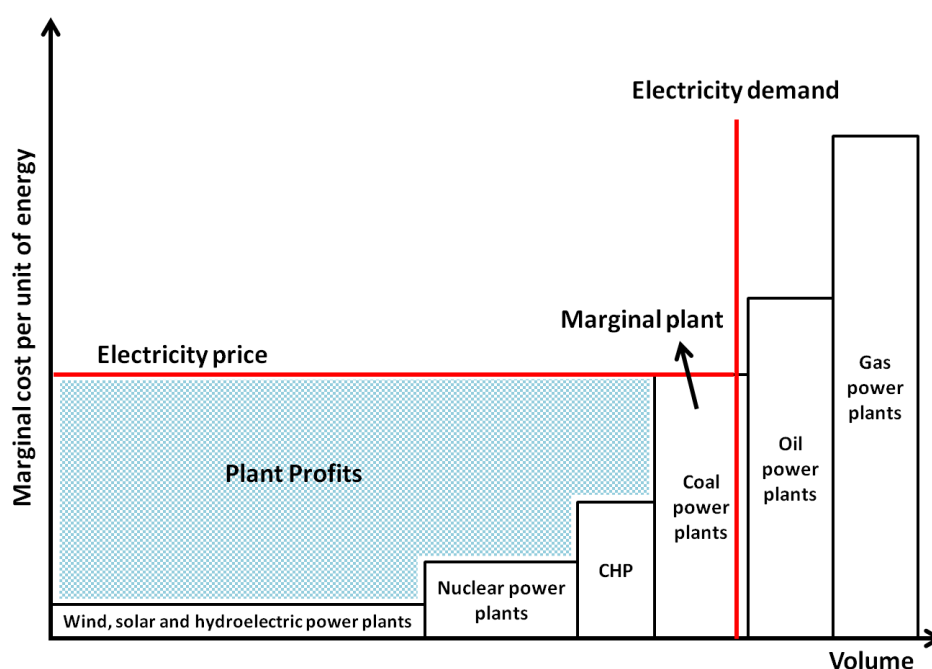
Because electricity cannot be stored in any significant quantity, it will remain necessary for each TSO to take control of the system at some point ahead of real time to ensure that supply and demand is precisely balanced on a minute-by-minute basis. In that sense, day-ahead markets remain limited in responding to daily changes in demand.

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2.   In some countries the electricity price is also defined for every half-hour.

3.   As long as the generator receives the market clearing price, and there are enough competitors so that each generator assumes that it will not itself be the marginal plant, then the optimal bid for each generator is the its true marginal cost: to bid more would only lessen the chance of being dispatched, but not change the price received. To bid less would create the risk of running and being paid less than the cost of generation for that plant. Hence, with enough competitors and no collusion, the short-run central dispatch market model can elicit bids from both buyers and sellers.

In order to deal with imbalances and increase participation in wholesale markets, in addition to the day-ahead auction, countries have introduced **intraday auctions,** which are usually conducted around an hour before the actual dispatch of electricity. The main role of these auctions is to adjust market participants' positions due to observed changes in generators' behaviour before the operation hour. As a result of this auction, an intraday market price is defined.

Once day-ahead and intraday auctions are closed by **gate-closure time** (the time when PXs or TSOs stop accepting bids), market participants have to rely on TSOs to balance any remaining difference between supply and demand (including real-time differences at the time of operation) in the control area for which they are responsible. This market is called the **balancing market.** There are usually two different ways to manage balancing markets. First, TSOs organise another competitive auction (as in day-ahead and intraday markets) in order to define the **balancing price** of electricity. There are usually two different prices in balancing markets; for those plants who are under-scheduling and those who are over scheduling. Second, TSOs buy and sell electricity in order to balance the system. This process usually does not include a competitive procedure. In addition to these, some TSOs also charge an **imbalance penalty fee** according to market participants' positions.

Day-ahead, intraday and balancing markets operate in different timeframes of the day, and countries usually have different auction rules for these markets (Figure B2). Wholesale transactions (bids and offers) in electricity are typically cleared and settled by the system operator or a special-purpose independent entity entitled exclusively for that function. More and more countries establish independent companies to manage day-ahead and intraday auctions. These companies are called PXs**.** They are platforms (like stock markets) where market participants trade electricity.

Figure B2. Electricity trading arrangements, timeframes and products
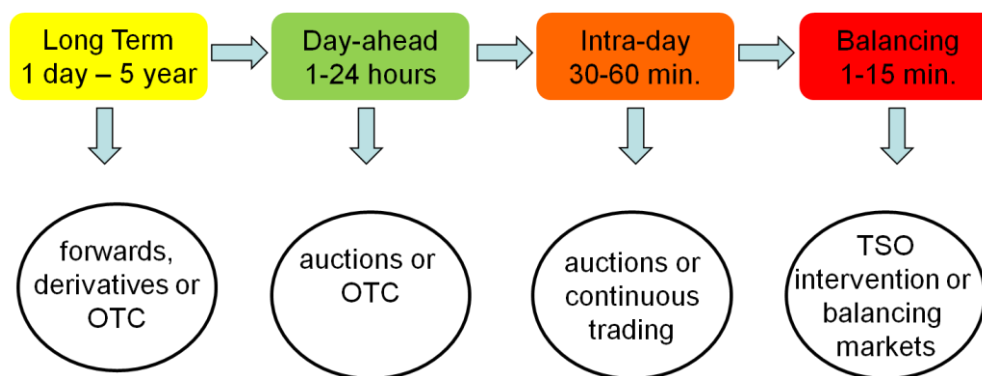
In addition to day-ahead and intraday markets, electricity is also traded in **forward markets**. Forward markets provide a way for market participants to manage the risks associated with price volatility in the wholesale market (Figure B3).[4] Forward contracts can be traded from two days to five years ahead. There are usually two different markets where forward contracts are traded. First are **over-the-counter (OTC)** markets, which allow market participants to enter into confidential contracts (Figure B2). Many OTC contracts are bilateral arrangements between generators and retailers. Prices for these

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4.   www.ceem.unsw.edu.au/content/documents/contractsurvey_short_May2006.pdf

bilateral contracts are not usually public since they are agreed between two companies. Second, companies can trade contracts with forward products offered by PXs. Contrary to OTC transactions, forward contracts traded through PXs are usually publically reported.[5]

Figure B3. Volatility in wholesale electricity prices in the EPEX spot market
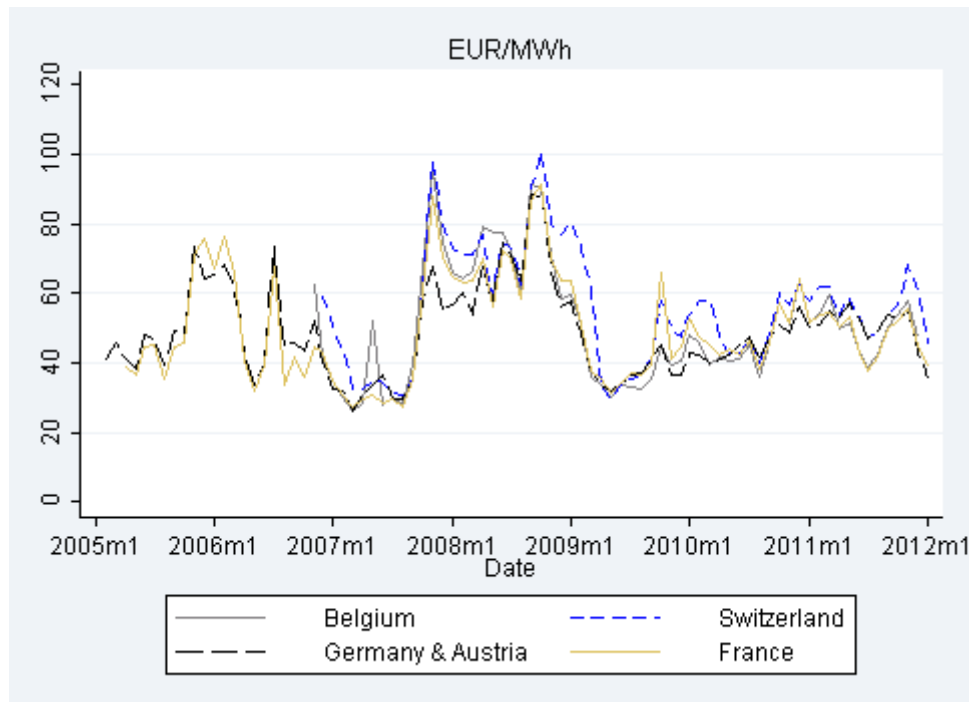
Source: OECD based on industry data (see Annex d).

Drivers of cross-border trade

Historically, countries have sought more system stability, which led national electricity systems to pool together. The first recorded cross-border trade took place between Canada and the United States in 1901 (World Bank, 1995). In Europe, the first cross-border exchange took place in 1929 between Germany and Austria. At the time, the main driver of cross-border trade in electricity was the quest for security of supply (World Bank, 1995). After the Second World War, interconnectors in Europe developed under political pressure by the US and the Soviet Union. NATO set up a working group on ―energy security‖ dealing with new investments in interconnecting capacity. In the early 1950s, the Marshall Plan invested in regional grids in Western Europe in order to achieve ―electricity independence‖ (IFRI, 2009).

During the Cold War, countries started to realise the economic benefits associated with cross-border trade in electricity. Differences in the production costs of electricity have traditionally been the major motivation for countries to initiate cross-border electricity exchanges. Lower electricity production costs in Central and Eastern Europe

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www.accc.gov.au/content/item.phtml?itemId=904614&nodeId=6c8b829fea70563efcef4234
776aea1c&fn=Chapter%203%20%20Electricity%20financial%20markets.pdf

attracted interest from countries in the West. Cheap coal from Poland and the hydroelectric potential of Yugoslavia made imports attractive. Thus, the former countries of Yugoslavia and Czechoslovakia in the late 1950s initiated trade between the East and the West (IFRI, 2009).

Before the liberalisation of electricity markets, cross-border trade in electricity was managed by vertically-integrated utility companies through **bilateral long-term contracts** (more than 90% of UCPTE exchanges take place under these conditions, and about 50% of NORDEL exchanges). The main motivations behind these electricity exchanges were: ―back-up exchanges for emergency support, marginal exchanges for spinning reserves, and occasional exchanges, in which no guarantee of capacity is given" (World Bank, 1995). In addition to that, TSOs had agreed to help each other in order to **prevent black-outs** from occurring. Although the liberalisation process introduced competition in generation in the early 1990s, former vertically-integrated monopolies continued to hold significant market power. These incumbents held on to their long-term contracts for interconnector capacity, which prevented competition from other markets.

Open trade across country or regional borders allows countries to realise mutual economic benefits by finding and **exploiting comparative advantage** in the division of capital and labour. Electricity generation is highly dependent on countries' resource endowments, geographical situation and national skills; it is also a very capital-intensive business. These factors are reflected in differences in electricity prices across countries. Thus, there are many reasons to look for and exploit comparative advantages, and many ways to realise large potential gains by optimising the use of assets across as large an area as possible (IEA, 2005).

