The Economics of Wind and Solar Variability

How the Variability of Wind and Solar Power affects their
Marginal Value, Optimal Deployment, and Integration Costs

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Non-technical summary

Variable renewable energy sources (VRE) for electricity generation, such as wind and solar power, are subject to inherent output fluctuations. This variability has significant impacts on power system and electricity markets if VRE are deployed at large scale. While on global average, wind and solar power currently supply only a minor share of electricity, they are expected to play a much larger role in the future – such that variability will become a major issue (which it already is in some regions). This thesis contributes to the literature that assesses these impacts the "system and market integration" literature.

This thesis aims at answering the question: What is the impact of wind and solar power variability on the economics of these technologies? It will be laid out that the impact can be expressed in (at least) three ways: as reduction of value, as increase of cost, or as decrease of optimal deployment. Translating between these perspectives is not trivial, as evidenced by the confusion around the concept of 'integration costs'. Hence, more specifically: How does variability impact the marginal economic value of these power sources, their optimal deployment, and their integration costs? This is the question that this thesis addresses.

This study comprises six papers, of which two develop a valuation framework that accounts for the specific characteristics of the good electricity, and the specific properties of wind and solar power versus "dispatchable" power plants. Three articles then assess quantitative questions and estimate marginal value, optimal deployment, and integration costs. These estimates stem from a newly developed numerical power market model, EMMA, market data, and quantitative literature reviews. The final paper addresses market design.

In short, the principal findings of this thesis are as follows. Electricity is a peculiar economic good, being at the same time perfectly homogenous and heterogeneous along three dimensions - time, space, and lead-time. Electricity's heterogeneity is rooted in its physics, notably the fact it cannot be stored. (Only) because of heterogeneity, the economics of wind and solar power are affected by their variability. The impact of variability, expressed in terms of marginal value, can be quite significant: for example, at 30% wind market share, electricity from wind power is worth 30-50% less than electricity from a constant source, as this study estimates. This value drop stems mainly from the fact that the capital embodied in thermal plants is utilized less in power systems with high VRE shares. Any welfare analysis of VRE needs to take electricity's heterogeneity into account. The impact of variability on VRE cannot only be expressed in terms of marginal value, but also in terms of costs, or in terms of optimal deployment. The mentioned value drop corresponds to an increase of costs by 30-50%, or a reduction of the optimal share by two thirds.

These findings lead to seven policy conclusions:

1. Wind power will play a significant role (compared to today).
2. Wind power will play a limited role (compared to some political ambitions).
3. There are many effective options to integrate wind power into power systems, including transmission investments, flexibilizing thermal generators, and advancing wind turbine design. Electricity storage, in contrast, plays a limited role (however, it can play a larger role for integrating solar).
4. For these integration measures to materialize, it is important to get both prices and policies right. Prices need to reflect marginal costs, entry barriers should be tiered down, and policy must not shield agents from incentives.
5. VRE capacity should be brought to the system at a moderate pace.
6. VRE do not go well together with nuclear power or carbon capture and storage – these technologies are too capital intensive.
7. Large-scale VRE deployment is not only an efficiency issue, but has also distributional consequences. Re-distribution can be large and might an important policy driver.

Zusammenfassung

Die Variabilität von Wind- und Solarenergie hat signifikanten Einfluss auf Stromsysteme und Elektrizitätsmärkte, sobald diese Technologien in signifikantem Maßstab Anwendung finden. Im weltweiten Durchschnitt erzeugen solche „variablen Erneuerbaren“ heute zwar nur 2.5% der elektrischen Energie, aber alle Prognosen weisen auf eine zunehmende Bedeutung hin – und eine Reihe von Ländern erreicht schon heute Wind- und Solaranteile von 20% oder mehr. Diese Doktorarbeit trägt zu System- und Marktintegrations-Literatur bei, die die Effekte der Variabilität untersucht.

Welchen Einfluss hat die Variabilität von Wind- und Solarenergie auf die Wirtschaftlichkeit dieser Technologien? Der Einfluss lässt sich in (mindestens) drei Perspektiven darstellen: als Reduktion des ökonomischen Wertes (Grenznutzen) von Windstrom, als Anstieg der Erzeugungskosten, und als Reduktion des wohlfahrtsoptimalen Ausbaus. Zwischen diesen drei alternativen Perspektiven zu übersetzen ist nicht trivial, wie die Unklarheiten und Missverständnisse um das Konzept von „Integrationskosten“ belegen. Deshalb die Forschungsfrage, noch einmal, präzisiert: Wie beeinflusst die Variabilität von Wind- und Solarenergie den Wert, die optimale Menge, und die Integrationskosten dieser Technologien?

Diese Studie besteht aus sechs eigenständigen Artikeln. Zwei davon entwickeln einen ökonomischen Analyserahmen, in dessen Zentrum die spezifischen Eigenschaften des Gutes Strom sowie die spezifischen Eigenschaften von Wind- und Solarenergie als Stromerzeuger stehen. Im Anschluss untersuchen drei Artikel quantitative Fragen und schätzen den Wert und den optimalen Ausbau von variablen Erneuerbaren. Diese Artikel basieren auf dem dafür entwickelten numerischen Strommarktmodell EMMA, auf einer ökonometrischen Auswertung empirischer Marktdaten, sowie einer quantitativen Metastudie der publizierten Literatur. Der letzte Artikel befasst sich mit Fragen des Marktdesigns.

Die zentralen Ergebnisse lassen sich wie folgt zusammenfassen. Strom ist ein spezielles ökonomisches Gut, das gleichzeitig perfekt homogen und heterogen ist. Strom ist entlang dreier Dimensionen heterogen: Zeit, Raum, und Vorlaufzeit. Diese Heterogenität ergibt sich aus der Physik von Elektrizität, insbesondere ihrer Nicht-Speicherbarkeit. Als unmittelbare Konsequenz beeinflusst die Variabilität von Wind und Solar deren Wirtschaftlichkeit. Beispielsweise ist der Wert von Windstrom bei einem Wind-Marktanteil von 30% etwa 30-50% geringer als der Wert von Strom aus einer konstanten Quelle. Diese Wertminderung ist vor allem darauf zurückzuführen, dass in einem Stromsystem mit hohem Windanteil kapitalintensive thermische Kraftwerke schlechter ausglastet sind. Der Einfluss von Variabilität lässt sich nicht nur in Wertverlust ausdrücken, sondern als Kostenanstieg, oder als Einfluss auf die optimale Menge. Der genannte Wertverlust entspricht einem Kostenanstieg von 30-50% oder einer Reduktion des optimalen Windanteils um zwei Drittel.

Daraus lassen sich sieben politik-relevante Schlussfolgerungen ableiten:

1. Windkraft wird eine signifikante Rolle im zukünftigen Strommix spielen (im Vergleich zu heute).
2. Gleichzeitig wird ihre Rolle begrenzt sein (im Vergleich zu einigen politischen Ambitionen).
3. Es gibt eine Reihe von effektiven Maßnahmen, um Windkraft in Stromsysteme zu integrieren, wie Investitionen in Übertragungsnetze, Flexibilisierung von thermischen Erzeugern, und neuem Turbinendesign. Stromspeicher spielen dagegen eine untergeordnete Rolle (sind allerdings für Solarenergie relevanter).
4. Um diese Änderungen anzureizen, müssen effiziente Preissignale vorhanden sein.
5. Der Ausbau der Erneuerbaren sollte in einer angemessenen Geschwindigkeit erfolgen.
6. Variable Erneuerbare sind keine guten Komplementärtechnologien zu Kernkraft oder CCS – diese Technologien sind zu kapitalintensiv.
7. Der Ausbau der Erneuerbaren ist nicht nur eine Frage von Effizienz, sondern auch von Umverteilung. Umverteilungseffekte können quantitativ bedeutsam sein und sind möglicherweise ein zentraler politischer Treiber.

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I am indebted to many of my friends and colleagues for support, help, and inspiration during the last years. I would like to thank my colleagues at Vattenfall and PIK for their patience and generosity. I would like to thank the participants of numerous conferences and workshops for their feedback and ideas, and the members of Strommarktgruppe for their support and inspiration. I have enjoyed these past years a lot, thanks to you.

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Chapter 1

Introduction

Chapter One: Introduction

Variable renewable energy sources (VRE) for electricity generation, such as wind and solar power, can only generate electricity if the primary energy source is available, such as the kinetic energy of wind and radiant energy is solar radiation. Wind speeds, solar radiation, and temperature fluctuate with weather, climate, and the rotation of the earth, hence the output of wind and solar power is variable. VRE output variability has significant impacts on power system and electricity markets if they are deployed at large scale. This thesis contributes to the system and market integration literature that assesses these impacts. My aim is to identify, explain, and quantify the economic consequences of variability on wind and solar power.

What is the impact of wind and solar power variability on the economics of these technologies? The impact can be expressed in (at least) three ways: as reduction of value, as increase of cost, or as decrease of optimal deployment. Translating between these perspectives is not trivial, as evidenced by the confusion around the concept of 'integration costs'. Hence, more specifically: How does variability impact the marginal economic value of these power sources, their optimal deployment, and their integration costs? This is the question that I want to address in this thesis.

The thesis consists of an introduction, six articles, and a conclusion. Two articles, ECONOMICS OF ELECTRICITY[1] and FRAMEWORK, develop analytical concepts and a valuation framework. Three papers answer primarily quantitative questions, MARKET VALUE, OPTIMAL SHARE, and REDISTRIBUTION. Based on numerical modeling, market data, and quantitative literature surveys, they provide estimates of the marginal value and optimal deployment of wind and solar power. The last article, BALANCING POWER, addresses market design questions.

The remainder of this introduction motivates the research topic, details research questions, and outlines the thesis. The first section argues that an analysis of VRE is relevant, because wind and solar power will account for a significant part of future electricity supply. Section 2 shows that this thesis is a topical contribution, as it contributes to three major public policy debates. In section 3, I claim that standard economic analysis does not account for important characteristics of the good "electricity" and explain how this work extends economic theory and modeling. Section 4 argues that VRE feature specific properties that require an extension of standard tools in power system analysis. Section 5 presents the two existing branches of the literature that assess the economics of VRE, identifying crucial gaps in the literature. Having established the context, section 6 breaks down the high-level research question into more specific questions, and section 7 clarifies what is beyond the scope of this thesis. Section 8 introduces the numerical power market model EMMA that I have developed for this dissertation. Section 9 present the articles and outlines the structure thesis.

1. *The increasing importance of wind and solar power*

Today, wind and solar power supply not more than 2.5% of global electricity (REN21 2013). Hence, studying VRE and their impact at high penetration rates might seem of little relevance. This section argues that studying variable renewables is indeed relevant, because their market share are growing fast and they will play an important role in global future electricity supply. The following paragraphs provide an updated of the recent development of variable renewables and their prospects: the political landscape, the current status of built-out, recent technological progress, and their role in long-term mitigation scenarios.

Policy makers all around the world have ambitious plans for electricity generation from renewable sources, as evidenced by quantity targets and support policies. Overall 138 countries have formulated renewable en-

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I would like to thank Meike Riebau, Eva Schmid, Brigitte Knopf, and Alice Färber for helpful comments.

[1] For brevity, I term the articles "Economics of Variability", "Framework", "Market Value", "Optimal Share", "Redistribution", and "Balancing Power" and denote them in SMALL CAPS. Full references are given in Table 2.

ergy targets and virtually all of them have implemented support policies, many of which specifically target the electricity sector (REN21 2013). In addition, there are myriads targets and policies at federal state or local level. The European Union has set a renewables target in electricity generation of 35% by 2020[2] and suggests a renewables target of 60-80% of electricity consumption by 2050 (European Commission 2011). All EU member states have implemented policies to support renewables deployment and more than half of all U.S. states have implemented renewable portfolio standards (DSIRE 2013). These policies are motivated by a multitude of arguments, including mitigation of greenhouse gases and local pollutants, security of supply and import independence, industrial policy and green jobs (Borenstein 2012, Edenhofer et al. 2013).

Support policies have resulted in dramatic growth of global capacity and electricity generation from renewable sources, especially from VRE. The global share of renewables in electricity generation is 22%, of which three quarters stem from the traditional electricity source hydro power. Wind and solar power currently play a small role, supplying 2.1% and 0.4% of global electricity, respectively, but they are growing fast: wind power capacity has reached 280 GW, a three-fold increase since 2007. Most capacity is installed in China (26%), USA, Germany, and Spain. Solar PV capacity is 100 GW, a ten-fold increase since 2007, with most capacity is installed in Germany (32%), Italy, USA, and China (all data end of 2012, REN21 2013)

During the past three years, $ 250 bn p.a. were invested in renewables, more than 90% of which into wind and solar power (IEA 2013). According to IEA's (2013) mid-term projections, renewables will surpass natural gas, become second-largest electricity source after coal, in 2016. The renewables share in electricity, 19% in 2006, will rise to 25% by 2018, and non-hydro renewables account for all of the increase in market share (see also Figure 1). The growth will accelerate significantly in the five years to come, compared to the last quinquennium. This will be accompanied by a geographic shift away from OECD countries, with 40% of the 2012-18 growth taking place in China. The IEA projects that until 2018, global wind capacity will double, solar PV capacity triple, while biomass and hydro will only grow by 50% and 20%, respectively.

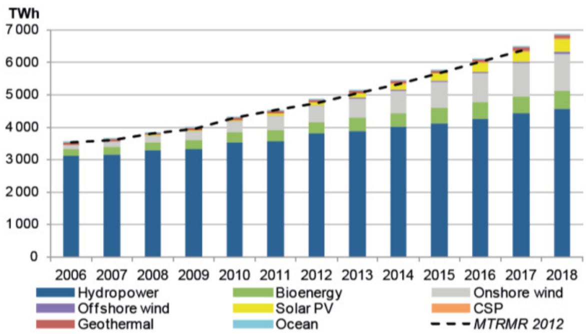

Figure 1: Global renewables electricity generation. 2013-18 numbers are projections. Total generation was 25,700 TWh in 2012. Source: IEA (2013)

In the European Union, VRE play a larger role than on the global average. Renewables supply 26% of electricity, of which hydro delivers 11%, wind 7%, biomass 5%, and solar 3%. Hence the VRE share is four times the global average, and it is growing dynamically. In the last twelve years, while hydro generation decreased by 1% p.a., biomass grew by 14%, and VRE by 25% – wind by 20% and solar by 80%. Moreover, wind and solar power growth has accelerated since 2008, the 2012 increase of VRE being larger than total five-year growth 2001-06 (Figure 2). At EU level, the current growth rate of wind power is about 10 GW p.a., almost in line with action plan targets. Solar power has even grown by 15-20 GW p.a. during the last three years, much more than planned (Figure 3). Several countries now accommodate high VRE shares in their power systems, including Denmark (30%), Spain (23%), Ireland (17%), and Germany (15%), see Fig-

[2] Aggregated from National Renewable Energy Action Plans. Beurskens & Hekkenberg (2011), ENTSO-E (2011), PointCarbon (2011) and ENDS (2010) provide comprehensive summaries of the 27 NREAPs. DG Energy provides the national action plan documents themselves: www.ec.europa.eu/energy/renewables/transparency_platform/action_plan_en.htm

ure 4 (all data end of 2012, IHS 2013a). These high shares have led to significant impacts on power markets and challenges to system integration, which has sparked major public policy debates, as will be discussed in the following section.

The dynamic development of VRE has led some observers to conclude that "the Energiewende is all about wind and solar power" (Agora 2013). In this context, it is remarkable that only 20 years ago, German utilities claimed in a public advertisement campaign that renewables "cannot supply more than 4% of electricity, even in the long-term".[3]

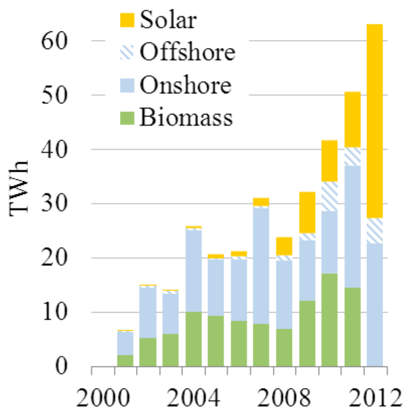

Figure 2: Increase in renewable electricity generation in the EU-27. Hydro generation (not shown) fluctuates widely between years, but did not increase over the years. Source: own work based on IHS (2013a)

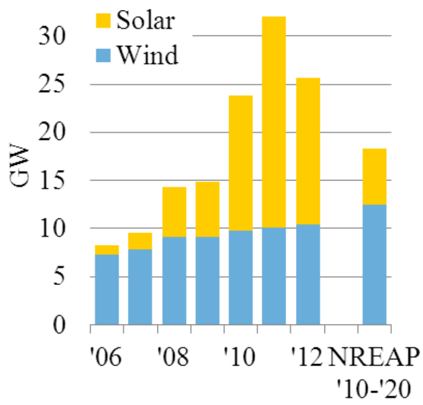

Figure 3: Wind and solar power capacity additions in the EU 2006-12, compared to the yearly growth as implied by the national action plans. Source: own work based on IHS (2013a) and ENDS (2010).

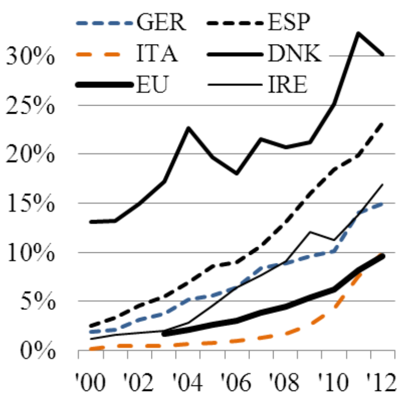

Figure 4: The share of variable renewables in electricity consumption for the EU and selected countries. Source: own work based on IHS (2013a)

The remarkable growth of wind and solar power has been accompanied by a decrease of equipment cost. Prices for solar panels and wind turbines have decreased, a reason for and most probably also a consequence of the deployment boom. Retail prices for small-scale roof-top installations in Germany have fallen by 15% p.a. during the last seven years and reached 1700 €/kW. However, both retail and wholesale prices seem to have stopped falling by end of 2012 (BSW 2013, PVXchange.org 2013). There continue to exist very large regional differences in solar PV investment costs (Feldmann et al. 2012, IEA 2013). Wind investment costs have fallen by 25% since 2009 (BNEF 2013), after a 90% increase during the decade before (IEA 2012). Not only wind investment costs have fallen, also technological characteristics of turbines have changed. During the last years, low-wind speed wind turbines have successfully entered the market, which have a higher tower and a larger rotor diameter-to-generator ratio. This leads both to lower generation costs at less windy sites (IEA 2012) and more constant power output, a factor that is highly important in the context of this dissertation. A smoother generation profile mitigates some of the consequences of variability, as found in MARKET VALUE, and OPTIMAL SHARE.

Not only is recent growth of VRE impressive, long-term scenarios find the role of wind and solar power to continue to grow also in the future. In a comprehensive survey of model inter-comparison studies, Fischedick et al. (2011, figure 10.9) report a median global VRE share of total electricity consumption of 10% by 2050 without climate policy and between 15-20% under climate policy. Luderer et al. (2013) report a similar range. Regional assessments confirm this trend. For the EU, Knopf et al. (2013) find median VRE shares of 11% without and 25% with climate policy by 2050 in the reference scenarios, but shares of 50-60% if nuclear power is restricted or assumption on VRE are more optimistic. For the Western U.S., Nelson et al. (2012)

[3] Die Zeit, 30.7.1993, page 10. The advertisement is reproduced in the appendix.

report comparable numbers. Hence, the share of VRE will increase four-fold until 2050 without climate policy and at least ten-fold under ambitious decarbonization.

The fact of fast growth of VRE and the prospect of further increase has triggered three large public policy debates, which will be discussed in the following section.

2. *Three public policy debates: market value, system integration, depressed prices*

This doctoral thesis relates to three major energy policy debates that are going on among academics and practitioners: the market value of VRE, system integration challenges, and the financial pressure the deployment of VRE puts on incumbent generators. All three debates are often framed under the umbrella of "market and system integration" of VRE.

Because wind and solar power do not produce electricity constantly, they depress the wholesale electricity prices only in times they are generating. This reduces their spot market income relative to that of dispatchable power plants. Academics have understood this effect for quite a while (Grubb 1991, Swider & Weber 2006, Lamont 2008). However, since significant installed capacities reduce spot prices and affect policy design in the real world (Figure 5), a public policy debate has emerged on the long-term competitiveness of VRE (Sensfuß & Ragwitz 2011, Energy Brainpool 2011). In the German context, several authors have claimed that a flawed electricity market design is responsible for the value drop (Kopp et al. 2012, Winkler & Altmann 2012, Matthes et al. 2012). The market value of VRE is the central topic of this dissertation. In one paper we lay out conceptually how the (social) marginal value of electricity generators is determined, how it relates to the (private) market value, and how VRE's variability impacts their value (ECONOMICS OF ELECTRICITY). In a second paper I estimate the marginal value quantitatively and find a pronounced decline of market value with increased penetration (MARKET VALUE); and in a third paper I gauge the optimal deployment, based on these marginal value estimates (OPTIMAL SHARE).

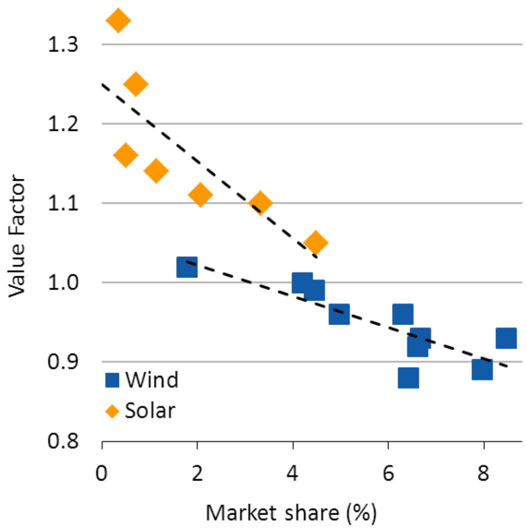

Figure 5: Observed relative prices of wind and solar power on day-ahead spot markets relative to the base price. Value factor is specific revenue relative to the base price. Source: own work, published in MARKET VALUE.

In a second - and maybe even larger - debate, the technical challenges of integrating VRE into power systems are discussed. Technical challenges occur in form of congested transmission and distribution grids, increased need for holding and using balancing reserves, more frequent ramping and cycling of thermal plants, local voltage stability issues, and efforts to ensure generation adequacy (Figure 6). These issues are discussed in academia (Grubb 1991, Denny & O'Malley 2007, Holttinen et al. 2011, Pérez-Arriga & Battle

2012) and among practitioners, system operators, and regulators (Dena 2005, Gross et al. 2006, GE Energy 2010, IEA 2011, Bundesnetzagentur 2013, IEA 2014). The economic impact of these challenges is sometimes discussed under the term “integration costs”; however, the economic implications of this concept are poorly understood (section 5). This dissertation adds to the literature by proposing a framework to assess integration costs of wind and solar power in an economically rigorous way (FRAMEWORK). The framework directly relates to the papers mentioned above by proposing a way to conciliate integration costs and the marginal value to each other, and by reviewing both branches of the literature side by side.

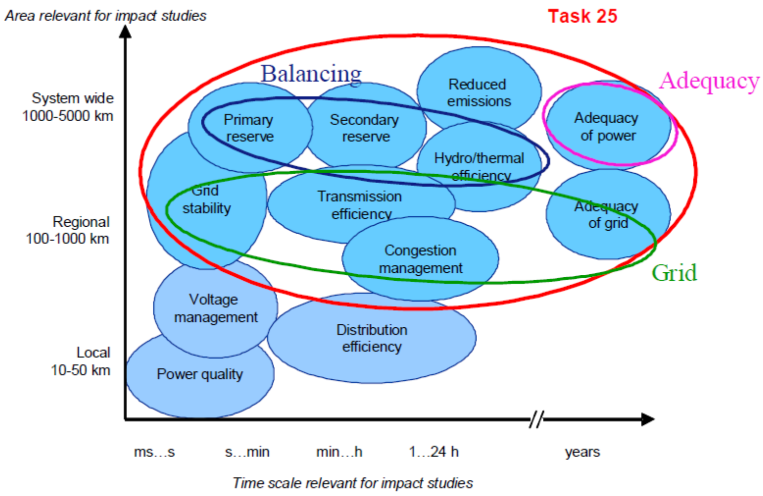

Figure 6: Integration challenges. The IEA “wind task 25”, an international working group, has been important in studying these challenges. Source: Holttinen et al. 2011.

The third debate concerns the impact of subsidized renewables on the profits of the utility industry, investment incentives, and the need for capacity payments. Subsidizing additional investments in (renewable) generation capacity depresses the electricity price below the level it would have been otherwise. Since the size of the drop depends on the shape of the merit-order curve, Sensfuß (2007) has termed this the “merit-order effect”. A number of academic papers have modeled the price impact theoretically and numerically, including Unger and Ahlgren (2005), Sensfuß et al. (2008), de Miera et al. (2008), Munksgaard & Morthorst (2008), Fischer (2010) and others. Mount et al. (2012) stresses the effect on producer profits and the “missing money” to finance capital costs from short-term profits. Wissen and Nicolosi (2008) and MacCormack et al. (2010) emphasize that the merit-order effect is only a short-term or “transient” phenomenon, since in the long-term equilibrium prices need to include capital costs. In Europe, power prices have fallen to the lowest level since 2005, which many observers attribute to renewables (Figure 7), despite lack of quantitative estimates about the role of renewables versus the recession and overinvestments. As a consequence, in several European countries the introduction of capacity payments is discussed in order to ensure generation adequacy (IHS 2013b, Finon & Roques 2013), including Germany (Cramton & Ockenfels 2011, EWI 2012, Ecofys 2012, Consentec 2012). This dissertation relates to this debate by providing a paper on the impact of energy policy on the short-term impact of producers (REDISTRIBUTION). In the article, we compare renewable support, which indeed decreases incumbents’ profits, with carbon pricing, which on average increases producer rents. However, a more complete appraisal of potential failures of energy-only markets with scarcity pricing is beyond the scope of this document; first steps have been taken elsewhere (Edenhofer et al. 2013).

Figure 7: Front-year base future. Source: own work based on EEX data

3. *Electricity: an economic good with peculiar characteristics*

If electricity was an economic good as any other, the variability of VRE would have virtually no implications. But electricity has peculiar characteristics, most of which stem from the fact that it can be stored only at high cost. As a consequence, simple microeconomic analyses such as maximizing welfare with respect to the mix of different generation technologies require care and specific tools. This section sketches the reasons why electricity is an economic good unlike most others.

Electricity, being a perfectly homogeneous good, is the archetype of a commodity. Like other commodities, trade of electricity often takes place via standardized contracts on exchanges. In that sense, it seems straightforward to apply simple textbook microeconomics to wholesale power markets. However, the physical laws of electromagnetism impose crucial constraints, with important economic implications: storing electricity is costly and subject to losses; transmitting electricity is costly and subject to losses; supply and demand of electricity need to be balanced at every moment in time to guarantee frequency stability. These three aspects require an appropriate treatment of the good "electricity" in economic analyses.

As an immediate consequence of these constraints, the equilibrium wholesale spot electricity price varies over time, across space, and over lead-time between contract and delivery:

- Since inventories cannot be used to smooth supply and demand shocks, the equilibrium electricity price varies dramatically over *time*. Wholesale prices can vary by two orders of magnitudes within one day, a degree of price variation that is hardly observed for other goods.
- Similarly, transmission constraints and the physics of meshed electrical grids limit the amount of electricity that can be transported geographically, leading to sometimes significant price spreads between quite close *locations*.
- Because demand and supply has to be balanced at every instant, but fast adjustment of power plant output is costly, the price of electricity supplied at short notice can be very different from the price contracted with more lead-time. Hence, there is a cost to *uncertainty*.

Across all three dimensions, price spreads occur both randomly and seasonally (and with predictable patterns). In other words, electricity indeed is a perfectly homogenous good and the law of one price applies, but this is true only for a given point in time at a given location for a given lead-time. Along these three dimensions, electricity is a heterogeneous good and electricity prices vary. Figure 8 visualizes the three dimensions of heterogeneity by displaying the array of wholesale spot prices in one power system in one year.

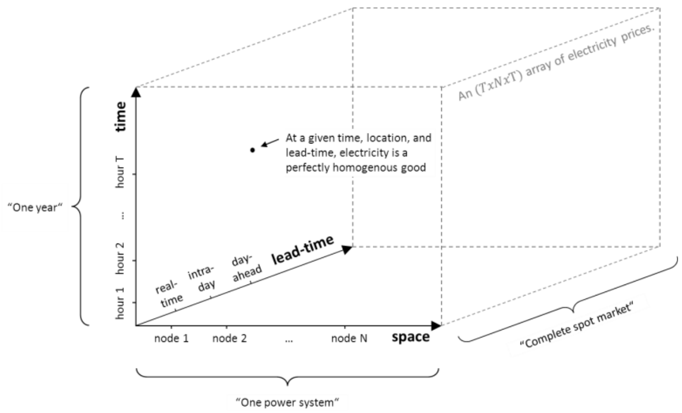

Figure 8: An array of wholesale spot electricity prices. The electricity price varies along three dimensions: time, space, and lead-time. At a single point in the three-dimensional space of prices, electricity is perfectly homogeneous. Source: own work, published in ECONOMICS OF ELECTRICITY

This fundamental economic property of electricity is approximated in real-world power market design: at European power exchanges, a different clearing price is determined for each hour and for each geographic bidding area. Most U.S. markets feature an even finer resolution, clearing the market every five minutes for each of several thousand transmission nodes. In addition, there is a set of power markets with different lead-times: in most European markets, there is a day-ahead market (12-36 hours before delivery), an intra-day market (few hours before delivery), and a balancing power market (close to real-time). Consequently, there is not *one* electricity price per market and year, but 26,000 prices (in Germany) or three billion prices (in Texas).[4] Hence, it is not possible to say what "the" electricity price in Germany or Texas was last year.

Any welfare, cost-benefit, or competitiveness analysis of electricity generation technologies need to take heterogeneity into account. It is generally *not* correct to assume that i) the average price of electricity from VRE (its marginal value) is identical to the average power price, or that ii) the price that different generation technologies receive is the same. Comparing generation costs of different technologies or comparing generation costs of a technology to an average electricity price has little welfare-economic meaning. Specifically, marginal cost of a VRE technology below the average electricity price or below the marginal costs of any other generation technology does *not* indicate that this technology is competitive. However, this has been repeatedly suggested by interest groups, policy makers, and academics (BSW 2011, EPIA 2011, Kost et al. 2012, Clover 2013, Koch 2013). Instead, the marginal cost of VRE has to be compared to its marginal value. To derive the marginal value, one needs to take into account when and where it was generated and that forecast errors force VRE generators to sell their output relatively short before real time.

While the economic literature has emphasized temporal heterogeneity (Bessiere 1970, Stoughton et al. 1980, Bessembinder & Lemmon 2002, Lamont 2008, Joskow 2011), the other two dimensions have not received similar attention. In ECONOMICS OF ELECTRICITY, we lay out what welfare maximization needs to take into account in the presence of multi-dimensional heterogeneity and suggest approaches how to handle that in numerical economic models. The quantitative assessments in MARKET VALUE and OPTIMAL SHARE explicitly account for heterogeneity when estimating the economic properties of VRE.

4. *Three intrinsic properties of variable renewables*

Many studies of renewables identify three specific characteristics of VRE that impose integration challenges on the power system (Milligan et al. 2011, Sims et al. 2011, Borenstein 2012). This thesis contributes to this

[4] The German spot market EPEX clears for each hour of the year as a uniform price; the ERCOT real-time market of Texas clears every five minutes for all 10,000 bus bars of the system

literature by proposing a framework that enables a welfare-economic interpretation of the costs that these characteristics incur.

- The supply of VRE is *variable* because it is determined by weather conditions and cannot be adjusted like the output of dispatchable power plants. Because VRE generation does not follow load and electricity storage is costly, this variability is costly.
- The supply of VRE is *uncertain* until realization. Electricity trading takes place, production decisions are made and power plants are committed the day before delivery. Deviations between forecasted VRE generation and actual production need to be balanced on short notice, which is costly.
- The supply of VRE is *location-specific*, i.e. the primary energy carrier cannot be transported like fossil or nuclear fuels. Costs occur because electricity transmission is costly and good VRE sites are often located far from demand centers.

Renewable technologies are sometimes compared along these dimensions (cf. Sims et al., 2011, Table 8.1), but the literature lacks approaches to incorporate them into economic modeling and to provide a consistent economic interpretation in the public policy debate. ECONOMICS OF ELECTRICITY argues that the three characteristics correspond to the three dimensions of heterogeneity introduced above. The higher degree of uncertainty and the fact that VRE are more bound to some locations make it more relevant for VRE than for other technologies to take all three dimensions of heterogeneity into account. Another paper, FRAMEWORK, suggests attaching a cost tag to each of these characteristics, to compare them economically (Figure 9). The paper exploits the fact that markets have evolved along the heterogeneity dimensions and estimate these costs not only from models, but also from market data.

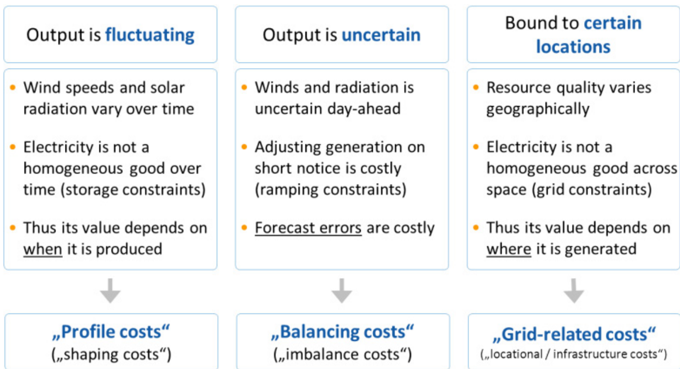

Figure 9: The characteristics of VRE and corresponding cost components. Source: own work.

5. Two strands of the literature: integration costs and marginal value

There are two literature traditions that evaluate the economic impact of wind and solar variability. For simplicity we will label them the “integration cost” and the “marginal value” literature, acknowledging that such a simplistic classification ignores significant heterogeneity within each group. The two literature branches appear quite separated, providing little cross-references, using different concepts and incompatible terminology.

The *integration cost* literature seeks to accurately calculate integration costs of VRE, which have been defined as “the extra investment and operational cost of the nonwind part of the power system when wind power is integrated” (Holttinen et al. 2011) or “the additional cost of accommodating wind and solar” (Milligan et al. 2011). In particular as part of wind integration studies, there is a significant body of integration cost studies seeking to operationalize and to accurately quantify those costs with high-resolution production cost modeling techniques. Calculating integration costs is done by setting up different scenarios, one including variable resources and one without them. Differences in production costs are noted and allocated to variable generation using different techniques. However, problems frequently arise with isolating integration costs from other effects. More specifically, the difference between scenarios is often dominated by fuel costs savings, which need to be accounted for correctly to identify integration costs (Milligan et al. 2011). More generally, the economic interpretation of integration costs remains somewhat opaque in the literature.

The *marginal value* literature analyses VRE by estimating their marginal economic value of the electricity these generators produce. The marginal economic value is an important concept in economic analysis: the intersection of marginal economic value and marginal (long-term) costs determines the welfare-optimal amount of a generation technology. While the integration cost literature is mainly rooted in the field of engineering, the marginal value literature is mainly written by economists. The models that are used typically closer to models used in economics, consider longer time horizons, and tend to have a poorer representation of technical system constraints than the models used in the integration cost field. Table 1 contrasts the two branches.

Table 1: "Integration Cost" vs. "Marginal Value" literature

	Integration Cost	**Marginal Value**
Field	(power system) engineering	(energy) economics
Key concept	integration cost, the additional system cost when integrating VRE	marginal economic value, the marginal increase in welfare when adding an incremental quantity of VRE generation
Time horizon	typically short term (capital stock given)	short term and long term (capital stock endogenous)
Main references	Dragon & Milligan (2003), Gross et al. (2006), Smith et al. (2007), Denny & O'Malley (2007), DeCesaro & Porter (2009), Milligan & Kirby (2009), GE Energy (2010), Holttinen et al. (2011), NEA (2012)	Grubb (1991), Swider & Weber (2006), Lamont (2008), Twomey & Neuhoff (2010), Joskow (2011), Nicolosi (2012), Mills & Wiser (2012)
Main Journals	IEEE Transactions on Power Systems, Wind Energy, Energy Policy; wind integration studies	The Energy Journal, Energy Economics, Energy Policy; dissertations

This Ph.D. thesis relates to these two branches. Two papers, MARKET VALUE and OPTIMAL SHARE, being economic in nature, clearly belong to the second research paradigm. However, an important contribution of this thesis is to integrate the two schools of thought, or at least translate between them. In FRAMEWORK, we attempt to conciliate the two approaches. The paper proposes a new definition of integration costs that is based on the reduction of marginal value. Such a definition allows for a welfare-economic interpretation of integration costs. Elsewhere (Ueckerdt et al. 2013b), we have taken further steps to identify and close additional differences between the two schools of thought.

6. *Research questions: what this dissertation is all about*

What are the economic consequences of the variability of wind and solar power? More specifically, how does variability impact the economic value of wind and solar power, their optimal deployment, and their integration costs? This high-level research question is operationalized in this doctoral thesis by addressing a number of more specific questions. These questions built on each other and jointly constitute a coherent set of topics. Important theoretical or "conceptual" questions include the following:

- What is “heterogeneity” and why is electricity a heterogeneous economic good?
- What are appropriate analytical tools to understand the economics of electricity generation? How can variability be accounted for in low-resolution economic models such as integrated assessment models?
- How can common cost indicators of generation technologies be interpreted, such as “levelized electricity costs” (LEC) and “grid parity”?
- What is the “variability” of VRE? What are the opportunity costs of VRE variability? How can these costs be estimated in the presence of incomplete models and imperfect markets?
- Which approaches are currently used to assess the economic consequences of variability, and what are their limitations? How can “integration costs” be economically interpreted? What is the relationship between integration costs and the marginal value of VRE?
- How can different aspects of variability be separated and compared to each other in economic terms?

These questions are addressed in the conceptual papers. The answers to these conceptual questions lead to a number of “how large” questions. The following numerical issues have been addressed in quantitative papers:

- How large is the marginal economic value of wind and solar power? How is it affected by their variability?
- What is the welfare-optimal deployment of wind and solar? How is it affected by their variability?
- What is the parameter uncertainty around the point estimates of marginal value and optimal deployment?
- What are important drivers for marginal value and optimal share? How do policies affect those? How effective are integration options, such as storage, transmission, or system flexibility?
- What are costs of VRE forecast errors and how will they develop? What is the impact of VRE on balancing power?
- What is the effect on producer and consumer rents of introducing VRE in large scale?

These quantifications are heavily related to the methodological question, what is the right empirical methodology? This feeds back to the fundamental questions around heterogeneity and variability.

7. *Topics beyond the scope of this thesis*

Of course, this study cannot provide an exhaustive treatment of economic questions around wind and solar power. Many topics are related to this work but are beyond its scope, such as the following fundamental economic issues: endogenous learning and technological progress of VRE technologies; environmental and health externalities of power generation; the political economy and game theory of security of supply; or biomass supply economics such as competition with other forms of land use.

Moreover, many questions of policy and market design are not covered. This includes efficiency of different renewables support schemes (prices vs. quantities); energy-only markets in the presence of high shares of VRE and the need for capacity markets; risk and uncertainty and its efficient allocation.

Also, as a study in the field of economics, this dissertation does not provide an exhaustive discussion of system impacts of VRE, hence it does not cover the following issues: operational challenges at the level of individual power plants; optimal transmission grid extension; challenges at the distribution grid level and optimal responses; the consequences of VRE being non-synchronous generators.

Moreover, this study does *not* aim at providing projections, forecasts, or scenarios of how specific power systems evolve over historical time. Rather, quantifications are developed to identify relevant causal mechanisms, provide an indication of their relative importance and single out policy implications and promising directions of further research.

8. The power market model EMMA

A major methodological contribution of this Ph.D. project is the Electricity Market Model EMMA. EMMA has been developed from scratch and has turned into an important tool for answering the quantitative research questions in this dissertation. It has been applied in MARKET VALUE, OPTIMAL SHARE, and REDISTRIBUTION to derive the marginal value and optimal deployment of wind and solar power both in the mid and the long term, the optimal capacity mix, and changes of consumer and producer rents after policy shocks.

EMMA is a stylized numerical dispatch and investment optimization tool of the interconnected Northwestern European power system. In economic terms, it is a long-term partial equilibrium model of the wholesale electricity market with a focus on the supply side. For each market area, it determines yearly generation, transmission and storage capacity, and hourly generation, trade, and clearing prices. Model formulations are parsimonious while representing VRE variability, power system inflexibilities, and flexibility options with appropriate detail. Markets are assumed to be perfect and complete, such that the social planner solution is identical to the market equilibrium: market values equal marginal values and optimal deployment equals competitive deployment. The model is linear, deterministic, and solved in hourly time steps for one year.

The model minimizes total system costs with respect to investment, production and trade decisions for a given electricity demand under a large set of technical constraints. Total system costs are the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs, of generation, transmission, and storage facilities. Capacities and generation are optimized jointly. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and investment and disinvestment in each technology, including wind and solar power. The important constraints relate to energy balance, capacity limitations, and the provision of district heat and ancillary services.

Generation is modeled as eleven discrete technologies with continuous capacity: two VRE with zero marginal costs – wind and solar –, six thermal technologies with economic dispatch – nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and lignite carbon capture and storage (CCS) –, a generic "load shedding" technology, and pumped hydro storage. Hourly VRE generation is limited by generation profiles, but can be curtailed at zero cost. Dispatchable plants produce whenever the price is above their variable costs. Storage is optimized endogenously under turbine, pumping, and inventory constraints. Existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments including VRE have to recover their annualized capital costs from short-term profits. This guarantees that in the long-term equilibrium the zero-profit condition holds. The hourly zonal electricity price is the shadow price of demand, which can be interpreted as the prices on an energy-only market with scarcity pricing.

Demand is exogenous and assumed to be perfectly price inelastic at all but very high prices, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short time scales. While investment decisions take place over longer time scales, we justify this assumption with the fact that the average electricity price does not vary dramatically between model runs.

Combined heat and power (CHP) generation is modeled as must-run generation: a certain share of the co-generating technologies lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of these technologies can be freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity is fixed. Ancillary service provision is modeled as a must-run constraint for dispatchable generators as a function of peak load and VRE capacity.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs). Investments in interconnector capacity are endogenous to the model. As a direct consequence of our price modeling, interconnector investments are profitable if and only if they are socially beneficial. Within regions transmission capacity is assumed to be non-binding.

The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up cost or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior: assigned base load plants bid an electricity price below their variable costs in order to avoid ramping and start-ups.

The model is fully deterministic. Long-term uncertainty about fuel prices, investment costs, and demand development are not modeled, and there is no adequacy margin. Short-term uncertainty about VRE generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the ancillary service constraint, and by charging VRE generators balancing costs.

Being a stylized power market model, EMMA has significant limitations. An important limitation is the absence of hydro reservoir modeling. Hydro power offers intertemporal flexibility and can readily attenuate VRE fluctuations. Hence, results are only valid for predominantly thermal power systems. Demand is assumed to be perfectly price inelastic up to high power prices. More elastic demand would help to integrate VRE generation. However, it is an empirical fact that demand is currently very price-inelastic in Europe and possible future demand elasticities are hard to estimate. Technological change is not modeled, such that generation technologies do not adapt to VRE variability. Not accounting for these possible sources of flexibility potentially leads to a downward-bias of VRE's marginal value and optimal share. Hence, results can be interpreted as conservative estimates.

EMMA is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. In a back-testing exercise, model output was compared to historical market data from 2008-10. Crucial features of the power market can be replicated fairly well, like price level, price spreads, interconnector flows, peak / off-peak spreads, the capacity and generation mix.

The model code and all input data and output visualization routines are available under Creative Commons-BY-SA license and can be accessed at http://www.pik-potsdam.de/members/hirth/emma. There is no specifically methodological paper published that explains and documents EMMA, but complete model descriptions can be found in MARKET VALUE and (updated) in OPTIMAL SHARE, as well as in the Appendix B of this document.

9. *Outline of the thesis*

This thesis comprises six published articles that are reproduced in the following chapters. Four of the articles have been written with co-authors, Falko Ueckerdt, Ottmar Edenhofer, and Inka Ziegenhagen. In the following, the articles are briefly outlined. Two articles, ECONOMICS OF ELECTRICITY and FRAMEWORK, develop analytical concepts and a valuation framework. The former, targeted to an economic audience, introduces the idea of electricity as an economic good that is heterogeneous along three dimensions. Consequently, electricity from different generating technologies can be viewed as different economic goods. The article derives formally how welfare maximization with respect to the generation mix is conducted under these conditions. FRAMEWORK, targeted to a more interdisciplinary readership of academics and practitioners, relates more directly to the established literature on integration costs. In line with Ueckerdt et al. (2013), it proposes a new definition of integration costs and suggests a decomposition of those along the three characteristics of renewables.

Three papers answer primarily quantitative questions, MARKET VALUE, OPTIMAL SHARE, and REDISTRIBUTION. The first article estimates the marginal economic value of wind and solar power. It reports model results from EMMA, the numerical power market model that was developed for this thesis. It also provides econometric evidence from market prices and a quantitative survey of the published literature. OPTIMAL SHARE uses an advanced version of EMMA to estimate the welfare-optimal penetration rate of wind and solar power. It gauges the impact of VRE variability on optimal deployment, and examines the effect of policy, technology, and price shocks. It also provides an extensive discussion of different classes of numerical models and assesses to what extent they are able to capture different aspects of VRE variability. While these two papers are concerned with question of efficiency, REDISTRIBUTION assesses distributive effects. The study compares two policies, renewables support and CO_2 pricing, with respect to their impact on consumer rents and profits of existing firms. It finds the effect is large in size and asymmetric: carbon pricing increases generators' profits and decreases consumer rents, while renewable support has the opposite effect.

The final paper, BALANCING POWER, addresses three links between variable renewables and the balancing system. It discusses the impact of wind and solar forecast errors on the calculation of the balancing reserve, the possibility of VRE to supply balancing power, and the dynamic incentive the imbalance price provides for improving forecasts. Table 2 lists the chapters references the articles.

Table 2: Chapters and papers

2	ECONOMICS OF ELECTRICITY	Hirth, Lion, Falko Ueckerdt & Ottmar Edenhofer (2014): "Why Wind is not Coal: On the Economics of Electricity", *The Energy Journal* (submitted). Also available as *FEEM Working Paper* 2014.039.
3	FRAMEWORK	Hirth, Lion, Falko Ueckerdt & Ottmar Edenhofer (2015): "Integration Costs Revisited – An economic framework of wind and solar variability", *Renewable Energy* 13-149. Also available as *USAEE Working Paper* 13-149.
4	MARKET VALUE	Hirth, Lion (2013): "The Market Value of Variable Renewables", *Energy Economics* 38, 218-236. Also available as *USAEE Working Paper* 2110237.
5	OPTIMAL SHARE	Hirth, Lion (2015): "The Optimal Share of Variable Renewables", *The Energy Journal* 36(1), 127-162. Also available as *FEEM working paper* 2013.090.
6	REDISTRIBUTION	Hirth, Lion & Falko Ueckerdt (2013): "Redistribution Effects of Energy and Climate Policy: The electricity market", *Energy Policy* 62, 934-947. Also available as *FEEM Working Paper* 2012.082.
7	BALANCING POWER	Hirth, Lion & Inka Ziegenhagen (2013): "Balancing Power and Variable Renewables. A Glimpse at German Data", *Renewable & Sustainable Energy Reviews* (submitted). Also available as *USAEE Working Paper* 13-154.

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Chapter 2

Why Wind is not Coal
On the Economics of Electricity [*]

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[*]under revision at *The Energy Journal*

Why wind is not coal: on the economics of electricity generation

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Abstract – Electricity is a paradoxical economic good: it is highly homogeneous and heterogeneous at the same time. Electricity prices vary dramatically between moments in time, between location, and according to lead-time between contract and delivers. This three-dimensional heterogeneity has implication for the economic assessment of power generation technologies: different technologies, such as coal-fired plants and wind turbines, produce electricity that has a different economic value. Several tools that are used to evaluate generators in practice ignore these value differences, including 'levelized electricity costs', 'grid parity', and simple macroeconomic models. This paper provides a rigorous and general discussion of heterogeneity and its implications for the economic assessment of electricity generating technologies. It shows that these tools are biased, specifically, they tend to favor wind and solar power over dispatchable generators where these renewable generators have a high market share. A literature review shows that, at a wind market share of 30-40%, the value of a megawatt-hour of electricity from a wind turbine can be 20-50% lower than the value of one megawatt-hour as demanded by consumers. We introduce 'System LCOE' and suggest to use this new metric for economic comparisons of generation technologies.

