

Market Design for Long-Distance Trade in Renewable Electricity

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Abstract

While the 2009 EU Renewables Directive allows countries to purchase some of their obligation from another member state, no country has yet done so, preferring to invest locally even where load factors are very low. If countries specialised in renewables most suited to their own endowments and expanded international trade, we estimate that system costs in 2030 could be reduced by 5%, or €15 billion a year, after allowing for the costs of extra transmission capacity, peaking generation and balancing operations needed to maintain electrical feasibility.

Significant barriers must be overcome to unlock these savings. Countries that produce more renewable power should be compensated for the extra cost through tradable certificates, while those that buy from abroad will want to know that the power can be imported when needed. Financial Transmission Rights could offer companies investing abroad confidence that the power can be delivered to their consumers. They would hedge short-term fluctuations in prices and operate much more flexibly than the existing system of physical point-to-point rights on interconnectors. Using FTRs to generate revenue for transmission expansion could produce perverse incentives, so revenues should instead be deducted from payments under the existing ENTSO-E transit flows compensation scheme. FTRs could also facilitate cross-border participation in capacity markets, which are likely to be needed to reduce risks for the large numbers of extra peaking plants required.

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Executive Summary

While the 2009 EU Renewables Directive allows countries to purchase some of their obligation from another member state, no country has yet done so. Instead, the UK is investing in solar power and Italy in wind generation, despite pitifully low load factors. This paper considers the cost of this inefficient allocation, and mechanisms to allow a better policy that puts renewable generators where the best resources are.

We use a detailed engineering-economic model of the European power system, WeSIM, which finds the optimal amount of transmission capacity and peaking plant to make scenarios for renewable and conventional generation operationally feasible at least cost. In other words, it takes as given the differing attitudes of, say, France and Germany to nuclear power, but optimises the operation of those plants and the capacity of the transmission system to minimise the cost of delivering a secure supply of energy to consumers. We have high-quality renewable output simulations from specialised wind and solar models, which we use to consider the consequences of changing the distribution of renewable capacity across Europe. The model has 76 regions with 104 (actual or potential) transmission lines between them, and is simulated on an hourly timescale for a year of operation.

Our National scenario assumes 475 GW of wind power with an average load factor of 25% and 189 GW of solar PV with an average load factor of 13%. A Coordinated scenario obtains the same annual energy outputs from 402 GW of wind and 173 GW of solar PV, saving 15% and 8% of their capacity respectively. This cuts the cost of renewable generation by €9 billion a year in 2012 prices. This is not reflected in the wholesale prices calculated by the model, as different amounts of peaking capacity are added to ensure demand can normally be met. This caps the highest prices within each region at similar levels in each scenario, anchoring the average market price. The savings would instead be seen in the form of reduced subsidies that are paid by consumers on top of wholesale market prices.

To make either scenario feasible, additional transmission capacity is needed both within and between countries, but the Coordinated deployment of renewables requires an annuitised cost of €3 billion more than the National scenario. Concentrating renewable generators into a few regions means fluctuations in

the weather lead to much greater changes in output than when they are spread more evenly across Europe, and transmission flows rise to offset these. This greater capacity is more heavily utilised, but the proportion of hours in which lines are congested actually falls slightly. When the lines *are* congested, however, the price differences are greater in the Coordinated scenario.

These price differences (and congested lines) would expose companies importing renewable power to significant risks. A system of Financial Transmission Rights can hedge these risks by paying the difference in wholesale prices between an importing region and an exporting one. Depending on the market design in force, this either allows the company to pay transmission charges for moving power between regions based on nodal price differences, or to sell power at the generator's location and buy it back in the consumers' region, with any difference offset by an FTR payment. Large numbers of FTRs in different directions can be issued as long as the overall net flows are feasible, allowing for a greater volume of trade than with physical contracts for specific interconnectors, which are limited in volume to the capacity of the line in each direction.

We find that a large amount of peaking capacity will be required to offset fluctuations in renewable output, but that it will typically have a load factor of only 1%. Its energy market revenues will vary from year to year, implying significant risks and a relatively high cost of capital. Capacity markets could provide an alternative income stream to reduce those risks and hence the cost of capital. Cross-border participation in these markets is likely to be beneficial as long as system operators can be confident that the power could actually be delivered, which might be signalled by requiring the generator to hold an FTR for all the capacity it is selling.

Overall, the costs of extra transmission capacity (€3 billion a year), peaking generation capacity (€0.3 billion a year) and fuel and operating costs (€0.9 billion a year) offset less than a quarter of the savings in renewable generation costs, giving a net saving of €15 billion a year. That is about 5% of the projected cost of generation and transmission in Europe in 2030, and finding market mechanisms to unlock those savings is an important project.

1 Introduction

Europe has adopted ambitious targets for renewable energy: 20% of all its energy consumption in 2020, and 27% in 2030. Meeting these will imply a significant expansion in the amount of wind and solar generation across Europe. The output obtained from a given investment in capacity depends strongly on where that capacity is located, since wind speeds and solar insolation vary significantly across Europe. Given that both technologies are still relatively expensive, the advantages of deploying them mainly in areas with good potentials, in order to minimise the capital cost per unit of renewable output, ought to be clear.

If renewable output in many regions of Europe is thus dominated by either wind *or* solar capacity, however, this means that it is likely to vary more over time than with a more diverse mix. This will exacerbate the well-known problem of intermittency, and steps must be taken to deal with this. One option is to build spare capacity to act as a back-up for times when the renewable generators are not running; an alternative is to use transmission links to other countries to get the benefits of diversity.