Prices as the main driver of cross-border trade in electricity

Wholesale electricity prices change according to the factors affecting supply and demand for electricity. On the supply side, the technology mix (power mix) that a country adopts to produce electricity matters. This mix is usually shaped according to a country's available natural resources, geographical location and its government's energy strategy. Although countries adjust their power mix according to new environmental regulations, the generation fleet still mostly represents the availability of or access to natural resources.[6] Countries having significant natural-gas and coal resources typically have a power mix reflecting this relative abundance. The same holds true for countries having great water resources that allow them to produce more electricity from hydro-electricity plants. However, there are many examples where power mix does not always reflect the availability of resources. Rather, government energy policy defines the power mix. For instance, some countries have chosen to produce a significant amount of electricity using nuclear technology. The same holds true for countries exploiting their renewable resources with the help of incentives.

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6.   Here, access means having the necessary infrastructure to access natural resources (e.g. pipelines for natural gas).

All electricity-generating technologies have different costs of producing electricity depending on their size, vintage and location. In that sense, the power mix has a significant impact on wholesale electricity prices of a country. Another important factor on the supply side is temporary changes in the availability of these technologies. This availability can depend on meteorological conditions as for some renewable-based power plants (rain and snow fall for hydro-electricity, wind speed for wind power, and solar incidence for solar power) or fuel prices for conventional plants, as well as scheduled and unscheduled outages.

On the demand side, economic growth and meteorological conditions are the main factors affecting the demand for electricity. It is thus expected that higher economic growth would also increase the consumption of electricity, though some decoupling may be observed in particular cases. Meanwhile, temperature levels have a significant impact of their own on consumption. Consumers tend to consume more electricity in cold winter and hot summer days. In these periods, wholesale electricity prices usually increase significantly (Table B1).

Table B1. Temperature and electricity price changes in France (4 February – 10 February 2012)

France	04/02	05/02	06/02	07/02	08/02	09/02	10/02
Prices EUR/MWh	68.5	71.6	99.4	129.5	117.3	367.6	147.2
Temperatures in Celsius	-4	-5	-7	-8	-8	-11	-8

Source: Prices from EPEX, temperature data from meteofrance.com.

At a national level, as the system operator dispatches electricity starting from low-cost to high-cost generators, a well-functioning wholesale electricity market maximizes social welfare for market participants as a whole. Figure B4 illustrates consumer and producer surplus in an isolated electricity market with a single equilibrium price.

When two electricity systems are interconnected, it is expected in a competitive market that electricity will be transmitted from the low-price zone to the high-price zone. In the exporting zone, prices increase because additional, more expensive generators are required to operate, whereas in the importing zone prices fall. Cross-border flows generate an overall increase in social welfare, since a part of the high-price demand is met by a part of the low-price supply. In Figure B5, it is assumed that wholesale electricity prices are lower in Market A than in Market B.

Figure B4. Consumer and producer surplus in electricity markets
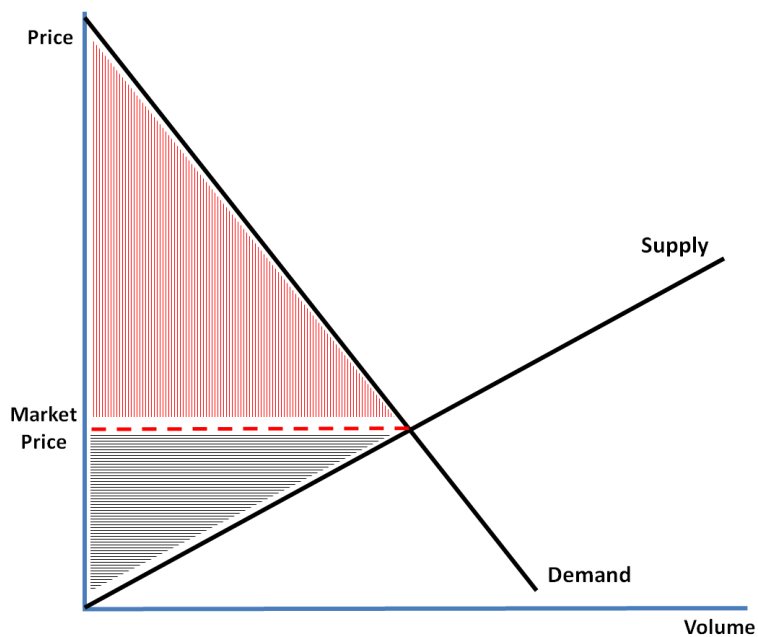
Figure B5. Social welfare changes in an electricity-exporting country
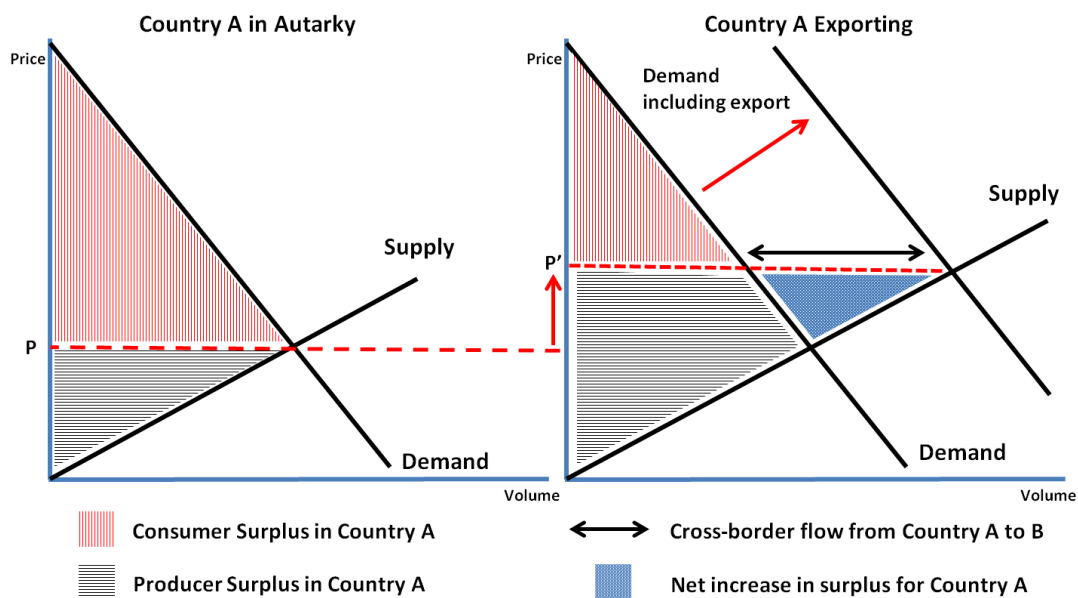
Source: OECD based on CEER (2009).

If A is the country exporting to high-price country B, wholesale prices there are expected to increase after the cross-border flow occurs. This cross-border flow results in a decrease in consumer surplus in market A due to an increase in prices. However, it increases producer surplus to a greater extent due to the increase in demand for electricity coming from market B. These changes in social welfare in market A can be thought of as a transfer of surplus from consumers to producers. Because the difference between the increase in surplus for producers and the decrease in surplus for consumers is positive, the overall net change in welfare is positive.

A similar situation is observed in the importing market in country B. The cross-border flow from A to B results in a decrease in producer surplus due to imports coming from A, and an increase in consumer surplus because consumers now enjoy lower prices (Figure B6). The difference between the increase in surplus for consumers in market B and the decrease in surplus for producers there is again positive. Consequently, the net surplus for market B as a whole is positive.

Figure B6. Social welfare changes in an electricity-importing country
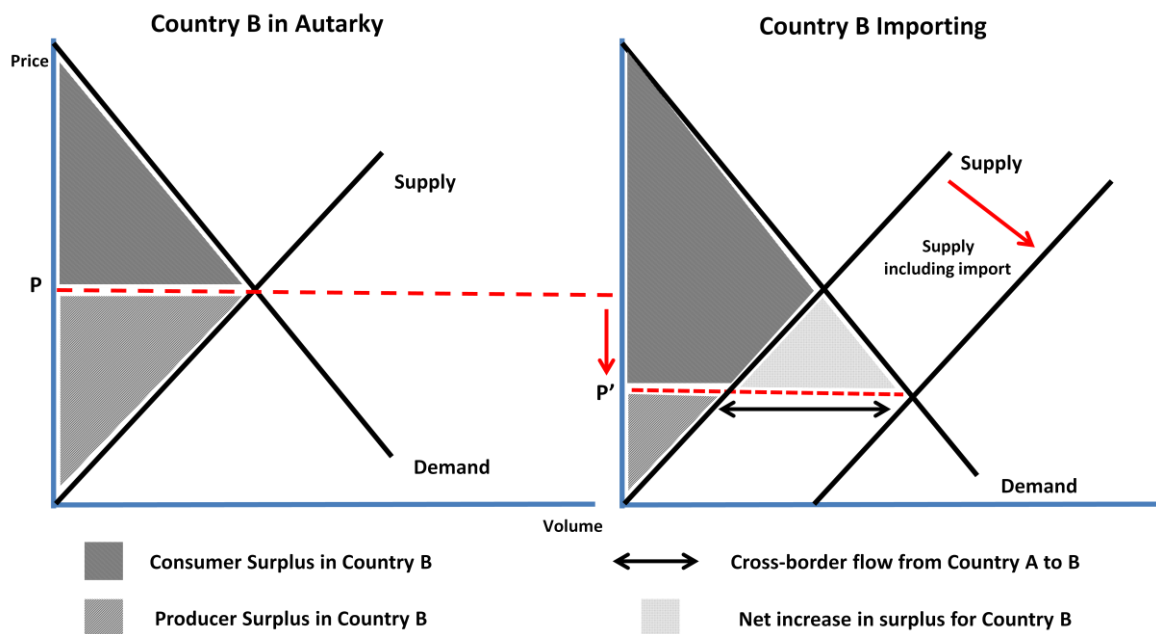
Source: OECD based on CEER (2009).

The interaction between these two markets can be summarised by the illustration of net-export curves for each market (Figure B7). For a given hour, net export curves (NECs) for each market are constructed. To each price *P* corresponds a given demand for imports (excess domestic demand) or supply of exports (excess domestic supply). These quantities represent the difference existing between the offer and bid at each price level. In other words, the NEC of a market gives, for each additional megawatt exported or imported by the market, the price that would be observed in this market (CEER, 2009).

Provided there is enough transmission capacity connecting A and B in a given hour and no other trade costs are applied, the market clears at the intersection of the two net export curves (Figure B7). At this ideal point, prices in market B decrease while those in market A increase (for a given hour) until they become equal. These changes in prices

that occur in the two interconnected markets following the cross-border flow of electricity correspond to a process of **price convergence** (Figure B8).

Provided there is enough transmission capacity connecting A and B in a given hour and no other trade costs are applied, the market clears at the intersection of the two net export curves (Figure B7). At this ideal point, prices in market B decrease while those in market A increase (for a given hour) until they become equal. These changes in prices that occur in the two interconnected markets following the cross-border flow of electricity correspond to a process of **price convergence** (Figure B8).

Annex C outlines a simple, conceptual model of cross-border trade in electricity based on relative prices. Table 1 shows the results that were obtained when testing this model empirically using the industry data described in Annex D. While essentially focussed on Europe, the authors' findings confirm the important role that relative prices play in driving cross-border power exchanges.