Keywords – power generation, electricity sector, integrated assessment modeling, wind power, solar power, variable renewables, integration costs, welfare economics, power economics, levelized electricity cost, LCOE, grid parity

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1. Introduction

In several parts of the world today, it is cheaper to generate electricity from wind than from conventional power sources such as coal-fired plants, and many observers expect wind turbine costs to continue to fall. It is widely believed that this cost advantage by itself implies that wind power is profitable (as a private investment option) or efficient (for society). However, this is not the case.

Inferring about competitiveness from a cost advantage would only be correct if electricity was a *homogenous* economic good. In such a case, electricity generated by wind turbines would be a perfect substitute for electricity generated by coal plants, and only then could their output be compared on a pure cost basis. However, electricity prices vary over short time scales, and hence electricity is a *heterogeneous* good. Such heterogeneity of electricity over time has long been acknowledged (Boiteux 1949, Bessembinder & Lemmon 2002, Joskow 2011). This article offers a rigorous and more general discussion of heterogeneity and its implications for the economic assessment of electricity generating technologies, especially the implications for tools and metrics used by practitioners. In this way we extend and formalize previous work (Hirth 2013, 2015a, Hirth et al. 2015, Ueckerdt et al. 2013a, 2013b).

We show how ignoring heterogeneity causes two biases in economic assessments of power plant technologies. First, it favors conventional base-load generators relative to peak-load generators, and second, at high penetration rates, it favors variable renewable energy sources (VRE), such as wind and solar power, relative to dispatchable generators ('VRE bias'). There are at least three common tools that are used in practice for policy advice and decision support that implicitly assume homogeneity and thus run the risk of biasing results: 'grid parity', 'levelized costs of electricity' (LCOE), and large numerical economical models.

LCOE, the discounted lifetime average generation costs per unit of energy ($/MWh), are used in policy and industry studies as well as in academic analyses to compare different generation technologies, such as nuclear power, coal and natural-gas fired plants, wind power, and photovoltaics (for references see section 3b). These studies seem to suggest that low LCOE signal competitiveness – at least that is how many readers interpret them. This reasoning implicitly assumes that the generation units (MWh) from different technologies are perfect substitutes, which would imply that the value of output from all generators is identical. This is not, however, the case. A second widely used indicator is 'grid parity', the point where generation costs drop below retail electricity prices. Some observers seem to believe that once a technology has reached grid parity, its deployment is economically efficient (Koch 2013, Fraunhofer ISE 2013). We will show that this is not the case.

In addition, many multi-sector models also implicitly assume homogeneity and consequently tend to deliver biased results. For many years economists have used calibrated macroeconomic multi-sector models for research and policy advice, starting with Leontief (1941). Today, 'integrated assessment models' (IAMs), sometimes based on computable general equilibrium (CGE) models, are an important tool for assessing climate policy and the role of renewables in mitigating greenhouse gas emissions. Such models often use a simple representation of the electricity sector where generation from different power technologies are perfect substitutes.

To understand the impact of heterogeneity on these tools, this paper derives first-order conditions for the optimal generation mix whilst considering heterogeneity. 'Screening curves' have been used for decades to find the least-cost thermal capacity mix (Phillips et al. 1969, Stoughton et al. 1980, Green 2005). We generalize this approach by deriving optimality conditions accounting not only for heterogeneity time, but also in two more dimensions: space and lead-time. We also provide theoretical foundations for studies that determine the optimal generation mix from numerical power market models (Neuhoff et al. 2008, Lamont 2008, Müsgens 2013). The paper also relates to the ‘marginal value’ literature that estimates the marginal economic value of wind and solar power (Grubb 1991, Borenstein 2008, Mills & Wiser 2012, Schmalensee 2013). A major finding of these studies is that the marginal value of these renewables decreases with the penetration rate. This study links these results to the heterogeneity of electricity and shows that not only the marginal value of VRE diverges from that of dispatchable generators, but that all technologies have a specific marginal value.

After discussing how the above-mentioned tools are biased, we suggest how this can be corrected. In order to do this we derive equivalent optimality conditions from a second perspective that allows us to formally overcome heterogeneity. This leads to a new cost metric, System LCOE that provides economically meaningful cost comparisons of different technologies. Implementing this metric into multi-sector models is also one way of modelling the electricity sector e.g. in IAMs.

After discussing the peculiarities of electricity as an economic good, we address a closely related question: what is, and what is not, special about variable renewable electricity sources, such as wind and solar power? Previous literature suggests that VRE have specific properties that lead to ‘integration costs’ (e.g. Sims et al. 2011, Holttinen et al. 2011, Milligan et al. 2011, NEA 2012, Ueckerdt et al. 2013a, Hirth et al. 2015). This study relates integration costs to heterogeneity and offers a new definition of integration cost that has a welfare-theoretical interpretation. We argue that VRE are not fundamentally different from dispatchable power plants: all technologies are subject to integration costs. However, it turns out that what is special about wind and solar power is not the existence but the size of integration costs.

We hope to offer value to four types of readers: (i) to general economists without an electricity background, we hope to show how standard microeconomics, like first-order conditions, can be adapted to apply to the electricity sector, (ii) to IAM modelers, we suggest how the electricity sector, and in particular VRE, can be incorporated in multi-sector models, (iii) to policy advisors, we propose a rigorous welfare-economic interpretation of indicators that are often used in the field, notably LCOE and grid parity, (iv) to energy economists, we hope to offer a new perspective on well-known issues, such as a new formula for optimality conditions, and an analogous treatment of time, space, and uncertainty in the economic theory of electricity.

Specifically, the paper contributes to the literature in the following ways. First, it offers a rigorous and general discussion of heterogeneity, including a formal definition. Second, it shows that different power generating technologies produce different (electricity) goods. Third, it derives first-order conditions for optimal quantities of each generation technology. It turns that there are (at least) two equivalent formulations of optimality, each corresponding to a different electricity good. Fourth, it shows that common tools to assess generators are biased. Fifth, the article offers a rigorous definition of wind and solar power variability and variability costs. We argue that all generators are subject to variability, not only VRE. Finally, a number of methodologically remedies are proposed. We specify a new cost metric, System LCOE, that allows economically meaningful cost comparisons of different technology, discuss how electricity’s heterogeneity and VRE’s variability can be accounted for in integrated assessment modeling, and propose a pragmatic decomposition of variability cost that facilitates quantification.

The remainder of this paper is organized as follows. Section 2 discusses heterogeneity and gives a formal definition. Section 3 derives first-order conditions for the optimal power mix and shows how neglecting heterogeneity biases the results of LCOE comparisons, grid parity, multi-sector models. Section 4 suggests an alternative formulation of first-order conditions and derives System LCOE. Section 5 proposes a decomposition of variability costs. Section 6 discusses the impact of heterogeneity on the economics of VRE and presents estimates for variability costs of wind power. Section 7 concludes.

2. *Electricity is a heterogeneous good*

Electricity is a paradoxical economic good, being at the same time homogeneous and heterogeneous. In many aspects, it is a homogenous commodity, possibly more so than most other commodities. However, it is also heterogeneous in the sense that the price of a single MWh of electricity can vary dramatically between different moments in time. This section argues that electricity is not only heterogeneous over time, but along two further dimensions: space, and lead-time between contract and delivery. Figure 1 illustrates how wholesale electricity prices vary along these three dimensions, using price data from Germany and Texas.

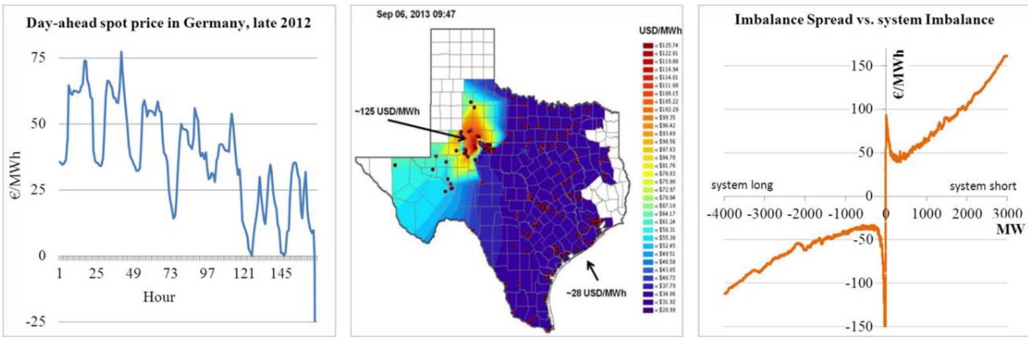

Figure 1: Observed electricity prices very between moments in time (left, hourly German day-ahead spot prices), between locations (mid, Texas nodal prices), and between different lead times between contract and delivery (right, spread between day-ahead and real-time prices in Germany).

a) *Homogeneity of electricity*

Electricity can be seen as the archetype of a perfectly homogenous commodity: consumers cannot distinguish electricity from different power sources, such as wind turbines or coal-fired plants.[2] In other words, electricity from one source is a perfect substitute for electricity from another source, both in production functions and utility functions. The law of one price applies: electricity from wind has the same economic value as electricity from coal.

This perfect substitutability is reflected in the real-world market structure, where bilateral contracts are not fulfilled physically in the sense that electrons are delivered from one party to another, but via an ‘electricity pool’: generators inject energy to the grid and the consumer feed out the same quantity. In liberalized markets, electricity is traded under standardized contracts on power exchanges. Wholesale markets for electricity, both spot and future markets, share many similarities with markets for other homogenous commodities such as crude oil, hard coal, natural gas, metals, or agricultural bulk products.

However, homogeneity applies *only at a certain point in time*. Since storing electricity is (very) costly, the price of electricity varies over time. More precisely, its price is subject to large predictable and random fluctuations on time scales as short as days, hours, and even minutes. Before we discuss this and the other two dimensions of heterogeneity, we formally define ‘homogeneity’ and ‘heterogeneity’.

b) *A formal definition of heterogeneity*

We classify a good as heterogeneous *if its marginal economic value is variable*. More formally, we define a good q to be heterogeneous along a certain dimension (e.g., time) if its marginal

[2] In some markets, certificates of origin exist, in order to allow consumers to discriminate between different power sources (Kalkuhl et al. 2012). However, such certificates are traded independently from electricity.

economic values varies significantly between different points p (e.g., hours) within a certain range P (e.g., one year).

We define the 'instantaneous' marginal economic value v'_p at a point $p \in P$ as the derivative of welfare W with respect to an increase of consumption of q at point p.

$$v'_p := \frac{\partial W(q_p, \cdot)}{\partial q_p} \qquad \forall p \in P \qquad (1)$$

We define a good to be homogeneous along a dimension if

$$v'_p \cong v'_q \qquad \forall p, q \in P \qquad (2)$$

Otherwise, the good is heterogeneous along that dimension.[3]

For example, a good is heterogeneous in time if its marginal value differs significantly between two moments during one year; a good is heterogeneous in space if its marginal value differs significantly between two locations in one country. Examples of heterogeneous goods include hotel rooms (which are much more expensive during the holiday season or during trade fairs), airplane travel (which is much more expensive on Fridays and Mondays), and many personal services.

Heterogeneity requires three conditions. The most fundamental condition for heterogeneity is the absence of arbitrage possibilities. For example, storable goods feature little price fluctuations over time, because the existence of inventories allow for inter-temporal arbitrage,[4] and, in the same way, transportable goods feature little price fluctuation across space.

Constrained arbitrage is a necessary condition of heterogeneity, but it is not sufficient. Demand and/or supply conditions also need to differ between points along the dimension. Take the example of time: if supply and demand functions are unchanged over time, the lack of ability to store electricity would not lead to price fluctuations. In addition, both demand and supply need to be less than perfectly price-elastic. For example, if the supply curve was horizontal, despite demand fluctuations and lack of storability, the price would remain unchanged.

Summing up, there are three conditions that are individually necessary and jointly sufficient to make a heterogeneous good: 1. constrained arbitrage; 2. differences in demand and/or supply conditions; 3. non-horizontal demand and supply curves.

c) The three dimensional heterogeneity of electricity

Now we come back to the three dimensions of the heterogeneity of electricity. The physics of electricity imposes three arbitrage constraints, along the dimensions *time*, *space*, and *lead-time*:

- Electricity is electromagnetic energy. It can be stored directly in inductors and capacitors, or indirectly in the form of chemical energy (battery, hydrogen), kinetic energy (flywheel), or potential energy (pumped hydro storage). In all these cases, energetic losses and capital costs make storage very, often prohibitively, expensive. Hence, arbitrage over time is limited. The storage constraint makes electricity heterogeneous over time: it is economically different to produce (or consume) electricity 'now or then'.
- Electricity cannot be transported on ships or trucks, in the same way as tangible goods. It is transmitted on power lines which have limited thermal capacity, and give rise to losses. Moreover, Kirchhoff's circuit laws, which govern load flows in meshed net-

[3] This definition excludes small price variations, such as changes driven by intra-year discounting.

[4] Inventories both prevent predictable price fluctuations and limit random price fluctuations.

works, further constrain transmission capacity, and transmission distances are limited by reactance. The transmission constraint makes arbitrage limited between locations and electricity becomes heterogeneous across space: it is economically different to produce electricity 'here or there'.

- In alternating power (AC) systems, there has to be a balance between demand and supply at every moment in time. Imbalances cause frequency deviations, which can destroy machinery and become very costly. However, thermal power generators are limited in their ability to quickly adjust output as there are limits on temperature gradients in boilers and turbines (ramping and cycling constraints). Hence, arbitrage is limited across different lead-times between contract and delivery. The flexibility constraint makes electricity heterogeneous along lead-time: it is economically different to produce electricity with a flexible or an inflexible plant, and forecast errors can be costly.

Summing up, storage 'links stuff in time', transmission 'links stuff in space', and flexibility 'links stuff in lead-time'. Since storage, transmission, and flexibility are constrained, electricity is a heterogeneous good in time, space, and lead-time (Table 1).

Table 1: The heterogeneity of electricity along three dimensions.

Dimension (differences between points in …)	Time	Space	Lead-time between contract and delivery
Arbitrage constraint	Storage (storing electricity is costly*)	Transmission (transmitting electricity is costly*)	Flexibility (ramping & cycling is costly*)
differences in demand and/or supply conditions	– shifts of the demand curve (day-night patter, temperature) – shifts of the supply curve (weather, plant availability)	– location of demand – good sites for electricity generation	– uncertainty in demand (weather) – uncertainty in supply (weather, outages)

* 'Costly' both in the sense of losses (operational costs) and the opportunity costs of constraints.

'Lead-time' might be less intuitive than the other dimensions and merits some further discussion. We can think of three types of generators: inflexible generators that produce according to a schedule that is specified one day in advance, like nuclear power; flexible generators that can quickly adjust, like gas-fired plants; and stochastic generators that are subject to day-ahead forecast errors, like wind power. If demand is higher than expected, only flexible generators are able to fill the gap. In such conditions the real-time price rises above the day-ahead price, and hence, everything else equal, flexible generators receive a higher average price than inflexible generators. Contrast this with the stochastic generators: when they generate more than expected there tends to be oversupply in the real-time market, and hence they sell disproportionally at a lower price.[5]

Figure 2 visualizes this three-dimensional heterogeneity. Each axis represents one dimension. The length of each axis represents the 'range' P: one year, one power system, and the complete set of spot markets. At a given point in this three-dimensional space, electricity is a perfectly homogenous good. As physical constraints limit arbitrage between points in that space, the marginal value varies along all three axes. This, according to our definition, is heterogeneity.

[5] This is true, although, as a referee noted, the average levels of day-ahead, intra-day, and real-time prices are very close.

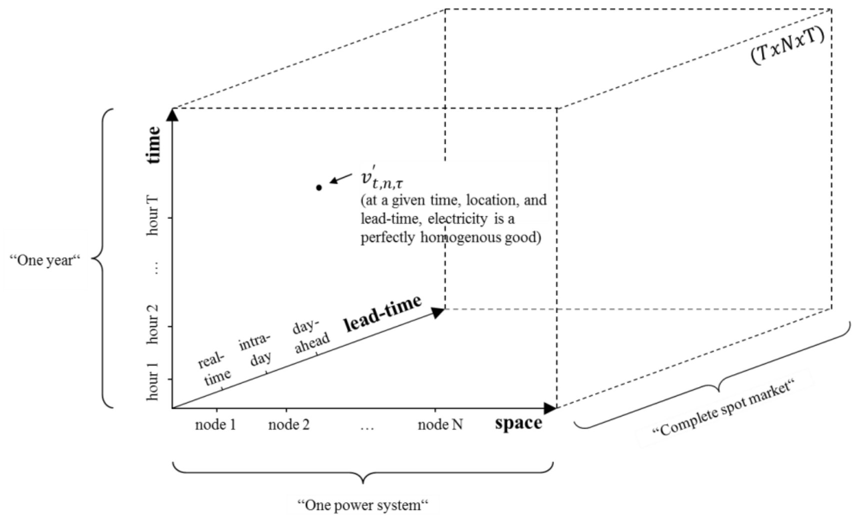

Figure 2: The marginal value space. Source: adopted from Hirth (2015a).

More formally, Figure 2 can be thought of as a $[TxNx\mathrm{T}]$-Matrix where each element is an instantaneous marginal value $v'_{t,n,\tau}$ at time step $t \in T$, at node $n \in N$, and at lead-time $\tau \in \mathrm{T}$. We call the $[TxNx\mathrm{T}]$-Matrix $\boldsymbol{v}$ of the elements $v'_{t,n,\tau}$ the 'marginal value space'. Electricity is heterogeneous because not all elements of $\boldsymbol{v}$ are the same.

Of course, we are not the first to note that production-profile, location, and flexibility of power plants matter for economics. Dedicated numerical tools, such as stochastic security-constrained unit commitment models, implicitly take these factors into account. Our formulation of three-dimensional heterogeneity provides an economic interpretation in terms of prices. To us, it seems to be an elegant and general way of thinking about a wide range of economic issues in power generation, ranging from economic evaluation of power plant flexibility and forecast errors to congestion pricing and the costs of wind and solar intermittency. These topics are usually discussed separately; however, they can also be thought of as aspects of the three dimensional heterogeneity of electricity. To the best of our knowledge, this is the first paper that formulates a general definition of heterogeneity and applies it not only to time but also to the dimensions of space and lead time.

d) Observing heterogeneity in the power sector

Three-dimensional heterogeneity is reflected in reality: through price variation, market design, and technology development. Take German price data from 2012 as an example: the range of electricity prices was 1000% of the mean electricity price, and prices varied by a factor of two within a normal day. The price of other energy carriers fluctuated much less: natural gas prices varied 70% of the mean price, and crude oil prices by 36% of their mean; neither commodity demonstrated within-day price variation.[6] This is in line with expectations, as storage costs for natural gas are higher than for oil, but much lower than for electricity. Price variation along the other dimensions can also be substantial. The spread between day-ahead and real-time price in Germany varied between -1600 €/MWh and 1400 €/MWh (Hirth & Ziegenhagen 2013); while the electricity price is uniform across Germany, in Texas price difference of several hundred $/MWh between different locations were not uncommon (Schumacher 2013). The peak load

[6] Mean [range] prices for electricity were 44 €/MWh [-222; +210]; for natural gas 26 €/MWh [21; 38]; for crude oil 114 €/bbl [89; 130]. German spot prices from EPEX Spot, natural gas prices from German gas hub TTF, crude oil prices for Brent. Texas spot prices from ERCOT, German imbalance prices from TSO TenneT,

pricing literature (Boiteux 1949, Crew et al. 1995) offers the theoretical foundations for equilibrium pricing of time-heterogeneous goods.

More structurally, heterogeneity is reflected in the design of whole power markets and market-clearing mechanisms. European power exchanges typically clear the market each hour in each bidding zone; U.S. markets often clear the market in steps of five minutes in each node of the transmission grid. Such high-frequency market clearing would be of no use without temporal heterogeneity. Many spot markets feature a sequence of markets along lead-times, ranging from day-ahead to intra-day to real-time (or balancing) markets. Hence, there is not *one* electricity price per market and year, but 100,000 prices (in Germany) or three billion prices (in Texas).[7] Figure 2 can readily be thought of as an array of market-clearing spot prices with, in the case of Texas, three billion elements. Not all dimensions of heterogeneity are, however, reflected in all markets: German prices are uniform across space; grid constraints are managed via command and control instruments.

Heterogeneity of electricity has not only shaped market design, but also technology development. For homogenous goods, one single production technology is typically efficient. In electricity generation, there is a set of generation technologies that are efficient (Bessiere 1970, Stoughton et al. 1980, Grubb 1991, Stoft 2002). ‘Base load’ plants have high investment, but low variable costs; this is reversed for ‘peak load’ plants (Table 2). The latter are specialized in only delivering electricity at high prices, which rarely occurs. If electricity was a homogeneous good, no such technology differentiation would have emerged.

Table 2: Electricity generation technologies have adapted to temporal heterogeneity.

Technology	Annualized fixed costs (€/kWa)	Variable costs (€/MWh)	Efficient capacity factor range
Nuclear	400	10	>95%
Lignite	240	30	75% - 95%
Hard coal	170	40	50% - 75%
CCGT (natural gas)	100	55	5% - 50%
OCGT (natural gas, oil)	60	140	<5%

Cost data for central Europe with 2012 market prices for fuel, assuming a CO_2 price of 20 €/t. About 85-90% of fixed costs are capital costs. CCGTs are combined-cycle gas turbines, and OCGTs are open-cycle gas turbines. Source for technology cost parameters: Hirth (2015a), based on the primary sources IEA & NEA (2010), VGB Powertech (2011), Black & Veatch (2012), and Schröder et al. (2013).

3. *Welfare economics of electricity generation: technology perspective*

This section derives the optimal generation mix. , We formally derive the first-order conditions which explicitly account for three-dimensional heterogeneity (a). These conditions can be interpreted such that each technology produces a different economic good (b). This turns out to violate a crucial assumption implicit in common interpretations of tools such as LCOE-comparisons, grid parity, and multi-sector modelling. We show how a common way of using these tools introduces two major biases (c). This section generalizes Joskow (2011) and formalizes Hirth et al. (2015).

[7] The German spot market EPEX clears for each quarter-hour of the year as a uniform price; the ERCOT real-time market of Texas clears every five minutes for each of all 10,000 bus bars of the system

a) Optimality conditions: marginal benefit equals marginal cost (for each technology)

The welfare-optimal quantity q^* of any good is given by the intersection of the marginal economic value (benefit) of consuming the good $v'(q^*)$ and marginal economic cost of producing it $c'(q)$:[8]

$$v'(q^*) = c'(q^*) \tag{3}$$

Throughout the paper, we will specify value and cost in energy terms ($/MWh). The long-term marginal cost of producing one MWh of electricity with technology i, c_i', is the average discounted private life-cycle cost per unit of output (e.g., IEA & NEA 2010, Moomaw et al. 2011):

$$c_i' := \frac{\sum_{y=1}^{Y} c_{i,y}(1+r)^{-y}}{\sum_{y=1}^{Y} g_{i,y}(1+r)^{-y}} \qquad \forall i \in I \tag{4}$$

where $c_{i,y}$ is the fixed and variable cost (including capital cost) that occurs in year y, $g_{i,y}$ is the amount of electricity generated in that year, r is the real discount rate, and Y is the life-time of the asset in years. c_i' is termed 'levelized energy costs' or 'levelized costs of electricity' (LCOE). LCOE is a standard concept and broadly used.

The marginal value of a power generating technology is the value of its aggregated output:

$$\bar{v}_i' = \sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} g_{i,t,n,\tau} \cdot v_{t,n,\tau}' \qquad \forall i \in I \tag{5}$$

where $v_{t,n,\tau}'$ is the instantaneous marginal value of electricity as defined in (1). This is the consumers' willingness to pay for consuming one additional unit of electricity (MWh) at time t, node n, and lead-time τ. We define T to be one year, N one power system, and T the complete set of spot markets. Note that $v_{t,n,\tau}'$ does not carry a subscript for generation technology – this is why section 2a) denoted electricity to be perfectly homogeneous.

The weights $g_{i,t,n,\tau}$ is the share of output of technology i at the respective time step, node, and lead-time, such that

$$\sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} g_{i,t,n,\tau} = 1 \qquad \forall i \in I \tag{6}$$

We label the $[TxNx\mathrm{T}]$-Matrix $\boldsymbol{g_i}$ of the elements $g_{i,t,n,\tau}$ the 'generation pattern' of technology i. Hence, the marginal value of a coal-fired plant, $\bar{v}_{coal}'$, is the average of the instantaneous value of electricity, weighted with the production pattern of coal plants. [Under perfect and complete markets, $v_{t,n,\tau}'$ equals the locational spot price, and $\bar{v}_i'$ equals the market value of a technology.][9]

The I first order conditions for the optimal generation mix are:[10]

$$c_i' = \bar{v}_i' \qquad \forall i \in I \tag{7}$$

b) Interpretation: different generators produce different goods (imperfect substitutes)

These equations look innocent, but provide a number of relevant interpretations.

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[8] Throughout the paper, we restrict the analysis to first-order conditions, assuming well-behaved functions.

[9] The existence of $v_{t,n,\tau}'$ does not require perfect and complete markets, nor equilibrium conditions. We add interpretation in terms of prices (which requires these assumptions) in brackets for convenience.

[10] Assuming the optimal quantity of all technologies is positive. Otherwise the corresponding KKT-inequalities apply.

In general, the generation patterns of two technologies do not coincide $(\boldsymbol{g_i} \neq \boldsymbol{g_j})$.[11] Hence, their marginal value ($/MWh) does not coincide $(\bar{v}_i' \neq \bar{v}_j')$. The two technologies produce the same physical output (MWh of electricity), but they produce *different economic goods*. The value difference shows that these 'electricity goods' are only imperfectly substitutable. While at a single point ('instantaneously'), electricity from wind and coal is perfectly substitutable, over one year (more precisely, over the full value space), it is not. The law of one price does *not* apply (Figure 3). The simple optimality condition (4) actually represents I optimality conditions for I different goods. Each optimality condition is stated in terms of a different electricity good, corresponding to one generation technology. Hence expressing optimality in this way might be called a 'technology perspective'.

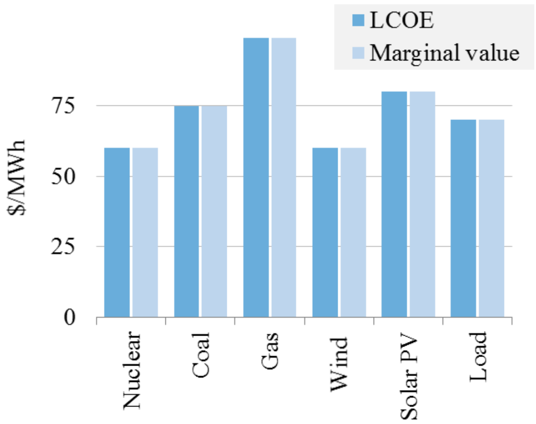

Figure 3: In the long-term optimum, the marginal value of each technology coincides with the marginal cost of that technology – but it does not coincide with the marginal value of another technology (levels are illustrative).

c) Implications: what is problematic with LCOE-comparisons, grid parity, and IAMs

The fact that each generation technology produces output of different value has important implications for the interpretation of commonly used metrics and tools such as LCOE-comparisons, grid parity, and multi-sector modelling.

It is common practice in policy and industry documents (and also in academic articles) to compare the LCOE of different technologies (Karlynn & Schwabe 2009, Fischedick et al. 2011, IEA & NEA 2010, BSW 2011, EPIA 2011, Nitsch et al. 2010, IRENA 2012, GEA 2012, EIA 2013, DECC 2013). Many readers interpret cost advantage as a sign of efficiency or competitiveness. Such reasoning would be correct if and only if, the value of output of all generators was identical – which is not the case. In fact, comparing LCOE from different technologies is comparing the marginal costs of producing different goods.[12]

Some authors seem to suggest that once a technology has reached 'grid parity', its deployment is economically efficient (BSW 2011, EPIA 2011, Koch 2013, Fraunhofer ISE 2013, Breyer & Gerlach 2013). Grid parity is usually defined as the point where LCOE of solar (or wind) power

[11] For example because they feature different variable costs, and hence are dispatched differently – or, because they are located at different sites, maybe because at some locations wind speeds are high while at others local coal resources are abundant.

[12] Comparing LCOE is meaningful if generators produce comparable output. If, say, nuclear power and lignite plants have similar low variable costs and are hence dispatched similarly, comparing the costs of these two technologies can be interpreted as relative competitiveness.

fall below the retail electricity price. Again, this indicator ignores heterogeneity, and implicitly compares the marginal value of one good ($\bar{v}'_{load}$) with the marginal cost of a different good (c'_{solar}).[13] Comparing a technology's LCOE to the wholesale electricity price (Kost et al. 2012, Clover 2013, Rüdiger & Matieu 2014) is based on the same flawed implicit assumption.

Economists have used calibrated multi-sector models for many years for research and policy advice (Leontief 1941, Johansen 1960, Taylor & Black 1974). Today, 'integrated assessment models' (IAMs), sometimes based on computable general equilibrium (CGE) models, are an important tool for assessing climate policy and the role of renewables in mitigating greenhouse gas emissions (Fischedick et al. 2011, Edenhofer et al. 2013, Luderer et al. 2013, Knopf et al. 2013, IPCC 2014). Numerical constraints often require multi-sector models to model electricity generation as one single sector. When optimizing the generation mix, such models equate the LCOE of all generation technologies. This implicitly equates the marginal costs of different goods.

Ignoring value differences among generation technologies introduces a bias: it makes low-value technologies look better than they actually are, biasing their optimal/equilibrium market share upwards. This systematically favors conventional base-load generators relative to peak-load generators ('base load bias'), and, at high penetration rates, wind and solar power relative to dispatchable generators ('VRE bias', for quantitative evidence see section 6). In the following section, we develop an alternative formulation of the optimality conditions, based on which we propose alternative metrics that are not subject to these biases.

4. *Welfare economics of electricity generation reformulated: load perspective*

The previous section derived first-order conditions for the optimal generation mix as the equality of marginal costs and marginal benefits in terms of each of all *I* electricity good, corresponding to *I* generation technologies. This section derives an alternative formulation of the same optimality conditions in terms of *the same* electricity good, i.e. a reference good. This perspective is mathematically equivalent, but offers a range of interpretations and will turn out to be helpful for amending LCOE. One can think of 'transforming' the output of each generator into the same good, such that they can be compared in terms of costs, where the 'transformation' is analytical, rather than technical or physical.

a) Choosing 'load' as a reference electricity good

As a reference electricity good, we choose 'load', defined as having the same pattern as electricity consumption ($\boldsymbol{l}$). The elements of $\boldsymbol{l}$, $l_{t,n,\tau}$ represent the share of consumption at the respective time-step, node, and lead time, and sum up to unity. This is analogously defined as the 'generation pattern' (6). The simplest way to supply the reference good can be imagined as a (hypothetical) ideal generator that follows load over time as if it was perfectly dispatchable, has the same spatial distribution as load, and exhibits the same forecast errors.

Accordingly, we define the marginal value of load $\bar{v}'_{load}$ as the demand-weighted average of all $v'_{t,n,\tau}$.

[13] Furthermore, 'grid parity' conceals the fact that grid fees, levies, taxes comprise a large share of retail prices. Hence it takes a private perspective that has little implication for social efficiency (Hirth 2015b).

$$\bar{v}'_{load} = \sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} l_{t,n,\tau} \cdot v'_{t,n,\tau} \qquad (8)$$

$\bar{v}'_{load}$ is the consumers' willingness to pay for an additional MWh of yearly consumption with pattern $l_{t,n,\tau}$, the pattern of infra-marginal consumption. [Under perfect and complete markets, $\bar{v}'_{load}$ equals the average electricity prices consumers pay $\bar{p}'_{load}$.]

b) Optimality conditions from a LOAD-perspective

Now we reformulate the optimality conditions (7) in terms of the electricity good load. Optimally, the marginal benefit of the good load $\bar{v}'_{load}$ coincides with the marginal cost of producing this good by technology i, which we term System LCOE σ'_i:

$$\bar{v}'_{load}(q_i^*,\cdot) = \sigma'_i(q_i^*,\cdot) \qquad \forall i \in I \qquad (9)$$

Where the System LCOE σ'_i consist of generation costs c'_i and the costs of 'transforming' the electricity good Δ'_i:

$$\sigma'_i(q_i,\cdot) := c'_i(q_i) + \Delta'_i(q_i,\cdot) \qquad \forall i \in I \qquad (10)$$

Below we discuss how this metric can be used. Note that while the LCOE of technology i, c'_i, are a function of the quantity supplied by that technology only, σ'_i is also a function of other factors, including power system parameters and the plant mix (as is $\bar{v}'_i$). While c'_i is strictly positive, Δ'_i can be of either sign. In Ueckerdt et al. (2013a) we have previously introduced System LCOE in a different but equivalent way. Therein we derive an expression for Δ'_i as the additional costs in the power system to accommodate additional generation from a technology i (in this case variable renewables).

This set of I first-order conditions can also be expressed as equalities of marginal costs σ'_i:

$$\sigma'_i(q_i^*,\cdot) = \sigma'_j\left(q_j^*,\cdot\right) \qquad \forall i,j \in I \qquad (11)$$

To sum up, the first-order condition for the optimal quantity q_i^* of a technology i can be written in two ways. First, in terms of the electricity good that corresponds to the technology i (equation 7), and second, in terms of the reference good load (equation 9). This duality can be neatly illustrated graphically (Figure 4). The 'technology perspective' is depicted in bold lines. The intersection of marginal costs (LCOE) and marginal value of i gives the optimal quantity q_i^*. The 'load perspective' is drawn in dotted lines. The intersection of marginal costs (System LCOE) and marginal value of load results in the same optimal quantity q_i^*. By contrast, the intersection of marginal value of load with the marginal costs of technology i gives quantity q_i^0, which is *not* the optimal quantity.

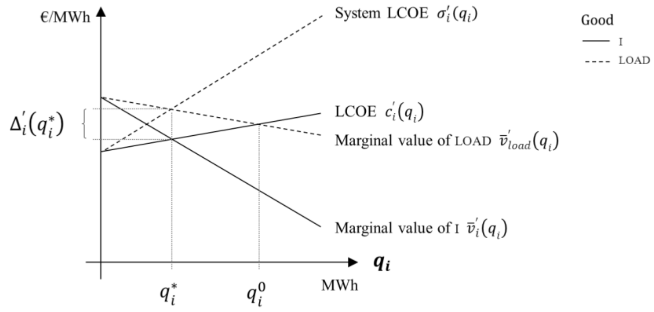

Figure 4: Optimal quantity q_i^* of technology i in terms of the goods i (technology perspective) and load (load perspective).

c) *Interpreting Δ_i': System cost, value gap, variability cost, integration cost*

Δ_i' can be interpreted in at least four different ways.

First, it can be understood as the costs of transforming output from a technology to cover load. These costs not only depend on the generation pattern of the technology but also on properties of the power system like the structure of load and deployment of all other technologies. Hence, the additional costs might be called *system costs*, which has inspired us to coin the term 'System LCOE' for σ_i', being the sum of LCOE and these system costs.

Second, we can reformulate (10), using (9) and (7), to derive

$$\Delta_i'(q_i^*,\cdot) = \bar{v}_{load}'(q_i^*,\cdot) - \bar{v}_i'(q_i^*,\cdot) \qquad \forall i \in I \qquad (12)$$

Δ_i' is the *value gap* between the value of electricity that consumers demand $\bar{v}_{load}'$ and the value of electricity that a certain generator supplies, $\bar{v}_i'$. In this interpretation, comparing the System LCOE (σ_i') of two technologies means simultaneously comparing *both* cost and value differences.

Third, the value difference between technologies is determined by the deviations of the generation pattern of a technology from the load pattern. We interpret this mismatch as *variability* of that technology and Δ_i' as *opportunity cost of variability* (in short 'variability cost'). It follows that all generators, not just VRE, are subject to variability and associated costs. More fundamentally, it is the *combination* of electricity being heterogeneous (not all elements of $\boldsymbol{v}$ are the same) and power plant variability ($\boldsymbol{g_i} \neq \boldsymbol{l}$) that causes a value gap to emerge ($\bar{v}_i' \neq \bar{v}_{load}'$). If electricity was either homogeneous, *or* its generation was not variable, it would hold that $\bar{v}_i' = \bar{v}_{load}' \ \forall i \in I$.

Fourth, there is a branch of literature that assesses the impact of wind and solar variability. They discuss that VRE have specific properties that lead to 'integration costs' when integrating VRE generators into power systems (e.g. Sims et al. 2011, Holttinen et al. 2011, Milligan et al. 2011, NEA 2012, Baker et al. 2013). Existing integration cost studies often calculate different items, such as balancing, grid, and adequacy costs, but it is unclear how the sum of these items can be interpreted economically. We believe it is sensible to define integration costs as Δ_i' (Ueckerdt et al. 2013a, Hirth et al. 2015), which offers a welfare-economic interpretation. According to such a definition, integration costs are not specific to VRE.

In the remainder of this paper we label Δ_i' as variability costs.

d) Implication: Improving biased tools with a new metric – System LCOE

The optimality conditions (12) imply that System LCOE from different technologies can be compared to infer about efficiency of each technology. We suggest that, if used for such purpose, System LCOE should replace LCOE. Figure 5 illustrates LCOE, variability costs, and their sum, System LCOE, in the long-term optimum. While LCOE of different technologies do not coincide, System LCOE do.

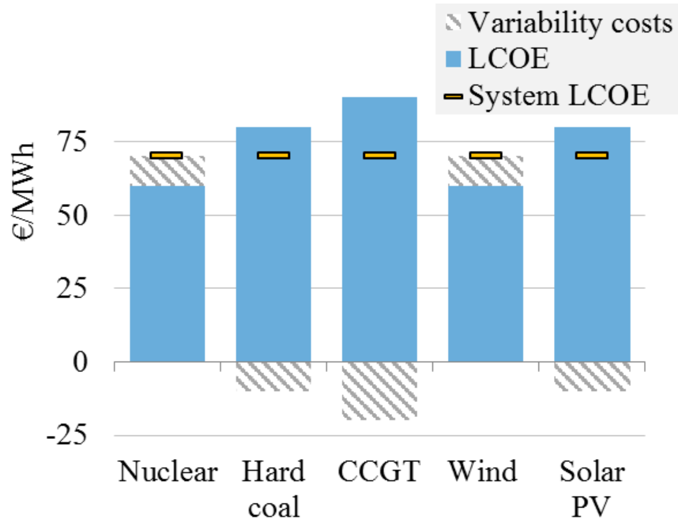

Figure 5: LCOE, variability costs, and System LCOE in the long-term economic equilibrium (levels are illustrative).

Some IAMs use ‘flexibility constraints’ (Sullivan et al. 2013) or cost penalties to capture the system-level costs of VRE variability (e.g., MERGE, MESSAGE, ReMIND, and WITCH), however, parameterizing such cost penalties is challenging. System LCOE can improve cost penalties by providing a rigorous welfare economic motivation. It becomes clear that not only wind and solar power, but all generation technologies are associated with such costs.

To estimate variability costs, tools other than IAMs are needed, such as high-resolution numerical power system models. Hereby IAMs should prioritize those aspects of variability that have the largest impact on model results. Well-parameterized System LCOE are a good way of implicitly representing variability costs in IAMs. These can be combined with other explicit approaches. Those aspects of variability that can be directly represented in a robust way could be exempt from the System LCOE metric. For example an explicit representation of residual load duration curves can be complemented with a System LCOE for other aspects of variability such as grid and balancing costs or the effect of integration options such as short-term storage or demand-side management (Ueckerdt et al. 2014).

5. Empirically estimating variability costs: pragmatic ideas

The first-order conditions derived above, assume complete information – specifically, full knowledge about the marginal value space $\boldsymbol{v}$ (Figure 2). In reality, information is often far from complete. This section suggests how to estimate variability costs empirically under incomplete information. It proposes splitting variability costs into three ‘cost components’ and shows how they can be estimated from existing power sector models and observed market data. We hope thereby to provide a pragmatic and feasible approach to estimate variability costs.

a) Decomposition – the three components of variability costs

Many published studies estimate the impact of *one* dimension of heterogeneity (e.g. 'the costs of wind forecast errors'). Such studies are often based on models that represent one dimension of variability (much) better than others. 'Super models' that represents all three dimensions in full detail are rare: the best stochastic security-constrained unit commitment models might come close to this ideal, but in practice many studies rely on much less sophisticated tools.[14] Not only models are incomplete, the same is true for markets – for example, transmission constraints are not priced in most European markets. Given such incomplete knowledge about the marginal value space $\boldsymbol{v}$, we propose a pragmatic approximation: estimating the impact of each dimension of heterogeneity separately as one 'cost component' and adding them up.

- The impact of time is called 'profile costs' (because the temporal generation profile determines this component).
- The impact of space is called 'grid-related costs' (because grid constraints determine this component).
- The impact of lead-time is called 'balancing costs' (because forecast errors need to be balanced).

We use the sum of the three components as an estimator $\widehat{\Delta}_i'$ of the cost of variability:

$$\widehat{\Delta}_i' = \Delta_i^{profile} + \Delta_i^{grid\text{-}related} + \Delta_i^{balancing} \qquad \forall i \in I \qquad (13)$$

$\widehat{\Delta}_i'$ is only an approximation of the variability costs Δ_i'. The three cost components interact with each other such that there is an (unknown) interaction term.

When there is only information about the temporal structure of the marginal value of electricity, $v_{t,n,\tau}'$ reduces to v_t'. We define profile costs as the difference between the load-weighted and the generation-weighted marginal value:

$$\Delta_i^{profile} := \sum_{t=1}^{T} (l_t - g_{i,t}) \cdot v_t' \qquad \forall i \in I \qquad (14)$$

We define grid-related costs and balancing costs accordingly:

$$\Delta_i^{grid\text{-}related} := \sum_{n=1}^{N} (l_n - g_{i,n}) \cdot v_n' \qquad \forall i \in I \qquad (15)$$

$$\Delta_i^{balancing} := \sum_{\tau=1}^{\mathrm{T}} (l_\tau - g_{i,\tau}) \cdot v_\tau' \qquad \forall i \in I \qquad (16)$$

Even if a 'super model' is available that captures all three dimensions appropriately, these three 'cost components' might provide a helpful way of post-processing and interpreting model results. The Appendix provides further discussion on the interaction term and an example calculation of the cost components.

The waterfall diagrams of Figure 6 illustrate the three cost components for different technologies. Base load generators such as nuclear power (a) have a lower value than the marginal value of consumption ($\bar{v}_{load}'$), while mid-load generators such as coal-fired plants (b) have a value that is similar to $\bar{v}_{load}'$. The inflexibility of these generators reduces their value. Peak-load generators such as gas-fired plants (c) have a higher value, because they produce disproportionally during times of high prices, are located closer to load centers, and can provide short-term flexibility – hence all cost components increase their marginal value. The value of VRE is strongly

[14] Multi-sector models that capture important issues such as learning curves or macroeconomic effects often need to reduce power system detail to remain numerically feasible.

affected by their penetration. At low penetration, their value is typically higher than the marginal value of consumption, especially in the case of solar power (d): the benefits of producing during times of high prices outweighs the costs of forecast errors. At high penetration, profile, balancing, and grid related costs tend to reduce the value of solar as well as of wind power (e).

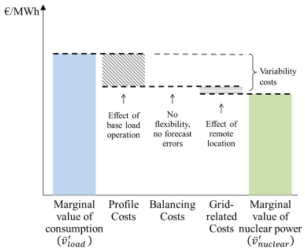

Figure 6a: The marginal value of nuclear power (illustrative).

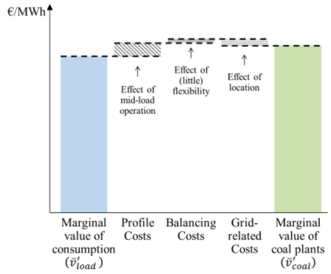

Figure 6b: The marginal value of coal-fired mid-load power plants (illustrative).

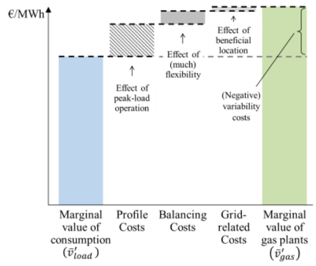

Figure 6c: The marginal value of gas-fired peak-load plants (illustrative)

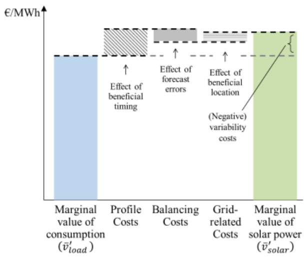

Figure 6d: The marginal value of solar power at low penetration (illustrative).

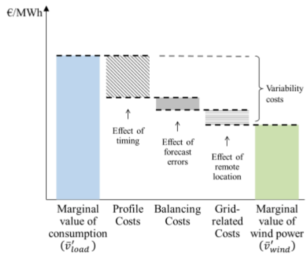

Figure 6e: The marginal value of wind power at high penetration (illustrative).

The three cost components, profile, balancing, and grid-related costs, are not constant parameters, but functions of many system properties. They typically increase with penetration, as illustrated in Figure 7.

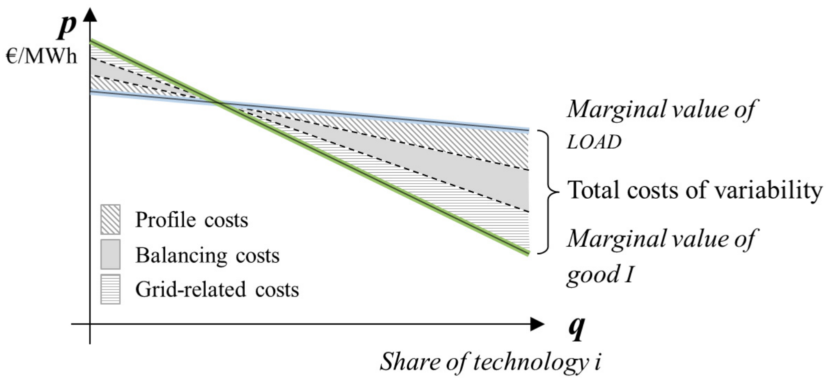

Figure 7: Profile, balancing, and grid-related costs typically increase with penetration. For wind and solar power, profile costs are often negative at low penetration.

b) Market- and model-based estimation

Each cost component can be estimated from modeled shadow prices or from observed market prices. Table 3 lists market and model types that provide information for each cost component. Take the example of grid-related costs: they can be estimated from locational shadow prices derived from grid models; and from empirically observed nodal prices. Where such prices do not exist, zonal prices and locational differentiated grid fees can serve as proxies.

Table 3: Estimating cost components from markets and models.

	Models	**Markets**
Profile costs	power market models	day-ahead spot markets
Balancing costs	stochastic unit commitment models	real-time spot markets; balancing power / imbalance markets
Grid-related costs	power flow (grid) models	locational (nodal, zonal) spot markets; locational grid fees

Both markets and models have limitations: markets are never complete and free of market failures and can be, in the case of electricity, off the equilibrium for extended periods of time. Moreover, in some markets (e.g. many balancing markets) regulators have implemented average, not marginal, pricing. Models, in turn, are necessarily simplifications of reality: externalities are often incompletely captured, and some models do not estimate the long-term equilibrium. In addition, numerical models are often calibrated to historical market prices, and might be subject to the same limitations. While both sources of empirical data are imperfect, diversified estimation methodology helps derive robust estimates.

6. What is special about wind and solar power?

When we began writing this paper, we were looking for the fundamental economic differences between VRE and other generators – ‘the economics of intermittency’ – in order to parameterize ‘integration costs’ in multi-sector models. The previous literature had identified three specific properties of VRE: fluctuations, forecast errors, and the fact that good sites are often far from load centers (GE Energy 2010, Milligan et al. 2011, Borenstein 2012, IEA 2014).

However, as shown above, these properties are not limited to wind and solar power. It is true that the generation patterns in time, space, and lead-time affects the economic value of electricity generated from wind and solar power – but that is true for all generation technologies! It is true that using LCOE comparisons, grid parity, or simple multi-sector models to compare VRE with dispatchable generators introduces a bias – but the comparison between dispatchable technologies is also biased.

Fundamentally, it is not a group of (‘intermittent’) generators that is different to another group of (‘dispatchable’) generators, but electricity itself that is different from other economic goods. So – are wind and solar power just two more power generation technologies?

What *is* special about wind and solar power is not the existence, but the *size* of variability costs. In predominantly thermal power systems, at high penetration rates (such as 20+% for wind or 10+% for solar in annual energy terms), they are the technologies that produce least-value output. In other words, ignoring value differences can bias the assessment of all generators, but the upward bias might be greatest for wind and solar power. In the following, we present results from a quantitative literature review of wind power variability costs (updated from Hirth et al. 2015).

Table 4 lists all studies we are aware of that can be used to extract wind variability cost estimates. With a few exceptions (notably Grubb 1991, Holttinen et al. 2011, and Mills & Wiser 2012), most of these studies report estimates of one single cost component.

Table 4: Quantitative literature on integration costs of wind power.