Europe is building a Single Electricity Market, which should facilitate international trade in renewable energy. The aims of this paper are to estimate the benefits of using international trade in renewable energy to allow more renewables to be deployed in areas with higher resources, and to assess the challenges involved. We use an engineering model of the European power system (WeSIM) to calculate the amounts of transmission capacity and peaking power stations needed to allow a secure, optimal, dispatch in two scenarios. One is based on a national deployment of wind and solar power, as in (Booz, 2013); the other has the same amounts of wind and solar output (in TWh over the year) but obtains them from less capacity, concentrated in areas with greater resource.

We find that it is possible to save 73 GW of wind capacity (16%) and 16 GW of solar capacity (8%) by deploying them in more suitable areas. This would bring a saving of €18.9 billion a year in 2030 (in 2012 prices), offset by an extra €4.2 billion of cost to deal with a greater level of intermittency. This is made

up of €0.9 billion in extra fuel and operating costs, €0.3 billion in extra peaking capacity and €3 billion in additional transmission.

Despite the extra investment, the transmission lines between regions are frequently congested, even within countries, suggesting that market-splitting will be required inside countries alongside market coupling between them. Peaking generators will have very low average load factors, and if they depended on market prices to cover all their costs, their profits would be volatile, reacting to each year's weather. A cross-border capacity market might be a suitable way to reduce their risks and to share the burden of paying for these stations; it might be hard to reconcile this kind of sharing with the natural desire to have "reliable" local generators available when system conditions are tight. We also find that while the overall savings from coordinating renewables are worth about 5% of the cost of generation and transmission, some countries are likely to lose, unless a carefully-designed renewable certificate trading scheme provides transfers to those building additional high-cost capacity.

If countries are to obtain a significant proportion of their renewable electricity from schemes outside their borders, they are likely to want confidence that this power can actually be consumed by the people paying for it. We show that a system of Financial Transmission Rights could offer this reassurance, and would be more flexible in practice than relying on the link-by-link physical rights that have demonstrated electricity trading in Europe to date.

The next section discusses the background to our work. Section 3 describes the model and its data, and section 4 presents the results. We discuss some of the implications for market design in section 5, and offer summary conclusions in section 6.

2 Background

The principle of trade based on comparative advantage goes back to Ricardo, and applying it to either the electricity industry or to environmental problems is hardly a new idea. Countries have traded power

across borders for decades, and Nord Pool has had a formal international wholesale market since 1996. Even before Nord Pool was established, the hydro-based systems in Norway and Sweden would tend to import power from Denmark (and Germany) in dry years and export it when they had plenty of water. While the availability of hydroelectricity varies from year to year, wind outputs vary from hour to hour. Denmark was the first European country to source a high proportion of its electricity from wind, and duly exported more electricity (or imported less) in hours with above-average wind output, compared to the monthly norm for that time of day. This allowed it to deal with the intermittency of wind output at a relatively modest cost (Green and Vasilakos, 2012).

The traditional approach to environmental regulation involved setting standards for every source of pollution and perhaps allowing them to vary if different sources faced different costs of clean-up; the newer approach of environmental markets can allow polluters to meet an overall cap on pollution in an efficient manner by trading. The US Acid Rain Program was an inspiration for the EU Emissions Trading Scheme, which has succeeded in keeping Europe's carbon emissions down to the level agreed by its governments; unfortunately, it has not been able to maintain a price at a sufficient level to encourage investment in low-carbon generation.¹ Achieving the EU's targets for renewable energy therefore requires direct intervention, mainly in the form of national feed-in tariffs or tradable green certificate schemes.

When the European Commission set national targets for renewable energy in 2009, it was aware that Member States differed in their renewable resources and in the extent to which these had already been exploited. The starting point for these targets was therefore to *increase* the share of renewable energy in

¹ In the first phase of the market (2005-7) this was due to the over-allocation of permits; from the autumn of 2008 onwards, it was due to economic recession reducing the level of business as usual emissions and therefore making it very easy to achieve targets that might have been demanding, had Europe continued to grow as predicted when those targets were set. It should also be said that if the targets for renewable generation are raised after emissions limits are set, and those limits are not adjusted to reflect this, the level of emissions allowed per MWh of conventional generation will be higher, allowing coal-fired stations to crowd out gas (Böhringer and Rosendahl, 2010). Europe set its emissions and renewables targets at the same time and should have been able to avoid this trap.

each country by the same amount, although those numbers were immediately adjusted to require richer countries to do more and the poorer ones to do less. The Directive also allowed a country with a demanding target, relative to its renewable resources, to develop joint projects with another country (inside or outside the EU) and share the renewable energy produced or simply to use a Statistical Transfer from another country that had over-achieved its target. These mechanisms are similar to the Clean Development Mechanism, established to allow companies and governments from industrialised countries to offset some of their carbon emissions by supporting projects in developing countries. As of March 2015, nearly 8,000 projects with potential emissions reductions of 8 GT of carbon dioxide by 2020 had been registered (UNFCCC, 2015).

In contrast, almost all the proposals for cooperation under the EU Renewables Directive are still hypothetical (Klessmann et al. 2014). One reason for this is that most EU countries seem to prefer schemes within their borders which have a greater prospect of creating “green jobs” than those further afield;² getting voters to pay for an expensive power station in another EU country does not appeal to most politicians. Even if the principle can be agreed, Söderholm (2008) shows that a number of practical problems had to be solved to create the rare cross-border tradable green certificate market between Sweden and Norway (which is, of course, outside the EU but covered by many EU Internal Market rules).

