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OFFICIAL MASTER'S DEGREE IN THE
ELECTRIC POWER INDUSTRY

Master’s Thesis

THE TOTAL COST OF RENEWABLE ENERGY: INTEGRATING VARIABLE GENERATION IN TODAY’S ELECTRIC POWER SYSTEM

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Of making many books there is no end, and much study wearies the body.

Ecclesiastes 12:12

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For the mistakes, errors and opinions herein, there is no one to blame but me.

Abstract

Driven by environmental concerns and a desire to secure energy supplies, significant quantities of variable generation from wind, solar and wave power are installed in today's power systems. However, the intermittent, uncertain and location specific nature of these variable renewable energy sources (VREs) imposes *integration costs* on power systems that have been designed for "on-and-offable" conventional generators. This report estimates *total costs (generation costs + integration costs)* for onshore wind in four diverse European countries with high wind penetration: Germany, Spain, Ireland and Denmark. Firstly, a broad literature review and discussion of fundamental concepts and VRE market effects is presented. Then, explanation of the market based cost methodology using market and transmission system operator data from 2012 and 2013 is given. Finally, results across the four countries find total costs to range from 72 – 86 €/MWh with integration costs from 10 – 16 €/MWh, a 16 – 24 % premium on commonly estimated levelised generation costs. This dissertation concludes that system characteristics have a greater impact than penetration levels alone and that decision makers should stop using incomplete levelised generation cost estimates and account for total VRE costs in planning future electric power systems.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1. Introduction

For decades now, changes in the earth's climate have been attributed to anthropogenic causes. Studies have attempted to forecast the effects, environmentalists have warned against inaction and the voting public has elected leaders with policies that appear committed to altering carbon based emissions and mitigating undesirable consequences. As the US Secretary of Energy recently stated "the time has passed for debate on climate change" (Moniz, 2013).

In 2004, energy supply was the largest single contributor to greenhouse gas emissions making up 26 % of the global total (IPCC, 2007). Accordingly, the promise of low emissions power generation from renewables like wind, solar, geothermal, oceanic, biomass and hydro has been of great interest. In Europe, government support for renewable energy sources (RES) effectively began in Germany on the 1st January 1991 when *Stromeinspeisungsgesetz* or the *Electricity Feed-in Act* was implemented to abate global climate change following the German Meteorological Society's report on climate warming (Jus, 2013).

However, the oil crisis of the 1970s had sparked interest in RES support across the Atlantic well over a decade earlier. The *National Energy Act 1978* promoted RES not principally for environmental reasons but to establish security of supply. Abundant renewables available everywhere would reduce dependence on foreign oil from OPEC nations who for political reasons might restrict supply once more as they had in 1973-1974.

Reducing greenhouse emissions and energy security are the primary drivers for implementing RES in any nation. The EU, who today is largely considered the world leader in RES, adds promotion of technological innovation and employment growth to their justification for RES support (EC, 2014a).

Policy makers seek to achieve these objectives by setting goals. In the European context the *2030 Framework for climate change and energy policy* released on the 22nd January 2014, makes significant alterations to the former 20-20-20 goals for 2020, detailing a six-point strategy (EC, 2014b):

1. **Binding emissions reduction targets:** reducing domestic greenhouse gas emissions by 40% in 2030 based on 1990 levels.
2. **EU-wide binding renewable energy target:** at least 27% of all energy to be generated by renewable sources.
3. **Energy efficiency:** improved energy efficiency measures throughout the EU.
4. **EU ETS reform:** establishment of market stability reserve at the beginning of the next trading period (2021) to control the quantity of emissions allowances and avoid a repeat of current surplus.
5. **Competitive, affordable and secure energy:** set of key indicators to assess Member States' performance, e.g. measuring price differentials between major trading partners (related to interconnection capacities), supply diversification and reliance on indigenous energy sources.

6. **New governance system:** iterative process between Member States and the Commission to ensure plans remain ambitious, promoting greater transparency and investor certainty.

Whether directly (as in points 2 and 5) or indirectly (the remainder) the EU maintains an aggressive implementation plan for RES. Yet at what cost? One only needs to open a newspaper to be confronted with headlines like: *Germany sets out to rein in surging electricity costs* (Reuters, 2013) or *Renewable energy in Spain: The cost del sol* (The Economist, 2013) or *Europe's renewable energy push has completely backfired* (Business Insider, 2013), to realise the issue is a topical one.

The significant influence of energy prices on industry competitiveness and everyday cost-of-living implies that the cost of renewable policies should be well understood. Equally, the cost of inaction, which may not necessarily constitute a numeric figure but a series of consequences, ought to provide a base against which to compare these costs, e.g. rising sea levels, energy supply at risk, increased extreme weather, etc. Given the weight of scientific evidence and subsequent governmental action, this dissertation assumes that costs of inaction are far greater than any cost of action[1]. Moreover, renewable installations to date have predominantly consisted of wind and solar power. Driven by variable primary energy sources (wind and sun), these installations are known as variable renewable energy sources (VREs). Thus, this report considers the costs of implementing VREs.

The complexity of electric power systems in general and VREs in particular, however, makes the determination of VRE costs decidedly difficult. The variety of alternative technologies, available resources, physical location of generators, grid characteristics, existing generation, forecasting errors, market characteristics, government support, rapid technological improvements, generation variability, etc. mean that even *identifying* costs is a complex problem. Additionally, biases frequently arise from interest groups of all persuasions meaning misconceptions in VRE costs are presented in the media and to policy makers.

Decision makers require the *total cost of variable energy sources* to choose between competing alternatives and determine the most economic solution. This report broadly separates the total cost of VRE into two categories: generation costs and integration costs.

While generation costs are better understood and more easily determined using levelised costs of electricity (LCOEs), integration costs are often misunderstood and always difficult to determine. This study defines integration costs as "the extra investment and operational cost of the non-VRE part of the power system when VRE is integrated" (Holttinen et al., 2011). Specifically, it is comprised of three elements:

1. Profile costs: VRE is variable and uncontrollable
2. Balancing costs: VRE is uncertain and unpredictable
3. Grid costs: VRE is location specific

[1] Readers interested in the cost of inaction are referred to Stern, 2006; Nordhaus, 2007; Fankhauser, 1995; Yergin, 2006; Vázquez et al., 2002; Winzer, 2011, etc.

This research will lead an in-depth discussion into determining factors of VRE integration costs by using onshore wind as a reference technology. The power systems of Germany, Spain, Ireland and Denmark will provide four case studies each exhibiting high, albeit varying levels of wind in evidently different contexts. The impact of existing system characteristics and market design will then be discussed.

Importantly, while this study will discuss the implications of government intervention any cost calculations will be made net of subsidies, tax credits and other support. This will enable a comparison that would otherwise vary significantly across countries which, according to national policy, implement different support mechanisms. In a similar manner to the International Energy Agency's (IEA's) *World Energy Outlook* the calculated cost will be a *social resource cost*: "the cost of society to build and operate a given plant, independent of all taxes, subsidies and transfers" (IEA, 2010).

This dissertation will take the following structure. Chapter 2 will review the literature and describe the problem setting by explaining key economic concepts and defining each cost element, including cost estimates. Chapter 3 will justify and expound the methodology used, incorporating a comparison of the four analysed countries. Chapter 4 will present and analyse the results. Finally, Chapter 5 will lead a discussion on the methodology, results and application to the integration of VRE in today's electric power system.

2. LITERATURE REVIEW AND PROBLEM SETTING

The determination of total costs can be broken into two categories:

1. Generation costs; and,
2. Integration costs.

This literature review details methods for calculating each cost. Fundamental economic concepts, discount rate sensitivities, the insufficiency of LCOE estimations, cost calculation principles and justification for why operating characteristics contribute to technology specific costs are discussed and define the problem setting. For each cost element, literature reviewed estimates are given.

2.1 GENERATING COSTS

Generating costs include investment, fuel, and operating and maintenance (O&M) costs; or more broadly, capex and opex[2]. However, generation investments have significant lifespans and therefore projects clearly require a time-weighted assessment. Levelised costs of electricity (LCOEs) are the most commonly used metric to compare such costs.

2.1.1 Levelised costs of electricity (LCOEs)

Levelised costs of electricity "are the lifetime discounted fixed and variable costs of a generating technology expressed [usually, in USD] or €/MWh" (Edenhofer et al., 2013). The metric arises because differing cost structures between generation technologies make cost comparisons difficult. For instance, a combined cycle gas turbine (CCGT) unit is considered to have a relatively low capex with comparatively high opex because large quantities of gas are required for electricity production. A nuclear power plant by contrast has a very high capital outlay and relatively low opex. Thus, by levelising the cost structure of a generator, a fair comparison can be made; at least as far as conventional, dispatchable technologies might be concerned.

Equation 1 (after Fraunhofer, 2013) shows the basic formula used to determine LCOEs:

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{C_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+i)^t}} \qquad (1)$$

LCOE	Levelised cost of electricity [€/MWh]
I_0	Investment cost [€]
C_t	Annual total costs in year t [€]
E_t	Energy produced in year t [MWh]
i	Real interest/discount rate [%]
n	Economic life span in years

[2] Capex = Capital expenditure, opex = Operational expenditure

t Year [1, 2, ..., n]

Equation 1 demonstrates that LCOEs include all annual total costs (capex plus opex minus plant salvage value), divided by the annual energy production to yield a figure that compares generation costs to expected revenues[3]. The implicit assumption, visible in this formula as E_t is that the value of all electricity is constant through time. As any conscientious bill payer with an off-peak water heater might tell you this is a plainly invalid assumption (that only becomes more complex with wholesale markets; see Section 2.2). Additionally, if E_t is reduced, for example, because of variable wind supply, the LCOE will increase.

The International Renewable Energy Agency's (IRENA's) *Renewable Power Generation Costs in 2012*, claims that seven major components determine the LCOE for any given technology:

1. Resource quality
2. Equipment cost and performance (including capacity factor)
3. Project/Investment costs
4. Fuel costs (if any)
5. O&M costs (including reliability)
6. Economic life of the project
7. Cost of capital

Thus, there can be no single LCOE for a given technology but only a range of values. If considering a conventional, thermal generator, like a coal-fired unit, calorific values, ash content, fixed carbon and other properties of available coal will substantially impact fuel costs. However, considering the same inputs for RES, LCOEs will vary even more. Unlike thermal generators, renewable resource quality has a very high locational specificity, as demonstrated by any wind or solar irradiation map.

Furthermore, as with all net present value calculations, LCOE is highly sensitive to the real interest rate, i, usually taken as the weighted average cost of capital (WACC) to reflect the debt to equity mix, and the amortisation period. Table 1 illustrates this sensitivity through a simplified example of a 400 € million investment in a new 450 MW CCGT unit with annual costs of around 80 € million (fuel and O&M) assuming a 50 % capacity factor. Real interest rates and amortisation periods are then modified to determine the effect of assumptions on LCOE estimates.

[3] Fraunhofer, 2013 is careful to point out that although the denominator, E_t, represents energy in MWh this figure is directly related to revenues since electricity is non-storable and therefore sold immediately. Amortization of E_t therefore poses no problems.

Table 1 - LCOE assumptions variance

Case	Real Interest rate	Amort. period (years)	LCOE (€/MWh)
Low	7%	30	64.06
Low	7%	20	67.21
Low	7%	10	78.71
Medium	10%	30	69.88
Medium	10%	20	72.48
Medium	10%	10	82.82
High	13%	30	76.12
High	13%	20	78.16
High	13%	10	87.74

These results demonstrate that by only altering the interest rate between 7 – 13 %, estimates vary by more than 12 €/MWh (>18 % of original LCOE estimate). By altering the amortisation period between 10 – 30 years, estimates vary by more than 14 €/MWh (>22 %). And by altering both, estimates can vary by as much as 23 €/MWh (>35 %). Indeed, in a comprehensive study of LCOE inputs, Cory and Schwabe (2009) have shown that depending on each of the seven variables identified by IRENA (2013), estimates of an LCOE can vary by as much as *five times* between an optimal and substandard wind project.

Many international organisations cite LCOE as a "convenient summary measure of the overall competitiveness of different generating technologies" (EIA, 2010); "a handy tool for comparing the costs of different technologies over their economic life" (IEA, 2010) and "a basis of comparison for weighted average costs of different power generation technologies" (Fraunhofer, 2013). And so it may be. But it is not more. For although LCOE provides a convenient ratio to compare investment and operational costs of various generation technologies to their expected energy output, it does not include externalities incurred by the power system as a whole. Indeed, the same authors qualify LCOE limitations: "it is important to note that actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous considerations other than the levelised cost of competing technologies" (EIA, 2010); "this study does not take into account system costs… an issue that concerns all technologies, in terms of location or grid connection… There is no disagreement between experts that such system costs for non-dispatchable renewables exist" (IEA, 2010); and, "[LCOE] is not to be equated with the feed-in compensation. The actual spot value of electricity is determined by the daily and hourly variations and weather-related fluctuations in supply and demand and therefore cannot be represented by LCOE" (Fraunhofer, 2013).

That is, even if generation costs reduce because of technologies with a lower LCOE, these new generators may impose significant costs on existing generators by increasing ramping demands, reducing full-load hours or increasing congestion. LCOE can therefore only represent generation costs, requiring integration costs to form a complete cost assessment.

Figure 1 shows a range of LCOEs for various RES technologies, indicating their usefulness in comparing generation costs.

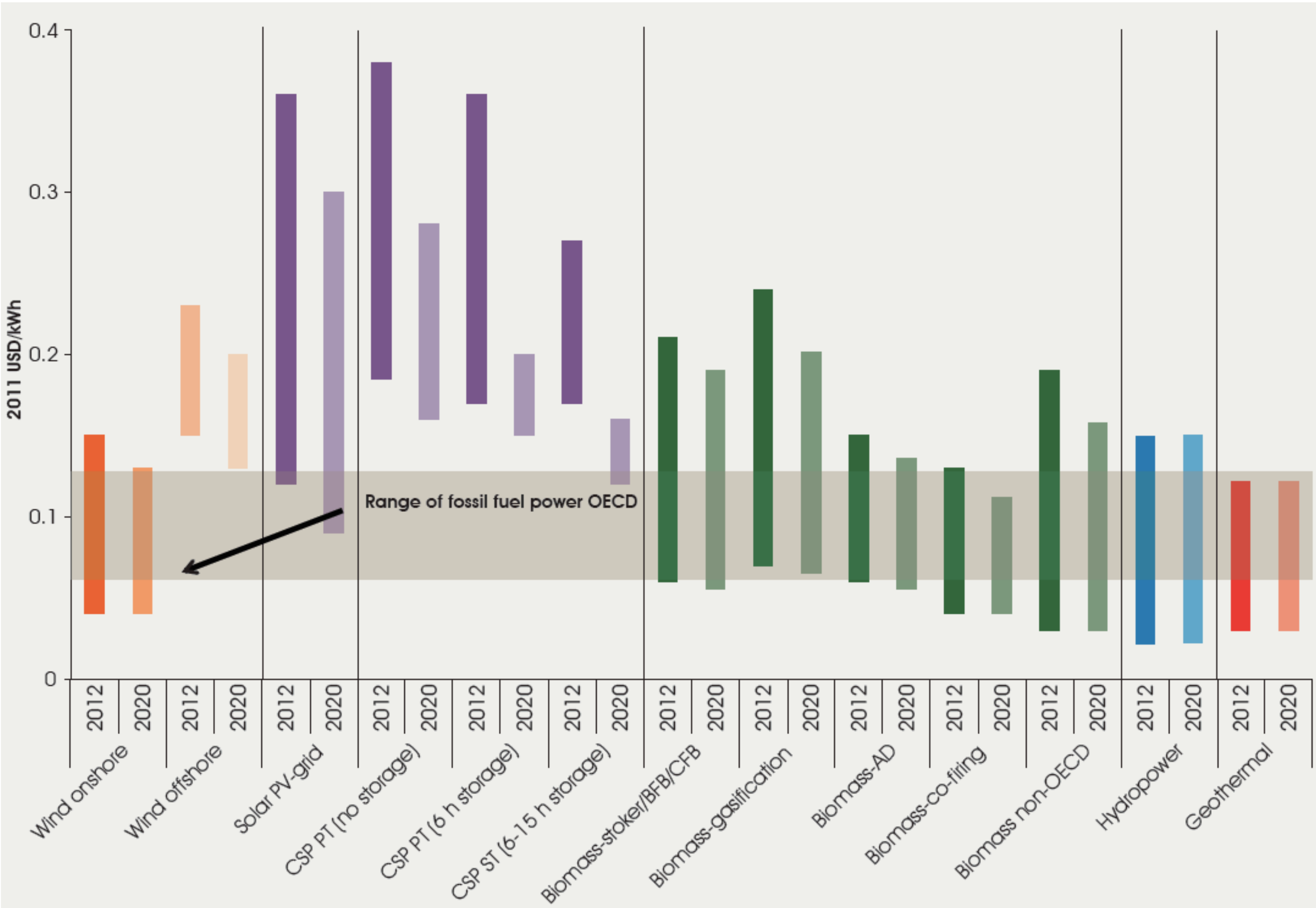

Figure 1 – Typical LCOEs for RES technologies
(Source: IRENA, 2013)

2.2 THE INSUFFICIENCY OF LEVELISED COSTS

Generating costs commonly represented by LCOEs contribute to an only partial picture of true costs. Two limitations are evident. The first limitation concerns the dependence of LCOEs on input variables that may be incorrectly estimated (see Section 2.1). These errors may occur unintentionally, because data is unknown or difficult to determine, or because authors expressly seek to make a certain technology look more attractive. Contrary to the preceding example shown in Table 1, Awerbuch (2003) claims that LCOE estimates often *under* value RES because higher operating costs associated with conventional generators are discounted. By critically choosing to use a higher discount rate, the impact of operating fuel costs is reduced, favouring thermal generation over capital-intensive RES and vice-versa. Awerbuch (2003) points to "irresponsible" claims from the NEA/IEA/OECD[4] that state no consensus exists within the literature for determining discount rates and argues that oil prices are highly volatile and negatively correlated with economic activity. Negative correlation between oil prices and economic activity is partially supported by Hunt et al. (2001) and Papapetrou (2009) though much contention surrounds this issue in the economic literature (see the same authors; Lescaroux and Mignon, 2008; Federal Reserve Board, 2011). In either case, it is clear that the study of LCOE inputs is complex and a comprehensive analysis is beyond the scope of this work[5].

The second limitation, however, is more fundamental. Joskow (2011) argues that the "serious flaw" with LCOE comparisons is that they "treat all MWhs supplied as a homogenous product governed by the law of one price." Such an assumption is plainly erroneous given that wholesale electricity prices vary at least every hour – if not every half hour or every five minutes – as wholesale markets are cleared. When comparing annual variations between the highest and lowest prices in a 12 month period, the same author has shown prices varying by as much as four orders of magnitude (Joskow, 2008).

Accordingly, it is not the duration of generation alone that matters but also *when* this power is generated. This is what Joskow (2011), Borenstein (2011) and Kopsakangas-Savolainen and Svento (2013) refer to as a generator's "production profile." Nuclear generators, for example, have very low marginal generating costs and are usually dispatched for more than 7000 hours per year: a *base load* profile. Yet, despite having virtually zero marginal generating costs, wind generators are not dispatched anywhere near 7000 hours per year because their availability depends on wind speed and direction: what we could term, a variable profile. "If production profiles are the same the value of the electricity supplied will be the same and the technology with the lowest levelised cost will also have the highest net value and [will] be the most profitable choice in the market context" (Joskow, 2011). Since LCOE comparisons do not account for generators' production profiles, instead equalising the value of electricity in every hour of the year, their results are incomplete at best and misleading at worst. Thus, if LCOEs are to be used alone, only technologies with similar production profiles should be compared: base load with base load, intermediate with intermediate, peaking with peaking.

These difficulties are intensified by variable renewable energy sources (VREs)[6] which fit no conventional production profile and have a far more unpredictable variance within their profile. Indeed, VREs are frequently over valued by LCOE comparisons (despite Awerbuch's, 2003 protest) because of a failure to account for production profiles and integration costs. That is, even if LCOE calculation inputs were perfect, a cost calculation using this methodology for VREs would be incomplete.

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[4] NEA = Nuclear Energy Agency, IEA = International Energy Agency, OECD = Organisation for Economic Co-operation and Development.

[5] Interested readers are directed to the aforementioned sources.

[6] *Variable renewable energy source (VRE)* or more generally, 'variable' will be used in this report for consistency. It is equivalent with 'intermittent' and 'non-dispatchable' used elsewhere in the literature. Importantly, geothermal, CSP, biomass and other non-variable RES are not defined as VRE since they are dispatchable.

2.3 VARIABLE RENEWABLE ENERGY SOURCES (VRE)

Many authors (Grubb, 1991; Joskow, 2011; Hirth, 2012a; Ueckerdt et al., 2013; Keay, 2013; Henriot and Glachant, 2013; Hirst and Hild, 2004) have argued that discounting any positive environmental externalities, VREs impose substantial integration costs on the electric power system. This is because electricity is an unusual commodity that, though perfectly homogenous, cannot be stored, can only be transported in limited quantities along network lines and requires that supply and demand be balanced at every second of the day. Therefore, the value of electricity varies depending on the time it is sold, where it is sold (and/or produced) and the lead time before it is delivered (uncertainty). Figure 2 from Hirth (2013) presents a good visual representation of this phenomenon.

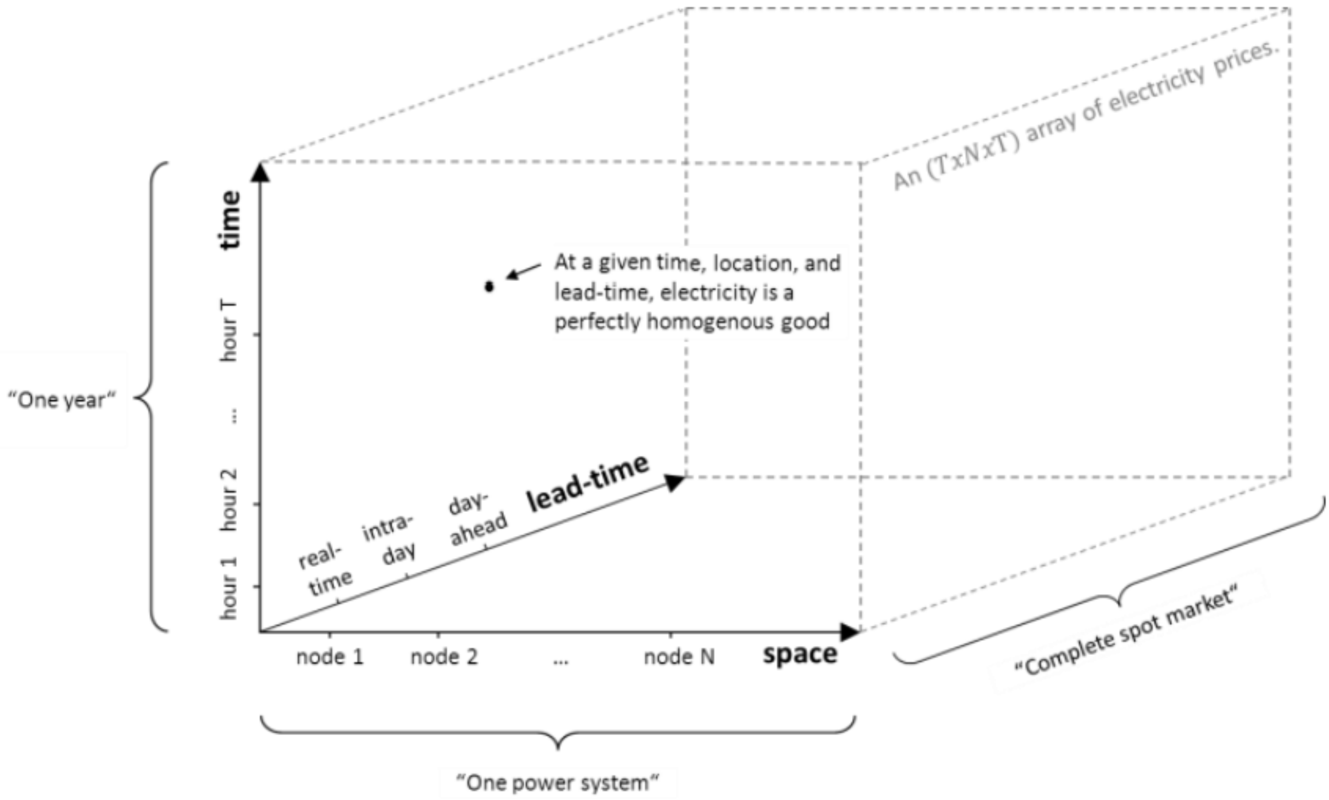


Figure 2 - Wholesale spot prices array, varying across three dimensions
(Source: Hirth, 2013)

These three aspects can further be illustrated by answering three questions: *How* is power generated? *When* is it generated? *Where* is it generated and delivered to?

How?
Generating power with VREs is inherently different from generating with conventional technologies. VREs are not controlled by opening gas taps or shovelling extra coal but are limited to operating when the sun shines and the wind blows. Thus, trying to coordinate these resources to meet a specific demand is beyond the control of human beings. As their name suggests, VREs operate variably and with limited control over

their output. This lack of correlation between VRE production and demand induces costs.

When?

Forecasting when VREs might be able to generate is difficult. GE Energy (2010) point out in their *New England Wind Integration Study* that conventional power systems with minimal or no VRE have been designed to manage load variability and uncertainty, as well as unplanned generator outages for decades. Conventional resources: base load, intermediate and peaking generation function to ensure *security*[7] and *firmness*[8] conditions are met for a given system. However, VREs "introduce a variability and uncertainty of forecasting that makes [them] fundamentally different from analysing and operating [a conventional system]" (GE Energy, 2010). Because VREs are present in increasingly large proportions, this uncertainty affects the output of other generators who must compensate by increasing or decreasing the energy provided to the network to maintain supply equal to demand. This usually means these balancing generators operate in inefficient ways, increasing system costs.

Where?

VREs also have high location specificity. Unlike transporting fossil fuels to conventional generators, renewables must be positioned in areas where primary energy sources (wind, sun, waves, etc.) are concentrated. This can lead to network congestions and induced network costs (Chaves-Ávila, 2014), especially since load centres are far from VRE generation sources. One case study examining wind power in Ontario, Canada, shows uncongested wind production reduces prices by up to 5.5% compared to congested wind production which only reduces prices by 0.8%; a 4.7% difference dependent on congestion alone (Amor et al., 2014).

VREs therefore function in a different manner to conventional generation technologies. Their output is variable and difficult to forecast and they frequently induce undesired network costs. Following Ueckerdt et al. (2013) and Hirth (2012a), we shall term these three cost drivers variability, uncertainty and location-specificity, respectively. In other words, electricity prices vary in three dimensions: time, lead-time and space.

[7] *Security* is a measure of the systems ability to support disturbances and/or unexpected losses. It considers short to very short-term operation.

[8] *Firmness* is a measure of the ability for installed capacity to meet demand efficiently, supplying generation and network services "when needed". It considers short to medium-term operation. (Pérez-Arriaga, 2013).

BOX 1: THE ELECTRIC POWER SYSTEM AND BALANCING REQUIREMENTS

While storage remains economically infeasible, electricity is a unique commodity in which supply and demand must be balanced at all times to ensure safe operation of the network. Although it is possible to forecast demand, future estimates encounter uncertainty. Day-ahead demand forecasts for example, typically have an average error of ± 1.5%, increasing to 5% for week-ahead or unit commitment scheduling (IEA, 2011). However, even if forecasts were perfect, variability of demand and supply is still present in electric power systems. VRE technologies exacerbate this variability. Milligan et al. (2011) separate variability induced balancing requirements into three time categories (Figure 3):

1. Regulation – seconds to minutes, random
2. Load following – tens of minutes to hours
3. Scheduling – day-ahead

For each time interval the power system is designed with various ancillary services which ensure all variations from day-ahead or hour-ahead schedules are managed and supply maintained. These services include: frequency control: primary, secondary and tertiary reserves; reactive power and voltage regulation; and black start capabilities. Because of its variability, system operators ordinarily consider VRE as a negative load. Thus, the characteristics of a given power system and the capacity and variety of installed VRE technologies affects the quantity and type of balancing products required. In turn, this affects costs of integrating VRE.

VRE generation varies more in the minutes-to-hours (following) time frame than in the minute-to-minute (regulation) time frame (Milligan et al., 2011). Accordingly, most costs incurred by VRE arise due to load following requirements. Aggregation of VRE resources or expansion of balancing responsible parties helps to smooth production at the regulation level (Milligan et al., 2011).

For more info: Chapter 7, *Regulation of the Power Sector*, editor: Ignacio J. Perez-Arriaga

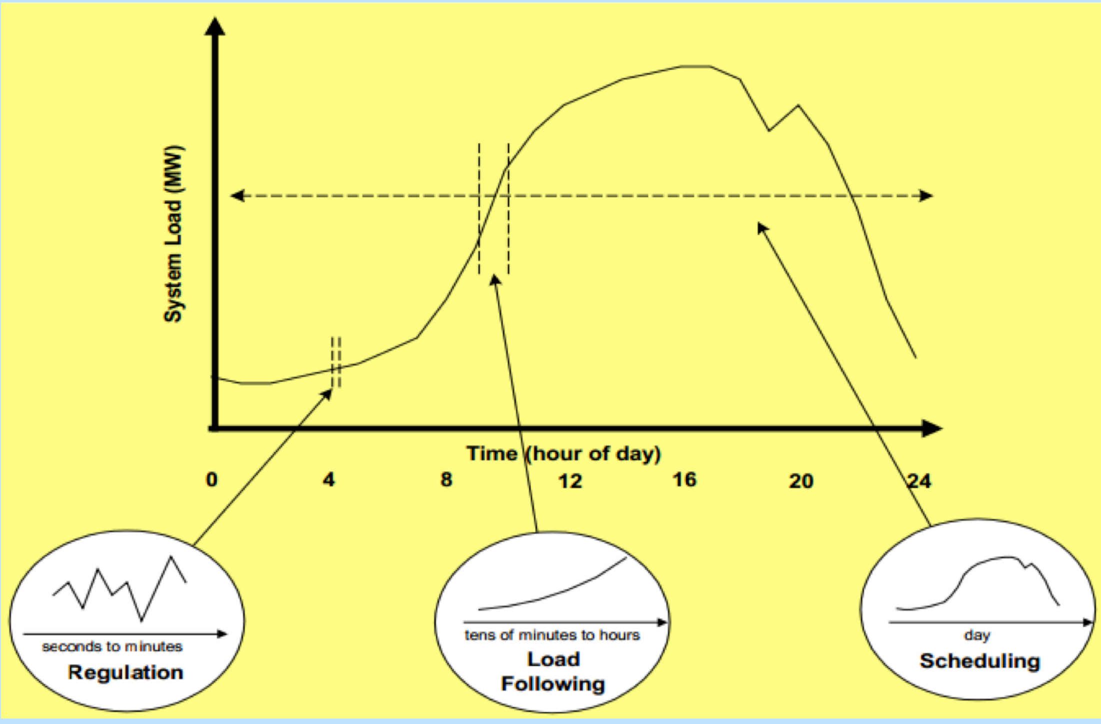


Figure 3 - The three time intervals of power system variability
(Source: Milligan et al., 2011)

2.4 INTEGRATION COSTS

The incomplete cost analysis provided by LCOE comparisons and variable behaviour of VREs has led many authors to model, analyse and assess the impact of integration costs. Knowing the true costs of VREs assists in evaluating which generation technologies will produce the most efficient outcomes. This section presents the various subcategories of integration costs.