	Models	Markets
Profile costs	Grubb (1991), Rahman & Bouzguenda (1994), Rahman (1990), Bouzguenda & Rahman (1993), Hirst & Hild (2004), ISET et al. (2008), Braun et al. (2008), Obersteiner & Saguan (2010), Obersteiner et al. (2009), Boccard (2010), Green & Vasilakos (2011), Energy Brainpool (2011), Valenzuela & Wang (2011), Martin & Diesendorf (1983), Swider & Weber (2006), Lamont (2008), Bushnell (2010), Gowrisankaran et al. (2011), Mills & Wiser (2012, 2014), Mills (2011), Nicolosi (2012), Kopp et al. (2012), Hirth (2013), Hirth & Müller (2015)	Borenstein (2008), Sensfuß (2007), Sensfuß & Ragwitz (2011), Fripp & Wiser (2008), Brown & Rowlands (2009), Lewis (2010), Green & Vasilakos (2012), Hirth (2013)
Balancing costs	Grubb (1991), Gross et al. (2006), Smith et al. (2007), DeMeo et al. (2007), Mills & Wiser (2012, 2014), Gowrisankaran et al. (2011), Holttinen et al. (2011), Garrigle & Leahy (2013), Strbac et al. (2007), Holttinen et al. (2011), Carlsson (2011)	Holttinen (2005), Pinson et al. (2007), Obersteiner et al. (2010), Holttinen & Koreneff (2012), Louma et al. (2014), Hirth et al. (2015)
Grid-related costs	Strbac et al. (2007), Denny & O'Malley (2007), dena (2010), NREL (2012), Holttinen et al. (2011)	Hamidi et al. (2011), Schumacher (2013), Brown and Rowlands (2009), Lewis (2010), Hirth et al. (2015)

Figure 10 and Figure 11 summarize estimates of profile costs and balancing costs that we extracted from these studies. Profile costs are estimated to be ~20 €/MWh at 30 – 40% penetration; many studies find negative costs at low penetration (implying a higher price received at spot markets than the load-weighted price). Balancing costs are estimated to rise from ~2 €/MWh at low penetration to ~4 €/MWh at high penetration. Grid-related costs (not in figure) are likely to be below 15 €/MWh under most conditions (Hirth & Müller 2015).

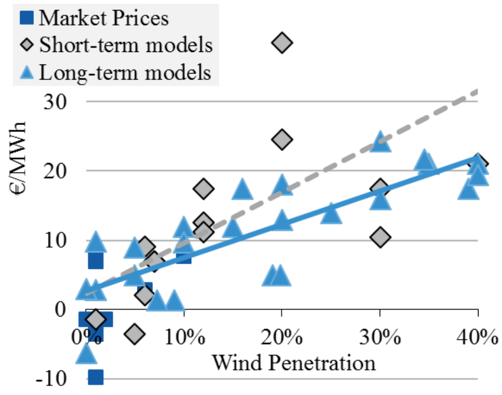

Figure 8: Wind profile cost estimates for thermal power systems from about 30 published studies. Studies are differentiated by how they determine electricity prices: from markets (squares), from short-term dispatch modeling (diamonds, dotted line), or from long-term dispatch and investment modeling (triangles, bold line). To improve comparability, the system base price has been normalized to 70 €/MWh in all the studies. Updated from Hirth et al. (2015).

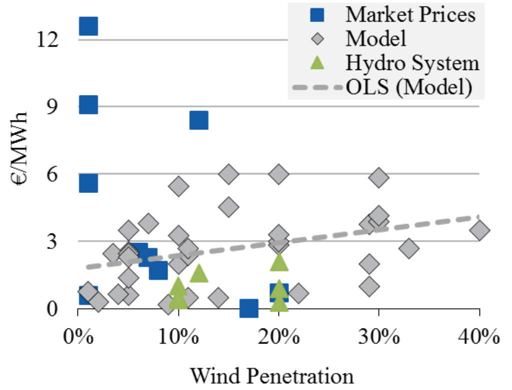

Figure 9: Wind balancing cost estimates for thermal power systems from about 20 published studies based on market prices (squares) or models (diamonds, dotted line). Three market-based studies report very high balancing costs, but these are unlikely to reflect marginal costs. All other estimates are below 6 €/MWh. Studies of hydro-dominated systems show very low balancing costs (triangles). Updated from Hirth et al. (2015).

The most important finding of the literature review is that variability costs can become very high at high penetration rates. When wind penetration reaches 30 – 40%, they can be in the range of 25 – 35 €/MWh, assuming an average electricity price of 70 €/MWh. In other words, electricity from wind power is worth only 35 – 45 €/MWh under those conditions, 35 – 50% less than the average electricity price. If wind LCOE are 60 €/MWh, system (variability) costs are ~50% of generation costs.

However, the literature also shows that variability costs are low, or even negative, at low penetration rates. Up to 10% penetration rate, variability costs are most likely to be small relative to generation costs.

Four additional findings can be identified in the literature: (i) costs increase with penetration; (ii) at high penetration, profile costs are higher than balancing costs; (iii) long-term models (with endogenous investment) report lower profile costs than short-term models; (iv) costs are lower in hydro-dominated systems than in thermal systems.

Positive variability costs imply that optimal deployment is lower than it would be otherwise but it is not necessarily low in absolute terms. Even IAMs that attach significant integration costs to wind power often find high renewable shares under strict climate policy. The same is true for power market models: Neuhoff et al. (2008) reports an optimal wind share for the UK of 40%. Hirth (2015a) finds an optimal wind share of 20% [1-45%], roughly in line with Lamont (2008). Müsgens (2013) and Eurelectric (2013) reports an optimal wind share in Europe of more than one third by 2050.

7. Concluding remarks

This paper has taken a micro-economic perspective on electricity generation – which we hope has been beneficial to economists with and without an energy background. We have shown that electricity is a heterogeneous economic good and that, consequently, cost comparisons and multi-sector models have to be used with care. We hope this serves modelers as well as those who advise decision makers based on such tools.

We have argued that electricity is a paradoxical economic good: it can be understood as being perfectly homogenous, and as very heterogeneous. Electricity prices vary over time, across space, and with respect to lead-time between contract and delivery. As a consequence, the economic value of electricity generated from different power plant technologies diverges. Physically, the all produce megawatt-hours of electricity, but economically they produce different goods. Common tools to evaluate generation technologies – LCOE, grid parity, (simple) multi-sector models – account for costs differences among generation technologies, but ignore these value differences. They implicitly equate marginal costs and benefits of different goods. Ignoring value differences introduces two biases: the 'base-load bias' and the 'VRE bias'. VRE generators, such as wind and solar power, produce particularly low-value electricity, if deployed at large scale, hence the upward bias is particular strong. System planning based on biased analyses will lead to a sub-optimal plant mix and corresponding welfare losses.

This leads us to three *methodological conclusions*. First, when comparing the economics of power generation technologies in a one-dimensional figure, System LCOE should be used instead of LCOE. System LCOE accounts for both value and cost differences; the metric can be interpreted as the cost of each generation technology to produce the same good. Second, multi-sector models, such as integrated assessment models or general equilibrium models, need to carefully account for value differences among generation technologies. This is especially relevant if they are used to model structural shifts in electricity supply such as deep decarbonization of the power sector. Finally, grid parity is not a useful indicator for the economic efficiency of generation technologies. We recommend that it is not used.

The most important *policy conclusion* of this assessment might be that there is none. In principle, markets are well equipped to price heterogeneity, neither electricity heterogeneity nor wind and solar variability constitutes an externality, and there is no need for policy interventions. Looking closer to real-word markets, the situation is less black and white. More than in other sectors, governments and regulators shape the design of electricity markets – in in many markets, electricity prices variation are suppressed by the way markets are designed. For example, in many European markets, regulators mandate geographically uniform prices. Often, balancing prices do not reflect marginal, but average, costs. The findings of this article imply that policy should allow electricity prices to vary along all three dimensions of heterogeneity. They should do so at the level of wholesale markets, retail markets, and policy instruments. In the implementation of heterogeneous prices, especially retail prices, there is a trade-off with transaction costs, of course. Policy instruments should consider heterogeneity. Specifically, renewable support schemes should be permeable for price signals in the sense that they should transmit price variations to investors. Simple feed-in-tariffs eliminate all price variability.

Finally, this paper might also offer a *fundamental interpretation* of the nature of power generating technologies. It shows that wind and solar are not that different from other generators in the end. It is indeed questionable if it is sensible to draw a line between 'variable' and 'dispatchable' generators. Each generation technology has specific characteristics and produces output of a different value in \$/MWh terms. Accounting for these value differences is important when assessing wind and solar power – but it is equally important when assessing other generators.

Appendix

Interaction term

$\hat{\Delta}_i'$ is only an approximation of the variability costs Δ_i'. The three cost components interact with each other and there is an (unknown) interaction term $\hat{\varphi}_i$.

$$\Delta_i' = \hat{\Delta}_i' + \hat{\varphi}_i \qquad \forall i \in I \qquad (17)$$

However, lacking knowledge of the sign of the interaction, we believe setting $\hat{\varphi}_i$ to zero it is a sensible first-order approximation.

Example calculation

As an illustrative example, assume one needs to assess the marginal value of wind power in Germany at some point in the future. Say, there is a power market model available that delivers estimates for the marginal value of load of 70 €/MWh and of wind power of 60 €/MWh, but that model does not capture the grid, nor does it capture uncertainty - hence does not account for the second and the third dimension of heterogeneity. From a literature review, one estimates balancing costs (the cost of wind forecast errors) to be 3 €/MWh. Finally, a grid study reports the marginal value of electricity in Northern Germany to be 6 €/MWh higher in the South than in the North , and it is known that two thirds of all turbines are located in the North while two thirds of consumption in the South. Hence, profile costs are 10 €/MWh, balancing costs 3 €/MWh, and grid-related costs 2 €/MWh.[15] In sum, the marginal value of wind power is $\hat{\bar{v}}_{wind}' = 55\ €/MWh$, and the variability cost of wind power $\hat{\Delta}_{wind}' = 15\ €/MWh$.

[15] Grid-related costs are the spread between the load-weighted and the wind-weighted electricity price: $\frac{12}{3} - \frac{6}{3} = 2$

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Chapter 3

Integration Costs and the Value of Wind Power
Thoughts on a valuation framework for variable renewable electricity sources *

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Integration costs revisited – An economic framework for wind and solar variability[☆]

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ABSTRACT

The integration of wind and solar generators into power systems causes "integration costs" – for grids, balancing services, more flexible operation of thermal plants, and reduced utilization of the capital stock embodied in infrastructure, among other things. This paper proposes a framework to analyze and quantify these costs. We propose a definition of integration costs based on the marginal economic value of electricity, or market value – as such a definition can be more easily used in economic cost-benefit assessment than previous approaches. We suggest decomposing integration costs intro three components, according to the principal characteristics of wind and solar power: temporal variability, uncertainty, and location-constraints. Quantitative estimates of these components are extracted from a review of 100 + published studies. At high penetration rates, say a wind market share of 30–40%, integration costs are found to be 25–35 €/MWh, i.e. up to 50% of generation costs. While these estimates are system-specific and subject to significant uncertainty, integration costs are certainly too large to be ignored in high-penetration assessments (but might be ignored at low penetration). The largest single factor is reduced utilization of capital embodied in thermal plants, a cost component that has not been accounted for in most previous integration studies.

1. Introduction

As with any other investment, wind turbines and solar cells incur direct costs in the form of capital and operational expenses. These costs can be aggregated to average discounted life-time costs, called "levelized energy costs" or "levelized costs of electricity" (LCOE). In addition, integrating wind and solar power or other variable renewable energy sources (VRE)[1] into power systems causes costs elsewhere in the system. Examples include distribution and transmission networks, short-term balancing services, provision of firm reserve capacity, a different temporal structure of net electricity demand, and more cycling and ramping of conventional plants. These costs have been called "hidden costs" [3,87], "system-level costs" [19,61], or "integration costs" [67,33,68,53–55,58]. These need to be added to direct costs of wind and solar power when calculating total economic costs.[2] Integration costs are relevant for policy making[3] and system planning: ignoring or underestimating these leads to biased conclusions regarding the welfare-optimal generation mix and the costs of system transformation. This paper proposes a valuation framework for variable renewables and offers a new perspective on integration costs.

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1 Variable renewables have been also termed "intermittent", "fluctuating", or "non-dispatchable".

2 Total economic costs is the sum of all direct and indirect costs of increasing VRE generation. Total economic costs can be used to calculate welfare-optimal deployment levels, conducting cost-benefit analysis, or comparing LCOE across generation technologies. We define this term more rigorously in Section 2 and label it "System LCOE".

3 There has been a major public policy debate on integration costs in recent years in many countries, including the USA, the UK, and Germany.

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Previous studies have identified three specific characteristics of VRE that impose integration costs on the power system [9,68,86]:

- The supply of VRE is *variable:* it is determined by weather conditions and cannot be adjusted in the same way as the output of dispatchable power plants. VRE generation does not perfectly follow load and electricity storage is costly, so integration costs occur when accommodating VRE in a power system to meet demand.
- The supply of VRE is *uncertain* until realization. Electricity trading takes place, production decisions are made, and power plants are committed significant time in advance of physical delivery. Deviations between forecasted VRE generation and actual production need to be balanced at short notice, which is costly.
- The supply of VRE is *location-specific*, i.e. the primary energy carrier cannot be transported in the same way as fossil or nuclear fuels. Integration costs occur because electricity transmission is costly and good VRE sites are often located far from demand centers.[4]

While these properties of VRE are well-known and the term "integration costs" is widely used, there does not seem to be a consensus on a rigorous definition [68]. Previous studies have defined integration costs as "an increase in power system operating costs" [67], as "the additional cost of accommodating wind and solar" [68], as "the extra investment and operational cost of the nonwind part of the power system when wind power is integrated" [53], as "the cost of managing the delivery of wind energy" [26], as "comprising variability costs and uncertainty costs" [58], or as "additional costs that are required in the power system to keep customer requirement (voltage, frequency) at an acceptable reliability level" [54].[5] All these definitions are qualitative and challenging to operationalize. According to our reading of the literature it is not clear how to interpret the sum of generation and integration costs, and if and how integration cost estimates can be used for economic analyses of VRE – such as calculating their welfare-optimal deployment, conducting cost-benefit analysis, or comparing LCOE across generation technologies.

Lacking a rigorous definition, integration studies typically operationalize integration costs as the sum of three cost components: "adequacy costs", "grid costs", and "balancing costs". However, there is no consensus on how to consistently calculate and compare each of these cost components, and it is not clear if this enumeration is exhaustive.

This paper addresses these issues by making two contributions to the literature. First, we propose a valuation framework for wind power. This includes a definition of integration costs that has a rigorous welfare-economic interpretation, and a decomposition of these costs into three components. We show that reduced capital utilization has a major impact and explain why it has not been accounted for in many previous studies. Second, we provide a quantification of these components, based on an extensive literature review.

Section 2 provides the definition and Section 3 proposes the decomposition. Section 4 discusses the underlying technical constraints that explain integration costs, with a focus on reduced capital utilization. Section 5 reviews the literature and extracts quantitative estimates while Section 6 elaborates on who bears the costs under current market and policy design and identifies externalities. Section 7 concludes.

Readers mainly interested in numerical findings might proceed directly to section 5. The costs of forecast errors ("balancing costs" in our terminology) are found to be less than 6 €/MWh even at high wind penetration rates. In contrast, the reduction of energy value ("profile costs") are 15–25 €/MWh at high penetration. Increasing wind penetration affects profile costs about ten times more than balancing costs.

2. A new definition of integration costs

Our definition of integration costs aims to be economically rigorous and comprehensive. Integration costs should be defined such that they can be used in economic assessments, e.g. on the welfare-optimal deployment of VRE. Moreover, the definition should include all economic impacts of variability to make sure that an economic evaluation of VRE is complete.

The definition of integration costs is derived from the marginal economic value of electricity from VRE in terms of €/MWh. The marginal economic value (or benefit) is the increase in welfare when increasing wind generation by one MWh. If demand is perfectly price-inelastic, this equals the incremental cost savings when adding one MWh to a power system. This value is impacted by the properties of VRE mentioned in the introduction: variability, uncertainty, and location. Here we assume perfect and complete markets so that the marginal value of VRE equals the market value.[6] The market value is the specific (€/MWh) revenue that an investor earns from selling the output on power markets – excluding subsidies such as green certificates or feed-in premiums. In other words, the market value is the wind-weighted average electricity price, p_{wind}. A formal definition can be found in the Appendix.

Previous studies have shown that the characteristic properties of VRE reduce the market value of VRE with increasing VRE penetration [30]; [8,32,44,57,62,70,72]. This reduction in market value is caused by the interaction of VRE variability[7] and the inflexibilities of the rest of the power system. We interpret this reduction as integration costs. Already at this point it becomes clear that integration costs are not "caused by VRE", but by the interactions of VRE and power system properties.

We define integration costs of wind Δ_{wind} as the market value of wind p_{wind} compared to the load-weighted average electricity price $p_{electricity}$.[8]

$$\Delta_{wind}(q) = p_{electricity}(q) - p_{wind}(q) \tag{1}$$

[4] VRE generators have more specific characteristics, e.g. they are typically not electromechanically synchronized with the system frequency and hence provide no inertia to the system. We believe, in accordance with most authors, that the economic implications of these features are small, and neglect them in the further discussion.

[5] According to most definitions (including ours), it is not only VRE that are associated with integration costs. In Ref. [45]; we generalize the concept of integration costs to all generating technologies. Moreover, strictly logically one cannot say that VRE "cause" integration costs, as such costs emerge from the interaction of VRE and the rest of the power system. This implies that integration costs are not only affected by the properties of the VRE generator, but are system-specific. On the "cost-causation" debate see Ref. [68].

[6] We assume perfect and complete markets mainly to allow a more simple terminology. In Ref. [45] we drop this assumption and use the more general (but also more complicated) terminology.

[7] We use *variability* as an umbrella term for the three characteristic properties of VRE: temporal variability, uncertainty, and location.

[8] The average electricity price is chosen as a point of reference to estimate integration costs. It corresponds to the market value of a benchmark technology that generates electricity in perfect correlation with load. Choosing other reference points would be possible, but the average electricity price has a number of advantages [45]. With a different reference point, integration costs and System LCOE are different, but resulting optimal VRE shares are the same.

This definition of integration costs is comprehensive as it captures the economic impact of all characteristic properties of a technology that reduce (or increase) its market value. It implies that *all* generating technologies have integration costs, not just VRE. As prices reflect marginal costs, this definition specifies integration costs in marginal, not average, terms.

A key strength of this definition is that it reconciles the concept of integration costs with standard economic theory: it is a basic economic principle that the welfare-optimal deployment q^* of a technology is given by the point where market value $p_{wind}(q)$ and marginal costs coincide. The long-term marginal costs of a technology can be expressed as LCOE (€/MWh). Hence, VRE like any technology, are optimally deployed when their market value equals their LCOE.[9]

$$\begin{aligned} p_{wind}(q^*) &= LCOE_{wind}(q^*) \\ p_{electricity}(q^*) - \Delta_{wind}\left(q^*\right) &= LCOE_{wind}(q^*) \end{aligned} \quad (2)$$

As defined here, integration costs can be used for the economic evaluation of VRE and have a welfare-economic interpretation. Integration costs reduce the market value of VRE and consequently reduce their optimal deployment q^*. We refer to this way of accounting for integration costs and evaluating VRE as the *value perspective* (Fig. 1, left).

There is an alternative but equivalent perspective of understanding integration costs. From a *cost perspective*, integration costs can be added to the LCOE of wind, resulting in the metric "system levelized costs of electricity" (system LCOE, [96]). This metric comprises the total economic costs of a technology (Fig. 1, right).

$$sLCOE_{wind}(q) = LCOE_{wind}(q) + \Delta_{wind}(q) \quad (3)$$

In the cost perspective the above optimality condition (equation (2)) can be analogously formulated: VRE, like any technology, are welfare-efficient when their system LCOE equals the average electricity price.

$$p_{electricity}(q^*) = sLCOE(q^*) \quad (4)$$

Consequently the sum of generation and integration cost (system LCOE) of each generation technology is identical in the long-term optimum.

This shows that there are two ways of accounting for integration costs. First, from a value perspective they reduce the market value of a technology, and second, from a cost perspective they can be added to the marginal costs (LCOE) of a technology. Fig. 2 illustrates this duality. Integration costs of VRE tend to increase with VRE penetration. At low penetration VRE typically have negative integration costs because their output is often positively correlated with demand. The welfare-optimal deployment q^* is equivalently given either at the intersection of market value and LCOE, or where system LCOE intersect with the average electricity price.

A cost perspective has at least three merits [96]: LCOE is commonly used in industry, policy, and academia as a metric to compare technologies - apparently there is demand for cost comparisons. System LCOE can correct the flawed metric while retaining its intuitive and familiar touch. Secondly, a cost perspective is often applied by the integration cost literature. System LCOE can help to connect this literature with the economic literature on market value. Finally, a cost metric that comprises generation and integration costs can help parameterize VRE variability in multi-sector models.

9 For quantitative estimates of the "optimal share" of wind power see Ref. [46].

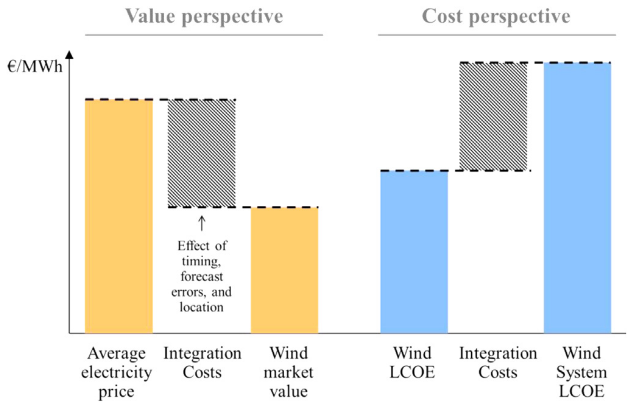

Fig. 1. We define wind integration costs as the gap between its market value and the average electricity price. The *value perspective* (left) is equivalent to the *cost perspective* (right).

Integration costs not only depend on the characteristics of VRE technologies but also on the power system into which they are integrated, and the power system's flexibility to adapt [97]. Published studies typically estimate integration costs by analyzing the impact of VRE on currently existing power systems with a fixed capacity mix and transmission grid. This is a short-term perspective. Integration costs depend on the properties of the legacy system: short-term integration costs are increased by a large stock of inflexible and capital-intensive base-load power plants, a scarce grid connection to regions with high renewable potentials and an inflexible electricity demand profile that hardly matches VRE supply.

In contrast, over the long term, the power system can fully and optimally adapt to increased VRE volumes. These potential changes comprise operational routines and procedures, market design, increased flexibility of existing assets, a shift in the capacity mix, transmission grid extensions, a change in load patterns, demand-side management and technological innovations. Integration costs can be expected to be generally smaller in the long term than in the short term (Fig. 3). Hence, short-term costs should be carefully interpreted and should not be entirely attributed to VRE. Integration cost studies should be explicit about the assumed time horizon

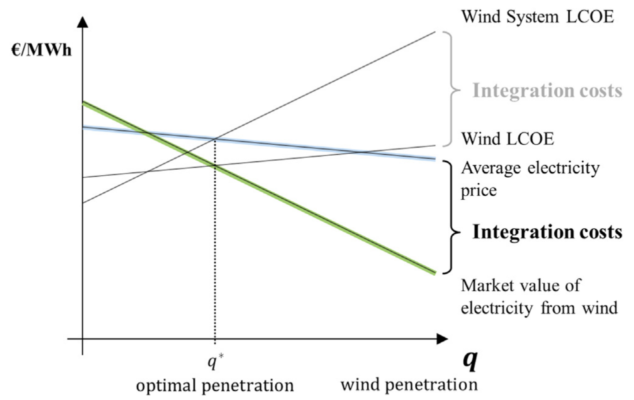

Fig. 2. Integration costs can be accounted for by reducing the market value of VRE compared to the average electricity price (value perspective). Alternatively, they can be accounted for by adding them to the generation costs of VRE leading to system LCOE (cost perspective). The welfare-optimal deployment q^* is defined by the intersection of market value and LCOE, and, equivalently, by the intersection of system LCOE with the average electricity price.

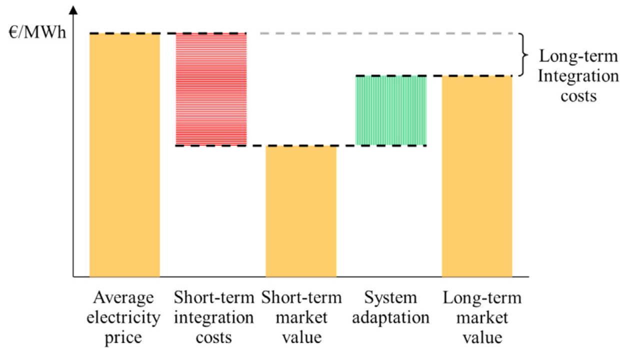

Fig. 3. Integration costs depend on how the system adapts in response to VRE deployment. In the short term when the system does not adapt integration costs can be high (red area), while in the long term VRE can be better accommodated and thus long-term integration costs are smaller. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

and considered system adaptations. In Section 5 we show report costs estimates from both a short and long-term perspective.

3. Decomposing integration costs

This section suggests a decomposition of integration costs into three approximately additive components.

Our definition of integration costs can in principle be directly used in economic assessments – there is no need to disentangle integration costs into components. However, such a decomposition might be helpful for three reasons. First, it allows single components with specialized models to be estimated. Estimating total integration costs directly would require a “super model” that accounts for all characteristics and system impacts of VRE, and such a model might be impossible to construct. By contrast, estimating individual components allows using specialized models. Second, a decomposition allows the cost impact of different properties of VRE to be evaluated and compared to each other. It helps identifying the major cost drivers and prioritizing integration options (e.g., storage vs. transmission lines vs. forecast tools) to more efficiently accommodate VRE. Third, by decomposing integration costs, the new definition can be compared to the standard literature that typically calculates integration costs as the sum of balancing, grid and adequacy costs.

Previous authors have identified three fundamental properties of VRE: uncertainty, locational specificity, and variability. We propose to decompose integration costs according to the effect of each of these characteristics. The impact of uncertainty is called “balancing costs”, the impact of location “grid-related costs”, and the impact of temporal variability “profile costs”. We define them here in terms of prices[10]:

- *Balancing costs* are the reduction in the VRE market value due to deviations from day-ahead generation schedules, for example forecast errors. These costs appear as the net costs of intraday trading and imbalance costs. They reflect the marginal cost of balancing those deviations. We define balancing costs to be zero if VRE forecast errors are perfectly correlated to load forecast errors.
- *Grid-related costs* are the reduction in market value due to the location of generation in the power grid. We define them as the spread between the load-weighted and the wind-weighted electricity price across all bidding areas of a market. They reflect the marginal value of electricity at different sites and the opportunity costs of transmitting electricity on power grids from VRE generators to consumers.
- *Profile costs* are the impact of timing of generation on the market value. We define them as the spread between the load-weighted and the wind-weighted electricity price over all time steps during one year. They reflect the marginal value of electricity at different moments in time and the opportunity costs of matching VRE generation and load profiles through storage.

A formal definition is provided in the Appendix. Fig. 4 illustrates how each cost component can reduce (or increase) the market value of a VRE technology.

These cost components interact with each other and we do not know the direction or the size of the interaction. This should be the subject of further research. In this paper we assume that the integration cost components are independent and can be approximately summed. This approximation allows the three components to be separately estimated and totaled to determine integration costs.

The decomposition has four beneficial properties:

1. Temporal variability, network constraints, and forecast errors can be evaluated *consistently* in a uniform valuation framework. Balancing costs of one €/MWh are equivalent to one €/MWh of grid-related costs in the sense that both have the same effect on the marginal economic value of VRE.
2. All costs of variability at the system level are accounted for *comprehensively*, including reduced energy value (profile costs). This allows using integration costs for economic assessment of VRE.
3. The decomposition allows *operationalizing* integration costs. Integration costs can be estimated by summing up its components. This is important as an accurate estimation of integration costs with one “super model” might be infeasible.
4. It allows *robust* estimation in the sense that a quantification of each component can either be derived from empirical market prices or from modeled shadow prices.

The next section investigates the techno-economic mechanisms behind each cost component and relates them to traditionally used cost components.

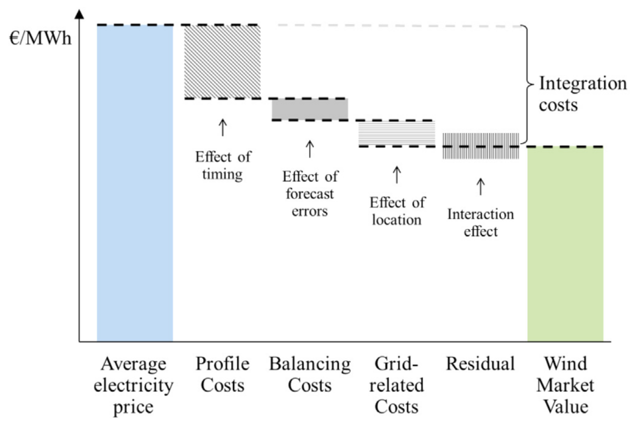

Fig. 4. We decompose integration costs into three components, balancing, grid-related, profile costs. They correspond to the three characteristics of VRE uncertainty, locational specificity, and temporal variability.

[10] We use prices to avoid complex language. Recall the assumption of perfect and complete markets. Hence prices correspond to marginal costs and marginal benefits.

4. The technical fundamentals behind integration costs

We have proposed a definition of integration costs derived from the market value of electricity and suggested a decomposition into balancing, grid-related, and profile costs. Although these have been defined in terms of prices, prices are nothing more than the monetary evaluation of underlying technical constraints and opportunity costs. This section discusses these fundamental constraints. We will discuss profile costs particular, since they have received least attention in the literature. We also try to explain why they have received so little attention.

4.1. Balancing costs

Balancing costs are the marginal costs of deviating from announced generation schedules, for example due to forecast errors. They are reflected in the price spread between day-ahead and real-time prices. Depending on the market, real-time prices can be intraday prices and/or imbalance charges. As a result of correlated forecast errors, VRE generators tend to produce disproportionally more power at times of depressed real-time prices. The corresponding reduction in market value represents balancing costs.

There are three fundamental technical reasons jointly causing balancing costs. (i) Frequency stability of AC power systems requires supply and demand to always be balanced with high precision. (ii) Thermal gradients cause wear and tear of thermal plants, implying that output adjustments (ramping and cycling) are costly; ramping constraints also make costly part-load operation necessary for spinning reserve provision. (iii) The forecast errors of individual wind (and solar) generators are positively correlated because weather at nearby sites is correlated and operators use similar forecast tools.

Under complete and perfect markets, balancing costs reflect the marginal costs of providing balancing services: both capacity reservation and activation.

In addition to forecast errors, there is another (and minor) reason for balancing costs: electricity contracts are specified as stepwise schedules with constant quantities over certain time periods such as 15 or 60 min. Costs arise to balance the small variations within these dispatch intervals (intra-schedule variability).

The size of balancing costs depends on a number of factors:

- The absolute size of the VRE forecast error, itself being a function of (i) installed VRE capacity, (ii) the relative size of individual forecast errors, which is determined by the quality of forecast tools [31], and (iii) the correlation of forecast errors between VRE generators. It is sometimes argued that solar can be more accurately forecasted than wind, hence solar power should feature lower balancing costs. The correlation of forecast errors is a function of the geographic size of the balancing area: a larger area typically reduces correlation and hence reduces the absolute size of VRE forecast errors [35].
- The correlation of VRE forecast errors with load forecast errors and other imbalances. At low penetration, VRE forecast errors might even decrease the system imbalance.
- The capacity mix of the residual system. Specifically, hydro power can typically deliver balancing services at lower costs than thermal plants [14]; [1].
- The design and liquidity of intraday markets [51,101] and balancing markets [49,77,100].

4.2. Grid-related costs

Grid-related costs are the marginal costs of transmission constraints and losses. They are reflected in the price spread between locations. Locational prices can be implemented as nodal or zonal spot prices, or as locational grid fees. VRE generators tend to produce disproportionally more power in regions of low electricity prices. The corresponding reduction in market value represents grid-related costs.

There are three fundamental technological reasons for grid-related costs: (i) transmission capacity is costly and hence constrained; (ii) transmitting electricity is subject to losses; (iii) VRE generation costs vary geographically with varying resource quality and land prices.

In the long-term market equilibrium under complete and perfect markets and endogenous transmission capacity, grid-related costs reflect the marginal costs of building new transmission capacity and recovering losses.[11]

The size of grid-related costs depends on several factors:

- The location of good wind and solar sites relative to the geographic distribution of loads. An often mentioned example is that windy sites where land is cheap and there are little acceptance issues are typically located far away from load centers.
- The location of good VRE sites relative to the location of conventional power plants.
- Existing transmission constraints.
- The cost of transmission expansion.
- The design of locational price signals to electricity generators: nodal prices, zonal prices, differentiated grid fees, and cost-based re-dispatch can result in quite different grid-related costs.

Typically solar photovoltaics is installed closer to consumers than onshore wind, which in turn is closer than offshore wind. Thus grid-related costs are lower for solar than for onshore wind and highest for offshore wind. Highly meshed and strong transmission networks (as in many parts of continental Europe) feature lower grid-related costs than large countries with weak grids (e.g. the Nordic region and several regions in the U.S.).

4.3. Profile costs

Profile costs are the marginal costs of the temporal variability of VRE output. They are reflected in the structure of day-ahead spot prices and materialize as reduced “energy value” [67] of wind and solar power. VRE generators tend to produce disproportionally more power at times of low electricity prices. The corresponding reduction in market value represents profile costs.

To understand their nature, consider the following thought experiment: assume that VRE generation can be perfectly forecasted and that the entire market is a copper plate with unrestricted transmission capacity. This would dissolve balancing and grid-related costs. Despite this, VRE variability would have economic consequences, which are reflected in varying spot prices and (often) in lower market value for VRE generators than for hydro-thermal generators [44].

4.3.1. Flexibility effect

One reason for this gap is the cost of adjusting the output of thermal plants. Thermal gradients of power plants cause ramping and cycling to be costly and ramping constraints require plants to run at part load to be able to follow steep gradients of residual load (load net of VRE generation). Following Ref. [72]; we call this the “flexibility effect.” The flexibility effect covers only scheduled

[11] See Refs. [83,50,78] point out several market failures that might prevent such an equilibrium to be reached.

ramping and cycling, while uncertainty-related ramping and cycling are reflected in balancing costs.

We now derive a rough estimate of the size of the flexibility effect. We use German load and VRE in-feed data from 2010, and scale in-feed to simulate VRE penetration rates between 0% and 40%.[12] Fig. 5 illustrates that residual load ramps increase with penetration. We measure cycling in terms of "system cycles", the sum of upward residual load ramps during one year over peak load. Without renewables, i.e. with load variability only, the system follows about 100 of such system cycles. At 40% VRE, the number increases to 160. This means that the average plant cycles 60% more often. Assuming high cycling costs of 100 €/MW per cycle,[13] the increase in cycles results in marginal costs of 3 €/MWh$_{VRE}$ (Fig. 6).

In other words, the economic impact of cycling is very small. This rough calculation is confirmed by the literature review in Section 5.3.

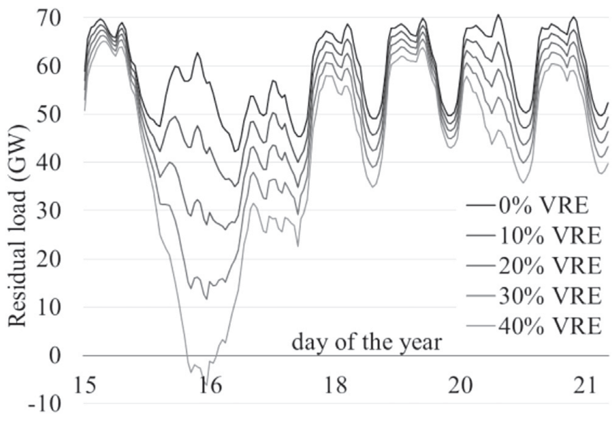

Fig. 5. Residual load curves during one week. Residual ramps increase at high VRE shares.

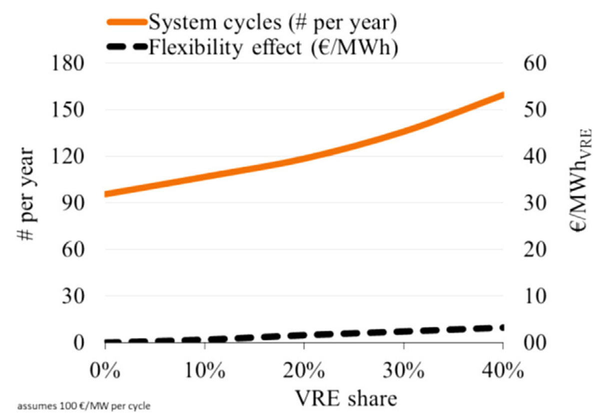

Fig. 6. The flexibility effect, based on simple residual load scaling and assuming 100 €/MW per cycle (same right-hand scale as Fig. 8 for better comparability).

4.3.2. Utilization effect

For further understanding of the nature of profile costs, let us continue the thought experiment. Assume that all plants can ramp and cycle without costs, hence the flexibility effect disappears. Still, the market value of wind and solar generation is often lower than the average electricity price, and it decreases with penetration. In the following, we will show that these costs are caused by a reduced utilization of thermal plants, the "utilization effect".

The generation of new VRE plants is correlated with that of existing VRE, so VRE generation is increasingly concentrated in times of low residual load. The impact of VRE on residual load can be expressed as residual load duration curves (RLDC), the sorted hourly residual load of one year. With increasing VRE penetration, the RLDC becomes steeper (Fig. 7). The *y*-intercept of the RLDC is the thermal capacity requirement,[14] while the integral under the RLDC is thermal generation. The average utilization of thermal plants is given by the ratio of *y*-intercept to integral. With increasing VRE penetration the ratio decreases.

Using the above data we roughly estimate the size of the utilization effect. Without renewables, the utilization rate of thermal capacity is roughly 70% (Fig. 8, Table 1). As VRE penetration grows to 40%, utilization decreases to 47%. Reduced utilization increases specific (€/MWh) capital costs. Assuming constant annualized capital costs of € 200/kWa, which roughly represents the costs of a coal-fired plant, reduced utilization drives up capital costs of thermal generation from 33 €/MWh to 49 €/MWh. Moreover, if VRE generation is curtailed at times of negative residual load, VRE capacity utilization is also reduced, driving up the capital costs of VRE generation from 80 €/MWh to 85 €/MWh.

We then relate this cost increase to the increase in VRE generation. For example, increasing the VRE share from zero to 10% increases thermal capital costs from 33 €/MWh$_{thermal}$ to 34 €/MWh$_{thermal}$ (Table 1, row 5), which corresponds to 10 €/MWh$_{VRE}$ (row 6), as the thermal generation volume is about ten times larger than VRE generation. In this example, VRE capital costs do not increase, as no generation is curtailed (rows 9–11). Rows 6 and 11 show the cost increase (relative to the prior column), reflecting the marginal nature of our integration cost definition. The sum of increased capital costs for thermal and VRE generation is the utilization effect (row 12).

At 40% penetration, the utilization effect is about 51 €/MWh, almost 20 times larger than that of cycling costs, and in the same order of magnitude as VRE generation costs. Of course, this

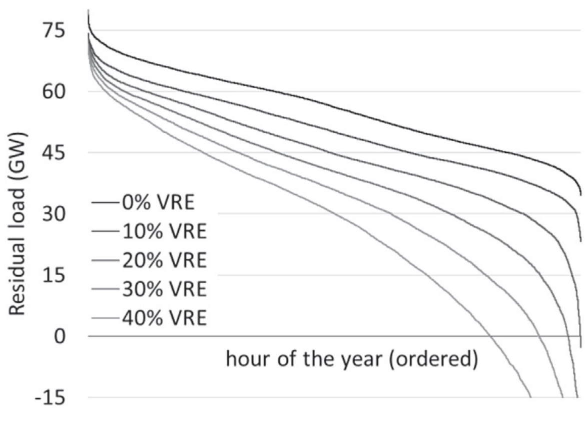

Fig. 7. Residual load duration curves for one year. The average utilization of the residual generation fleet decreases.

[12] We use empirical wind and solar in-feed data as well as load data from 2010. All data come from the four German transmission system operators and is publicly available. To illustrate different shares, we scale VRE profiles to reach between 0% and 40% of electricity generation, assuming a wind-to-solar ratio of 2:1 in energy terms.

[13] This corresponds to start-up costs of 100,000 for a one-GW block, which is a conservative (high) estimate, even for a cold start, let alone for warm or hot starts. This also ignores that part of the ramps are covered by hydro plants, which have much lower cycling and ramping costs.

[14] Ignoring balancing and planning reserves.

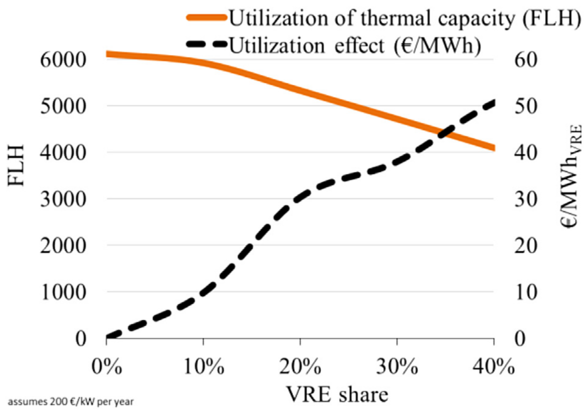

Fig. 8. The utilization effect, based on simple residual load scaling and assuming thermal capital costs of 200 €/kWa.

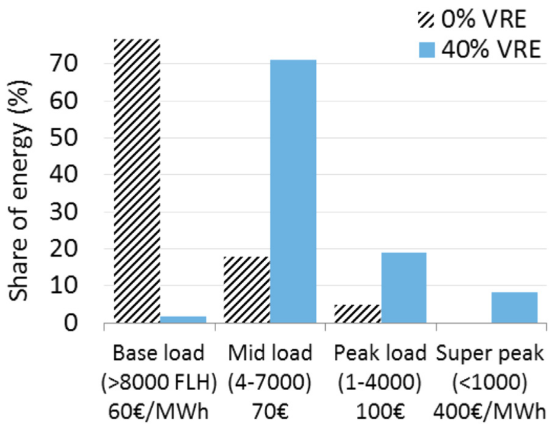

Fig. 9. Utilization of residual capacity without renewables and at 40% penetration. Electricity generated in base load plants strongly decreases, while mid and peak load generation increase (not only relatively, also absolutely).

calculation has made a number of (very) simplifying assumptions. Most importantly, the thermal capacity mix will adjust (capital costs will not remain constant at 200 €/kW*a), mitigating the utilization effect. However, we believe the general findings to be valid. The literature review of Section 5.3 supports the finding that the capital cost-driven utilization effect is the single most important integration cost component and finds quite similar absolute cost levels.

Reduced thermal plant utilization is *not* only a *transitory* phenomenon. While it is true that a swift introduction of renewables reduces thermal plant utilization (and reduces investor profits [47]), high VRE shares lead to lower average plant utilization even in the long-term equilibrium. Fig. 9 shows the share of energy that is generated in plants that run base load (>8000 FLH), mid load, peak load, and super peak load (<1000 FLH), using the same data as above. Without VRE, three quarters of all electricity is generated in base load plants. At 40% penetration, virtually no base load generation is left. This leads to higher average generation costs even in the long-term, since levelized electricity costs strongly decrease with increasing utilization, even under optimal technology choice (Fig. 10). The fact that steeper RLDCs require a different technology mix and that such a mix is more expensive is implicit in the classical screening curve literature [37,79,90].

In the long-term market equilibrium under complete and perfect markets, day-ahead spot market prices reflect both the utilization and the flexibility effect. The size of profile costs is dependent on the VRE share and power system characteristics. Specifically, it depends on:

- VRE penetration rate. Profile costs increase with penetration, mainly because the utilization of residual capacity decreases [44,62].
- The distribution of VRE generation. A flatter (more constant) generation profile leads to lower profile costs at high penetration rates. Offshore wind profiles are flatter than onshore wind profiles, which are flatter than solar PV profiles [8,36,45,70,72]. A geographically larger market leads to a flatter aggregated VRE generation profile resulting from geographical smoothening [35].
- The correlation of VRE generation with demand. Positive correlation can to negative profile costs. An obvious example is the diurnal correlation of solar power with demand, often leading to negative solar profile costs at low penetration (high energy value).

Table 1
Calculating the utilization effect.

	VRE share (% of consumption)	0%	10%	20%	30%	40%
(1)	Thermal capacity (GW)	80	74	73	73	72
(2)	Thermal generation (TWh)	489	440	391	342	293
(3)	Utilization of thermal capacity (%)	70%	68%	61%	54%	47%
	Utilization of thermal capacity (FLH)	6100	6000	5300	4700	4100
(4)	Thermal capital costs (€/kW*a)	200	200	200	200	200
(5)	Thermal capital costs (€/MWh$_{thermal}$)	33	34	38	42	49
(6)	Increase of thermal capital costs ("marginal costs") per VRE generation (€/MWh$_{VRE}$)	0	10	30	34	38
(7)	Installed VRE capacity (GW)	0	36	72	110	154
(8)	Potential VRE generation (TWh)	0	49	97	149	208
(9)	VRE Curtailment (TWh)	0	0	0	2	13
(10)	VRE capacity costs (€/MWh$_{VRE}$)	80	80	80	81	85
(11)	Increase of VRE capital costs ("marginal costs") per VRE generation (€/MWh$_{VRE}$)	0	0	0	4	12
(12)	Utilization effect (€/MWh$_{VRE}$) (6) + (11)	0	10	30	38	51

Assuming that all residual load is served by thermal units, no intertemporal flexibility or constraints, 80 €/MWh$_{VRE}$ and a constant average capital costs of the thermal system of 200 €/KW*a. The underlying excel sheet is available from the authors on request.

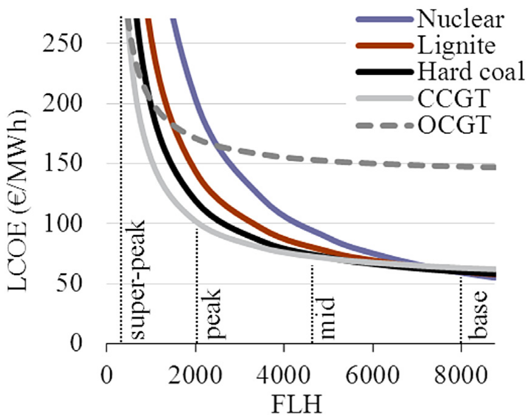

Fig. 10. Average costs for different technologies at different full load hours. CCGT and OCGT are combined-cycle and open-cycle gas turbines, respectively. While base load plants (8000 FLH) supply electricity for around 60 €/MWh, super peakers cost around 400 €/MWh.

- The shape of the merit-order curve: the steeper the curve, the larger the utilization effect [44]. In the long term, the shape of the merit-order curve is determined by the differentiation of available technologies in terms of fixed-to-variable cost ratio.
- The intertemporal flexibility of the power system, both on the supply side (e.g., storage) and the demand side (e.g., demand response). Reservoir hydro power can have an especially large impact. This technology allows shifting generation over time, hence “flattening-out” residual load [70,82].

Wind integration studies and other integration cost literature often account for the costs of grid extensions, balancing services, and cycling of thermal plants. Our findings indicate that it is at least as important to account for the reduced utilization of thermal generators and their capital costs. Surprisingly, many previous studies have not done this.

4.4. Relation to the standard integration cost literature

There is a rich body of wind and solar integration studies that estimate integration costs. For an overview see Refs. [53]; [20,88]; or [40]; [54] provides a blueprint of such an assessment. These studies typically understand integration costs in a more narrow sense: their definition of integration costs does not cover the utilization effect. This might be because costs due to this effect differ conceptually from other cost components. Grid and balancing costs are *additional costs* in the strict sense of increased expenses due to a higher VRE share, e.g. for more grid infrastructure, fuel consumption, or maintenance. By contrast, the utilization effect does not refer to increasing expenses but *diminishing cost savings* in the non-VRE system when increasing the VRE share.

Note that some integration cost studies also cover a specific aspect of the reduced utilization of non-VRE plants: the low capacity credit of VRE [2,27]. Motivated by the need for firm capacity to ensure generation adequacy these costs are called “adequacy costs”. Hereby the studies expand their focus away from only calculating *increasing expenses*: it is not necessary to add conventional capacity when introducing VRE to an existing system. Adequacy costs refer to the dispatchable capacity that could be removed in the long term if VRE had a higher capacity credit. Similarly, profile costs refer to the dispatchable capacity that could be better utilized if VRE followed load.

While adequacy costs only address the low capacity credit of VRE, the utilization effect is more general: thermal utilization is reduced as the RLDC becomes steeper and VRE utilization is reduced as generation needs to be curtailed. These three cost impacts are all determined by the same driver: the (lack of) temporal coincidence of VRE generation and load. Hence, profile costs and the utilization effect can be understood as a generalization of adequacy costs.