The lack of practical progress has not deterred academics from studying the gains that might be achieved from greater coordination across Europe. Aune et al (2012) estimate that using an EU-wide certificate trading scheme would save 70% of the cost of implementing a 20% renewable energy target, measured in terms of economic welfare. They point out that while certificate trading could equalise the marginal cost of renewable production, the marginal value of electricity consumption will vary (inefficiently) between countries if they have different national targets for the share of renewable energy. This is because a higher national target implies that the cost of a larger number of certificates have to be added to the price of each unit of electricity, and different targets will produce different prices, even if the marginal cost of

² In fact, the number of jobs created by renewable generation, net of those that would have been required in a conventional alternative, is likely to be limited (Blyth et al, 2014).

power is the same. Unteutsch and Lindenberger (2014) calculate slightly lower savings (41-45%) from coordination while reaching a 55% renewables target by 2030, using the more common metric of system costs (and ignoring the knock-on welfare effects from higher prices). This is worth between €57bn and €73bn over a ten-year period; Booz et al (2013) find savings of €15-30 billion *per year* by 2030.

The European Commission (2015) points out the importance of increasing interconnection. Its target is that every member state should have cross-border transmission equal to at least 10% of its installed generation capacity. Zachmann (2013) points out that the gains from increasing interconnection are particularly significant when countries with high shares of renewables can coordinate the back-up capacity needed, but also discusses the barriers to this coordination. Saguan and Meeus (2014) use a stylised model to predict that some national planners may have an incentive to build less transmission than would be optimal for Europe as a whole. Our simulations assume that neither national self-interest nor local opposition to new lines prevents transmission from expanding optimally.

3 Modelling and Data

We combine three different models to simulate the impact of better coordinating the deployment of renewable generators across Europe. The main power system simulations are performed on WeSIM, a detailed model of the European power system that takes a scenario for the deployment of power stations across Europe and then builds transmission and peaking plant in an optimal way to ensure that the system can be dispatched to meet demand. The renewable output data are taken from two specialised models, for wind and solar outputs respectively. We model two scenarios, one based on the European Commission's Energy Roadmap 2050 in which most countries choose to deploy both wind and solar plants to meet renewable generation targets, whatever their resource, and a second which rebalances wind and solar capacity towards regions with better resources. Wind generators are therefore concentrated in countries around the Atlantic and the North Sea, and solar generators towards the south of Europe.

3.1 Whole-electricity System Investment Model (WeSIM)

WeSIM (formerly *DSIM*) is a detailed electricity systems model that co-optimises long-term investment and short-term operation decisions across generation, transmission and distribution systems. The model considers several time horizons: long-term investment, also optimising capacity margins to meet security of supply requirements; hourly dispatch of generation, storage and demand-side response; and real-time balancing of supply and demand on a second-by-second basis, including allocation of frequency response and reserve, and the impact of inertia effects. It also covers different assets in the electricity system: generation assets (from large-scale to distributed small-scale), transmission network (national and interconnections), and local distribution network operating at various voltage levels.

The objective function is to minimise the overall system investment and operating costs, across the time horizon of a snapshot year. The investment cost includes (annualised) capital cost of new peaking generating and storage units, new interconnection capacity, and the reinforcement of transmission networks. System operating cost consists of the annual generation operating cost and the cost of energy not served (load-shedding).

Generators' operating costs consist of variable costs (determined by fuel and carbon prices), no-load cost (driven by efficiency) and start-up cost. The cost minimisation is subject to a set of operating constraints which reflect the dynamic physical limits of system components and the need for secure operation. These include power balance, operating reserve and frequency response, generator-specific operating windows (minimum stable generation, ramping, up- and down-time), power flows down on transmission and distribution lines, and security standards (through the loss of load expectation). Security constraints ensure that there is sufficient generating capacity in the system to supply the demand with a given level of security taking into account the long-term reliability of generating plants. The cost of providing response or reserve is not modelled explicitly; however the efficiency losses of generators running part-loaded due to response and reserve provision are modelled and therefore the cost of providing these ancillary services is taken into account.

WeSIM is formulated as a large-scale Mixed Integer Linear Programming optimisation problem and solved using FICO Xpress. The output of the model provides investment decisions in the network and peaking capacity, storage devices, hourly generation dispatch and allocation of response and reserve, demand response scheduling, investment and operating costs, and locational electricity market (energy, capacity, and ancillary service) prices for each region which are obtained from the respective Lagrangian multipliers of the respective constraints in the WeSIM formulation. Further technical detail on the model can be found in Strbac *et al.* (2012) and Pudjianto *et al.* (2013, 2014).

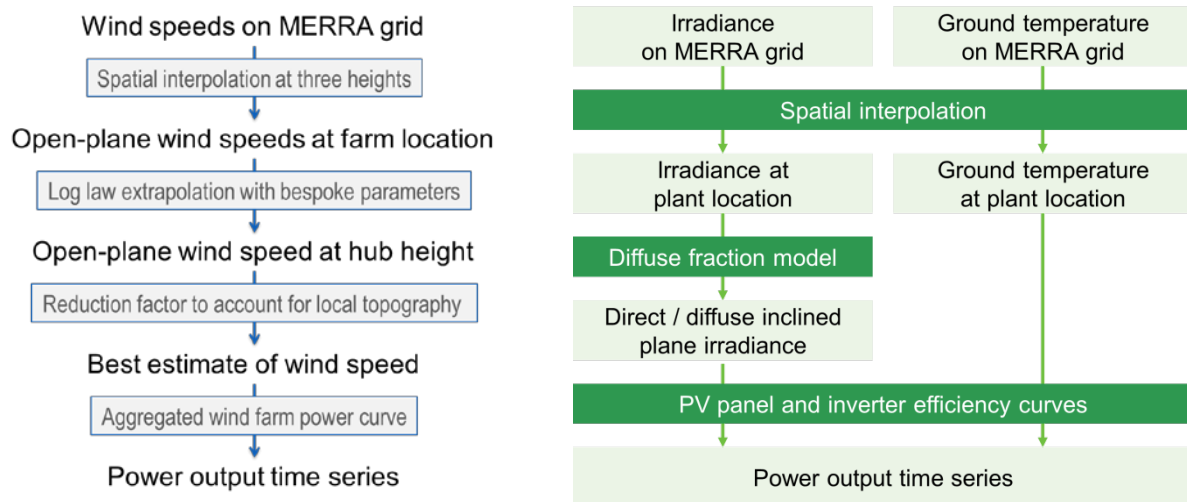
Some European countries have well-known attitudes towards particular generation technologies. France has favoured nuclear power since the 1970s, whereas Germany is now phasing out its nuclear stations. It would be hard to reflect these differences within a fully optimising model of investment in generation, except via (binding) constraints that would make the model fully optimising in name only. WeSIM takes an alternative approach, which is to accept a scenario for generation capacities as an input and then build the optimal set of additional transmission lines and peaking plants to make that scenario work in practice. In this study, the model divides Europe into 76 regions connected by 104 (actual or potential) transmission lines. It simulates 11 types of power station³ on an hourly timescale.