Figure B7. Net exporting curves for an exporting and importing country
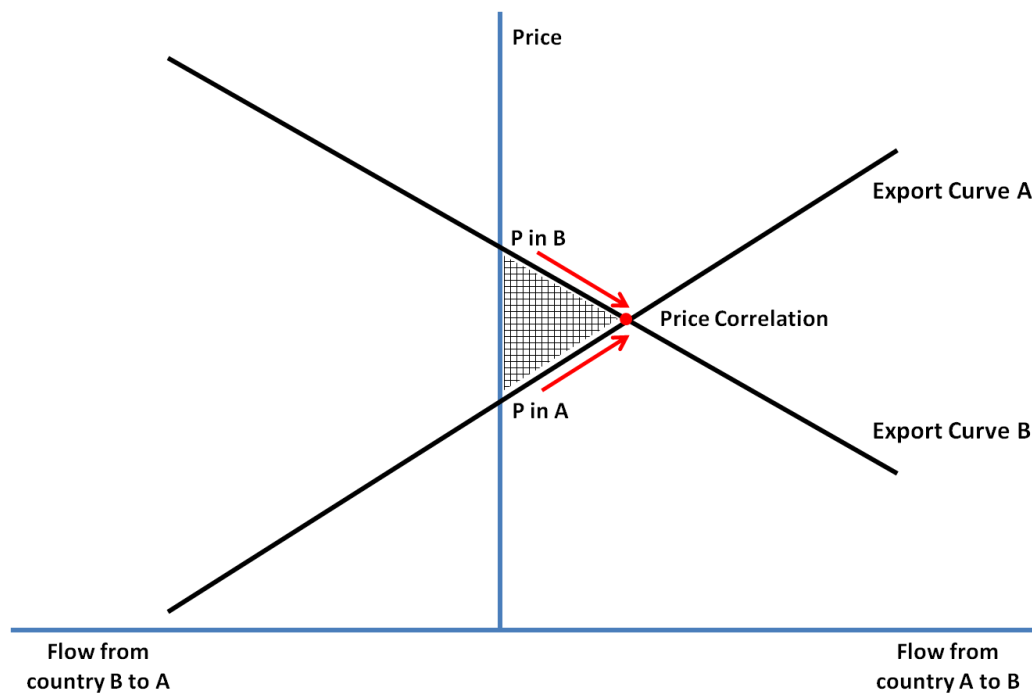
Source: OECD based on CEER.

Figure B8. Price correlation across selected country pairs

	BEL	CHE	DEU	FRA	ITA	ESP	NLD	PRT
BEL	1 *62*							
CHE	0.8963* *61*	1 *62*						
DEU	0.9178* *62*	0.8736* *62*	1 *84*					
FRA	0.9356* *62*	0.9368* *62*	0.9258* *82*	1 *82*				
ITA	0.6968* *62*	0.7119* *61*	0.6487* *83*	0.6039* *81*	1 *84*			
ESP	0.7105* *62*	0.6779* *61*	0.7425* *83*	0.6524* *81*	0.5940* *84*	1 *84*		
NLD	0.9560* *69*	0.8758* *62*	0.9621* *84*	0.8990* *82*	0.6343* *84*	0.7627* *84*	1 *91*	
PRT	0.8163* *37*	0.7259* *37*	0.8104* *37*	0.7633* *37*	0.8683* *37*	0.9754* *37*	0.8541* *37*	1 *37*

Note: Asterisks denote significance at the 5% level. Numbers in italics indicate the number of monthly observations for each country pair.

Source: OECD based on industry data (see Annex D).

How does cross-border trade in electricity work in reality?

In summary, the international exchange of electricity has four main advantages. "Trade allows countries to make better use of complementary resources, for example to use flexible hydroelectric generation to export peak power and import thermal power during off peak hours [the available hydro-electric generation in Norway was one of the driving forces in the Nordic market integration, see Annex E]. Secondly international interconnections allow balancing of annual demand variations, for example if little rain reduced hydro reserves and thermal output in a specific year. Thirdly, international electricity trade allows countries to balance historically grown generation with current needs. A fourth advantage of international trade is that it allows the pooling of reserve capacity thereby reducing costs for extra power stations and limiting inefficient dispatch of power stations required for provision of reserves" (Neuhoff, 2002).

Definition of interconnector capacity

An electricity interconnector is a cable connecting two separate markets or pricing areas.[7] Interconnectors have capacity limits that are calculated and announced by TSOs. An interconnector has a **rated capacity,** which is defined according to ambient temperature and other meteorological conditions. However, an interconnector cannot always allow power to flow at its rated capacity. This rated capacity is adjusted according to a forecasted generation and consumption pattern for each of the interconnected networks. This adjusted capacity is the **total transfer capacity,** which is the maximum continuous programmed power exchange between two areas consistent with the safe operation of both interconnected systems (Turvey, 2006). TSOs take into account the transmission reliability margin in order to calculate the **net transfer capacity (NTC)** of the interconnector (ENTSO-E, 2009). NTCs constitute important indicators for market

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7.   In some countries different regions are managed by different TSOs where prices defined regionally and not nationally (e.g. Norway, Sweden, Denmark).

participants who are involved in cross-border electricity exchanges. In that sense, they are the first steps in trading electricity across borders.

Most of the existing interconnection capacity was originally developed to provide security of supply rather than to facilitate trade. However, countries have grown more aware of the benefits of trade, which have led them to consider the **efficient use of interconnectors**. Efficient use of interconnection means that ―the maximum capacity is made available to market participants, while maintaining operational security, and that electricity flows in response to price differences in two interconnected markets" (OFGEM, 2010). This requires the allocation of NTC to market participants, which is the second step necessary in trading electricity across borders.

Allocation of available interconnector capacity

In order for market participants to trade electricity, they need to have an access to the electricity grid. In the case of cross-border exchanges, access has to be granted from both sides of the interconnector. This access is called the **"Third Party Access or TPA"** to the cross-border transmission system. TPA is an important concept in liberalised electricity markets where market participants are given access to an infrastructure which they do not actually own.

Both market and non-market based methods are used to allocate available interconnection capacity. Non-market based methods include first-come-first-served and pro-rata allocation methods. On the other hand, market-based methods such as explicit and implicit auctions are also commonly implemented. Many OECD countries implement auctions to allocate cross-border capacity (Figure B9). The main goal of these allocation methods is to deal with **congestion** issues in interconnectors.

The **first-come-first-served** method is a co-ordinated schedule for allocating NTC by TSOs through bilateral agreements on a regular basis (daily, weekly, monthly or yearly). TSOs publish their NTC, and expect market participants to submit their requests for transfer capacity in MWs. TSOs normally accept requests until the NTC is fully committed in both directions. Once the interconnection capacity is reached, no more transactions are accepted by TSOs. Each request has to be confirmed by market participants at least a day-ahead. Any change in submitted schedule has to be notified to the TSO, and penalties should be paid for last-minute changes. This method is consistent with the assumption that the users who really need transfer capacity will be the first to request it. Thus, the method encourages participants to make longer forecasts. And, it allows a better and more rapid security assessment for TSOs because they know accurately the entire volume of cross-border exchanges in advance.

In **pro-rata** allocations, TSOs continue to accept requests when demand exceeds available capacity. As in the first-come-first-served method, interconnected TSOs form together a schedule for allocating NTC on a regular basis respecting bilateral agreements. TSOs then estimate physical flows and detect which interconnectors are congested. Having calculated the level of congestion, TSOs reduce each bid proportionally, so that no congestion remains. No bid is refused, but they are not accepted to their full extent.

In market-based allocations, an **auction** is conducted either by TSOs or PXs. Each market participant offers a price for the use of cross-border transfer capacity in one direction. TSOs find out which direction is congested, and then prioritise the bids from the highest price offered to the lowest. Bids for transfer capacity in the constrained direction are accepted until the NTC is fully allocated. Usually, market participants do not

pay anything if the interconnector is not congested. There are two types of auctions used for allocating NTCs.

Figure B9. Cross-border capacity allocation methods in Europe
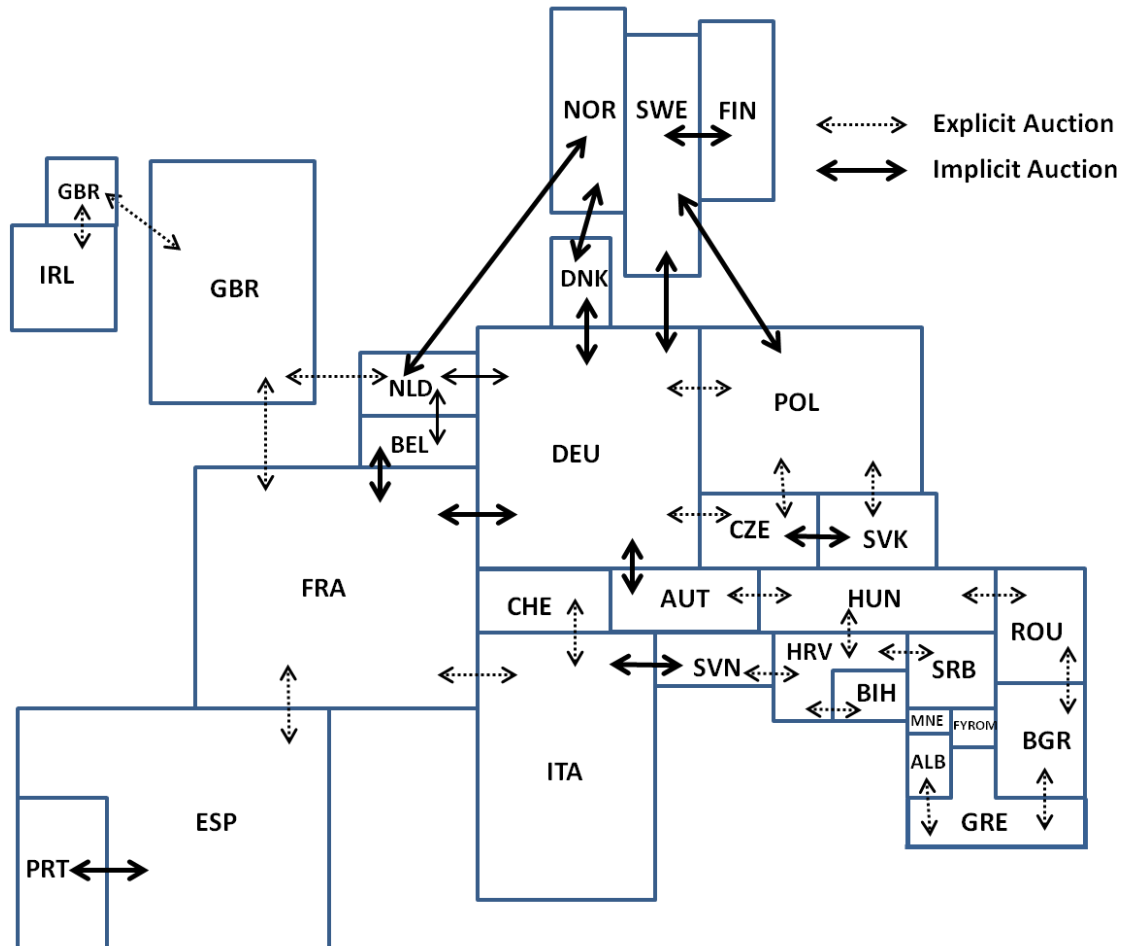
An **explicit auction** is used when the transmission capacity on an interconnector is auctioned off to market participants separately and independently from the marketplaces in which electrical energy itself is traded. Explicit auction is considered a simple method for handling the capacity of interconnectors. The capacity is normally auctioned in portions through annual, monthly and daily auctions.[8] The price of each successful request for capacity can be **the same as the bid in the auction** (**"Pay-As-Bid"**), or it could be **equal to the lowest accepted bid** (**"Marginal Bid Auction"**).