From an economic perspective these two categories of *increasing expenses* and *diminishing cost savings* are equivalent: both are opportunity costs [97]. It makes no difference for the economic evaluation of VRE if more balancing costs are imposed or if less peak capacity can be substituted when adding additional VRE capacity. In fact, a comprehensive economic evaluation of VRE needs to account for both categories and thus needs to cover all cost components of integration costs described in this paper. Hereby each cost component can be either accounted for as increasing the costs of VRE or as decreasing their value. Consequently, there are a number of different ways of comprehensively attributing the cost components, which are all equivalent in the sense that they lead to the same cost-optimal share of VRE. We can think of four intuitive ways of attributing the cost components:

- First, one can take a *value perspective* where all cost components reduce the value of VRE (see Section 2). In order to derive the cost-optimal share of VRE the resulting market value needs to be compared to the generation costs of VRE (LCOE).
- Second, from a pure *cost perspective,* all cost components need to be added to the LCOE of VRE (see Section 2). The resulting costs (system LCOE) can be compared to the average annual electricity price to derive optimal VRE shares.
- Third, from a *mixed* perspective, diminishing avoided costs can be counted separately from additional costs: balancing and grid costs can be added to the LCOE of VRE because they reflect increasing expenses. Profile costs can be regarded as reducing the value of VRE because they reflect diminishing avoided costs of VRE. At the cost-optimal deployment of VRE the increased costs equal the resulting reduced value (Fig. 11).
- Fourth, an attribution can also be made considering the way a *real-world power market* deals with these costs. The specific market design determines whether a certain cost component is reflected in reduced market value or is put to generators as a cost after markets have cleared. In most European power markets, profile costs appear as reduced value. Balancing and grid-related costs often appear as a mix of reduced value (e.g., low intraday prices) and costs (e.g., imbalance charges).

5. Quantifications from the literature

One merit of the proposed cost decomposition is that cost components can be estimated individually, and that they can be estimated either from models or market prices. We reviewed more than 100 published studies, of which about half could be used to extract quantifications of balancing, grid-related, or profile costs. The studies varied significantly in methodology, rigor, and related to different power systems. Model-based estimates are valid only to the extent that models can be regarded as realistic, and estimates from market data are only valid to the extent that markets can be treated as being complete and free of market failures. We discuss market failures in the following section.

5.1. Balancing costs

There are three groups of studies that provide wind balancing cost estimates: wind integration studies often commissioned by system operators, academic publications based on stochastic unit commitment models, and empirical studies based on market prices. We discuss these publications in turn and summarize results in Fig. 12. Ref. [45] provides a similar review for solar power.

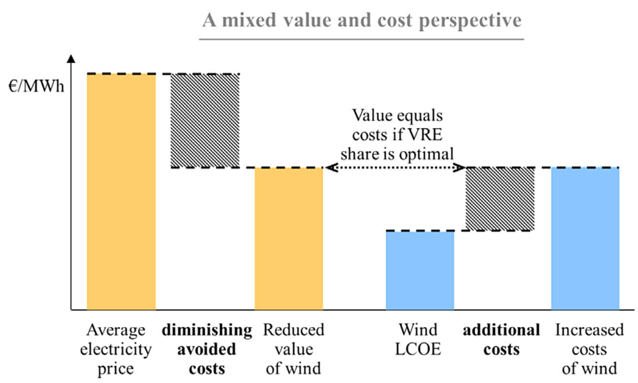

Fig. 11. From a “mixed” perspective diminishing avoided costs of VRE reduce the value of wind compared to the average electricity price whereas additional costs increase costs of wind. VRE deployment is optimal when their value and costs coincide.

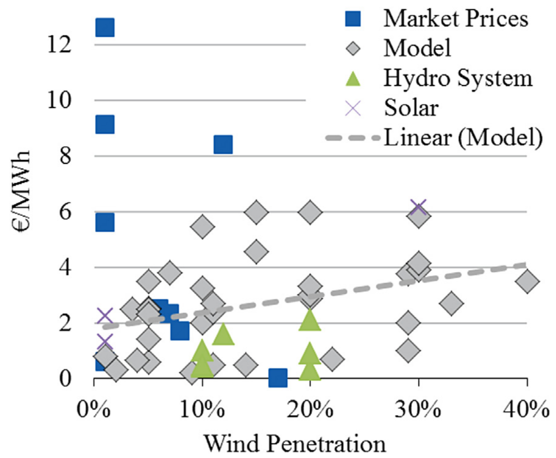

Fig. 12. Balancing cost estimates for wind and power from market prices (squares) and model prices (diamonds) for wind and solar power (crosses). Three market-based studies report very high balancing costs. All other estimates are below 6 €/MWh. Studies of hydro-dominated systems show low balancing costs (triangles). A list of studies can be found in the Appendix.

There are too many wind integration studies to review all of them individually here. A number of meta-studies have reviewed wind integration studies. Covering much of the earlier literature [40], reports balancing costs to be below 3 £/MWh in most cases. Surveying six American studies [88], report a range of 0.7–4.4 $/MWh. [21]; focusing on the United States, find costs of 3–4.5 $/MWh for penetration rates around 30%, but find one outlier of 9 $/MWh. The most recent survey is provided by Refs. [53]; who estimate balancing costs at 20% penetration rate to be 2–4 €/MWh in thermal power systems and less than 1 €/MWh in hydro systems. In several of the studies reviewed, balancing costs arise mainly because wind power increases reserve requirements.

A handful of academic articles have derived balancing costs from stochastic unit commitment models. They typically compare total system costs with and without wind forecast errors. Forecast errors introduce costs because more expensive plants have to be scheduled than under perfect foresight. Ref. [70] estimate wind balancing costs to be in the range of 2–4 $/MWh at penetration rates up to 30%. Several other studies do not report balancing costs in marginal terms, as we have defined them, but only report system costs with and without forecast errors. As a rough indication, we calculate average, not marginal, balancing costs by dividing the cost increase by wind generation. Ref. [94] find average wind balancing costs of about 3 €/MWh at 34% penetration in Ireland, which is similar to that found by Ref. [34]. Ref. [98] find costs for The Netherlands to be “small”. [41] and [91] assess balancing costs based on the statistical properties of wind forecast and reserve costs, resulting in low estimates. Grubb reports 3.6% of the value of electricity and Strbac 0.5 £/MWh, both at a 20% penetration.

The third group of studies does not use models, but evaluates wind forecast errors with observed imbalance prices or the price spreads between day-ahead and intraday markets. Such market-based evaluations are of course limited to historical conditions, such as low penetration rates. Ref. [51] reports balancing costs in Demark to be 3 €/MWh. If intraday markets had been liquid up to two hours ahead of delivery, balancing costs would be reduced by 60%. Denmark has an impressive wind penetration rate, but benefits from the integrated Nordic balancing market and much interconnector capacity. Ref. [80] report balancing costs of 4 €/MWh for the best unbiased forecast based on Dutch data. However, the profit-maximal (biased) bidding strategy reduced balancing costs by half. Ref. [77] use Austrian, Danish, and Polish data. They confirm that balancing costs are often reduced by biased forecasts. The authors find balancing costs of close to zero in Denmark, 6 €/MWh in Austria, and 13 €/MWh in Poland. Ref. [52] use 2004 Finnish market prices to evaluate wind balancing costs. They report costs to be 0.6 €/MWh if all forecast errors are settled via balancing markets. Surprisingly, they find costs to increase if the intraday market is used. Ref. [58] estimate balancing costs in Texas to be 2–5 $/MWh for a small group of turbines.

For this study, we have assessed wind imbalance costs for Germany. Using historical system operator wind forecast errors and observed imbalance prices at quarter-hourly granularity, we find balancing costs for wind of 1.7–2.5 €/MWh during the last three years.[15]

Estimating balancing costs from market prices is not without problems, because many real-world balancing markets are subject to market failures and do not reflect the marginal costs of balancing forecast errors [49]. Moreover, day-ahead forecasts are sometimes biased, either because of biased prediction tools, of because it is profitable to under- or oversell on day-ahead markets. Such strategic behavior can be profitable if real-time and day-ahead markets are not arbitrage free, or if punitive mark-ups for forecast errors are imposed [6,15,80,100]; [64].

Fig. 12 displays the results from all studies. A complete list of studies and estimates can be found in the Appendix (Table 2). Despite the heterogeneity of results, the findings are striking: virtually all estimates are below 6 €/MWh even at high penetration rates in thermal power systems, and several estimates are well below that number. All estimates above 6 €/MWh are market-based estimates of systems where imbalance prices contain punitive mark-ups and are not likely to reflect the marginal costs of balancing. There is not a single model-based estimate above 6 €/MWh, even at 40% wind penetration. All estimates for hydro systems are below 2 €/MWh. The trend-line is fitted on modeled prices for wind power in thermal systems. It indicates that for each percentage point market share, the balancing costs of wind power increase by 0.06 €/MWh. Balancing costs increase from 2 €/MWh to 4 €/MWh as wind penetration increases from zero to 40%. In other words, even at high penetration rates, balancing costs are quite low.

VRE do not only increase the demand for balancing, but can also supply balancing services [60]; [7,89]; and [49]; [24]. While this is a possible additional income stream for VRE, it will not be considered here due to lack of robust quantifications.

5.2. Grid-related costs

Quantitative evidence on grid-related costs is scarce. Integration studies sometimes calculate the cost for additional grid investments, but seldom report marginal costs. Furthermore, results are often not based on cost-optimized grid expansion, and it is usually not clear if VRE expansion or other factors drive grid investments.

Ref. [91] find grid-related costs in the UK to be 0.9 £/MWh at 20% wind penetration. Ref. [23] report them to be about 3 €/MWh

[15] www.tennet.eu/de/kunden/bilanzkreise/preise-fuer-ausgleichsenergie.htmlt, www.tennet.eu/de/kunden/eegkwk-g/erneuerbare-energien-gesetz/windenergie-on-und-offshore/tatsaechliche-und-prognostizierte-windenergieeinspeisung.html, www.50hertz.com/cps/rde/xchg/trm_de/hs.xsl/Netzkennzahlen.htm?rdeLocaleAttr=de&&rdeCOQ=SID-E67C66B1-E5C66222, www.amprion.net/windenergieeinspeisung, www.transnetbw.de/de/kennzahlen/erneuerbare-energien/windenergie?activeTab=table&app=wind.

in Ireland for 30–40% penetration. Ref. [22] estimates the transmission-grid related costs to integrate 39% renewables in Germany by 2020 to be about € 1bn per annum. If that is attributed to the increase in renewable generation, it translates to about 10 €/MWh. Ref. [73] estimates grid investment costs to support 80% renewables (of which half are VRE) to be about 6 $/MWh. Ref. [53] review a handful wind integration studies that estimate grid costs. They report wind-related investment costs of 50–200 €/kW at penetration rates below 40%, which is equivalent to 2–7 €/MWh.[16] However, all these estimates are average costs and do not represent the impact on the marginal value of wind and solar electricity.

Ref. [42] model locational marginal prices to derive the locational value of wind power. They find the value of wind power to differ by 18 €/MWh between locations. Ref. [92] models locational marginal prices in Germany to evaluate wind power. He finds that transmission constraints introduce a spread in the value of VRE between low and high price areas of about 10 €/MWh. With VRE being quite well distributed around the country however, the average impact of location on the market value is close to zero – both for solar and wind.

Three studies use empirical locational electricity prices to estimate grid-related costs. Ref. [12] estimate the market value of solar power in Ontario to be 20–35 $/MWh higher in large cities than the system price. Ref. [65] finds similarly large differences for different locations in Michigan. However, the data provided by these two studies does not allow the impact of spatial price variations on the market value of electricity from VRE to be calculated. Evaluation locational prices in Texas [92], finds, surprisingly, that the value of wind power is slightly *increased* by its location – grid-related costs are negative. This can be explained by the fact that electricity price in Western Texas, where most wind power is situated, are above state average.

For this study, we have assessed grid-related costs in Sweden. In Sweden, zonal prices were introduced in November 2011, making it one of the few European countries with locational price signals. The price difference between the Northern bidding zone, where many future wind projects are planned, and the system price has been 0.5–1.1 €/MWh for the past two years. In addition, there are geographically differentiated grid fees for generators.[17] If these are totaled, grid-related costs are in the order of 5 €/MWh.

The quantitative evidence on grid-related costs is thin. Notwithstanding, the few studies available provide a consistent picture: VRE expansion causes only moderate costs for grid expansion. While individual sites provide a significantly higher value than others, the market value of wind or solar generators as a whole does not seem to be affected much by spatial price variation, because generators are spatially quite well distributed. Grid-related costs seem to be in the single-digit range in €/MWh terms.

5.3. *Profile costs*

We discuss the flexibility effect and the utilization effect separately. Costs estimates of the *flexibility effect* are rather scarce and most of these find the cost of hour-to-hour variability to be very small. Based on an analytical approach [41], estimates variability costs to be 0.2–0.3% of the value of wind electricity. Ref. [88] find slightly higher values of 0.4–1.7 $/MWh; [43] report 0.2–2 $/MWh. Recently, [74] published an extensive assessment of ramping and cycling costs, estimating the cost to be 1.0–3.2 $/MWh at a renewables share of 33%. Ref. [72] finds the utilization effect to be much larger than the flexibility effect. Ref. [16] concludes that ramping constraints are not binding even at high penetration rates in Germany. Similarly, report that ramping requirements are easily met in all power systems except small island systems. Overall, increased ramps do not seem to have significant impact on the market value of VRE generators. This finding is consistent with the simple calculations in Section 4.3.

Many studies (implicitly) report estimates of the *utilization effect*. Elsewhere, we have provided extensive quantitative assessments for wind and solar power [44,45]; hence we keep the discussion here short. Fig. 13 summarizes wind profile cost estimates from some 30 publications. A complete list of references can be found in the Appendix (Table 3). Wind profile costs are estimated to be zero or slightly negative at low penetration rates and to be around 15–25 €/MWh at 30–40% market share.

The gray dotted trend-line is fitted on short-term (dispatch) models, the blue bold line on long-term (combined dispatch and investment) models. As expected, the bold line has a lower gradient, reflecting system adaptation. The bold line indicates that for each percentage point market share, the profile cost of wind power increase by 0.5 €/MWh. This is a full order of magnitude larger than the increase in balancing cost. The estimate from short-term models is 50% higher.

Summing up all three cost components, integration costs might be around 25–35 €/MWh at 30–40% penetration rate in thermal power systems, if the average electricity price is around 70 €/MWh. In other words, electricity from wind power is worth only 35–45 €/MWh under those conditions, 35–50% less than the average electricity price. Levelized electricity costs of wind are currently around 70 €/MWh in Europe. This means, integration costs increase direct generation costs by 35–50%.

Of integration costs at high penetration, about two thirds are profile costs. An increase in the wind penetration rate of one percentage point is estimated to increase profile costs by 0.5 €/MWh, almost ten times more than balancing costs.

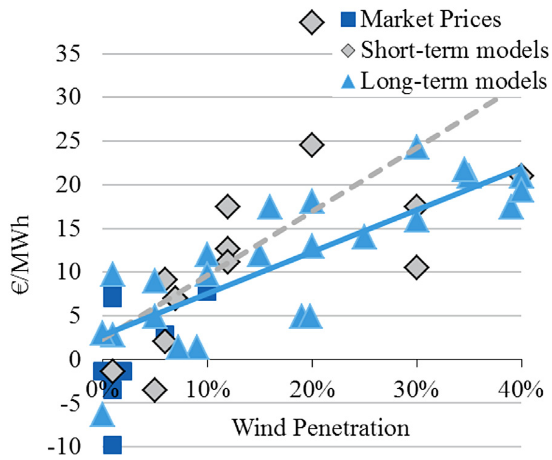

Fig. 13. Wind profile cost estimates from about 30 published studies. Studies are differentiated by the way they determine electricity prices: from markets (squares), from short-term dispatch modeling (diamonds), or from long-term dispatch and investment modeling (triangles). To improve comparability the average electricity price was normalized to 70 €/MWh. The OLS-estimate of all long-term models results in profile costs of 15–25 €/MWh at 30–40% market share. A list of studies can be found in the Appendix.

[16] At a 7% discount rate and 2000 wind full load hours.

[17] Spot prices from http://www.nordpoolspot.com/Market-data1/Elspot/Area-Prices/ALL1/Hourly/, retrieved 20 May 2014. Grid fees from personal communication with Svenska Kraftnät.

6. Who bears integration costs?

The last sections discussed how integration costs are defined, how they are composed, and how large they are. A related, but independent question is who *bears* these costs. Are integration costs an externality? This is a question of policy and market design and will be discussed (briefly) in this section.

Under perfect and complete electricity markets in long-term equilibrium, profile costs would appear as reduced revenues from the day-ahead spot market, balancing costs would arise from the net costs for intraday trading and imbalance charges, and grid-related costs would appear as differentiated locational spot prices or differentiated grid fees. If electricity and ancillary service prices reflect social costs, there are no externalities and "integration costs are borne by those who cause them".

In the real word, markets are not always perfect and complete:

- Externalities in generation distort the market price of electricity. Negative externalities from thermal and hydro generation, such as carbon and pollutants emissions, biodiversity, and visual impact, are often considered to be larger than those of VRE [9,29].
- There is disagreement in the literature as to whether energy-only markets can appropriately price capacity via scarcity prices [5]; [18]; [17].
- Market power distorts electricity prices and reduce VRE market value [71,95].
- Given the long investment cycles, power markets can be out of equilibrium for extended time periods after shocks [47,84,97].
- Balancing prices often reflect average, not marginal, costs for providing balancing services. Furthermore, they typically only cover the costs for balancing energy, but not the costs of reserve capacity. These costs are often socialized via grid fees [28,49,100].
- Many power systems lack locational price signals. Spot prices are often settled in larger geographical bidding areas, grid fees are not locationally differentiated, and re-dispatch costs are socialized via grid fees.

Finally, most VRE generators are currently subsidized. Many subsidy schemes such as fixed feed-in-tariffs remunerate energy supply independent of temporal, locational, or uncertainty-related price signals. This implicitly socializes all integration costs. However, under some support policies, such as most tradable green certificates schemes, investors bear integration costs to the extent that the market internalizes costs.

Considering these potential externalities, at least two conclusions can be drawn. First, the empirically observed (private) market value might deviate from the theoretical (social) marginal value. Hence, any inference of marginal values from market prices needs to check for potential bias from externalities. Second, for efficient resource allocation externalities should be internalized: environmental and health externalities should be priced, spot markets should be allowed to price scarce capacity, locational prices should be introduced, and imbalance prices should reflect marginal costs of balancing. Once that is completed, integration costs do not constitute an externality.

7. Concluding remarks

This paper proposes a valuation framework for variable renewables and offers a new perspective on "integration costs". Integration costs are those costs that do not occur at the level of the wind turbine or solar panel, but elsewhere in the power system. We suggest defining them as the gap between the average electricity price and the market value of electricity from wind (or solar) power. This definition is rigorous, comprehensive, and has a straightforward welfare-economic interpretation: in the long-term optimum, the sum of generation and integration costs of all generation technologies coincide. We propose a decomposition of integration costs along three inherent properties of VRE: uncertainty causing balancing costs, locational inflexibility causing grid-related costs, and temporal variability causing profile costs. We believe this decomposition to be comprehensive, robust, consistent, and operationable.

The decomposition is operationable in the sense that existing models can be used to quantify the components, and it is robust in the sense that a range of methods can be used, including numerical modeling and empirical estimates. We reviewed the literature and extracted quantitative estimates. The studies vary considerable in definitions, methodology, regional focus, and quality, so the results need to be interpreted carefully. Moreover, the large range of estimates testifies considerable methodology and parameter uncertainty. We nevertheless synthesize:

- Wind and solar integration costs are high if these technologies are deployed at large scale: in thermal systems, wind integration costs are about 25–35 €/MWh at 30–40% penetration, assuming a base price of 70 €/MWh. Integration costs are 35–50% of generation costs.
- As integration costs can be large in size, ignoring them in cost-benefit analyses or system optimization can strongly bias results.
- The size of integration costs depends on the power system and VRE penetration: integration costs can be negative at low (<10%) penetration, they generally increase with penetration, and are typically smaller in hydro than in thermal systems.
- System adaptations can significantly reduce integration costs. For example, dispatch models estimate profile costs to be 50% higher than investment models. Authors should be explicit about the time horizon and boundary conditions. High-penetration studies should account for system adaptation.
- Balancing costs are quite small (<6 €/MWh). The cost of scheduled thermal plan cycling, the flexibility effect, is even smaller. This is surprising, as these phenomena receive much attention in the literature and public debate.
- In thermal systems with high VRE shares, the utilization effect amounts to more than half of all integration costs. Maybe this is the most important finding of this study: the largest integration cost component is the reduction of utilization of the capital embodied in the power system. Most previous integration cost studies have not touched upon this effect. VRE-rich power systems require flexible thermal plants, but even more so they require plants that are low in capital costs.

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Appendix

Formal definition of wind market value p_{wind}

Formally, the wind market value is the sum of electricity prices at time step t, location n, and lead-time τ, weighted with the share of wind generation $w_{t,n,\tau}$.

$$p_{\text{wind}} = \sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} w_{t,n,\tau}\cdot p_{t,n,\tau} \tag{5}$$

The weights are defined to sum up to unity: $\sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} w_{t,n,\tau} = 1$.

Think of time steps as the temporal granularity of power markets, such as hours. Locations refer to the spatial granularity of power markets, such as bidding zones or transmission nodes. Lead-time refers to the sequence of power markets with decreasing time between contract and delivery, such as day-ahead, intraday, and real-time markets. If wind power is traded only day-ahead, the weights for the other markets are zero. See Ref. [48] for a more in-depth discussion of these dimensions. The average electricity price $p_{\text{electricity}}$ is defined accordingly, using load $l_{t,n,\tau}$ as weighting factors instead of wind generation.

Formal definition of profile, grid-related, and balancing costs

We define profile costs for the situation in which only information about the temporal structure of the electricity price is known, hence $p_{t,n,\tau}$ reduces to p_t. Wind profile costs $\Delta_{\text{wind}}^{\text{profile}}$ are defined as the difference between the load-weighted and the generation-weighted price:

$$\Delta_{\text{wind}}^{\text{profile}} = \sum_{t=1}^{T}(l_t - w_t)\cdot p_t \tag{6}$$

The weights are defined to sum up to unity: $\sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} w_t = \sum_{t=1}^{T}\sum_{n=1}^{N}\sum_{\tau=1}^{\mathrm{T}} l_t = 1$.

This implies a VRE generator has zero profile costs if it is perfectly correlated with load over time. Profile costs are negative if it generates disproportionally at times of high prices and positive if it generates disproportionally at times of low prices.

We define grid-related costs and balancing costs accordingly:

$$\Delta_{\text{wind}}^{\text{grid-related}} = \sum_{n=1}^{N}(l_n - w_n)\cdot p_n \tag{7}$$

$$\Delta_{\text{wind}}^{\text{balancing}} = \sum_{\tau=1}^{\mathrm{T}}(l_\tau - w_\tau)\cdot p_\tau \tag{8}$$

We do not suggest decomposing integration cost estimates if they stem from models that represent all three properties of VRE. Only if such a “super model” is unavailable, integration costs should be calculated by adding up estimates of components. For instance, a model that does neither represent uncertainties nor grid constraints can be used to calculate profile cost – and estimates for balancing and grid-related costs need to come from other models.

Table 2
Balancing cost literature.

Prices	Reference	Technology	Region	Balancing cost estimates [range] (at different market shares)
Market prices	[51]	Wind	Denmark	2.8 €/MWh (12%)
	[80]	Wind	Netherlands	3.7 €/MWh (small)
	[77]	Wind	Austria	5.6 €/MWh (small)
			Denmark	0 €/MWh (17%)
			Poland	12.6 €/MWh (small)
	[52]	Wind	Finland	0.6 €/MWh
	[64]	Solar	California	1.7–2.9 $/MWh (small)
	this study	Wind	Germany	1.7–2.5 €/MWh
Model results	[41]	Wind	UK	2.5 €/MWh (5%)
	[40]. survey	Wind	several UK studies	0.5–3 £/MWh (5–40%)
	[88], survey	Wind	UWIG	1.9 $/MWh (3.5%)
			MNDOC	4.6 $/MWh (15%)
			CA	0.5 $/MWh (4%)
			We	1.9–2.9 $/MWh (4–29%)
			PacificCorp	4.6 $/MWh (20%)
			PSCo	2.5–3.5 $/MWh (10–15%)
	[21], survey	Wind	several US systems	3–4.5 $/MWh (~30%) –one outlier of 9 $/MWh
	[70]	Wind	California	1–4 $/MWh (0–30%)
	[36]	Solar	Arizona	8 $/MWh (30%)
	[53], survey	Wind	Finland	2–3 €/MWh (10–20%)
			UK 2007	1.4–3.3 €/MWh (5–20%)
			Ireland	0.2–0.5 €/MWh (9–14%)
			Colorado	2.3–3.8 €/MWh (5–7%)
			Minn. 2006	2.3–3.4 €/MWh (15–25%)
			California	0.3 €/MWh (2%)
			PacificCorp	3.5 €/MWh (5%)
			Germany	2.4–2.7 €/MWh (11%)
			Denmark	1–2 €/MWh (29%)
			Finland	0.5–0.7 €/MWh (11–22%)
	[34]	Wind	Ireland	2.7 €/MWh
	[91]	Wind	UK	0.5 £/MWh (20%)
Model results (for hydro systems)	[53]	Wind	Nordic	1.0–2.1 €/MWh (10–20%)
			Norway	0.4–0.3 €/MWh (10–20%)
			Sweden	0.5–0.9 €/MWh (10–20%)
	[14]	Wind	Sweden	1.6 €/MWh (12%)

Where necessary, output was re-calculated to derive balancing costs. Where marginal costs could not be calculated, average costs are reported. Some studies report balancing costs for shorter prediction horizons than day-ahead. If costs were given relative to the base price, a base price of 70 €/MWh was assumed.

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Table 3
Profile cost literature.

Prices	Reference	Technology	Region	Profile costs estimates in €/MWh [range] (at different market shares)
Historical Prices	[8]	Solar	California	−14 to 0 at different market design (small)
	[84,85]	Wind	Germany	−1 to 3 (2% and 6%)
		Solar		−23 to −10 (0% and 2%)
	[32]	Wind	WECC	−4 to 7 at different sites (small)
	[12]	Solar	Ontario	−14 based on system price (small)
	[65]	Wind	Michigan	−10 to 8 at different nodes (small)
	[39]	WIND	Denmark	only monthly value factors reported
Prices from Dispatch Model	[41]	Wind	England	11 to 18 (30%)
				21 to 42 (40%)
	[82]	Solar	Utility	only absolute value reported
	[81,10]			
	[43]	Wind	Utility	7 to 49 (0% and 60% capacity/peak load)
	[56,11]	Solar	Germany	only absolute value reported
	[76]	Wind	Europe	−1 to 2 (0% and 6%)
	[75]			
	[4]	Wind	Germany	7 to 9 (6–7%)
			Spain	7 to 13 (7–12%)
			Denmark	18 to 25 (12–20%)
	[38]	Wind	UK	39 (20%)
	[25]	Wind	Germany	11 (12%)
		Solar		−4 (6%)
	[99]	Wind	PJM	−4 (5%)
Dispatch & Investment Model	[66]	Wind	England	only absolute value reported
	[93]	Wind	Germany	5 to 14 (5% and 25%)
	[62]	Wind	California	10 to 18 (0% and 16%)
		Solar		0 to 11 (0% and 9%)
	[13]	Wind	WECC	no prices reported
	[36]	Solar	Arizona	7 to 21 (10% and 30%)
	[70]	Wind	California	3 to 21 (0% and 40%)
	[69]	Solar		−19 to 43 (0% and 30%)
	[72]	Wind	Germany	1 to 21 (9% and 35%)
		Solar	Germany	−1 to 21 (0% and 9%)
		Wind	ERCOT	18 (25%)
	[59]	Wind	Germany	5 (19%) and 18 (39%)
	[44]	Wind	Europe	−6 (0%) and 14–35 (30%)

These publications usually do not use terms “profile cost” or “utilization effect”. Profile costs were calculated from reported output assuming a load-weighted electricity price of 70 €/MWh. Source: updated from Ref. [44].

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Chapter 4

The market value of variable renewables
The effect of solar wind power variability on their relative price *

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The market value of variable renewables ☆,☆☆
The effect of solar wind power variability on their relative price

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ABSTRACT

This paper provides a comprehensive discussion of the market value of variable renewable energy (VRE). The inherent variability of wind speeds and solar radiation affects the price that VRE generators receive on the market (market value). During windy and sunny times the additional electricity supply reduces the prices. Because the drop is larger with more installed capacity, the market value of VRE falls with higher penetration rate. This study aims to develop a better understanding on how the market value with penetration, and how policies and prices affect the market value. Quantitative evidence is derived from a review of published studies, regression analysis of market data, and the calibrated model of the European electricity market EMMA. We find the value of wind power to fall from 110% of the average power price to 50–80% as wind penetration increases from zero to 30% of total electricity consumption. For solar power, similarly low value levels are reached already at 15% penetration. Hence, competitive large-scale renewable deployment will be more difficult to accomplish than as many anticipate.

1. Introduction

Electricity generation from renewables has been growing rapidly during the last years, driven by technological progress, economies of scale, and deployment subsidies. Renewables are one of the major options to mitigate greenhouse gas emissions and are expected to grow significantly in importance throughout the coming decades (IEA, 2012; IPCC, 2011). According to official targets, the share of renewables in EU electricity consumption shall reach 35% by 2020 and 60–80% in 2050, up from 17% in 2008.[1] As hydropower potentials are largely exploited in many regions, and biomass growth is limited by supply constraints and sustainability concerns, much of the growth will need to come from wind and solar power. Wind and solar are variable[2] renewable energy sources (VREs) in the sense that their output is determined by weather, in contrast to “dispatchable” generators that adjust output as a reaction to economic incentives. Following Joskow (2011), we define the market value of VRE as the revenue that generators can earn on markets, without income from

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[1] National targets for 2020 are formulated in the National Renewable Energy Action Plans. Beurskens et al. (2011), Eurelectric (2011a), PointCarbon (2011) and ENDS (2010) provide comprehensive summaries. The EU targets for 2050 have been formulated in the European Commission (2011). Historical data are provided by Eurostat (2011).

[2] Variable renewables have been also termed intermittent, fluctuating, or non-dispatchable.

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subsidies. The market value of VRE is affected by three intrinsic technological properties:

- The supply of VRE is variable. Due to storage constraints and supply and demand variability, electricity is a time-heterogeneous good. Thus the value of electricity depends on when it is produced. In the case of VRE, the time of generation is determined by weather conditions. Variability affects the market value because it determines when electricity is generated.
- The output of VRE is uncertain until realization. Electricity trading takes place, production decisions are made, and power plants are committed the day before delivery. Forecast errors of VRE generation need to be balanced at short notice, which is costly. These costs reduce the market value.
- The primary resource is bound to certain locations. Transmission constraints cause electricity to be a heterogeneous good across space. Hence, the value of electricity depends on where it is generated. Since good wind sites are often located far from load centers, this reduces the value of wind power.[3]

We use a framework introduced in Hirth (2012a) and compare the market income of a VRE generator to the system base price. The system base price is the time-weighted average wholesale electricity price in a market. The effect of variability is called "profile costs", the effect of uncertainty "balancing costs" and the effect of locations "grid-related costs" (Fig. 1). We label these components "cost" for simplicity, even though they might appear as a discount on revenues and not as costs in a bookkeeping sense.

Profile, balancing, and grid-related costs are not market failures, but represent the intrinsic lower value of electricity during times of high supply, at remote sites, and the economic costs of uncertainty.

In this paper, we focus on the impact of variability on the market value of VRE, leaving uncertainty and location for further research. The reason for doing so is that in a broad literature review we have identified profile costs as the largest cost component and found this topic under-researched relative to balancing costs (Hirth, 2012a).

The market value of VRE will be measured as its relative price compared to the base price. We call this relative price "value factor"[4] and define it more rigorously in Section 3. The value factor is calculated as the ratio of the hourly wind-weighted average wholesale electricity price and its time-weighted average (base price). Hence the value factor is a metric for the valence of electricity with a certain time profile relative to a flat profile (Stephenson, 1973). The wind value factor compares the value of actual wind power with varying winds with its value if winds were invariant (Fripp and Wiser, 2008). In economic terms, it is a relative price where the numeraire good is the base price. A decreasing value factor of wind implies that wind power becomes less valuable as a generation technology compared to a constant source of electricity.

There are two mechanisms through which variability affects the market value of renewables in thermal[5] power systems. We label them "correlation effect" and "merit-order effect". If a VRE generation profile is positively correlated with demand or other exogenous parameters that increase the price, it receives a higher price than a constant source of electricity (correlation effect) — as long as its capacity remains small. For example, while the 2011 base price in Germany was 51 €/MWh, solar power received an average price of 56 €/MWh (a value factor of 1.1) on the market, because it is typically generated when demand is high. In Europe, there is a positive correlation effect for solar due to diurnal correlation with demand, and for wind because of seasonal correlation.

However, if installed VRE capacity is non-marginal, VRE supply itself reduces the price during windy and sunny hours by shifting the residual load curve to the left (merit-order effect, Fig. 2). The more capacity is installed, the larger the price drop will be. This implies that the market value of VRE falls with higher penetration. The figure also suggests that the price drop will be larger if the merit-order curve becomes steeper in the relevant region. The fundamental reason for the merit-order effect is that the short-term supply function is upward sloping because a) there exists a set of generation technologies that differ in their variable-to-fix costs ratio and b) electricity storage is costly.

More generally, it is of course a well-known economic result that the price of a good decreases as supply is increased.

Profile costs have important implications for policy makers, investors, and energy system modelers alike. In a market environment, investors

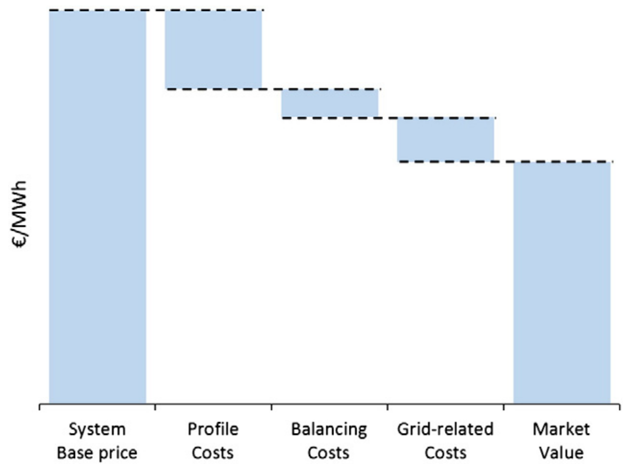

Fig. 1. The system base price and the market value of wind power. The difference between those two can be decomposed into profile, balancing, and grid-related costs.

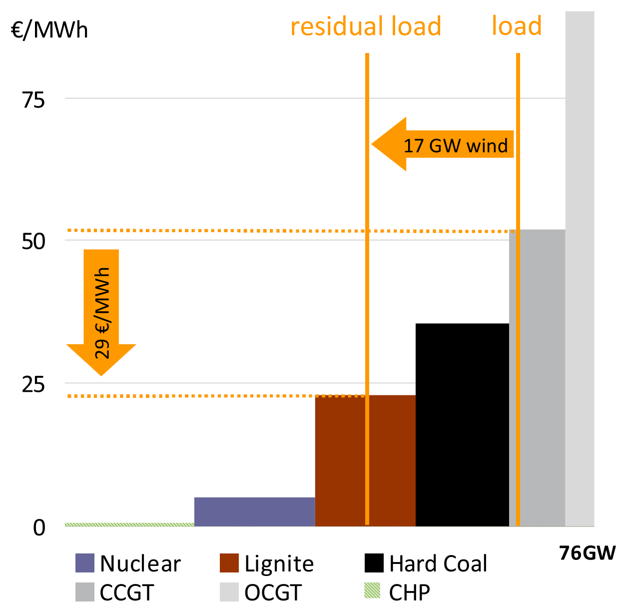

Fig. 2. Merit-order effect during a windy hour: VRE in-feed reduces the equilibrium price. Numbers are illustrative.

[3] Of course all types of generation are to some extent subject to expected and unexpected outages and are bound to certain sites, but VRE generation is much more uncertain, location-specific, and variable than thermal generation. Also, while weather conditions limit the generation of wind and solar power, they can be always downward adjusted and are in this sense partially dispatchable. The fourth typical property of VRE that is sometimes mentioned (Milligan et al., 2009), low variable costs, does not impact the value of electricity.

[4] In the German literature known as "Profilfaktor" or "Wertigkeitsfaktor."

[5] "Thermal" (capacity-constrained) power systems are systems with predominantly thermal generators. These systems offer limited possibility to store energy. In contrast (energy-constrained) "hydro" systems have significant amounts of hydro reservoirs that allow storing energy in the form of water.

bear profile costs by receiving the market value as income; hence they play a crucial role for investment decisions. However, VRE today is subsidized in most markets and some support schemes result in profile costs becoming an externality. Under renewable portfolio standards (green certificate obligations) or premium feed-in tariffs (FiTs), hourly price signals are passed on to investors. Under other policies, such as fixed FiTs, profile costs are commonly paid by electricity consumers or through government funds.[6] However, the gap between market revenues and the FiT is filled by subsidies. Thus profile costs matter for policy makers, since their size affects the costs of subsidies.[7] In any case, understanding the market value of VRE at high penetration rates is key in evaluating under which conditions subsidies can be phased out.

More fundamentally, under perfect and complete markets, the market value is identical to the marginal economic value that wind power has for society. Hence it is the market value that should be used for welfare, cost–benefit, or competitiveness analyses (Fig. 3), and not the base price as in EPIA (2011) and BSW (2011). For a discussion of welfare-economic analysis of variable renewables see Edenhofer et al. (submitted for publication). Ueckerdt et al. (2013) propose a methodology on how profile costs can be taken into account in energy system models that lack the high temporal resolution needed to capture them directly.

This paper provides a comprehensive discussion of the market value of VRE within an innovative framework, based on a thorough review of previous publications, new market data analysis, and tailor-made power system modeling. More specifically, it contributes to the literature in five ways. Firstly, we focus on variability and its economic consequence for the market value of VRE, profile costs. We quantify profile costs based on a literature survey, market data, and numerical model results. Secondly, we use relative prices throughout the analysis. Most of the previous literature reports either absolute prices, total system costs, or other metrics such as \$/KW, \$/MWa, or \$/m^2, which are difficult to compare across space, over time, and between studies. More fundamentally, relative prices have a more straightforward economic interpretation. Thirdly, new market data are presented and analyzed econometrically, a novelty to this branch of literature. Fourthly, we develop and apply a new calibrated numerical model: the European Electricity Market Model EMMA. It models hourly prices as well as investment endogenously, covers a large geographical area, allows for international trade, uses high quality wind and solar data, and incorporates crucial technical constraints of the power system. Finally, we identify and quantify the impact of prices and policies on the market value of VRE. By doing so, it is possible to provide a range of estimates that takes into account parameter uncertainty, and to identify integration options that help mitigate the value drop.

The paper is structured as follows. Section 2 reviews the literature. Section 3 presents new market data and regression analysis. Section 4 outlines an electricity market model. Section 5 presents results. Section 6 summarizes the results and Section 7 concludes.

2. Literature review

There is extensive literature on the effects of VRE on power markets. A well-known branch of this literature estimates the effect of VRE on the average electricity price (Gil et al., 2012; Hirth and Ueckerdt, 2012; Jónsson et al. 2010; MacCormack et al., 2010; Munksggard and Morthorst, 2008; Olsina et al., 2007; O'Mahoney and Denny, 2011; Rathmann, 2007; Sáenz de Miera et al., 2008; Sensfuß, 2007; Sensfuß et al., 2008; Unger and Ahlgren, 2005; Woo et al., 2011). While some of these papers discuss the effect of VRE deployment on income of conventional generators, they do not report the effect on VRE generators' income via a change of their relative price. Other studies discuss specific consequences of VRE, such as curtailment (Denholm and Margolis, 2007; Revuelta et al., 2011; Thohy and O'Malley, 2011), demand for back-up capacity (Mount et al., 2012; Weigt, 2009), or dispatch and cycling of thermal plants (Göransson and Johnsson, 2012; Maddaloni et al., 2011; Ummels et al., 2007). Although these are the underlying reasons for integration costs, this literature does not translate technical constraints into price effects. A number of *integration studies* quantify economic costs of VRE variability, but these publications focus on balancing or grid-related costs while not accounting for profile costs, and seldom report the price impact (DeCesaro and Porter, 2009; GE Energy, 2010; Gross et al., 2006; Holttinen et al., 2011; Milligan and Kirby, 2009; Smith et al., 2007) Balancing markets are discussed in Hirth & Ziegenhagen (in press).

This remainder of this section will discuss the methodologies and findings of the theoretical and empirical literature that focuses more narrowly on the market value of VRE (Table 1).

2.1. Theoretical and market power literature

Joskow (2011) and Borenstein (2012) discuss the economics of variability. They conclude that average full costs of different generation technologies, sometimes called the levelized costs of electricity

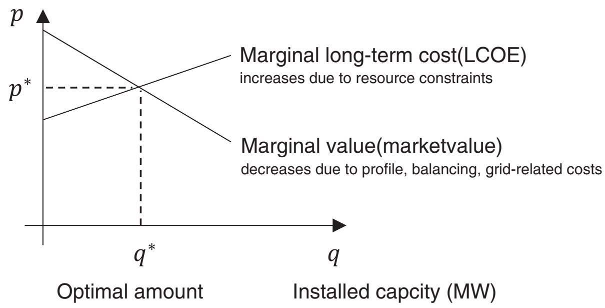

Fig. 3. The intersection of long-term marginal costs (LCOE) and the market value gives the optimal amount of VRE (Hirth, 2012b).

Table 1
Literature on the market value of VRE.

	Theoretical literature	Empirical literature
Main references	Grubb (1991a,b), Lamont (2008), Twomey and Neuhoff (2010), Joskow (2011)	Lamont (2008), Nicolosi (2012), Mills and Wiser (2012)
Main findings	• Comparisons of generating technologies are incomplete when confined to costs (LCOE) → "market test" • Market power of conventional generators decreases the relative value of VRE	• Value factor of VRE drops with increased penetration (Table 2) • At high penetration (> 15% wind) • Hydro systems have higher VRE value factors than thermal systems • Models without high temporal resolution overestimate the value of VRE • Models without endogenous investment underestimate the value of VRE

[6] Countries that use a fixed FiT include Germany, Denmark, and France. Certificate schemes or a premium FiT is used for example in Spain, the UK, Sweden, Norway, Poland, and many US states. Germany introduced a premium FiT in 2012; see Sensfuß and Ragwitz (2011) on VRE market value in the context of this policy.

[7] The cost for FiT is often put directly on electricity consumers. In Germany, electricity consumers pay a specific earmarked levy on electricity that is labelled "EEG-Umlage". Balancing costs and location costs are often covered by subsidy schemes or socialized via grid tariffs.

(LCOE), are an incomplete metric to compare dispatchable and non-dispatchable technologies, because the value of electricity depends on the point in time and space it is produced.[8]

Bode (2006), Lamont (2008) and Twomey and Neuhoff (2010) derive analytical expressions for the market value of VRE. While Lamont uses a general functional form for the merit-order curve, Bode assumes it to be linear and Twomey and Neuhoff assume it to be quadratic. Lamont shows that the market value of VRE can be expressed as the base price and an additive term that is a function of the covariance of VRE generation and power prices. It is important to note that the covariance is not a static parameter, but a function of wind power penetration. Overall, the main contribution of the theoretical literature has been to stress the fundamental economic differences between dispatchable and VRE technology.

Twomey and Neuhoff (2010), Green and Vasilakos (2010), and Sioshansi (2011) analyze VRE market value in the context of market power of conventional generators, applying Cournot or supply function equilibrium theory. In times of little VRE supply, strategic generators can exercise market power more effectively, implying that mark-ups on competitive prices are inversely correlated with VRE in-feed. Thus market power tends to reduce the value factor of VRE. Twomey and Neuhoff (2010) report that in a duopoly of conventional generators that engage in optimal forward contracting, the wind value factor is 0.7, as compared to 0.9 in a competitive setting.

2.2. Empirical literature

There is a long tradition of quantifying market effects of VRE, emerging in the 1980s. This empirical literature is quite heterogeneous with respect to methodology and focus. Some studies have a very broad scope and report profile costs as one of many results, while others focus on VRE market value. Results are reported in a variety of units and often in absolute terms. Furthermore, the literature is scattered in economic and engineering journals, with very little cross-referencing, and few papers provide a thorough literature review. In this subsection, we aim to give an overview of the literature, and extract quantifications of value factors from previous studies. Therefore, value factors were calculated from reported data whenever possible. Studies are clustered according to the approach they use to estimate electricity prices: historical market prices, shadow prices from short-term dispatch models, or shadow prices from long-term models that combine dispatch with endogenous investment.

2.2.1. Historical prices

To derive value factors from historical data, it is sufficient to collect hourly electricity prices and synchronous VRE in-feed, as done in Section 3. The drawback of this approach is that results are limited to the historical market conditions, especially historical penetration rates.

Borenstein (2008) estimates the solar value factor in California to be 1.0–1.2, using 2000–03 prices and a synthetic generation profile. Sensfuß (2007) and Sensfuß and Ragwitz (2011) estimate the wind value factor in Germany to drop from 1.02 to 0.96 between 2001 and 2006, when the wind share grew from 2% to 6% and the solar value factor to fall from 1.3 to 1.1 between 2006 and 2009. Green and Vasilakos (2012) calculate value factors on a monthly basis, instead of a yearly one. They estimate the wind value factor to be 0.92 in West Denmark and 0.96 in East Denmark during the last decade. They also calculate the costs of converting Danish wind generation into a constant supply of electricity by means of imports and exports to Norway to be 3–4% of its market value. Fripp and Wiser (2008) estimate the value of wind at different sites in the Western US. Because the correlation effect varies between sites, value factors differ between 0.9 and 1.05.

Some studies use locational electricity prices to estimate grid-related costs. Brown and Rowlands (2009) estimate the solar value factor in Ontario to be 1.2 on average, but 1.6 in large cities. Lewis (2008) estimates the value factor to vary between 0.89 and 1.14 at different locations in Michigan.

2.2.2. Shadow prices from (short-term) dispatch models

To derive value factors under conditions other than those which have been historically observed, electricity prices can be derived from dispatch models. However, since by definition the capacity mix remains constant, pure dispatch modeling does not account for changes in the capital stock triggered by higher VRE penetration. Thus, historical market data and dispatch models can only deliver estimates of the short-term market value of VRE. The models applied in the literature vary starkly in terms of sophistication and temporal resolution.

More than 20 years ago, Grubb (1991a, 1991b) used analytical approximations and UK data to estimate the market value of wind power to be between 0.75 and 0.85 at 30% penetration rate. Rahman and Bouzguenda (1994), based on Bouzguenda and Rahman (1993) and Rahman (1990), estimated the value of solar energy to be around 90–100 $/MWh at low penetration rates. They report the value to drop dramatically when solar capacity increases beyond 15% of installed capacity. Hirst and Hild (2004) model a small power system with a short-term unit commitment model and report the value factor to drop from 0.9 to 0.3 as wind power increases from zero to 60% of installed capacity. ISET et al. (2008) and Braun et al. (2008) use a simple three-technology model to estimate the value of solar power in Germany, but report only absolute prices. Obersteiner et al. (2008) estimate wind value factors for Austria. Assuming a polynomial merit-order curve they estimate the value factor to be 0.4–0.9 at 30% market share, depending on the order of the polynomial. Obersteiner and Saguan (2010) use a cost-based merit-order curve and report the wind value factor to drop from 1.02 to 0.97 as the market share in Europe grows from zero to 6%. Green and Vasilakos (2011) report a low UK wind value factor of 0.45 at 30 GW installed capacity. Energy Brainpool (2011) forecasts market values for hydro, onshore and offshore wind, and solar power in Germany until 2016, finding a drop of the onshore value factor to 0.84 while the offshore factor remains more stable at 0.97 due to its flatter generation profile. Valenzuela and Wang (2011) show how crucial temporal resolution affects the results: increasing the number of time steps from 16 to 16,000 reduces the wind value factor from 1.4 to 1.05, a bias that is confirmed by Nicolosi and Nabe (2011) and Nicolosi (2012).

2.2.3. Shadow prices from (long-term) dispatch and investment models

Introducing significant amounts of wind and solar power to the market alters the structure of electricity prices and incentives investors to react by building or decommission power plants. To take into account investor response to VRE and to derive long-term value factors one needs to model investment endogenously.