Ueckerdt et al.'s (2013) *System LCOE* is one of the most comprehensive and recent pieces of research on integration costs. Figure 4 summarises their integration cost breakdown and it is used this study as a base for discussing integration costs. Importantly, integration costs only exist compared to some alternative. In this study that "alternative" will be defined as a system without VREs (see Section 3.1).

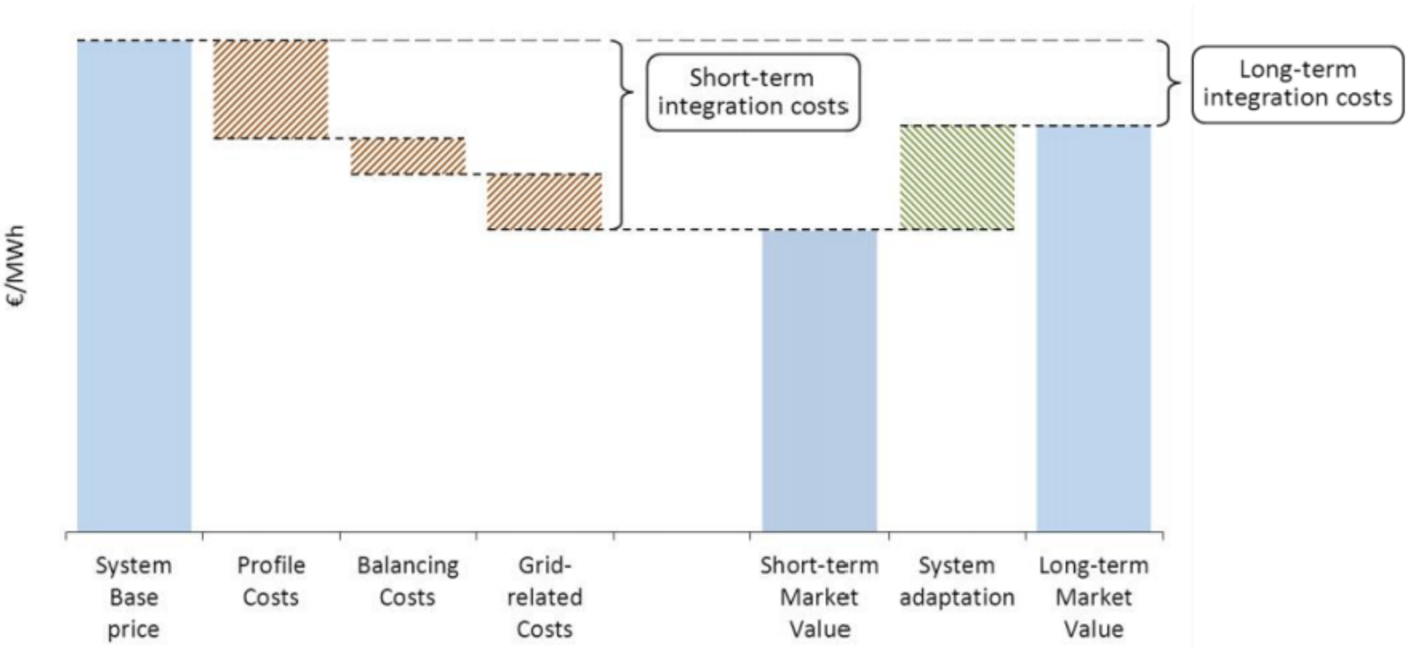


Figure 4 - Integration cost breakdown
(Source: Hirth et al., 2012a)

2.4.1 Profile costs

2.4.1.1 An introductory example

An oversimplified though illustrative example (similar to one used by Joskow, 2011) is depicted in Figure 5. Here, market prices vary only according to demand (i.e. supply does not alter prices) and are defined by three price bands: high, intermediate and low. Whenever demand is above a given price all available generating units receive this price. Wind, however, is not present in every hour and generally receives the lowest price and occasionally the intermediate price because generation is typically greater in the late evening and early morning. As such, wind generators miss the high price in between 10:00 – 20:00.

By contrast, Figure 6, imagines a perfect base load generator which is able to provide 1000 MW in every hour of the day (e.g. nuclear unit) depicted at the top of the demand curve to highlight that it receives all three prices throughout the day. The average price therefore received by this base load unit is the same as the time weighted average price.

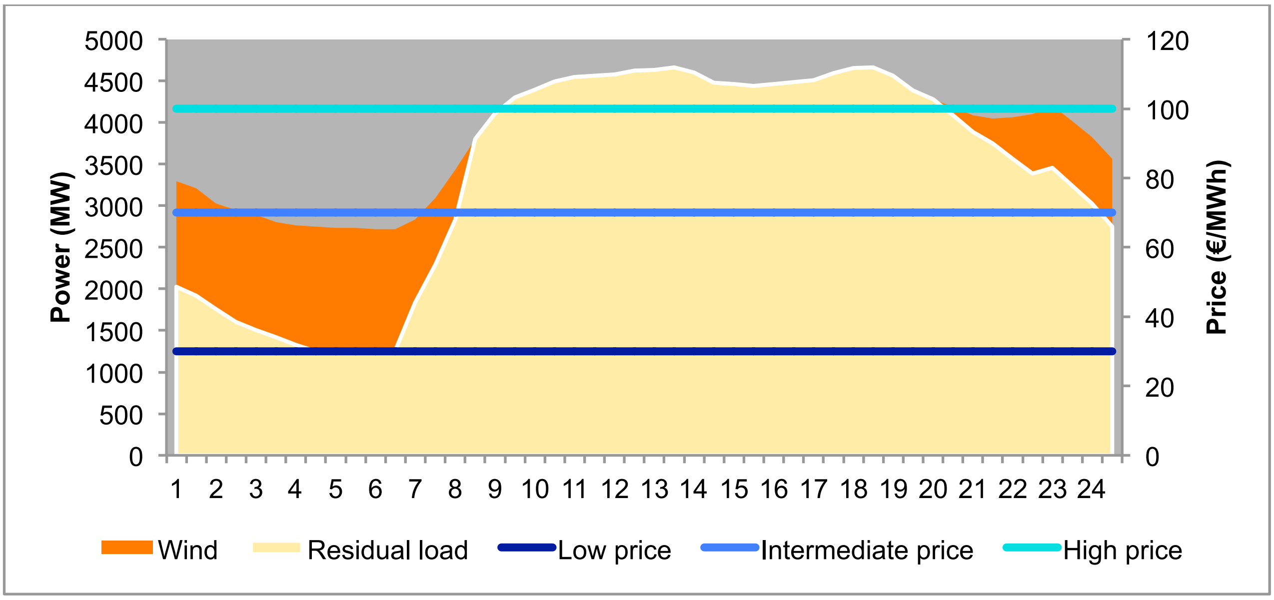
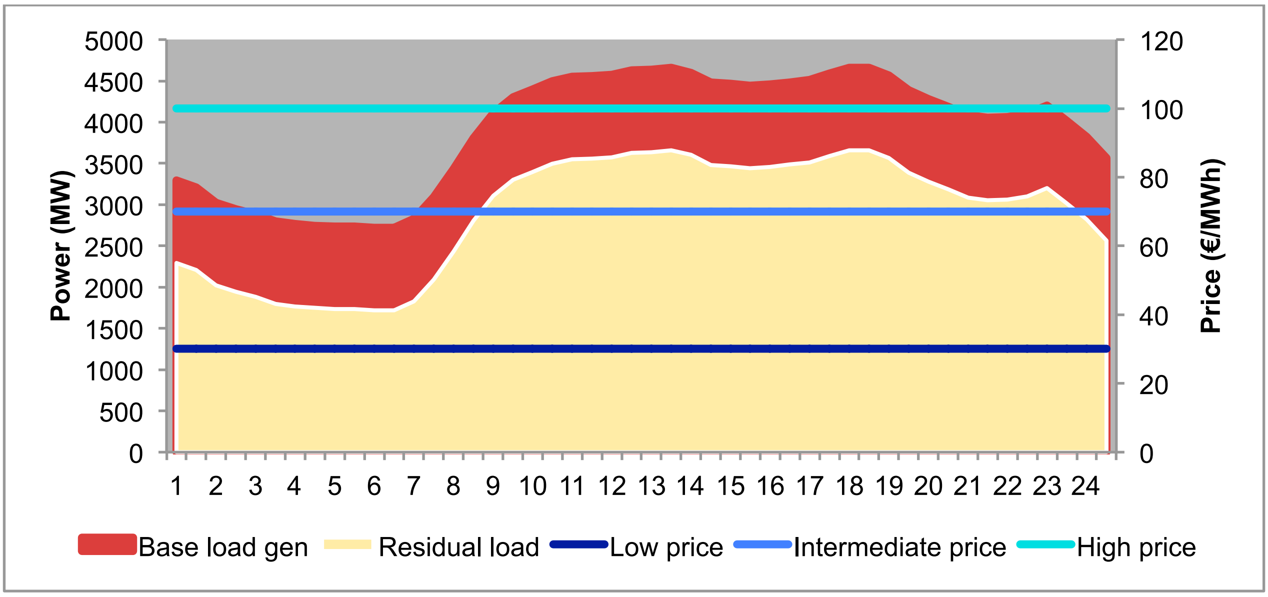


Figure 5 – Hypothetical wind profile



Source: Demand data from SEMO, 22 May 2013, else author's own

Figure 6 – Perfect base load profile

Of course, the wind profile could have taken any host of other forms including wide variations throughout the day, even during peak hours, such that occasionally the unit receives the highest price. Despite some exaggeration, however, this example is indicative of the variability of VREs and the subsequently lower market value. Indeed, for Joskow (2011), this reduction in market value is the precise reason why LCOEs provide an insufficient metric for assessing different types of generation technologies and in particular, VREs. The difference between the value of energy produced by the VRE unit and this perfect base load generator is what we shall soon define as the profile cost.

Increasing the complexity of this example, assume price now varies with both demand *and* supply. Wholesale electricity prices thus decrease as more expensive generators are removed from the market by production from extremely low variable cost VREs. Yet as can be seen in the peak hours of Figure 5, VREs are frequently unavailable and thus cannot replace large amounts of firm capacity. However, full-load hours and therefore revenues of pre-existing generation are still reduced. Thus, VRE induce costs by: (1) reducing the utilisation of existing generation without replacing capacity and (2) reducing the electricity price. In turn we shall define these two effects as the compression effect and the merit order effect, respectively.

The following section will now elaborate on this introductory example, define the key concepts and discuss why profile costs are not part of ordinary market operations.

2.4.1.2 Fundamental concepts

Profile or adequacy costs arise because the supply from VRE is variable: wind mills only generate when the wind blows, solar panels only when the sun shines, marine power only when the sea rolls. Thus, it is not possible to dispatch VREs to satisfy the load unless the primary energy source (wind, sun or waves) is available. This has two effects on the electric power system which must maintain reliability indexes[9] "keeping the lights on" (after Nicolosi, 2012):

1. VRE increases variability of the residual load: *flexibility effect.*

    a. Consequently, dispatchable generators must increase or decrease their production more often and more quickly because of steeper ramps. Expensive fuel generators may also be dispatched more often.

2. VRE reduces utilisation of dispatchable units: *utilisation effect*.

    a. Zero variable cost generation ensures VRE units win their bid, reducing full-load hours of conventional generators. In the short-term, conventional units respond by increasing bid prices to recover capital costs. In the long-term, low cost base load generation is forced out of the market, increasing operational costs as flexible resources with higher variable costs are implemented (e.g. gas, pumped hydro).

    b. The low capacity credit[10] of VRE means increasing wind, solar or wave capacity does little to displace conventional generation which is required as backup. Accordingly, utilisation of capital is reduced or "underutilised."

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[9] In developed nations these figures are usually above 99.9 % availability or less than 2 hours without power per year.

[10] *Capacity credit* is the proportion of firm capacity that can be displaced by a newly installed generator whilst maintaining the same level of system reliability, in other words, an unchanged probability of failure to meet the reliability criteria of the system (Ramos, 2013). It is typically given as a percentage of the installed capacity and for wind, capacity credits range from 5 – 25 % (IEA, 2011). However, the metric should be used with caution since it is dependent on the technology used, the quality of the primary

c. In high proportions, output from VRE sources occasionally needs to be curtailed or spilled signalling the inefficient use of resources and mismatch between VRE generation and load requirements.

Profile costs, however, are highly contestable. Point 2a and the example above may well provoke one to ask "isn't the displacement of existing generation by cheaper units simply the direct application of competition?" Ordinarily, yes: newer, more efficient technologies disrupt the market place, lowering prices. Incumbent operators are forced to respond and reduce their inefficiencies or leave the market altogether. Once the market has undergone this process it is said to have reached a new equilibrium. However, if government support is present, the market is distorted and no such equilibrium process is possible. In this case the answer to our question above must be, no.

The NEA (2011[11]) gives two reasons as to why this is the case:

1. Without subsidies, high capital cost VRE generators would be most affected by lower electricity prices due to the technology's low, short-term costs. Consequently, investors would quickly reassess their investment.
2. The reduced profitability of conventional generators would result in a rapid decline of installed, dispatchable capacity. "This will lead to increased price volatility with large price spikes necessary to finance remaining generators. Given the resulting impacts on system stability, investment conditions and consumer preferences, the resulting system costs may well be higher than in a system where dispatchable producers were unaffected from the price impacts of variable renewables" (NEA, 2011).

Thus, profile costs cannot be dismissed as the ordinary functioning of competitive markets since as far as renewables are concerned, markets are not competitive. Indeed, in almost all countries where renewables are being deployed in significant amounts, RES owners derive their income external to market operations, i.e. via regulatory measures. As such, renewable operators do not receive the same signals and incentives as conventional market participants. In fact, if feed-in tariffs, where generators are paid per MWh produced, are the only support used, there is no signal for renewable producers to control their output at all – the more produced, the better. This effect is especially notable when supply, usually from wind producers, exceeds demand and results in negative prices as base load technologies bid to avoid having to shutdown or wind itself pays up to the point at which their generation costs plus the negative price equal the feed-in tariff they receive.

Profile costs are thus real and their quantification is imperative for any total cost assessment. The following section elaborates on how the flexibility effect and the utilisation effect affect profile costs.

2.4.1.3 Flexibility effect

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energy source and, to a lesser extent, the reliability rates for the power system in which it is applied. Capacity credits of VREs are considerably lower than those of conventional units.

[11] Readers may also be interested in Ignacio Pérez-Arriaga (2011) where a very similar argument is pursued.

Because of their variability, VREs are usually considered by system operators as negative load rather than dispatchable supply. When production profiles of VRE match load profiles (often the case with solar), profile costs can be negative, i.e. they reduce overall system costs. However, when the load is increasing and simultaneously, VRE output is decreasing (or vice versa; often the case with wind), costs are induced on the system because ramping rates increase, as shown in Figure 7. Bird et al. (2013) point out that sunrise and sunset events can also exacerbate ramping rates, particularly in regions with evening loads. However, precise foreknowledge of sunrise and sunset times means these events can be managed by dispatching units in advance without relying on reserves. Conversely, increased ramp rates increase wear and tear on existing generators, augmenting cycling and maintenance contract costs (Batlle and Rodilla, 2011).

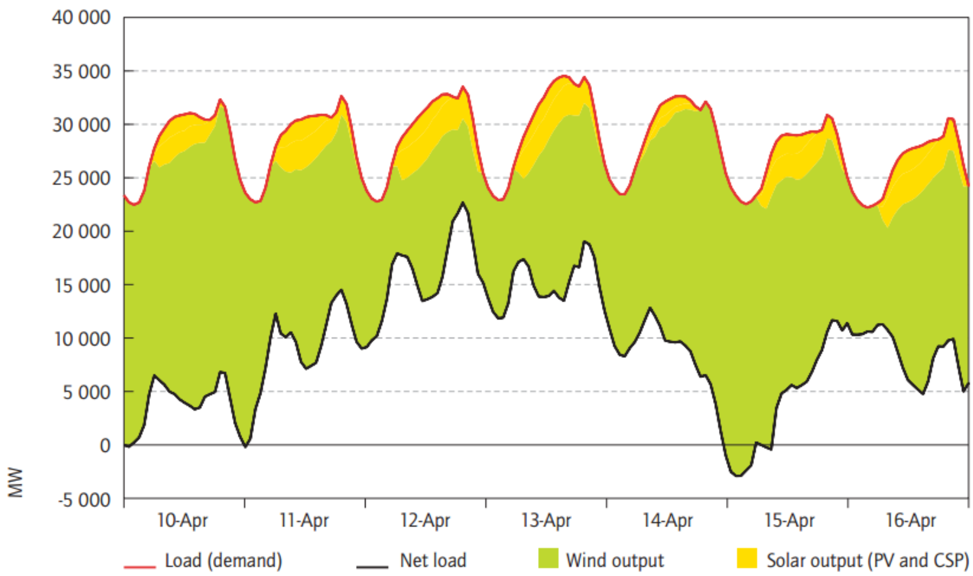


Figure 7 - Net load experiencing increased ramp rates due to VREs
(Source: GE Energy, 2010)

Ueckerdt et al. (2013) conclude that the flexibility effect does not induce significant costs and, in accordance with Grubb (1991) and CONSENTEC (2011), neglect it in their analysis. In their most recent report *The Power of Transformation* (2014), the IEA also reach this conclusion when considering a test case which adds 45% VRE without altering the existing system. In short, the flexibility effect makes only a small contribution to cost increases.

2.4.1.4 Utilisation effect

VRE technologies are always dispatched when available because they either have very low (approximately, zero) variable costs and are the cheapest available technology or because regulations stipulate priority dispatch (à la the EC's *Renewables Directive 2009/28*). This reduces full-load hours of conventional units. While this is not a problem *per se* dispatch of VRE is often economically inefficient and reduces overall welfare.

This loss of welfare is often represented by the *residual load duration curve*[12] (see Figure 8). Firstly though, it is important to distinguish the time frame we are speaking about since short-term and long-term effects are different (Hirth, 2012a; NEA, 2012). In the short-term, the system is taken as given as though VRE were added over night; hence, VRE integration sees little or no change in existing generation investments. In modern electric power systems installed capacities are such that an addition of VRE does not usually require additional investments to maintain security of supply.

Conversely, in the long-term, the system adapts to VRE sources by completely changing the generation mix. Low-cost base load generation is replaced by more flexible (and generally expensive) gas generators capable of load following and profitability despite reduced load hours. This long-term situation is often described as a blank slate in which the conventional energy mix is matched to the installed VRE such that security of supply is maintained and investors receive a return on their investment. Taking a long-term approach when considering profile costs nullifies any argument which states that existing generators are sunk costs and therefore do not count towards VRE integration costs (NEA, 2012).

Residual load curves can be used to represent both the short and long-term system effects of VRE. Figure 8 shows that in the short-term, reduced load hours most affect units with high marginal costs like gas and fuel oil peakers when 30 % wind is incorporated into the generation mix. Three things are noteworthy:

1. The slope (grey line) of the RLDC is steeper implying that a higher portion of the residual load occurs over a shorter period of time.
2. The full-load hours have been reduced. This will increase LCOE/generation costs of the residual system because existing generator utilisation (energy output or full-load hours) has been reduced. Units are likely to respond by increasing prices to recover their capital costs.
3. There has been only a small reduction in peak power demanded; implying a low capacity credit for the wind power and the need for large backup capacity.

[12] The *load duration curve (LDC)* is an ordered representation of demand from greatest to least over a given time period (typically one year, 8760 hours). Knowing the fixed and variable costs of generators, this load can then be dispatched using the screening curve technique (see Batlle and Rodilla, 2011). The *residual LDC* is the original LDC minus power supplied by VRE units.

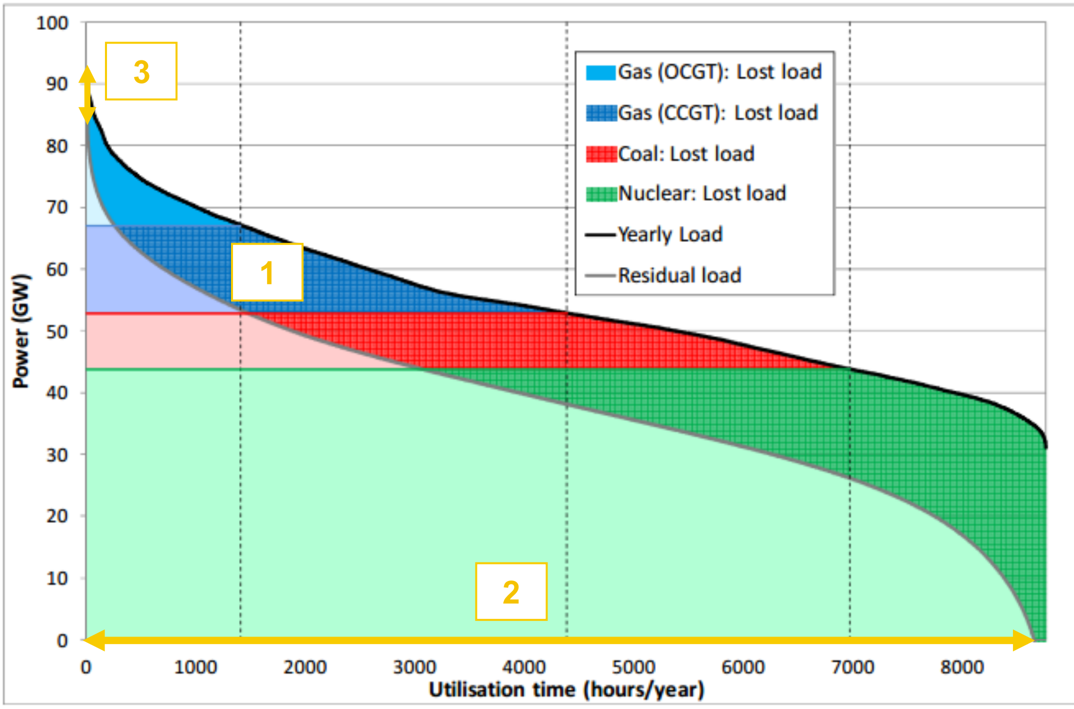


Figure 8 – Short term impact of the utilisation effect
(Source: Keppler and Cometto, 2013)

Having no recourse to immediately change the system generation mix, existing units are met with significantly reduced loads. It is primarily the peaking and intermediate units that are affected by VREs' low marginal cost electricity. This reduces the total energy produced by peak and intermediate units through the *compression effect*[13] and lowers wholesale electricity prices due to the *merit order effect*[14] (Keppler and Cometto, 2013).

In the long-term, however, the generation mix optimally adjusts to the reduction of prices. Figure 9 shows the results of modelling two combined cycle gas units (an Integrated Gas and a Natural Gas Combined Cycle) incorporating 2 500 MW of offshore wind in a simulation which accounted for environmental externalities (Kennedy, 2005). The upper graph depicts the two units as they would ordinarily be dispatched and the lower shows the incorporation of wind power. Four things are noteworthy between the two graphs:

1. The slope (blue line) of the RLDC is again steeper in the second graph implying that a higher portion of the residual load occurs over a shorter period of time. Thus, a higher share of (more expensive) peaking capacity is required.
2. The full-load hours have again been reduced. This increases LCOE generation costs of the residual system because existing generator utilisation (energy output or full-load hours) has been reduced. This full-load hour reduction impacts high capital base load generators the most, shifting the generation mix toward flexible peaking and intermediate sources.

[13] *Compression effect:* "electricity produced from sources with low marginal costs reduces the operating hours and thus the load factor of conventional power plants." (NEA, 2012)
[14] *Merit order effect:* see Box 2

3. Again, there has been only a small reduction in peak power demanded; implying a low capacity credit for the wind power and need for backup power.
4. The lightly shaded "dump" region (bottom right) represents over supply. This energy is wasted/spilled/curtailed if it cannot be stored or exported via interconnections and thus, capital costs increase because wind generation is inefficiently matched to demand.

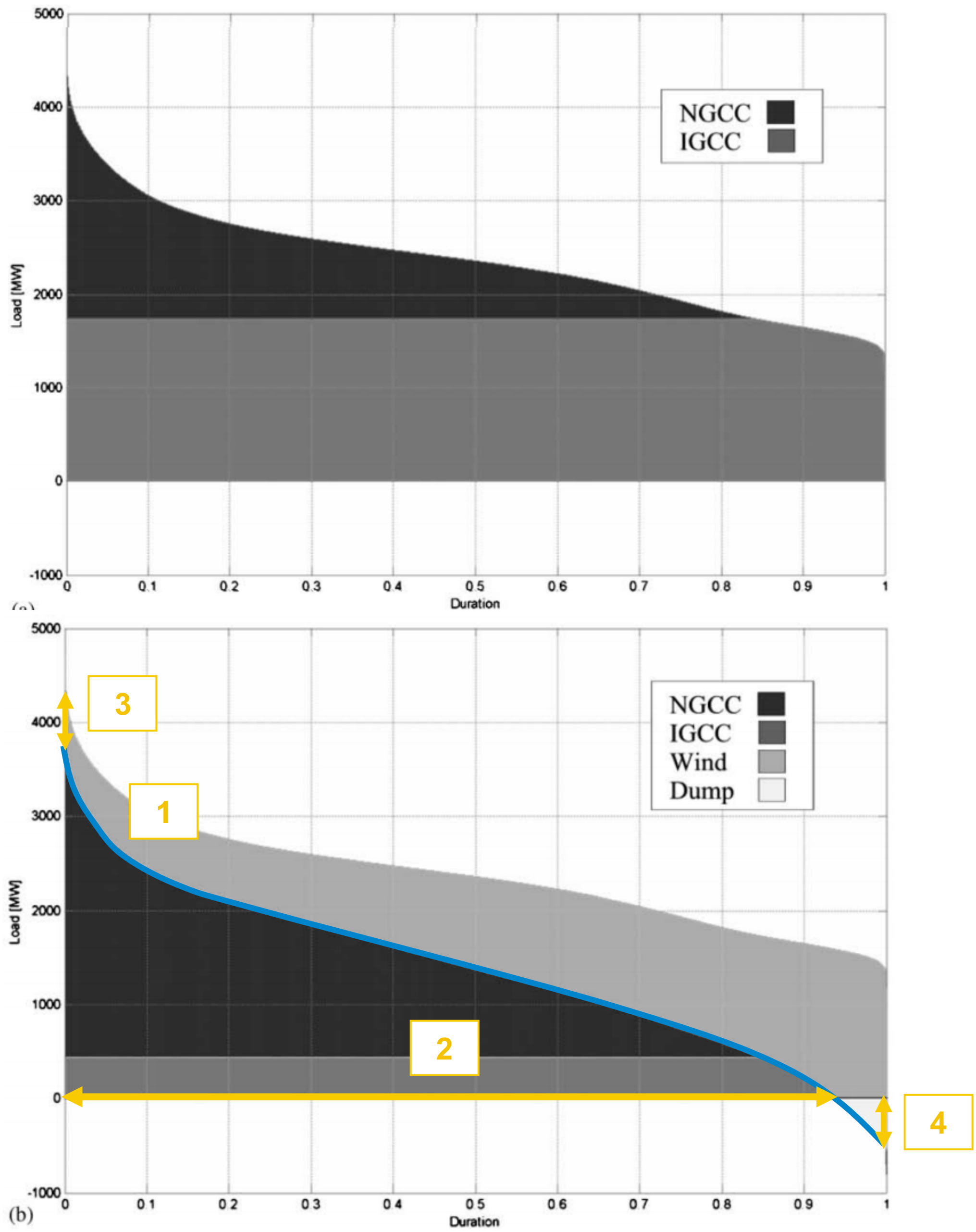


Figure 9 – Long-term impact of the utilisation effect
(Source: Kennedy, 2005)

These curves demonstrate that in the long-term integrating large amounts of wind into an electric power system drastically alters the dispatch of existing generators. Reduced load hours of existing units increase average costs of the residual system because underutilised capital incurs costs that must be remunerated (see Equation 1 - *LCOE* in Section 2.1, noting that decreased energy supplied increases costs). Figure 9 demonstrates that in the long-term, this increase in costs has the greatest impact on base load capital intensive technologies like nuclear units which benefit from economies of scale by operating almost year round. Eventually, these capital intensive generators will be replaced by more flexible units with lower capital costs, albeit much higher operating costs. In the long-term, system costs will therefore increase, though a better adapted generation mix means long-term system costs are less than short-term system costs (Hirth, 2012a; Keppler and Cometto, 2013). Although the simulation depicted in Figure 9 is obviously a relatively simple illustration (even using an IGCC to reflect operations of a base load plant), Nicolosi (2012) confirms this effect using real data from the Texan grid, ERCOT.

By examining both short (Figure 8) and long-term residual load curves (Figure 9) it is obvious that VRE integration impacts the revenues of existing generators. In the short-term, peak and intermediate generators are hardest hit because of reduced full-load hours and a reduction in average electricity prices. In the long-term as the system is able to adapt, these same two effects alter the generation mix entirely shifting from low-cost base load technologies to more flexible and more costly, intermediate and peaking plants. Critically, in neither case do VREs significantly reduce capacity requirements. This is the fundamental driver of profile costs.

BOX 2: THE MERIT ORDER EFFECT

The merit order effect describes the reduction in wholesale electricity prices resulting from additional, low variable cost renewables. These renewables shift the generation supply curve (a.k.a. the merit order curve) towards the right when low variable cost renewables are integrated into the electricity market, lowering the wholesale price (Figure 10). Price reductions in consumers' bills will depend on the competitiveness of consumer (retail) markets.