An **implicit auction** differs from an explicit auction in the sense that the price for the interconnector's capacity is included directly in the price of the transmitted electricity. The day-ahead transmission capacity is used to integrate the spot markets in different bidding areas. The auctioning of transmission capacity is included (implicitly) in the auctions of electrical energy in a given power market. In implicit auctions, the transmission capacity between bidding areas (price areas or TSOs' control areas) is made available to the wholesale-price mechanism so that the resulting prices per area reflect

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8.   Weekly auctions are also possible.

both the cost of energy in each internal bidding area (price area) and the cost of congestion. If demand for available cross-border capacity is lower than supply, market participants do not pay any additional fee to send electricity across borders. Implicit auctions try to ensure that electrical energy flows from the surplus areas (low-price areas) to the deficit areas (high-price areas), thus also leading to more convergence in prices.

Cross-border trading arrangements

Cross-border trading arrangements are similar to wholesale trading. Market participants trade electricity through different contracts. Generally speaking, cross-border electricity is traded either on an exchange (where trading is typically anonymous) or through OTC bilateral contacts.

In general, the available capacity announced by TSOs is divided into three different maturities, and sold out at different auctions. Usually, the way in which TSOs allocate these maturities is regulated by national energy regulatory agencies. **In long-term explicit and implicit auctions**, capacity is usually auctioned **yearly and monthly**. A successful bid for one MW of yearly capacity entails the right to transport one MW of power in one direction for the whole year. **The monthly auction** functions with the same principle but the capacity is only given out for one month at a time. In several markets, shorter term **weekly auctions** exist. In addition to these auctions, some **day-ahead capacity** is made available to market participants the day prior to delivery. For these auctions, TSOs announce everyday their day-ahead cross-border capacity left from yearly, monthly and weekly auctions. Some countries allow re-selling of cross-border maturities. In these countries, market participants who already bought long-term capacity do not have to use it. The **"use it or sell it"** principle allows transmission capacity holders to sell on their unused capacity rights (yearly, monthly, weekly) in the day-ahead market.[9]

In addition to these auctions, some borders also feature **intraday auctions** to allocate cross-border capacity **closer to real time**. A cross-border intraday auction usually opens sometime between the day-ahead auction and the actual dispatch of electricity. While most energy is traded on the day-ahead market, it is clearly useful to be able to adjust one's position as more information about likely consumption (e.g. meteorological conditions) becomes available near **dispatching.** In fact, trading volumes on the intraday markets have increased substantially in recent years. With an ever-greater share of generation being provided by **variable renewable-energy sources** such as wind and solar power, intraday trading is bound to become more and more important.

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9.   If intraday cross-border allocation exists, capacity rights can be transferred intra-daily as well.

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Annex C.

Modelling Cross-Border Trade in Electricity

This annex describes the model derived by the authors to assess the importance of various factors in explaining cross-border trade flows of electricity. The model operates in a partial-equilibrium setting, and therefore uses a very simplified representation of electricity markets. A number of specific assumptions are made to reflect the particular characteristics of electricity trading and to minimise complexity. Those assumptions are generally grounded in empirical evidence and were informed by interviews conducted with stakeholders.[1]

We assume that each country's electricity demand is fixed and price-inelastic, which accords well with the fact that consumers in OECD countries are sometimes exposed to regulated electricity tariffs, and with the observation that economic activity tends to be a main driver of the demand for electricity. Even where consumers do not pay regulated tariffs, demand responses to prices are generally limited in the short run.

$$D_i = \overline{D_\iota}$$

Where D_i denotes total electricity demand in country i. On the supply side, we assume heterogeneous producers that differ in terms of their respective costs. This heterogeneity in costs is modelled by inserting a productivity scaling factor φ_k in each producer's cost function as in Chaney (2008).[2]

$$C_k = \frac{1}{\varphi_k} L_k^\alpha + F$$

Here, $k = 1, \cdots, K$ indexes producers, L_k denotes each producer's load (i.e. electricity output), and F stands for fixed costs. This particular cost structure is such that the marginal cost increases with load for $\alpha > 1$ — which is the range of the parameter we consider here — and decreases with φ_k, the producer's productivity factor.

As in Bhattacharyya (2011), we seek to minimise total production costs $\sum_{k=1}^{K} C_k$ under the constraint that $D = \sum_{k=1}^{K} L_k$ at all times. This formulation of the problem finds its justification in the particular structure of electricity markets, where economic dispatch obeys a merit order, which ensures that power is sourced from the lowest cost producers

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1. Staff at power spot exchanges, transmission system operators, and other market participants.

2. For simplicity, the i country subscript is omitted in what follows.

to meet a given volume of demand. System operators thus act to dispatch electricity in the least costly way.[3] This formulation gives us the following first-order condition:

$$\frac{\partial C_k}{\partial L_k} = \frac{\alpha}{\varphi_k} L_k^{\alpha-1} = \lambda$$

This equation implies that the Lagrange multiplier λ equals each producer's marginal cost, so that marginal costs must be the same for all producers. This allows us to express each producer's load as a function of that producer's productivity factor and the Lagrange multiplier, which corresponds to the optimal marginal cost and indicates the shadow price of electricity.

$$L_k = \left(\lambda \frac{\varphi_k}{\alpha}\right)^{1/\alpha-1}$$

Plugging this expression for each producer's load into the constraint yields an expression for the shadow price of electricity as a function of demand and overall productivity (expressed as a CES-like index of productivity).[4]

$$\lambda = \alpha \frac{D^{\alpha-1}}{\Phi}$$

$$\Phi = \left[\sum_{k=1}^{K} \left(\varphi_k^{1/\alpha-1}\right)\right]^{\alpha-1}$$

This expression for λ implies that the higher the productivity indice, the lower the price of electricity. As expected, the reverse holds for demand. Using this expression, we can now rewrite the equation for each producer's load.

$$L_k = D \left(\frac{\varphi_k}{\Phi}\right)^{1/\alpha-1}$$

This means that each producer's load increases with total demand and with that producer's relative productivity. In what follows, we now seek to introduce the possibility of cross-border trade between countries.

Let us assume that there exists sufficient transmission capacity interconnecting country i and country j. Prior to the establishment of that capacity, prices in both countries are given by the following equations:

$$\lambda_i = \alpha \frac{D_i^{\alpha-1}}{\Phi_i}$$

$$\lambda_j = \alpha \frac{D_j^{\alpha-1}}{\Phi_j}$$

As shown, countries are here allowed to differ in their size (*i.e.* demand) and average productivity. Suppose now that for some reason (having to do with demand, productivity, or both) prices in country i stand below prices in country j. Producers in country i thus

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3.   While this reflects the perspective of system operators, the existence of longer-term bilateral contracts can in some cases undermine this logic since they provide for the delivery of electricity from generators that may turn out to be less efficient than others.

4.   The use of such indices for prices and quantities is typical of models with constant elasticity-of-substitution (CES) functions. See Dixit and Stiglitz (1977).

have an interest to sell electricity to country j. However, the existence of technical and policy-induced barriers could act to create a wedge between prices in country j and the price of electricity sent from country i to country j. This is modelled using a standard ‚iceberg' specification, where $\tau_{ij} > 1$ units of electricity must be sent in order for one unit to arrive at the destination.[5] The per-unit price received by producers in country i for sending electricity to country j is therefore λ_j/τ_{ij} where $\tau_{ij} > 1$. The expression for each producer's load in country i thus becomes:

$$L_{i,k} = \left(\frac{\lambda_j}{\tau_{ij}}\frac{\varphi_{i,k}}{\alpha}\right)^{1/\alpha-1}$$

From there, we can derive an expression for the total exports of electricity from country i to country j.

$$X_{ij} = \sum_{k=1}^{K} L_{i.k} - D_i = \left(\frac{1}{\alpha}\frac{\lambda_j}{\tau_{ij}}\right)^{1/\alpha-1}\sum_{k=1}^{K}\left(\varphi_{i,k}^{1/\alpha-1}\right) - D_i$$

Using our definition for the productivity indice, dividing both sides by D_i, and rearranging yields:

$$\left(\frac{X_{ij}}{D_i}+1\right)^{\alpha-1} = \frac{\lambda_j}{\tau_{ij}}\frac{\Phi_i}{\alpha}D_i^{1-\alpha}$$

Last, we use our definition for prices in country i and rearrange further to obtain an expression for total exports of electricity from country i to country j relative to country i's electricity demand as a function of both countries' prices and bilateral trade costs.

$$\frac{X_{ij}}{D_i}+1 = \left(\frac{\lambda_j}{\lambda_i}\right)^{1/\alpha-1}\tau_{ij}^{1/1-\alpha}$$

From there, we can derive an empirical version of the model adding time subscripts, a constant, and an error term ε_{ijt}.

$$\ln\left(\frac{X_{ijt}}{D_{it}}\right) = \beta_0 + \beta_1\ln\left(\frac{\lambda_{jt}}{\lambda_{it}}\right) + \beta_2\ln\left(\tau_{ijt}\right) + \varepsilon_{ijt}$$

As explained in Annex D, we use bilateral net transfer capacity relative to the exporting country's total net electricity use as an indication of some of the trade barriers that hamper cross-border trade in electricity. This variable is denoted $OPEN_{ijt}$ in what follows (as in ―openness"). Sets of dummy variables are also added to account for unobserved heterogeneity across country pairs (γ_{ij}) and time periods (δ_t).

$$\ln\left(\frac{X_{ijt}}{D_{it}}\right) = \beta_0 + \beta_1\ln\left(\frac{\lambda_{jt}}{\lambda_{it}}\right) + \beta_2\ln(OPEN_{ijt}) + \gamma_{ij} + \delta_t + \varepsilon_{ijt}$$

Table C1 shows the results obtained when estimating this equation using ordinary least squares and the dataset described in Annex D. To account for potential heteroskedasticity and for the fact that standard errors appear over-estimated, robust

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5.   The original use of the ―iceberg" specification to model trade costs is generally attributed to Samuelson (1954).

standard errors and clustering by country pair are also each used in turn, along with the more refined two-way clustering method described in Cameron et al. (2006).[6]

Table C1. Level regressions

	(1)	(2)	(3)	(4)
Log of weighted relative prices	1.903*** (14.86)	1.903*** (14.65)	1.903*** (6.00)	1.903*** (4.89)
Log of relative net transfer capacity	0.0611 (0.55)	0.0611 (0.37)	0.0611 (0.20)	0.0611 (0.31)
Constant	-2.639** (-2.01)	-2.639 (-1.32)	-2.639 (-0.62)	-2.639 (-0.97)
Observations	1253	1253	1253	1253
Adjusted R-squared	0.832	0.832	0.832	0.845

Notes: Standard errors are in parentheses and asterisks denote the level of statistical significance (*** at the 1% level, ** at the 5% level, and * at the 10% level). The dependent variable is the log of bilateral exports of electricity from country *i* to country *j* relative to total electricity demand in country *i*. All equations have country-pair and time dummies. Equation (2) also uses "White-robust" standard errors. Equation (3) clusters standard errors by country pair. Equation (4) clusters standard errors by reporting country and by partner country as in Cameron et al. (2006).