Martin and Diesendorf (1983), estimating the absolute market value of wind power in the UK, find that the value of wind power decreases by a quarter as installed capacity in the UK increases from 0.5 GW to 8 GW. They do not report the base price; hence value factors cannot be derived. Lamont (2008) uses Californian generation and load profiles, reporting the wind value factors to drop from 0.86 to 0.75 as its market share increases from zero to 16%, and solar value factors to drop from 1.2 to 0.9 as its share rises to 9%. Bushnell (2010) finds that wind revenues are reduced by 4–15% as the wind share increases from zero to 28% in the Western US, but doesn't provide value factors. Gowrisankaran et al. (2011) compare the revenues of solar power in Arizona to LCOE of a gas plant, which is a proxy for the long-term equilibrium base price. As the solar market share grows from 10% to 30%, the value factor drops from 0.9 to 0.7. These four models are long-term in the sense that all investment is endogenous.

Other studies combine endogenous investment with an existing plant stack, an approach that we will label "mid-term" in Section 4.3.

[8] One might add that LCOE are also inappropriate to compare dispatchable technologies that have different variable costs and are thus dispatched differently.

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Swider and Weber (2006) apply a stochastic dispatch and investment model to Germany and report the wind value factor to drop from 0.9 to 0.8 as penetration increases from 5% to 25%. Kopp et al. (2012) model wind value factors of 0.7–0.8 at 39% penetration. Nicolosi (2012) uses a sophisticated model of the European electricity market to estimate both the wind and the solar value factors in Germany. He reports them to drop from roughly unity to 0.7 as installed capacities increase to 35% and 9% market share, respectively. Nicolosi finds a comparable drop when using data from Texas. Mills and Wiser (2012) apply a similarly elaborated mid-term model to California, finding comparable results: the wind value factor drops to 0.7 at 40% penetration. Since electricity demand for cooling is better correlated with solar generation, the solar value factor is higher in California than in Germany. However, it drops similarly dramatically with increased solar shares, despite the flexible hydro capacity available in California dampens the value loss somewhat. Mills & Wiser also model concentrated solar power and find that at high penetration rates, thermal energy storage increases its value significantly. Because of their sophisticated and well-documented models, the studies by Nicolosi and Mills & Wiser will serve as point of reference for the model results presented in Section 5. All results are summarized in Table 2, Fig. 4 and Fig. 5.

Summing up the literature review, at low penetration rates, wind value factors are reported to be close to unity and solar value factors are somewhat higher. Wind value factors are estimated to drop to around 0.7 at 30% market share. Solar value factors are reported to drop faster, so they reach 0.7 at 10–15% penetration rate, albeit there is large variation both in wind and solar value factors.

The literature review also leads to some methodological conclusions: to estimate value factors at high market shares, more recent studies rely on endogenous investment modeling while taking the existing capital stock into account. Keeping the capacity mix constant would

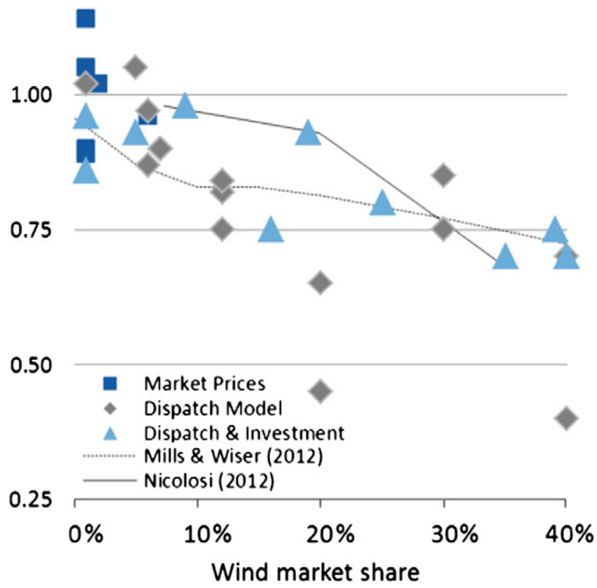

Fig. 4. Wind value factors as reported in the literature.

downward-bias the VRE value factor. Several papers emphasize the importance of high temporal resolutions and report that low-resolution models overestimate the value of VRE. Only few of the models feature reservoir hydropower (Mills and Wiser, 2012; Nicolosi, 2012; Rahman and Bouzguenda, 1994), and those treat hydropower in a relatively stylized way. This can be seen as a serious shortcoming of the literature, since hydro provides a potentially important source of flexibility. It

Table 2
Empirical literature on the market value of VRE.

Prices	Reference	Technology	Region	Value factor estimates (at different market shares)
Historical prices	Borenstein (2008)	Solar	California	1.0–1.2 at different market designs (small)
	Sensfuß (2007), Sensfuß and Ragwitz (2011)	Wind	Germany	1.02 and 0.96 (2% and 6%)
		Solar		1.33 and 1.14 (0% and 2%)
	Fripp and Wiser (2008)	Wind	WECC	0.9–1.05 at different sites (small)
	Brown and Rowlands (2009)	Solar	Ontario	1.2 based on system price (small)
	Lewis (2008)	Wind	Michigan	0.89–1.14 at different nodes (small)
	Green and Vasilakos (2012)	Wind	Denmark	*Only monthly value factors reported*
Prices from dispatch model	Grubb (1991a)	Wind	England	0.75–0.85 (30%) and 0.4–0.7 (40%)
	Rahman and Bouzguenda (1994)	Solar	Utility	*Only absolute value reported*
	Rahman (1990), Bouzguenda and Rahman (1993)			
	Hirst and Hild (2004)	Wind	Utility	0.9–0.3 (*0% and 60% capacity/peak load*)
	ISET et al. (2008), Braun et al. (2008)	Solar	Germany	*Only absolute value reported*
	Obersteiner and Saguan (2010)	Wind	Europe	1.02 and 0.97 (0% and 6%)
	Obersteiner et al. (2008)			
	Boccard (2010)	Wind	Germany	.87–.90 (6–7%)
			Spain	.82–.90 (7–12%)
			Denmark	.65–.75 (12–20%)
	Green and Vasilakos (2011)	Wind	UK	0.45 (20%)
	Energy Brainpool (2011)	Onshore	Germany	0.84 (12%)
		Offshore		0.97 (2%)
		Hydro		1.00 (4%)
		Solar		1.05 (6%)
	Valenzuela and Wang (2011)	Wind	PJM	1.05 (5%)
Dispatch & Investment Model	Martin and Diesendorf (1983)	Wind	England	*Only absolute value reported*
	Swider and Weber (2006)	Wind	Germany	0.93 and 0.8 (5% and 25%)
	Lamont (2008)	Wind	California	0.86 and 0.75 (0% and 16%)
		Solar		1.2 and 0.9 (0% and 9%)
	Bushnell (2010)	Wind	WECC	*no prices reported*
	Gowrisankaran et al. (2011)	Solar	Arizona	0.9 and 0.7 (10% and 30%)
	Mills and Wiser (2012)	Wind	California	1.0 and 0.7 (0% and 40%)
	Mills (2011)	Solar		1.3 and 0.4 (0% and 30%)
	Nicolosi (2012)	Wind	Germany	0.98 and 0.70 (9% and 35%)
		Solar	Germany	1.02 and 0.68 (0% and 9%)
		Wind	ERCOT	.74 (25%)
	Kopp et al. (2012)	Wind	Germany	0.93 (19%) and 0.7–0.8 (39%)

These publications usually do not use terms “profile cost” or “utilization effect”. Output was re-calculated to derive yearly value factors.

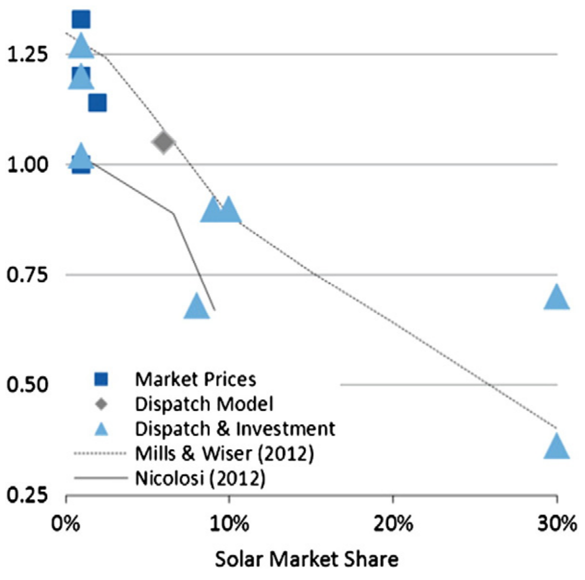

Fig. 5. Solar value factors as reported in the literature.

might be worthwhile to note that there is a strong methodological focus on numerical modeling, while other empirical methods such as regression analysis are not used. Finally, only half of the reviewed studies are published in peer-reviewed journals.

3. Market data

In this section, historical VRE value factors are calculated ex-post from observed VRE in-feed data and market prices. In contrast to most previous studies (Borenstein, 2008; Brown and Rowlands, 2009; Fripp and Wiser, 2008; Sensfuß, 2007), actual instead of estimated VRE generation data are used, and results are provided for a number of different markets. These value factors are then used to estimate the impact of penetration on market value econometrically, a novelty in this branch of the literature.

3.1. A formal definition of value factors

To start with, value factors are formally defined. The base price $\overline{p}$ is the time-weighted average wholesale day-ahead price. In matrix notation,

$$\overline{p} = (\mathbf{p}'\mathbf{t})/(\mathbf{t}'\mathbf{t}) \tag{1}$$

where $\mathbf{p}_{[Tx1]}$ is a vector of hourly spot prices and $\mathbf{t}_{[Tx1]}$ is a vector of ones, both with dimensionality ($Tx1$) where T is the number of hours. The average revenue of wind power or "wind price" $\overline{p}^w$ is the wind-weighted spot price,

$$\overline{p}^w = (\mathbf{p}'\mathbf{g})/(\mathbf{g}'\mathbf{t}) \tag{2}$$

where the generation profile $\mathbf{g}_{[Tx1]}$ is a vector of hourly generation factors that sum up to the yearly full load hours (FLH). Accordingly, $\mathbf{p}'\mathbf{g}$ is the yearly revenue and $\mathbf{g}'\mathbf{t}$ the yearly generation.[9] The wind value factor v^w is defined as the ratio of average wind revenues to the base price:

$$v^w = \overline{p}^w/\overline{p}. \tag{3}$$

[9] This nomenclature can be easily generalized for price periods of unequal length (by changing the ones in t to non-uniform temporal weights) and, more importantly, to account for spatial price and wind variability and grid-related costs (see Appendix A).

This definition relies on day-ahead prices only and ignores other market channels such as future and intraday markets (discussed in Obersteiner and von Bremen, 2009). The solar value factor is defined analogously. Here, value factors are calculated for each year, while others have used different periods (Green and Vasilakos, 2012; Valenzuela and Wang, 2011). Using longer periods tends to lower the value factor if VRE generation and demand are not correlated over these time scales.

3.2. Descriptive statistics

In the following, wind and solar value factors are calculated for Germany and wind value factors for a number of countries. Day-ahead spot prices were taken from various power exchanges. Generation profiles were calculated as hourly in-feed over installed capacity. In-feed data come from transmission system operators (TSOs) and capacity data from TSOs as well as public and industry statistics. Installed wind capacity is usually reported on a yearly basis and was interpolated to account for changes during the year. Because solar capacity has changed rapidly, daily capacity data was used. For earlier years, German in-feed data were not available, consequently proxies were used.[10] The market share of wind m^w is wind power generation over total electricity consumption.

Table 3 reports descriptive statistics for Germany. At low penetration rates, the wind value factor was slightly above unity and the solar factor was around 1.3. This can be explained by the positive correlation of VRE with demand (correlation effect): solar power correlates positively with electricity demand on a diurnal scale and wind power on a seasonal scale. As wind's market share rose from 2% to 8% from 2001 to 2012, its value factor declined by 13 percentage points. Similarly, an increase of the solar market share from zero to 4.5% led to a decline of its value factor by 28 percentage points. These drops are primarily caused by the merit-order effect (see also Fig. 6).

Historical market data indicates that the merit-order effect significantly reduced the market value of VRE, even at modest market shares in the single digit range.

An alternative way of visualizing the impact of solar generation on relative prices is to display the daily price structure (Fig. 7). As 30 GW solar PV capacity was installed over the years, prices between 8 a.m. and 6 p.m. fell relative to the prices at night. While the price at noon used to be 80% higher than the average price, today it is only about 15% higher.

Table 4 shows wind value factors for different European countries. Value factors are close to unity in the Nordic countries, where large amounts of flexible hydro generation provide intertemporal flexibility and reduce short-term price fluctuations. In thermal power systems, such as in Germany, VRE value factors are more sensitive to penetration rates. The strong interconnections between Denmark and the Nordic countries keep the Danish value factors from dropping further.

3.3. Econometrics

A simple regression model is applied to estimate the impact of increasing penetration rates on value factors. Based on the theoretical arguments from Section 1, we hypothesize that higher market shares reduce the value factor, and that the drop is more pronounced in

[10] Price data were obtained from the electricity exchanges EPEX-Spot, Nordpool, and APX. In-feed data come from the TSOs Statnett, Svenska Kraftnät, Energienet.dk, 50 Hz, Amprion, TenneT, EnWG, and Elia. Installed capacities were taken from BMU (2011), BNetzA Stammdatenbank (2012), World Wind Energy Association (2011), and European Wind Energy Association (2011). All data are available as Supplementary material to the online version of this article. German solar data for 2008–2010 are proxied with 50 Hz control area data. Generation in Germany correlates very well with generation in the 50 Hz area ($\rho = 0.93$), so the proxy seems appropriate. Wind profiles from 2001 to 2006 are taken from Sensfuß (2007) and solar profiles 2006 to 2007 from Sensfuß and Ragwitz (2011).

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Table 3
Base price, average revenue, market value, and market share for wind and solar power in Germany.

	$\bar{p}$ (€/MWh)	Wind $\bar{p}^w$ (€/MWh)	v^w (1)	m^w (%)	Solar $\bar{p}^s$ (€/MWh)	v^s (1)	m^s (%)
2001	24	25[a]	1.02	2.0	–	–	0.0
2004	29	29[a]	1.00	3.0	–	–	0.1
2005	46	46[a]	.99	3.5	–	–	0.2
2006	51	49[a]	.96	4.7	68[b]	1.33	0.4
2007	38	33	.88	4.9	44[b]	1.16	0.5
2008	66	60	.92	5.5	82[c]	1.25	0.7
2009	39	36	.93	7.1	44[c]	1.14	1.1
2010	44	42	.96	7.3	49[c]	1.11	2.1
2011	51	48	.93	8.8	56	1.10	3.3
2012	43	38	.89	8.0	45	1.05	4.5
Average	*43*	*40*	*0.94*	*5.6*	*55*	*1.16*	*1.8*

Market for Germany data otherwise.
[a] Estimates from Sensfuß (2007).
[b] Estimates from Sensfuß and Ragwitz (2011).
[c] Market data for 50 Hz control area.

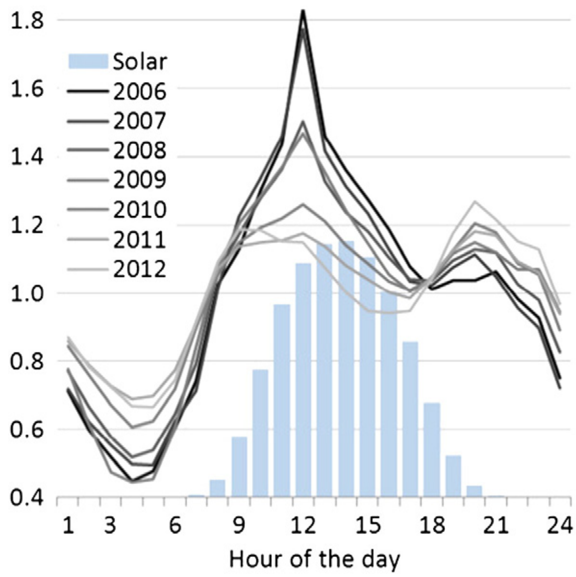

Fig. 7. The daily price structure in Germany during summers from 2006 to 2012. The bars display the distribution of solar generation over the day.

thermal systems. The regression model includes the market share of wind power, a dummy for thermal system that interacts with the share (such that the impact of market share in thermal systems is β_1 and in thermal system $\beta_1+\beta_2$), and time dummies as control variables to capture supply and demand shocks:

$$v^w_{t,c} = \beta_0 + \beta_1 \cdot share_{t,c} + \beta_2 \cdot share_{t,c} \cdot thermal_c + \beta_3 \cdot thermal + \varepsilon_{t,c} \qquad (4)$$

where $\varepsilon \sim iid(0,\sigma^2)$ and t,c are indices for time and countries, respectively. The model is specified as a random effects model and estimated using OLS. The model formulation is equivalent to estimating thermal and hydro systems separately.

The results, which are summarized in Table 5, are striking: increasing the market share of wind by one percentage point is estimated to reduce the value factor by 0.22 percentage points in hydro systems (β_1) and by 1.62 percentage points in thermal systems ($\beta_1+\beta_2$). The wind value factor without any installed wind capacity is estimated to be 0.98 in hydro systems (β_0) and 1.04 in thermal systems ($\beta_0+\beta_4$). All coefficients are significant at the 5%-level.

However, there are several reasons to suspect biased estimates and to treat results cautiously. The number of observations is very small. Penetration rates are small compared to expected long-term levels and it is not clear that results can be extrapolated. Furthermore, power systems might adapt to increasing penetration rates. Finally, in the past, exporting electricity during windy times has helped German and Danish value factors to stabilize. In the future, when similar amounts of VRE are installed in surrounding markets, there will be much less potential to benefit from trade and value factors might drop more.

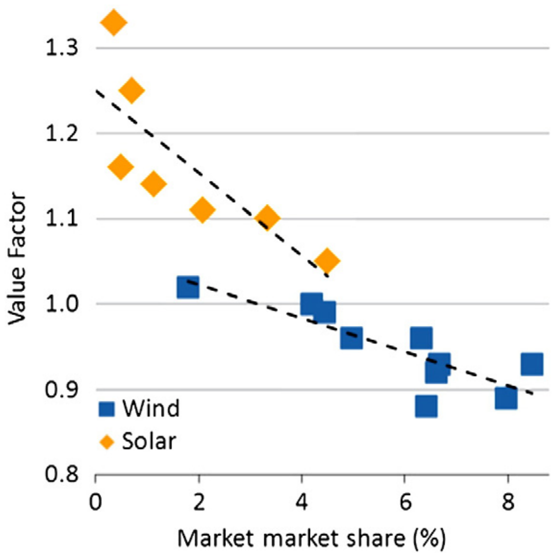

Fig. 6. Historical wind and solar value factors in Germany (as reported numerically in Table 3).

4. Numerical modeling methodology

This section introduces the European Electricity Market Model EMMA, a stylized numerical dispatch and investment model of the interconnected Northwestern European power system. In economic terms, it is a partial equilibrium model of the wholesale electricity market. EMMA has been developed specifically to estimate value factors at various penetration rates, under different prices and policies, and in the medium-term as well as the long-term equilibrium. Model development followed the philosophy of keeping formulations parsimonious while representing VRE variability, power system inflexibilities, and flexibility options with appropriate detail. This section discusses crucial features verbally. All equations and input data can be found in Appendix B in the Supplementary material. Model code and input data are available for download as Supplementary material to the online version of this article.

4.1. The electricity market model EMMA

EMMA minimizes total costs with respect to investment, production and trade decisions under a large set of technical constraints. Markets are assumed to be perfect and complete, such that the social planner solution is identical to the market equilibrium. Hence, the market

Table 4
Wind value factors in different countries.

	Germany	Denmark-West	Denmark-East	Sweden	Norway
2007	0.88	0.88	0.92	1.03	–
2008	0.90	0.90	0.93	0.97	–
2009	0.91	0.96	1.00	1.01	0.99
2010	0.94	0.96	0.99	1.01	1.03
2011	0.92	0.94	0.93	n/a	n/a
2012	0.89	0.90	0.90	n/a	n/a
Average	*0.91*	*0.92*	*0.95*	*1.01*	*1.01*

Table 5
Regression results.

Dependent variable	Wind value factor (%)
Share of wind power (% of consumption)	−0.26[a]
	(3.5)
Share of wind power∗thermal dummy	−1.36[b]
	(3.2)
Constant	98.3[b]
	(82.5)
Thermal dummy	0.06[a]
	(2.1)
R^2	.51
Number of obs	30

Absolute *t*-values in brackets.
[a] Significant at 5% level.
[b] Significant at 1% level.

value represents both the marginal benefit to society as well as the income that an investor earns on the market. The model is linear, deterministic, and solved in hourly time steps for one year.

For a given electricity demand, EMMA minimizes total system cost, the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs, for generation, transmission, and storage. Capacities and generation are optimized jointly. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and investment and disinvestment in each technology. The important constraints relate to electricity demand, capacity limitations, and the provision of district heat and ancillary services.

Generation is modeled as eleven discrete technologies with continuous capacity: two VRE with zero marginal costs — wind and solar, six thermal technologies with economic dispatch — nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and lignite carbon capture and storage (CCS), a generic “load shedding” technology, and pumped hydro storage. Hourly VRE generation is limited by generation profiles. Dispatchable plants produce whenever the price is above their variable costs. Storage is optimized endogenously under turbine, pumping, and inventory constraints. Existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments have to recover their annualized capital costs from short-term profits.

The hourly electricity price is the shadow price of demand. In other words, we model an energy-only market with scarcity pricing, assuming perfect and complete markets. This guarantees that in the long-term equilibrium, the zero-profit condition holds. Curtailment of VRE is possible at zero costs, which implies that the electricity price cannot become negative.

Demand is exogenous and assumed to be perfectly price inelastic at all but very high prices, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short time scales. While investment decisions take place over longer time scales, we justify this assumption with the fact that the average electricity price does not vary dramatically between model scenarios.

Combined heat and power (CHP) generation is modeled as must-run generation. A certain share of the cogenerating technologies lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of these technologies can be freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity is fixed. Ancillary service provision is modeled as a must-run constraint for dispatchable generators.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs). Investments in interconnector capacity are endogenous to the model. As a direct consequence of our price modeling, interconnector investments are profitable if and only if they are socially beneficial. Within regions transmission capacity is assumed to be non-binding.

The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up cost or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior: assigned base load plants bid an electricity price below their variable costs in order to avoid ramping and start-ups.

Being highly stylized, the mode has important limitations. The most significant caveat might be the absence of hydro reservoir modeling. Hydropower offers intertemporal flexibility and can readily attenuate VRE fluctuations. Similarly, demand response in the form of demand shifting or an elastic demand function would help to integrate VRE generation. Technological change is not modeled, such that generation technologies do not adapt to VRE variability. Ignoring these flexibility resources leads to a downward-bias of VRE market values, thus results should be seen as conservative estimates.

EMMA is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. In a back-testing exercise, model output was compared to historical market data from 2008 to 2010. Crucial features of the power market can be replicated fairly well, like price level, price spreads, interconnector flows, peak/off-peak spreads, the capacity and generation mix. Wind value factors are replicated sufficiently well (Table 6). Solar value factors are somewhat below market levels, probably because of the limited number of generation technologies.

4.2. Input data

Electricity demand, heat demand, and wind and solar profiles are specified for each hour and region. Historical data from the same year (2010) are used for these time series to preserve empirical temporal and spatial correlation of and between parameter as well as other statistical properties. These correlations crucially determine the market value of renewables. Unlike in Section 3, VRE profiles are not based on historical in-feed, which is not available for all countries. Instead, historical weather data from the reanalysis model ERA-Interim and aggregate power curves are used to derive profiles. Details on this procedure and the statistical properties of VRE are discussed in Hirth and Müller (2013). Wind load factors in all countries are scaled to 2000 full load hours. Load data were taken from various TSOs. Heat profiles are based on ambient temperature.

Fixed and variable generation costs are based on IEA and NEA (2010), VGB Powertech (2011), Black & Veatch (2012), and Nicolosi (2012). Fuel prices are average 2011 market prices and the CO_2 price is 20€/t. Summer 2010 NTC values from ENTSO-E were used to limit transmission constraints. CHP capacity and generation is from Eurelectric (2011b). A discount rate of 7% is used for all investments, including transmission, storage and VRE.

4.3. Long-term vs. short-term market value

The market value of VRE depends crucially on assumptions regarding the previously-existing capital stock. In the following, we discuss three alternatives that are found in the literature.

One option is to take the existing generation and transmission infrastructure as given and disregard any changes to that. The

Table 6
Value factors in Germany.

	Wind		Solar	
	Model	Market	Model	Market
2008	0.93	0.92	1.04	1.25
2009	0.95	0.93	1.03	1.14
2010	0.94	0.96	0.98	1.11

Table 7
Analytical frameworks.

	Short term (static)	Medium term/transition	Long term (green field)
Existing capacity	Included	Included/partially included	Not included
(Dis)investment	None	Endogenous/exogenous	–
VRE cost savings	Variable costs (fuel, variable O&M, CO_2)	• Variable costs • Quasi-fixed costs (if incumbent plants are decommissioned) • Fixed costs (if new plants are avoided)	Variable and fixed costs
Long-term profits	Positive or negative	• Zero or negative for incumbent capacity • Zero for new capacity	Zero
References (examples)	Studies based pure dispatch models (Table 2)	Swider and Weber (2006), Rosen et al. (2007), Neuhoff et al. (2008), Short et al. (2011), Haller et al. (2011), Mills and Wiser (2012), Nicolosi (2012)	Martin and Diesendorf (1983), DeCarolis and Keith (2006), Lamont (2008), Bushnell (2010), Green and Vasilakos (2011)

Quasi-fixed costs are fixed O&M costs. Fixed costs are quasi-fixed costs plus investment (capital) costs.

optimization reduces to a sole dispatch problem. We label this the *short-term* perspective. Another possibility is to disregard any existing infrastructure and optimize the electricity system "from scratch" as if all capacity was green-field investment. This is the *long-term* perspective. Finally, one can take the existing infrastructure as given, but allow for endogenous investments and disinvestments. We call this the *medium term*. A variant of the mid-term framework is to account only for a share of existing capacity, for example, only those plants that have not reached their technical life-time (*transition*) (Table 7). In Section 5 we present mid-term and long-term results.

For the short, mid, and long-term framework corresponding welfare optima exists, which are, if markets are perfect, identical to the corresponding market equilibria. It is only in the long-term equilibrium that all profits are zero (Boiteux, 1960; Crew et al., 1995; Hirth and Ueckerdt, 2012; Steiner, 1957). Note that the expressions short term and long term are *not* used to distinguish the time scale on which dispatch and investment decisions take place, but refer to the way the capital stock is treated.

Under perfect and complete markets and inelastic demand, the market value of VRE equals marginal cost savings in the power system. Under a short-term paradigm, adding VRE capacity reduces variable costs by replacing thermal generation — Grubb (1991a) calls the short-term market value "marginal fuel-saving value". In a long-term framework, VRE additionally reduces fixed costs by avoiding investments. In a mid-term setup, VRE reduces only quasi-fixed costs if plants are decommissioned, but cannot reduce the capital costs of (sunk) capital. Typically the long-term value of VRE is higher than the mid-term value.

5. Model results

The model introduced in the previous section is now used to estimate VRE market values at various penetration levels. For each given level of VRE, a new equilibrium is found in the rest of the system. This is done both in a mid-term and a long-term framework. Furthermore, the effects of a number of policies, prices, and parameters are discussed. Of course all findings should be interpreted cautiously, keeping model shortcomings and data limitations in mind. Specifically, only the market shares of VRE are increased. A broader renewables mixed with hydropower and biomass would have different effects. "(Market) share" is used interchangeably with "penetration (rate)" and is measured as generation over final consumption. Prices are calculated as the load-weighted average across all six countries, unless stated otherwise.

5.1. Mid-term wind market value

At low penetration levels, the wind value factor is 1.1 (Fig. 8). In other words, the correlation effect increases the value of wind power by ten percent. However, with higher market share, the value factor drops significantly, reaching 0.5 at 30% penetration. In other words, at 30% penetration, electricity from wind is worth only half of that from a constant source of electricity. This is the merit-order effect at work. The slope of the curve is very similar to the estimated coefficient for thermal systems in Section 3 (on average 1.8 percentage points value factor drop per percentage point market share compared to 1.6).

In absolute terms, wind's market value drops even quicker (Fig. 9): the average income of wind generators falls from 73 €/MWh to 18 €/MWh as base price drops from 66 €/MWh to 35 €/MWh. To put this into context, we compare this to the generation costs of wind that shrink at a hypothesized learning rate of five percent.[11] Model results indicate that falling revenues overcompensate for falling costs: the gap between costs and revenues remains open, and indeed increases. Under these assumptions, wind power does not become competitive.

Looking at the results from a different angle, costs would need to drop to 30 €/MWh to allow 17% market share without subsidies. From another perspective, with a value factor of 0.5 and LCOE of 60 €/MWh, the base price has to reach 120 €/MWh to make 30% wind competitive.

Here, the market value for wind is estimated for given penetration levels. One can turn the question around and estimate the cost-optimal (or market equilibrium) amount of wind power, which we do in a related paper (Hirth, 2012b).

Fig. 10 displays the capacity mix with increasing wind shares. At 30%, equivalent to 200 GW of wind power, total dispatchable capacity reduces only by 40 GW. While the profitability of peak load plants increases and the profitability of base load technologies is reduced, the shifts are too small to trigger new investments. Remarkably, there is no investment in storage, and interconnector investments are moderate (about 50% higher capacity than today, of which two thirds can be attributed to wind power).

The value drop can be explained by the shift in price-setting technologies. Fig. 11 shows the share of hours of the year in which each generation technology sets the electricity price by being the marginal generator. The share of low-variable cost dispatchable technologies such as lignite and nuclear increases with higher wind deployment, the reason being that residual load is often reduced enough to make these technologies price setting. At 30% wind market share the price drops to zero during 1000 h of the year, when must-run generation becomes price-setting. Because these are precisely the hours when much wind power is generated, 28% of all wind power is sold at a price of zero.

The value factors for individual countries are similar to the regional value, with one exception (Fig. 12). France has a large fleet of nuclear power plants. When adding wind power to the system, the price drops quickly to the low variable costs of nuclear during wind hours. As a consequence, the value factor drops quicker than the other markets. Model results are robust to the choice of the wind year (Fig. 13).

[11] We assume that full costs are today 70 €/MWh, the global learning rate is 5%, and that global capacity doubles twice as fast as European capacity. This implies that the LCOE would drop to 60 €/MWh at 30% market share.

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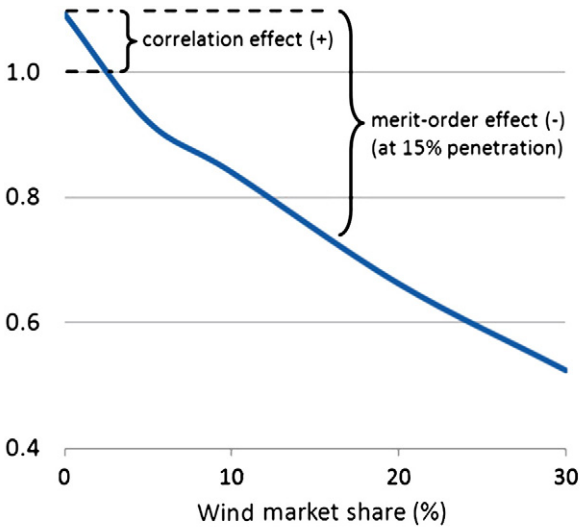

Fig. 8. Mid-term value factor of wind.

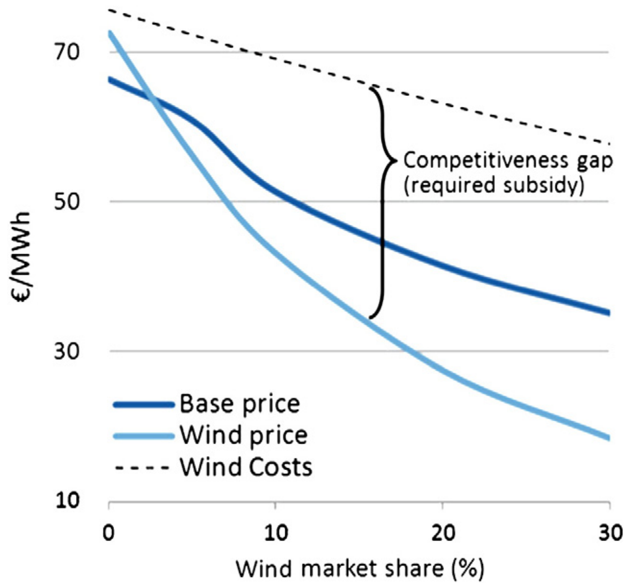

Fig. 9. Mid-term absolute market value, compared to the base price and indicative LCOE under learning.

5.2. Mid-term solar market value

The high market value of solar power that is observed on markets might suggest that solar's market value is more stable than wind's. Model results indicate that this is not the case. Its value factor actually drops slightly below 0.5 already at 15% market share (Fig. 14). However, one must keep in mind that unlike in the case of wind, the model is not able to replicate the high solar value factor that markets indicate for low penetrations. Even at a learning rate of 10% solar LCOE remains above market value.[12]

The steep drop of solar market value confirms previous studies (Borenstein, 2008; Gowrisankaran et al., 2011; Mills and Wiser, 2012; Nicolosi, 2012) and consistent with historical German market data (recall Figs. 5 and 6). This can be explained with the fundamental characteristics of solar power. The solar profile is more "peaky" than wind, with a considerable amount of generation concentrated in few hours. This is shown in Fig. 15, which displays the sorted hourly distribution of one MWh generated from wind and solar during the course of one year.

In the remainder of this section we will focus on wind power. Solar value factors are available from the author upon request.

5.3. Renewables mix

If both wind and solar power are introduced simultaneously, the respective value shares drops less when calculated as a function of renewable capacity (Fig. 16). However, the drop is still considerable. This indicates that notwithstanding wind speeds and solar radiation being negatively correlated, an energy system with large shares of both VRE technologies leads to low value factors for both technologies.

5.4. Long-term market value

This subsection applies a long-term framework, without any previously existing conventional power plants. In comparison to the mid-term, the power system can adjust more flexibly to a given amount of VRE.

Higher shares of VRE reduce the amount of energy generated by thermal power plants, without reducing total thermal capacity much (Hirth, 2012a). This reduces the average utilization of thermal plants, which increases specific capital costs. Nicolosi (2012) termed this the "utilization effect". In a long-term framework this effect exists, but is weaker than in the mid-term, because the system is not locked in with too high amounts of base load technologies. Thus, the long-term market value of VRE is usually higher than its mid-term value (Fig. 17).

In the EMMA simulations, the average utilization of dispatchable capacity decreases from about 54% to 39% as the wind penetration rate is increased to 30%. The long-term wind value factor is 0.65 at 30% market share, almost 15 percentage points higher than the mid-term factor. At penetration rates below 10%, wind power does not alter the optimal capacity mix significantly, thus mid-term and long-term value factors are identical (Fig. 18).

The base price is also more stable in the long run than in the medium run (Fig. 19). As formally shown by Lamont (2008), the long-term base price is set by the LCOE of the cheapest base load technology as long as there is one technology that runs base load. At high penetration, the absolute long-term wind value is about twice as high as the mid-term value.

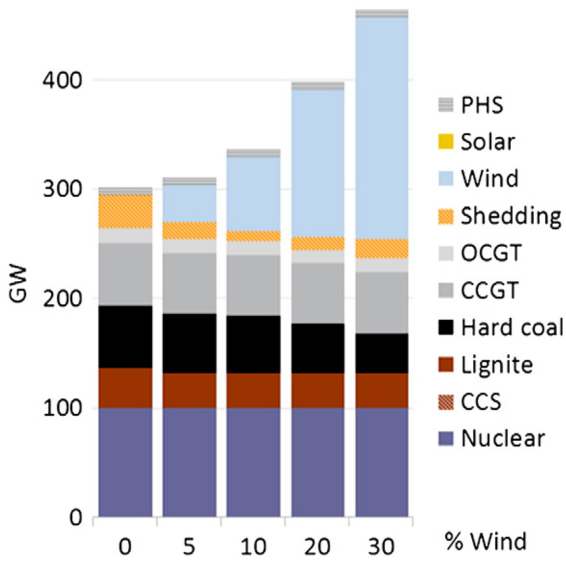

Fig. 10. Capacity development for given wind capacity. One reason for the drop in value is that wind power is less and less capable of replacing dispatchable capacity.

[12] If we assume that full costs are today 250 €/MWh on European average, the global learning rate is 10%, and that global capacity doubles four times as fast as European capacity, we will have full costs of around 100 €/MWh at 15% market share.

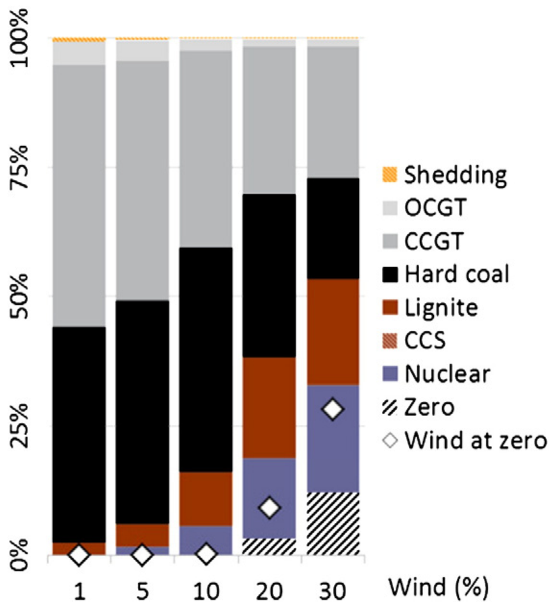

Fig. 11. Price-setting technology as a share of all hours (bars) and the share of wind energy that is sold at zero price (diamonds).

The capacity mix has a higher share of peak load capacity in the long-term equilibrium (Fig. 20). The difference between market values is larger in countries with a high base load capacity such as France. However, it is important to note that also the long-run market value drops significantly with increasing market shares.

In the remainder of Section 5, the effects of changing price assumptions and policies on the market value of wind and solar will be tested. Specifically, CO_2 prices, fuel prices, interconnector and storage capacity, and the flexibility of conventional generators will be varied. There are two reasons for doing this: on the one hand we want to understand the range of outcomes due to parameter uncertainty. On the other hand, we use the findings to identify promising integration options that help mitigating the value drop of VRE. The run with unchanged parameters is used as a point of reference or “benchmark”.

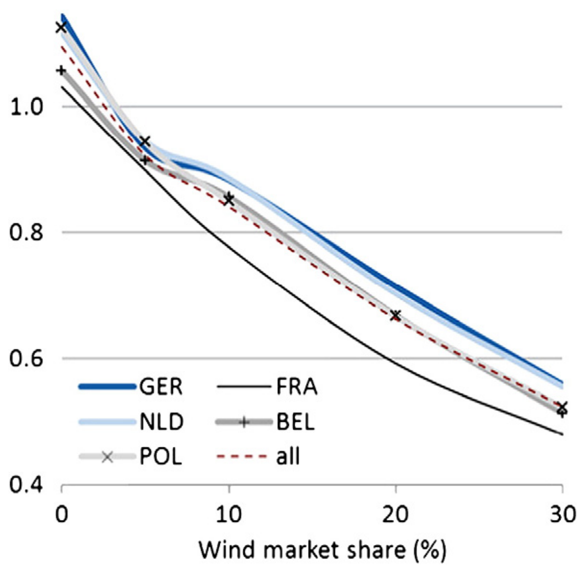

Fig. 12. Wind value factors in individual countries.

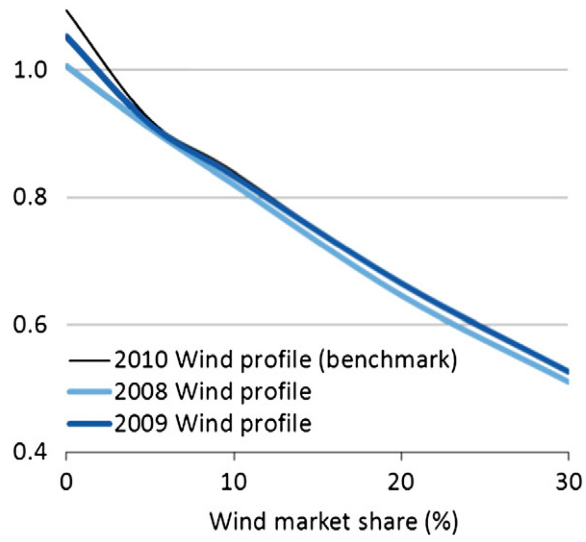

Fig. 13. Wind profiles from different years lead to almost exactly the same value factors.

5.5. CO_2 pricing

Carbon pricing is one of the most important policies in the power sector, and many observers suggest that CO_2 pricing has a significantly positive impact on VRE competitiveness: a higher carbon price increases the variable costs of emitting plants, and hence increases the average electricity price. However, there are two other channels through which carbon pricing affects the value of VRE. A higher price makes the merit-order curve flatter in the range of lignite – hard coal – CCGT, increasing the value factor at high penetration. Finally, a higher CO_2 price induces investments in low-carbon technologies. The available dispatchable low-carbon technologies in EMMA are nuclear power and lignite CCS, both featuring very low variable costs. Thus, these new investments make the merit-order curve steeper. In contrast, a lower CO_2 price reduces the electricity prices, makes the merit-order curve of emitting plants steeper, and induces investments in lignite, further increasing the slope of the merit-order curve. Thus the overall effect of a higher carbon price on the market value of VRE is ambiguous a priori, but a lower carbon price should strictly reduce VRE value.

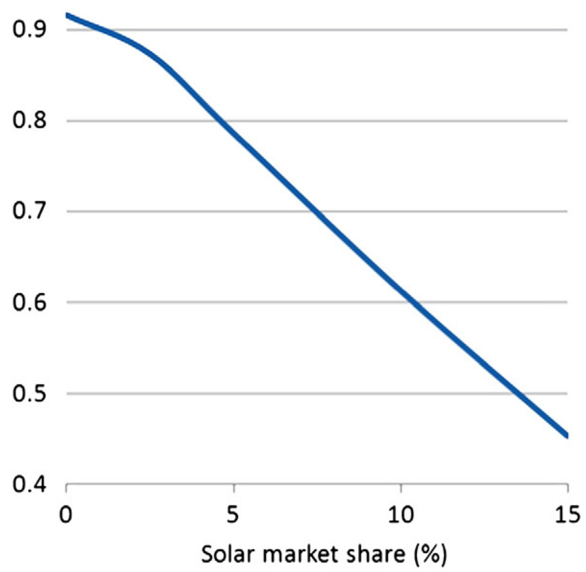

Fig. 14. Mid-term solar value factor drops below 0.5 at only 15% penetration rate.

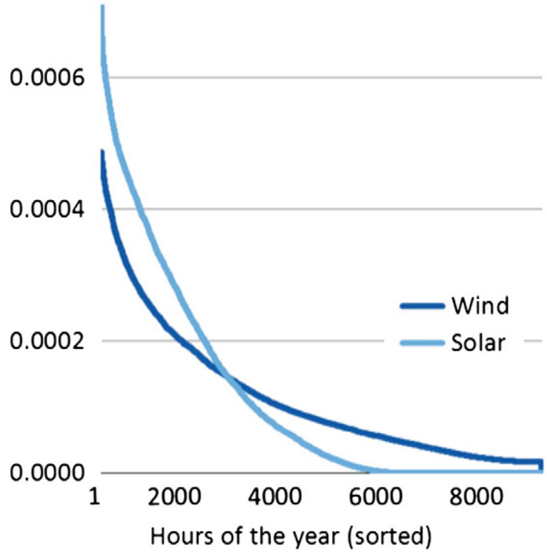

Fig. 15. Generation duration curves for solar and wind power. Solar generation is concentrated in fewer hours than wind generation.

To quantify these arguments, the benchmark CO_2 price of 20 €/t was changed to zero and 100 €/t. Because mid-term and long-term effects are quite similar, only long-term results are shown. The central finding of this sensitivity is that *both* higher and lower CO_2 prices reduce the absolute market value of wind power (Fig. 21). At a CO_2 price of 100 €/t, about half of all dispatchable capacity is nuclear power, such that the merit-order effect is so strong that even absolute revenues of wind generators are reduced — despite a significant increase in electricity prices. This might be one of the more surprising results of this study: tighter carbon prices might actually reduce the income of VRE generators, if the adjustment of the capital stock is taken into account.

This finding heavily depends on new investments in nuclear or CCS. If those technologies are not available for new investments – for example due to security concerns or lack of acceptance – the market value of wind is dramatically higher (Fig. 22). The base price increases, and the merit-order becomes so flat that the price seldom drops below the variable costs of hard coal. Indeed, even at current wind cost levels, more than 30% of wind power would be competitive. However, excluding

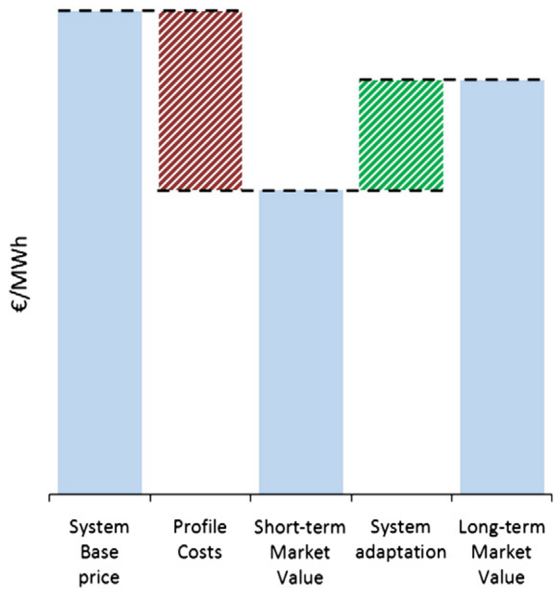

Fig. 17. System adaptation causes the long-term market value to be higher than the short-term value. The major factor is a shift of the generation mix from base load towards mid and peak loads.

nuclear power and CCS results in a dramatic increase of carbon emissions: while a CO_2 price of 100 €/t brings down emissions from 900 Mt to 200 Mt per year, emissions increase to more than 500 Mt if nuclear and CCS are unavailable, even at 30% wind. Hence, excluding nuclear and CCS from the set of available technologies will help wind power to become competitive, but it also leads to dramatically higher CO_2 emissions.

5.6. Fuel prices

For the benchmark run, 2011 market prices are used for the globally traded commodities hard coal (12 €/MWh_t) and natural gas (24 €/MWh_t). It is sometimes argued that higher fuel prices, driven by depleting resources, will make renewables competitive. In this section, gas and coal prices were doubled separately and simultaneously. A plausible expectation is that higher fuel costs, driving up the electricity price, increase the value of wind power.

However, results do not confirm this hypothesis. Again, fuel price changes affect the value of RES through different channels. A change

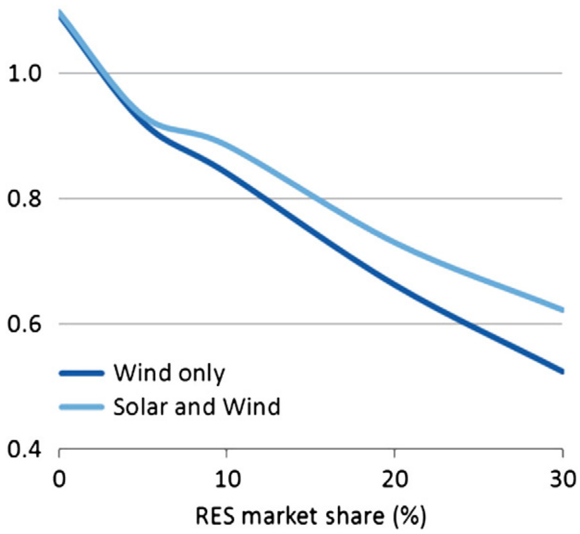

Fig. 16. Wind value factor with and without solar.

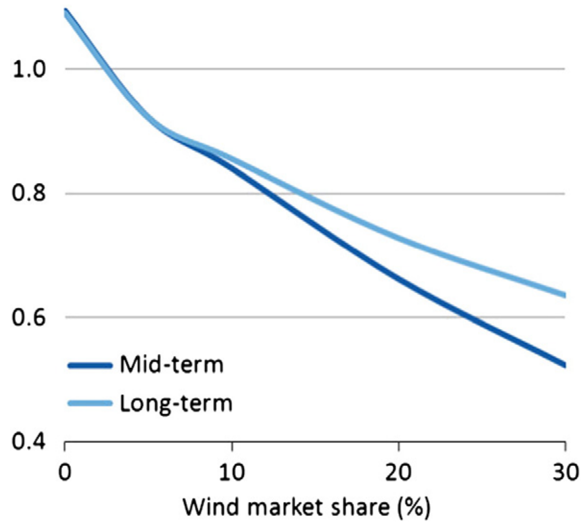

Fig. 18. At high penetration rates, the long-term value factor is significantly higher than the mid-term value factor.