3.2 Wind and Solar Output Models

The hourly profile of output from wind and solar farms was simulated using the *Virtual Wind Farm* and *Global Solar Energy Estimator* models respectively (Staffell and Green, 2014; Pfenninger and Keirstead, 2015). As summarised in Figure 1, these models take weather data from NASA and use physics-based models of wind turbines and solar panels to convert them to time series of power output. Further details on the methodology of each model and their validation can be found in the references above.

³ These are coal, gas, oil (peaking), nuclear, hydro with reservoir, hydro run of river, pumped storage hydro, biomass, geothermal, wind and PV.

Figure 1: Overview of the renewable resource models used to produce hourly power output time series for wind (left) and solar (right).



NASA’s MERRA reanalysis (Rienecker, 2011) provides wind speeds and solar irradiance data at hourly resolution on a regular grid of $\frac{1}{2}^\circ$ latitude and $\frac{2}{3}^\circ$ longitude (approx. 55 by 44 km), giving around 2,900 onshore and 2,700 offshore locations across the extent of Europe.

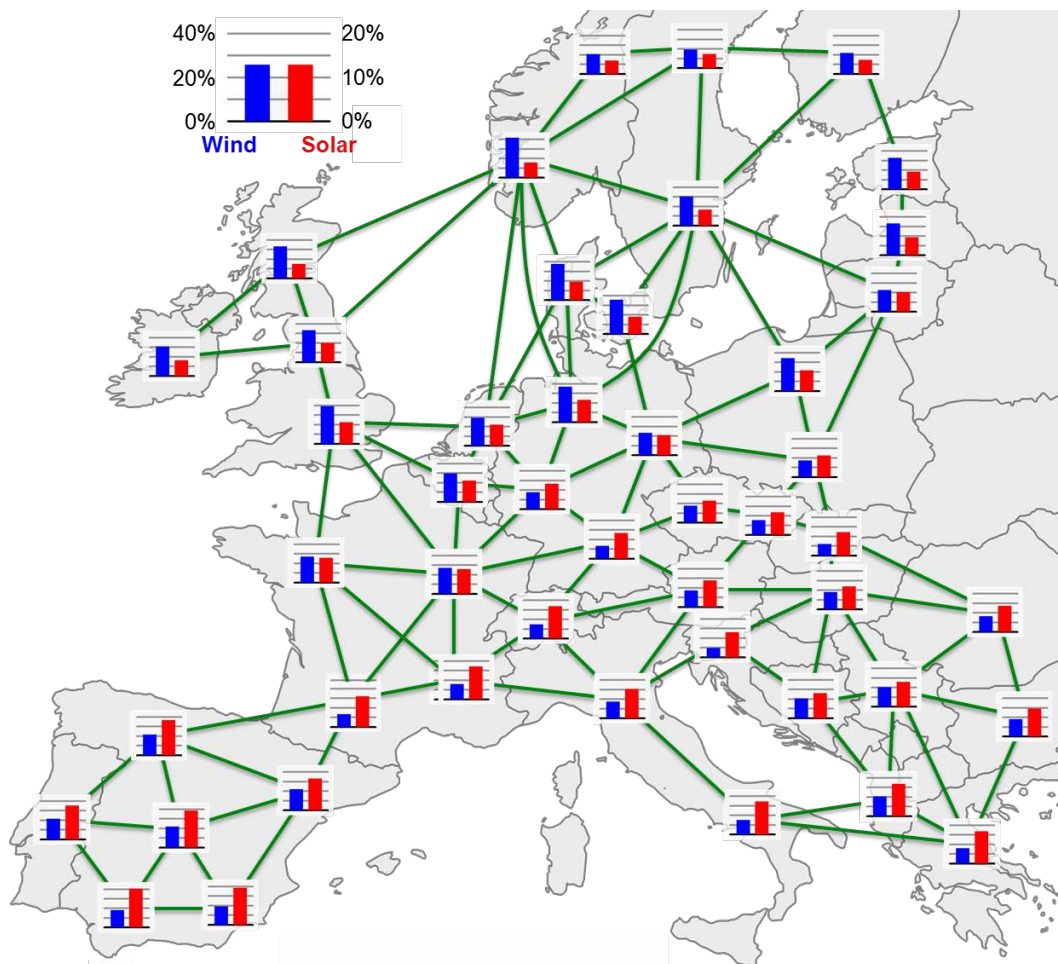
There is no record of the location of every solar panel in Europe, so we assumed a uniform distribution of panels over space, with the capacity installed at each point proportional to the annual output raised to the fourth power, to reflect the general trend that installations are biased towards the southern latitudes within a given country. Time series for solar output were simulated for each grid point from 1995 to 2014 and were aggregated to national or regional level.