Source: OECD based on industry data (see Annex D).

While encouraging when it comes to the role of prices in driving cross-border trade, coefficients for the net-transfer-capacity variable are clearly small and not significant, though they do have the correct sign. Moreover, those results seem subject to serial correlation, which is confirmed by a quick look at the residuals. Because serial correlation results in biased estimates, we therefore choose to express our baseline equation in first differences for estimation purposes. A subsequent look at the residuals shows that this proves successful in removing serial correlation. Estimating the equation in first differences also serves to eliminate unobserved factors that are time-invariant, thereby removing the need for any country or country-pair fixed effects:

$$\Delta \ln\left(\frac{X_{ijt}}{D_{it}}\right) = \beta_0 + \beta_1 \Delta \ln\left(\frac{\lambda_{jt}}{\lambda_{it}}\right) + \beta_2 \Delta \ln\left(OPEN_{ijt}\right) + \delta_t + \varepsilon_{ijt}$$

Where a Δ signifies that the corresponding variable is expressed as the difference between its value at time t and its value at time $t-1$. The use of a logarithmic specification means that variables are expressed as percentage changes between two time periods (*i.e.* months in the present case).

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6.   This particular estimation method is implemented using the cgmreg Stata command available online. It allows standard errors to be clustered both by reporting country and by partner country, which can prove useful when datasets have more than two dimensions as is the case here.

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Annex D.

Data Sources and Description

This annex details the sources used to collect data on electricity prices, volumes exchanged, and cross-border trade flows. A brief overview of the assembled dataset is also provided, including some general descriptive statistics.

Electricity prices

Data on hourly electricity prices were collected directly from power spot exchanges, many of which cover more than one country. Each observation thus reflects the day-ahead market price that prevailed in a given exchange for a given country, at a given hour-day-month-year. In a few cases, prices were only available on a daily basis. However, because our data on cross-border electricity flows are expressed on a monthly basis, prices had to be averaged over months at later stages anyway.[1] The use of volume weights to average hourly or daily prices over months was found to make almost no difference when compared with the use of simple, arithmetic averages. Table D1 lists the various power exchanges from which data were collected along with the countries for which this was done.

Table D1. Power spot exchanges and data coverage

Power spot exchange	Country coverage	Time coverage
EPEX	Austria, France, Germany, Switzerland	2005-2012 (H)
Belpex	Belgium	2006-2012 (H)
APX Power NL	Netherlands	1999-2012 (H)
GME	Greece, Italy, Slovenia	2004-2011 (H)
MIBEL	Portugal, Spain	2006-2010 (H)
OMIE	Spain	1999-2011 (D)
POLPX	Poland	2000-2011 (D)

Notes: (H) and (D) indicate that data are available on an hourly and daily basis respectively.

Although only part of all electricity trade occurs through power spot exchanges, the analysis uses day-ahead market prices since these are commonly taken as reference prices in most other transactions, including over-the-counter (OTC) transactions (i.e. bilateral contracts between market participants). Their economic significance therefore extends beyond power spot exchanges.

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1.   A comprehensive set of hourly data on cross-border trade could not be assembled as only monthly data were available for a sufficient number of countries and years.

Electricity volumes

The analysis uses two different variables as indicators of total electricity demand in a given country. The baseline relies on total market volumes, for which data are available hourly or daily from the same sources used to collect data on prices (Table Annex D1). Market volumes have the advantage of being directly comparable and relevant to the prices data, but only capture a subset of all transactions effectively happening in a given country at a given time.[2] For that reason, we also used IEA data on countries' monthly net electricity supply, which corresponds to the total quantity of electricity supplied from all of a country's power plants, minus its exports and the energy used in pumping, plus its imports. Because the supply and demand for power must balance at all times, net electricity supply should provide a fairly reasonable indicator of a country's total electricity demand. It is found that using market volumes or net electricity supply does not change the estimation results much based on the authors' model of cross-border trade (see Annex C for a discussion of the model and of the estimation method used).

Cross-border trade

Data on bilateral cross-border flows of electricity come from the European Network of Transmission System Operators for Electricity (ENTSO-E) and are expressed on a monthly basis for the years 1994 to 2011. We choose to use this particular source rather than more conventional international-trade databases (e.g. Comtrade) because the data it provides tend to be more reliable when it comes to electricity. They are also available at a higher frequency.

The dataset

Putting all of the above data together gives a dataset where the unit of observation is the country pair in a given month. The countries covered are Austria, Belgium, France, Germany, Greece, Italy, the Netherlands, Poland, Portugal, Slovenia, Spain, and Switzerland. While the time coverage spreads between the years 2004 through 2011, most observations (about 83%) relate to the 2007-11 period. Table D2 provides summary statistics for the main variables of interest.

Table D2. Summary statistics

Variable	Obs	Units	Mean	Std. Dev.	Min	Max
Bilateral exports	1,775	MWh	480,713	567,331	1,000	2,832,000
Unweighted electricity price	1,775	EUR/MWh	51.69	15.84	19.63	99.10
Weighted electricity price	1,775	EUR/MWh	52.76	16.57	20.48	103.89
Total volume traded	1,775	MWh	9,204,389	8,937,004	59,068	31,100,000
Net electricity supply	1,526	MWh	30,900,000	18,900,000	3,136,000	61,900,000

Source: OECD based on industry data (as explained above).

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2. The extent to which this subset is representative of all transactions depends on the country under consideration. Spain has made participation in the Iberian power exchange compulsory in most cases, which results in market volumes representing around 70% of all transactions. Germany presents a different case where only 37% of total domestic consumption is traded through EPEX (EPEX, n.d.).

Trade barriers

Because data do not generally allow a direct observation of the bilateral costs of trading electricity, one needs to use proxy variables that are meant to capture some of the barriers facing electricity traders. One such variable is the relative net transfer capacity, which we define as bilateral net transfer capacity relative to the exporting country's total net electricity supply. It is both country-pair-specific and time-variant. Data for bilateral net transfer capacities and for countries' net electricity supply are from ENTSO-E's website and the IEA respectively.

References

IEA, *Electricity Information*, 2011 Edition, OECD Publishing, Paris.

EPEX (n.d.), *EPEX SPOT: A Power Exchange at the Heart of Europe — Our Role in the Wholesale Power Market*, European Power Exchange.

Annex E

Case Study on Nordpool

In 2010, 74% of total electric power consumption in the Nordic countries was traded on Nord Pool Spot.[1] This high rate was achieved despite wide differences in generation mixes among the countries. This market enables trade in electricity generated by hydropower, thermal power and wind power, which helps to maintain reliable supply despite random precipitation and temperature, and increasing use of unpredictable, variable power sources. A number of trade barriers had to be overcome to achieve an open market.

Nordic electricity at a glance

Norway, Sweden, Finland and Denmark each have distinct generation mixes. Figure E1 shows the skewed distribution of hydropower, thermal power including nuclear, and wind. These differences in generation mixes, as well as the seasonal variability and high share of hydropower, are central to the development of the Nordic electric power trade. More recently, the ability to adjust quickly the quantity of hydropower enables it to complement less predictable wind power.

Figure E1. Electricity generation by source in the Nordic countries
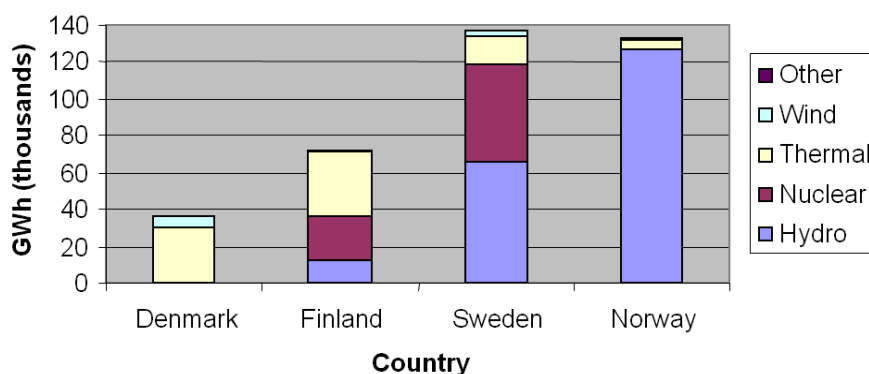
Source: IEA.

One synchronous area covers most of the region. However, western Denmark is synchronous with continental Europe. Several cross-border interconnectors link the Nordic countries. In addition, Finland has a longstanding DC link with Russia, and Denmark an AC link with Germany. More recently, links between Sweden and Germany

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1.   Nord   Pool   Spot: The   Leading   Power   Market   2011,   p. 2,   at www.nordpoolspot.com/Global/Download%20Center/Annual-report/Nord-Pool-Spot-Company-Presentation_2011.pdf

(1994), Sweden and Poland (2000), Finland and Estonia (2006), and Norway and Netherlands (2008) have been built.[2]

Liberalisation and cross-border trade in the Nordic market

Electricity trade in the Nordic region is mainly transacted through organised markets operated by NordPoolSpot. The voluntary day-ahead market, ―Elspot,‖ handles much of the trade, but the intraday balancing market, ―Elbas,‖ is increasingly important as it can reflect information revealed as little as one hour in advance. In 2010, for example, their respective trading volumes were 305.2 TWh (Elspot) versus 2.2 TWh (Elbas).[3] Elspot and Elbas trade in one-hour increments. The transmission-system operators (TSOs) operate the regulating or balance power market that provides intra-hour adjustments. Bilateral transactions outside these markets also take place. There is a market for financial products based on Elspot prices.

The unconstrained Elspot market clearing price is the ―system price‖. It is unconstrained in the sense of ignoring the physical limits of the transmission system.