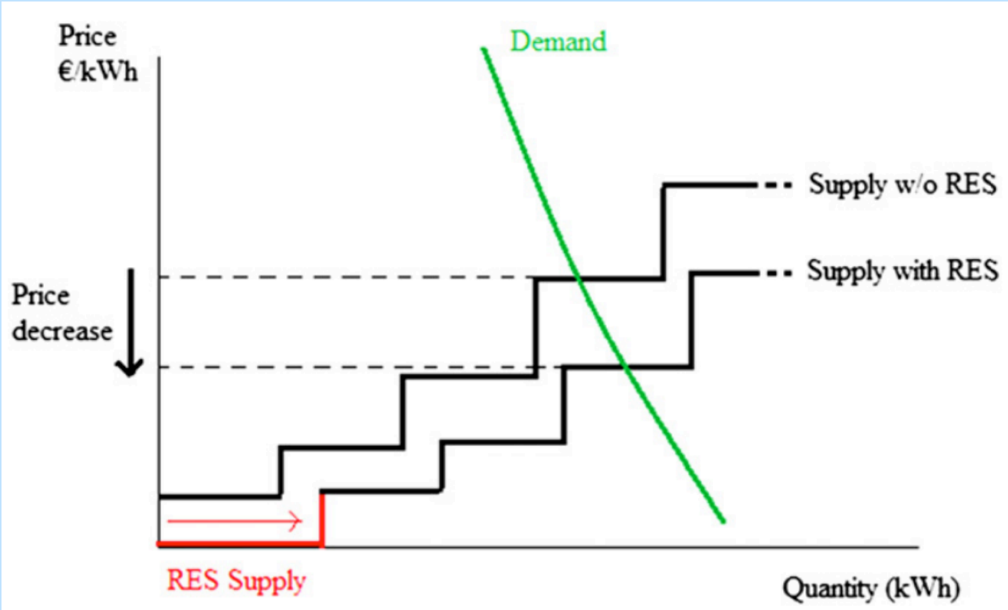


Figure 10 - The merit order effect
(Source: Moreno et al., 2011)

Both proponents and sceptics of the merit order effect's welfare improving characteristics admit that wholesale electricity prices (generators' profits) are reduced in the short term (Würzburg et al., 2013 including very comprehensive literature review; Sáenz de Miera et al., 2008; Sensfuss et al., 2007; McConnell et al., 2013; McConnell, 2013; Cludius et al., 2013; Hildmann et al., 2014; Nelson et al., 2012). While a convenient political tool for selling RES support schemes to the voting public, lower prices are simply a transfer of wealth from producers to consumers who benefit from a lower price (Nelson et al., 2012; Hildmann et al., 2014; Gelabert et al., 2011).

However, in most markets where renewable implementation is encouraged, RES generators are frequently isolated from the market by fixed feed-in tariffs (FITs). While the effect of such policies on general electricity costs forms the basis of this entire study, some authors have undertaken investigations to determine whether there can be a net positive benefit from FITs and merit order induced retail price reductions. That is, from the consumer perspective, FITs are paid as an additional surcharge in electricity bills. If this value is less than the reduction in price there has been a net positive benefit for consumers. Sensfuss et al. (2007), Sáenz de Miera et al. (2008) and McConnell et al. (2013) modelling Germany, Spain and the Australian National Electricity Market, respectively, all conclude that in the short term consumers receive a net positive benefit. For example, McConnell et al. (2013) model 5 GW of solar energy at a similar density per capita as installed in Germany and find that wholesale prices would have been reduced by more than A$ 1.8 billion over 2009-10.

In the long-term however, welfare benefits are heavily contested. Transferring profits from producers to consumers reduces incentives to invest in generation capacity and increases security of supply risks. Reduced wholesale prices reduce potential profits and therefore inhibit future generation investments as returns are diminished via the merit order effect. Indeed, even RES technologies will have an increasingly diminished market value with increased renewable installations and subsequently reduced spot prices (Nelson et al., 2013; Hirth, 2012b). Many have suggested that alternative remuneration mechanisms, increased spot market participation (Hildmann et al., 2014) and/or capacity markets may be necessary to maintain the desired security of supply because of insufficient returns for conventional generators. In any case, if insufficient investments in future capacity are made, higher prices can be expected in future periods (Gelabert et al., 2011). Accordingly, any consumer benefit from the merit order effect today is only transitory (Nelson et al., 2013). As the NEA (2012) report concludes, "integration of renewable energy does not significantly affect the long-term market price of electricity."

In conclusion, the introduction of RES into the electricity market reduces spot prices to a price lower than they otherwise would have been. This reduces profits for all generators, including any market price exposed renewables, and transfers wealth from producers to consumers in the short term. In the long-term, reduced wholesale prices reduce incentives to invest, presenting problems for future investment and security of supply. Accordingly, the merit order effect is only a transitory phenomenon as capital costs will need to be remunerated in the long-term (Hirth and Ueckerdt, 2012). Therefore, under the assumption of perfect and complete markets where market value is equal to marginal economic value, the merit order effect represents a reduction in value, i.e. an integration cost.

2.4.2 Balancing costs

Balancing costs arise because output from VRE is uncertain. Outputs from any wind, solar or wave source are only as accurate as the weather forecast. Thus, costly forecast errors and intra-hour variations in VRE output must be managed by backup generation. This generation includes spinning reserves, part-loading thermal generators, increased ramping and cycling, increased on/off operation and reserve capacity (Hirth, 2012a and Pérez-Arriaga & Batlle, 2012). Therefore, in the market context "forecast errors increase the demand and utilisation of balancing capacity... [where] the price of balancing energy is the market representation of the costs of uncertainty" (Hirth, 2012a).

Curtailing wind provides one alternative for managing unexpected wind outputs and subsequent ramping rates, provided the cost of curtailment is less than part-loading costs and flexible unit operating and/or investment costs. However, in a market context this solution presents difficulties regarding cost causation and attribution of payment. In today's context of regulated support for wind generators based on energy input (i.e. payment per MWh) this is clearly an unattractive proposition for wind producers.

As with all integration costs, balancing costs are dependent on the system in which VREs are installed. The IEA (2011) provides a concise summary of contextual elements that alter balancing costs, as detailed in Table 1.

Table 2 - Elements of the electric power system affecting balancing costs

EPS Contextual element	Increases/Reduces costs
Greater capacity of installed VRE	↑
Greater capacity of existing flexible sources in the electric power system	↓
Greater geographical distribution of VRE	↓
More interconnections with other systems	↓
Greater capacity of demand side response	↓
Greater accuracy of forecasts	↓
Shorter gate closure time	↓
Increased VRE curtailment	**Usually,** ↓

Source: IEA, 2011

2.4.3 Grid costs

Grid costs arise because VRE generators have a high location-specificity (Dale et al., 2004; Hirth, 2012a; Ueckerdt et al., 2013; DeCarolis and Keith, 2006). Often, good renewable resources are located far from load centres meaning:

1. High investment costs to connect to the grid;
2. Mismatched transmission investments due to smaller capacity generators that reduce economies of scale; and,
3. Potential congestions during periods of high production or in poorly meshed grids.

The first problem arises because the distance to reach remote primary VRE sources is typically much greater than if a conventional generator was installed. As such, the extension of existing infrastructure in order to connect VRE generation induces substantial system costs that would not be incurred with the installation of a conventional generator.

Secondly, capacities of VRE installations normally range from tens of megawatts to a few hundred and are, in even the largest case, usually smaller than a conventional generator. By contrast, high-voltage transmission lines are most efficiently constructed at scales of 1 GW or more. Lines constructed at this capacity are therefore grossly oversized as they wait for additional generation to come online (MIT, 2011).

Finally, when there are significant VRE installations, congestions may arise in moments of high production that can be exacerbated by a radial connection installed because the primary source is far from pre-existing infrastructure. High levels of wind production in Northern Germany for instance create frequent congestions in transferring this power to load centres in the south (Barth et al., 2008). Increased distances also mean increased power flows and network losses. Yet, even the retirement of conventional generators closer to load centres does little to offset these transmission costs from location specific VRE (Dale et al., 2004).

Unfortunately, when assessing grid costs in the European context, it is very difficult to calculate congestion costs because almost all countries apply a single national electricity price, except Norway and Sweden who apply zonal pricing. This means asides from geographically differentiated tariffs (Hirth, 2012a), there are no prices which may be used to calculate congestion costs.

Furthermore, Dena (2005) points out that reactive power requirements may increase with growing VRE installations, necessitating increased investment in ancillary devices like capacitors, inductors and converters. However, distributed generation (i.e. generation connected to the distribution network, e.g. localised wind farms or solar PV), may be able to provide these services at lower cost than conventional generators (Passera, 2014).

Distributed generation, however, raises a second problem. As is common in academic literature, Ueckerdt et al.'s (2013) and Hirth's (2012a) research considers only VRE connected to transmission networks and not distribution networks. The complexity of adding distribution analysis to a system wide cost calculation can be immense. Yet, this may be a significant oversight given VRE is often connected in large proportions as distributed generation.

Power systems vary in the amount of distributed generation connected: 5 % of total installed capacity in California (KEMA, 2011), 21 % in Spain (Reneses, 2014) and 48 % in Germany (EY, 2013). However, VRE usually constitute a considerable portion of distributed generation. German PV units, for instance, comprise over 40 % of German distributed generation (≈ 32/86 GW; EY, 2013). Therefore, distributed generation connected VRE is significant because it reduces transmission network costs, principally by avoiding expensive line extensions between generators and load. On the other hand, additional costs concerning power quality, voltage levels, power flow directions or reactive power may be induced by these distributed generation installations. Thus, because distributed generation connected VRE is already present in amounts that affect grid costs, further analysis may be justified in order to determine these costs.

2.5 RECAP

Total costs of VREs therefore include generation costs typically represented by LCOEs and integration costs which include profile costs, balancing costs and grid costs. Profile costs caused by the variability of VREs firstly increase load following and ramping demands on conventional generators and secondly, reduce the utilisation of existing capital in the system, supressing prices via the merit order effect which, in the long-term, requires a more flexible and expensive conventional generation fleet. Balancing costs arise because of uncertainty and mandate increased use of costly balancing reserves. And finally, grid costs exist because of the location-specificity of primary VRE sources that necessitate additional grid connection or reinforcement that is usually inefficiently sized, far from load centres and can increase network congestion during moments of high production.

Figure 11 summarises these costs and their causes.

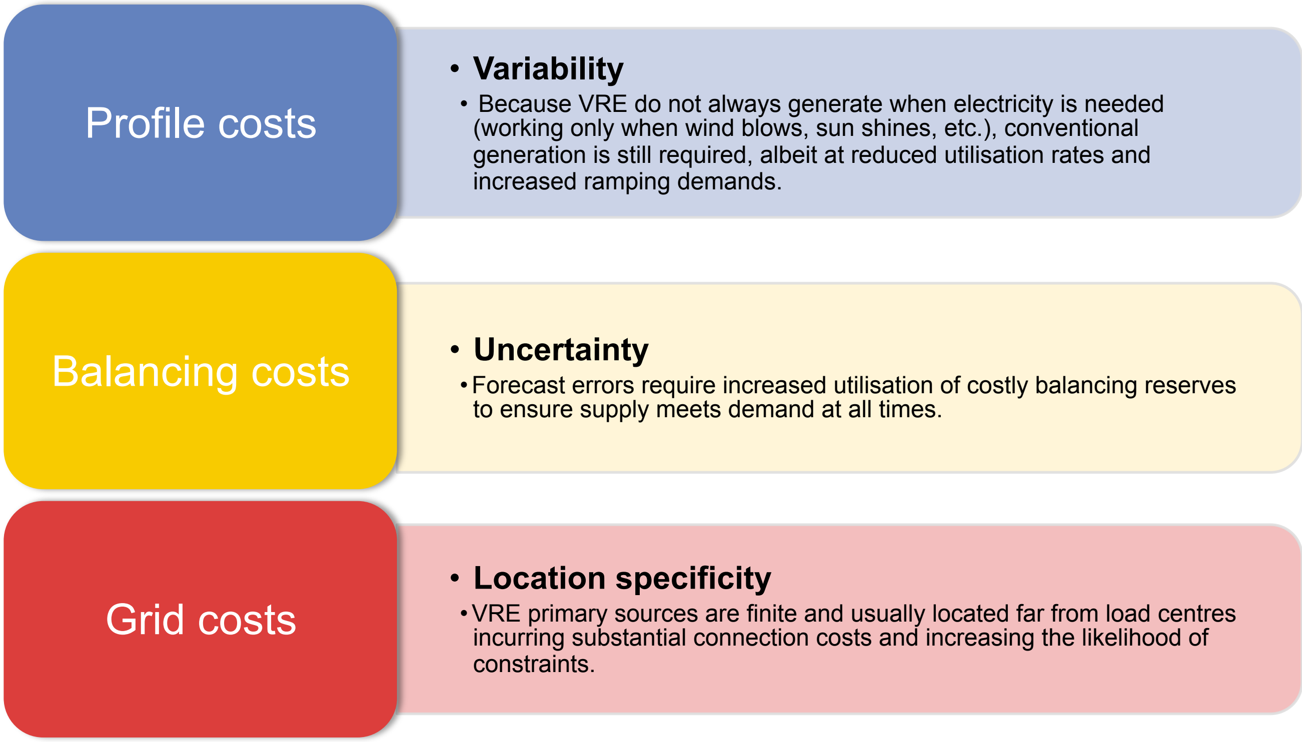


Figure 11 - The three components of integration costs

2.6 COST ESTIMATES FROM THE LITERATURE

2.6.1 Profile costs

There are not many studies that explicitly estimate profile costs, although in Hirth (2012a) there is a comprehensive literature review that assesses 30 odd papers with implicit estimates. Hirth (2012a) concludes that profile costs comprise around 15 — 35 €/MWh at 30 % penetration. Ueckerdt et al. (2013) find profile costs to be around 30 €/MWh at 30 % and the NEA (2011) claims "adequacy costs" (their equivalent for profile costs) amount to 5.60 – 13.20 €/MWh at 14 – 33 % penetration. These results are summarised in Figure 12.

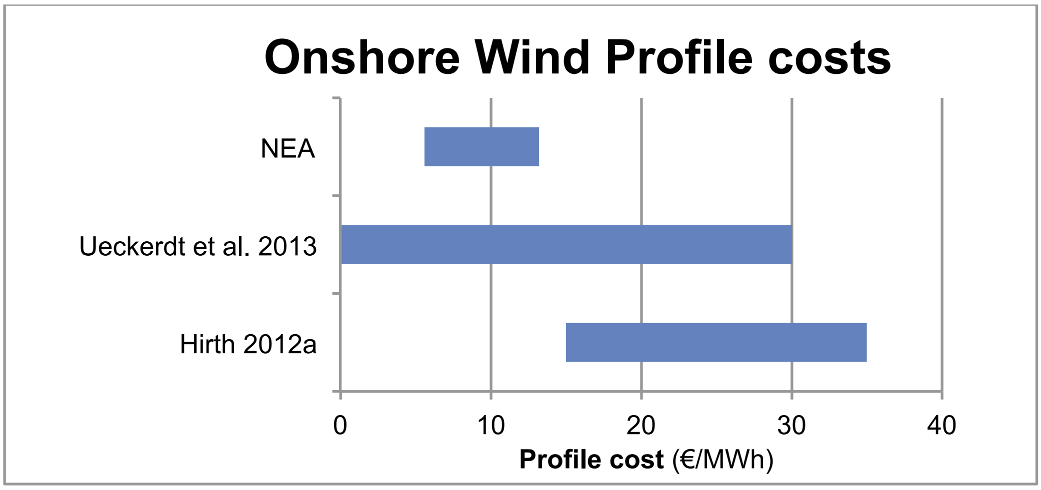


Figure 12 - Profile costs from the literature

2.6.2 *Balancing costs*

Balancing cost estimates have been well researched and several of the studies used in this report synthesised multiple prior investigations. Figure 13 summarises the information found in these reports with further description in the following paragraph.

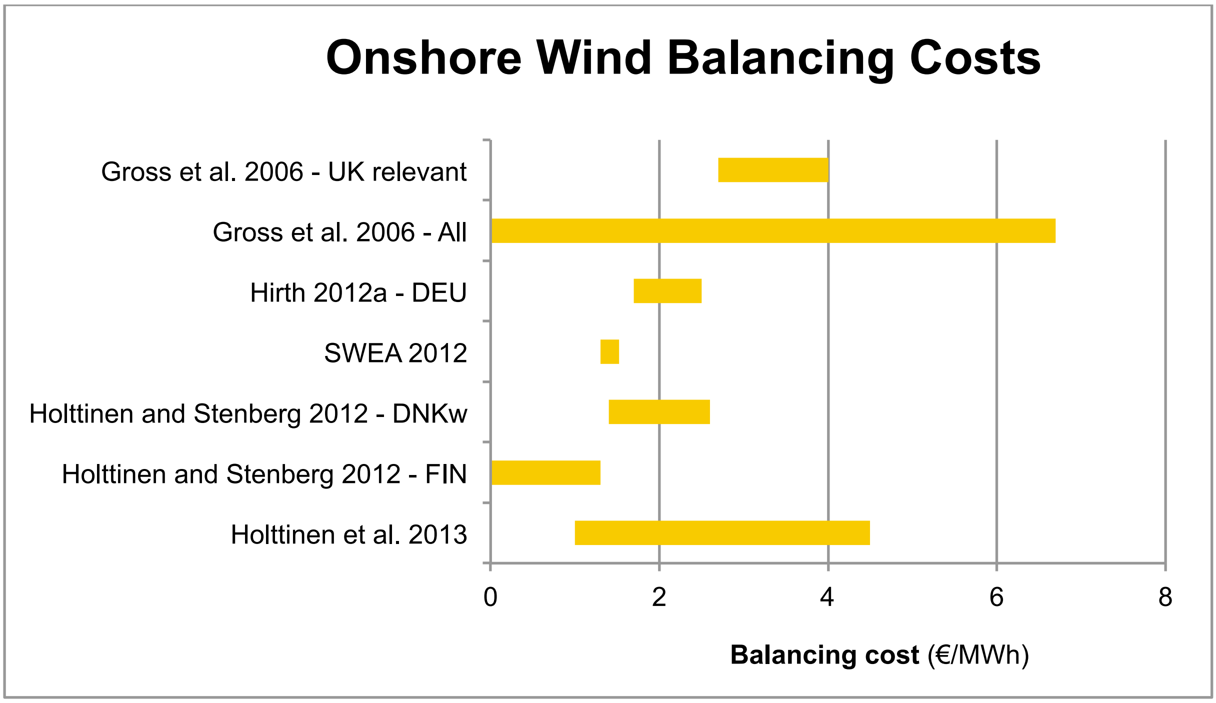


Figure 13 – Balancing costs from the literature

Perhaps the most comprehensive overview is provided by Holttinen et al. (2013) in their work for the IEA's *Wind Task 25* where over 16 studies are synthesised. They estimate costs to lie between 1 – 4.50 €/MWh or 10 % or less than the wholesale value of wind at penetration rates[15] up to 20 % of total gross energy demand. Interestingly, Hirth (2012a) points out that in hydro dominated systems in Finland, Sweden and Norway as assessed

[15] *Penetration rate* or *penetration level* is widely used in the literature, albeit inconsistently. It is here defined as the percentage of gross energy demand.

by Holttinen et al. (2011) balancing costs are less than 1 €/MWh. Another estimate for Finland however, estimates balancing costs slightly higher at 1.30 €/MWh (Holttinen and Stenberg, 2012). In Western Denmark, balancing prices range from 1.40 – 2.60 €/MWh at wind penetration of 24 % (Holttinen et al., 2011) in a market based analysis. According to the Spanish Wind Energy Association (2012) balancing costs in Spain have decreased since 2010 from 1.53 €/MWh (2010), 1.40 €/MWh (2011) to 1.30 €/MWh (first 3 months of 2012). Using statistical techniques, Grubb (1991) estimated balancing costs at approximately 3.6 % of the value of electricity. Hirth (2012a) assessed German balancing costs for wind to be between 1.7 – 2.5 €/MWh from 2008 – 2011. In their comprehensive review, the UK Energy Research Centre under Gross et al. (2006) find balancing costs rarely exceed 6.7 €/MWh and within the island nation are around 2.70 – 4 €/MWh.

The EU's GreenNet initiative for Germany and Denmark reveals that balancing costs increase when a neighbouring country installs more wind (Holttinen et al., 2011). Figure 14 from Holttinen et al. (2013) summarises many of these costs as published in *Wind Task 25*.

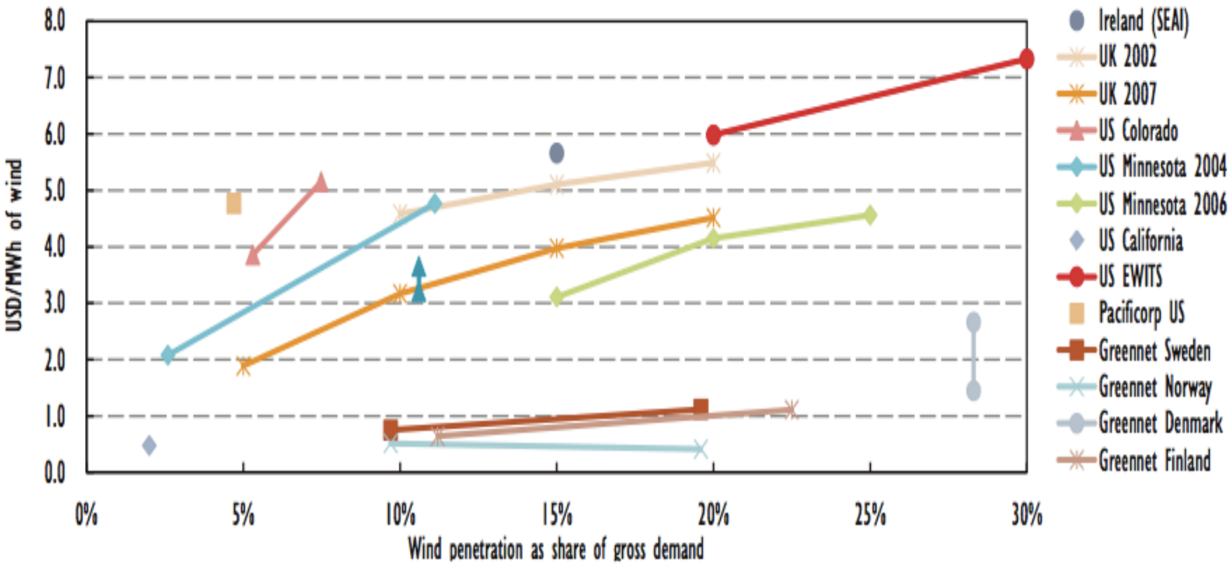


Figure 14 - Balancing costs from the IEA's Wind Task 25
(Source: Holttinen et al., 2013)

2.6.3 Grid costs

Estimates of grid costs resulting from wind integration are rarely quantified and always difficult to calculate. Academic literature often discusses their presence, cause and ramifications though seldom attempts to quantify them. The complexity of high grid connection and reinforcement costs, mismatched transmission and unidentified congestion costs makes this understandable, however, grid costs are a contributing factor that requires inclusion.

The most comprehensive attempts to assess these costs are probably Holttinen et al.'s (2013) which used TSOs' long-term transmission planning studies to estimate grid costs between 0 – 270 €/kW and Mills, Wiser and Porter's (2009) report for Berkley Labs which examined 40 transmission planning studies broadly estimating grid costs pertaining to wind at US$ 0 – 79/MWh (0 – 59 €/MWh) with a median value of US$ 15/MWh (11 €/MWh) and most studies claiming costs below US$ 25/MWh (19 €/MWh). Other literature suggests grid costs range from 8 – 12 % of plant-level investment costs (≈ 5.20 – 7.80 €/MWh).

BOX 3: INTEGRATION COSTS FOR CONVENTIONAL GENERATORS

While integration costs are frequently assessed for VRE technologies, conventional technologies also impose system wide costs (Barth et al., 2008; Hirth, 2012a; Milligan et al., 2012). The usual example imagines installing a large base load generation source (e.g. a nuclear unit) that increases the cycling and load-following demand on existing units by forcing generators which formerly operated as base load up the merit order curve. Additionally, if a generator larger than any existing unit is installed on the network, this will increase the contingency costs usually managed via the *N-1 criterion*. This criterion implies that sufficient reserves must be maintained in case the largest generator fails (the "1" in N-1). Therefore, expensive reserves must be available to support this generator which effectively receives a subsidy since reserve costs are usually socialised (Milligan et al., 2012).

However, integration costs even exist for flexible gas units. Gas contracting significantly impacts the flexibility of a given unit because contract terms and conditions alter units' economic operation, often limiting flexibility. Milligan et al. (2012) point out that this is because gas is usually nominated day-ahead, committing generators to operate (or not) at a time scale much less flexible than they are physically capable of. Indeed, the problem is compounded on weekends when schedules are set on Friday for Saturday, Sunday and Monday. Furthermore, gas generators may be restricted by take-or-pay clauses within their contracts that cause them to generate even though it would be inefficient to do so except for the take-or-pay clause. In summary, contractual and scheduling obligations limit the flexibility of gas units, increasing inefficiencies and therefore integration costs.

The nexus between gas and electricity networks imposes additional integration costs for gas generators. In particular, cold weather increases demand for gas and electricity at the same time. In the recent *January Freeze* in North-East USA, power prices were given special exception to exceed the US$ 1000/MWh price cap. The high demand for heating from both gas and electric sources drove prices to unprecedented levels, with gas prices dramatically impacting production costs for gas generators.

Integration costs apply to conventional generators and not only to VRE sources.

3. METHODOLOGY

3.1 COST ANALYSIS METHODS

Understanding the total cost of VREs requires comparison of the generation plus the integration costs in an electric power system. Isolating the integration component by cost analysis demands comparison of system costs with and without VRE sources (Milligan et al., 2011; Ueckerdt et al., 2013; Hirth, 2012a). However, one difficulty with determining these integration costs is the definition of the "without case" (Milligan et al., 2011).

3.1.1 Flat energy block

Many integration cost analyses implement a *flat energy block* or *proxy resource* which represents the VRE supply, fixed without uncertainty or variability. However, this flat block also captures the value of the VRE. For example, we have already seen that typically more wind is delivered in off-peak hours and less during peak hours (Section 2.4.1). Therefore, any constant supply of wind energy in a flat block would likely *over*value the energy produced because more power is supplied during peak hours than would realistically be the case. Milligan and Kirby (2009) prove that this additional value is non-trivial.

3.1.2 Total system costs

Another alternative is to calculate a system cost for VRE, removing the proxy resource from the *without VRE scenario* and only adding the VRE to the *with VRE scenario*. Unfortunately, this method does not discriminate integration costs from any change in overall production costs, e.g. saved fuel. However, it does not suffer the same shortcoming of overvaluing variable energy. Given the subject of this report and the general interest in knowing integration costs, we shall yet consider other alternatives.

3.1.3 Load reduction

Ueckerdt et al. (2013) propose implementing the proxy resource method, albeit as a load reduction. This method imagines the VRE supply as a perfectly reliable resource exactly matched to load both spatially and temporally. Thus, there are neither induced congestions nor any requirements for backup generators because demand is perfectly satisfied by every MW supplied from the proxy resource. That is, the proxy reduces the load by the nominal capacity of the VRE under investigation. The residual load thereby maintains the exact ramping, full-load hours and reserve requirements, allowing integration costs to be calculated by comparison with a second scenario which includes VRE.

3.1.4 Perfect base load benchmark

Finally, Hirth (2012a) proposes comparing VRE with a "constant and perfectly reliable source of electricity... located at average distance from consumers." Thus, this perfect base load benchmark takes a physically comprehensible form as a generator (cf. load reduction). While profile and balancing costs are compared to a perfect benchmark, grid-related costs are only positive if the VRE source is located greater than average distance from consumers. This therefore relativises grid-related costs more so than the load reduction method yet without necessarily discounting any comparisons which might be made between technologies.

3.1.5 Computer modelling

Ordinarily, integration cost studies utilise computer based models. These models are useful for forecasting future impacts of VRE integration on a system with minimal or no existing VREs. They allow great flexibility in testing almost any scenario desired by simply altering input numbers. Impacts of anything from 1-100 % VRE can be tested using only a desktop PC. However, as with all models, the quality of the output is only as good as the quality of the input. Such input data can be notoriously difficult to find and, when available, so large that various approximations are necessary to simplify the model. Furthermore, computer models demand significant time and expertise to create.

3.1.6 Market modelling

Integration cost calculation is possible using market data. High levels of VRE penetration and market liberalisation over the past decade mean there is a plethora of real-life data available. Indeed, each cost element: profile, balancing and grid costs with their respective causes: variability, uncertainty and location specificity are traded on markets. After Hirth (2012a) profile costs are simply the difference between the time-weighted spot price and the VRE energy-weighted spot price; balancing costs represent uncertainty which is traded on intraday and balancing markets; and grid costs represent spatial variation determined by locational marginal prices (LMPs) or zonal prices and where non-existent, geographically discriminated grid fees. Thus, by undertaking relatively simple cost analyses using market data integration costs can be determined for a specific power system, e.g. France, Spain, ERCOT, etc.

Furthermore, market analysis avoids estimations of VRE generator operation, instead using actual historic data. This ensures realistic operation is modelled and with sufficient detail to avoid estimation errors induced by computer modelling.

Market analysis is based on the fact that in perfect and complete markets the marginal economic value applicable to society is equal to the private market value, as proven in Ueckerdt et al. (2013). Thus, integration costs are equal to a reduction in VRE market revenues. If fully internalised payment of these costs would be made by VRE investors, however, if non-market related subsidies like feed in tariffs are used, integration costs are socialised (Hirth, 2013).

3.1.7 Cost analysis conclusion

This analysis will therefore follow the work of Hirth (2012a) implementing a perfect base load benchmark using market data. This benchmark generator will be represented by the time-weighted hourly day-ahead spot price.

3.2 METHODOLOGY JUSTIFICATION

Market based techniques simplify calculation of integration costs and implement real-life data to determine costs. The profile and balancing costs methodology proposed by Hirth (2012a) and Ueckerdt et al. (2013) is adopted on a case-by-case basis in four different European countries for 2012 and 2013 in this paper. Grid costs will be calculated using country specific data, from TSO planning reports. The methodology suggested by the above authors requires either geographically differentiated tariffs or locational or zonal pricing. European markets apply a single electricity price system wide. Locational or zonal pricing does not apply in the European market. Hence, to estimate grid costs methodologies suggested by Mills, Wiser and Porter (2009) and Holttinen et al. (2013) are adopted by considering TSO reports from national operators. Specifics of each cost calculation are detailed in following sections.

Onshore wind will be used as the VRE cost comparison technology. There are several reasons for this choice. Firstly, onshore wind is by far the most widely installed and cost competitive VRE technology currently available. In a recent NEA study (2011), onshore wind was found to have the lowest integration costs and is therefore the "best of the best" when it comes to comparing VRE integration costs. Overall integration costs for onshore wind will therefore provide a lower bound for VRE integration costs.

Secondly, onshore wind has already been installed in significant quantities in several countries. This means that effects of VRE integration are felt in very real ways in these power systems. Despite nuanced differences, investigating onshore wind integration costs will highlight future impacts from increased solar or wave based technologies. Future wind installations are also anticipated worldwide (Holttinen et al., 2013) and better understanding the effects today will avoid complications and inefficiencies in the future.