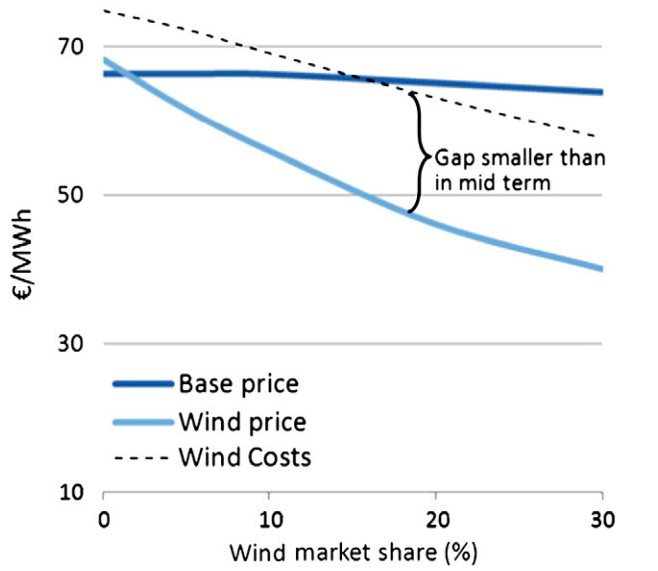

Fig. 19. The long-term wind market value in absolute terms. While the value is twice as high as the mid-term value at high penetration rates, it is still significantly below full costs.

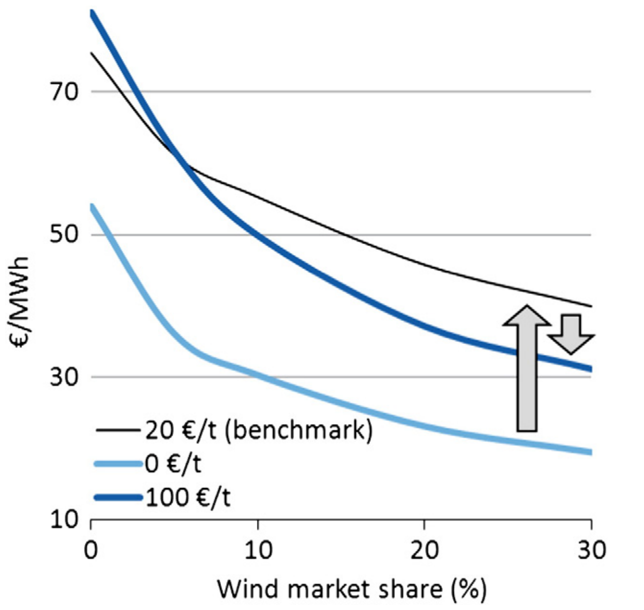

Fig. 21. Absolute long-term wind value at different CO_2 prices. At penetration rates above 5%, a CO_2 price of 100€/t results in *lower* income for wind generators than 20€/t. The arrows indicate the change in income as the CO_2 rises.

in relative input prices induces substitution of fuels, such that the average electricity price remains virtually unchanged. In contrast, the merit-order curve changes significantly. With a higher coal price, it becomes flatter. With a higher gas price, it becomes steeper. If both prices double, new lignite and nuclear investment lead to it becoming much steeper.

As a result, higher gas prices reduce the wind value factor (Fig. 23) and reduce the absolute value of wind. These results indicate that it is not necessarily the case that VRE benefit from higher fuel prices; indeed they might even lose. Mid-term results are similar and not shown.

The seemingly counter-intuitive effects of CO_2 and fuel prices on the value of wind indicate how important it is to take adjustments of the capital stock into account when doing policy analysis.

5.7. Interconnector capacity

Higher long-distance transmission capacity helps to balance fluctuations of VRE generation. In the benchmark runs, it was assumed that interconnectors have today's capacities. To understand the effect of transmission expansion on VRE market value, NTC constraints were first set to zero to completely separate markets, they were then doubled from current levels, and finally taken out to fully integrate markets throughout the region.

The impact of transmission expansion is dramatically different in a long-term and a mid-term framework. Long-term results indicate that long-distance transmission expansion supports the market value of wind in all countries (Fig. 24). However, the size of the effect is small: doubling the capacity of all existing interconnectors merely leads to

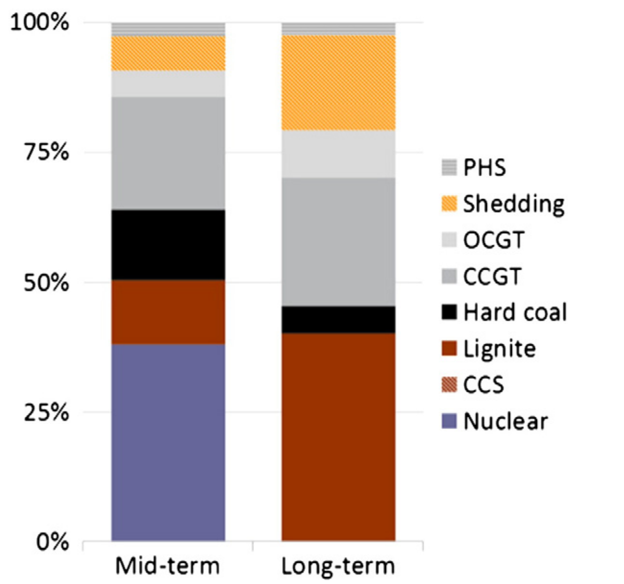

Fig. 20. Capacity mix at 30% wind power. The long-term equilibrium capacity mix has larger shares of mid and peak load technologies.

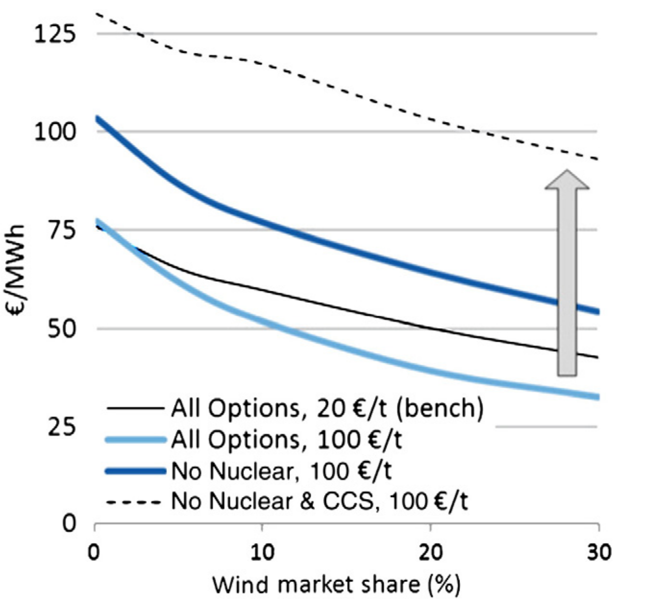

Fig. 22. Absolute long-term wind value at 100€/CO_2 prices for different technology assumptions. The arrow indicates the effect of excluding nuclear and CCS at 100€/t CO_2.

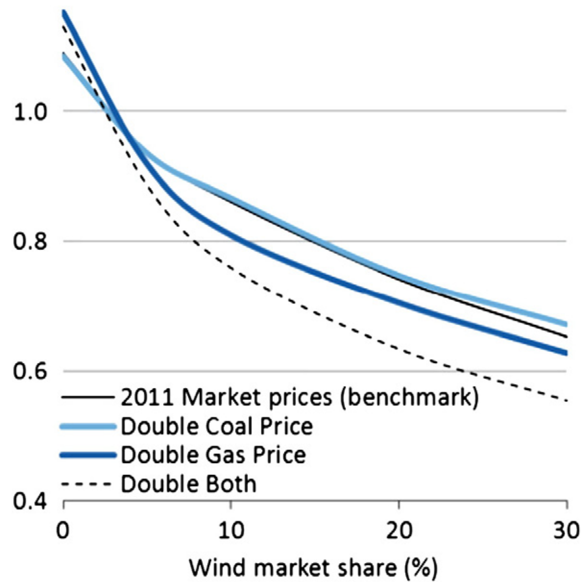

Fig. 23. Long-term wind value factors at various fuel prices. The base price is virtually identical in all four runs.

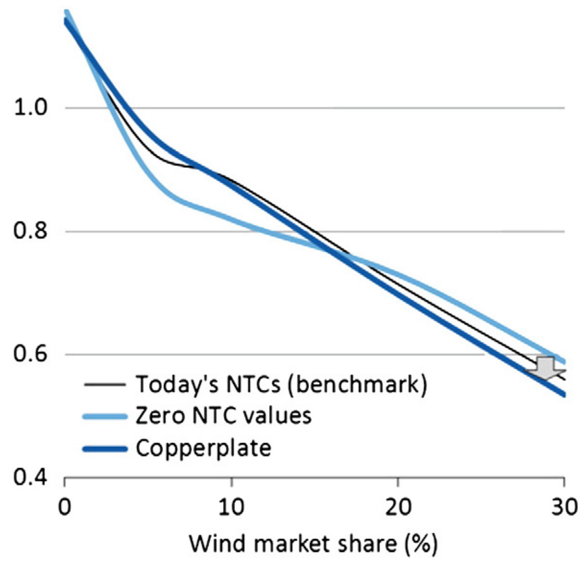

Fig. 25. The German mid-term wind value factor is reduced if interconnector capacity is increased (arrow).

an increase of wind's value factor by one percentage point at high penetration levels.

Mid-term results show how existing thermal capacity interacts with shocks to the system and how dramatically this can alter outcomes. While more interconnector capacity reduces the mid-term value of wind in Germany, it increases it dramatically in France (Figs. 25, 26). This result is explained by the large existing French nuclear fleet: in France, prices are often set by nuclear power during windy hours at high wind penetration rates. Since French and German winds are highly correlated, during windy hours French nuclear power becomes the price setter in Germany. With more interconnector capacity, this effect is more pronounced. Thus long-distance transmission prevents French wind power from being locked in with low nuclear prices, but hits German wind power by importing French nuclear power during windy times.

These findings are consistent with previous studies. Obersteiner (2012) models the impact of interconnectors on VRE market value and reports a positive impact if generation profiles are less then perfectly correlated and supply conditions similar. This is indeed the case in the long run, but not when taking the existing French nuclear capacities into account. While Nicolosi (2012) finds a strong and positive effect of grid extension on the mid-term market value of German wind power, his finding is driven by the assumption that Germany will continue its role as a "renewable island," with much higher wind shares than its neighboring countries. If this is the case, German wind power benefits from exporting electricity during wind times. In contrast, we assume penetration to be identical in all markets.

5.8. Storage

Electricity storage is widely discussed as a mean of VRE integration and as a prerequisite for system transformation. Here the influence of storage on the value of VRE is tested by setting pumped hydro storage capacity to zero and doubling it from current levels.

The effect on wind is very limited: at 30% penetration, the difference in value factors between zero and double storage capacity is only one

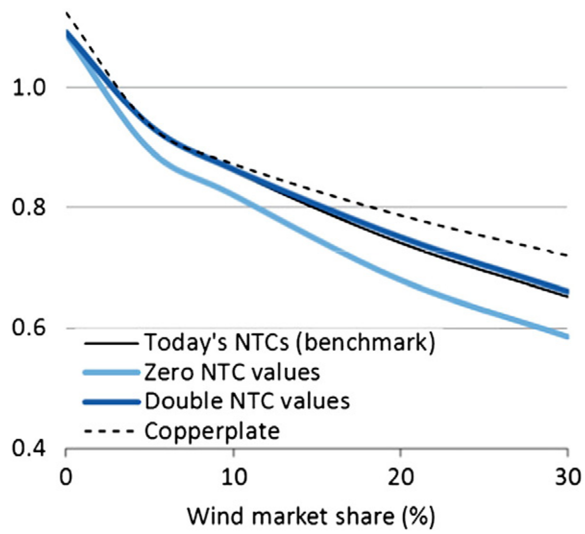

Fig. 24. Long-term wind value factors in the model region at different NTC assumptions. The impact of doubling NTC capacity is moderate in size, but positive in all countries.

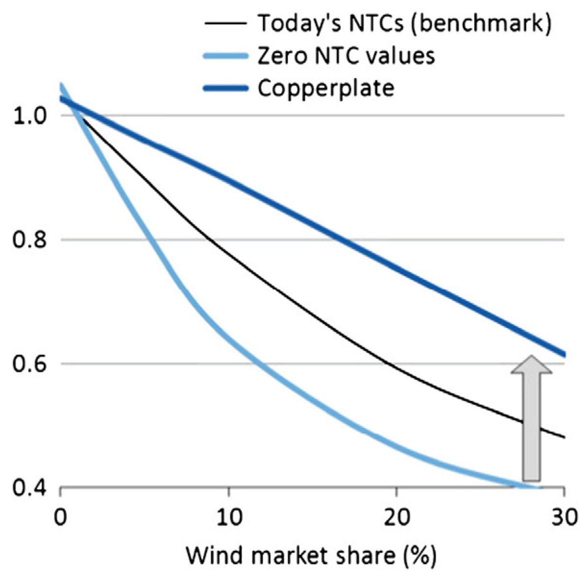

Fig. 26. The French mid-term wind value increases strongly with more interconnector capacity (arrow).

percentage point in the mid-term and five points in the long term (Fig. 27). The driver behind this outcome is the design of pumped hydro plants. They are usually designed to fill the reservoir in six to eight hours while wind fluctuations occur mainly on longer time scales (Hirth and Müller, 2013). Thus, wind requires a storage technology that has a large energy-to-power ratio than pumped hydro storage.

For solar, the situation is different. Due to its pronounced diurnal fluctuations, solar power benefits much more from additional pumped hydro storage: at 15% solar market share, its mid-term value factor is five percentage points higher with double storage capacity than without storage. The long-term value is nine percentage points higher. At low penetration levels, however, storage actually *reduces* the value of solar power by shaving the noon peak.

Both wind and solar power could potentially benefit from hydro reservoir power. Hydropower plants in Norway, Sweden, and the Alps often have large hydro reservoirs. They are able to provide flexibility, even though they usually lack the capability of pumping. As mentioned in Section 4, reservoirs are not modeled in EMMA.

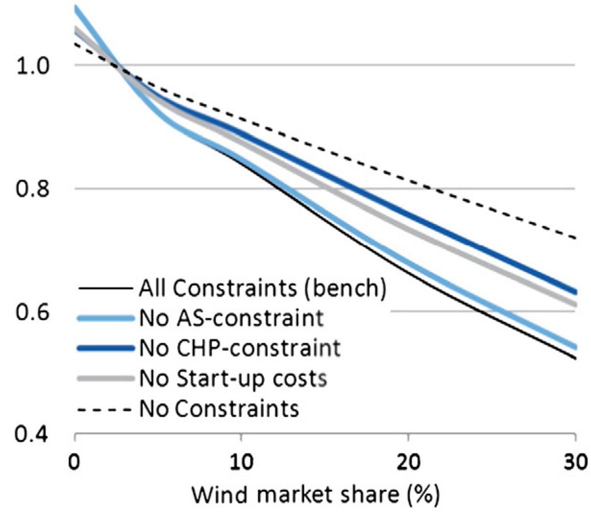

Fig. 28. Mid-term market value for wind with additional flexibility measures.

5.9. Flexible conventional generators

There are many technical constraints at the plant and the power system level that limit the flexibility of dispatchable plants. If they are binding, all these constraints tend to reduce the value of variable renewables at high market shares. Three types of inflexibilities are modeled in EMMA: a heat-supply constraint for CHP plants, a must-run constraint for suppliers of ancillary services, and a run-through premium that proxies start-up and ramping costs of thermal plants (Section 4).

There are technologies that can be used to relax each of these constraints: CHP plants can be supplemented with heat storages or electrical boilers to be dispatched more flexibly. Batteries, consumer appliances, or power electronics could help to supply ancillary services. Both measures imply that thermal plants can be turned down more easily in times of high VRE supply. In general, new plant designs and retrofit investments allow steeper ramps and quicker start-ups.

To test for the potential impact of such measures, each constraint is disabled individually and jointly. Disregarding the constraints altogether is, of course, a drastic assumption, but gives an indication of the potential importance of increasing the system flexibility.

The mid-term value factors indicate that the impact of adding flexibility to the system is large (Fig. 28). As expected, adding flexibility increases the market value of wind. What might be surprising is the size of the effect: making CHP plants flexible alone increases the value factor by more than ten percentage points at high penetration levels. All flexibility measures together increase the market value of wind by an impressive 40%. At high wind penetration, the amount of hours where prices drop below the variable costs of hard coal is reduced from more than 50% to around 20% (Fig. 29).

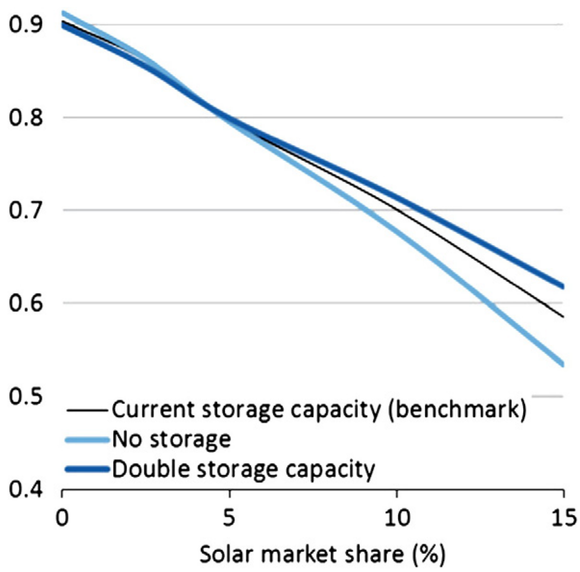

Fig. 27. Long-term solar value factor at different storage assumptions.

While one needs to keep in mind that in this modeling setup complex technical constraints are implemented as simple linear parameterizations, these results indicate that increasing system and plant flexibility is a promising mitigation strategy to stem the drop in VRE market value. Furthermore, flexibility can provide additional benefits by reducing balancing costs — thus, the importance of flexibility for the market value of wind is probably underestimated.

6. Discussion

All model results should be interpreted keeping methodological shortcomings in kind. Hydro reservoirs, demand elasticity, and technological innovations are not modeled, which probably is a downward bias to VRE market values. Internal grid bottlenecks and VRE forecast

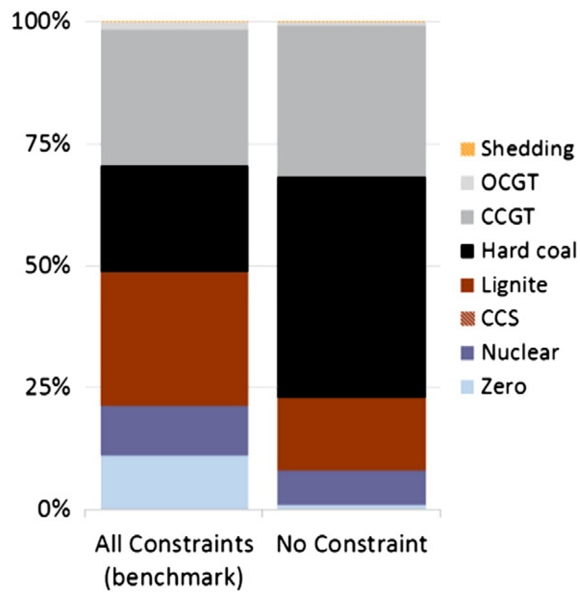

Fig. 29. Price setting fuel at 30% wind share with and without inflexibilities in Germany.

Table 8
Divers of wind value factors.

Change	Value factor	Dominating chains of causality
CO_2 price ↓	↓	Steeper merit-order curve due to lower variable costs of coal
CO_2 price ↑	↓	Steeper merit-order curve due to investment in nuclear and CCS
CO_2 price ↑ nuc/CCS ↓	↑↑	Flatter merit-order curve due to higher variable costs of coal; overall price increase
Coal price ↑	↑	Flatter merit-order curve in the range hard coal — gas; lignite investments partly compensate
Gas price ↑	↓	Steeper merit-order curve due to higher variable costs of gas; lignite and hard coal investments reinforce this effect
Interconnectors ↑	↑ (LT) ↑/↓ (MT)	Long term: smoothening out of wind generation across space; midterm: German wind suffers from low prices set by French nuclear
Storage ↑	–	Small impact of wind because of small reservoirs; negative impact on solar at low penetration rates, positive at high rates
Plant flexibility ↑	↑↑	Reduced must-run generation leads to higher prices especially during hours of high wind supply

errors are not accounted for, which might bias the value upwards. Also historical market data should be interpreted carefully, keeping historical conditions in mind. The relatively low market share and the fact that Germany and Denmark are surrounded by countries with much lower penetration rates raise doubts if findings can be projected to the future. These considerations in principle also apply to the literature reviewed.

The first and foremost result of this study is that the market value of both wind and solar power is significantly reduced by increasing market shares of the respective technology. At low penetration levels, the market value of both technologies is comparable to a constant source of electricity, or even higher. At 30% market share, the value of wind power is reduced to 0.5–0.8 of a constant source. Solar reaches a similar reduction already at 15% penetration.

Secondly, it is important to note that the size of the drop depends crucially on the time frame of the analysis. If previously-existing capacity is taken into account (mid-term framework), value factor estimates are usually lower than if it is not (long-term), especially at higher penetration rates. This holds for the reviewed literature as well as EMMA model results. Model results indicate that at high penetration rates, the absolute long-term market value is about twice the mid-term value.

Finally, prices and policies strongly affect the market value of VRE. Table 8 summarizes the effects of the price and policy shocks on wind value factors as estimated in Section 5. Some results are as expected, such as the negative effect of low CO_2 prices on the value of wind, the positive effect of high coal prices on the wind value, or the long-term benefits of market integration. A number of results, however, might come as a surprise. For example, a higher CO_2 price reduces the value of wind by inducing nuclear investments, a higher natural gas prices has a similar effect by inducing coal investments, and interconnection expansion reduce the value of German wind because of cheap imports from France. Typically, the reason is that shocks trigger new investments or interact with existing conventional capacity, which can qualitatively alter the impact on VRE market value. As a consequence, there are three channels through which changes in the energy system affect the value of VRE, of which the obvious – the impact on the price level – is often not the most important one (Fig. 30).

Figs. 31 and 32 summarize all mid-term and long-term model runs for wind power, including those that were not discussed in detail in Section 5. The resulting family of value factor curves can be interpreted as the range of value factors introduced by uncertainty about energy system parameters (Fig. 33). The model suggests that the mid-term wind value factor is in the range of 0.4–0.7 at 30% market share, with a benchmark point estimate of slightly above 0.5. The long-term value is estimated to be between 0.5 and 0.8, with a point estimate of 0.65. Historical observations and the regression line from Section 3.3 lie within the range of model results.

The estimations of wind value factors are consistent with most of the previous studies that model investments endogenously (Lamont, 2008; Mills and Wiser, 2012; Nicolosi, 2012), but somewhat lower than Swider and Weber (2006). Also, other findings are consistent with the existing literature, such as the wind value factor being above unity at low penetration levels (Energy Brainpool, 2011; Obersteiner and Saguan, 2010; Sensfuß, 2007) and the solar value factor dropping more rapidly than wind with growing market shares (Gowrisankaran et al., 2011; Lamont, 2008; Mills and Wiser, 2012; Nicolosi, 2012).

The model results do *not* imply that a different "market design" is needed to prevent the value drop of VRE. In contrast, the reduction in value is not a market failure but a direct consequence of the inherent properties of VRE. Why we use the term "market value", more precisely it is the marginal economic value that is calculated in EMMA — which is independent from the design of markets.

7. Conclusions

Electricity systems with limited intertemporal flexibility provide a frosty environment for variable renewables like wind and solar power. If significant VRE capacity is installed, the merit-order effect depresses the electricity price whenever these generators produce electricity. This implies that the per MWh value of VRE decreases as more capacity is installed.

A review of the published literature, regression analysis of market data, and a numerical model of the European power market were used in this study to quantify this drop and identify drivers. We find that the value of wind power is slightly higher than the value of a constant electricity source at low penetration; but falls to 0.5–0.8 at a market share of 30%. Solar reaches a similar level at 15% penetration, because its generation is concentrated in fewer hours. We identify several drivers that affect the value of renewables significantly.

These findings lead to a number of conclusions. Firstly, there are a number of integration options that help mitigating the value drop of VRE: transmission investments, relaxed constraints on thermal generators, and a change in wind turbine design could be important measures. Especially increasing CHP flexibility seems to be highly effective. Increasing wind turbine rotor diameters and hub heights reduce output variability and could help to stabilize wind's market value. Secondly, variable renewables need mid and peak load generators as complementary

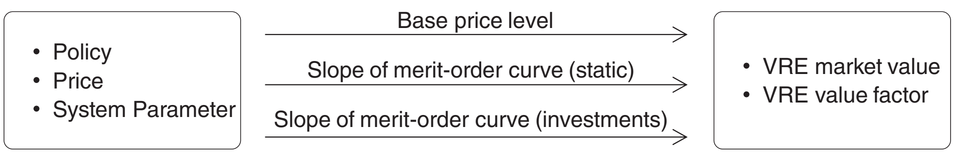

Fig. 30. Policies, price shocks, and a change of power system parameters affect the absolute and relative value of VRE through three channels: changes of the electricity price level, changes of the slope of the merit-order curve via variable cost changes, and changes of the merit-order curve via changes in the capacity mix.

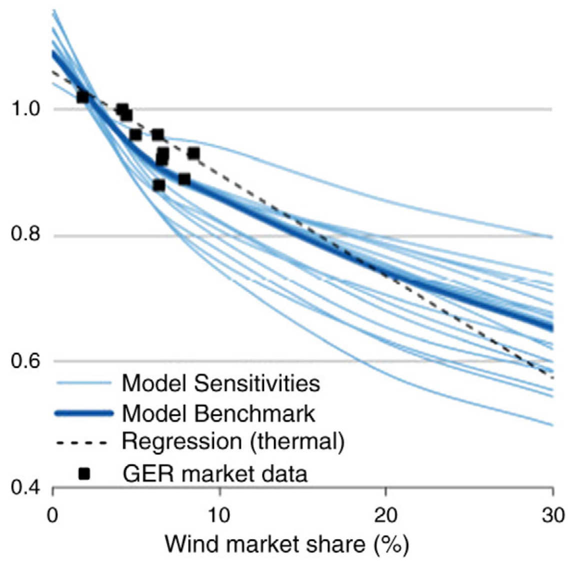

Fig. 31. All long-term wind value factors. The lowest value factors are estimated at 100 €/t CO_2 pricing and the highest at 100 €/t CO_2 if nuclear and CCS are unavailable.

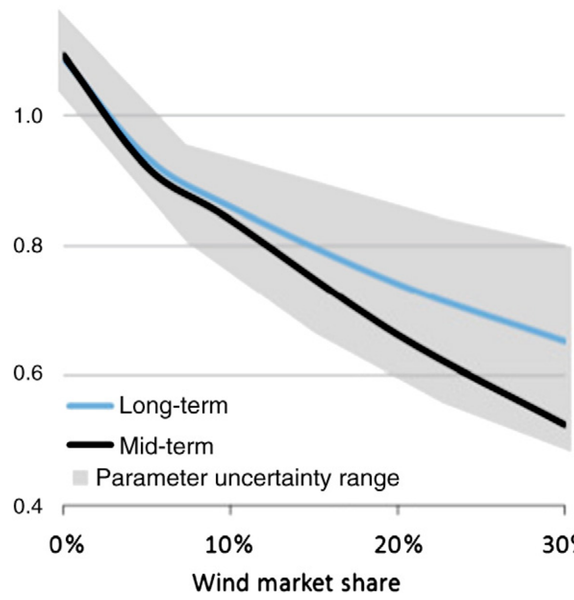

Fig. 33. Parameter uncertainty. The shaded area indicates the upper and lower extremes of mid- and long-term runs.

technologies. Biomass as well as highly efficient natural gas-fired plants could play a crucial role to fill this gap. On the other hands, low-carbon base load technologies such as nuclear power or CCS do not go well with high shares of VRE. Thirdly, we find that a high carbon price alone does not make wind and solar power competitive at high penetration rates. In Europe that could mean that even if CO_2 prices pick up again, subsidies would be needed well beyond 2020 to reach ambitious renewables targets. Finally, without fundamental technological breakthroughs, wind and solar power will struggle becoming competitive on large scale, even with quite steep learning curves. Researchers as well as policy makers should take the possibility of a limited role for solar and wind power into account and should not disregard other greenhouse gas mitigation options too early.

In terms of methodology, we conclude that any model-based evaluation of the value of VRE needs to feature high temporal resolution, account for operational constraints of power systems, cover a large geographic area, take into account existing infrastructure, and model investments endogenously.

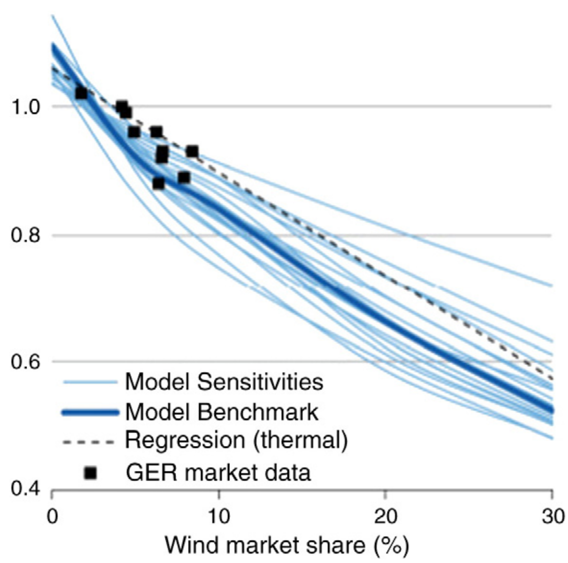

Fig. 32. All mid-term wind value factors.

The work presented here could be extended in several directions. A more thorough evaluation of specific flexibility options is warranted, including a richer set of storage technologies, demand side management, long-distance interconnections, and heat storage. A special focus should be paid to the existing hydro reservoirs in Scandinavia, France, Spain and the Alps. While this study focuses on profile costs, there are two other components that determine the market value of VRE: balancing and grid-related costs. Further research on those is needed before final conclusions regarding the market value of variable renewables can be drawn.

Appendix A. Supplementary data

Supplementary data to this article can be found online at http://dx.doi.org/10.1016/j.eneco.2013.02.004.

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Chapter 5

The Optimal Share of Variable Renewables How the Variability of Wind and Solar Power Affects their Welfare-optimal Deployment *

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The Optimal Share of Variable Renewables: How the Variability of Wind and Solar Power affects their Welfare-optimal Deployment

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ABSTRACT

This paper estimates the welfare-optimal market share of wind and solar power, explicitly taking into account their output variability. We present a theoretical valuation framework that consistently accounts for the impact of fluctuations over time, forecast errors, and the location of generators in the power grid on the marginal value of electricity from renewables. Then the optimal share of wind and solar power in Northwestern Europe's generation mix is estimated from a calibrated numerical model. We find the optimal long-term wind share to be 20%, three times more than today; however, we also find significant parameter uncertainty. Variability significantly impacts results: if winds were constant, the optimal share would be 60%. In addition, the effect of technological change, price shocks, and policies on the optimal share is assessed. We present and explain several surprising findings, including a negative impact of CO_2 prices on optimal wind deployment.

Keywords: Wind power, Solar power, Variable renewables, Cost-benefit analysis, Numerical optimization, Competitiveness

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1. INTRODUCTION

Many jurisdictions have formulated quantitative targets for energy policy, such as targets for greenhouse gas mitigation, energy efficiency, or deployment of renewable energy sources. For example, the European Union aims at reaching a renewables share in electricity consumption of 35% by 2020 and 60–80% in 2050;[1] similar targets have been set in many regions, countries, states, and provinces around the globe. Implicitly or explicitly, such targets seem to be determined as the welfare-maximal or "optimal share" of renewables, however, it is often unclear how targets are derived. This paper discusses the socially optimal share of wind and solar power in electricity supply. It provides a theoretical analysis that is focused on the variability of these energy sources, a structured methodological literature review, and numerical estimates for Northwestern Europe.

The optimal amount of wind and solar capacity is determined by the intersection of their marginal benefit and marginal cost curves. Both curves are not trivial to characterize, since they

1. National targets for 2020 are formulated in the National Renewable Energy Action Plans. Beurskens et al. (2011), Eurelectric (2011a), PointCarbon (2011) and ENDS (2010) provide comprehensive summaries. EU targets for 2050 have been formulated in European Comission (2011).

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are affected by many drivers. Marginal costs are impacted by technological learning, raw material prices, and the supply curve of the primary energy resource. Marginal benefits are driven by the private and social costs of alternative electricity sources, such as investment costs, fuel prices and environmental and health externalities. They are also affected by the variability of wind and solar power. This paper discusses the impact of variability on solar and wind power's marginal benefit curve and their welfare-optimal quantities.

Wind and solar power have been labeled variable renewable energy (VRE) sources (also known as intermittent, fluctuating, or non-dispatchable), since their generation possibilities vary with the underlying primary energy source. Specifically, we refer to "variability" as three inherent properties of these technologies: variability over time, limited predictability, and the fact that they are bound to certain locations (cf. Milligan et al., 2011; Sims et al., 2011). These three aspects of variability have implication for welfare, cost-benefit, and competitiveness analyses. For example, the marginal value (or price) of electricity depends on the time it is produced, and hence the marginal benefit of solar generators might be increased by the fact that they produce electricity at times of high demand. For unbiased estimates of the optimal amount of wind and solar capacity, their variability has to be accounted for. This paper explains theoretically why variability matters, how it can be accounted for, and presents an empirical application.

This study contributes to the literature in four ways. Firstly, we theoretically explain why variability has economic consequences. We present a framework that allows accounting comprehensively and consistently for of all aspects of VRE variability, but is simple enough to allow for quantifications. Secondly, we provide an extensive review of the existing empirical model landscape to explain which kind of modeling approaches are able to capture which driver of marginal costs and benefits, and specifically, which models are able to represent variability. Thirdly, we present new numerical model results. Results are derived from the power market model EMMA that has been developed to capture variability appropriately. Variability is shown to have a large impact on the optimal share of VRE. Finally, we test the impact of price, policy, and technology shocks on the optimal share numerically. We find and explain a number of unexpected results, for example that higher CO_2 or fuel prices can reduce the optimal VRE share under certain conditions.

The paper is structured as follows. Section 2 discusses welfare analysis theoretically. Section 3 reviews the literature. Section 4 introduces the numerical electricity market model EMMA that is used in section 5 to estimate optimal penetration rates of wind and solar power for Northwestern Europe. Section 6 summarizes the numerical results and section 7 concludes.

2. THEORY: THE ECONOMICS OF VARIABILITY

This section discusses the economics of variable renewables theoretically. It applies microeconomic theory to electricity markets to derive the welfare-optimal quantity of wind and solar capacity. This paper focuses on different aspects of variability. Other economic issues such as endogenous learning, externalities, or political economy issues of security of supply are important, but beyond the scope of this paper. The theoretical arguments put forward in this section are not restricted to variable renewables, but apply to all generation technologies.

As common practice in economics, we determine the "optimal amount" of wind and solar power as the welfare-maximizing amount. Elsewhere, the optimal VRE capacity has been determined by minimizing curtailment (Bode 2013), minimizing storage needs (Heide et al. 2010), or optimizing other technical characteristics of the power system. Denny & O'Malley (2007) determine the "critical amount" of wind power, where net benefits become zero.

As for all other goods, the welfare-optimal quantity of wind or solar capacity is characterized by the intersection of its long-term marginal costs and marginal value (benefit). However, deriving wind power's marginal cost and marginal benefit is not trivial. Economic cost-benefit analyses of electricity generation technologies require careful assessment and appropriate tools, because electricity as an economic good features some peculiar characteristics that make it distinct from other goods. In this section, we identify those peculiarities (2.1), derive the marginal cost (2.2) and marginal value (2.3) of VRE, and determine its optimal quantity (2.4). Throughout the paper, we expressed VRE quantities as share of total electricity consumption.

2.1 Electricity is a Peculiar Commodity

Electricity, being a perfectly homogeneous good, is the archetype of a commodity. Like other commodities, trade of electricity often takes place via standardized contracts on exchanges. In that sense, it seems straightforward to apply simple textbook microeconomics to wholesale power markets. However, the physical laws of electromagnetism impose crucial constraints, with important economic implications: i) storing electricity is costly and subject to losses; ii) transmitting electricity is costly and subject to losses; iii) supply and demand of electricity need to be balanced at every moment in time to guarantee frequency stability. These three aspects require an appropriate treatment of the good "electricity" in economic analysis (Hirth et al. 2014).

As an immediate consequence of these constraints, the equilibrium wholesale spot electricity price varies over time, across space, and over lead-time between contract and delivery:

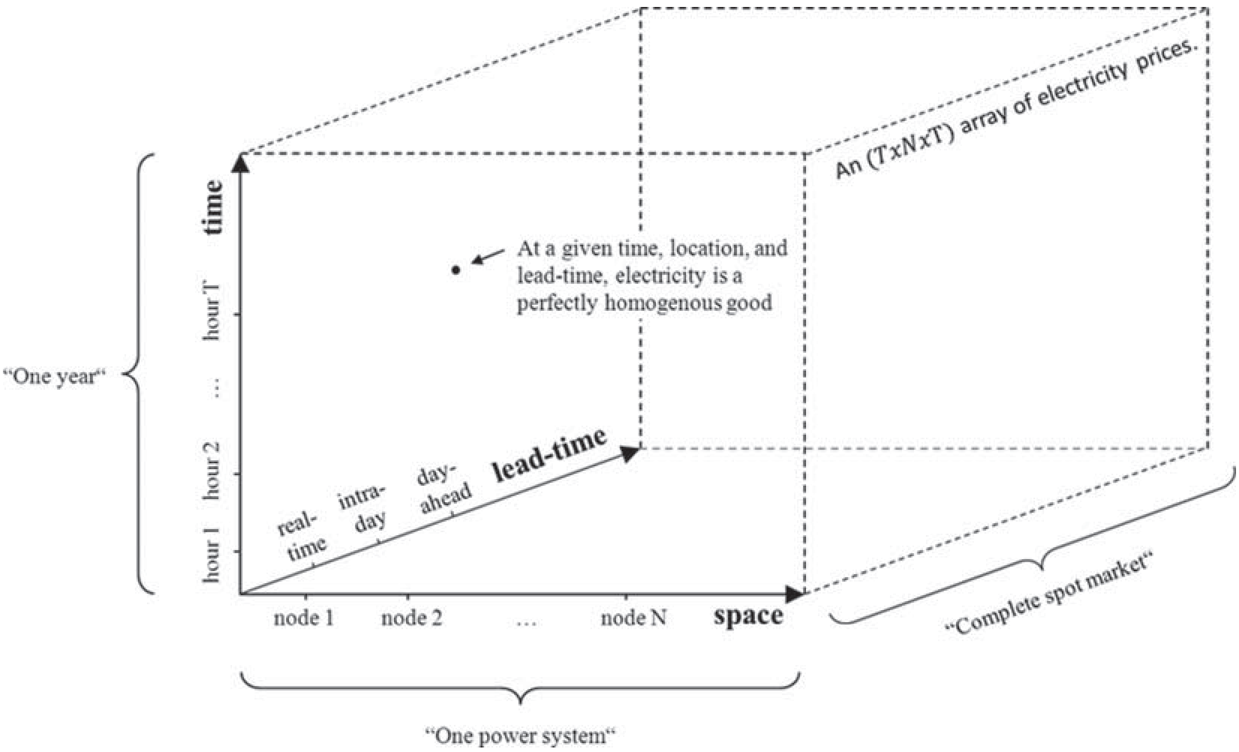
i) Since inventories cannot be used to smooth supply and demand shocks, the equilibrium electricity price varies dramatically over time. Wholesale prices can vary by two orders of magnitudes within one day, a degree of price variation that is hardly observed for other goods.
ii) Similarly, transmission constraints limit the amount of electricity that can be transported geographically, leading to sometimes significant price spreads between quite close locations.
iii) Because demand and supply has to be balanced at every instant, but fast adjustment of power plant output is costly, the price of electricity supplied at short notice can be very different from the price contracted with more lead-time. Hence, there is a cost to uncertainty.

Across all three dimensions, price spreads occur both randomly and with predictable patterns. While the economic literature has emphasized temporal heterogeneity (Bessiere 1970, Stoughton et al. 1980, Bessembinder & Lemmon 2002, Lamont 2008, Joskow 2011), the other two dimensions have not received similar attention.

In other words, electricity indeed is a perfectly homogenous good and the law of one price applies, but this is true only for a given point in time at a given location for a given lead-time. Along these three dimensions, electricity is a heterogeneous good and electricity prices vary. Figure 1 visualizes the three dimensions of heterogeneity by displaying the array of wholesale spot prices in one power system in one year.

This fundamental economic property of electricity is approximated in real-world power market design: at European power exchanges, a different clearing price is determined for each hour and for each geographic bidding area. U.S. markets typically feature an even finer resolution, clearing the market every five minutes for each of several thousand transmission nodes. In addition,

Figure 1: The Array of Wholesale Spot Electricity Prices



Notes: The electricity price varies along three dimensions: time, space, and lead-time (uncertainty). At a single point in the three-dimensional space of prices, electricity is perfectly homogeneous.

there is a set of power markets with different lead-times: in most European markets, there is a day-ahead market (12–36 hours before delivery), an intra-day market (few hours before delivery), and a balancing power market (close to real-time). As a consequence, there is not *one* electricity price per market and year, but 26,000 prices (in Germany) or three billion prices (in Texas).[2] Hence, it is not possible to say what "the" electricity price in Germany or Texas was in 2012.

The heterogeneity of electricity is not only reflected in market design, but also in technology. For homogenous goods, *one* production technology is efficient. In electricity generation, this is not the case: there exists a set of generation technologies that are efficiently used simultaneously in the same geographic market. There are nuclear and coal-fired so-called "base load", natural gas-fired "mid load" combined cycle gas turbines, and gas- and oil-fired "peak load" open cycle gas turbines. These technologies can be distinguished by their fixed-to-variable costs ratio: Base load have high capital costs but low variable costs. They are the most economical supply option for the share of electricity demand that is constant. Peak load plants have low fixed costs but high variable costs. They are the cheapest supply option for the few hours during a year with highest demand. Classical power market economics translates this differentiation into graphical approaches to determine the optimal fuel mix (section 3.2).

Any welfare, cost-benefit, or competitiveness analysis of electricity generation technologies need to take heterogeneity into account. It is in general *not* correct to assume that i) the average price of electricity from VRE (its marginal value) is identical the average power price, or that ii)

2. The German spot market EPEX clears for each hour of the year as a uniform price; the ERCOT real-time market of Texas clears every five minutes for all 10,000 bus bars of the system

the price that different generation technologies receive is the same. Comparing generation costs of different technologies or comparing generation costs of a technology to an average electricity price has little welfare-economic meaning. Specifically, marginal cost of a VRE technology below the average electricity price or below the marginal costs of any other generation technology does *not* indicate that this technology is competitive; still this is repeatedly suggested by lobby groups, policy makers, and academics (BSW 2011, EPIA 2011, Kost et al. 2012, Clover 2013, Koch 2013). Instead, the marginal cost of VRE has to be compared to its marginal value. To derive that marginal value, one needs to take into account when and where it was generated and that forecast errors force VRE generators to sell their output relatively short before real time. After discussing the marginal cost of VRE in the following subsection, we will derive its marginal value taking these aspects into account.

2.2 Marginal Costs: Levelized Electricity Costs

It is common and convenient to report long-term marginal value and marginal cost in energy terms (€/MWh). We will follow this convention here. Long-term marginal costs are the discounted average private life-cycle costs (fixed and variable, including the cost of capital) of the last VRE generator built. We will assume there are no externalities in wind turbine manufacturing or construction (supported by Hoen et al. 2013), hence private costs equal social costs. In the field of energy economics, average life-cycle costs are commonly called levelized costs of electricity or levelized electricity costs (LEC). We define the LEC of a generator as

$$LEC = \sum_{y=1}^{Y} \frac{1}{(1+i)^y} \frac{c_y}{g_y} \tag{1}$$

IEA & NEA 2010 define LEC slightly differently: $LEC = \frac{\sum_{y=1}^{Y} c_y (1+i)^{-y}}{\sum_{y=1}^{Y} g_y (1+i)^{-y}}$

where c_y are the costs that occur in year y, g_y is the amount of electricity generated in that year, i is the real discount rate, and Y is the life-time of the asset in years.

Onshore wind LEC are globally currently in the range of 45–100 €/MWh, depending on wind resource quality, turbine market conditions, and discount rate. Offshore wind costs might be at 100–150 €/MWh and solar photovoltaic costs have reached similar levels after dramatic cost reductions during the past years. For an overview of LEC estimates for various generation technologies, see IPCC (2011, Figure 5), Borenstein (2012), and Schröder et al. (2013). IEA (2012) provides recent global investment cost estimates for wind and solar power. Seel et al. (2013) point out the considerable differences between solar costs in Germany and the US.

In economic analyses, marginal costs are often a function of quantity. In the case of VRE, levelized costs might increase with penetration because land becomes scarce, or might decrease because of learning-by-doing and economies of scale. Nemet (2006), Hernández-Moro & Martínez-Duart (2013) and Brazilian et al. (2013) discuss and quantify the drivers for solar cost reductions and Schindler & Warmuth (2013) report recent market data. Lindman & Söderholm (2012) and van der Zwaan et al. (2012) estimate wind learning curves. Nordhaus (2013) provides a critique of the specification of econometric models to estimate learning curves. NREL (2009) and 3Tier (2010) provide estimates of resource-constrained supply curves for wind power in the US. Baker et al. (2013) provide an extensive literature survey on both topics.

Both learning and resource constraints happen outside the electricity market and a detailed analysis is beyond the scope of this paper. The electricity market determines the marginal value, which we will discuss in turn.

2.3 Marginal Value: Market Value

We define the "market value" of a generation technology as the average discounted private life-time income from electricity sales, excluding any direct subsidies such as feed-in-tariffs, green certificates, or investments subsidies (Joskow 2011, Hirth 2013). We will assume perfect and complete power markets in long-term equilibrium, hence the (private) market value coincides with the (social) marginal value, and we will use both terms interchangeably. The market value of wind power can then be written as

$$MV^{w} = \sum_{y=1}^{Y} \frac{\bar{p}_y^{w}}{(1+i)^y} \tag{2}$$

where $\bar{p}_y^{w}$ is the average specific price (€/MWh) that wind generators received in year y. We will use "wind" for simplicity in the rest of this section. All analytics apply to solar power and any other generation technology as well.

a) An exact definition of market value

Assuming there exists one representative year, the wind market value equals the discounted average specific price of wind power in that representative year $\bar{p}^{w}$. This value can be written as the wind-weighted electricity price of all T time steps in all N price areas at all T lead-times:

$$\bar{p}^{w} = \sum_{t=1}^{T} \sum_{n=1}^{N} \sum_{\tau=1}^{\mathrm{T}} w_{t,n,\tau} \cdot p_{t,n,\tau} \tag{3}$$

where $w_{t,n,\tau}$ is the share of wind generation in time t at node n that was sold at lead-time τ and $p_{t,n,\tau}$ is the respective price, one of the elements of the price array displayed in Figure 1.

In some cases the relative price of electricity from wind power is of interest. We define the "value factor" (Stephenson 1973, Hirth 2013) of wind power VF^{w} here as the market value over the load-weighted electricity price:

$$VF^{w} = \bar{p}^{w} / \bar{p}^{d} \tag{4}$$

$$\bar{p}^{d} = \sum_{t=1}^{T} \sum_{n=1}^{N} \sum_{\tau=1}^{\mathrm{T}} d_{t,n,\tau} \cdot p_{t,n,\tau} \tag{5}$$

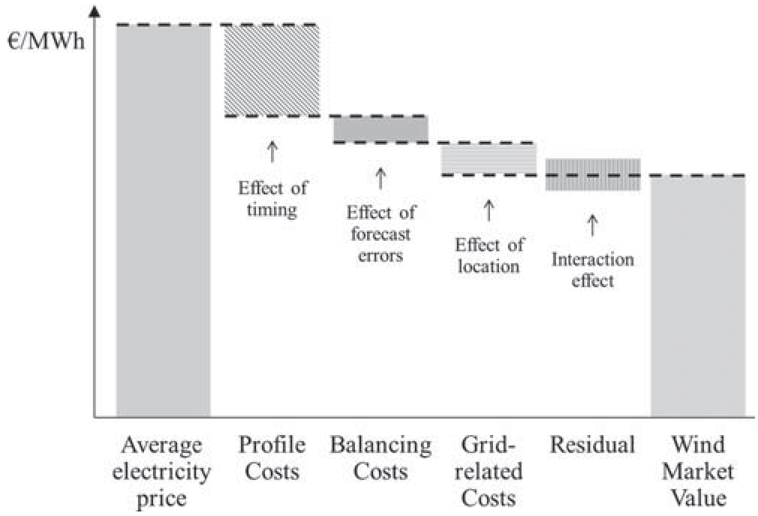
where $d_{t,n,\tau}$ is the share of load in time t at node n at lead-time τ. Hence the market value can be written as the average price times the value factor

$$\bar{p}^{w} = \bar{p}^{d} \cdot VF^{w} \tag{6}$$

In principle the market value $\bar{p}^{w}$ can be estimated directly either from observed market prices or modeled shadow prices $p_{t,n,\tau}$—to the extent that models can be regarded as realistic and markets can be treated as being complete, free of market failures, and in equilibrium.