Figure E2. Operation of day ahead and intraday markets in NordPool
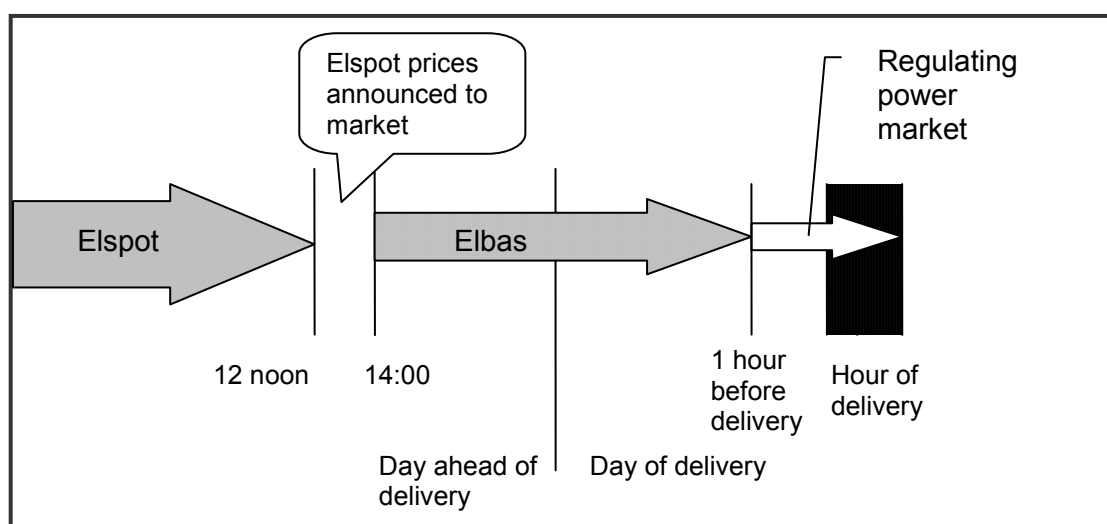
The Nordic region is divided into ―price areas.‖ Within these areas, the spot price is identical at any given hour. Where the flows implied by a single system price would exceed the transmission capacity across the boundary of a price area, then a price different from the system price applies. In 2010, the Nordic region did not split into different price areas 11% of time, compared with 25% in 2009.[4] Transmission capacities are established by the TSOs according to principles in the Nordic Grid Code.

New price areas are created, in principle, when transmission capacities are persistently and significantly exceeded when prices are identical on both sides of a

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2.   Pöyry and Thema (2010) Challenges for Nordic Power Report R-2010-083, Table 3.1, p.11 citing Nordel. www.t-cg.no/userfiles/file/Report_R-2010-003.pdf

3.   NordPool (2010), *Annual Report*, p. 22.

4.   NordPool (2010), Annual Report, pp. 23-24. www.nordicenergyregulators.org/upload/Reports/nmr2011-final%20for%20publication.pdf.

constraint. Norway split into five areas from three in 2010 and Sweden split into four price areas in 2011.[5] Within a price area, transmission constraints are handled by counter-trades. In other words, TSOs order more generation at some places and less generation at others.[6] The cost of counter-trade, as well as the gains from transferring power from low-priced to high-priced areas, are transferred to the TSOs and ultimately to network users via adjustments in transmission network tariffs.

Transmission capacity within the Nordic area is allocated implicitly in Elspot and Elbas markets. Capacity remaining after Elspot clears is allocated in Elbas. ―Coupling‖ of Nordic markets with power markets in continental Europe means that interconnector capacity between the ―coupled‖ regions is now allocated by implicit auction. Within the Nordic area, there are no longer border fees or import duties for electricity. Participants or ―members‖ in NordPoolSpot must post collateral. The minimum is EUR 30.000.[7] At year end 2011, 350 traders were active on NordPoolSpot.

Cross-border trade in electricity in the Nordic region has deep roots, as the next section describes. Further sections describe the development of intraday trading and markets for regulating power, the integration of additional renewable-energy sources, and the integration with continental Europe.

Early cross-border exchanges and the Norwegian power pool

Denmark, Finland, Norway and Sweden have been in various and shifting political unions for much of the past half millennium. The 1963 Helsinki Treaty established permanent Nordic co-operation. This history results in mutually intelligible languages, except Finnish, and similar legal and administrative systems.

Nordel has been a key instrument for the development of Nordic electricity trade. Founded in 1963, it is the formalisation of co-operation among the major vertically integrated power producers in Denmark, Finland, Iceland, Norway and Sweden. Over succeeding decades, Nordel facilitated regional planning of transmission investments including of interconnections, through data exchange, as well as made a series of recommendations[8] which, much later, were incorporated into the Nordic Grid Code. ENTSO-E, the European Network of Transmission System Operators for Electricity, absorbed Nordel in 2009.

International trade in electric power began in 1915 by means of an underwater cable between eastern Denmark and Sweden. Power exchange among domestic generators was

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5. The Swedish split into price areas occurred pursuant to agreement with the European Commission. A group of Danish energy companies had complained that the Swedish TSO, Svenska Kraftnät, had curtailed interconnection capacity in order to reduce its costs of counter-trading and Swedish spot prices, to the detriment of consumers in eastern Denmark. European Commission Decision of 14.4.2010, Case 39351 – Swedish Interconnectors. http://ec.europa.eu/competition/antitrust/cases/dec_docs/39351/39351_1211_8.pdf.

6. Svenska Kraftnät (2007), ―The Swedish Electricity Market and the Role of Svenska Kraftnät,‖ p. 6.

7. NordPool (2010), Annual Report, p. 33. Number from ―No. 72/2011 All members to re-sign new Trading Agreements‖ of 20.12.2011 NordPoolSpot Market News.

8. Nordel 1981 Annual Report, p. 52.

encouraged by governments as early as the interwar years.[9] Cross-border trade between vertically integrated electricity entities developed, too. Overwhelmingly, these were short-term, usually hour by hour, trades but also involved longer term —ifm" contracts. Trade magnitude and direction varied seasonally and by time of day. The pricing convention for cross-border trade in —temporary surplus" power established by Nordel in 1971 aimed to encourage the use of least variable cost generation and split the profits equally between buyer and seller, with a price cap.[10] Thus, economic efficiency, short-term reliability and longer-term security of supply in dry spells were drivers of cross-border trade.

Nordel laid foundations for increased trade during the 1980s. A 1982 study concluded that while the high-voltage grid in the Nordel system was already treated as one unit, greater co-ordination of production would yield additional benefits.[11] By 1989, power exchanges among Nordel members totalled about 8.5% of total production.[12] In 1990, Nordel recommended power producers to consider buying electricity before deciding to expand their own generating capacity.[13]

The high share of hydropower in Norwegian generation combined with natural variations in precipitation implies capacity that varies from one year to the most. Indeed, in 1987, as Norway was on the cusp of electricity market liberalisation, capacity in a —wet year — i.e. the highest precipitation in a 30-year series — was 25% higher than in an average year in the Nordic area and, in a —dry" year, was 25% lower. In that year, the magnitude of the dry-wet range in the Nordic region was about equal to the annual consumption of Denmark and Finland combined.[14] (In 2011, the annual variation in Norway was 20% around a median of 124TWh, or about half the annual consumption in Denmark and Finland.[15]) The unpredictable quantity of hydropower cannot be sold under firm contract, but can be sold after the seasonal hydrological conditions are revealed.

The Norwegian power pool was established in 1971 to enable large generators to trade —temporary surplus" power. Later, surplus power was sold to large industrial users with oil-fired and electric boilers. Eventually these transactions would take place at electricity market prices rather than based on oil prices.[16] In 1984, 5 TWh of —temporary surplus" power was sold to such customers.[17] By 1988, industrial users had terminated

9. Hjalmarsson, Lennart (1996) —From club-regulation to market competition in the Scandinavian electricity supply industry," Ch. 4 in Gilbert and Kahn (eds), *International Comparisons of Electricity Regulation*, Cambridge University Press, p. 131.

10. Nordel, —The Daily Power Exchange among the Nordic Countries", 1980 Annual Report, pp. 61-66.

11. Nordel 1983 Annual Report, pp. 73-75.

12. Nordel 1989 Annual Report, p. 41.

13. Nordel 1990 Annual Report, p. 44.

14. Nordel 1987 Annual Report, p. 55.

15. NVE (2011), —Hydro Power in Norway", presentation by Rune Flatby, 22.11.2011. http://norwegen.ahk.de/fileadmin/ahk_norwegen/Dokumente/Presentasjoner/wasserkraft/Hydro_ Power_in_Norway-Status__Opportunities_and_Challenges_NVE_Flatby.pdf.

16. Nordel 1981 Annual Report, —Reducing dependence on oil in Nordic countries in particular through production of electric power," p. 67.

17. Nordel, 1984 Annual Report, p. 41.

several ―firm‖ power contracts in favour of far cheaper ―temporary‖ power from the pool.[18] Statkraft, the largest Norwegian generator, stuck with power it could not sell at the parliament-set price, could either dispose of it at a low price in the pool market or spill the water rather than generate electricity.[19]

Liberalisation

Norway‗s Energy Act of 1990, which went into effect in 1991, is usually taken as the beginning of the Nordic electricity market. ―The objectives for deregulation and introducing competition in the power supply sector are, among other things, to level out power costs between different regions, to reduce price discrimination between different consumers and to make the most of the variation in the hydro power production.‖[20]

- **The pool market** was transformed into a spot market whereby buyers of any size could in principle participate. High switching fees discouraged participation by small consumers until they were eliminated in 1997. A financial market developed soon after.[21]

- **Vertical separation** in 1992 split the largest electricity company into Statkraft SF and Statnett SF. Statkraft SF retained the generating assets and a temporary export license, while being transformed into a state-owned company with commercial freedom. Thus, it could negotiate contracts without the terms having to be approved by Parliament. Statnett SF became the owner of the central grid and system operator.[22] Statnett Marked, a Statnett subsidiary, operated the spot market. Statnett was licensed to engage in short-term cross-border power exchanges subject to price and quantity constraints.[23] Other electricity companies were subject to accounting separation.

- The basis for **transmission tariffs** changed in 1992 from the geographic distance between producer and consumer to a system in which input and outtake are charged without regard for the (domestic) location of the buyer.[24] This is referred to as a point tariff.

- Network companies were subject to **rate-of-return regulation**, transformed in 1997 into revenue regulation.

- No privatisation occurred: The sector remains publicly owned.

Sweden and Finland also progressed towards electricity markets. Over time, generation was separated from transmission, including foreign interconnections, and system operation. Domestic pools were considered and tried, but concerns related to

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18.   Nordel 1988 Annual Report, p. 52.

19.   Bye, Torstein and Tor Arnt Johnsen (1992), ―Utviklingen i kraftmarkedet,‖ pp. 31-41 in *Økonomiske analyser*, No. 4, Statistik sentralbyrå, p. 33, www.ssb.no/histstat/oa/oa_199204.pdf.

20.   Nordel 1990 Annual Report, p. 62.

21.   Bye, Torstein and Einar Hope (2005), ―Deregulation of electricity markets – The Norwegian experience,‖ Statistics Norway Discussion Paper No. 433, p. 9.

22.   Nordel 1991 Annual Report, pp. 24, 26.

23.   Nordel 1993 Annual Report, p. 23.

24.   Nordel 1991 Annual Report, p. 23.

liquidity, price stability and concentration in the generation market led eventually to both Sweden and Finland joining the Norwegian spot market.[25] When Sweden joined at the beginning of 1996, fees on exchange across the Norwegian-Swedish border were abolished, but Swedish-Finnish border tariffs were removed later.[26] The spot market operator, by then jointly-owned by Statnett and Svenska Kraftnät, was renamed Nord Pool ASA. Western Denmark joined the Nordic market in July 1999, and eastern Denmark in October 2000.[27] Estonia joined in 2010.

Reducing barriers to cross-border trade

Transmission capacity imposes a physical limit on cross-border trade in electricity. Within the Nordic area, and after ―market coupling" also on interconnectors to continental Europe, transmission capacity is allocated implicitly in the electricity markets. The transition to an open market involved negotiations and compensation, harmonisation is not complete, and trade in ancillary services could raise potential barriers.