Finally, the abundance of wind generation means market data is widely available for the technology. TSOs and market operators publish not only wind feed-in data but also wind forecast data. Although both system and market operators are introducing data for other technologies like solar, these databases are not yet comparable to those for wind.

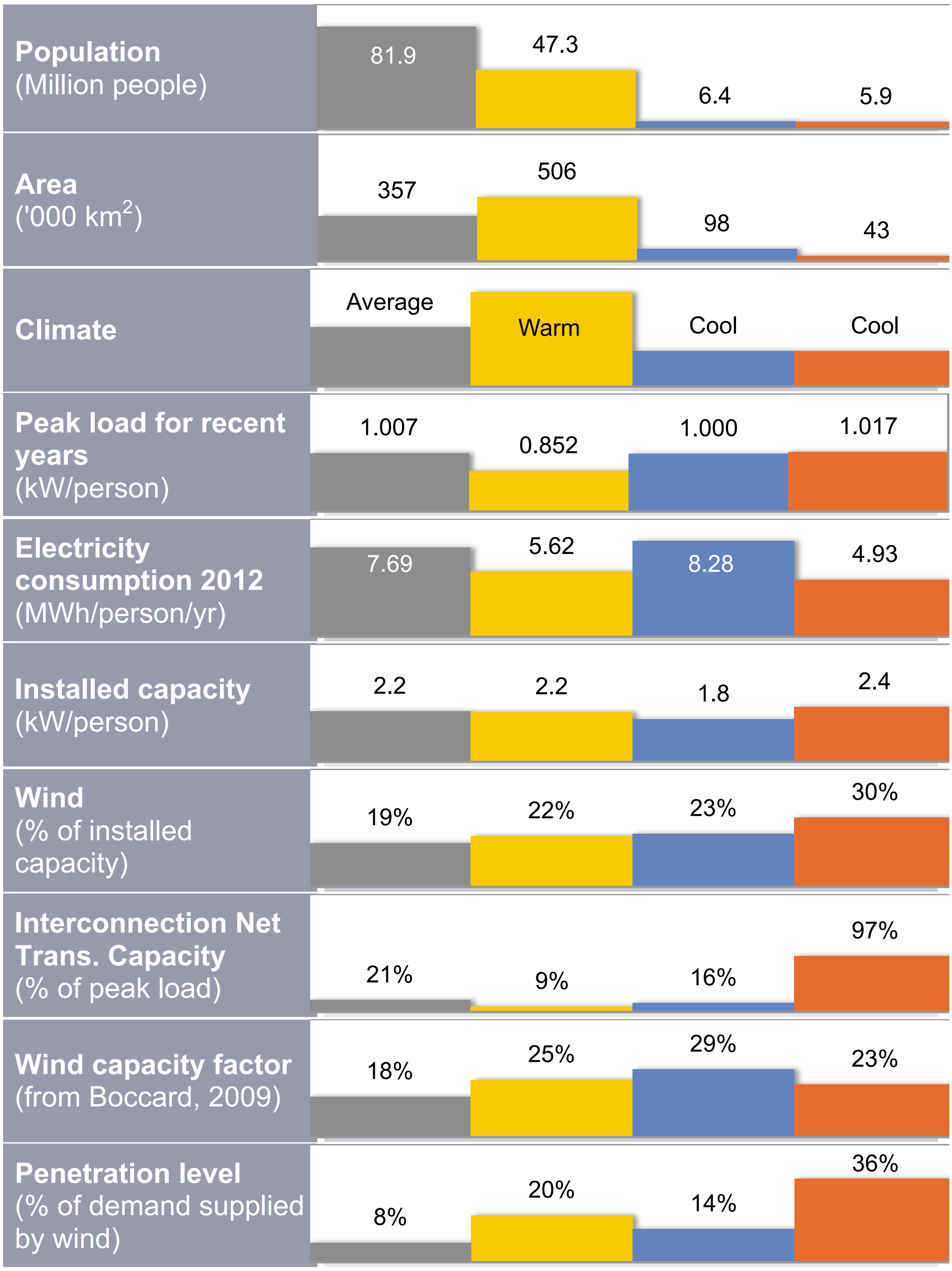
The years 2012 and 2013 were chosen to define the VRE costs *today*. This enables a cross-section comparison between the four power systems rather than an investigation of cost variations through time. In addition, not all relevant data was available from TSOs or market operators before 2012.

3.3 COUNTRY COMPARISONS

This study uses four countries: Germany, Spain, Ireland and Denmark, each with high onshore wind penetration, albeit very different power systems and overall geographic and economic features. Table 3 details the pertinent features of each country and their respective electric power system. It is obvious from this table that the systems investigated differ in many respects and it is anticipated that integration costs will also take different values. More detail for each country is available from Appendix A.

Table 3 - Country comparisons

	Germany	Spain	Ireland	Denmark



One particularly interesting feature of the systems to compare is the generation mix available in each country. Figure 15 demonstrates that across the four countries there is remarkable difference in generation fleets. In particular, it is worth noting that flexible hydro reserves supply a significant portion for the demand in Spain, and although present, are only utilised (and available) in small quantities in Germany and Ireland. The use of gas generation in Ireland dominates all other technologies. International power imports are not shown in Figure 15 though a relevant proxy to recall is the Interconnection Net Transmission Capacities (NTCs) shown in Table 3 and Figure 16.

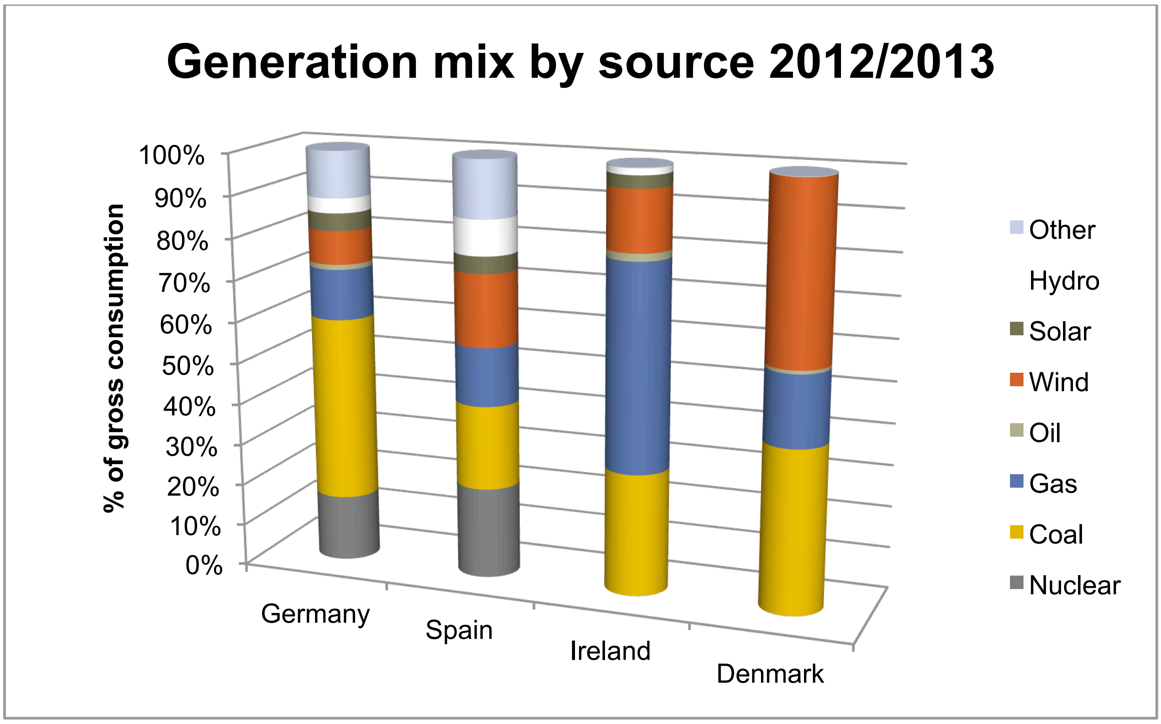
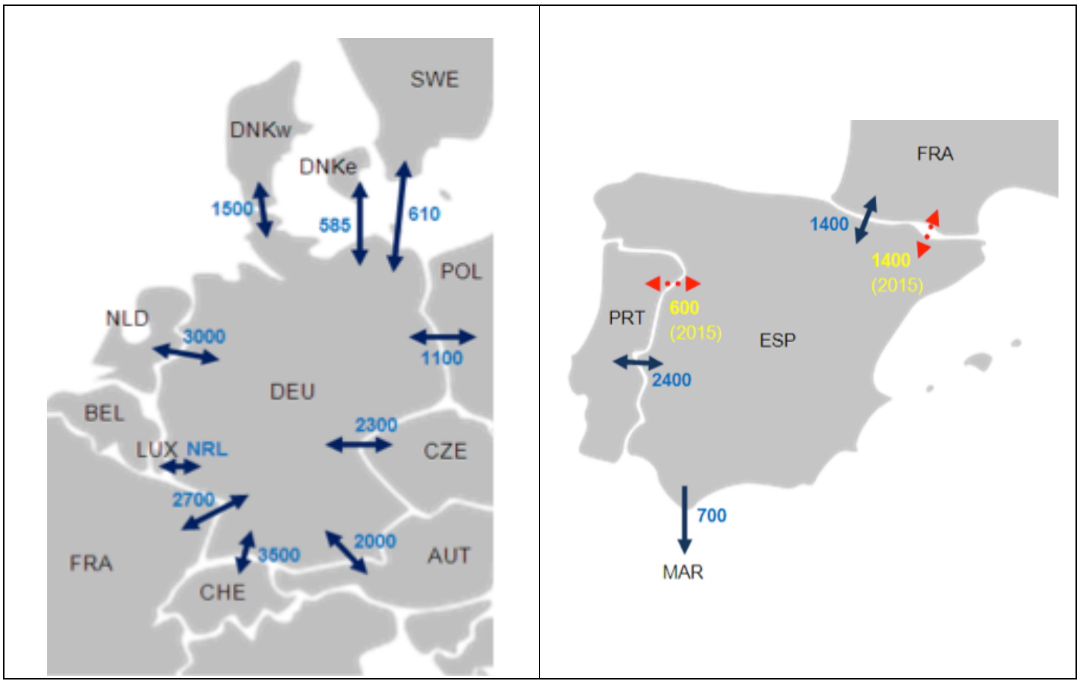


Figure 15 - Generation mix by source in 2012/2013



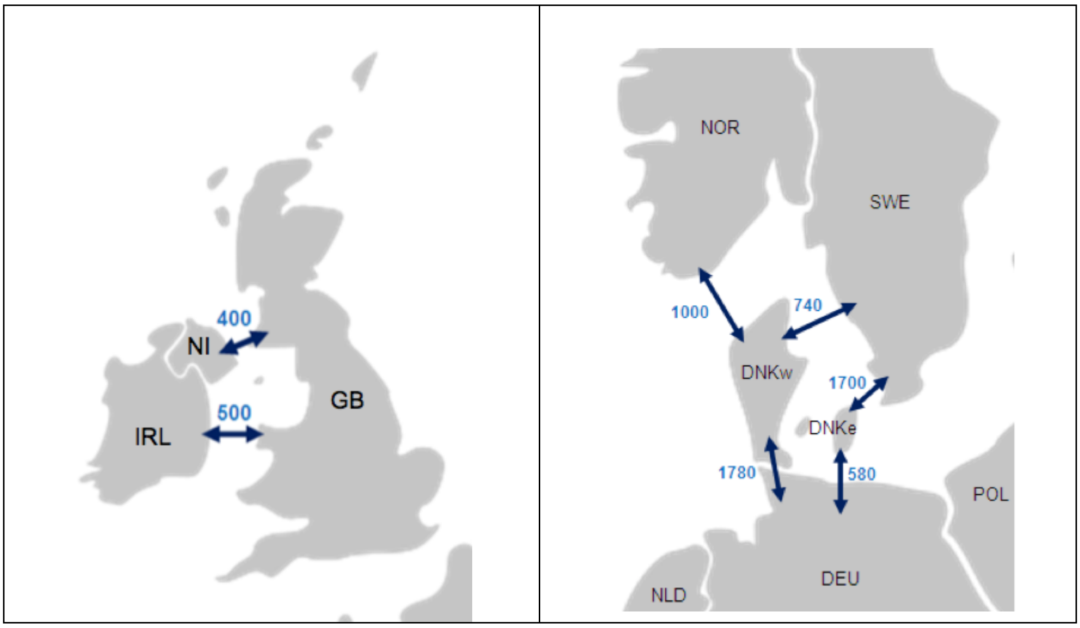


Figure 16 - Interconnector NTCs 2012/2013

In comparing the four power systems the different market operations that determine prices and data to be used as model inputs should be considered. Market operations, however, are complex, varying across each of the four countries analysed. Although Table 4 attempts to summarise the most salient features, readers are directed to Appendix A which provides a comprehensive overview of all four power systems and their market operations.

Table 4 – Country market comparisons

	Germany	Spain	Ireland	Denmark
TSO	Amprion, 50 Hertz, TenneT and TransnetBW	REE	Eirgrid and SONI	Energinet.dk
Market Operator	EEX in EPEX	OMIE	SEMO	Nordpool
Day-ahead Market	Closes: 12:00 D-1	Closes: 12:00 D-1	Closes: 9:30 D-1 for EA1	12:00 D-1
D-1 Market bid type	Simple/Semi-complex	Simple/Semi-complex	Complex	Simple/Semi-complex
% Consump. Traded on D-1 Market	34.5 %	71 %	100 % (Compulsory pool)	75 %
Intraday Market	Opens: 15:00 D-1, Closes: 45 mins before delivery	6 sessions x 1:45 between 17:00 D-1 and12:00 D	2 x "windows": 9:30 D-1 – 11:30 D-1, 11:30 D-1 – 8:00 D	Opens: 14:00 D-1, Closes: 1 hour before delivery
Balancing Market	Single price Interval: 15 mins	Dual price Interval: 1 hour	N/A	Dual price Interval: 1 hour
Last update of Wind Forecast	Estimated at 8:00 D-1, published at 18:00 D-1	00:01 D	N/A	17:00 D-1

3.4 COST CALCULATIONS

3.4.1 Profile Cost

The market-based profile cost analysis used in this study is taken from Hirth (2012a and 2013) and Ueckerdt et al. (2013). These authors develop a methodology using market data to calculate profile costs that arise because of VRE variability.

This methodology is based on the assumption of perfect and complete markets. Under such conditions, market values equal marginal economic values, or in other words, private investors' benefits equal public social benefits. Thus, if there is a reduction in market value an integration cost has been incurred (Ueckerdt et al., 2013; see discussion in Section 2.4.1).

However, the meaning of an integration cost (of any kind) is worthless without a technology with which to compare it. This report has discussed and authors have shown (Miligan et al., 2012, Awerbuch, 2003; Hirth, 2012a) that VRE are not the only technology with integration costs, nor more specifically, profile costs. All generation sources should be compared to a standard that determines the *integration cost*. This paper follows the work of Hirth (2012a) by selecting a "constant and perfectly reliable source of electricity that is located at average distance away from consumers." The generator produces power at all times and has the profile of a continuous base load generator as shown in in Figure 5 where profile costs were introduced. As previously mentioned, a perfect base load generator is equivalent to a unit which receives the time weighted average price.

In order to compare wind energy therefore, we shall take the difference between the time weighted average price and the wind weighted average price as shown in Equations 2, 3 and 4 below. Using this methodology, the profile costs determined will be marginal costs.

$$Wind\ W.A. = \frac{\sum_i p_i . E_i}{\sum_i E_i} \qquad Time\ W.A. = \frac{\sum_i p_i . t_i}{\sum_i t_i} \qquad (2, 3)$$

p_i	Day-ahead spot price [€/MWh]
E_i	Energy [MWh]
t_i	Period time unit

$$Profile\ costs = Time\ W.A. - Wind\ W.A. \qquad (4)$$

3.4.2 Balancing cost

Balancing costs are calculated using the wind imbalance multiplied by the balancing price. In many markets, including the four analysed in this report, the direction of the imbalance determines whether the units are paid or pay for their production difference. For example, in the Danish balancing market units are paid the down-regulation price when they deviate from their schedule in favour of the system, i.e. they produce less than forecast. However, the down-regulation price is lower than the spot price and thus the unit suffers a penalty since it receives less than the spot price for his production (Holttinen and Stenberg, 2012). This maintains an incentive for the unit to accurately predict its output rather than relying on revenues from balancing income.

As such, it is important to account for opportunity costs – the income which would have been earned without forecast errors – when calculating the balancing price, as shown in Equation 5 (after Holttinen and Stenberg, 2012 and van der Veen et al., 2010). This equation is applicable to both dual price balancing markets (e.g. Spain and Denmark) and single price balancing markets (e.g. Germany):

$$Balancing\ price = Balancing\ market\ price - Day\ ahead\ spot\ price \tag{5}$$

As such, the overall equation for calculating balancing costs is shown in Equation 6:

$$Balancing\ cost\ = Balancing\ price \times (Q_{actual}^{wind} - \ Q_{forecast}^{wind}) \tag{6}$$

Q_{actual} Delivered wind energy [MWh]
$Q_{forecast}$ Forecast wind energy [MWh]

This study assumes that all balancing of wind errors has been undertaken on the balancing market and that no imbalances were settled on the intraday market, thus providing a conservative estimate (Hirth, 2012a). The effect of intraday trading on balancing costs is not necessarily neglected however. If intraday trading has been effective, the amount of balancing services required will be reduced. Since balancing market prices are a function of the quantity of balancing services required, these balancing prices will reduce with effective intraday markets.

The following subheadings address the individual idiosyncrasies of each national balancing market as used in this study. It is worth noting that in all countries except Denmark, balancing market prices are not based on marginal but average costs. By incorporating the opportunity cost, this report has attempted to approximate a marginal cost estimate for Germany and Spain.

3.4.3 *National balancing market data*

All wind forecast data has been taken from TSO websites with balancing market prices retrieved from national market operators or TSOs, as shown in Table 5. The Mean Absolute Percentage Error (MAPE[16]) in Table 5 indicates the level of forecast accuracy.

Table 5 - Wind forecast and balancing market data

	Germany	Spain	Ireland	Denmark
TSO	Amprion, 50 Hertz, TenneT and TransnetBW	REE	Eirgrid and SONI	Energinet.dk
Last update of Wind Forecast	Estimated at 8:00 CET D-1, published at 18:00 CET D-1	00:01 CET D	N/A	17:00 CET D-1
2012 Forecast MAPE	24 %	11 %	N/A	DKw = 38 % DKe = 41 %
2013 Forecast MAPE	25 %	10 %	N/A	DKw = 24 % DKe = 46 %

3.4.4 *German balancing cost data*

All German wind and price data is published in 15 minute intervals. The four TSOs in the German market appear to delegate data collection to Amprion TSO from whom the reBAP (balancing market price) was collected. Wind forecast data and actual wind delivered was obtained from each of the separate TSOs and aggregated to determine the national balance. Wind forecasts are estimated at 8:00 D-1 and published 10 hours later at 18:00 D-1 for all hours of the trading day.

German balancing costs were calculated using the logic detailed in Section 3.4.2.

3.4.5 *Spanish balancing cost data*

All Spanish wind and price data is hourly and was kindly provided by REE. Wind forecast data in Spain is released 10 days before delivery and updated every hour until the first minute of delivery day. For example, 20/05/2014 00:01 data are updated hourly from 11/05/2014 00:01 until 20/05/2014 00:01 with the most recent data published online (personal communication with Soporte Proyecto eSIOS, 22 May 2014).

[16] MAPE = $\frac{100\ \%}{N}\sum_{t=1}^{N}\left|\frac{A_t-F_t}{A_t}\right|$ where; A_t = Actual wind (MWh), F_t = Forecast wind (MWh)

Table 6 - Spanish imbalance pricing

Units which deviate from their programs		
	In favour of the system	**In opposition to the system**
Upward imbalances *(less consumption, more generation)*	Receive DMP	Receive minimum of: - DMP - Average price of downward energy used (SE + TR + DM)
Downward imbalances *(more consumption, less generation)*	Pay DMP	Pay maximum of: - DMP - Average price of upward energy used (SE + TR + DM)

Source: de la Fuente, 2013. DMP = Daily Marginal Price, SE = Secondary Energy, TR = Tertiary Reserves, DM = Deviation Management (Appendix B for more info)

Spanish balancing costs were calculated using the imbalance pricing matrix outlined in Table 6 (more detail in Appendix B). Accordingly, there was only considered to be a balancing cost for wind when the wind imbalance was in opposition to the system, intensifying overall demand for costly balancing power. In this instance, if the system requires more power wind generators receive the minimum of the DMP and the average price of downward energy. If the system requires less power, wind generators are charged the maximum of the DMP and the average price of upward energy. It is important to note that when calculating this average price in Spain that even if a particular reserve is not required during a given hour, the average price is still calculated using all three services (personal communication with Ignacio de la Fuente, 2014).

For example, if Secondary Energy (SE) and Tertiary Reserves (TR) were required but not Deviation Management (DM) the average calculation would always include the three services, that is:

$$Average\ hourly\ imbalance\ cost\ = \frac{Price_{SE} + \ Price_{TR} + \ Price_{DM}}{3} \qquad (7)$$

Given the price of DM in this example will be zero, this effectively reduces the average hourly balancing cost since we continue to divide by three.

3.4.6 Danish balancing costs

The Danish "wind power prognosis" used in this report is provided by Danish TSO, Energinet.dk to Nordpool at 17:00 CET D-1. It contains hourly data for the two areas of Denmark, Denmark West and Denmark East (DK1 or DKw and DK2 or DKe, respectively). It was obtained from the website of Nordpool.

Danish balancing costs were calculated using the dual price balancing mechanism depicted in Figure 17 below and further described in Appendix A – Section 1.4.3.

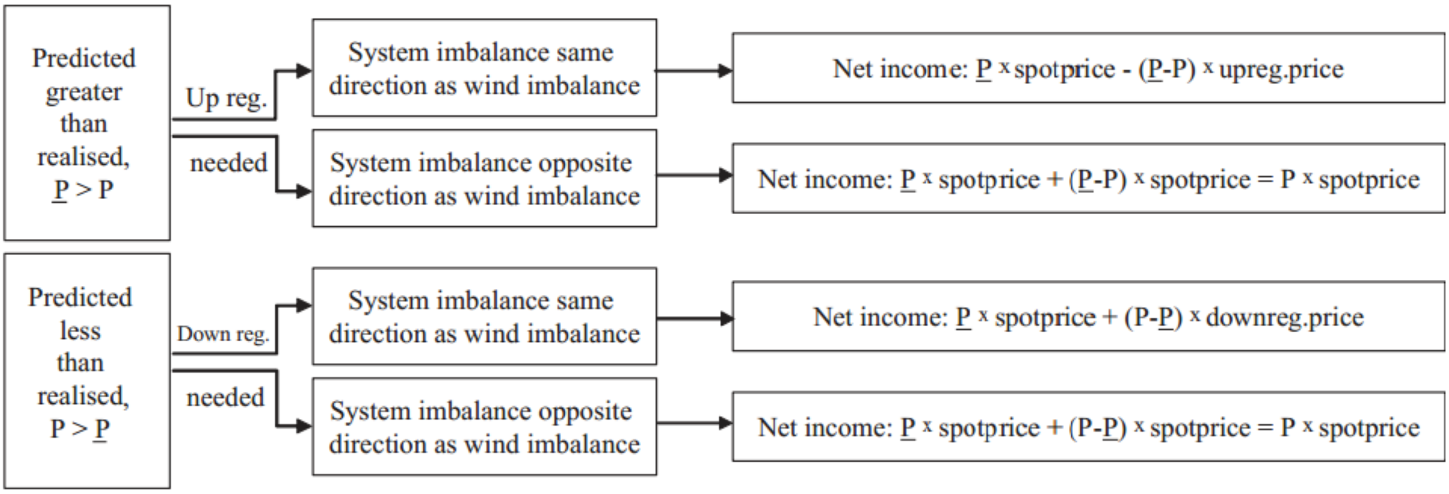


Figure 17 - Danish dual price balancing market
(Source: Holttinen, 2005)

3.4.7 Irish balancing costs

There is no centralised market price for Irish balancing prices; instead, individual units are directly charged for their imbalances. However, many units, especially wind generators, are exempt from these charges because they are registered as Autonomous or Price Taking units and are thus exempt from imbalance charges (see Appendix A – Section 1.3.3). Thus, it is virtually impossible to determine wind induced balancing costs from market data. Consequently, a review of existing balancing cost studies was conducted to give an estimate for Irish balancing costs.

These included:

- Holttinen et al., (2011) *Impacts of wind power on design and operation of power systems* and Ilex Energy (2004) *Operating reserve requirements as wind power penetration increases in the Irish electricity system.*

  The latter study used historical metered wind data to generate wind production profiles which were fed into sophisticated computer software to model future balancing requirements in 2006 at 845 MW of wind (9 % penetration) and 2010 at 1 950 MW of wind (14 % penetration). Both interconnectors were modelled though the capacity of the Moyle interconnector to provide balancing reserves was limited. The costs in these scenarios were, respectively, 0.20 €/MWh and 0.50 €/MWh. Holttinen et al. (2011) in their work for the IEA Wind Task 25 used these estimates until the most recent publication.

- Gross et al. (2006) *The Costs and Impacts of Intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network*.

Although focusing on the UK market, this review analysed over 200 studies and determined that for variable renewables up to 20 % penetration, balancing costs rarely exceed £ 5/MWh (6.70 €/MWh) or concerning the UK in particular, £ 2-3/MWh (2.70 – 4 €/MWh). Given the geographic, generation mix and limited interconnection similarities between the UK and Ireland, this latter estimate is a reasonable approximation for Irish balancing costs.

- Broderick (2011) *Wind Energy Economics*.

  The study investigated the influence of gas and carbon prices for the power system on the island of Ireland in 2030. Assuming a gas price of 35 €/MWh and CO_2 of 80 €/t, which are significantly different from today's prices, with wind representing 42 % of peak load, the same level as today, a balancing cost of 9.30 €/MWh was found.

- Holttinen et al. (2013) *Design and operation of power systems with large amounts of wind power* and The Sustainable Energy Authority of Ireland's (SEAI's; 2011) *Impact of Wind Generation on Wholesale Electricity Costs.*

  The former paper is the final summary report for the IEA Wind Task 25. It includes data from the latter study to calculate a balancing cost of approximately, 4.30 €/MWh. The SEAI used constraint software, *PLEXOS* together with a market model from the Irish regulator to determine this result.

3.5 GRID COSTS

As mentioned in Section 2.6.3, estimation of grid related costs is difficult and rarely quantified. Estimates have nevertheless been provided by some authors as identified in Section 2.6.3, although these costs only give generalised grid costs and are not specific to a given power system. In order to assess grid costs specific to each of the four countries in this report, TSO data will provide an insight into the individual requirements of each country.

In long-term transmission planning reports, TSOs normally estimate total average costs. Using this aggregated data, it is difficult to partition costs applicable to wind generators because grid expansions benefit producers and consumers alike. An expanded and more interconnected network: removes constraints by expanding capacity, increases the number of available connection points, increases international interconnections and improves overall system reliability and security. Thus, even if TSOs made an estimate of network costs attributable to wind generators, the complexity of the problem and multitude of beneficiaries means it is unlikely to represent an accurate cost allocation.

However, a second problem is encountered when using TSO reports. Receiving their income from regulated tariffs, TSOs will always overestimate the costs of network expansion in order to justify increasing tariffs or to ensure that the regulator agrees to an increase that approximately matches the required investment. That is, as in any good negotiation, the requesting party asks for more than is required and negotiates down, not the other way around. Thus, the figures provided in these reports are likely to overestimate costs and therefore provide a conservative estimate.

A third problem with TSO reports is that the amount allocated to renewable installations may be overestimated since such technologies are generally looked upon favourably by policy-makers and the voting public. Like a rug for visible dirt, TSOs may therefore use renewables to hide previously unforeseen expenditures.

Fourthly, using TSO reports does not allow cost calculation of constraints that may be induced during periods of high wind. In fact, in Europe, except where zonal pricing is used in Norway and Sweden, this data may only be determined by using computer modelling.

Finally, TSO reports provide an estimate. It is potentially the best estimate available yet cannot be expected that these aggregate figures are 100 % precise.

Unfortunately, this means we are able to estimate only very proximate grid costs for wind generators. Nevertheless, it is possible to provide a range for the grid costs imposed by onshore wind. Namely, we shall allocate 33 %, 66 % and 100 % of the TSO provided total network upgrade costs to determine the likely range of grid costs for onshore wind. Obviously allocating 100 % of total network upgrades found in TSO reports provides an upper bound for our estimate. From Table 3 it can be seen that 33 % is a good estimate for a lower bound because all four countries have been or will continue to install large quantities of onshore wind. The 66 % allocation will provide an approximation for grid costs, assuming that the remaining 34 % of costs only can be classified as positive externalities.

It is obvious that allocating 100 % of total network upgrades provides an upper bound for our estimate. Because all four countries have been or will continue to install large quantities of onshore wind, 33 % is a good estimate for a lower bound in terms of cost allocation. The 66 % allocation will provide an approximation for grid costs, assuming that only the remaining 34 % of costs can be classified as positive externalities.

In order to compare costs across the four countries, this report uses a methodology set out in Mills, Wiser and Porter (2009) to generate grid costs based on energy generated (€/MWh of wind). Specifically, capital transmission costs are levelised and divided by the amount of energy generated, i.e. the levelised transmission cost of wind is determined by implementing the LCOE formula detailed in Equation 1. Importantly, this report assumes a 7 % discount rate (CEER, 2013), project life of 40 years before transmission lines may need replacing and wind capacity factors as outlined in Table 7. The capacity factors in Table 7 are considered more appropriate given they are calculated over a longer time period than those determined from the data used for profile cost calculations in this report.

Table 7 - Average capacity factors over 2003 – 2007

Country	EU15	DE	ES	IR	DK
Capacity (GW)	56.3	22.2	14.1	0.8	3.1
Energy (TWh)	97.7	33.7	28.8	1.9	6.1
Capacity Factor (%)	20.8	17.5	24.8	29.3	22.8

Source: Boccard, 2009

The installed wind capacity up until 2013 is determined by examining the incremental wind installations available in TSO annual reports or other equivalent publications. When installed capacities or future installation predictions are no longer available, wind is considered to be installed at a very slow rate (e.g. 100 – 375 MW per year) until the end of the 40 year amortisation period. In any case, cost amortisation means later installations have a much lower effect on the grid cost estimate.

Finally, all grid cost estimates will be average cost estimates and not marginal costs, presented in 2013 euros. Under each country heading wind cost allocations and particular grid expansion plans are discussed below.