We used The Wind Power database (Pierrot, 2015) to give the location, height and installed turbine model for every wind farm that was existing or under construction as of January 2015, and for larger offshore farms that are in planning (predominantly in the North Sea and Baltic Sea). The wind speeds were adjusted within each country so that national average capacity factors for the existing fleets were aligned to historic statistics derived from EuroStat and ENTSO-E. This yielded capacity factors in the region of 35–42% for some regions of Britain, Denmark and Norway due to the high proportion of large offshore

farms. Time series of output from each farm were simulated from 1995 to 2014, and aggregated together within each WeSIM region.

The average capacity factors for wind and solar are plotted in Figure 2. They are weakly anti-correlated ($R = -0.49$), and the simple averages across Europe (not weighted by capacity) were 25.0% for wind and 12.7% for solar – or 2,188 and 1,108 full-load running hours per year.

Figure 2: The annual average capacity factor for wind and solar plants at each node in WeSIM, with lines showing the routes where transmission capacity exists or is added.



3.3 Cost, Demand and Plant data

We take our demand and cost data from (Booz, 2013), which is itself based on the High Renewables scenario in the European Commission's (2011) Energy Roadmap 2050. This has a system-wide peak

demand of 662 GW and total electricity consumption (including losses) of 3834 TWh, 22% greater than in 2013. The investment costs for wind generators are equal to €2,413/kW, which is annuitized to €204/kW-year. PV plants cost €2,873/kW, annuitized to €258/kW-year and peaking plants cost €441/kW or €35/kW-year. Plant costs are shown in Table 1: most renewable generators have no variable costs.

Table 1: Generation costs in 2012 Euros

	Fixed Cost (€kW-year)	Average Variable Cost (€MWh)		Fixed Cost (€kW-year)
Coal conventional	180	61.83	Wind	204
Gas Conventional	80	68.83	PV	258
Nuclear	371	7.53	CSP	276
Oil Peaking	35	103.14	Geothermal	361
Biomass	64	14.21	Hydro	213
			Storage	213

We model two scenarios for the distribution of generation across Europe. Our National scenario is based on the High Renewables scenario in European Commission (2011). This includes 556 GW of existing thermal and hydro generation (shown in Table 2), 475 GW of wind power and 189 GW of solar capacity (shown in Table 3). The wind capacity has an average load factor of 25%, generating 1039 TWh over the course of our modelled year. The solar panels have an average load factor of 13% and generate 209 TWh over the year.

Table 2: Thermal and Hydro Generation

Country / group	Coal	Gas	Nuclear	Hydro	Biomass & Geothermal	Peaking
Denmark, Finland, Norway, Sweden	2.5	9.2	13.0	54.2	16.5	2.1
UK & Ireland	2.5	7.4	6.8	7.0	10.1	0.2
France & Benelux	5.9	8.7	45.3	30.5	10.9	5.3
Spain and Portugal	1.4	13.7	3.0	29.3	10.2	2.3
Germany	13.0	8.9	0.0	13.5	11.3	1.2
Austria, Czech Rep., Slovakia, Slovenia, Switzerland	4.7	4.7	10.5	40.8	4.1	0.5
Poland, Baltic states	5.5	7.2	5.3	5.8	5.1	0.4
Italy	4.3	16.1	0.0	21.7	10.9	7.4
Bulgaria, Greece, Hungary, Romania, former Yugoslav states	7.9	3.0	9.0	29.6	5.0	0.5
Total	47.8	78.9	92.8	232.4	84.0	20.0

Our second scenario assumes the same targets for wind and solar output (in TWh over the year) but distributes the stations differently. There is more wind capacity in regions with high wind speeds, and less in calmer areas. Similarly, solar capacity is moved south towards countries with a high solar incidence. This allows us to obtain the same amount of energy from significantly less capacity – PV capacity falls by 8% and wind by 15%. Table 3 shows the distribution of capacity in the two scenarios. This Coordinated scenario has not been formally optimised, and so it is possible that further redistribution could bring additional benefits.

The regions which gain wind capacity in the Coordinated scenario typically have access to good offshore resources – around 80% of the capacity in Scandinavia and the British Isles is offshore (strong increases),

32–45% in Germany and France (modest declines), and none in the remaining regions (more substantial declines).

Table 3: The Distribution of Intermittent Renewable Generation

Country / group	Solar Capacity		Wind Capacity	
	National	Coordinated	National	Coordinated
Denmark, Finland, Norway, Sweden	3.4	0.2	26.3	65.8
UK & Ireland	8.4	0.1	87.8	151.8
France & Benelux	27.1	20.6	98.7	47.4
Spain and Portugal	31.6	59.1	78.3	28.1
Germany	48.7	21.8	119.1	80.0
Austria, Czech Rep., Slovakia, Slovenia, Switzerland	6.9	0.6	9.2	3.3
Poland, Baltic states	7.7	0.0	8.7	1.2
Italy	40.1	58.4	26.9	14.9
Bulgaria, Greece, Hungary, Romania, former Yugoslav states	14.6	12.1	19.9	9.8
Total	188.5	173.0	475.1	402.3

Our starting point for transmission is that 96,500 GW-km of transmission exist in each scenario; more is added by WeSIM if cost-effective or necessary to ensure demand is met. There are 15 potential corridors which have no capacity installed at the starting point. The cost of building or reinforcing overland transmission lines is route-specific, based on the terrain involved, and varies between €0.73 and €1.27 million per GW-km, with the data given in (Pudjianto *et al.*, 2014). Sub-sea lines are assumed to cost €1.8 million per GW-km.