However, estimating the full array of shadow prices $p_{t,n,\tau}$ (Figure 1) would require a stochastic model with sufficient high temporal and spatial resolution. Such a "supermodel" might not

Figure 2: From the Average Electricity Price to Wind's Market Value (illustrative)



Notes: At high penetration, timing and location as well as forecast errors typically reduce the market value.

be always available or actually impossible to construct. In the following, we propose a feasible approximation to determine $\bar{p}^w$ from several specialized models or data sources.

b) An approximation of market value

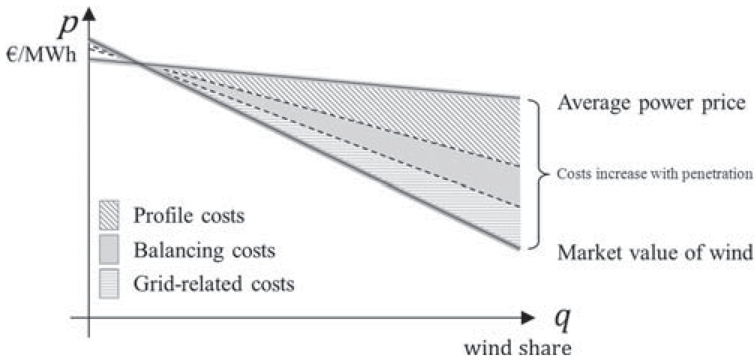
Hirth et al. (2013) have proposed an approximate derivation of market value. The idea of the approach is to estimate the impact of temporal variability, spatial variability, and forecast errors separately using specialized models or empirical datasets where a direct derivation is impossible. Along each dimension of heterogeneity there exist established modeling traditions that can be used for quantifications. We call the impact of timing on the market value of wind power "profile cost", the impact of forecast errors "balancing cost" and the impact of location "grid-related cost". Depending on the market design, these "costs" appear as reduced revenue or actual costs.

$$\bar{p}^w \approx \bar{p}^d - c^w_{profil} - c^w_{balancing} - c^w_{grid\text{-}related} \tag{7}$$

Figure 2 illustrates how profile costs, balancing costs, and grid-related costs reduce the wind market value vis-á-vis the average load-weighted electricity price. This is typically the case at high penetrations. At low penetrations, the costs components might become negative, increasing the market value above the average electricity price, for example if solar power is positively correlated with demand.

We define profile costs as the price spread between the load-weighted and wind-weighted day-ahead electricity price for all hours during one year. Profile costs arise because of two reasons. On the one hand, demand and VRE generation are often (positively or negatively) correlated. A positive correlation, for example the seasonal correlation of winds with demand in Western Europe, increases the value of wind power, leading to negative profile costs. On the other hand, at significant installed capacity, wind "cannibalizes" itself because the extra electricity supply depresses the market price whenever wind is blowing. In other words, the price for electricity is low during windy hours when most wind power is generated. Fundamentally, profile costs exist because electricity storage is costly, recall physical constraint i). A discussion of profile costs and quantitative estimates

Figure 3: Average Electricity Price and Market Value as a Function of the Quantity of Wind Power in the System



Notes: At low penetration, the wind market value can be higher than the average power price, because of positive correlation between generation and load.

are provided by Lamont (2008), Borenstein (2008), Joskow (2011), Mills & Wiser (2012), Nicolosi (2012), Hirth (2013), and Schmalensee (2013).

We define balancing costs as the difference in net income between the hypothetical situation when all realized generation is sold on day-ahead markets and the actual situation where forecast errors are balanced on intra-day and real-time or balancing markets. Fundamentally, balancing costs exist because frequency stability requires a balance of supply and demand and short-term plant output adjustments are costly, recall iii). Balancing costs are reviewed by Smith et al. (2007), Obersteiner et al. (2010), Holttinen (2011), and Hirth et al. (2013). Hirth & Ziegenhagen (2013) discuss to what extend balancing markets reflect marginal costs.

We define grid-related costs as the spread between the load-weighted and wind-weighted price across all price areas of a market. Grid-related costs exist because transmission is costly and wind speeds as well as land availability constrain wind power to certain sites, recall ii). Grid-related costs are estimated by Brown & Rowlands (2009), Lewis (2010), Hamidi et al. (2011), and Baker et al. (2013).

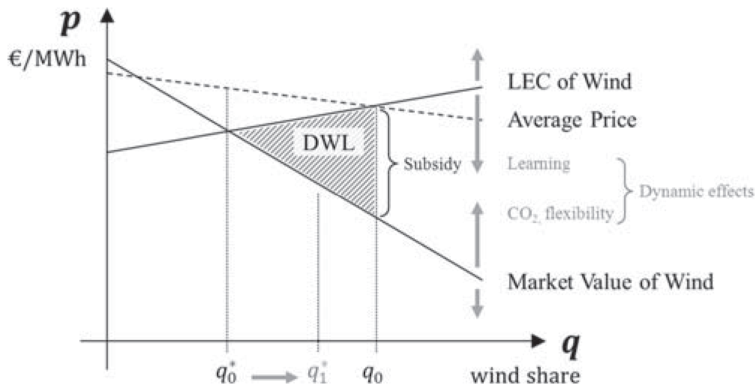
c) Market value as a function of penetration

The three cost components are not fixed parameters, but typically increase with penetration (Figure 3). This is no coincidence, but a consequence of the market-clearing role of prices: During windy times the additional electricity supply depresses the price; at windy locations, the additional supply depresses the price; and correlated wind forecast errors systematically lead to balancing costs. All three effects are stronger with larger installed capacities. In other words, both VF and $\bar{p}^d$ are in general a function of the wind share q.

d) Market value and "integration costs"

A number studies discuss the costs that variability induces at the level of the power system under the term "integration costs" (Milligan et al. 2011, Holttinen et al. 2011). Ueckerdt et al. (2013a) discuss the "integration cost" literature in relation to the "market value" literature and Ueckerdt et al. (2013b) and Hirth et al. (2013) propose to define integration costs as the difference between market value and demand-weighted average electricity price.

Figure 4: Static Partial Equilibrium of the Electricity Market.



Notes: The optimal share of wind power is given by the intersection of the market value of wind power (marginal benefits) and its levelized electricity costs (long-term marginal costs). The LEC curve can be upward-sloping because of limited land or downward-sloping because of endogenous learning. The market value curve is always downward-sloping. Installing more wind power than optimal, for example q_0, leads to dead weight losses (DWL). Dynamic effects (grey) such as technological learning and price shocks can reduce marginal costs and benefits, shifting the optimal wind share q^*

2.4 The Optimal Share of Wind Power

a) Static (For a Given Power System)

The optimal wind capacity q^* in a price-quantity-diagram is given by the point where marginal costs and marginal benefits intersect (Figure 4). The marginal benefit is *not* the average power price, but the market value of wind power. The market value can be either estimated directly (from a "supermodel") or via the approximation proposed in section 2.3.

$$LEC(q^*) = \bar{p}^d(q^*) \cdot VF(q^*) \tag{8}$$

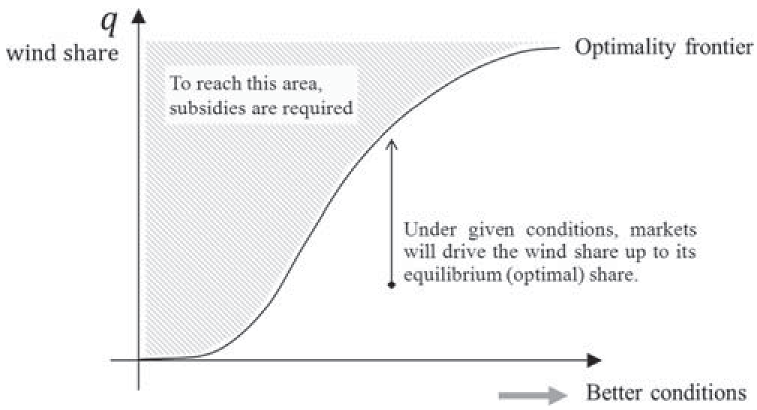
An immediate consequence is that, even if marginal costs were flat and the average electricity price constant, competitiveness is not a "flip-flop" behavior. In the policy debate it is often suggested that, one cost of wind turbines have reached a certain level, "wind is competitive". This is misleading: at a certain cost level, *a certain amount* of wind power is competitive.

b) Dynamic (For a Changing Power System)

Dynamic effects change the optimal wind share. Such effects can affect either shift the marginal cost curve or the marginal benefit curve. Technological learning of wind turbine technology shifts the LEC curve downwards. Increasing fuel or CO_2 prices increase the electricity price level and shift the market value curve upwards. Introducing "system integration" measures such as more flexible thermal plant fleet, electricity storage, more price-elastic demand, and more interconnector capacity typically pivot the marginal value curve clock-wise without affecting the electricity price level much (Hirth & Ueckerdt 2013b).

For a given set of conditions, there exists always a certain optimal amount of wind power. Figure 5 displays such a set of market equilibria, the "optimality frontier". If the wind share is below its equilibrium point, it increases until it reaches the frontier. If higher shares shall be reached under the same conditions, wind power requires subsidies. In the numerical analysis (section 5) we

Figure 5: Dynamics of the Market Equilibrium



Notes: Under better conditions, such as reduced costs or increased costs of substitutes, a higher share of wind power is competitive (and welfare-optimal).Competitiveness is not a "flip-flop" behavior, but an equilibrium condition. Higher shares require subsidies and cause dead weight losses.

Table 1: Overview of VRE Model Approaches

	Exogenous VRE capacity	**Endogenous VRE capacity**
Low resolution (years / continents)	—	Integrated Assessment Models Energy System Models
High resolution (hours / countries)	Power Market Models / Investment Planning Models	*This study*

estimate optimality frontiers: we estimate the optimal share as a function of cost reductions, and take additional dynamic effects into account via sensitivities.

The following section reviews the model-based literature that estimates the optimal share of wind and solar power. Model approaches are assessed regarding their ability to estimate the three factors of equation (8): marginal costs, average electricity price, and value factor of VRE.

3. REVIEW OF THE QUANTITATIVE LITERATURE

The welfare-optimal electricity generation mix is one of the most researched topics in numerical model-based energy economics. This study identifies three strands of this literature: Models with low temporal and spatial resolution (integrated assessment and energy system models), models with high resolution that optimize the conventional mix for a given amount of VRE (power market or investment planning models), and high-resolution models with endogenous VRE capacity (like the one employed for this study), see Table 1. Electricity network models and pure dispatch or unit commitment models are not covered by this survey. These are sometimes used to test if a certain amount of VRE can be "accommodated" in a power system, but do not optimizes VRE capacity. The borderline between model classes is gradual, such that classification is to some degree subjective.

Different classes of models have different merits and caveats when estimating the optimal VRE share. In the following, we structure the discussion along equation 8, which expresses the optimal share of, say, wind power as an equilibrium between marginal costs ($LEC(q^*)$) and the average electricity price or electricity price level ($\bar{p}^d(q^*)$) times the value factor or relative price

Table 2: Drivers and Model Requirements.

	Driver	Model requirement
Levelized electricity cost *LEC*	technological learning of VRE	global geographic scope
	VRE resource supply curve	- (data issue)
	raw material prices	global scope, multi-sector
Average electricity price (Electricity price level) $\bar{p}^d$	fuel prices	global scope, multi-sector
	carbon price	regional scope, multi-sector
	electricity demand	multi-sector
Value factor (Electricity price structure) *VF*	share of VRE	—
	flexibility of thermal plants	high temporal resolution, power system details
	hydro reservoir power	consecutive time
	transmission grid constraints	regional scope, high spatial resolution
	electricity storage	high temporal resolution, consecutive time
	VRE forecast quality	power system details
	VRE generation profile	high temporal resolution

of wind power ($VF(q^*)$). Some models are well suited to estimate marginal costs, others are well suited to estimate the average electricity price, and some are good in estimating the value factor.

Table 2 lists drivers behind these three factors, and names necessary model features to be able to model the respective driver endogenously. For example, the LEC is determined by technological learning. Modeling learning endogenously as an experience curve requires a global coverage, because VRE technology is traded globally and significant learning takes place at the level of equipment manufacturing.

In general, low-resolution models with broad scope tend to be better suited to estimate the marginal cost and the average electricity price, while high-resolution models with narrow scope are better equipped to estimate the value factor.

3.1 Low-resolution Models

For numerical and complexity reasons, there is a trade-off between model scope and resolution. Broad multi-sector models with a large geographic coverage have to limit temporal and spatial resolution.

a) Integrated assessment models

"Integrated Assessment Models" (IAMs) are numerical macroeconomic models that typically cover the entire world and all sectors of the economy. They are used to determine the optimal share of wind and solar in the electricity generation mix for example as part of greenhouse gas mitigation studies. Well-known IAMs include GCAM (Calvin et al. 2009), IMAGE (van Vliet et al. 2009), MESSAGE (Krey and Riahi 2009), TIAM (Loulou et al. 2009), MERGE (Blanford et al. 2009), EPPA (Morris 2008), and ReMIND (Leimbach et al. 2010). While these models differ considerable in terms of methodology, they usually have a temporal resolution of one or several years and a geographic resolution of world regions, such as Europe. They usually have a temporal scope until 2050 or 2100.

IAMs are capable to capture important drivers of marginal costs and the average electricity price. Cost drivers include global endogenous technological learning and, in the case of biomass, land use by other sectors. The average electricity price is impacted by macroeconomic growth, the carbon price, fuel prices, and the electricity demand for example driven by the electrification of the heat and transport sector, all of which are usually endogenous to these models.

However, they are not able to explicitly represent the heterogeneity of the good "electricity" in any of its three dimensions. They typically treat electricity as one sector with one price. Variability needs to be approximated using parameterizations. Luderer et al. (2013) and Baker et al. (2013) present overviews of how VRE are modeled and Ueckerdt et al. (2010a, 2010b) and Sullivan et al. (2013) propose new approaches for variability representation.

In a comprehensive survey of model inter-comparison studies, Fischedick et al. (2011, figure 10.9) report a median global VRE share of total electricity consumption of 10% by 2050 without climate policy and between 15–20% under climate policy.

b) Energy system models

"Energy system models" have a more narrow scope and a somewhat finer resolution. They are partial equilibrium models of the energy sector of one world region. Some models, such as PRIMES (European Commission 2011, Eurelectric 2013), MARKAL/TIMES (Loulou et al. 2004, 2005, Blesl et al. 2012), or the World Energy Model (IEA 2013) cover all three energy subsectors heat, electricity, and transportation. Others focus on the electricity sector, such as ReEDs (Short et al. 2003, 2011), US-Regen (Blanford et al. 2012), SWITCH (Nelson et al. 2012) and CAPEW (Brun 2011) for North America, and LIMES (Haller et al. 2012), PERSEUS (Rosen et al. 2007), and DEMELIE (Lise & Kruseman 2008) for Europe. Finally, some models cover the power and natural gas sectors and include a gas supply curve and gas infrastructure constraints, such as LIBEMOD (Aune et al. 2001). These models typically have a geographical resolution of countries or states and represent temporal variability by modeling typical days or weeks or modeling ten to 50 non-consecutive time slices. They are often applied to time horizons between 2030 and 2050.

The capabilities and shortcomings of IAMs discussed above in general apply to energy system models, but to a lesser extent. Global phenomena like technological learning or fuel markets, including carbon and biomass, cannot be modeled. However, regional carbon prices and electricity demand from the heat and power sector are often endogenous. Often these models have more detailed supply curves for wind and solar power than IAMs, allowing estimating their LEC quite accurately at a finer geographic resolution. Variability in the power sector can be modeled, but is subject to the models' limited resolution. If variability is not parameterized somehow, the low resolution introduces a bias towards too high VRE shares. Nicolosi (2011, 2012) reports estimates of the bias introduced by low resolution: the capacity mix is biased towards base load technologies, the capacity factor of VRE is overestimated, and the marginal value of VRE is overestimated. Some models use non-consecutive "time slices" to represent variability. However, time slices impedes to model electricity storage and hydro reservoirs, and selecting appropriate time slices is far from trivial given the multiple time series (wind, solar, load) in all model regions. Furthermore, these models often lack technical constraints of power systems, such as combined heat and power (CHP) generation, ancillary services, and ramping constraints of thermal generators. Typically, they are not back-tested to replicate historical power plant dispatch, electricity price, or interconnector flow patterns.

Knopf et al. (2013) report on a European model intercomparison project that covers both IAMs and energy system models. They report median VRE shares of total electricity consumption in the European Union of 11% without and 25% with climate policy by 2050 in the reference scenarios, but shares of 50–60% if nuclear power is restricted or assumption on VRE are more optimistic. Nelson et al. (2012) report somewhat lower numbers for the Western Interconnection of the United States.

Both IAMs and energy system models are tools that focus on estimating marginal costs and the average power price, but are not appropriate to estimate the value factor. Instead, parameterizations of *VF* have to be taken from high-resolution models. Moreover, these low-resolution models cannot be used to assess the impact of sectoral policies and technological changes. For example, the impact of heat storages on the marginal value of wind power via CHP plant flexibility can only be assessed if CHP generation is modeled, which is usually only the case in high-resolution models. We will discuss high-resolution models in turn.

3.2 High-resolution Models with Exogenous VRE

Vertically integrated utilities have used "investment planning models" of "expansion planning models" for decades to optimize their capacity mix. These models explicitly account for variable demand by applying a high, for example hourly, resolution. This comes at the price of reduced scope: these models are partial equilibrium models of a single or few countries, and are restricted to the power sector. In liberalized markets this class of models is often called "power market models" and used for fundamental long-term price projections. We discuss these models here for two reasons, even though they do not model VRE capacity endogenously: on the one hand, they are sometimes used to calibrate parameterizations of low-resolution models, on the other hand they are the precursors of the models discussed in section 3.3.

The classical version of these models is based on screening curves and load duration curves and can be solved graphically to derive the cost-minimal capacity mix (Stoughton et al. 1980, Grubb 1991, Stoft 2002, Green 2005). Because several constraints of power systems cannot be represented in load duration curves, numerical models were developed starting in the 1960s (Bessiere 1970), for instance WASP (Jenkins & Joy 1974, Covarrubias 1979).

Current power market models account for more details and constraints of power systems, such as CHP generation, ancillary services, pumped hydro storage, price-elastic demand, imports and exports, start-up and ramping costs of thermal plants, and hydro reservoirs. These models have typically a temporal resolution of 15 to 120 minutes and a spatial resolution of countries or bidding areas. They are usually able to reproduce hourly historical price, dispatch, and export patterns. Power market models are typically used in utility companies and consulting firms to forecast prices and guide investment decisions.

While such commercial models are not published, we summarize VRE-related academic studies based on such models in the following. Krämer (2002), Bushnell (2010), Green & Vasilakos (2011), and Nagl et al. (2012) compare the optimal long-term thermal capacity mix with and without VRE. They find that overall thermal capacity is only slightly reduced, but that there is a noticeable shift from baseload to mid- and peakload technologies with the introduction of VRE. Nagl et al. (2011), Tuohy & O'Malley (2011), and Lamont (2012) model the impact of VRE on storage. These models are also used estimate wind and solar market value, often as a function of penetration. Recent estimates are provided by Swider & Weber (2006), Lamont (2008), Fripp and Wiser (2008), Mills & Wiser (2012, 2013), Nicolosi (2012), and Hirth (2013), who also surveys the respective literature. Early studies include Martin & Diesendorf (1983), Grubb (1991), and Rahman & Bouzguenda (1994).

All these studies take VRE capacity as given and only optimize the thermal plant fleet. This can be explained by the fact that VRE played only a marginal role at the times when these models were developed. Furthermore, since VRE were often owned by independent power producers and not the integrated utilities that operated such models, they were not subject to the utility's optimization. Today's commercial power market models usually still regard VRE investments as exogenous, since those are driven by subsidies and subject to political decisions rather than subject to market prices.

3.3 High-resolution Models with Endogenous VRE

Surprisingly few studies optimize VRE capacities based on high-resolution models. Those that do so usually stem from the tradition of power market models and have endogenized VRE capacity. These models endogenized the VRE value factor by providing high resolution and power system details. However, for reasons of scope, factors like technological learning, power demand, and fuel and carbon prices are typically exogenous.

a) Pure long-term models (green field)

Pure long-term models derive optimal VRE capacities "from scratch", without taking existing infrastructure such as power plants into account, but they usually assume today's demand structure.

DeCarolis & Keith (2006) derive the cost-minimal electricity mix for Chicago, but consider only one thermal technology. They find that wind power needs a CO_2 price of at least 150 \$/t to be competitive. Doherty et al. (2006) apply a simple linear investment-dispatch model to Ireland, finding the optimal amount of wind capacity strongly dependent on the price of CO_2 and gas. Olsina et al. (2007) derive the optimal capacity mix for Spain. They find that at investment costs of 1200 €/kW virtually no wind power is installed, but if costs drop by 50%, about 20 GW should be installed. One drawback of this study is that the simulated wind profiles do not capture spatial correlations well. Also, the electricity system is modeled as a merit-order approach that omits must-run constraints, storage, or international trade. Lamont (2008) finds that no wind power should be deployed if annualized fixed costs amount to 120 \$/kW. If costs drop to 85 \$/kW, a third of total capacity should be wind power.

b) Models with existing power plants

A few studies do take existing infrastructure into account. Neuhoff et al. (2008) apply an elaborated investment-dispatch model with 1040 time steps per year to optimize gas-fired plant and wind investments in the UK until 2020, also accounting for grid constraints. They report an optimal wind share of 40% based on very optimistic wind cost assumptions. Möst & Fichtner (2010) couple an investment model with a 15 min-resolution dispatch model. They find that both wind and solar cannot be efficiently deployed in Germany under current conditions. Müsgens (2013) applies a two-hourly model of Europe. Under a strict emission cap, a limit on nuclear power, and endogenous technology learning, he finds optimal shares of 25% wind and 10% solar power by 2050.

The model EMMA, which will be introduced in the following section, belongs to this last class of models. It is comparable to Neuhoff et al. (2008), but covers a larger geographic region, like Müsgens (2013). While Müsgens uses his model to project the optimal amount of VRE capacity under today's political constraints, we use EMMA to understand the impact of a variety of policy, price, and technology shocks on the optimal share. Hence, while Müsgens (2013) is comparable to this study in terms of modeling methodology, the research questions are quite complementary.

4. NUMERICAL MODELING METHODOLOGY

This section introduces the European Electricity Market Model EMMA, which is used in the following section to estimate the optimal share of wind and solar power both in the medium and long term. EMMA is a stylized numerical dispatch and investment model of the interconnected Northwestern European power system that has been applied previously in Hirth (2013) and Hirth & Ueckerdt (2013a). In economic terms, it is a partial equilibrium model of the wholesale electricity market. It determines optimal or equilibrium yearly generation, transmission and storage capacity, hourly generation and trade, and hourly market-clearing prices for each market area. Model formulations are parsimonious while representing VRE variability, power system inflexibilities, and flexibility options with appropriate detail. This section discusses crucial features verbally.[3]

4.1 The Power Market Model EMMA

EMMA minimizes total costs with respect to investment, production and trade decisions under a large set of technical constraints. Markets are assumed to be perfect and complete, such that the social planner solution is identical to the market equilibrium and optimal shares of wind and solar power are identical to competitive shares. The model is linear, deterministic, and solved in hourly time steps for one year.

For a given electricity demand, EMMA minimizes total system cost, the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs, of generation, transmission, and storage assets. Capacities and generation are optimized jointly. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and investment and disinvestment in each technology, including wind and solar power. The important constraints relate to energy balance, capacity limitations, and the provision of district heat and ancillary services.

Generation is modeled as eleven discrete technologies with continuous capacity: two VRE with zero marginal costs—wind and solar, six thermal technologies with economic dispatch—nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and lignite carbon capture and storage (CCS), a generic "load shedding" technology, and pumped hydro storage. Hourly VRE generation is limited by generation profiles, but can be curtailed at zero cost. Dispatchable plants produce whenever the price is above their variable costs. Storage is optimized endogenously under turbine, pumping, and inventory constraints. Existing power plants are treated as sunk investment, but are decommissioned if they do not cover their quasi-fixed costs. New investments including VRE have to recover their annualized capital costs from short-term profits.

The hourly zonal electricity price is the shadow price of demand, which can be interpreted as the prices on an energy-only market with scarcity pricing. This guarantees that in the long-term equilibrium the zero-profit condition holds. As numerical constraints prevent modeling more than one year, capital costs are included as annualized costs.

3. Model documentation, equation, GAMS code, and input data are published under creative common CC BY-SA 3.0 license and are available at http://www.pik-potsdam.de/members/hirth/emma.

Demand is exogenous and assumed to be perfectly price inelastic at all but very high prices, when load is shed. Price-inelasticity is a standard assumption in dispatch models due to their short time scales. While investment decisions take place over longer time scales, we justify this assumption with the fact that the average electricity price does not vary dramatically between model runs.

Combined heat and power (CHP) generation is modeled as must-run generation. A certain share of the cogenerating technologies lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of these technologies can be freely optimized. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity is fixed. Ancillary service provision is modeled as a must-run constraint for dispatchable generators that is a function of peak load and VRE capacity.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs). Investments in interconnector capacity are endogenous to the model. As a direct consequence of our price modeling, interconnector investments are profitable if and only if they are socially beneficial. Within regions transmission capacity is assumed to be non-binding.

The model is linear and does not feature integer constraints. Thus, it is not a unit commitment model and cannot explicitly model start-up cost or minimum load. However, start-up costs are parameterized to achieve a realistic dispatch behavior: assigned base load plants bid an electricity price below their variable costs in order to avoid ramping and start-ups.

The model is fully deterministic. Long-term uncertainty about fuel prices, investment costs, and demand development are not modeled. Short-term uncertainty about VRE generation (day-ahead forecast errors) is approximated by imposing a reserve requirement via the ancillary service constraint, and by charging VRE generators balancing costs.

Being a stylized power market model, EMMA has significant limitations. An important limitation is the absence of hydro reservoir modeling. Hydro power offers intertemporal flexibility and can readily attenuate VRE fluctuations. Hence, results are only valid for predominantly thermal power systems. Demand is assumed to be perfectly price inelastic up to high power prices. More elastic demand would help to integrate VRE generation. However, it is an empirical fact that demand is currently very price-inelastic in Europe and possible future demand elasticities are hard to estimate. Technological change is not modeled, such that generation technologies do not adapt to VRE variability. Not accounting for these possible sources of flexibility potentially leads to a downward-bias of optimal VRE shares. Hence, results can be interpreted as conservative estimates.

EMMA is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. In a back-testing exercise, model output was compared to historical market data from 2008–10. Crucial features of the power market can be replicated fairly well, like price level, price spreads, interconnector flows, peak / off-peak spreads, the capacity and generation mix.

4.2 Input Data

Electricity demand, heat demand, and wind and solar profiles are specified for each hour and region. Historical data from the same year (2010) are used for these time series to preserve empirical temporal and spatial correlation of and between parameter as well as other statistical properties. These properties and correlations crucially determine the optimal VRE share. VRE profiles are based on historical weather data from the reanalysis model ERA-Interim and aggregate power curves are used to derive profiles. Load data were taken from ENTSO-E. Heat profiles are based on ambient temperature. Based on Hirth & Ziegenhagen (2013), we assume a balancing reserve requirement of 10% of peak load plus 5% of installed VRE capacity. Based on a literature survey by Hirth et al. (2013), balancing costs for wind and solar were assumed to be 4 €/MWh, independent of the penetration rate.

Fixed and variable generation costs are based on IEA & NEA (2010), VGB Powertech (2011), Black & Veatch (2012), and Schröder et al. (2013). Fuel prices are average 2010 (not 2011) European market prices, 9 €/MWh$_t$ for hard coal and 18 €/MWh$_t$ for natural gas, and the CO_2 price is 20 €/t. Summer 2010 NTC values from ENTSO-E were used to limit interconnection capacity. CHP capacity and generation is from Eurelectric (2011b). A discount rate of 7% in real terms is used for all investments, including transmission, storage and VRE.

For wind power we assume investment costs of 1300 €/kW and O&M costs of 25 €/kWa. At 2000 full load hours, as in Germany, this equals LEC of 68 €/MWh. The corresponding numbers for solar power are 1600 €/kW, 15 €/kW and 180 €/MWh. Learning and resource constraints are assumed to roughly offset each other such that wind and solar supply curves are flat.

4.3 Representing Different Aspects of Variability in EMMA

EMMA models endogenously important aspects of the three dimensions of heterogeneity of electricity and correspondingly the costs of VRE variability. Most importantly, the model features an hourly resolution, uses high-quality hourly input data, and accounts for several restrictions that limit the flexibility of the rest of the power system. In other words, the model accounts quite well for profile costs. Other costs of variability are added as cost mark-ups, as proposed in section 2.3.

However, other aspects are only modeled quite roughly. Geographically, EMMA features only moderate granular detail of countries. International trade is constrained, but internal grid restrictions are not modeled. Furthermore, trade is restricted by NTCs and physical load flows are not modeled. Schumacher (2013) estimates grid-related costs to be small in Germany both for wind and solar, hence we set them to zero.

Forecast errors are not modeled explicitly. EMMA features a spinning reserve requirement that is a function of installed VRE capacity. In addition, VRE generators pay for reserve activation in form of a constant balancing cost charge of 4 €/MWh.

4.4 Optimality at Different Time Horizons

The optimal share of VRE depends crucially on how flexibly the model is allowed to adjust (Ueckerdt et al. 2013a, Baker et al. 2013). A crucial point is the previously-existing capital stock, where the literature uses three different approaches.

One option is to take the existing generation and transmission infrastructure as given and disregard any changes. The optimization reduces to a sole dispatch problem. We label this the *short-term* perspective. Another possibility is to disregard any existing infrastructure and optimize the electricity system "from scratch" as if all capacity was green-field investment. This is the *long-term* perspective. Finally, one can take the existing infrastructure as given, but allow for endogenous investments and disinvestments. We call this the *medium term*. Note that the expressions short term and long term are *not* used to distinguish the time scale on which dispatch and investment decisions take place, but refer to the way the capital stock is treated. While all three time horizons are analytical concepts that never describe reality entirely correctly, we believe the long term as defined here is a useful assumption to analyze European power systems in 2030 and beyond. In systems with a higher rate of capital turnover the assumption might be quite valid already in 2020.

In section 5 we present mid-term and long-term results. Typically the long-term optimal share of VRE is higher than the mid-term value, since only in the long-term VRE saves capital costs.

For the short, mid, and long-term framework corresponding welfare optima exists, which are, absent of market failures, identical to the corresponding market equilibria. It is only in the long-term equilibrium that all profits are zero, including those of wind and solar power (Steiner 1957, Boiteux 1960, Crew et al. 1995). EMMA estimates the short, mid, or long-term equilibrium, but not the transition path towards the equilibrium or out-of-equilibrium situations.

5. NUMERICAL RESULTS

In this section we use EMMA to estimate the optimal amount of wind and solar power at various levels of cost reduction of up to 30% for wind and 60% for solar. For each cost level, the power system is optimized, including wind and solar capacity. Results are mostly reported as optimal shares of total electricity consumption. We focus on long-term optima, but also discuss the medium term in 5.7. The impact of different aspects of variability is reported and the effects of a number of price, policy, and technology shocks are examined. All findings should be interpreted cautiously, keeping model and data limitations in mind that have been highlighted in sections 3 and 4.

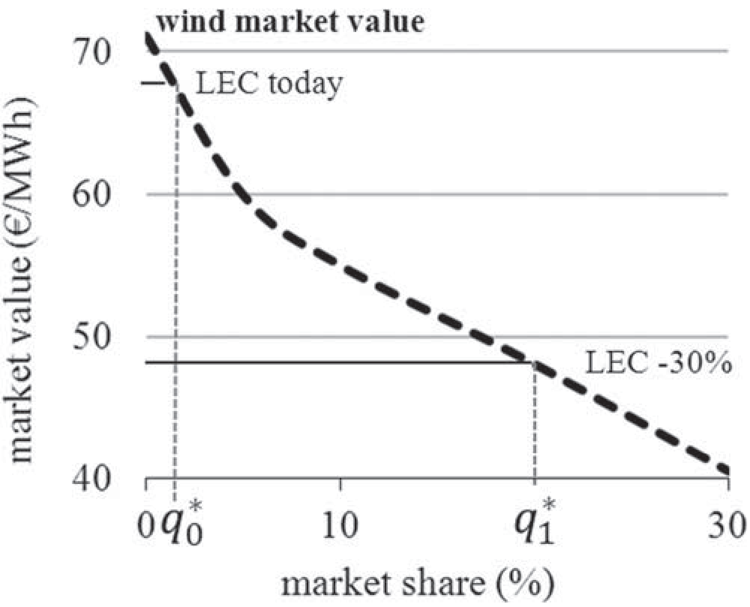
Assuming that onshore wind costs can be reduced by 30% to 50 €/MWh in the long term, we find that the optimal wind share on Northwestern Europe is around 20%, three times today's level, but lower than some policy targets. In contrast, even with solar costs 60% below today's levels to 70 €/MWh, the optimal solar share would be close to zero. We find that variability dramatically impacts the optimal wind share. Specifically, temporal variability has a huge impact on these results: if winds were constant (flat), the optimal share would triple. In contrast, forecast errors have only a moderate impact: without balancing costs, the optimal share would increase by less than half. The large impact of variability indicates that models that cannot represent variability explicitly need to approximate it carefully, and it implies that analyses which ignore variability are strongly biased. These "benchmark" results assume 2011 market prices for inputs and full availability of all generation technology options.

We then assess the effect of three shocks that are often seen as major determinants of VRE deployment: climate policy, technical integration measures, and fuel prices. We find that they do not change the picture qualitatively. Carbon pricing and higher fuel price can have a moderate positive impact on optimal wind shares, but sometimes even *reduce* it as they trigger baseload investments; storage has an insignificant impact; the impact of interconnector expansion and new turbine technology is positive, but moderate in size; flexibilizing thermal plants has the largest impact. The one case where we find very high optimal VRE shares (45% wind plus 15% solar) is a combination of high carbon prices and unavailability of the low-carbon technologies nuclear power and CCS.

5.1 Optimal Wind Share

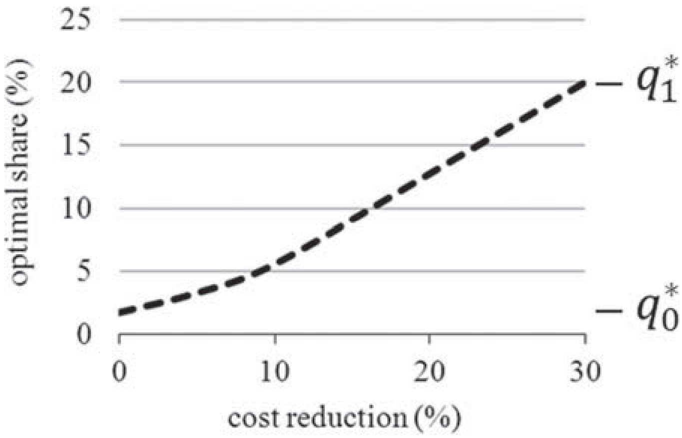
The long-term market value of wind power is displayed in Figure 6. As theoretically discussed in section 2.3 and empirically estimated in Hirth (2013), the market value is a downward-sloping function of wind penetration: it drops from about 71 €/MWh at low penetration to 40 €/MWh at 30% penetration. The intersection of the market value curve with LEC characterizes the optimal wind share. The demand-weighted average price declines, but only slightly from 76 €/MWh to 71 €/MWh.

Figure 6: Wind's Market Value Falls with Penetration



Notes: The intersection between LEC and market value gives the optimal share (section 2.4). At LEC of 68 €/MWh the optimal share is around 2%; if generation costs fall by 30%, the optimal share is about 20%.

Figure 7: The Optimal Share of Wind Power in Total Electricity Consumption as Function of Wind Power Cost Reduction under Benchmark Assumptions



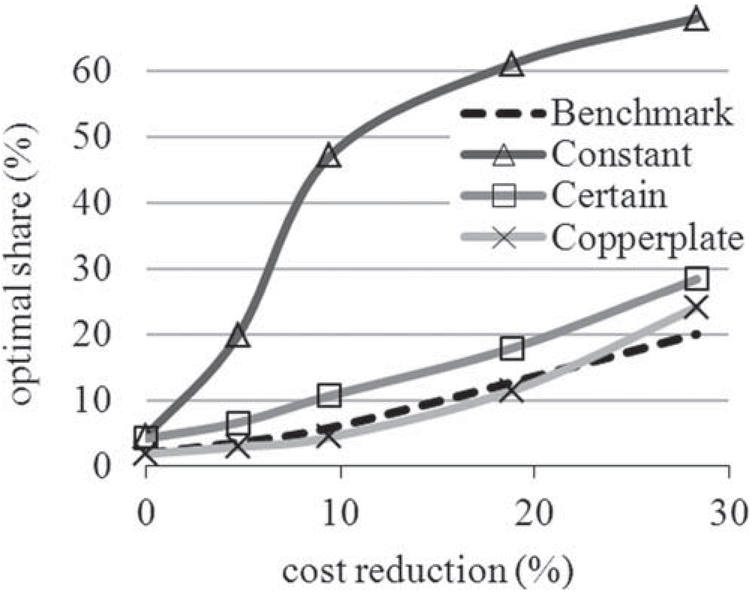
Notes: In Northwestern Europe, the share increases from 2% to 20%.

Figure 7 shows the optimal share as a function of decreasing costs ("optimality frontier"). At current cost levels of about 68 €/MWh, only marginal amounts of capacity are competitive in Northwestern Europe. However, if costs decrease by 30% to 48 €/MWh, wind power optimally supplies 20% of Northwestern European electricity consumptions, three times as much as today. In other words, if deployment subsidies are phased out, wind power will continue to grow, but only if costs decrease. We use these results that are based on best-guess parameter assumptions as benchmark.

5.2 Optimal Solar Share

Solar power has a marginal value of about 75 €/MWh at low penetration, compared to LEC of currently 180 €/MWh, hence its optimal share is zero. We model cost reductions of up to

Figure 8: The Impact of Temporal Variability and Forecast Errors



60% (LEC of 70 €/MWh), but even then the optimal share is small (2%). However, in a few cases solar becomes competitive in significant amounts (section 5.5). Otherwise we will focus on wind power in the remainder of the section due to space constraints.

Some authors claim that solar power becomes competitive once it reaches "grid parity", which is usually understood as costs falling below end-consumer price. However, grid parity has little to do with economic efficiency. Not only does this measure ignore electricity price heterogeneity (recall section 2), but also that retail electricity prices comprise mainly taxes, levies, and grid fees. Since decentralized solar generation saves at best marginal amounts of grid costs, the market value is the appropriate electricity price to evaluate solar power with (Hirth 2014).

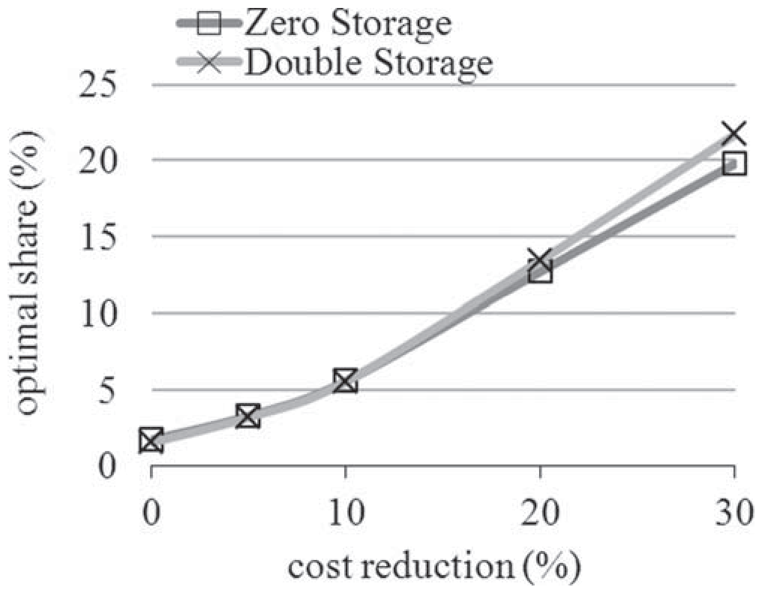
5.3 The Impact of Variability

As laid out in section 2, different aspects of variability impact the optimal amount of VRE capacity. Here we quantify two of them, temporal variability and forecast errors. EMMA lacks a representation of the transmission grid, such that the impact of locational constraints on the optimal share cannot be assessed. We find that variability has a dramatic impact (Figure 8). If wind generation was constant, its optimal share would rise above 60%. The impact of forecast errors is much smaller: switching off the reserve requirement and balancing costs increases the optimal share by only eight percentage points. This endorses previous findings that temporal variability is significantly more important for welfare analysis than uncertainty-driven balancing (Mills & Wiser 2012, Hirth et al. 2013). Relaxing grid connections has minor impact, but recall that only cross-border constraints were taken into account in the first place. These findings indicate how dramatically results can be biased if variability is ignored.

5.4 The Impact of Integration Options

Many technical measures have been proposed to better integrate VRE into power systems, and specifically, to alleviate the drop of market value. Electricity storage, interconnector capacity,

Figure 9: The Effect of Storage Capacity



Notes: Storage has a very small effect on optimal wind deployment.

more flexible thermal plants, and a different design of wind turbines are the most prominent (Mills & Wiser 2013, Hirth & Ueckerdt 2013b).

Both storage and interconnector capacity are endogenous to the model and hence deployed at their optimal level in the benchmark run. Here we test their impact of optimal wind shares by setting their capacities exogenously to zero and twice current capacity.

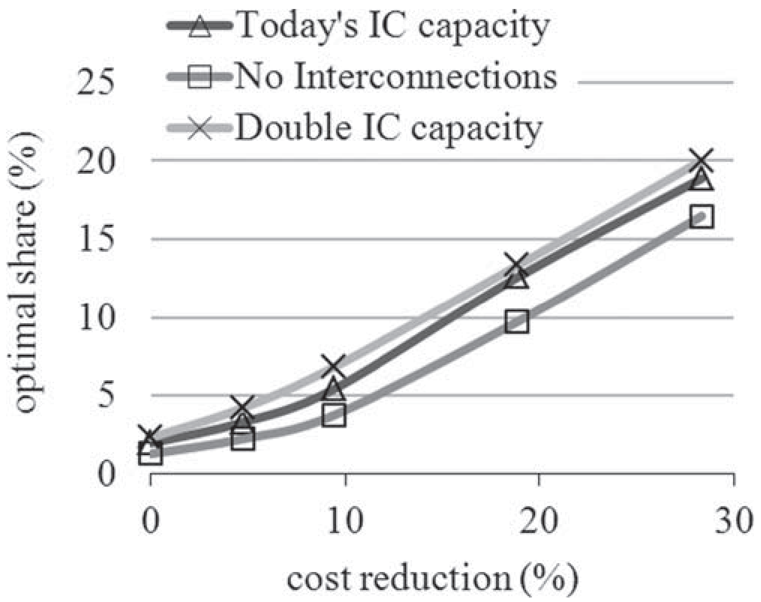
The first surprising result: wind deployment is only slightly affected by pumped hydro storage capacity (Figure 9). Doubling storage capacity from existing levels results in an optimal share of 22%, setting storage capacities to zero results in 20%. This option would cost about € 1.4bn per year. The driver behind this outcome, besides the fact that doubling storage capacity means adding relatively little capacity compared to installed wind capacity, is the design of pumped hydro plants. They are usually designed to fill the reservoir in about eight hours while wind fluctuations occur mainly on longer time scales. Thus wind requires a storage technology that has a large energy-to-power ratio than pumped hydro storage.

Higher long-distance transmission capacity helps to balance out fluctuations in VRE generation profiles and allows building where resources are best. Doubling interconnector capacity gives a four percentage point higher optimal wind share than setting interconnector capacity to zero (Figure 10). This measure would cost about € 0.8bn per year. Hence, in terms of increased penetration per Euro, interconnector investments are several times more efficient as wind power integration measure than storage investments.

Technical inflexibility of thermal plants impacts electricity prices and reduces the optimal share of VRE. EMMA features two important must-run constraints for thermal plants, CHP generation and ancillary service provision. Heat storages or heat-only boiler can be used to dispatch CHP plants more flexibly. Batteries, consumer appliances, or power electronics could help supplying ancillary services. Figure 11 shows the effect of taking these constraints out. Switching off CHP must-run increases the optimal share by three percentage points, switching off the ancillary service constraint by three percentage points, and both constraints by five points.

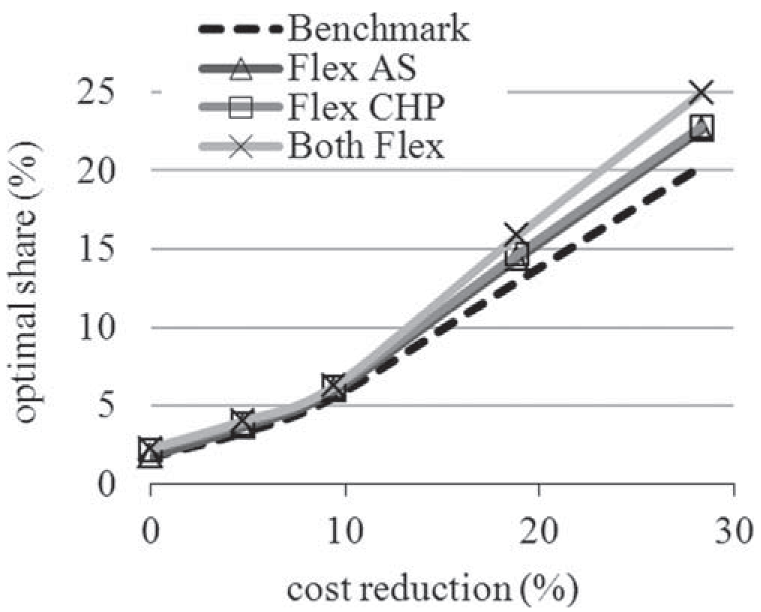
Wind turbine technology is still evolving quickly (IEA 2012, MAKE 2013). Low wind-speed turbines with higher hub heights and larger turbine-to-generator ratios have entered the mar-

Figure 10: The Effect of Interconnector Capacity



Notes: Interconnection capacity has a moderate impact on optimal wind deployment at all wind cost levels.

Figure 11: The Effect of Thermal Plant Flexibility

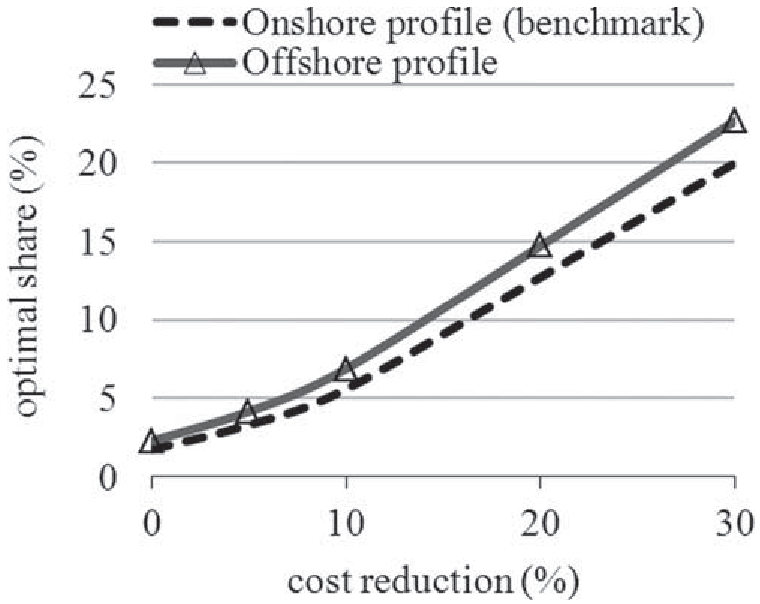


Notes: More flexible thermal plants quite strongly increase optimal wind deployment, especially at high cost reduction levels.

ket, resulting in flatter generation profiles. We tested the impact of flatter profiles by using a more steady offshore profile (without changing costs). As a consequence, the optimal share rises by almost three percentage points (Figure 12). Assessing the cost of thermal plant flexibilization and advanced wind turbine is beyond the scope of this analysis.

All integration measures increase the optimal wind share. The impact of doubling storage capacity on optimal wind deployment is very small, the impact of doubling interconnector capacity and changing the wind generation profile is moderate, and the impact of thermal plant flexibility is

Figure 12: The Effect of a Flatter Profile



Notes: A flatter generation profile increases optimal deployment moderately, but only at high cost reduction levels.

quite large. This does neither imply that these measures should be ignored or should be pursued, nor does it imply a ranking between these three options, as each measure comes at a cost. However, comparing storage and interconnector capacity in terms of cost and impact on wind deployment it seems that interconnector expansion is a more efficient integration option.