3.5.1 Spain

Relevant grid investments are assumed to have commenced in 2006, one year before the landmark Royal Decree 661/2007 was established providing substantial incentives for wind (and solar) investments (over 3.5 GW of wind was installed in 2007 alone). Calculating costs from 2006 thus ensures the influence such significant installations would have on grid costs are not overlooked. By examining REE's annual reports, summing grid investments from 2006 to 2017, including forecast investments between 2014 – 2017 of 425 – 450 € million (REE, 2012), total grid expansion costs are estimated at € 6.1 billion. REE explains these investments comprise a "transitional phase towards a new energy model characterized by greater complexity in its management due to the high level of renewable energies" (REE, 2013). Namely, investments include strengthening international interconnections between France, Portugal and Morocco; smart grid and efficiency preparations and island interconnections to improve security of supply. Thus, renewables feature in the grid expansion of Spain though they are not the sole focus of more than € 6 billion of investment.

3.5.2 Germany

German Energy Agency, Dena, published the often quoted, *Dena Grid Study I* in 2005 in which they outlined a total cost for onshore wind expansion of approximately € 1.1 billion: € 280 million (2005 – 2007), € 490 million (2007 – 2010) € 350 million (2010 – 2015). Given Dena already allocated this amount specifically for onshore wind expansions it was not necessary to further partition these costs relevant to wind.

Dena Grid Study II (2010), however, proposes a base case analysis in which € 946 million is allocated for grid upgrades per year between 2015 – 2020. All these figures have therefore been included in the cost estimates, subject to partitioning at 33 %, 66 % and 100 % allocations.

3.5.3 Ireland

Eirgrid's *Grid 25*, launched in 2010, provides an overview of network upgrades for Ireland until 2025. It strives for 40 % of consumption from renewable generation by 2020 and aims to safeguard Ireland from future price volatility of fossil fuels. In the words of the Minister for Communications, Energy and Natural Resources (Eirgrid, 2010): "the Strategy, when implemented in full, will provide a platform so that in each region, Ireland can harness her abundant renewable energy resources and provide clean and competitively priced electricity for homes, businesses and new high-tech industries." However, *Grid 25* also includes upgrades for a network that over the past 20 years has remained largely unchanged despite demand growth of 150 % (Eirgrid, 2010). Thus, although the € 4 billion of investment forecast for the project include substantial expansion to integrate large shares of wind and wave technology, a non-trivial portion of this cost arises due to external causes. More precisely, despite 80 % of the investment cost attributed to onshore wind integration[17] there is undoubtedly included in the € 4 billion a non-trivial investment pertaining to upgrades that, net of any renewables, would have been necessary.

3.5.4 Denmark

In 2008 Danish TSO, Energinet.dk, released their technical expansion plan to "underground" the network and incorporate increasing amounts of wind energy. Analysing several scenarios, Energinet.dk estimates grid upgrades between € 360 million for construction of new overhead 400 kV lines alone to € 6.4 billion if the entire network is undergrounded with today's technology (Elinfrastrukturudvalget, 2008). These estimates include onshore wind generation expansions of 1 GW and offshore of 2.5 GW as well as significant international connectors.

Recent communiqués (DEA, 2013 & Eirgrid, 2009) and "major technological problems" (Elinfrastrukturudvalget, 2008) reveal that with current technology, undergrounding the 400 kV lines in Denmark is prohibitively expensive. However, undergrounding of 132 and 150 kV lines is feasible (DEA, 2013). Accordingly, the scenario representing the undergrounding of all lines except for HV 400 kV as analysed in the aforementioned report will be utilised in our cost calculations. This project has an estimated cost of € 2 billion.

Additional to wind integration, HV grid upgrades have been minimal over the past 20 years in Denmark (DEA, 2013) and the project outlined in Elinfrastrukturudvalget (2008) includes significant international connectors for market expansion. Indeed, as with previous TSOs, Energinet.dk mentions increased security of supply and a competitive market as primary aims, including renewable integration as their third objective.

Considering installed capacities, onshore wind grid costs will be apportioned on the 1 : 3.5 ratio (approx. 29 %) in an attempt to isolate these costs from the offshore expansions.

4. RESULTS

4.1 PROFILE COSTS

Figure 18 presents the profile costs for 2012 and 2013 in the four countries. As expected, costs differ from country to country. In even the most expensive cases profile costs determined in this report are at the lower end of literature-reviewed estimates.

[17] The remainder includes 10 % of offshore wind and 9 % of wave generation

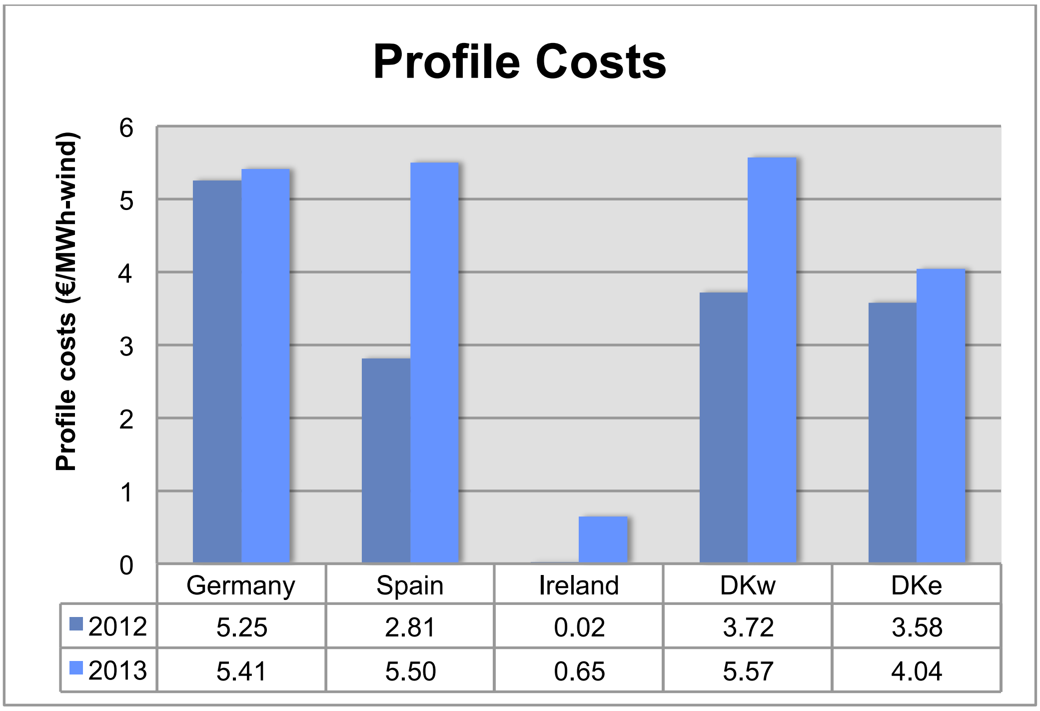


Figure 18 - Profile cost results for 2012 and 2013

There are many factors which determine the profile cost in any given system: price and demand, demand profile variability, wind generation variability, wind penetration, wind-demand correlation or more specifically, wind-price correlation, and existing generation flexibility. Hence, it is not easy to pinpoint one reason as to why profile costs were higher in one country or year.

That said, it is worth briefly discussing three notable points in the above costs:

1. The difference in profile costs for Spain between 2012 and 2013 is most likely due to an increased variance in both price and generated wind as well as a more than ten-fold increase in zero-price hours in 2013 data (44 instances in 2012 vs. 478 in 2013; Appendix C). Zero prices are undoubtedly correlated with the record power production from wind which exceeded all other sources, even nuclear at 21.2 % of total production in 2013, compared to 18.2 % in 2012 (REE, 2012 and REE, 2013).

2. In general, profile costs are anticipated to be lower in a system like Denmark where large capacity interconnections with hydro-rich Norway and Sweden are available to neatly compensate decreased wind output. This enables peak shaving and generally maintains steadier prices. Although the price is seen to increase from 2012 to 2013 in Denmark, this is in fact slightly misleading since wholesale prices also increased during this period, meaning there is proportionally minimal change[18].

3. The minimal profile cost for Ireland is noteworthy. In 2012, the profile cost was almost positively correlated (R^2 = -0.0011) with the system marginal price only

[18] E.g. Consider the Value Factor = Wind WA/Time WA: for DKw = 0.90 (2012) and 0.86 (2013), and DKe = 0.90 (2012) and 0.90 (2013).

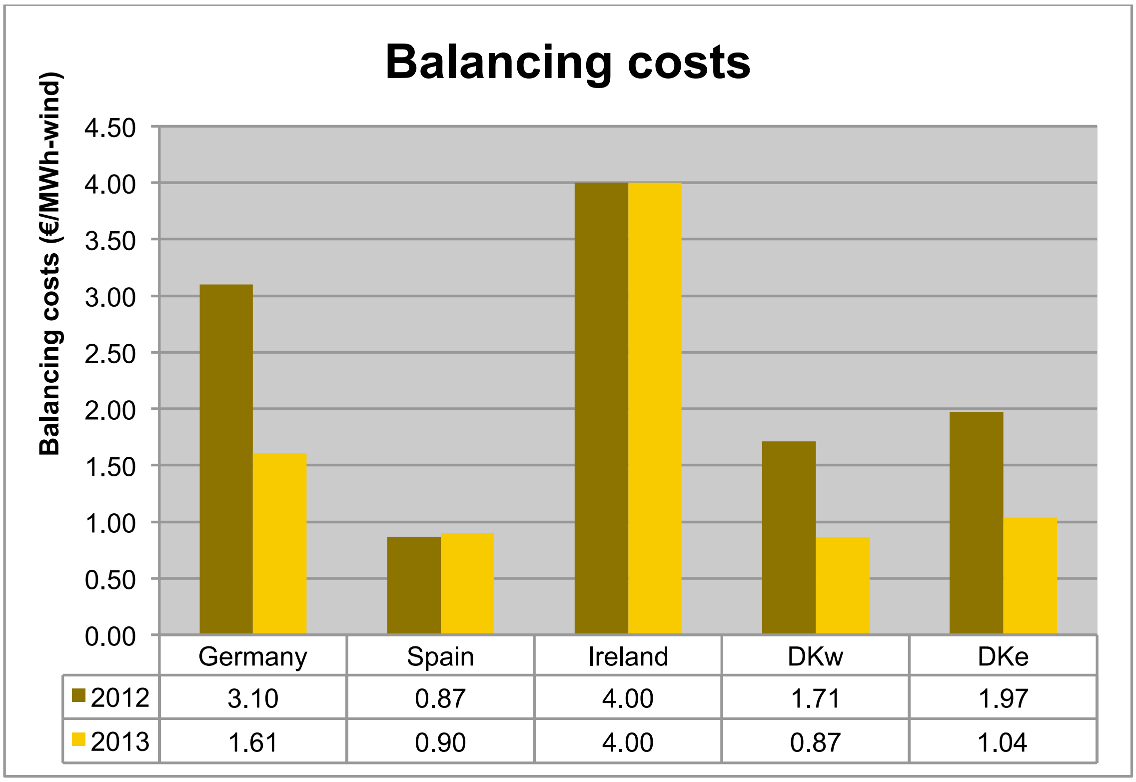
reducing the value of wind energy compared to the perfectly reliable base load generator by 0.02 €/MWh. The minimal profile cost for both years in Ireland is almost certainly because of the large share of gas units (approximately 50 % of demand supplied) which comprise the marginal, price setting units. Thus, with such a large quantity of these similarly priced units, even a substantial amount of wind will not alter the electricity price (see Pérez-Arriaga and Batlle, 2012). That is, the merit order effect has virtually no impact on Irish electricity prices over 2012-13.

4.2 BALANCING COSTS

4.2.1 Ireland

While the results for Germany, Spain and Denmark were obtained by empirical methods, the balancing costs for Ireland were acquired from various estimates found in the literature. Costs ranged from 0.20 €/MWh to 9.30 €/MWh, at penetration levels from 9 % to 19 %, respectively. However, the upper estimate included CO_2 costs of 80 €/t, well in excess of current prices and while plausible for 2030 are unrealistically high today. Given the increased cycling and spinning reserve requirements which substantially increase CO_2 emissions, it is likely that 9.30 €/MWh is an overestimate for balancing costs. 0.20 €/MWh, however, is also likely to be a serious underestimate and may be explained by model assumptions which endeavoured to forecast costs six years in advance. Furthermore, while these figures were used in initial studies of Holttinen et al. (e.g. 2011), latter studies published in 2013 implemented research from the SEAI completed in late 2011. In line with final estimates taken from over 200 articles by Gross et al. (2006), the SEAI found balancing costs to be somewhere in the middle of these minimum and maximum values at around 4.30 €/MWh. Accordingly, this report finds Irish balancing cost to be approximately equal to 4.00 €/MWh.

4.2.2 *Results for all power systems and further comments*



	Germany	Spain	Ireland	DKw	DKe
2012	3.10	0.87	4.00	1.71	1.97
2013	1.61	0.90	4.00	0.87	1.04

Figure 19 - Balancing cost estimates

As expected, Figure 19 demonstrates that balancing costs vary significantly across the four analysed power systems and between 2012 and 2013. In all cases, costs are in line with expectations from the literature, although towards the lower end of suggested estimates. In particular, balancing costs for Spain were found to follow the decreasing trend shown by the Spanish Wind Energy Association (in Holttinen et al., 2013), although they appear to decrease more rapidly than if the trend continued linearly (Trend: 1.53 €/MWh in 2010, 1.40 €/MWh in 2011, 1.30 €/MWh in 2012). In any case, balancing costs for Spain approximately 0.90 €/MWh are reasonable.

Comparing Spain to the other countries, the lower estimate can be explained by the significantly more accurate wind forecasts which are updated until the first minute of delivery day. Compared to wind forecast data for Denmark and Germany, Spanish forecasts are released 7 to 16 hours closer to real time, respectively. As with any temporal variable, this improves forecast accuracy, further attested to in the lowest Forecast MAPE of the four countries. Moreover, we expect balancing costs to be lower in Spain because of the availability of significant quantities of flexible hydro resources (see Figure 15 in Section 3.3).

Balancing costs for Germany are marginally above those estimated by Hirth (2012a), possibly because this report included the opportunity cost which is unspecified as being used in Hirth's work. The costs are higher compared with Spain, most likely because limited and often constrained interconnections and gas or fuel oil generators provide the majority of balancing services. The 16 hour delay between forecast updates and delivery day further increases forecast errors and thus, balancing costs.

In Denmark the balancing costs are on average, lower than those estimated for Western Denmark by Holttinen et al. (2011; i.e. 1.40 – 2.60 €/MWh). In both East and West Denmark balancing is largely provided by interconnections. As wind penetration is low in hydro-rich Norway and Sweden, provisions of balancing services can be at low cost through the respective, 1000 MW and 2440 MW tie-lines. Indeed, interconnection capacity that can be used for balancing services is known to reduce balancing costs (Ackerman, 2012). Conversely, increasing wind capacity in a neighbouring country, like Germany, is likely to increase balancing costs in Denmark (Holttinen et al., 2011).

Finally, balancing costs in Ireland assessed by literature review provide the highest estimate for costs of the four analysed countries. While potentially an overestimate, this cost of 4 €/MWh still falls within the range estimated in the IEA Task 25 study (1 – 4.50 €/MWh). Furthermore, balancing costs are likely to be higher in Ireland than any other country in our study. This is because the Irish system is small and therefore wind usually varies uniformly across the entire system (i.e. a drop in wind power will affect the whole island's generation). Balancing services are then only available from limited interconnections with the British system or from flexible gas units that have relatively expensive fuel costs when compared with hydro. Thus balancing cost estimates for the Irish power system are likely to be more expensive than elsewhere.

At an inter-yearly level, the curious reduction which almost halves balancing costs for Germany and the two regions of Denmark between 2012 and 2013 may be explained by the geographic proximity of these wind generators and a consequent correlation between annual variability in wind forecasts. Indeed, as seen in Table 8 the average balancing cost, which encapsulates both the average wind imbalance and balancing price variation[19], appears to explain this reduction between 2012 and 2013. That is, average balancing costs almost halved between these years. Deviation between balancing costs for Spain and Germany/Denmark are to be expected because of the geographical separation of these power systems.

Table 8 - Average balancing costs per programmed time unit (€/PTU)

Year	Germany	Spain	Ireland	DKw	DKe
2012	3993	4678	N/A	1391	627
2013	2136 (53%)	4337 (93%)	N/A	846 (61%)	313 (50%)

NB: Percentage change from 2012 to 2013 in brackets.

For all three analysed countries, wind imbalances were opposite system imbalances (i.e. they reduced system imbalances) between 40 – 50 % of the time.

[19] $Average\ balancing\ cost = \frac{\sum_{t=1}^{N} P_t \Delta Q_t}{N}$; P_t = Balancing price, ΔQ_t = Wind imbalance, N = no. of PTUs (typically, hours in the year)

4.3 GRID COSTS

Estimated grid costs found using TSO transmission planning and annual reports as detailed in Section 3.5, are displayed in Table 9 and represented in Figure 20.

Table 9 - Grid costs for onshore wind (€/MWh-wind)

Cost allocation	Germany	Spain	Ireland	Denmark
33 %	3.44	3.85	5.61	2.13
66 %	6.88	7.70	11.22	4.26
100 %	10.42	11.67	17.00	6.45

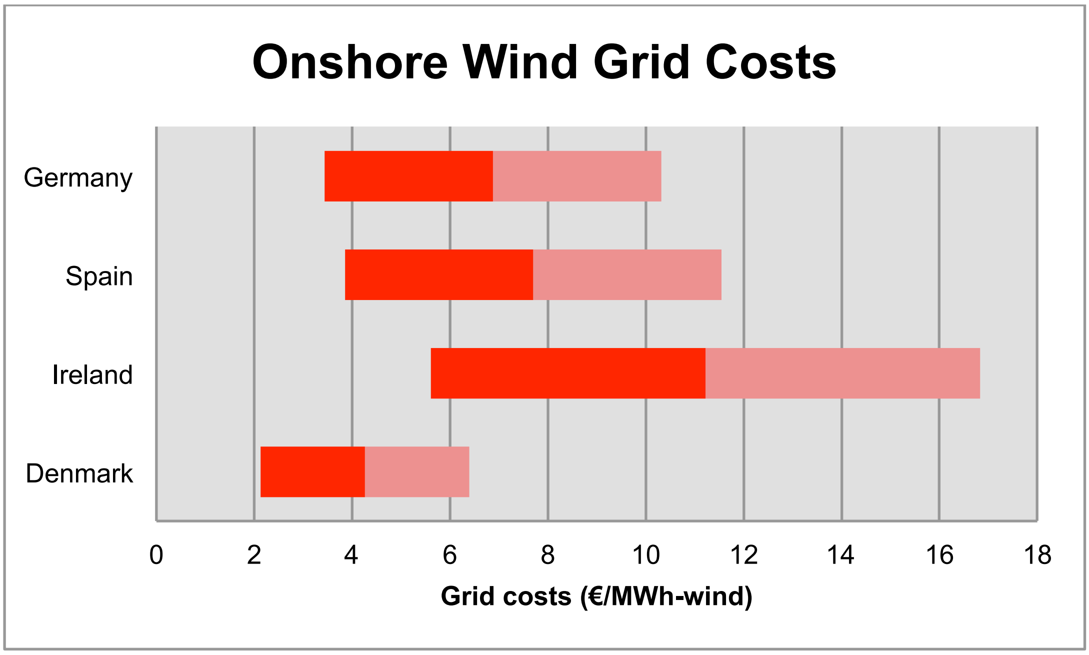


Figure 20 - Estimated grid costs: midpoint of two colours is 66 % value

The range of costs is large and as explained in Section 3.5, it is difficult to determine the precise grid cost attributable to onshore wind generation. Nevertheless, this estimation illustrates that even if 100 % of the grid expansion is allocated to onshore wind generation in a system where transmission infrastructure is known to be dated (e.g. Ireland), prices are unlikely to exceed 17 €/MWh. At the other end of the estimation, in a system where strong grid interconnections exist and merely aesthetic reasons for undergrounding the network are the primary driver of investment (e.g. Denmark), grid costs can be as little as almost 2 €/MWh.

4.4 GENERATION COSTS

As mentioned in Section 2.1, many factors influence the LCOE of a given technology. In this regard, Table 10 and the corresponding Figure 21 illustrate the geographic and temporal variation associated with LCOE estimates for onshore wind. Note, LCOE estimates presented do not include grid connection costs and are net of any subsidies or tax rebates. Capital and fixed costs are included.

Table 10 - Onshore Wind LCOE estimates

	(€/MWh)		
Source	**min**	**avg**	**max**
Germany (WEC) 2013	59	60	61
Spain (WEC) 2013	66	67	68
Denmark (WEC) 2013	60	62	63
EIA 2019^	57	57	
UK Dept. of Energy and Climate Change 2013#*	112	112	
Germany (Agora) 2013	75	75	
Lazard 2013	34	53	71
Germany (Fraunhofer) 2013	80	80	
Lantz, Wiser and Hand 2013*	45	54	63
Germany (Hand and Lantz) 2009	83	83	
Spain (Hand and Lantz) 2009	81	81	
Denmark (Hand and Lantz) 2009	60	60	
IEA 2010 @ discount rate = 5%*	75	75	
IEA 2010 @ discount rate = 10%*	102	102	
IRENA 2012*	67	93	119
Total average	70	74	74

^ Forecast
* When converting from other currencies US$ 1.341 = 1 € (2013), 0.853 £ = 1 € (2013)
# Includes Variable O&M costs

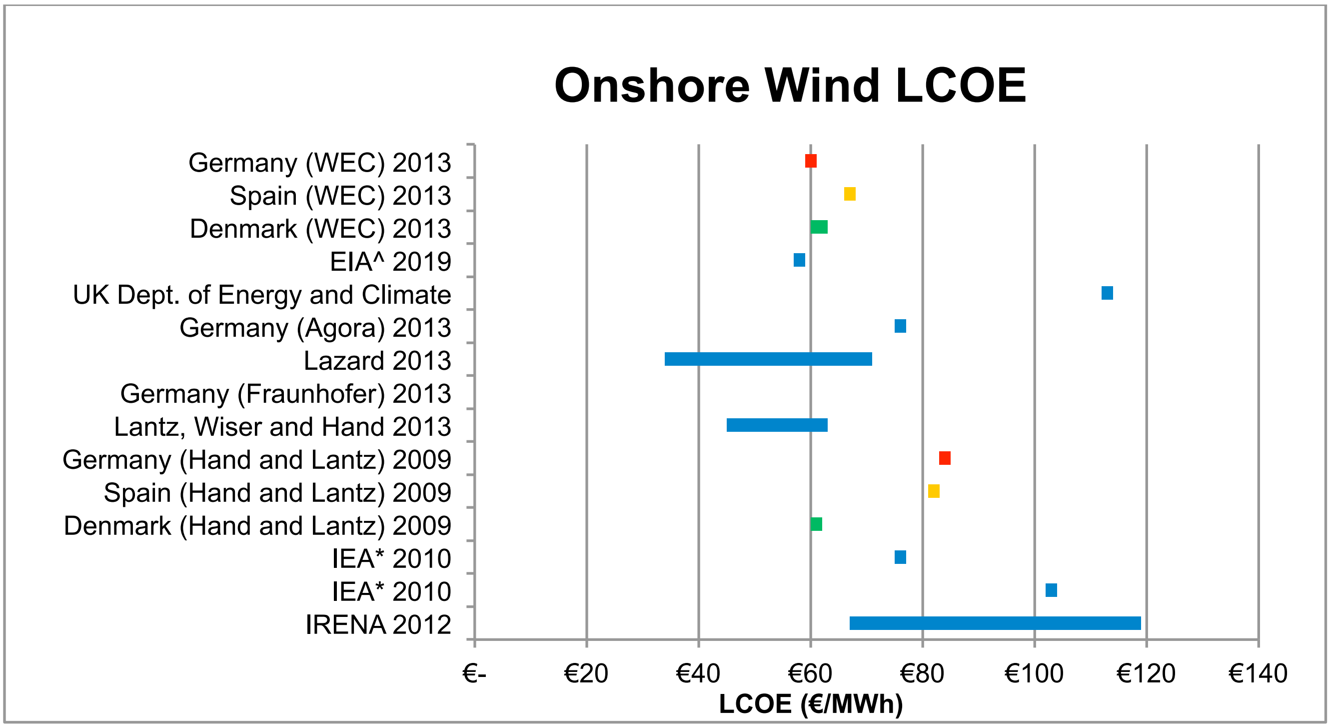


Figure 21 - Onshore wind LCOE estimates

This review of generation costs clearly illustrates the variation in LCOEs, highlighting that there is not one LCOE which may be associated with onshore wind generation. Depending on the interest rate, amortisation period, debt to equity ratio, capacity factor, national labour costs and other variables specified in Section 2.1.1 – LCOE costs, LCOEs are highly susceptible to variation.

One example of LCOE's sensitivity to input assumptions can be seen by the difference between global estimates provided by Lazard (2013) and IRENA (2012). Lazard (2013) assumes a weighted average cost of capital (WACC) of approximately 7.7 % while IRENA (2012) uses a WACC of 10 %. Both studies use approximately the same unit lifetime. In the former, capacity factors are even lower than in IRENA's study and yet the maximum price estimated by Lazard (2013) is roughly equivalent to the minimum price estimated by IRENA (2012). Indeed, between the lowest estimate provided by Lazard (2013) and the highest from IRENA (2012), a price increase of more than threefold can be seen. Thus, the assumptions for LCOE calculations must be clearly stated and their effects understood before any integration cost calculation can be added to these costs.

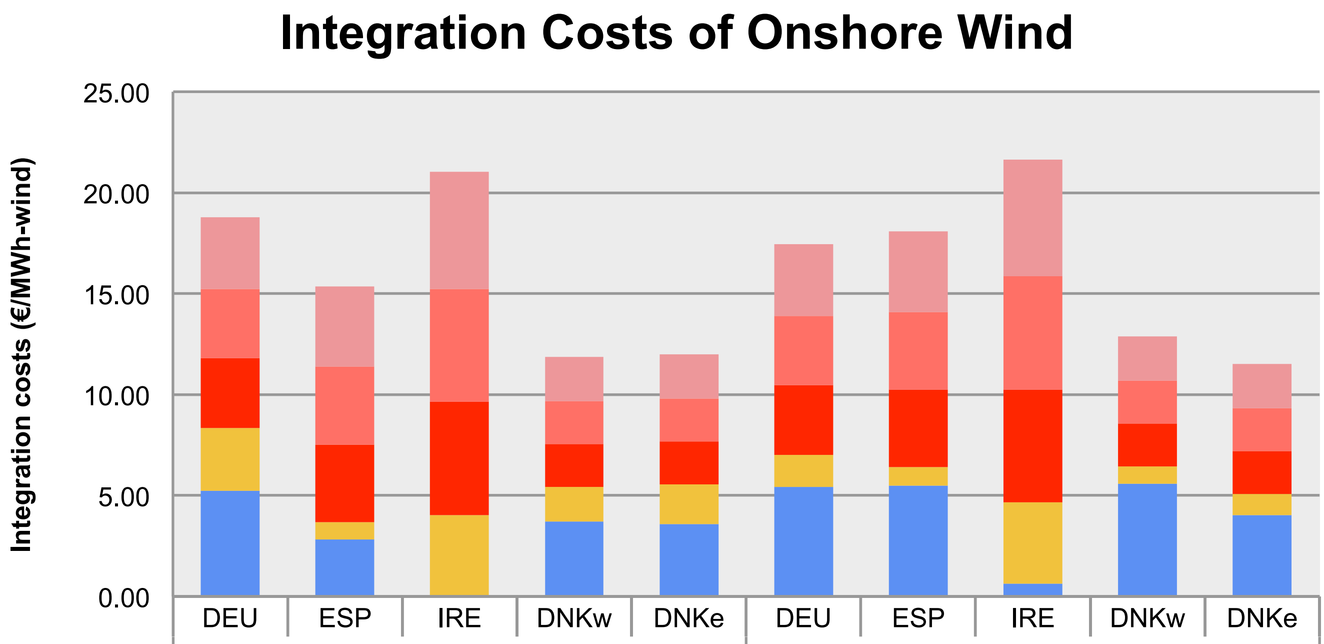
Nevertheless, though LCOE sensitivity is important the focus of this report is on integration costs that are commonly neglected. The LCOE generation costs provided by the World Energy Council in collaboration with Bloomberg New Energy Finance (2013) are the most recent and specific data for Germany, Spain and Denmark so are adopted in this report. The overall average of LCOEs from 2013 is used as the generation cost for Ireland (see Table 11).

Table 11 - LCOE generation costs used in report

	LCOE (€/MWh)
Germany	60
Spain	67
Ireland	70
Denmark	62

4.5 TOTAL COST OVERVIEW

4.5.1 Integration costs



	2012					2013				
	DEU	ESP	IRE	DNKw	DNKe	DEU	ESP	IRE	DNKw	DNKe
Δ Grid cost 100%	3.54	3.97	5.78	2.19	2.19	3.54	3.97	5.78	2.19	2.19
Δ Grid cost 66%	3.44	3.85	5.61	2.13	2.13	3.44	3.85	5.61	2.13	2.13
Grid cost 33%	3.44	3.85	5.61	2.13	2.13	3.44	3.85	5.61	2.13	2.13
Balancing cost	3.10	0.87	4.00	1.71	1.97	1.61	0.90	4.00	0.87	1.04
Profile cost	5.25	2.81	0.02	3.72	3.58	5.41	5.50	0.65	5.57	4.04

Figure 22 - Integration costs for onshore wind

It is now possible to sum the various integration costs for each of the four countries (see Figure 22). Significant differences in integration costs for onshore wind can be seen.

What explains these differences across power systems? The complexity of these systems and nature of the analysis prevents determination of precise reasons. For example, without knowing the merit order curve it is difficult to determine whether profile costs are more influenced by the generation mix and the merit order effect or by a correlation between wind and the market price. Therefore, while costs are explained carefully and diligently, in reality, there may be other reasons. However, knowingly ignoring integration costs imperils good decision making.

In both years analysed, Denmark records the lowest integration costs of the four power systems: average price 7.76 – 12.08 €/MWh (33 % grid costs – 100 % grid costs). Denmark has several advantages that explain this low integration cost: sizeable interconnections which allow access to cheap, bountiful hydro reserves in Norway and Sweden, a well developed internal network and good wind capacity.

Denmark also has the second lowest profile costs most likely because of relatively high price stability achieved by peak shaving using these Scandinavian hydro units. Indeed, as many authors have suggested, the large interconnection capacities rated at 140 % of installed wind capacity and 97 % of peak power may not justify the classification of Denmark as a truly independent power system. Rather, it is as though it sat in the middle of the much larger and extremely flexible Nordic power system. This effectively means the Danish power system is rich in flexible hydro generation even though Danish hydro units themselves contribute less than 0.1 % to annual generation (Energinet.dk, 2013).