Transmission tariffs and cross-border interconnector fees can also restrict trade. The point transmission tariff was eventually adopted throughout the NordPool area.[28] However, except for the Norway-Sweden border, the interconnectors were only slowly incorporated into the same point tariff system. For example, as early as 1995 the design of the [Swedish tariff] for interchange between Sweden and eastern Denmark was seen as inhibiting trade, but these tariffs were eliminated only in 2002.[29] The four countries raise revenue for network operations in different proportions on generation and consumption, from a 5-95 split in Denmark to a 25-75 split in Norway; transmission tariffs are multiples higher in Denmark than in the other countries.[30]

Interconnector capacity reserved under the former system of bilateral trades had to be brought into the Nordic market for the market to develop further. An example illustrates. In early 2000, western Denmark prices rose despite the interconnectors having sufficient capacity available to relieve the high prices. A use-it-or-lose it principle for interconnectors was adopted temporarily. Subsequently, to liberate physical access to the Skagerrak Interconnection between western Denmark and Norway, Statkraft, Elsam, E.ON Netz and Statnett negotiated an agreement to replace old exchange and transit agreements with financial agreements effective starting in 2001.[31]

Different responses to transmission congestion can have different effects on cross-border trade. Given the market design decision to use price areas, congestion must be addressed by a combination of market (price area boundaries) and non-market (TSO-

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25. Nordel 1991 Annual Report, p. 28; Nordel 1993 Annual Report, p. 33; Nordel 1994 Annual Report, p. 34; Nordel 1996 Annual Report, pp. 35-36; Swedish Competition Authority (1996), ―Deregulation of the Swedish Electricity Market," pp. 13-15.

26. Nordel 1995 Annual Report, p. 6; Nordel 1996 Annual Report, p. 35.

27. Nordel 2000 Annual Report, p. 15.

28. Nordel 2000 Annual Report, p. 9 has harmonization recommendation.

29. Nordel 1995 Annual Report, p. 9, Nordel 2001 Annual Report, p. 35.

30. ENTSO-E 2010 Overview of transmission tariffs in Europe: Synthesis 2010 (updated), pp. 6, 7.

31. Nordel 2000 Annual Report, pp. 16-17. The consortium imposed fees up to NOK 0.03 /kWh on non-members' use of the capacity, a substantial fraction of total electricity price. ―Fri kraftflyt over Skagerrak," Aftenbladet 14.07.2000.

ordered counter-trade) instruments. The effect of the choice of instruments on cross-border trade has been a focus of controversy,[32] although the choice also affects the distribution of economic benefits between consumers and suppliers. In a competition case, the use of countertrade by Svenska Kraftnät domestically was found to have decreased available interconnector capacity and thereby contributed to higher prices paid by consumers in eastern Denmark.[33]

Transit fees—fees to move power across the facilities of utilities not financially involved in a transaction—can affect cross-border trade in electricity. The former system, whereby fees were charged at each border crossing, did not reflect costs and restricted trade. The Nordic TSOs agreed to a new, more cost-reflective system: he transited TSO is paid the value of the difference in electrical losses with and without transit, using the area's market price at the hour of transit.[34]

Transmission is an input into many ancillary services that are needed to maintain balanced and reliable electricity supply. These services respond over various time scales; some are used often and others only rarely.[35] When ancillary services are traded cross-border, the question arises as to whether TSOs should reserve interconnection capacity from the spot and intraday market so as to be allocate these services. Distinctions can be drawn between services that deliver a small amount of energy, such as the quickest responding services, which need no capacity reservations on either AC or DC interconnectors, and other services. AC and DC connections can be distinguished in that AC links are operated with generous safety margins, making it easier to deliver ancillary services over them.[36] Denmark's TSO, responsible for reliability in areas to which it is importing ancillary services, is considering these questions.

Intraday trading and balancing in the Nordic area

The intraday market, Elbas, was started in 1999 for Swedish and Finnish participants as a complement to the Elspot day-ahead market.[37] Denmark joined later, an area in Germany followed in 2005 and Norway in March 2009. The market was extended, via the NorNed cable, to the Netherlands in March 2012.[38]

As the share of wind power increases, Elbas is expected to play a more important role as it can incorporate wind forecasts made shortly before the hour of delivery. A variety of services are needed to maintain balanced and reliable electricity supply. A large share of

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32. Nordic Council of Ministers, Report to (2008),"Congestion Management in the Nordic Market: Evaluation of different market models," p. 11. www.ea-energianalyse.dk/reports/730_congestion_management_in_the_nordic_market-evaluation_of_different_market_models.pdf.

33. Commission Decision of 14.04.2010 Case 39351 – Swedish Interconnectors, paras 38-42.

34. Nordel 2001 Annual Report, pp. 37-42.

35. Some services respond in 5 to 30 seconds, others in 150 seconds. Another set of services are provided within 10-15 minutes, taking over from the quick response services. A different set of services are reserves to be used during a very cold or dry spell.

36. Energinet.dk (2011), pp. 9-10, 14, 15.

37. www.regjeringen.no/upload/kilde/oed/bro/2000/0002/ddd/pdfv/110237-kap._7.pdf.

38. APX-ENDEX (2012), ―Cross-border Intraday market extended to Nordic region over NorNed cable, Member update 21.02.2012."

wind power is one source of the variations to which ancillary services respond. Intraday trading, by enabling the market to reflect more recently revealed information and more detailed operational planning,[39] can reduce the demand for some of these services.

A common Nordic market for certain ancillary services — "regulating power" or "balancing" activated within 15 minutes and enduring at least an hour — was established in 2002. Generators and large consumers submit bids which are assembled into a common merit order list. If there is no congestion, the cheapest regulating object is used regardless of location. In practice, the Norwegian and Swedish TSOs decide which offers to accept. Gate closure time is harmonised, but not the rules for what offers can be submitted. Western Denmark, in a different synchronous area, is not wholly integrated into this market. The different TSOs procure reserves — commitments to bid into the regulating market — in different ways. Balance settlement with respect to cost basis and pricing of imbalances has been harmonised since September 2009. However, settlement procedures remain unharmonised.[40]

Harmonisation of settlement procedures for balancing is a work in progress. A table illustrates the national differences as of November 2011, with an implementation deadline of early 2014.

	Exemption for small generators	Frequency of settling accounts	Reporting deadline	Billing	Corrections afterwards	Level of Report	Billing entity
Denmark	No	Daily + 5 days	+3 days	Monthly	Yes	BRP*	TSO
Finland	Yes, < 1MW	Fortnightly	(Unknown)	Fortnightly	No	RE**	Network owner
Norway	Yes, < 3MW	Weekly	+3 days	Weekly	No	BRP and BE	Network owner
Sweden	No	Daily + 1 day	Daily	Fortnightly	Yes	BRP	TSO

*BRP = Balance responsible party.

**RE = Retailer.

Source: Heiberg, Tor B. (2011), "Felles Nordisk Balanseavregning: NSB prosjektet," presented at Ediel- og Avregningskonferansen, Fredrikstad, 3 November, p. 6.

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39   Energinet.dk (2011), "Energinet.dk's ancillary services strategy," Doc. No. 77566-11, p. 20.

40   Nordic Energy Regulators (2010) "Harmonizing the balancing market," Report No. 5, pp. 11-16, 17, 19, 21.

Danish cross-border procurement of ancillary services

Denmark provides a relevant example with respect to cross-border trade in ancillary services as it must increasingly import them. The increase in wind power and consequent closure of coal-fired units that formerly provided ancillary services provides incentives to develop cross-border trade in those services that can be provided at a distance. At present, Energinet.dk, the Danish TSO, buys the quickest responding services via auction from Sweden, Norway and Germany. When the Skagerrak 4 cable between western Denmark and Norway begins operating in 2014, the Norwegian TSO will supply the services using hydropower.[41] Energinet.dk has identified a number of differences in specifications that impede the development of an eastern Denmark-Swedish joint market,[42] as well as a western Denmark-German joint market.[43]

With respect to those services activated in 30 seconds to 15 minutes, Energinet.dk has contracted to buy all of its requirements for the five years from 2014 from the Norwegian TSO, to be provided over Skagerrak 4 or parallel cables. However, further integration southwards is hampered by differences in specifications (5 minutes activation time in Germany versus 15 minutes in Denmark), and the need to reserve interconnector capacity to supply these services. Meanwhile, the area conforming to the German activation standard is increasing as areas are successively incorporated into the German Grid Control Cooperation.[44]

Other ancillary services are generally provided by large generators connected to the high-voltage grid. As wind generators displace such units, other technology to provide these services needs to be found. Also, wind generators are required to be able to remain connected during a fault or system disturbance. Physics implies geographically small markets for certain ancillary services, rendering cross-border trade infeasible in those services.[45]

Integration of NordPool and European electricity markets

NordPool is increasingly integrated with continental markets. The European Market Coupling Company, a joint venture of several market operators and system operators, provides market coupling services between NordPool and Germany and the Netherlands. Market coupling means that the supply and demand bids submitted to the two markets, as well as the available capacity between them and other physical constraints, are used to identify the most economically efficient flow between the two markets. Variants such as

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41.   Energinet.dk (2011), pp. 14, 16-17.

42.   These differences include different pricing practices (the Swedish TSO pays the same price for up- and downward regulation whereas the Danish TSO pays different prices) and the Nordic System Operation Agreement requiring that at least two-thirds of these services be within the TSO's area. However, one obstacle fell when the Swedish TSO redefined certain services to conform with Danish and indeed Nordic definitions. Energinet.dk (2011), pp. 14, 16-17.

43.   These changes include daily auctions, with different prices for up- and down-regulation. Energinet.dk (2011), pp. 15-16.

44.   Energinet.dk (2011), pp. 18-21.

45.   Examples are short-circuit power, continuous voltage control (reactive power), voltage support during faults, and inertia. Energinet.dk (2011), pp. 29-32.

volume coupling and price coupling involve larger sets of input data and more similar algorithms. Interconnection capacity is auctioned implicitly.

Market coupling has advanced step-wise. Market coupling of Germany and western Denmark day-ahead markets succeeded in November 2009 after the first attempt, September 2008, failed due to algorithm problems.[46] The Sweden-Germany cable was added in May 2010. The Norway-Netherlands cable was intended to support market coupling between Nord Pool Spot and APX. However, inconsistent gate closure times, i.e. deadlines for submitting bids, meant that the cable's capacity was auctioned explicitly after it entered operation.[47] The grid code changes to effect CWE (Central West European, i.e. Benelux, Germany and France) market coupling in November 2010 also enabled the inclusion of NorNed. The CWE market coupling occurred simultaneous with volume coupling at the German-Danish border. The NorNed capacity was incorporated into the volume coupling in January 2011.[48] Further market coupling within Europe is planned.

Renewables and cross-border trade

Much of the electricity generated in the Nordic area comes from renewable sources: large hydropower plants, small hydropower, wind, wood, waste, and straw. Power plants fuelled by coal, gas and peat are also connected. It is, however, not possible to distinguish power by the technology that produced it. But, it is possible to measure trade in certificates of electricity produced from renewable sources. This is discussed below, followed by a discussion of the integration of wind power into the Nordic market.