Given the two distributions of renewable capacity, we model one pair of scenarios in which the hourly demands are fixed, and a second pair in which it is possible to move up to 10% of demand by up to 24 hours, using a combination of energy storage and demand response.

4 Results

It should not be surprising that the cost of renewable generation is lower in the coordinated scenario than in the national scenario; the two have been constructed to give the same level of renewable output but coordination requires significantly less capacity. The cost of the overall electricity system, however, depends on the pattern of renewable output over space and time. Spreading renewable generators across Europe makes their output more diverse and reduces the cost of dealing with intermittency; some of this diversity is lost in the coordinated scenario. WeSIM copes with this by building additional transmission and peaking generators, while the output pattern of existing stations also changes. Table 4 shows that a large amount of additional peaking capacity is required in all four scenarios, and that this increases slightly (by 9-11GW) in the coordinated scenarios. Demand response and energy storage save much of this additional capacity (66-68 GW) but involve investment and operating costs of their own (not explicitly modelled here, but studied extensively in Strbac *et al.* (2012)).

Table 4: Additional Peaking Capacity (GW)

Country / group	No Demand Response		10% Demand Response	
	National	Coordinated	National	Coordinated
Denmark, Finland, Norway, Sweden	0.7	5.3	0.5	4.5
UK & Ireland	28.1	38.8	14.7	24.7
France & Benelux	45.9	30.4	33.1	23.9
Spain and Portugal	15.0	19.6	3.9	5.3
Germany	4.8	4.5	2.2	2.5
Austria, Czech Rep., Slovakia, Slovenia, Switzerland	2.9	3.5	0.0	0.3
Poland, Baltic states	2.7	6.0	0.4	1.4
Italy	10.0	12.2	0.0	0.0
Bulgaria, Greece, Hungary, Romania, former Yugoslav states	13.8	12.6	1.5	4.7
Total	124.0	132.9	56.2	67.3

Many studies of the impact of renewables find strong effects on average prices, usually because they hold constant the level of conventional capacity. WeSIM adjusts the total level of capacity in response to the deployment of renewable stations, even though the amount of non-peaking plant is assumed to be constant, and this means that changing the distribution of renewable capacity has no clear impact on average prices (Table 5). Similarly, while increasing levels of demand response (and storage) might be expected to reduce peak (and hence average) prices, in some regions this is more than offset by the fall in peaking capacity installed.

Table 5: Time-weighted average prices, unweighted averages across regions (€/MWh)

Country / group	No Demand Response		10% Demand Response	
	National	Coordinated	National	Coordinated
Denmark, Finland, Norway, Sweden	76.77	77.14	73.15	71.88
UK & Ireland	75.28	73.01	74.69	73.62
France & Benelux	79.86	80.84	79.95	81.37
Spain and Portugal	76.56	80.73	75.91	80.86
Germany	76.00	76.85	74.80	76.13
Austria, Czech Rep., Slovakia, Slovenia, Switzerland	84.74	87.09	85.53	87.85
Poland, Baltic states	81.55	83.94	81.28	84.74
Italy	82.99	83.74	81.18	82.82
Bulgaria, Greece, Hungary, Romania, former Yugoslav states	89.56	92.33	89.50	92.30
Average (unweighted)	80.37	81.74	79.55	81.28

Many previous studies find that raising the amount of renewable generation also increases the standard deviation of prices. The total amount of renewable generation is constant across our scenarios and so we cannot test this hypothesis directly, but find no clear pattern between changes in the distribution of renewable output and the standard deviations of our prices. Demand response, however, does lead to a noticeable reduction in price volatility (around 40%).

By concentrating renewables into specific areas, the coordinated scenario does see a stronger merit order effect, whereby renewables depress wholesale prices with their output, and thus earn less than other generators (Sensfuß, 2008). Per kWh of output, wind receives 89% of the time-weighted price in the national scenario, falling to 85% in the coordinated scenario. The strongest effect is seen in Ireland, where wind receives 75% and 70% respectively. The effect is less profound for solar, which earns 93%

in the national and 90% in the coordinated scenario; with the strongest effect being in southern Italy where PV receives 90%, declining to 86%.

The number of zero- or negative-price hours is relatively unchanged with coordination, reducing in countries that would be allocated less wind capacity (particularly Portugal and Spain), and increasing in those that gain it (GB, Ireland and Denmark). Averaged over all nodes, there are 116 hours in the national, and 101 hours in the coordinated scenario without demand response. The greater share of renewables in some regions (which would make negative prices more likely) is offset by additional transmission capacity.

The total value of output from wind generators is €67.0bn in the national scenario, which falls 6% to €62.7bn in the coordinated scenario. The value of solar output is almost unchanged between the scenarios at €14.3bn; possibly because solar capacity becomes less strongly concentrated than wind in the coordinated scenario. Coordinated policies sees the share of wind capacity held in the three largest nodes rises from 27% to 42%; whereas the share of solar in the top three nodes only rises from 32% to 37%.

Despite this reduction in value, placing renewables where they work best has a profound effect on the amount of subsidy required; taken to be the gap between the revenue from energy sales from wind and solar (normalised per kW) and their annuitized cost. The average yield for wind rises from €138 to €154 per kW per year by coordinating policies, and for solar rises from €81 to €91 per kW per year. Compared to their assumed costs of €204 and €258 per kW-year respectively,⁴ this reduces the total required subsidy from €33.0 to €20.9bn for wind, and from €34.0 to €28.8bn for solar – a combined saving of €2.1 billion, or €39 per household per year.

⁴ It should be noted that for compatibility with previous works, these are 2012 cost numbers from (Booz, 2013). If more recent (and lower) cost numbers were used, the absolute amount of subsidy required in both scenarios would decrease by the same amount, giving the same difference between scenarios, but a greater percentage reduction from coordination.