Danish grid costs are the least of all countries probably because the Danish grid is well developed. The already existing large interconnections and decision to underground the network demonstrate that the network does not require significant reinforcing compared to the other three countries. This is unsurprising given the long-term national focus on wind integration dating back to 1976.

Spain on average, has the second lowest integration cost at 8.93 – 16.75 €/MWh (even though higher profile costs push Spain to have a higher integration cost than Germany in 2013). The power system shows relatively low balancing costs because of substantial hydro and flexible gas generation.

Spain's profile costs are in the low to average range. These costs are potentially minimised by reduced price variation with hydro peak shaving and/or a lower merit order effect. These can be attributed to significant CCGT installations with similar marginal costs.

Finally, Spanish grid costs are slightly higher than average given substantial expansion projects including expanded international and island connectors. These results suggest that integrating wind depends more on flexible resources than interconnections

Germany has the third highest integration costs at 11.13 – 18.11 €/MWh. German profile costs are high for both years. Given the size of the German power system and varied generation mix, the merit order effect may suppress prices even more than other systems that have minimal hydro to balance operations.

German balancing costs are also relatively expensive. This is because of minimal hydro to balance operations and occasionally constrained interconnectors between Austria-Germany and Switzerland-Germany.

German grid costs are approximately the average of the four countries.

Ireland exhibits the highest integration costs of all the power systems at 9.95 – 21.34 €/MWh despite very low profile costs.

Low Irish profile costs are understood to stem from both the enormous capacity of installed gas generation (> 50 % of total capacity) which virtually negates the merit order effect; and the strong correlation of wind with the day-ahead price.

The Irish balancing costs are anomalous since they were not calculated using market data. However, higher Irish balancing costs were expected for several reasons: the small size of the country means wind variations affect the entire fleet; Ireland has almost no hydro generation; and only limited interconnections are available for balancing.

Lastly Irish grid cost estimates are very high. Aggressive wind installations pursued by the island nation undoubtedly contribute significant costs but the upgrade of the aged network detailed in TSO reports almost certainly overestimates these costs.

For these four nations then, considering the most favourable assumptions (33 % grid costs), integration costs range from as little as 7.50 – 12 €/MWh. Assuming the most conservative case in which 100 % of grid costs are attributed to onshore wind generation, integration costs range from 12 – 22 €/MWh.

4.5.2 Total costs

Summing the generation costs and integration costs Table 11 and Figure 23 therefore put together all the analysis discussed above to determine the total costs of onshore wind (generation costs plus the three integration costs).

Table 12 - True costs of onshore wind (€/MWh)

	2012					2013				
Cost	DEU	ESP	IRE	DKw	DKe	DEU	ESP	IRE	DNKw	DNKe
Gen. costs/LCOE	60	67	70	62	62	60	67	70	62	62
Profile costs	5.25	2.81	0.02	3.72	3.58	5.41	5.5	0.65	5.57	4.04
Balancing costs	3.10	0.87	4.00	1.71	1.97	1.61	0.98	4.00	0.87	1.04
Grid costs 33%	3.44	3.85	5.61	2.13	2.13	3.44	3.85	5.61	2.13	2.13
Δ Grid cost 66%	3.44	3.85	5.61	2.13	2.13	3.44	3.85	5.61	2.13	2.13
Δ Grid cost 100%	3.54	3.97	5.78	2.19	2.19	3.54	3.97	5.78	2.19	2.19
Grid cost total	10.42	11.67	17.00	6.45	6.45	10.42	11.67	17.00	6.45	6.45
Integration cost total	18.77	15.35	21.02	11.88	12.00	17.44	18.15	21.65	12.89	11.53
Minimum total	15.23	11.38	15.24	9.69	9.81	13.90	14.18	15.87	10.70	9.34
Maximum total	78.77	82.35	91.02	73.88	74.00	77.44	85.15	91.65	74.89	73.53

NB: *Δ Grid cost* shows the incremental cost, i.e. *Δ Grid cost 100% = Grid cost 100% - Δ Grid cost 66% - Grid cost 33%.* Or using numbers for Germany, *Δ Grid cost 100%* = 10.42 – 3.44 – 3.44 = 3.54 €/MWh.

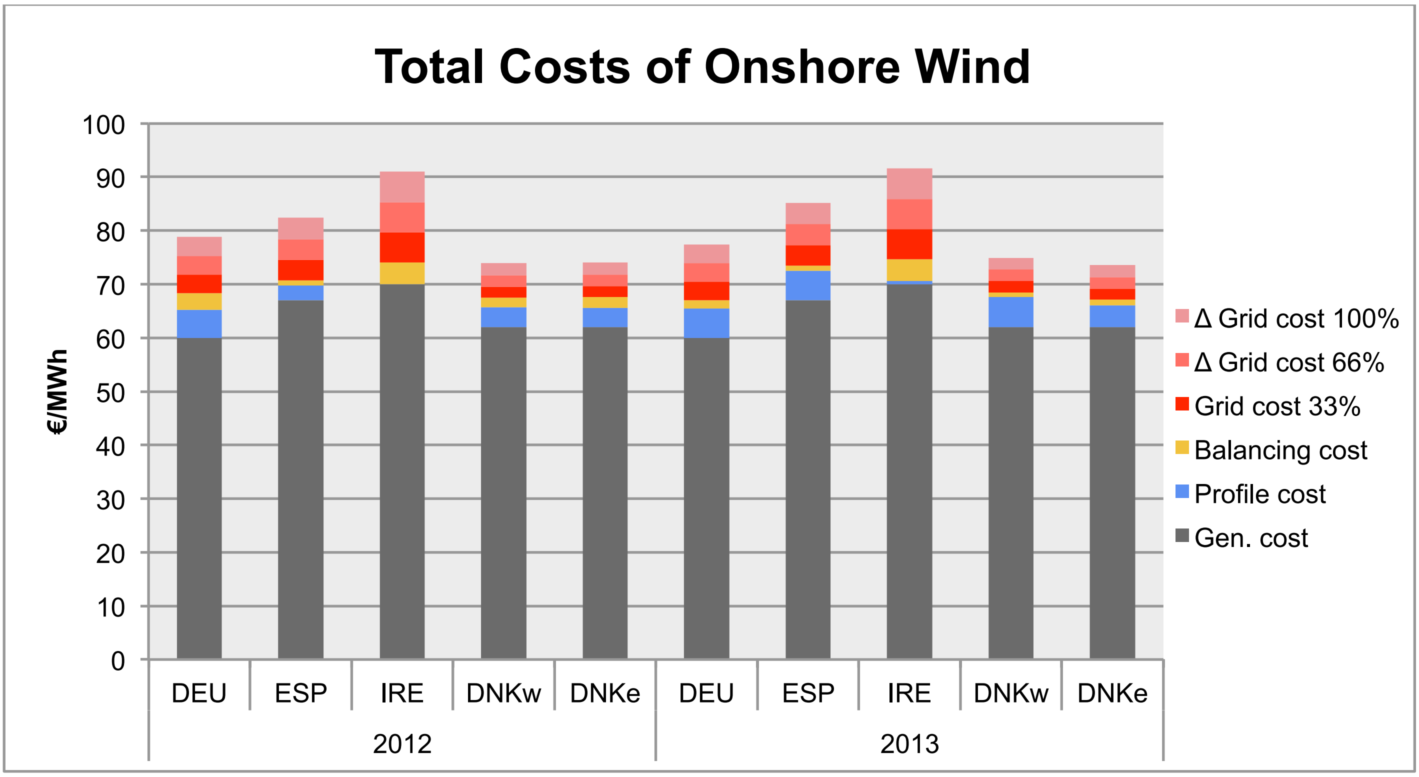


Figure 23 - Total costs for onshore wind

These estimates suggest that across the four countries analysed, total wind costs vary from approximately, 69 – 80 €/MWh assuming the lowest cost scenario (only 33 % of grid costs allocated to wind), to 73 – 92 €/MWh assuming the highest cost scenario (100 % of grid costs allocated to wind). 66 % of grid costs provides an approximate estimate of 72 – 86 €/MWh.

Figure 23 shows that the world's largest (pro rata) adopter of wind generation, Denmark, has the lowest total onshore wind costs. However, only by adding integration costs is Germany found to have the second lowest cost of wind. With over 34.2 GW of onshore capacity it is unsurprising that given the skills and expertise in installation Germany finds itself in this position. Finally, Spain and Ireland remain unaltered by the addition of integration costs as the third and fourth most expensive onshore wind generating countries, respectively. Figure 23 shows that the largest impact on total costs arises from generation and grid costs. Considering the sensitivities of generation costs to discount rates, amortisation periods and capacity factors (see Section 2.1) and the assumptions made in calculating grid costs, these estimates imply that integration costs are not proportional to generation costs nor are they constant. Figure 24 shows the variation of integration costs with respect to total costs.

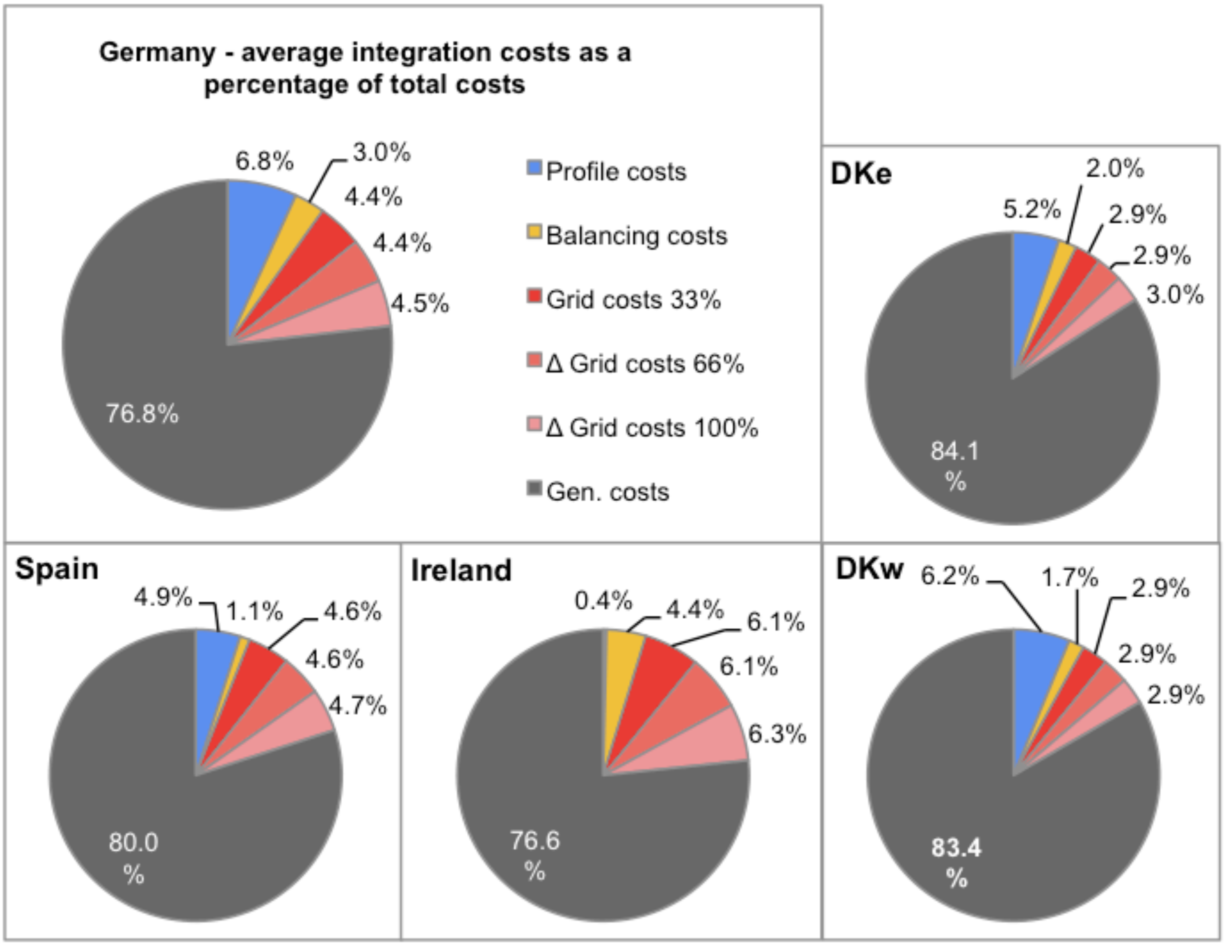


Figure 24 - Integration costs as a percentage of total costs (average of 2012-2013)

Figure 24 shows that integration costs comprise about 16 % of total costs in Denmark rising to about 24 % of total costs in Ireland. By considering these costs as a percentage of generation costs, which are equivalent to those normally paid by the investor, integration costs would equate to an additional 20 – 30 % on top of generation costs.

However, if only 33 % of grid costs are attributed to wind, integration costs as a percentage of total costs are reduced to 10 % in Denmark and 14 % in Germany. Similarly, if integration costs are given as a percentage of generation costs, the share reduces to 13 – 19 % (see Table 13).

Table 13 - Integration costs as a percentage of total and generation costs

	Cost Assumption	Germany	Spain	Ireland	DKw	DKe
IC as % of TC	Grid costs 33%	**14.2%**	10.6%	10.9%	10.8%	**10.1%**
	Grid costs 66%	**18.6%**	15.2%	17.0%	13.7%	**13.0%**
	Grid costs 100%	23.2%	20.0%	**23.4%**	16.6%	**15.9%**
IC as % of GC	Grid costs 33%	**18.5%**	13.3%	14.2%	13.0%	**12.0%**
	Grid costs 66%	**24.3%**	19.1%	22.2%	16.4%	**15.4%**
	Grid costs 100%	30.2%	25.0%	**30.5%**	20.0%	**19.0%**

NB: **Max**, **Min**

Therefore, integration costs for onshore wind generation vary depending on the electric power system in which they are installed.

It is also evident that integration cost estimates depend on the assumptions made prior to calculating them. Taking a midpoint (i.e. grid costs allocated at 66 %) to minimise the effect of assumptions, integration costs as a percentage of total costs vary from 13 – 19 % (approx. 10 – 16 €/MWh), equivalent to a 16 – 24 % premium for a private investor (summarised in Table 14).

Table 14 - Average total and integration costs using 66 % grid cost allocation

	DEU	ESP	IRE	DNK
Wind Penetration (% of demand)	8	20	14	36
Integration Cost (€/MWh)	14.57	12.78	15.56	9.89
Total Cost (€/MWh)	74.57	79.78	85.56	71.89

4.5.3 Integration costs and economic decisions

Additionally, it is worth knowing to what extent additional integration costs between 10 – 16 €/MWh would change the economic decision. That is, does adding integration costs change which generator would be most efficiently installed? Increased costs in any project affect investment decisions, however, the extent of their impact is dependent on the alternatives. Figure 25 shows the increase in generation cost estimates (LCOE estimates) if integration costs are added to wind. Assuming LCOE estimates are correct, it can be seen that onshore wind becomes uncompetitive against brown coal and the decision to install CCGT or black coal generation compared to wind becomes marginal. Using the point estimates given by EIA (2014) it is evident that integration costs have a marked affect, making wind less competitive than black coal and nuclear power.

However, the effect of 16 €/MWh is minimal considering the range of price estimates for wind generation costs in the first place. On average, a 16 €/MWh integration cost is equivalent to ¼ of the generation cost range. That is, the variability of estimates for wind generation costs is already so great that adding an integration cost of 16 €/MWh makes minimal difference. Given the aforementioned sensitivities regarding inputs for

LCOE calculations, this report argues that overall onshore wind integration costs of 10 – 16 €/MWh are relatively low.

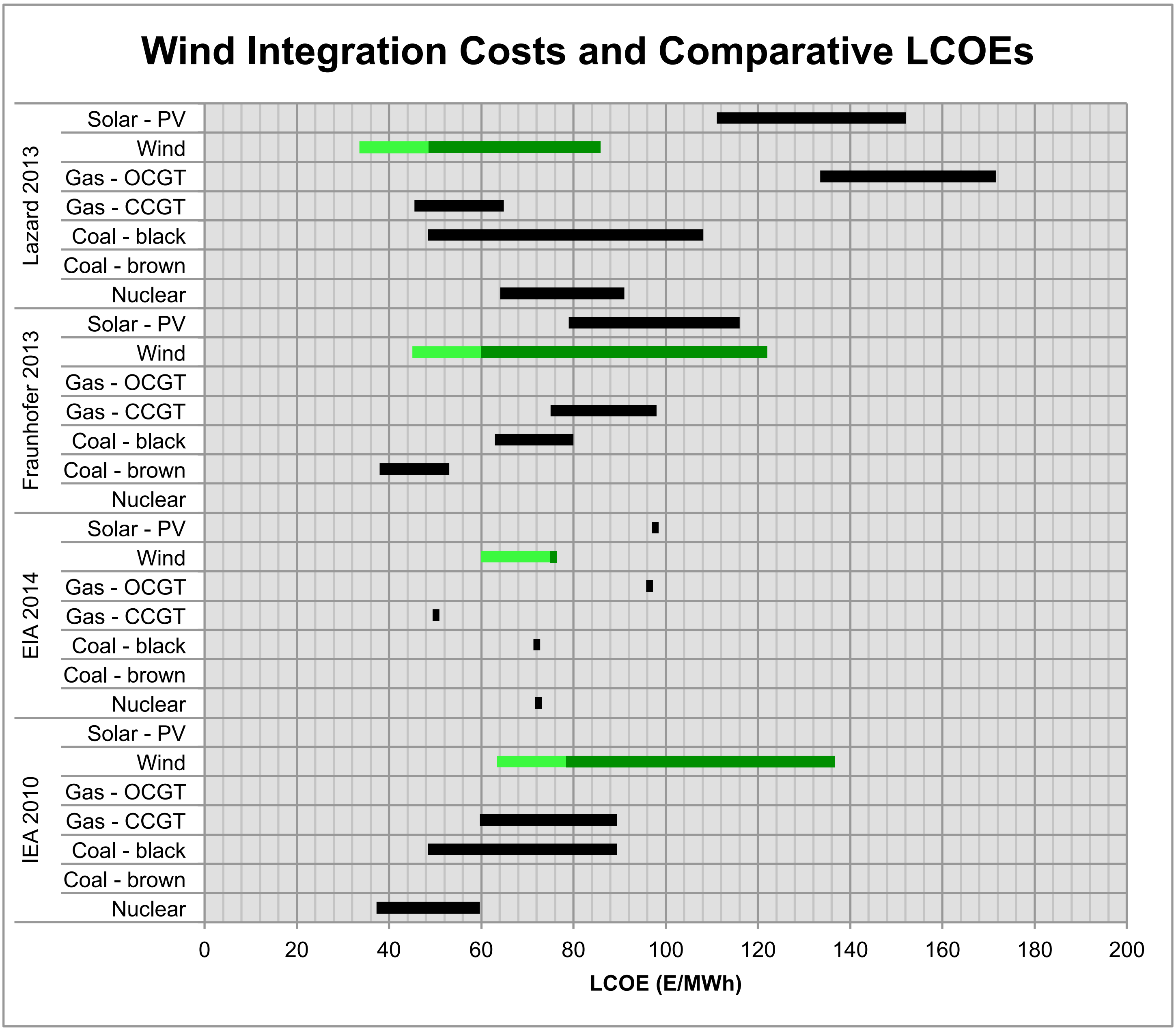


Figure 25 – Onshore wind integration costs and economic decisions

NB: Onshore wind integration costs shown in light green at 16 €/MWh

5. DISCUSSION

5.1 DISCUSSION ON THE METHODOLOGY

This study has quantified the total costs of VRE by investigating onshore wind generation in four distinct power systems: Germany, Spain, Ireland and Denmark over 2012 – 2013. After Hirth (2012a) and Ueckerdt et al. (2013), it has applied empirical, market based techniques to determine profile costs and balancing costs, two of the three components that make up integration costs. In contrast to computer models, this novel approach directly implements real-life data and analyses market behaviour. This collection of inputs from historical interactions of VREs on power markets, that are not based on assumptions nor uncertain forecasts are unique in the analysis of VRE costs.

In addition, the analysis is simple and requires nothing more than MS Excel™ such that those without high-level computing abilities can easily replicate and extend the results of this research.

However, while data inputs are real and have a high granularity they are not always consistent nor necessarily free from bias. For example, wind forecast timings as used in this report varied by more than 16 hours. As a time dependent variable, wind forecasts can markedly improve over this 16 hour period and influence balancing costs. Conclusions from inconsistent data are thus problematic because system characteristics are not the only variable. This shortcoming, unfortunately common in this type of research, can be remedied by the use of wind forecast data from another source like private or national meteorology bureaus. Hirth (2012a) suggests that bureau data is better than German TSO forecasts because the latter are biased.

A more fundamental shortcoming of the applied methodology is its assumption of "perfect and complete markets." Power markets have a way to go before they may be considered perfect or complete despite significant and ongoing market liberalisation in Europe. Market concentration is present in all four wholesale markets given Herfindahl-Hirschman Indexes (HHIs) exceed 1000 in all markets and 1800[20] in Germany (EC, 2011 and Nordic Energy Regulators, 2013). To assume an absence of market power in these four markets is false, even if proving its presence is difficult.

Furthermore, perfect markets are net of externalities and government intervention. This is obviously not the case. Negative environmental externalities are not internalised because of the EU's broken emissions trading scheme. Positive externalities, like an increased security of supply obtained from a peaking generator, produce heated debate on the topic "Are capacity payments needed."

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[20] HHI is a measure of market concentration. HHI < 1000 = adequate competition; HHI >1800 = inadequate competition. It is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers (EC, 2011).

Additionally, government intervention like price caps remove price signals and slows market response (IEA, 2005). This is especially true when price caps hardly reflect marginal costs, e.g. Spain's maximum wholesale price of 180 €/MWh.

The results of this report must be read with due caution recognising that the underlying assumption of market completeness is imperfect.

Grid costs, the third component of integration costs, have been estimated using country specific data found in long-term TSO planning reports. This is because grid costs pertaining to VRE like onshore wind, are notoriously difficult to determine. In the absence of locationally differentiated prices, no market based estimation is possible. Indeed, most estimates in the literature that do not use computer modelling techniques (see Holttinen et al.'s 2013 literature review) use TSOs' long-term reports.

While TSO reports provide country specific data to estimate grid costs they are limited in two ways. Firstly, the reports generally only provide total costs for all long-term network upgrades. To therefore partition costs despite any grid upgrade externalities, this report has assigned to onshore wind 33 %, 66 % and 100 % of total costs found in the TSO reports. This range provides a lower bound, an estimated cost attribution and a clear upper bound, respectively.

Secondly, TSO reports are subject to bias. Remunerated by governments and responsible for maintaining reliable grids, TSOs almost always overestimate grid upgrade costs. This ensures that after political negotiations, a reasonable amount of funding is won for network upgrades.

Estimating grid costs using TSO reports is therefore limited because neither the initial estimate is correct nor can the exact amount attributable to onshore wind be known. Nevertheless, the method is in line with existing techniques and enables a country specific value to be determined.

In order to simplify the analysis grid costs have also focused on transmission networks, neglecting additional or reduced costs that might result from distributed generation. Distributed generation is widely researched however. It would be valuable to consider this research in future integration cost analyses, especially considering so much VRE is connected directly to the distribution network.

The use of onshore wind employs the most cost competitive and widely installed VRE technology to provide a lower bound on total cost estimates for all other variable technologies. Comprehensive data for the technology ensures the research is feasible and well founded.

Finally, it should be noted that cost analyses such as this one are limited. "There is no single model that fully accounts for all costs and options"(Ueckerdt et al., 2013). In discussions with industry professionals and other authors like Cometto (2014) it is apparent that the estimation of integration costs is very much an *estimation.* Results in this study nevertheless concur with current estimates found in the literature.

5.2 DISCUSSION OF THE RESULTS BETWEEN COUNTRIES

This study has quantified total costs for four different power systems: Germany, Spain, Ireland and Denmark. Attributing 66 % of long-term system grid costs to onshore wind, it has calculated average costs over 2012 and 2013 as per Table 15. Integration costs today in the four analysed systems range between 10 – 16 €/MWh approximately.

Table 15 - Average total and integration costs by country

(€/MWh)	DEU	ESP	IRL	DNK
Penetration rate (%)	8	20	14	36
Profile Cost	5.33	4.16	0.34	4.23
Balancing Cost	2.36	0.93	4.00	1.40
Grid Cost 66%	6.88	7.70	11.22	4.26
Integration Cost	**14.57**	**12.78**	**15.56**	**9.89**
Total Cost	**74.57**	**79.78**	**85.56**	**71.89**

Generation cost or LCOE estimation methods have also been discussed. These estimates depend on seven input variables (IRENA, 2013), with key examples highlighting particular sensitivity to discount rates and amortisation periods. Even before considering integration costs, generation cost estimates are highly susceptible to input assumptions. The exemplar in Section 4.4 shows generation cost estimates vary by more than threefold (34 – 119 €/MWh)

What significance then is an integration cost between 10 – 16 €/MWh?

First, it is obvious these costs must be paid by someone. They are not generally paid by onshore wind farm investors. Yet, payment depends on which component of the costs is considered:

1. **Profile costs** in Germany, Spain and Ireland are socialised through feed-in tariffs, isolating wind investors from exposure to lower prices. In Denmark, profile costs are partially paid by wind producers and partially socialised. Danish wind producers are exposed to profile costs through lower market prices though they receive support through a feed-in premium which adds 33.5 €/MWh to the market price up to 22 000 full-load hours (Energinet.dk, 2011). Interestingly, recent decisions taken by the Spanish government in order to reduce the national tariff deficit have seen the abolition of feed-in tariffs and premiums for wind producers. Although replacing support with a scheme based on initial investment costs, this move exposes Spanish wind produces to profile costs.
2. **Balancing costs** in Germany and Spain are internalised through imbalance payments made to compensate for forecast errors. In Denmark and Ireland, balancing costs are socialised. In Denmark, units receive an additional balancing premium of 3.1 €/MWh (Energinet.dk, 2011) and in Ireland, wind generators

register as “Variable Price Takers” or “Autonomous” units in which they are exempt from paying balancing charges.

3. **Grid costs** are socialised in all four countries to varying degrees. German, Spanish and Danish connection charges are “shallow,” that is, they include connection costs (transmission line and associated equipment) but do not account for reinforcement charges. Shallow charges completely socialise grid costs as defined in this report. “Deep” connection charges, which include both connection and reinforcement costs, may be used in Ireland. This is because Irish connection charges are “partially deep,” calculated using the Least Cost Chargeable method which depends on the availability of appropriate infrastructure. If insufficient infrastructure exists, charges can include station common costs or station extension costs (whichever is higher; ENTSO-E, 2012). This is one exception where grid costs for Ireland may be partially paid by wind producers.

   Grid costs from losses are internalised in energy prices in Spain and Ireland, though not in Germany or Denmark.

Second, total wind costs (generation + integration costs) will alter investment decisions if integration costs are internalised by wind investors. A 10 – 16 €/MWh increase in generation costs is equivalent to a 13 – 19 % premium. If generation costs are taken to be equivalent with investor costs a 13 – 19 % premium will certainly alter investment decisions in renewable projects that commonly have hurdle rates of 10 % (WEC, 2013). However, it is impossible to assert that integration costs will alter *all* investment decision for a given system. For generation cost (LCOE) estimates vary so much that an integration cost of 16 €/MWh is four times smaller than the range of most LCOE estimates. Thus, whether integration costs alter the outcome of an investment decision depends on the generation/investment costs for the given project and the cost of alternatives, as shown in Figure 25.

Third, integration costs depend on the system in which wind is installed. This is evidenced by the range of estimates from 10 – 16 €/MWh. In quantifying costs for the four power systems this study found that penetration levels are not the determining factor of integration costs. While others have shown that penetration levels exacerbate integration costs (NEA, 2011; Ueckerdt et al., 2013; Holttinen et al., 2013) this study shows that the system context and market design have even more impact on integration costs. Four points were apparent:

1. Profile costs are lower in systems with interconnections and flexible hydro generation which both reduce price volatility (e.g. Denmark and Spain).

2. Profile costs depend on the existing generation mix and are almost eliminated where the merit order curve is very flat. This is evident in Ireland where many similarly priced CCGT units dramatically reduce the merit order effect. This is a curious finding because it implies that if the marginal generation in a system were supplied by a large quantity of similarly priced generators, profile costs would be low. However, the generation source need not be suitable for adapting to a variable energy in-feed from VRE generators. Thus, this finding should always be considered alongside Point 1 above and noted that at high enough

penetration levels the marginal technology will eventually change, altering prices.

3. Balancing costs are reduced by access to flexible hydro resources (e.g. Denmark and Spain)

4. Balancing costs are reduced by accurate wind forecasts. That is, the closer to real time VRE generators are able to sell their power, the lower the demand for costly balancing reserves (e.g. Spain). This conclusion supports that of Holttinen (2005).

This analysis is limited, however, in confirming precisely which system characteristics and market design elements influence integration costs. This arises because cost calculations do not in themselves determine influencing factors. As a result, the report recommends further research using econometric analysis to define the influence of various system characteristics (e.g. hydropower capacity, interconnection capacity, wind resource quality, etc.) and market designs (e.g. intraday market windows, balancing market pricing, centralised public wind forecasts, etc.).

5.3 APPLICATION OF THE FINDINGS

The introduction of VREs has dramatically altered the functioning of electricity markets. This report outlines the economic principles and fundamental effects of increasing VRE installation. It shows, through quantified integration costs for onshore wind, that these effects are impacting power systems today. In Germany, Spain, Ireland and Denmark where onshore wind penetrations range from 8 – 36 %, integration costs vary from approximately 10 – 16 €/MWh and total costs from 72 – 86 €/MWh. However, these estimates only consider externalities from the power system perspective. They do not consider broader environmental externalities, principally because the European carbon price is so low; nor do they include security of supply[21] externalities which arise because VRE units tap indigenous energy.

It is worth recalling that environmental concerns and security of supply were the principal drivers of renewable integration.

Climate change concerns remain at the forefront of global discussions and are more serious today than 23 years ago when Germany implemented the *Electricity Feed-in Act*. There remains strong international interest in getting a legally binding multilateral agreement to reduce greenhouse gas emissions at the United Nation's Climate Change Conference, *COP21*, in Paris 2015. Therefore any emissions offset by VREs ought to be quantified.

Security of supply, on the other hand, has received renewed interest following the events in Ukraine with Europe's largest gas supplier, Russia. Fossil fuel supply and price volatility risks can be examples of high risk cost streams. VRE technologies, however, are immune from supply risks. The late Shimon Awerbuch has written (2003) renewable

[21] This "security of supply" concerns overall primary energy sources. It is distinct from the aforementioned metric often used in electric power system which concerns voltage stability and the continual delivery of electrons.

energy costs are equivalent to "a 'societal insurance' against high fossil *fuel* prices, since they will pay off during times of high energy costs which are also [correlated with] bad economic times." Therefore fair assessments of total VRE costs should include some value that encapsulates the national or system based willingness to pay for increased supply security.