Green electricity certificates market

Sweden and Norway are integrating their procurement of new renewable energy sources to meet international obligations through a joint market for "electricity certificates." Sweden initiated a market in "el-certificates" in 2003 and, after rejecting a similar scheme in 2006,[49] Norway joined at the beginning of 2012. Under the scheme, certain generators are granted el-certificates equal to their production and most consumers are obliged to buy el-certificates in specified proportion to their total electricity purchases. The joint market means that electricity generated by qualifying sources is traded cross-border and thus, in principle, the cheapest (ignoring other subsidies) qualifying solutions in the joint area are chosen.

Complete harmonisation has not been sought. Rather, "Certain differences must be accepted and managed." Some harmonised rules were regarded as necessary for the

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46. Nordel 2008 Annual Report, p. 7.

47. Nordel 2007 Annual Report, p. 7.

48. Netherlands Energiekamer "2011 National Report to the European Commission," ERGEG, pp. 9, 10, 15, www.energy-regulators.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/NATIONAL_REPORTS/National%20Reporting%202011/NR_En/C11_NR_Netherlands-EN.pdf.

49. At the time, the Norwegian Government determined that participation in a common green certificate market on the terms negotiated with Sweden would be too expensive for Norwegian consumers and businesses and chose instead to increase direct subsidies to renewable energy and energy saving schemes. Oil and Energy Department (2006), "Felles sertifikatordning lar seg ikke gjennomføre – for dyrt for norske forbrukere" press release No. 26/06, 27.02.2006.

market to exist, others as beneficial, and yet others as ones where non-harmonisation would affect market efficiency but not existence. Necessary harmonisation includes which side of the market is obliged to buy el-certificates, the characteristics of el-certificates in terms of validity, value and expiration, and joint inspection and a linked registry. Beneficial harmonisation includes the kinds of and duration over which generation would qualify, the legal status of the el-certificates, state support that is not competitively neutral, and provision of information to the market. The following have not been entirely harmonised: different sets of users are exempt, Sweden but not Norway includes peat-fired generators; Norway reserves hydropower to public ownership; Sweden but not Norway charges wind generators the cost of grid reinforcement their connection necessitates; and Sweden continues aid to renewable energy projects despite potential market effects.[50]

Integration of wind

A large share of wind generation in a large synchronous region introduces issues related to secondary control and balancing. The development of cross-border trade in ancillary services is discussed above. Modifications in NordPool rules and transmission grid reinforcement have also been required in order to accommodate increased wind power.

Within the Nordic area, there have been three responses to increased wind power. First, the Nordic Grid Code (Connection Code) specifies certain control functions that wind farms must have to enable them to contribute to system stability. (This does not imply that wind generators are balancing responsible parties. In Denmark, the TSO is the BRP for all wind generators.[51] Second, NordPool introduced negative prices in 2009 in the day-ahead market, and 2011 in the intraday market, as a consequence of wind generation. Until the change, when there was high feed in of power from wind generators then some sales bids were curtailed at a zero price and the affected sellers incurred an imbalance cost. They are willing to pay to deliver power in order to avoid paying imbalance costs.[52] In addition, the completion of Skagerrak 4, the fourth cable between Norway and Denmark, in 2014 will increase transmission capacity between wind power and hydropower. As mentioned above, it will deliver certain ancillary services as well as enable increased export of wind-generated power.

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50. Energimyndighet (Swedish Energy Agency) (2010), ―Gemensamt elcertifikatsystem med Norge (Common Electricity Certificate System with Norway)," ER 2010:28, pp. 37, 44; (Swedish exemptions) ―Elintensiv industri" in Företrag - Elcertifikat – Kvotpliktig on the energimyndigheten.se website, also Swedish Energy Agency (2011)," The Electricity Certificate System 2011," p. 16, and ―Riksdagen har antagit ny lag om elcertifikat," press release 30.11.2011 http://energimyndigheten.se; (Norwegian exemptions) Bartnes, Gudmund (2011), ―Elsertifikatmarkedet på 1-2-3," presented at Edielkonferansen, 4 November; (Swedish aid) Energimyndighet (Swedish Energy Agency) (2010), ―Gemensamt elcertifikatsystem med Norge (Common Electricity Certificate System with Norway)," ER 2010:28, p. 13; (Swedish peat plants) *ibid*., p. 12.

51. Energinet.dk (2011) ―Regulation C1 – Terms of balance responsibility", p. 11.

52. Nordic Energy Regulators (2011), Report 3, p. 33.

The European Wind Integration Study recommended, from the perspective of TSOs,[53] a number of grid reinforcements to aid the incorporation of wind. Several of these are adjacent to or within the Nordic area.[54] EWIS also commented on intraday and balancing markets. In addition to standardised intraday, balancing and ancillary services market arrangements, it also recommended that network limits be more accurately represented in intraday markets.[55]

Conclusion

The Nordic area has traded electric power for nearly a century. Economic efficiency within the framework of geographic, economic and social conditions has been a main driver. Changes in the relative price of oil and a surplus of occasional hydropower spurred the initial liberalisation. Changes in the valuations of SOx, NOx, CO_2 emissions and wild rivers are now spurring further changes. International trade is increasingly used to identify the least-cost generation to meet renewable sources mandates as well as to provide the ancillary services complementary to wind power. The Nordic area has enjoyed increased efficient trade in electricity through the reduction of barriers and the development of a balance between harmonisation and heterogeneity of domestic rules and structure.

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53. The study notes that it ―took primarily the perspective of TSOs but sought … the input of transmission customers and stakeholders." European Wind Integration Study (2010), Executive Summary and Recommendations, p. 4.

54. The specific links are: (40) subsea multi-terminal cable among Denmark, Sweden, Germany and offshore wind farms; (41) subsea DC link between Norway and Germany; (42) and (43) upgrade of western Denmark-Germany link; (106) new high voltage AC and two new DC links between Sweden and Norway; (107-110) new lines within northern Norway; (113) more capacity between Norway and the Netherlands; (114) Skagerrak 4 between Norway and Denmark; (115) Denmark to the Netherlands; (116-122) new lines within Denmark. European Wind Integration Study (2010) Grid reinforcement projects identified or confirmed within EWIS. http://www.wind-integration.eu/downloads/library/EWIS-Grid-Reinforcement-Projects.pdf

55. European Wind Integration Study (2010), ―Executive summary and recommendations", p. 14.

Glossary

Ancillary services	Necessary services that must be provided in the generation and delivery of electricity. These include coordination and scheduling services (following load, addressing energy imbalances, controlling transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).
Balancing market	An institutional arrangement that establishes either market or non-market based mechanisms to procure necessary electricity after day-ahead and intraday markets are closed. Usually, market participants, who are eligible to participate in the balancing market, submit their bids to the grid operator to provide additional electricity needed to balance the grid.
Balancing responsible party (BRP)	An entity which is committed to guaranteeing the financial settlement to the system operator for all the imbalance charges subsequently recorded between injections and extractions of electricity to and from the grid.
Balancing services	Management processes and services associated with power system operation, which ensure quality and short-term security of supply. Balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply in and near real time.
Baseload units or plants	Typically large nuclear and coal-fired plants that supply the same amount of energy around the clock, though some coal units are run at minimum generation levels at night and near their maximum output during the day. These units have slow ramp rates and relatively high minimum-generation levels. They also can take a long time (days in some cases) to start back up once they have been taken off line. Large baseload units also tend to have lower operating costs relative to other fossil-fuelled facilities.
Combined-cycle gas turbine (CCGT)	A power station that generates electricity by means of one or more gas turbines whose exhaust is used to make steam to generate additional electricity via a steam turbine, thereby increasing the thermal efficiency of that of plant above that of an open-cycle gas turbines.
Capacity mechanism	A policy instrument designed to remunerate power plants based on the availability of their capacity. Capacity payment mechanisms or remunerations are generally based on the concept of a two-part price, with one set of revenues paying for energy on a MWh basis and another rewarding capacity needed on an installed-capacity basis.
Day-ahead market	A market for buying and selling electricity for delivery on the day after trading takes place.
Explicit auction	A cross-border capacity allocation method in which the transmission capacity on an interconnector is auctioned off to the market participants separately and independently from the marketplaces in which electrical energy is being auctioned.
Feed-in tariff (FiT)	A price-driven incentive for the production of electricity from renewable- energy sources. Most FiTs offer a guaranteed price over a specified number of months or years for each unit of electricity produced from renewable energy sources in general or from a particular energy technology. One variant of a FiT, a feed-in premium, offers an additional payment to electrical energy supplied above the market price.

Forward market	A market for buying and selling electricity for delivery at a future date.
Gigawatt (GW)	A power measure (usually of electricity) equivalent to 1 000 000 kilowatts.
Gigawatt-hour (GWh)	An energy measure (usually of electricity) equivalent to 1 000 000 kWh. One gigawatt-hour of electricity from wind could meet the annual energy needs of over 600 000 households.
Implicit auction	A cross-border capacity allocation method whereby the auctioning of transmission capacity is included (implicitly) in the auctions of electrical energy in a given power market.
Interconnection	The physical linking of a network with electricity generation, usually between countries which allow electricity to be imported and exported, usually, in response to price signals.
Intraday market	A market for buying and selling electricity for delivery on the same day.
Intermediate and peaking units	Generally natural gas or oil-fired facilities with relatively fast ramp rates and relatively low minimum generation levels. Intermediate and peaking units can be shut down and started up relatively quickly. However, they also have operating costs that are higher than for baseload units.
Load-following units	Dispatchable electricity-generating units that have been previously committed, or can be started quickly (within the bounds of the unit's operating constraints). Load following typically covers periods ranging from 5–15 minutes to a few hours.
Market coupling	An approach used to allocate capacity on interconnectors. It links interconnected wholesale energy markets with an implicit auction that determines efficient cross-border flows according to price differentials between markets. Under market coupling, power flows from low to high-price areas.
Ramp rate	The speed at which a generating unit can increase (ramp up) or decrease (ramp down) its output. This speed can range from seconds in the case of solar PV units to several hours for large thermal power plants.
Regulation	Control in response to the variability in electricity demand that occurs between the economic dispatching of generating units. The period of such regulation typically ranges from several seconds to five minutes. It is generally carried out using automatic generation control (AGC), which automatically adjust power-plant output to minute-by-minute load deviations in response to signals from grid operators. Changes in load that occur during "regulation time" are typically not predicted or scheduled in advance and must be met by the grid operator through generation that is on-line, grid-synchronised, and under automated control.
Spinning reserve	The extra generating capacity that is available by increasing the power output of generators that are already generating electricity into the network
Spot price of electricity	The wholesale price for electricity that is traded for delivery on the same day.
Transmission System Operator (TSO)	A centralised operator that is responsible for managing the actions of generators, within its designated area. TSOs estimate demand in day-ahead, schedule forecasted demand, reserves, other ancillary services, cross-border or regional flows through interconnectors, dispatch electricity, and manage the system in real time. The ownership of TSOs can be public or private (usually called Independent System Operators) depending on the electricity market design
Unit commitment	The starting and synchronising of thermal power generation so that it is available when needed to meet expected electricity demand. A unit is typically committed for a period ranging from several hours to several days.
Watt	An electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under a pressure of 1 volt at unity power factor.
Watthour (Wh)	An electrical energy unit of measure equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.