International trade in electricity rises significantly once investment in renewable generation is coordinated, as power flows can offset the reduction in diversity. Table 6 shows that cross-border trade rises by just over 40% and intra-national flows by over half. The flows are slightly greater in the presence of demand response, presumably offsetting the lower levels of peaking capacity available to manage intermittency. To allow this trade, €3,274 million (annuitized) is spent on additional transmission in the national scenario, and €6,171 million when renewables are coordinated; these figures decrease by about 10% with demand response.

Table 6: Statistics on electricity transmission across Europe

	No Demand Response		10% Demand Response	
	National	Coordinated	National	Coordinated
International flows (TWh)	812.3	1166.1	830.9	1173.2
Mean line utilisation (%)	38%	44%	39%	44%
Mean proportion of congested hours	12%	10%	10%	8%
Mean absolute price difference when congested (€/MWh)	15.42	19.80	17.96	22.81
Additional capacity required (GW-km)	37,173	58,091	32,510	49,305
Intra-country flows (TWh)	711.9	1092.4	721.3	1133.6
Mean line utilisation (%)	29%	35%	29%	36%
Mean proportion of congested hours	14%	9%	11%	8%
Mean absolute price difference when congested (€/MWh)	7.70	12.39	8.98	14.61
Additional capacity required (GW-km)	23,370	42,886	16,897	36,716

The revenue that transmission operators earn from arbitrage between nodes increases by 60%, from €5.6bn in the national to €9.0bn in the coordinated scenario. In both cases, 35% of this revenue goes to intra-country lines and 65% to cross-border lines.

Table 7 presents the total system cost, defined for each country grouping as the annuitized costs of generation and transmission assets, the variable costs of production and of net imports (valued at local market prices), less half the surplus from transmission (which shares the gains from trade when prices differ at the two ends of a line).

Table 7: Total cost of energy under each scenario by country grouping (€m)

Country / group	No Demand Response		10% Demand Response	
	National	Coordinated	National	Coordinated
Denmark, Finland, Norway, Sweden	22,864	22,077	23,175	22,144
UK & Ireland	34,623	36,357	33,567	35,338
France & Benelux	61,896	57,920	60,999	57,194
Spain and Portugal	40,547	41,221	40,045	40,577
Germany	61,252	51,814	60,581	51,069
Austria, Czech Rep., Slovakia, Slovenia, Switzerland	19,789	17,966	19,918	18,115
Poland, Baltic states	15,840	14,212	15,433	13,817
Italy	38,733	40,763	38,195	40,068
Bulgaria, Greece, Hungary, Romania, former Yugoslav states	26,173	24,688	25,755	24,314
Total	321,717	307,019	317,668	302,636

Coordination yields an EU-wide saving of €4.7bn, or €5bn if there is 10% demand-side response (which saves a further €4.3bn to €4.1bn). These savings are not evenly spread among member states; Germany gains €9.4bn (15%) from coordination (without demand side response) whereas the British Isles

and Italy spend an additional €1.7 and €2.0bn respectively (5%). The savings are not homogenous within regions. For example, Denmark spends an extra 12%, Norway and Sweden save 2–4%, and Finland saves 15% through coordination, yielding a regional saving of 3%. The general trend is that countries with high wind or solar resource see more renewable capacity installed and thus incur higher costs under coordination.

5 Implications for Market Design

The coordination described above is unlikely to be politically feasible, however large the overall gains, if some countries would face significant losses. Countries that specifically buy renewable energy in order to reduce the cost of meeting their targets should expect to pay more than the market price for conventional energy. We find that a premium of between €9-15/MWh for wind energy and €100-115/MWh for PV would minimise the number of countries that lose from the coordinated scenario or the sum of their losses.⁵ Even with this compensation, four or five countries would appear to lose from coordination.

With the costs we model, the premia required for PV and for wind are very different, and a single price would either deliver inadequate support for PV or excessive rents for wind farms. If countries simply had to acquire a given amount of “renewable electricity”, then they would naturally be tempted to find wind farms rather than PV schemes to support. If the supply of wind farms in good locations is inadequate, countries might be tempted to develop their own poor-quality resources rather than to pay the costs of supporting PV power elsewhere, however good its relative resource quality. A banding design, which gives more certificates per MWh of PV power than for wind power, would be the best way to mitigate this problem – although choosing the relative number of certificates would inevitably be the subject of

⁵ The premia needed to minimise the sum of absolute losses differ from those that minimise the sum of losses as a percentage of each country’s energy costs, and also lead to a slightly different group of losers. Our estimates use 2012 data but the costs of PV are falling quickly, and significantly lower premia might be needed for future investments.

much lobbying. In the longer term, this problem may disappear if the costs of PV panels continue to fall until the point that solar electricity in good locations needs no more support than wind power.

The Clean Development Mechanism has no requirement to import a product: should trade to meet Europe's renewable targets be linked to the physical ability to import the electricity? Green certificates that were completely divorced from the delivery of electricity would be simpler to administer, but it might be argued that a certain proportion of the electricity actually consumed in each country must come from renewable sources. It is of course impossible to determine the exact source of the electrons consumed by any given consumer at a particular time, but should be possible to allocate each unit of output to one (and only one) country. If this were done on an hour-by-hour basis, it would also be possible to require that the country buying renewable output also had sufficient transmission capacity to physically import it. This would be important if consumer-voters wanted to be sure that they were getting the "benefit" of the renewable power that they had paid for.⁶ The traditional approach to securing capacity for imported power is to buy it along a "contract path", but this ignores the nature of uncontrollable electricity flows in a meshed transmission system. Physical transmission rights have been used on many European interconnectors but create poor incentives: a holder with market power in generation may wish to withhold the rights in order to restrict competition. The rules governing physical rights differ from the laws of physics in that flows in opposing directions cannot be netted off, making it likely that capacity would be under-utilised if power flows could only be scheduled by the holders of physical rights.