Furthermore, total costs for VRE should be compared with total costs of any generation source. Though VRE technologies are unique in their magnitude of variability they are not the only technologies to impose integration costs.

This report therefore recommends further research to determine environmental costs/benefits of VRE, security of supply costs/benefits of VRE and integration costs of conventional generation technologies in order to complete the assessment of VRE integration.

In any case, it is clear that generation investments and/or renewable support mechanisms should not use LCOE estimates in isolation. LCOE metrics are an oversimplification that assumes a constant price for electricity. The sensitivity of LCOE inputs, like discount rates and amortisation periods, show that primarily these estimates are highly susceptible to manipulation. But secondly, integration costs prove that additional costs are not accounted for, even if LCOE inputs were perfect.

For now, integration costs between 10 – 16 €/MWh may not be considered expensive. However, given the increase in these costs with rising penetration levels, this report strongly advises caution. To avoid inefficient decisions policy makers should use total cost methods like the one used in this study (after Ueckerdt et al., 2013) or implement auction strategies similar to those proposed by Joskow (2011). Cost comparisons like this will also illuminate the four pillars of power system adaptation to reduce VRE integration costs:

1. Demand response;
2. Flexible generation;
3. Interconnections; and,
4. Storage.

The disruptive transition VREs are causing in the electric power system is sometimes compared to the impact of the mobile phone on telecommunications or the internet on print media. Yet, informed of total costs and equipped to assess adaptation options, decision makers have all that is required to chart the best course through the energy transition.

6. CONCLUSIONS

This dissertation has calculated total costs of variable renewable energy sources (VREs) to quantify the often neglected integration costs across four different countries. A simple, novel, market based technique was used to calculate costs in Germany, Spain, Ireland and Denmark using market and transmission system operator data from 2012 and 2013. Onshore wind was chosen as the comparison technology because it is the most competitive VRE source, providing a lower bound for VRE integration costs, and the most abundant, with more publicly available data than any other VRE. Accordingly, total costs for onshore wind in these countries were estimated at 72 – 86 €/MWh, with integration costs between approximately 10 – 16 €/MWh. Given the extreme differences in power systems and market designs, this range in integration costs is considered small.

The report has completed a broad literature review which explains the challenges and fundamental effects of integrating large shares of variable generation in today's power systems. Implementing methodologies of previous works, it has defined total costs as the sum of generation costs and integration costs. Generation costs, commonly represented by levelised costs of electricity, are an insufficient metric for comparing generation sources. They are highly susceptible to primary inputs, like discount rates and amortisation periods, and do not account for system wide costs. Integration costs attempt to include these system costs and are comprised of three elements:

1. Profile costs: due to VREs variability
2. Balancing costs: due to VREs uncertainty
3. Grid costs: due to VREs location-specificity

In comparing integration costs across the four countries, this study finds that:

- Profile costs are lower in systems with interconnections and flexible hydro generation which reduce price volatility (e.g. Denmark and Spain).

- Profile costs depend on the existing generation mix and are almost eliminated where the merit order curve is very flat (e.g. Ireland).

- Balancing costs are reduced by access to flexible hydro resources (e.g. Denmark and Spain).

- Balancing costs are reduced by accurate wind forecasts. The closer to real-time VRE can be sold, the lower the need for costly balancing services (e.g. Spain)

- System characteristics and market design where VREs are installed have a greater impact on integration costs than the penetration level.

- If integration costs were internalised, investment costs would increase by 16–24 % and investment decisions would change.

Finally, this research concludes that even with extremely conservative grid cost estimates, integration costs are not excessively expensive. However, decision makers should desist in using antiquated levelised cost calculations and incorporate total costs of all generation technologies (VRE and conventional) in order to make well-informed, efficient decisions. Given climate change concerns and the need for governments to ensure a stable security of supply, prudent integration of VRE will be paramount for future power systems and economies.

6.1 RECOMMENDATIONS

This report has been limited in calculating costs because it has not been able to identify the precise influence of system characteristics and market design. It thus recommends further analysis (e.g. econometric) to determine the most pertinent factors of VRE integration cost reduction. It has only considered grid costs at the transmission level and recommends comparing research in distributed generation to determine how grid costs would change by including these sources. Having been limited to externalities within the power system, this study also recommends further analysis to determine positive environmental and security of supply externalities imposed by VREs. Finally, it highly recommends determination of integration costs of other VREs and conventional generators to provide a complete and fair cost assessment.

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APPENDIX A - COUNTRY OVERVIEWS

1.1 GERMANY

1.1.1 *General overview*

The German electric power system services a population of 81.9 million people with a strong manufacturing and export sector that focuses on chemicals, automobiles and technical products to make Europe's largest economy. The weather across the 357 000 km^2 which form continental Germany varies depending on location, however, summers generally range from 20-30 °C with winter temperatures well below zero. Snow falls throughout the country, particularly in Bavaria, the Baltic Coast and North German Plain. Peak demand is approximately 80-85 GW (E.ON, 2013) and occurs around 19:00 on a winter's night, generally reaching the annual peak in January (see Figure 26).

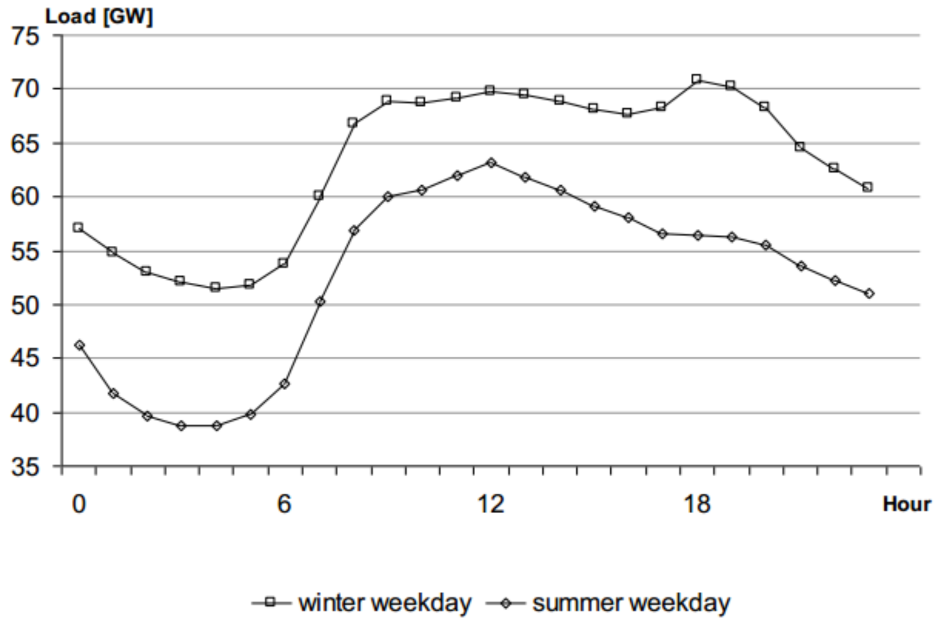


Figure 26 - Typical German winter and summer demand curves
(Source: ENTSO-E, 2010)

1.1.2 *Electric Power System and VRE*

Germany is Europe's largest electricity market with 178.3 GW of installed capacity as of 31 December 2012 (BNetzA, 2013). Around 75.6 GW (42.4 %) of installed generation is renewable. Table 16 below details the energy produced in the German system from various resources illustrated in Figure 27. It can be seen that despite an installed capacity of 42.4 %, only 22.1 % of energy is provided by renewable sources. Utilisation decreases further when only considering VRE sources which comprised 37 % of installed capacity, yet only generated around 12 % of energy consumed in 2013 (Fraunhofer, 2013). Specifically concerning wind, with an installed capacity of 34.2 GW (19.2 % of installed capacity) Germany generated around 8.4 % of total demand.

Table 16 - German power generation by source

	2012	2012	2013	2013
Source	*TWh*		*TWh*	
Lignite	160.7	25.5%	162	25.6%
Nuclear	99.5	15.8%	97.3	15.4%
Hard coal	116.4	18.5%	124	19.6%
Natural gas	76.4	12.1%	66.8	10.5%
Mineral oil products	7.6	1.2%	6.4	1.0%
Wind	50.7	8.1%	53.4	8.4%
PV	26.4	4.2%	30	4.7%
Water power*	21.8	3.5%	20.5	3.2%
Biomass	39.7	6.3%	42.6	6.7%
Household waste	5	0.8%	5.2	0.8%
Other	25.7	4.1%	25.4	4.0%
Total	629.8		633.6	

*Includes hydro, run-of-river and natural inflows to pumped hydro reservoirs
Source: Destatis, 2014.

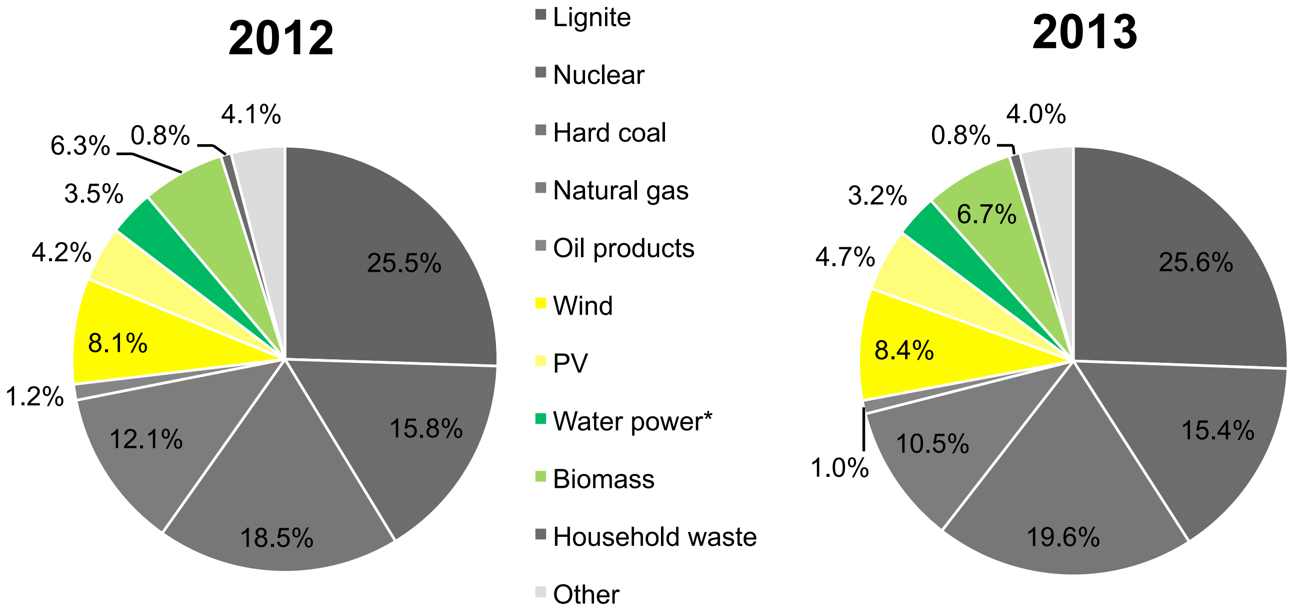


Figure 27 - Annual energy production by source

Unlike other countries who have liberalised and maintained one single regulated, TSO, Germany operates with four TSOs (Tennet, Amprion, TransnetBW and 50 Hertz) which follow the European trend of owning and operating the transmission networks. Figure 28 shows the geographical distribution of the TSOs.

Figure 28 - German TSOs and their balance control areas

Germany has more international interconnections by number than any other European country, connected to ten separate control areas. Figure 29 below gives indicative values for net transfer capacities (NTCs), demonstrating that approximately 17 GW of electricity (≈ 20 % of peak demand) can be transferred across international tie lines[22]. Knowledge of international transfer capacities is obviously significant when dealing with VREs because unexpected energy production or deficiencies from these sources can be, respectively, exported or imported.

[22] It is important to note that these values are indicative only. International capacity transfers are no simple matter with TSOs auctioning NTCs on a yearly, monthly, weekly and even daily basis. Available capacities are dependent on temperature, N-1 security criterion, intraday trading and other variables. There is usually a difference between import and export available capacities. Nonetheless, these figures give a rule-of-thumb figure useful for determining approximate available interconnection capacities. For more detail see ENTSO-E's interactive transmission tool: http://www.entsoe.net/dashboard/show NRL for DEU-LUX = *No Real Limit* in transfer capacity.

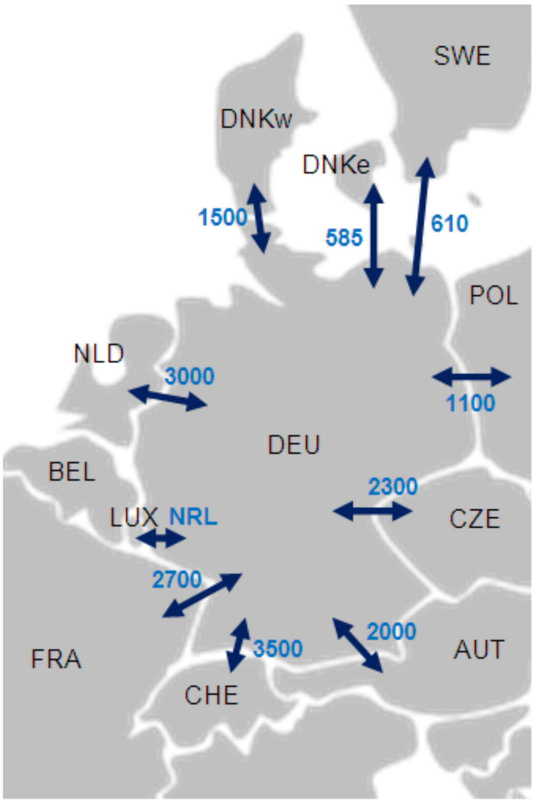


Figure 29 - Indicative NTCs for German tie-lines [MW]
(Source: ENTSO-E, 2011)

1.1.3 *Market Operations*

Day-ahead spot market

The European Power Exchange (EPEX SPOT), owned 50-50 by German based European Energy Exchange AG (EEX) and French Powernext SA, operates the electricity spot market for Germany, Austria, Switzerland and France, with the former two comprising a single price zone. In 2012 and 2013, respectively, approximately 34 % and 35 % of German and Austrian consumption was traded on the EPEX SPOT (EPEX, 2014a and EC, 2013). Members participating in the auction submit their bids for each hour to EPEX SPOT at 12:00 the day before physical delivery. EPEX SPOT then calculates the supply and demand curves, determining the intersection point and subsequent hourly spot price for the 24 hours commencing the next day. Prices are published 40 minutes later at 12:40.

The auction takes place seven days a week, year-long and accepts both hourly bids (simple bids) and block bids (semi-complex bids) where participants may specify price-quantity pairs to ensure a minimum operating time if their bid is accepted.

Intraday market

The EPEX SPOT also runs an intraday market where electricity trading can continue in the event that supply and demand situations (e.g. an unexpected plant outage or difference in wind forecasts) change after the day-ahead market has been cleared. Commencing at 15:00 the day before delivery (D-1), trading in the EPEX intraday market is continuous, matching supply and demand bids up until 45 minutes before physical delivery. Since December 2011, contract intervals as small as 15 minutes can be traded on the German market. There is however, only a small amount of electricity traded on EPEX intraday markets: in 2012 and 2013, respectively, approximately 15.5 TWh (≈ 2 % of DEU-AUT consumption) and 19.5 TWh (≈ 3 %; EPEX, 2014b).

Since 2009, TSOs have been required to trade wind imbalances on the intraday market. Accordingly, uncertainty of wind forecasts can now be shifted from balancing markets to, generally, more flexible intraday markets (Borgreffe and Neuhoff, 2011).

Balancing market

Under the German *Renewable Energy Sources Act* (EEG), German TSOs are obliged to correct wind energy imbalances (50 Hertz, 2014). Therefore, instead of correcting imbalances through the usual balance responsible party mechanism[23] (BRP or in Germany, *balancing group manager*) in which market trading entities are responsible for balancing their own deviations, TSOs directly assume this responsibility for wind generators by immediately correcting imbalances with the other TSOs. That is, TSOs effectively become the BRP for wind generators in their balance control area (see Figure 28). One of the smallest TSOs, TransnetBW (2014), remarks that this obligation forces them to "promptly absorb and balance approximately 14 % of the nationwide wind energy generation, whereas currently less than 2 % of the total wind capacity is physically connected in the TransnetBW control area." Payment for these services is thus socialised through electricity tariffs charged to consumers.

In Germany, a single price is calculated for deviations every 15 mins, based on TSOs total net costs of secondary and tertiary reserves used (Amprion, 2014). BRPs, or TSOs representing wind generators, with a surplus are paid the price for balancing group deviations and BRPSs with a deficit must pay the price for balancing group deviations (Amprion, 2014). Notably, it is the same, single price regardless, only in one circumstance BRPs are paid and in the other they pay. Despite the four TSOs in Germany there is only one balancing price calculated for the whole country known as the reBAP *(regelzonenübergreifender einheitlicher Ausgleichsenergiepreis*).

It is worth noting that there are systems (e.g. Nordpool) which use a dual price system consisting of the balancing price and the spot price. For example, if the system requires additional power and the BRP is imbalanced in the same direction (forecasts lower than demanded energy) then the BRP will pay the balance price because he exacerbates the system imbalance. Conversely, if the system requires less power and the BRP is imbalanced in the same direction (forecasts were higher than demanded energy) then the BRP will receive the balance price because he exacerbates the system imbalance. In both instances the BRP suffers a penalty: in the former, paying more for his power than the spot price he otherwise would have paid and in the latter, receiving less than the spot price he otherwise would have received. However, in the event that the BRPs imbalance is in the opposite direction to the system imbalance he will receive the spot price because he reduces the system imbalance.

[23] "A *balance responsible party* is a market player that is financially responsible for balancing injections and withdrawals (including possible purchases and sales) of electric power." (Pérez et al., 2013)

1.2 SPAIN

1.2.1 General overview

In 2004 the Spanish and Portuguese electricity markets merged to form MIBEL, the *Mercado Ibérico de la Electricidad*. The Iberian power system today serves the 59 million residents (47.3 million Spanish and 10.5 million Portuguese) over 597 900 km^2 which form the Iberian Peninsula. Both countries were heavily impacted by the 2008 financial crisis and effects can still be seen today. However, the Spanish economy has substantial tourism, automotive and energy sectors with Spanish energy major, Iberdrola today ranked as one of the world's largest renewable energy companies.

The Iberian climate is typically Mediterranean categorised by hot, dry summers and mild winters. Northern Spain generally has higher rainfall with a cooler, wetter climate, similar to Atlantic France. Annual summer highs of 28 °C with winter maximums around 14 °C are normal on the Mediterranean coast while inland, regions like Madrid have warmer summers at around 33 °C and cooler winters with highs of 11 °C. Snowfall is common though generally only in mountainous, inland regions. Peak demand in 2013 reached 40.3 GW on 27 February at 8:42 pm, a 7.5 % decrease from the previous year when 43.5 GW was demanded on 13 February at a similar hour (REE, 2013).

1.2.2 Electric power system and VRE

In 2013, there was approximately 102 GW of installed power on the Iberian Peninsula with over 22.7 GW of wind, 6.6 GW of solar, 17.7 GW of hydro and 25 GW of CCGT/OCGT as well as more than 18 GW of nuclear and coal fired plants. Large installations of renewable technology were promoted by the Spanish government through generous support schemes that saw installations grow at unsupportable rates, compounded by bizarre financing schemes that left the infamous "tariff deficit" owing to producers. This, combined with the harsh impact of the financial crisis on the Peninsula, sees Spain today with a significant over capacity of installed power.

Table 17 - Spanish Peninsula generation by source

	2012	2012	2013	2013
Source	*TWh*		*TWh*	
Nuclear	60.2	21.8%	56.4	21.2%
Coal	55.6	20.2%	39.8	14.9%
Fuel/gas	0.0	0.0%	0.0	0.0%
CCGT/OCGT	39.0	14.1%	25.4	9.5%
Wind	48.1	17.4%	53.9	20.2%
Solar PV	7.9	2.9%	8.0	3.0%
Solar thermal	3.4	1.2%	4.6	1.7%
Hydro	19.0	6.9%	34.2	12.8%
Hydro (< 50MW)	4.5	1.6%	7.1	2.7%
Thermal RES	4.9	1.8%	5.0	1.9%
CHP + other	33.3	12.1%	32.0	12.0%
Total	276.0		266.4	

Source: REE, 2012a & 2013

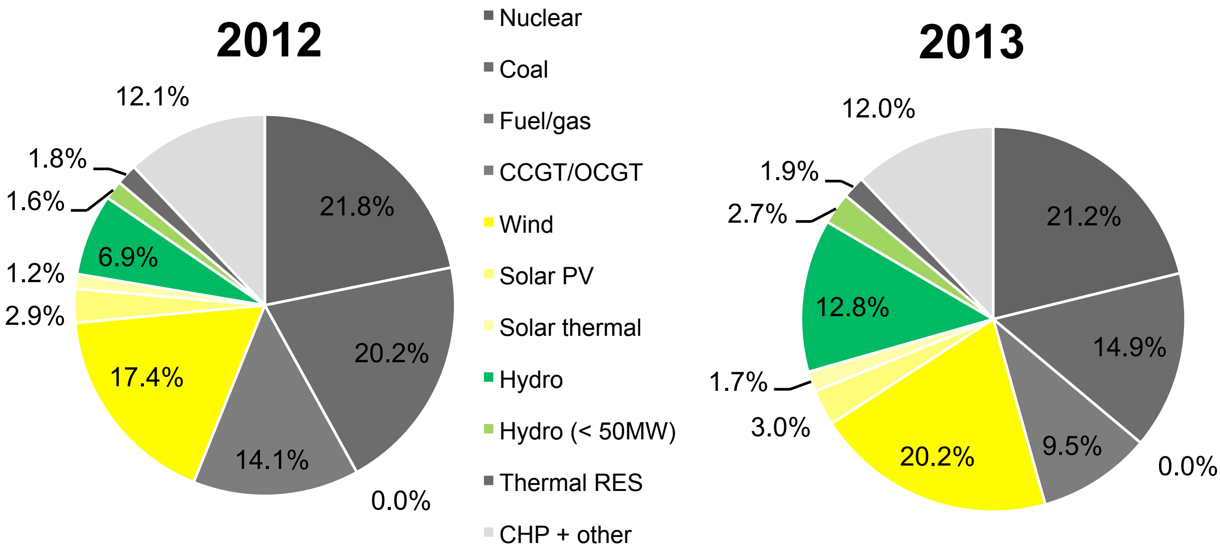


Figure 30 - Spanish Peninsula generation by source

From Table 17 and Figure 30 which show the Spanish Peninsula generation (i.e. not including Spanish islands like the Canary and Balearic nor Portugal), demonstrate that wind provides significant amounts of generation to the national grid. Wind energy comprised more than 22 % of installed capacity in both 2012 and 2013, albeit with significantly different outputs producing around 17.4 % of generated electricity in 2012, increasing to 20.2 % in 2013, despite only modest installations of 173 MW from 2012 to 2013.

Red Electric España (REE) is the Spanish TSO. However, as already mentioned, market operations are unified between Spain and Portugal with the former operating the daily spot and intraday market under the auspice of OMIE (*Operador Mercado Iberico España*) and the latter coordinating long-term trading of the futures and derivatives market through OMIP (*Operador Mercado Iberico Portugal*).

Interconnections to the Iberian Peninsula are limited (see Figure 31) with current tie-lines only capable of transferring 1400 MW between Spain and the European network (via France). While the *INELFE* project which would double this capacity has completed tunnelling the 8.5 km conduit through the Pyrenees, cable work remains unfinished. An additional 700 MW capacity exists between southern Spain and Morocco. It is the major connection between the European and North African network. An additional 2400 MW between Spain and Portugal opens the sizeable Portuguese hydro resources to the Spanish system, with expansion to 3000 MW planned through tie-lines in Galicia and Andalucía. As a percentage of peak demand, interconnections provide around 11 % if Spain-Portugal is included or only 5 % if the Iberian Peninsula is considered as a whole. This low interconnection capacity often leads authors to speak of Spain as an island system.

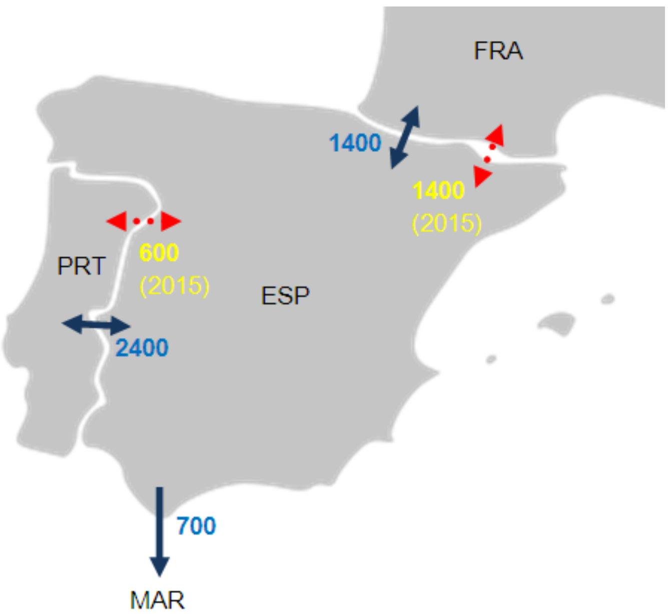


Figure 31 - Spanish interconnection NTCs: existing and under-construction
(Source: REE, 2012b)

1.2.3 Market Operations

Day-ahead market

The Iberian day-ahead market is operated by OMIE and closes at 12:00 CET D-1. Market rules oblige all generators without prior arranged physical contracts and with installed power greater than 50 MW to bid in the market either a simple or complex bids. Complex bids include conditions like minimum load hours, ramp rate conditions and total minimum income conditions for the day. The intersection of the supply (including complex bids) and demand curves then determines the marginal price of electricity. In 2013, 71 % of electricity in the Peninsula was traded on OMIE (OMIE, 2014).

Intraday market

The intraday market allows modification to the resultant day-ahead market schedule through six trading sessions open to all buyers and sellers who bid in the day-ahead market. Sessions run for 1:45 and are held between 17:00 D-1 and 12:00 trading day. In 2013, approximately 16 % of electricity traded on the day-ahead market was traded on the intraday market (i.e. 11 % of total electricity; OMIE, 2014). Borggrefe and Neuhoff (2011) argue that the focused trading through six sessions (as opposed to continual trading) elevates market liquidity in the Spanish system and despite increased renewable penetration has avoided the need for increased balancing services.

Balancing market

System balancing payments in Spain are managed by Red Eléctrica and utilise a dual price system, similar to Nordpool. In the Spanish context, imbalance prices are determined from ancillary service and system balancing costs according to Table 18:

Table 18 - Spanish imbalance pricing

Units which deviate from their programs		
	In favour of the system	**In opposition to the system**
Upward imbalances *(less consumption, more generation)*	Receive DMP	Receive minimum of: - DMP - Average price of downward energy used (SE + TR + DM)
Downward imbalances *(more consumption, less generation)*	Pay DMP	Pay maximum of: - DMP - Average price of upward energy used (SE + TR + DM)

Source: de la Fuente, 2013. DMP = Daily Marginal Price, SE = Secondary Energy, TR = Tertiary Reserves, DM = Deviation Management (Appendix XX for more info)

Interestingly, Spain has implemented the Control Centre of Renewable Energy (CECRE) that aggregates wind forecast and feed-in data to more efficiently manage RES generation. Communication and connection with CECRE is mandatory for all wind farms greater than 10 MW. CECRE therefore not only increases forecast and operational efficiency through data sharing but through central control is able to curtail wind as needed (Borggrefe and Neuhoff, 2011).

1.3 IRELAND AND NORTHERN IRELAND

1.3.1 General overview

The Irish electricity market serves 6.8 million inhabitants covering the 98 000 km^2 island which comprises the Republic of Ireland and Northern Ireland. The economy of the Republic of Ireland, home to more than 70 % of the island's inhabitants, is a service economy with many large multinationals thanks to its low 12.5 % corporate tax rate. However, Ireland is also a significant exporter of pharmaceuticals, medical devices and software and is Europe's largest zinc exporter and second largest lead exporter. On the other hand, despite Northern Ireland's heritage in heavy industry, particularly the renowned shipyards of Belfast, it is today mostly a service economy as well.

The weather across all of Ireland is not subject to extremes with temperatures around 18-20 °C in summer and 8 °C in winter. However, snow falls consistently in January and February and usually at other times throughout the year, even as late as April. The all-island peak demand is around 6 400 MW and usually occurs on the coldest days of winter. The north and west coast of Ireland are some of the windiest places in Europe (Met Éireann, 2014).

1.3.2 Electric power system and VRE

In 2013, between Northern Ireland and the Republic there was approximately 11.8 GW of installed capacity with 9.1 GW of conventional and 2.7 GW of wind generation (Eirgrid, 2012a). Utilising their wind resources, both governments have targeted wind generation to reduce emissions and dependence on gas imports, aiming to have 40 % of generation by renewables by 2020 (Eirgrid, 2013a). Installed capacity of wind in 2012 was over 18 % of total installed capacity (2.1 GW of 11.2 GW). From Table 19 and Figure 32 it can be seen that 14.4 % of gross consumption was produced by wind in 2012. Conventional generation by contrast made up around 81 % of installed capacity, yet generated approximately 81 % of consumed electricity. Over 2012 and 2013, wind had a capacity factor around 30 % (Eirgrid, 2013b).