It would be far better to create Financial Transmission Rights (Hogan, 1992) that hedge price differences between two points without allowing the holder to distort the physical dispatch of power. FTRs have successfully been used in several US power markets for nearly two decades. If transmission owners receive the price difference between two points on the network when power is sent across a congested line, then this makes them the natural counter-parties for the FTRs – they exchange a risky flow of

⁶ The ability to import power hour-by-hour may be less important from the point of view of the underlying aims of renewable support: aiding technology development, cutting carbon emissions and even reducing dependence on imported fossil fuels, which all depend on the amount of capacity deployed or on generation over a longer period of time.

payments dependent on actual power flows and prices for an up-front payment. They can issue as many FTRs as they like (since the contracts are purely financial) but will only enjoy the benefit of the hedge as long as the net power flows implied by the entire set of FTRs is feasible. This should ensure that if a country only bought renewable power that was backed by an FTR, that power could actually be consumed in the country. Since FTRs that imply flows in different directions along a line can be netted off, it is possible to issue more of them than with unidirectional physical rights that must be limited to the capacity of each line. A renewable project with an FTR need not worry if the price in its own region is low, since payments under the FTR will compensate for this.⁷ This would allow electricity companies in one region to invest in renewable projects abroad and yet to know that their customers will be able to consume that electricity.

The revenues from FTRs (inter- and intra-national) are more than sufficient to pay for the cost of additional transmission capacity, but would in general have been even higher, had the additional capacity not been built. This can produce perverse incentives, particularly given the difficulties involved in securing planning consent to build new lines. The incentives might be improved if transmission companies still received payments for transit flows under the ENTSO-E compensation scheme – the greater their capacity, the higher the flows and thus the compensation are likely to be. If the revenues from FTRs were actually deducted from these compensation payments, the scheme would then be revenue-neutral to actual price differences. This should remove the incentive to under-invest, although there may be other interactions which deserve further study.

The expansion of renewable capacity requires a large amount of peaking capacity to back it up, and even more in the Coordinated scenario. We find that most of these stations have very low load factors, around 1% on average. While the theory of energy-only markets suggests that the optimal number of stations should be able to recover their costs, Joskow (2008) gives a number of reasons why this may not happen in practice, and the actual running times and revenues could vary significantly from year to year,

⁷ The cost of buying an FTR from a low-price to a high-price region, which therefore involves large payments, will reflect the expected value of those payments, however.

depending on the weather. This is likely to imply a rather high cost of capital, at the very least. Capacity markets, or other payment schemes, can provide a hedge against the volatility of annual incomes and reduce peaking generators' cost of capital.

Imports can be critical in meeting demand at times of low renewable output within a country's borders; does this imply that capacity markets should be trans-national? This might give consumers (and politicians) more confidence that capacity on the other side of an interconnector would in fact be available when required, and also shares the burden of paying for it more widely. At the same time, organising a trans-national capacity market would be a complex task, and countries would have a natural tendency to want output from "their" generators to be used within their borders when system conditions were tight. Sharing peaking capacity could also involve the operational decision to share spinning reserves, but this would require some transmission capacity to be held back from energy transfers so that imports could increase rapidly when the need arose.

The current EU Target Model for electricity markets requires separate prices on each side of a major transmission constraint. Most European countries operate with a single price zone covering the entire country, and folk wisdom justifies this on the grounds that national transmission systems are stronger than interconnectors between countries. Table 6 shows that in our future scenarios, while the intra-country lines are less heavily used than interconnectors (on average), they are congested about as often. This suggests that many countries should prepare for zonal pricing within their borders; nodal pricing can give more accurate signals but is not suggested by the Target Model.

6 Conclusions

We have shown that Europe could save a significant amount of money – around €15bn a year – by better coordinating the deployment of renewable energy. This is about 5% of the annual cost of generation and transmission; a similar amount to the welfare gains that Newbery and Pollitt (1997) estimated as a result of the privatisation of the British Central Electricity Generating Board. In the absence of other policy interventions, however, it would create significant losses for some countries, and it seems unlikely that

any transfer scheme based on standard prices for wind power and for solar power could entirely avoid creating some losers.

A bigger obstacle may be that most governments have preferred to subsidise renewables in their own countries, partly because of “green jobs” but also because they want to be sure that their consumers can actually access the electricity generated. A system of Financial Transmission Rights could provide this access. The rights can only be issued if the overall pattern of flows they imply is feasible (hence ensuring that consumers can access the power) and they also insure against price fluctuations between the source and consuming region.

The revenues from FTRs can help to pay for the additional transmission capacity that will be needed if Europe is to concentrate renewable generation in the most productive areas. However, relying on FTR revenues alone can give transmission companies perverse incentives to under-invest (even though the extra spending needed on transmission is much less than the cost saving in generation). It would be better to finance the transmission investment from the existing ENTSO-E scheme for compensating transit flows, but adjusting the payments under that scheme to net off the revenues each transmission company receives from selling FTRs. FTRs could also provide the framework through which generators in one country participate in another’s capacity market: it is likely that these markets will be needed to reduce the risks faced by peaking generators. Allowing cross-border participation, but only if backed by an FTR, could make those markets more efficient. Many details remain to be worked out, not least the rules needed to ensure that the same capacity is not being simultaneously relied upon and expected to deliver in two separate markets. Using FTRs to facilitate the placing of renewable generators in the most productive areas could unlock large savings; the challenges are to agree the detailed rules and change the inward-looking behaviour that is currently raising Europe’s electricity costs.

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