Table 19 - Generation by source 2012

	2012	2012
Source	*TWh*	
Coal	5.5	19.8%
Peat	2.6	9.4%
Oil	0.3	0.9%
Gas	13.7	49.4%
Wind	4.0	14.4%
Hydro	0.4	1.5%
Other Renewables	0.8	3.0%
NR Wastes	0.1	0.2%
Total	27.8	100.0%

Source: SEAI, 2014

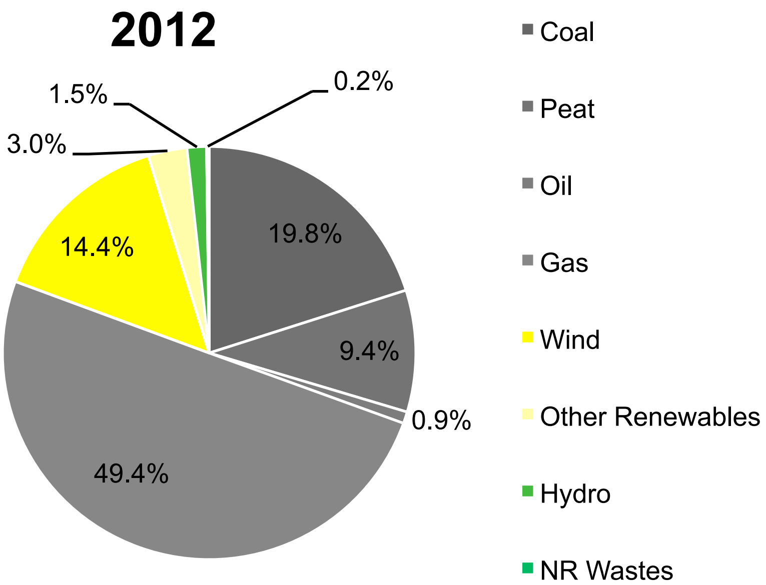


Figure 32 - Generation by source 2012

There are two Independent System Operators (ISOs)[24] on the island divided by a national border: Eirgrid (Republic of Ireland) and SONI (the System Operator of Northern Ireland). The two ISOs are owned by Eirgrid although operate as separate companies and, under contractual agreement, operate the Single Electricity Market Operator (SEMO) which coordinates trading throughout the island. The SEM is a gross mandatory pool market meaning all electricity traded in both Northern Ireland and Ireland is traded on this market, even utilising dual currencies (euros and pounds).

As a small island, there are only two interconnections, joining Ireland with the UK (Figure 33):

1. Moyle interconnector: Northern Ireland – Scotland; 400 MW NTC through HVDC (almost entirely import capacity, approx. 80 MW export)
2. The East West Interconnector (EWIC): Ireland – Wales; 500 MW NTC through HVDC

These two interconnections thus provide 900 MW of transfer capacity: 14 % of peak demand and 33 % of installed wind capacity, to assist in balancing the Irish electric power system.

[24] An *Independent System Operator* is responsible for transmission network operations but does not own the transmission network, as is the case with a TSO.

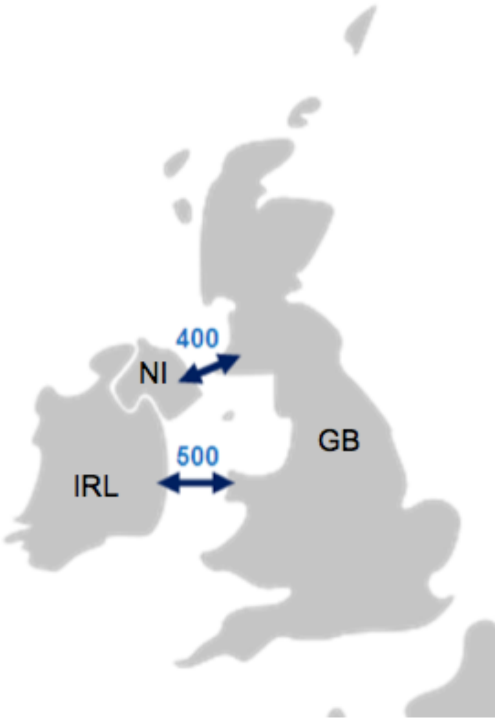


Figure 33 - Irish interconnections

1.3.3 Market Operations

Day-ahead market

The all-island Irish day-ahead spot market is a gross mandatory pool operated by the SEMO, a joint venture of Eirgrid and SONI. Unlike the German market clearing, generators and suppliers submit complex bids to SEMO. In addition to bid price and quantity these bids include technical offer data like ramp rates; and commercial offer data like no load costs, start up costs and price-quantity pairs. The complexity of this data means market clearing is more involved than simply crossing price and demand curves. Accordingly, these bids are processed by sophisticated software known as the Market Scheduling and Pricing (MSP) software and an optimal, least cost schedule determined. The cost of the marginal MW required to meet demand sets the *shadow price*. An *uplift* component is added to the shadow price to recover operating costs associated with start up and no load costs, such that the *system marginal price* (SMP), which defines the price for each trading period, is:

$$SMP = shadow\ price + uplift$$

To complicate matters, the MSP software is run five times, each time determining a different SMP. Namely, the *ex-ante 1* run determines the day-ahead market price; the *ex-ante 2* and *within-day* runs form the intraday market which is discussed in more detail below; and *ex-post 1* and *ex-post 2* occur after delivery and form the settlement prices, including all charges which form the final financial settlement.

In addition to the energy based SMP, the Irish market also includes a capacity payment which awards value to the MWs of power available at a given time. Specifically, "the capacity payments mechanism intends to strike a balance between providing the highest capacity prices at periods of highest loss-of-load probability... and providing a stable set of investment signals" (CER, 2013). Thus, capacity payments are made to units dependent on their availability and are funded by capacity charges levied on consumers. This mechanism is implemented to ensure system adequacy through continued dispatchable generation investment given the ambitious 40 % renewable targets.

In calculating the day-ahead spot prices for the island of Ireland it is important to note that despite there being five separate SMP calculations for a single day (*ex-ante 1*, *ex-ante 2*, *within-day*, *ex-post 1* and *ex-post 2*). This study has used the *ex-ante 1* (EA) price for profile cost calculations since all others involve intraday day trading corrections and would therefore bias the results compared to other systems. Additionally, intraday trading only commenced in July 2012 and would therefore introduce an additional and undesirable variable if incorporated into the analysis.

Intraday market

The intraday market has operated on the SEM since 22 July 2012. It was introduced because the market was deemed to be in breach of EU Electricity Regulations for not having a mechanism to manage intraday congestion at all interconnections. Intraday trading on the SEM thus allows unused capacity on interconnectors to be traded until the final gate closure. As previously mentioned, there are two dispatches which concern the intraday market: *ex-ante 2* with a gate window from 9:30 D-1 to 11:30 D-1 and *within day* with a gate window from 11:30 D-1 to 8:00 on delivery day. *Ex-ante 2* allows trading across the 48 half-hour time units of delivery day while the *within day* trading only allows trading on the second half of the delivery day (i.e. from 18:00 to 5:30 am; see Figure 34).

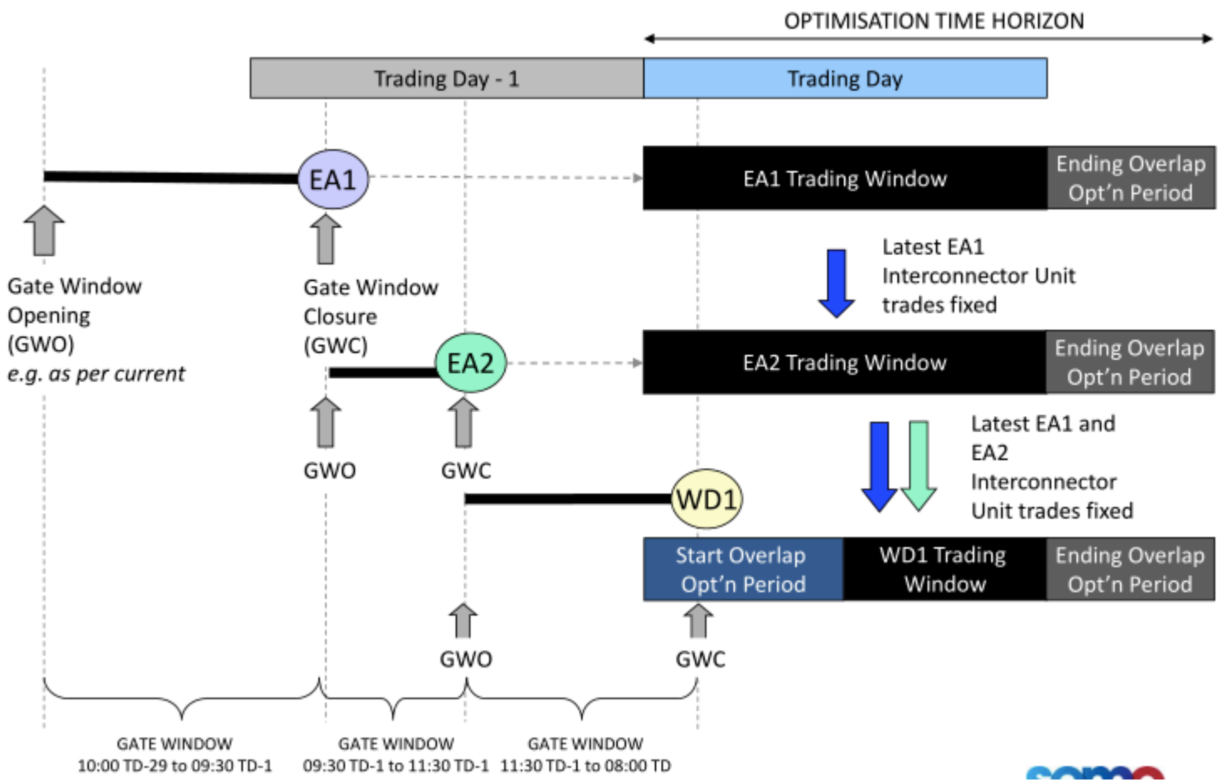


Figure 34 - Irish intraday trading schematic
(Source: SEMO, 2012)

Balancing market

The balancing market in the SEM, like many balancing systems, depends on whether the unit outputs more or less power than scheduled. Accordingly, units pay, or are paid, "Uninstructed Imbalance Payments" as follows (after CER, 2013):

- If the unit's actual generation is above its scheduled dispatch, the unit is paid, for each MWh, at the minimum of SMP and its dispatch offer price, less a nominated discount for over generation.
- Conversely, if the unit's actual generation is less than its scheduled dispatch, the unit must pay, for each MWh, the maximum of SMP and its dispatch offer price, plus a premium for under generation.

Notably, when generators register with SEMO they classify themselves under certain categories that alter the payments they are eligible/liable for. Variable generators like wind may only register under one of three categories:

1. Autonomous (non-dispatchable);
2. Variable Price Takers (partially "dispatchable"); or,
3. Variable Price Makers.

If they register as Autonomous units or Variable Price Takers, they receive the SMP for every MWh of power produced, however, units may only register as Variable Price Takers when they have priority dispatch (as almost all wind does). In the event a unit does not have priority dispatch, it must register as a Variable Price Maker and will enter the dispatch process (described above under *Day-ahead market*) being scheduled according to its complex bid and the outcome of the MSP software. Variable Price Makers then receive the SMP for every scheduled MWh minus the aforementioned balancing charges for over generation since Uninstructed Imbalance Payments only apply to Variable Price Makers when dispatched to deliver *reduced* output.

This classification of wind generators implies that any market based analysis of balancing charges will not reflect actual balancing costs since most wind units are registered as Autonomous or Variable Price Takers and do not pay imbalance charges. Furthermore, there is no balancing price determined by Irish TSOs and thus it is not possible to estimate balancing costs of forecast errors since SEMO data records only Imbalance Payments for each individual generator. As such, Irish balancing costs have been estimated using a literature review of previous studies.

1.4 DENMARK

1.4.1 General overview

The Danish electricity market serves around 5.9 million inhabitants over some 43 000 km². Geographically, the country is comprised of the Jutland peninsula and an archipelago of over 400 islands, although only 70 odd are inhabited. Despite limited natural resources, Denmark has a large agricultural sector, exporting significant volumes of food products as well as chemicals and pharmaceuticals. It has a significant transport sector encompassing rail and shipping (e.g. Maersk Group) as well as a strong fishing industry. In 2012 Danish GDP was US$ 314 billion.

The Danish climate experiences relatively mild winters with temperatures in winter averaging 0 °C and coolish summers at around 20 °C. Denmark receives over 900 mm of rain per year and has frequent snow from November to February. Danish weather is notorious for its unpredictability and rapid changes. Peak load occurs in the colder months, with demand reaching 6 142 MW on the 6th February 2012 (Nordic Energy Regulators, 2013) and 6002 MW on the 30th January 2013 (Nordpool, 2014a).

1.4.2 Electric power system and VRE

Installed capacity in the Danish power system is approximately 14 GW (2012) including 4.16 GW of wind power[25] and around 9.7 GW of thermal capacity, mostly comprised of combined heat and power plants (CHP). Nord Pool Spot (2014b) reports that in terms of generation greater than 100 MW, including coal, oil and gas units, there is only 4.2 GW installed, split roughly 50-50 between East and West Denmark. Accordingly, the majority of installed power is provided by smaller capacity units like CHP and windmills. As a percentage of installed capacity, wind represents nearly 30 % of capacity, yet contributes over 35.9 % of generated electricity (11.9 % of which comes from offshore sources). This figure is however, somewhat misleading given that Table 20 representing the generation by source does not show electricity imports/exports across interconnections (see below).

[25] Of the 4 160 MW, 782 MW are supplied by three offshore wind farms, with 130 MW in near-shore wind turbines. Onshore wind farms supply the balance.

Table 20 – Danish generation by source 2012

	2012	2012
Source	*TWh*	
Coal	9.6	33.1%
Oil products	0.2	0.7%
Natural gas	4.2	14.4%
Water	1.4	4.9%
Biofuels	3.1	10.8%
Hydro & PV	0.02	0.1%
Onshore wind	7.0	24.0%
Offshore wind	3.5	11.9%
Total	29.1	

Source: Energinet.dk, 2013

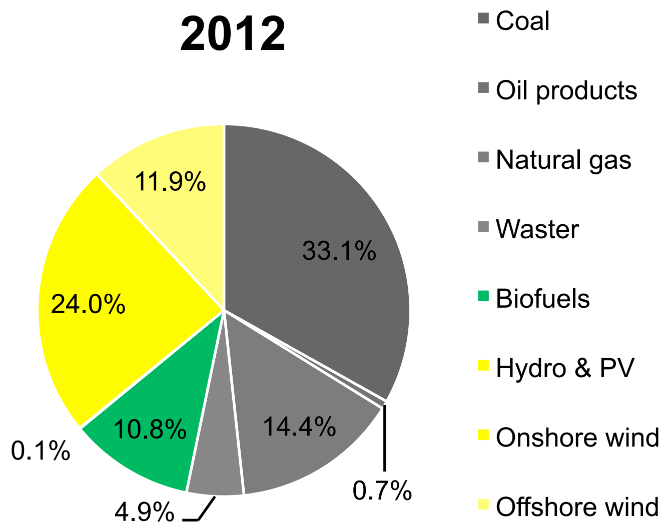


Figure 35 – Danish generation by source 2012

The Danish electricity market is split into two distinct zones: East Denmark (Zealand) and West Denmark (Jutland-Funen), without any transmission line between the systems. East Denmark is synchronised with the Nordic system and West Denmark is synchronised with the European system, although a single TSO, Energinet.dk presides over the transmission network (Energinet.dk, 2011). As shown in Figure 36 there are multiple international tie-lines in each system. Notably, while Figure 36 shows maximum export capacities, import capacities do not usually differ very much, although on the DNKw – DEU connection, imports are set at 1500 MW and on the DNKe – SWE at 1300 MW. The figure highlights most importantly that export capacities of 5.8 GW are approximately 97 % of peak demand and 140 % of installed wind capacity[26].

[26] Although not shown in the figure, import capacities are 70 % of peak demand and 94 % of installed wind capacity.

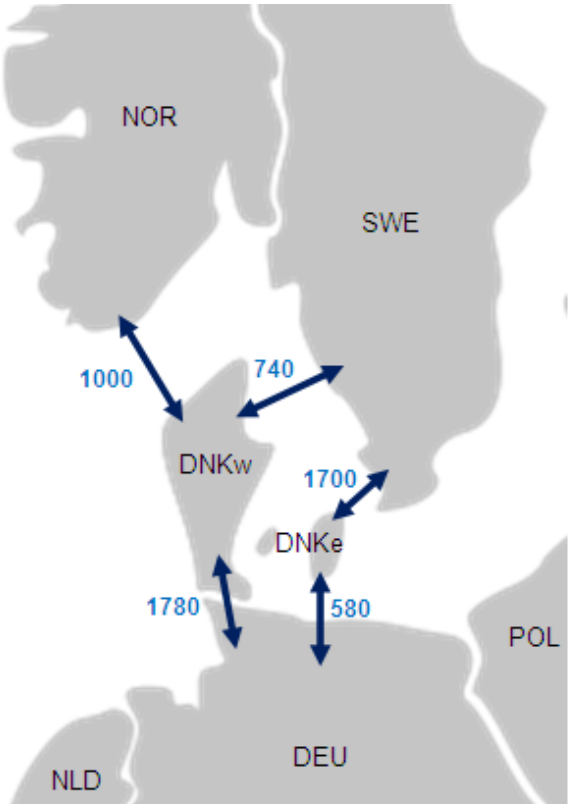


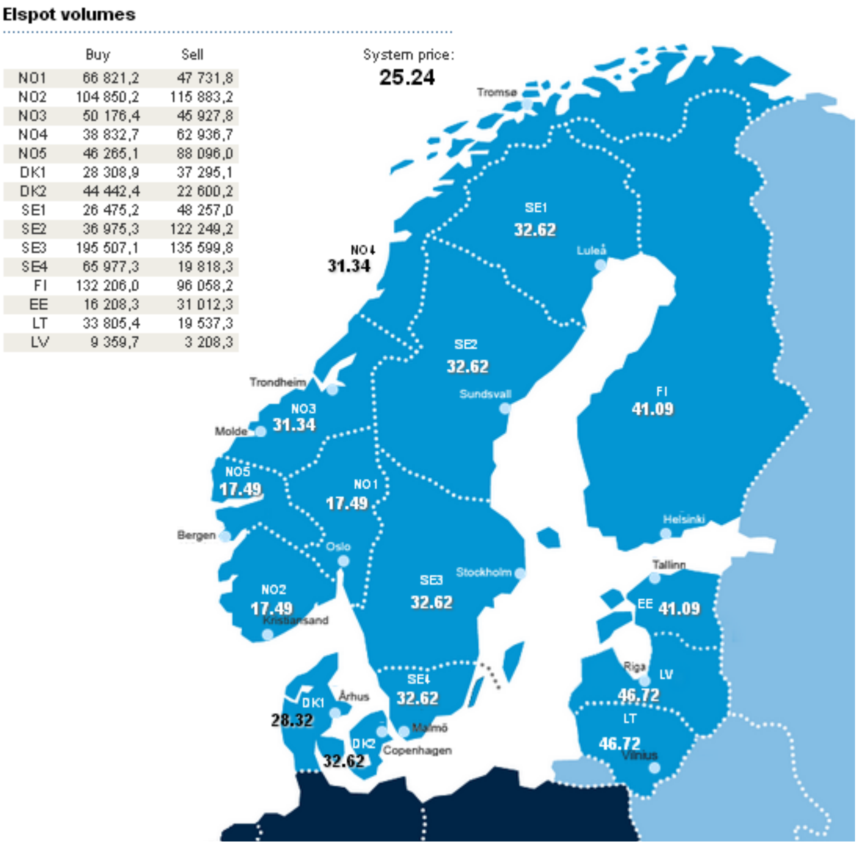
Figure 36 – Maximum export NTCs for Danish tie-lines
(Source: Nordpool, 2013b)

1.4.3 Market Operations

Day-ahead market

Typically, in Nordic countries around 75 % of all electricity is traded on the Nord Pool Spot power exchange (EC, 2013). Day-ahead trading closes on *Elspot* at 12:00 D-1. As bid supply and demand curves are then built and the system price determined at the intersection of the two curves. If transmission lines are constrained between bidding areas, then market splitting is activated and different area prices are determined in an attempt to relieve congestions and send more accurate price signals. Market prices are released as early as 12:42 D-1. Semi-complex block bids are also accepted in the Nord Pool Spot.

Currently, the minimum bid price is set at -500 €/MWh and the maximum at 3000 €/MWh (Nordpool, 2014).



	Buy	Sell
NO1	66 821,2	47 731,8
NO2	104 850,2	115 883,2
NO3	50 176,4	45 927,8
NO4	38 832,7	62 936,7
NO5	46 265,1	88 096,0
DK1	28 308,9	37 295,1
DK2	44 442,4	22 600,2
SE1	26 475,2	48 257,0
SE2	36 975,3	122 249,2
SE3	195 507,1	135 599,8
SE4	65 977,3	19 818,3
FI	132 206,0	96 058,2
EE	16 208,3	31 012,3
LT	33 805,4	19 537,3
LV	9 359,7	3 208,3

Figure 37 – An example of market splitting in Norway

Intraday market

Trading volumes on *Elbas*, Nordpool's intraday market, are published 14:00 D-1. Rather than operate between designated hours each day, Elbas is a continuous market that allows trading between parties until one hour before delivery. "Prices are set based on a first-come, first-served principle, where best prices come first – highest buy price and lowest sell price" (Nordpool, 2014b). Volumes traded on Elbas, which is open to Germany as well, are unsurprisingly much less than those traded on Elspot with 4.2 TWh traded on Elbas in 2013, compared to 348.9 TWh on Elspot.

Balancing market

For generation imbalances incurred less than one hour before delivery (i.e. after Elbas closure), balancing power is required and is managed by Danish TSO, Energinet.dk. As previously mentioned (Section 1.1.3 of Appendix A), Nordpool uses a dual pricing system. After Nordpool (2012), the balancing mechanism is as follows:

If the system requires up-regulation (there is a system wide shortage of power), then generators producing more than forecast will receive the market price (not the up-regulating price). However, generators producing less than forecast will be forced to pay the up-regulating price which is always greater than or equal to the market price. Conversely, if the system requires down-regulation (there is a system wide excess of power), generators producing more than forecast will be paid the down-regulating price (normally less than the market price). Generators producing less than forecast, however, will be paid the market price. Figure 38 explains this is diagrammatic form:

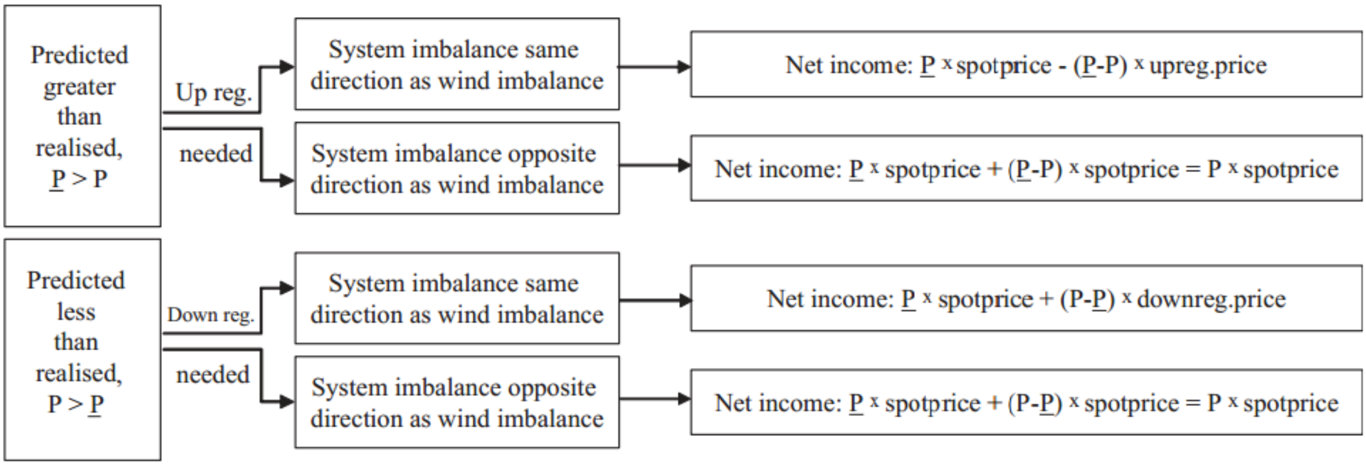


Figure 38 - Danish dual price balancing market
(Source: Holttinen, 2005)

Appendix B – Spanish Ancillary Services

Although there is an important distinction to be kept in mind between balancing markets and ancillary services, the pricing used in Spanish balancing markets is derived from ancillary service pricing. Accordingly, a brief overview of ancillary services should be enlightening for our discussion.

In Spain, generators are required to provide different types of ancillary services and are charged different prices depending on which services are required. The four types of services demanded are as follows:

1. Primary reserves
2. Secondary reserves
3. Tertiary reserves
4. Deviation reserves

Primary reserves are obligatory and non-numerated. They stipulate that a generator must be able to provide up or down-regulation at 1.5 % of their nameplate capacity.

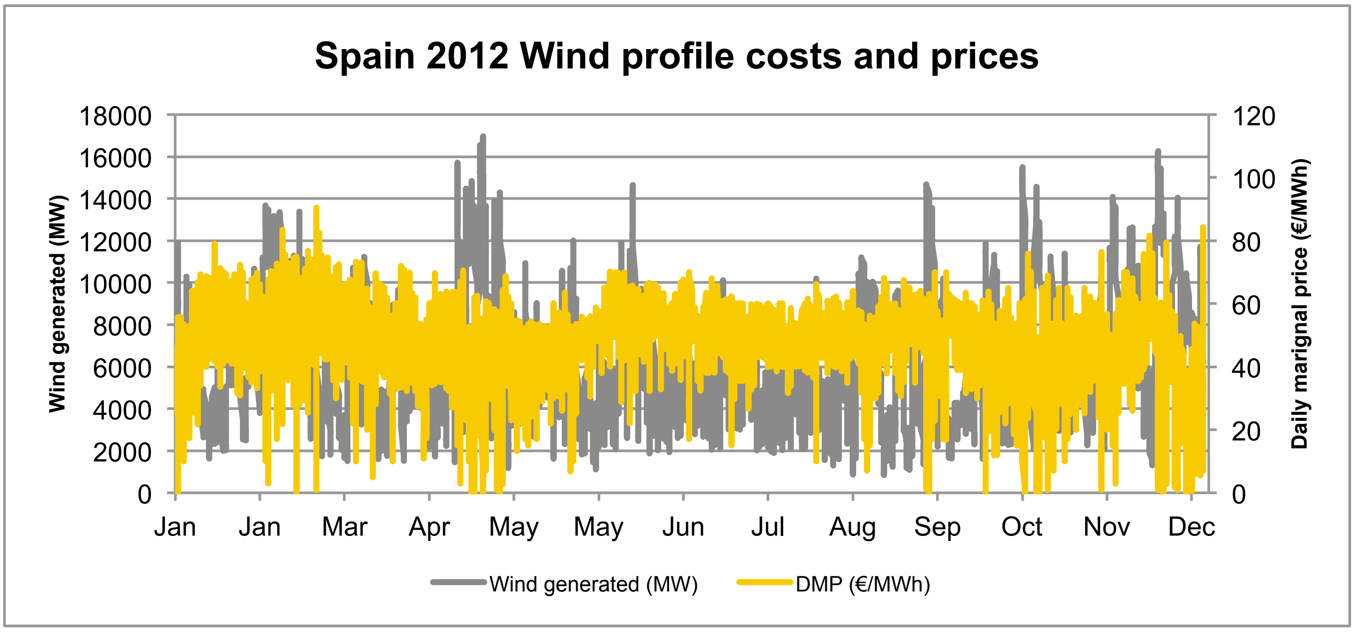
Secondary reserves are used to manage system frequency and power deviations which occur across international exchanges. Interestingly, Spain is the only country in the world which has a secondary reserve market. Pérez-Arriaga (2010) provides a good market overview:

> The market commences at 16:00 after the close of the day-ahead market, where required bands (of power, MW up and down) are specified by the TSO. Generators then bid *prices* (€/MW) and *bands* (MW) to go up and down as they desire. A marginal price is thus determined for available *capacity* (€/MW) and the cost charged as an uplift to consumers. All *energy* used is then paid the price of tertiary reserves (€/MWh) and the cost charged to generators and consumers who use secondary reserves.

Tertiary reserves act to recover or replenish secondary reserves. They are offered by generators in blocks of price-quantities (€/MWh), moving either up or down. An economic priority list is made by the SO and all used bids in each hour are paid the price of the most expensive bid used in that hour. These costs are charged to the agents who use the services (Pérez-Arriaga, 2010).

Deviation management is used to balance large deviations (≥ 300 MWh) after the close of intraday trading. These deviations may occur because of generator unit unavailability or justifiable schedule changes.

Appendix C – Spanish Wind



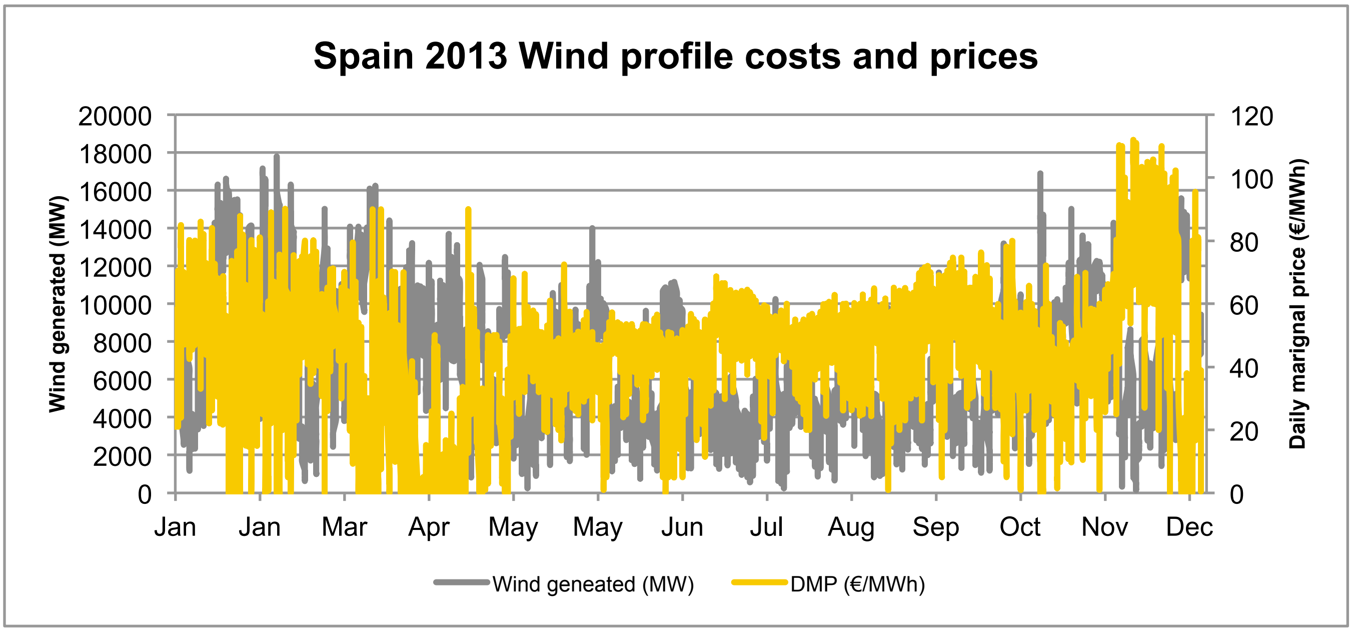


Table 21 - Standard deviations in Spanish wind

	2012	2013
σ DMP	13.13	20.74
σ Wind	2951	3530