5.5 The Impact of Climate Policy

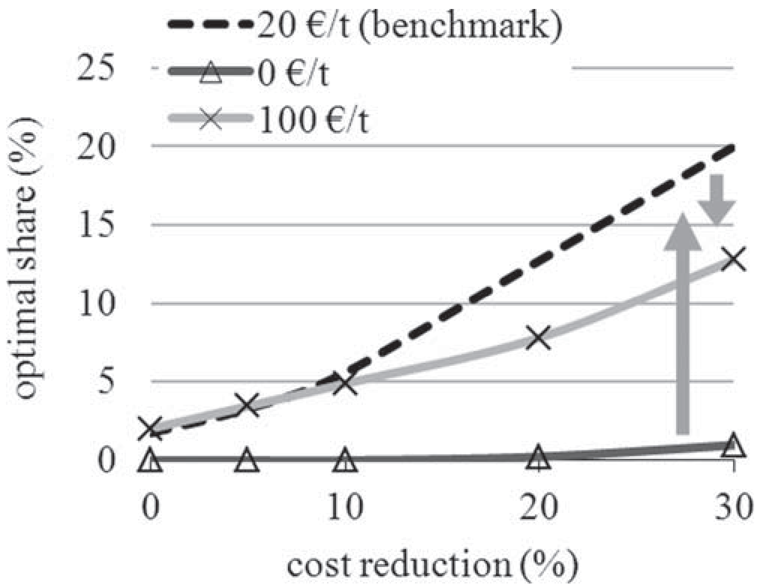
Many observers suggest that CO_2 pricing has a positive and significant impact on VRE competitiveness. Many European market actors argue that during the 2020s, renewable subsidies should be phased out, and expect VRE to continue to grow, driven by carbon prices. We estimate the optimal wind share at different CO_2 prices.

Figure 13 displays the optimal wind share at prices of 0 €/t, 20 €/t, and 100 €/t. As one would expect, a CO_2 price of zero results in less deployment than the benchmark price of 20 €/t. Lower costs of emitting plants reduce the marginal value of wind power, and optimal deployment is close to zero.

Yet increasing the CO_2 price further, from 20 €/t 100 €/t, shows a surprising result: wind deployment is *reduced*. Figure 14 shows in more detail the non-monotonic effect of CO_2 pricing on VRE deployment, assuming high cost reductions: the optimal wind share increases initially steeply with higher CO_2 prices, peaks at 40 €/t, and decreases afterwards. The optimal solar share rises until 40 €/t and remains relatively flat afterwards, such that the compound VRE share always remains below 25% and even decreases to 15% at 180 €/t CO_2. This might look counterintuitive at first glance.

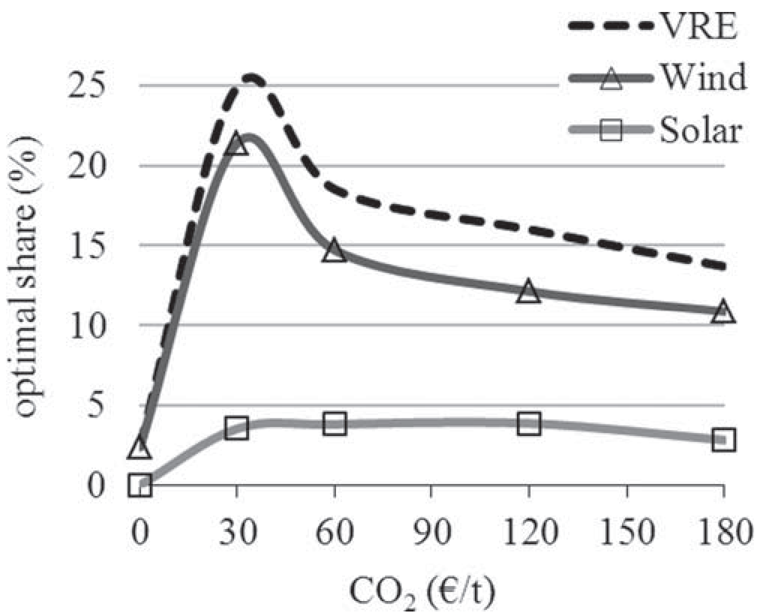
The reason for this surprising behavior is investments in competing low-carbon technologies. Nuclear power and CCS are the only dispatchable low-carbon technologies in the model, and these two are base load technologies with very high investment, but very low variable costs. Baseload capacity reduces the marginal value of VRE and hence its optimal share. Carbon prices below 40 €/t do not trigger any nuclear or CCS investments, such that up to that point carbon

Figure 13: Optimal Wind Share under Different CO_2 Prices



Notes: Arrows indicate how curves shift as carbon prices increase.

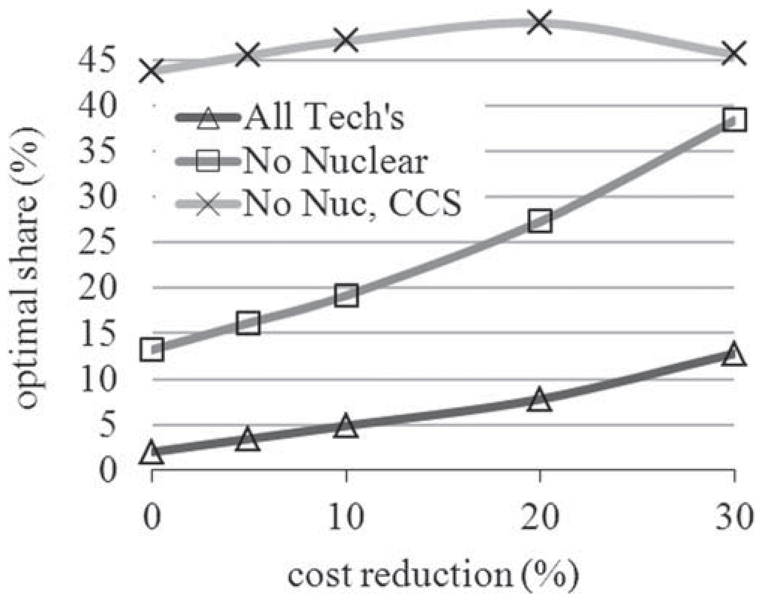
Figure 14: Optimal Wind and Solar Share under Different CO_2 Prices, Assuming High Cost Reduction



Notes: Shares increase with the carbon price up to the point where low-carbon baseload investments become profitable and decrease afterwards.

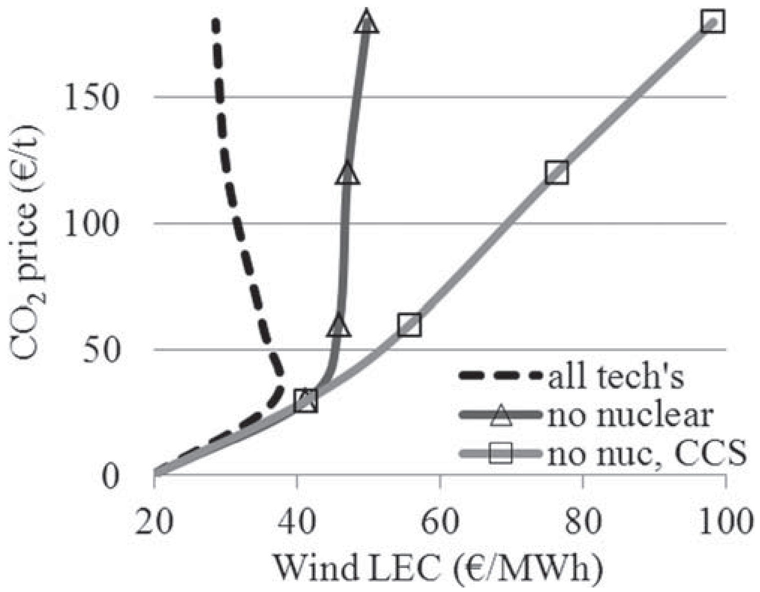
pricing has a positive impact of VRE via higher costs of emitting plants. Beyond 40 €/t, the baseload investment effect dominates the emission cost effect. To benefit from stricter climate policy, VRE technologies would need low-carbon mid and peak load generators as counterparts. In this context it is important to recall that generation from biomass is not included in the model. If biomass would be available sustainably in large volumes, it could fill this gap and possible change results significantly.

Figure 15: Optimal Wind Share under 100 €/tCO_2 and Different Technology Assumptions



Notes: Excluding low-carbon alternatives leads to dramatically higher shares of wind (and solar) power. The top line decreases because solar power investments are triggered. The combined VRE share keeps rising with cost reductions.

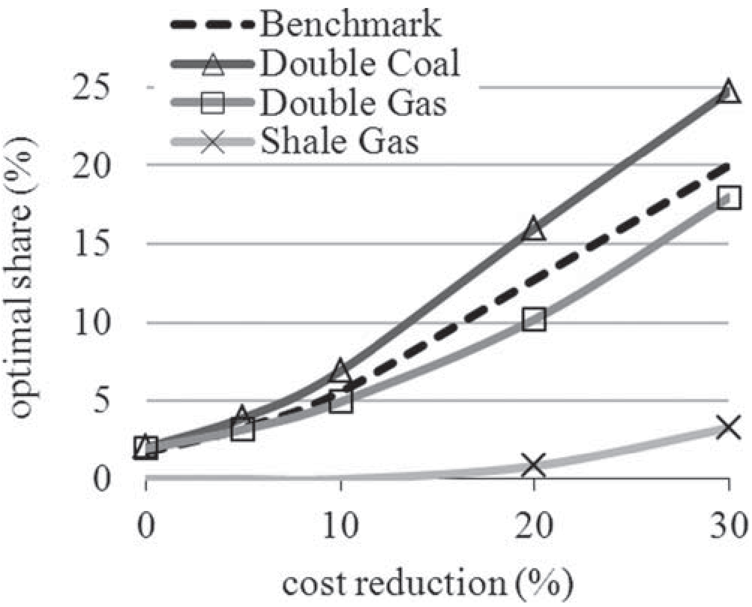
Figure 16: Contour Plot of the 40% Wind Share



Notes: The lines indicate which LEC / CO_2 price combination would be needed to achieve 40% wind penetration without wind subsidies. Above/left of the lines wind penetration is above 40%, below/right of the lines it is below 40%. Without restrictions on technologies, wind LEC need to fall below 40 €/MWh to trigger 40% penetration, no matter what the CO_2 price is. The investment cost for nuclear is 4000 €/kW.

Of course this effect can only appear if investments in nuclear and/or CCS are possible. However, uncertainty around costs, safety, waste disposal, and public acceptance could imply that these technologies are only available at prohibitive costs. Without nuclear power, the optimal wind share doubles at 100 €/t CO_2 and without both technologies it reaches more than 45% market share (Figure 15). In addition, the optimal solar share reaches 15%, such that VRE would supply almost

Figure 17: The Effect of Fuel Price Shocks



Notes: As expected, lower gas prices reduce and higher coal prices increase the optimal wind share. However, higher gas prices *reduce* the optimal share. The reason is the investments in baseload technologies triggered by high gas prices.

two thirds of electricity. However, the unavailability of nuclear and CCS comes at the price of increased emissions and welfare losses: CO_2 emissions increase by 100–200% (depending on VRE cost reductions), the electricity price increases by 15–35%, and total system costs by 13–25%. In absolute terms, welfare is reduced by 15–30 €bn per year, which would increase if the assumption of price-inelastic demand was relaxed.

Figure 16 shows which combination of LEC and carbon price would be needed to trigger a 40% wind market share in a contour plot.

Several conclusions can be drawn regarding the effect of CO_2 pricing on the optimal amount of VRE deployment: while increasing the CO_2 price from low levels increases optimal VRE shares, increasing it further reduces VRE deployment. The price that maximizes wind deployment is around 40 €/t, just before nuclear investments are triggered. Carbon pricing is not able to drive up the VRE share above 25%. These findings are obviously sensitive to the availability of alternative low-carbon generation technologies: excluding base load technologies like nuclear and CCS helps wind and solar dramatically. In general, this section indicates how important it is to take the adjustment of the capital stock into account when evaluation policies.

5.6 The Impact of Fuel Prices and Investment Costs

Rising fuel prices are often believed to drive renewables expansion. At first glance, the situation seems to be straightforward: higher input prices increase the costs of fossil generation, and hence increase the marginal value of competing technologies including VRE. In this subsection, hard coal and natural gas prices are varied to understand the effect of higher fossil fuel prices on optimal VRE deployment. As in the case of CO_2 pricing, results might come as a surprise.

Increasing the price of coal has the expected effect: doubling coal prices increases optimal wind deployment by about five percentage points (Figure 17). Lowering gas prices by half (“shale gas”) has a similarly expected effect, dramatically lowering optimal wind deployment. Surprisingly

Table 3: Price Elasticities at the Benchmark

	w.r.t. coal price	w.r.t. gas price
Coal generation	−3.9	0.5
Gas generation	1.5	−4.9
Wind generation	1.0	−0.2

however, doubling gas prices *reduces* the optimal wind share. As in the case of CO_2 pricing, the reason for this seemingly counterintuitive result can be found in the capital stock response to the price shock. Higher gas prices induce investments in hard coal, which has lower variable costs, reducing the value of wind power and its optimal deployment.

In economic terms, gas-fired mid- and peak-load plants are complementary technologies to VRE, since they efficiently "fill the gap" during times of little renewable generation. Hence, one can think of gas and wind generators as a gas/wind "package". Coal plants are a substitute technology to the gas/wind package. Increasing coal prices increases both the share of gas and wind. Increase gas prices increases the share of coal and reduces the share of gas/wind. Of course, wind becomes more competitive versus gas as well, but this effect is too weak to make wind benefit from higher gas prices. This can also be expressed in terms of own-price and cross-price elasticities (Table 3). The elasticity of wind generation with respect to the coal price is positive, but the elasticity with respect to the gas price is negative.

The cost of large investment projects is subject to high uncertainty, because projects are seldom conducted. Small, more industrialized projects can be assessed with more certainty because of more experience. Hence, uncertainty of nuclear investment cost is much higher than of wind or solar investment cost, where modularity and the high number of units allow reliable cost assessment. This is reflected in the broad range of cost estimates reported in the literature (section 4.2) and in a higher discount rate for technologies with little investment experience (Oxera 2011). If capital costs of thermal plants are 50% higher than assumed in the benchmark, either because of higher investment costs or a higher discount rate, the optimal wind share jumps by 13 percentage points (Figure 18).

5.7 Mid-term: Accounting for Today's Power Plants

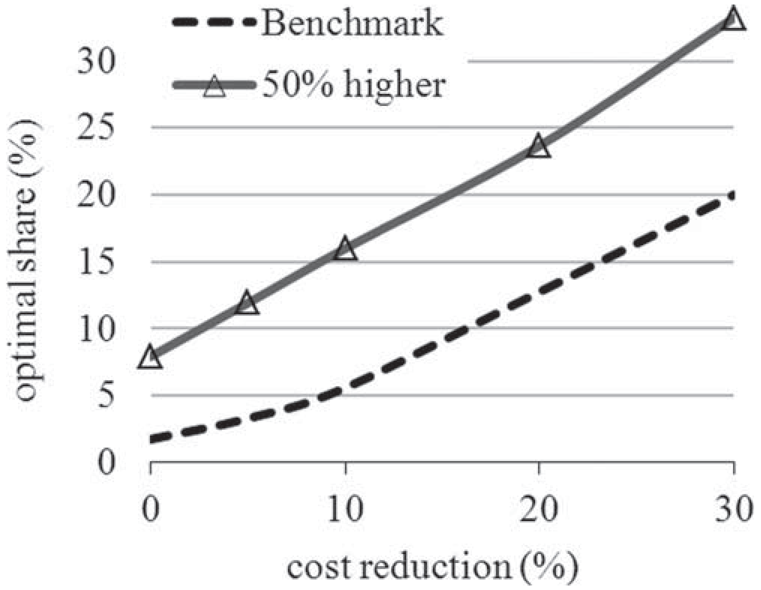
All results of sections 5.1 to 5.6 are long-term optimal wind shares. In this subsection, we briefly discuss the optimal wind shares in the medium term, when the existing capital stock (plants, storage, interconnectors) is taken into account and modeled as sunk investments.

Typically, the optimal wind share is much lower in the mid-term than in the long-term. The reason is straightforward: in the mid-term, wind only reduces fuel and other variable costs, while in the long-term it also reduces capital costs (section 4.4). The benchmark optimal share is 7% at 30% cost reduction, less than half of the long-term share. The impact of variability and integration options is qualitatively similar, but much smaller in size. In contrast to the long term, increasing the CO_2 price from 20 €/t to 100 €/t increase the optimal share in the medium term, because the capacity mix adjusts much less. For the same reason, higher gas prices have virtually no impact in the medium term.

6. DISCUSSION OF NUMERICAL RESULTS

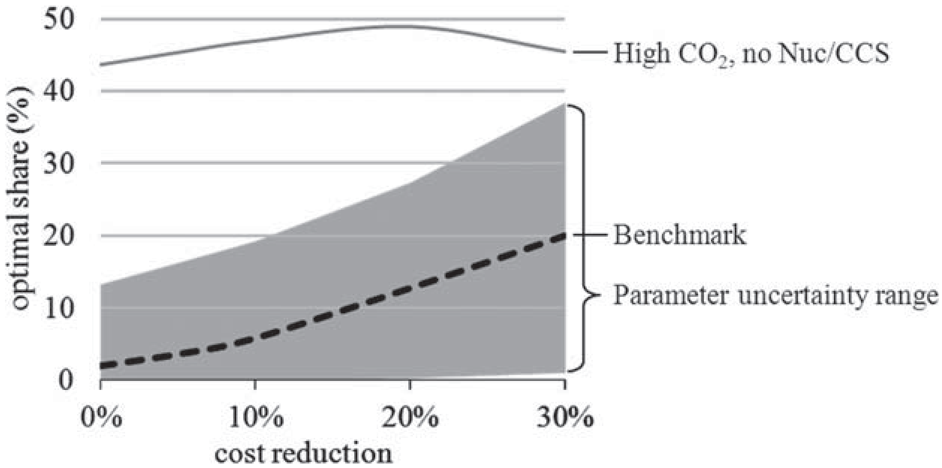
All numerical findings should be interpreted cautiously, since the applied methodology has important shortcomings that potentially bias the results. Being a regional partial equilibrium model,

Figure 18: The Impact of Thermal Plants' Investment Cost is Dramatic



Notes: This indicates high parameter uncertainty of model results.

Figure 19: Long-term Optimal Wind Shares in the Benchmark Run and the Range of All Sensitivities



Notes: The range does not include the noNucCC run at 100 €/t, where the optimal wind share is above 40%.

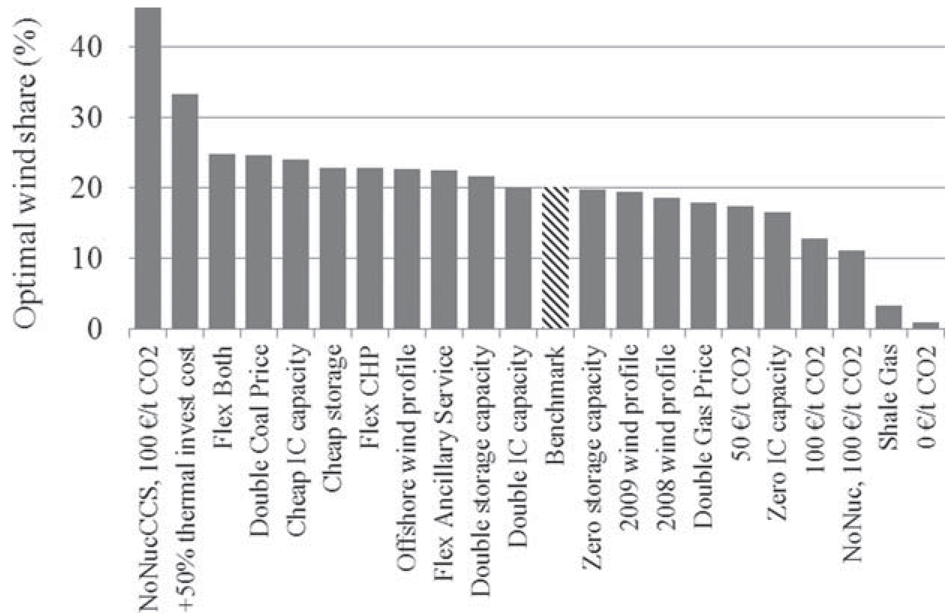
the power market model EMMA does not account for endogenous learning or wind and solar resource supply curves. Moreover, it disregards hydro reservoirs, demand elasticity and internal grid bottlenecks. Taken together, these factors might result in a moderate downward bias on the estimated optimal share, meaning that our results can be read as conservative estimates.

This section first summarizes the numerical findings, then discusses the impact of sub-optimal wind shares on welfare, and finally compares findings to previously published studies.

6.1 Summarizing Findings

Figure 19 summarizes the optimal long-term share of wind power in Northwestern Europe under all tested parameter assumptions (not including section 5.3). There is large uncertainty about

Figure 20: Comparing All Sensitivity Runs for 30% Cost Reductions



Notes: Sixteen out of twenty runs are in the range of 16%–25% optimal share.

the optimal wind share driven by parameter uncertainty (1%–45% at low costs). Our benchmark assumptions fall in the middle of this range. Additional uncertainty might be introduced by model uncertainty, or by parameters that have not been tested here. Moreover, cost reductions play a crucial role. At current cost levels, the optimal benchmark market share is 2%, with a range of 0%–13%. Reducing wind power's levelized electricity costs is crucial to introduce significant volumes of wind power competitively. If costs can be decreased by 30%, we estimate the competitive share at 20%, which is roughly three times today's level. In other words, wind power can be expected to keep growing even without subsidies—but only if costs come down.

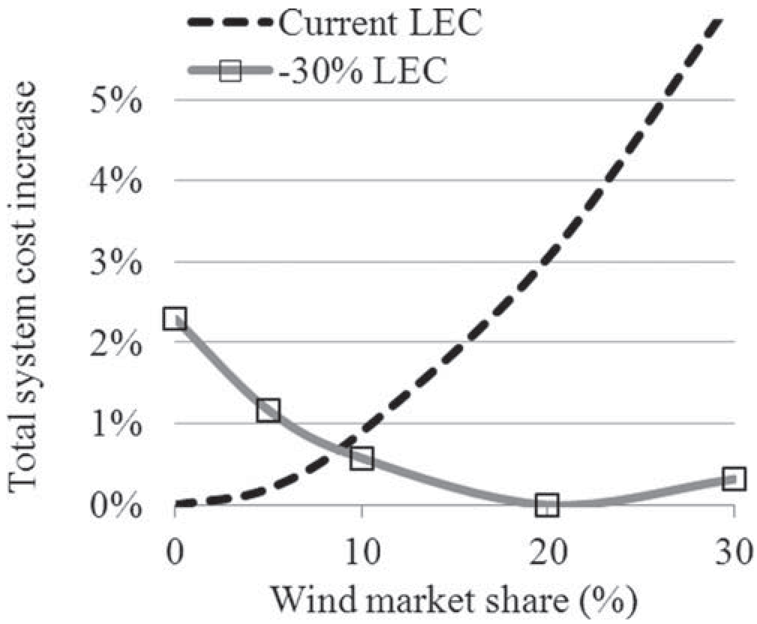
Figure 20 displays the optimal wind share at 30% cost reduction for all model runs. In 16 out of 20 runs, the share is between 16% and 25%, indicating somewhat more robust results than Figure 19 might suggest.

The results for solar are more disappointing: even at 60% cost reduction, the optimal solar share is below 4% in all but very few cases. This is consistent with previous findings that the marginal value of solar power drops steeply with penetration, because solar radiation is concentrated in few hours (Nicolosi 2012, Mills & Wiser 2012, Hirth 2013). In regions that are close to the equator, the optimal solar share might be significant higher, both because levelized costs are lower and the generation profile is flatter. In 5.3 and 5.4 we presented results for wind power that show how dramatic the impact of a flatter profile can be.

6.2 What is the Cost of Sub-optimal Shares?

Given the large uncertainty, it is likely that realized wind shares will ex post turn out to be sub-optimal, too high or too low. Here we briefly asses the costs of such sub-optimality. With perfectly inelastic demand, welfare losses are equivalent to increases in total system costs. Figure 21 displays the cost increase of sub-optimal wind shares for two cases: current cost levels and 30% lower costs. Total system costs increase moderately by 6% if instead of the optimal share of 2% a large share of 30% is installed. Similarly, costs increase by 2% if no wind is installed at low cost

Figure 21: Cost Increases for Suboptimal Wind Shares



Notes: Under wind current costs, the optimal wind share is 2%; if instead 30% wind power is installed, total system costs increase by 6%. At low wind costs, the optimal share is 20%; if no wind is build, system costs would be 2% higher than in the optimum.

Table 4: Comparing Müsgens (2013), Eurelectric (2013), and the Present Study

	CO_2 price	Nuclear assumptions	Wind share
Müsgens (2013)	110 €/t	restricted to current level in country without phase-out	~40%
PowerChoices Reloaded	300 €/t	restricted to country without phase-out	~30%
This study	100 €/t	no nuclear allowed	~45%

despite an optimal share of 20%. One percentage point of total costs is about € 1bn in absolute terms, or € 0.8 per consumed MWh of electricity. Note that welfare costs would be in general higher if demand is modeled price-elastically, because of the resulting quantity reactions.

As discussed in section 5.5, excluding nuclear and CCS from the set of possible technologies increases total system costs by 13–25% under strict climate policy. Hence such a ban would be more costly than targeting sub-optimal wind shares.

6.3 Comparing with Other Studies: When do VRE Shares become Very High?

Some policy makers have formulated very ambitious VRE targets (European Commission 2011). Only in one model run, this study found such high shares to be optimal: a combination of strict climate policy (a CO_2 price of 100 €/t) with a restriction of low-carbon base load generators (nuclear and CCS).

We compare this finding to two recent studies that have very high VRE shares to be optimal, Müsgens (2013) and PRIMES-based PowerChoices Reloaded (Eurelectric 2013). It turns out that these studies also assume these two conditions to be simultaneously fulfilled (Table 4). It seems a quite robust finding that very high VRE shares (>50%) are only optimal if those two premises are all satisfied. If they are, the cost level of wind and solar power does not seem to play a crucial role.

7. CONCLUSION

The theoretical analysis of section 2 showed that electricity is a heterogeneous good along three dimensions: time, space, and uncertainty. As a consequence, wind and solar variability affects welfare analyses. Ignoring variability leads to biased estimates of the welfare-optimal amount of VRE capacity.

The literature review of section 3 surveyed three classes of models that are in practice used to estimate the optimal VRE share: integrated assessment models, energy system models, and extended power market models. IAMs are appropriate tools to account for technological learning and global commodity markets. Energy system models are strong when it comes to estimating electricity demand and wind and solar resource supply curves. However, both model classes have a too coarse resolution to explicitly represent variability. Power market models provide sufficient details, but are seldom used to optimize VRE capacity endogenously.

The power market model EMMA was applied in section 5 to estimate the optimal share of wind and solar power. Assuming that onshore wind costs can be reduced to 50 €/MWh, we find the optimal wind share in Northwestern Europe to be around 20%. In contrast, even under further dramatic cost reductions, the optimal solar share would be close to zero. We find that variability dramatically impacts the optimal wind share. Specifically, temporal variability has a huge impact on these results: if winds were constant, the optimal share would triple. In contrast, forecast errors have only a moderate impact: without balancing costs, the optimal share would increase by eight percentage points.

In terms of methodological conclusions, both section 2 and section 5 show that variability significantly impacts the optimal share of wind and solar power. Models and analyses that cannot represent variability explicitly need to approximate the impact of variability carefully. Furthermore, while both a long-term and a mid-term perspective have their merits, the stark differences in results indicate how important it is to be explicit about the time scale on which analysis takes place. Finally, several findings of section 5 are counter-intuitive at first glance, underlining the necessity for rigorous analytical methods that can challenge intuition and conventional wisdom. Specifically, numerical models are needed to capture adjustments of the capital stock and policy interaction.

In terms of policy conclusions, the numerical results point out the important role of onshore wind power as a competitive electricity generation technology. The long-term benchmark estimate of a market share of 20% is equivalent to three times as much wind power as today. However, the share would be higher if low-carbon mid and peak load technologies were available to supplement VRE in the transition to a low-carbon electricity sector. Biomass as well as high-efficient gas-fired plants could play a crucial role in this respect. A second conclusion is that different wind turbine layouts with larger rotors relative to generator capacity could be quite beneficial, since they provide a flatter generation profile. Finally, system flexibility is key to achieve high VRE shares. Must-run units that provide heat or ancillary service severely limit the benefits of VRE. Relaxing these constraints through technological innovation increases optimal wind deployment, as does increasing interconnector capacity.

Significant methodological gaps have been identified that should be filled by future research. On the one hand, integrated modeling of hydro-thermal systems and a more explicit modeling of transmission grids are promising fields for power market model development. On the other hand, developing methods of how to integrate variability into large-scale, coarse models is needed to account for all significant drivers of optimal VRE quantities. These are necessary conditions before final conclusions on optimal shares of variable renewables can be drawn.

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Chapter 6

Redistribution effects of energy and climate policy: The electricity market [*]

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Redistribution effects of energy and climate policy: The electricity market[☆]

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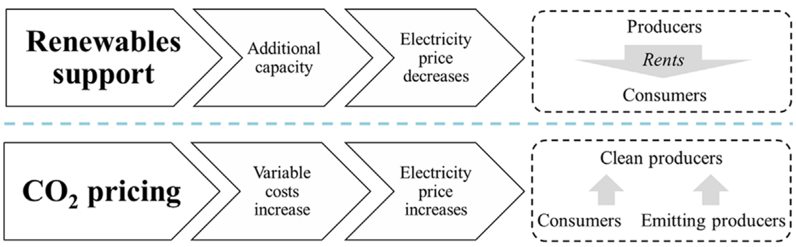
HIGHLIGHTS

- CO_2 pricing and renewables support have strikingly different impacts on rents.
- Carbon pricing increases producer surplus and decreases consumer surplus.
- Renewable support schemes (portfolio standards, feed-in tariffs) do the opposite.
- We model these impacts theoretically and quantify them for Europe.
- Redistribution of wealth is found to be significant in size.

GRAPHICAL ABSTRACT



Renewable support redistributes economic surplus from incumbent producers to consumers. CO_2 pricing does the opposite, but affects carbon-intensive and low-carbon technologies differently.

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ABSTRACT

Energy and climate policies are usually seen as measures to internalize externalities. However, as a side effect, the introduction of these policies redistributes wealth between consumers and producers, and within these groups. While redistribution is seldom the focus of the academic literature in energy economics, it plays a central role in public debates and policy decisions. This paper compares the distributional effects of two major electricity policies: support schemes for renewable energy sources, and CO_2 pricing. We find that the redistribution effects of both policies are large, and they work in opposed directions. While renewables support transfers wealth from producers to consumers, carbon pricing does the opposite. More specifically, we show that moderate amounts of wind subsidies can increase consumer surplus, even if consumers bear the subsidy costs. CO_2 pricing, in contrast, increases aggregated producer surplus, even without free allocation of emission allowances; however, not all types of producers benefit. These findings are derived from an analytical model of electricity markets, and a calibrated numerical model of Northwestern Europe. Our findings imply that if policy makers want to avoid large redistribution they might prefer a mix of policies, even if CO_2 pricing alone is the first-best climate policy in terms of allocative efficiency.

1. Introduction

Two of the major new policies that have been implemented in European, American, and other power markets during the last years are support for renewable energy generators and CO_2 pricing. Many countries have introduced support schemes for renewable electricity, such as feed-in-tariffs or renewable portfolio standards. As a consequence, the share of renewables in electricity generation has been growing rapidly (REN21, 2013; OECD/IEA,

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2013). In the European Union, it increased from 13% in 1997 to 17% in 2008, in Germany, from 4% to 23% within the last two decades. According to official targets, the share of renewables in EU electricity consumption shall reach 60–80% by 2050. The second major policy was the introduction of a price for CO_2. In Europe CO_2 pricing was implemented via an emission trading scheme in 2005, and several countries, regions, and states have followed. During the last 8 years, the European carbon price has fluctuated between zero and 30 €/t, with official expectations of prices between 100 €/t and 300 €/t by 2050.[1]

These new policies affect the profits of previously-existing (incumbent) electricity generators. More general, they redistribute economic surplus between producers and consumers and between different types of producers and consumers. Support policies bring renewable capacity in the market that decreases the wholesale electricity price below the level it would have been otherwise. For example, wind power has low variable costs and reduces the wholesale electricity price whenever it is windy. Lower electricity prices reduce the profits of existing generators and increase consumer surplus. If subsidy costs are passed on to consumers, the net effect on consumer surplus is ambiguous a priori.

CO_2 pricing increases the variable costs of carbon-emitting plants. Whenever such generators are price-setting, CO_2 pricing increases the electricity price. Low-carbon plants like nuclear and hydro power benefit from higher prices without having to pay for emission. Carbon-intensive generators like lignite, in contrast, see their profits reduced because costs increase more than revenues. Consumer surplus is reduced due to higher electricity prices, and increased if they receive the income from CO_2 revenues. Again the net effect on consumers is ambiguous.

Policy can impact producer rents only in the short term. In the long-term equilibrium, assuming perfect and complete markets, profits are always zero. Only if a market features some sort of inertia, and newly introduced policies are not fully anticipated, the policy impacts profits. We believe power markets to fulfill these two conditions.

In this paper, we model and quantify the redistribution effects of renewable support policies and CO_2 pricing, using an analytical (theoretical) and the numerical (empirical) model EMMA. We distinguish two sectors: incumbent generators with sunk investments, and electricity consumers. State revenues and expenditures are assumed to be passed on to consumers as lump-sum payments. Generators are further distinguished by technology, since the effect of CO_2 pricing on generators depends on their carbon intensity and the effect of renewable subsidies depends on their capital intensity. Disaggregating consumers could yield important insights, but is beyond the scope of this paper (see for example Neuhoff et al., 2013). Markets are assumed to be competitive, thus profits are zero in the long term. The modeling approach is valid for different types of CO_2 pricing (emission trading, carbon tax) and different types of renewables support (feed-in tariffs, renewable portfolio standards with or without certificate trading, investment grants, tax credits) and is in this sense very general. We use wind power as an example for a subsidized renewable electricity source, but all arguments apply to solar power and other zero marginal-cost technologies as well.

In our quantitative assessment of Northwestern Europe we find that the redistribution effects of both policies are large. Overall, wind support distributes surplus from producers to consumers and carbon pricing does the opposite. Wind support transfers enough producer rents to consumers to make those better off even if they pay the costs of subsidies. Wind support reduces the profits of base load generators more than those of peak load generators. CO_2 pricing reduces the profits of coal-fired generators, leaves those of gas plants largely unaffected, and increasing the rents of nuclear plants dramatically. As a group, electricity generators benefit from carbon pricing even without free allocation of emission permits.

We acknowledge that power markets feature a number of externalities that we ignore in this study. While CO_2 pricing has the clear objective of internalizing the costs of climate change, policy makers have put forward a multitude of motivations for renewable support. This paper does not assess these motivations, does not take into account externalities, and does not provide a cost–benefit analysis of these two policies or evaluates them against each other. Rather, our goal is merely to point out their peculiar effects regarding the redistribution of wealth. We focus here on the impact of two policies separately, and the joint impact. Interactions with existing or new policies, such as energy efficiency, are beyond the scope of this paper.

The next section reviews the literature. Section 3 presents the analytical framework and introduces the models. Section 4 discusses the effects of wind support, Section 5 those of carbon pricing, and Section 6 the compound effects of both policies. Section 7 concludes.

2. Literature review

Redistributive impacts of climate and energy policy have become a major topic in economics research during the last years. Redistributive flows between jurisdiction, between generations, and between resource owners vs. resource consumers have received much attention; see for example Bauer et al. (submitted for publication) on resource owners. Edenhofer et al. (2013) provides a broader survey of the issue. This paper adds to this literature by analyzing redistribution between firms and consumers via the electricity market.

Focusing on the narrower field of electricity policies, the present paper builds on three branches of the literature on implications of policy instruments: the “merit-order” literature, the “windfall profit” literature, and the “policy interaction” literature. The first branch focuses on the depressing effect of renewables generation on the electricity price, which has been termed “merit-order effect”. The second branch discusses the impact of carbon pricing on consumer and producer surplus, where increasing producer rents are sometimes labeled “windfall profits”. The third branch discusses the interaction between these two policies.

Attracting additional investments in (renewable) generation capacity depresses the electricity price below the level it would have been otherwise. Because the size of the drop depends on the shape of the merit-order curve, Sensfuß (2007) has termed this the “merit-order effect”. A number of papers model the price impact theoretically and numerically. Modeling exercises for the Nordic countries (Unger and Ahlgren, 2005), Germany (Sensfuß et al., 2008) and Spain (De Miera et al., 2008) indicate that the additional supply of electricity from wind power reduces the spot price so much that consumers are better off even if they have to bear the subsidy costs. Results for Denmark are less conclusive (Munksgaard and Morthorst, 2008). Based on a theoretical model, Fischer (2010) finds that the sign of the price impact depends on the relative elasticity of supply of fossil and renewable generation. MacCormack et al. (2010) find the merit-order effect to be larger when conventional generators have more market power because both the additional supply and the uncertainty introduced by wind power reduce the incentive to withhold capacity. While these studies apply numerical models, O’Mahoney and Denny (2011)

[1] 2050 targets are taken from the Energy Roadmap 2050 (European Commission, 2011).

and Gil et al. (2012) use regression analyses. Confirming model results, they find that both in Ireland and Spain the merit-order effect outweighs the subsidy costs for consumers. Mount et al. (2012) stresses the effect on producer profits and the "missing money" to finance capital costs from short-term profits. Wissen and Nicolosi (2008) and MacCormack et al. (2010) emphasize that the merit-order effect is only a short-term or "transient" phenomenon, since in the long-term equilibrium prices need to include capital costs. While the literature has collected an impressive amount of evidence, most of these papers are not explicit that the price is reduced by redistributing wealth from incumbent producers to consumers, and none accounts comprehensively for all redistribution and efficiency effects.

The second branch of literature deals with the redistribution effects of carbon taxes and emission trading schemes. Most of these studies are written in the context of discussions of different allocation rules for emission allowances. Typically, they model the impact of allocation rules on profits, and to what extent CO_2 costs can be passed through to consumers. A well-known result is that in the case of grandfathering large windfall profits for producers occur that are paid by consumers, for example reported by Bode (2006) and Sijm et al. (2006). Some authors find that the aggregated power generation sector benefits even if allowances are fully auctioned. This is shown for the UK (Martinez and Neuhoff, 2005) and for Northwestern Europe (Chen et al., 2008). Similarly, Burtraw et al. (2002) report for the US that only 9% of all allowances would need to be grandfathered to preserve total producer profits when introducing CO_2 certificates. In addition, Burtraw and Karen (2008) find that a number of US-electricity generators would benefit from emission trading even under full auctioning.

Finally, there is an established branch of the literature that discusses the interaction between CO_2 pricing and renewables support. It is found that these concurrent policies partly offset each other, in the sense that a more stringent renewable target reduces the CO_2 prices, and a more stringent CO_2 target reduces the prices of tradable green certificates (Unger and Ahlgren, 2005; Tsao et al., 2011). A perverse consequence is that more renewable support increases the supply of the most emission-intensive generators (Böhringer and Rosendahl, 2010). Because of lower allowance prices, wind support decreases electricity prices not only via the power market, but also via the carbon market (Rathmann, 2007). These publications focus on certificate markets, but do not compare both policies regarding their effect on the power market.

To the best of our knowledge, this is the first paper that comprehensively and consistently models and compares the redistribution effects of renewables support and CO_2 pricing. While previous studies do report effects on prices and sometimes on profits, they do not report consumer and producer surplus. We comprehensively account for all redistributive flows between actors such that they consistently add up. A newly developed framework that uses the long-term equilibrium as a benchmark is used to evaluate both policies consistently. This innovation is the main contribution to the literature.

Furthermore, combining an analytical with a numerical model allows us tracing the causal mechanisms as well as providing quantitative estimates where theoretical results are ambiguous. To the best of our knowledge, this is the first paper to provide an analytical model of redistribution via the electricity market. In addition, we allow for endogenous investment, a key gap in the literature identified by Tsao et al. (2011).

Finally, our numerical power market model takes into account a large number of technical side constraints and the intermittent character of wind power. This is crucial not only for quantifications, but also to understand the different impact on types of generating technologies.

3. Methodology

This section introduces the two models and outlines the framework in which we apply both models. The analytical model is meant to generate insights into the causal mechanisms of policy-induced redistribution effects. The numerical model EMMA quantifies redistribution flows for Northwestern European countries and provides results where analytical findings are ambiguous. Both models are applied within the same consistent framework that uses the long-term equilibrium as a starting point to compare the short-term impacts of both policies.

3.1. Framework

In a long-term equilibrium (LTE) on perfect and complete markets with free entry, profits (rents, producer surplus) are zero.[2] If a market features some sort of inertia and newly introduced policies are not fully anticipated, a policy shock displaces the system from its LTE. Only during the transition towards a new LTE the policy might change profits and thereby redistribute producer surplus to or from other actors. As MacCormack et al. (2010) put it, redistribution of producer surplus is a "transient phenomenon" that vanishes once the system has converged to the new LTE. In the power market, inertia is substantial due to long life times and building times of power plants and other infrastructure.

In this paper, we distinguish two time perspectives with corresponding market equilibriums: the "long term" and the "short term". In the long term, the amount and type of capacity is a choice variable that is decided upon by producers ("green field" model). In the short term, producers take the existing capital stock as given at zero costs (but are allowed to additionally invest). In both the long and the short term, producers face production decisions.[3] In other words, in the long term no capital stock is given while in the short term there is a stock of sunk investments. While long-term profits are zero in the LTE, short-term profits are positive in the short-term equilibrium (STE). Short-term profits are needed to repay capital costs. This is possible because there is no free entry that could drive down short-term profits to zero, since entrants had to build new capacity and pay the corresponding capital expenditures. In other words, in the STE previously-existing generators are able to extract rents from their sunk investments, which are used to finance capital costs. While both long term and short term are analytical concepts that never describe a real market entirely correctly, we believe the short term as defined here is a useful assumption to analyze moderate shocks to European power systems on a time horizon of 3–15 years.

In this research project, we exploit these two concepts to construct a framework that allows comparing the distribution effect of different policies consistently (Fig. 1). We assume that the power market is in its LTE before policies are introduced. Then we switch perspective and derive the STE by taking the previously derived capacity as given. Then a policy is introduced exogenously and unexpectedly that shifts the system to a new STE. We define

[2] Positive long-term profits would attract new investments that drive down prices to the point where profits disappear. Vice versa, negative profits would lead to disinvestment, driving up prices until negative profits vanish.

[3] Note that according to this definition, the capital stock is not fixed in the short term, but additional investments are possible. Others (Hirth, 2012; MacCormack et al., 2010) have labeled this the "medium term" and apply the term "short term" to a situation where the capital stock is fixed without the possibility of additional investments.

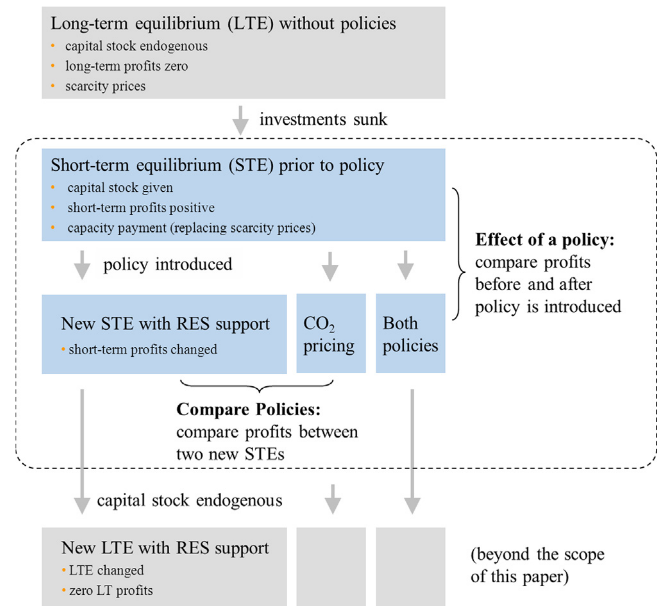

Fig. 1. This framework allows to consistently studying different policies with an analytical and a numerical model. Starting from a long-term equilibrium with no policy, two short-term equilibriums (STE) are compared: the STE prior to policy with a STE with a newly introduced policy.

the redistributive effect of that policy as the difference of short-term profits and consumer surplus between these two STEs. To compare two policies, they are independently introduced starting from the same STE, and the redistribution effects of the policies are consequently compared. Income from scarcity pricing is assumed to remain constant, for example due to capacity payments. The new LTE that would emerge after some time is not of interest for this paper. This framework features two properties that are necessary to compare redistribution effects of different policies:

1. The same benchmark is used for both policies.
2. All changes in short-term rents are strictly caused by policy changes.

While deriving the long-term equilibrium is a standard methodology in the power economics literature, using the resulting capacity mix to evaluate policies in a short-term equilibrium is to our knowledge a novel approach, which we regard as significant innovation. An alternative to our short term/long term dichotomy is to disregard adjustments of the capital stock, potentially overestimating the impact of policies (Sensfuß et al., 2008; Chen et al., 2008; Böhringer and Rosendahl, 2010; Tsao et al., 2011). Another alternative is to model the system′s adaptation to shocks dynamically over time (Prognos and GWS, 2010; Short et al., 2011; Nicolosi, 2012; Färber et al., 2012). However, such scenario analysis typically features a multitude of dynamic shocks that makes it very hard to identify the effect of a specific policy. Consequently, this scenario literature does not provide results of the distributional impact of individual policies. More fundamentally, the starting points of these studies are usually chosen in a way that the market is off its equilibrium in the first place, meaning that changes in rents are not only caused by policy changes, but simply by adjustment process towards the equilibrium. While the scenario literature can provide projection of rents, it is not helpful to disentangle individual drivers and evaluate specific policies.

3.2. Analytical model

This subsection introduces a stylized cost-minimizing analytical model of the electricity market and derives the LTE and the STE. We show that long-term profits are zero while in the STE producers are able to extract short-term rents from their sunk investment. Policies are assessed in Sections 4.1 and 5.1.

To develop a qualitative understanding of major effects it is sufficient to model two generation technologies, which we label “gas” and “coal” power. Dynamic aspects like ramping constraints and electricity storage are neglected, as well as heat and reserve market requirements, international trade, and grid constraints. These details are taken into account in the numerical model (Section 3.3). Both models assume fully competitive and complete markets with perfect foresight. Hence, the cost-minimizing solution is equivalent to the market equilibrium. Electricity demand is perfectly price-inelastic. All fees and taxes are assumed to be specific and remain constant. Externalities are assumed to be absent.

We extend a classical method from power economics (Stoughton et al., 1980; Grubb, 1991; Stoft, 2002; Green, 2005) that uses screening curves, a load duration curve[4] (LDC), and a price duration curves (PDC) that is derived from the first two (Fig. 2a–c). A screening curve represents the total costs per kW-year of one generation technology as a function of its full load hours. Its y-intercept is the annuity of investment costs and the slope equals the variable costs. The LDC shows the sorted hourly load of one year starting with the highest load hour. A price duration curve shows the sorted hourly prices of one year starting with the highest price. This model allows the representation of the two policies we aim to analyze: wind support[5] reshapes the LDC, while CO_2 pricing pivots the screening curves. Before introducing policies in Sections 4 and 5, the LTE and the STE are derived in the following. For a more detailed model description and an alternative application see Ueckerdt et al. (2012).

We first derive the cost-minimal long-term capacity mix and dispatch, then show that profits for all plants are zero in the cost minimum, and finally explain that this is the unique market equilibrium. Cost-minimal capacities and generation can be derived by projecting the intercepts of the screening curves on the LDC. The LDC is then horizontally divided. Each part of load is covered by the technology with the least-cost screening curve for the respective range of full load hours. Gas power plants are cost effective at lower full load hours (peak load) due to their low fixed-to-variable-cost ratio. Coal power plants cover base load. Hereby optimal capacities and dispatch of plants are determined. The PDC is derived from the equilibrium condition that the price equals the variable costs of the marginal plant, except in the one hour of the year when capacity is scarce. In this peak hour scarcity prices p_s occur.

We now show that gas plants earn zero profit. Unless capacity is scarce, the electricity price is set by the variable costs of the marginal plant. Hence, operating gas plants are always price-setting (Fig. 2c). To recover capital costs, gas plants need to demand a scarcity price p_s. Under perfectly inelastic demand, this is only possible in exactly one hour of the year, since at any other point in time there is some capacity available that would supply electricity if the price would rise above variable costs.

$$p_s = c_{gas} + \Delta \tag{1}$$

$$\Delta = I_{gas} \tag{2}$$

[4] For the illustrations we use hourly data for German power demand in 2009 (ENTSO-E).
[5] We use quarter hourly feed-in data from German TSOs for 2009.

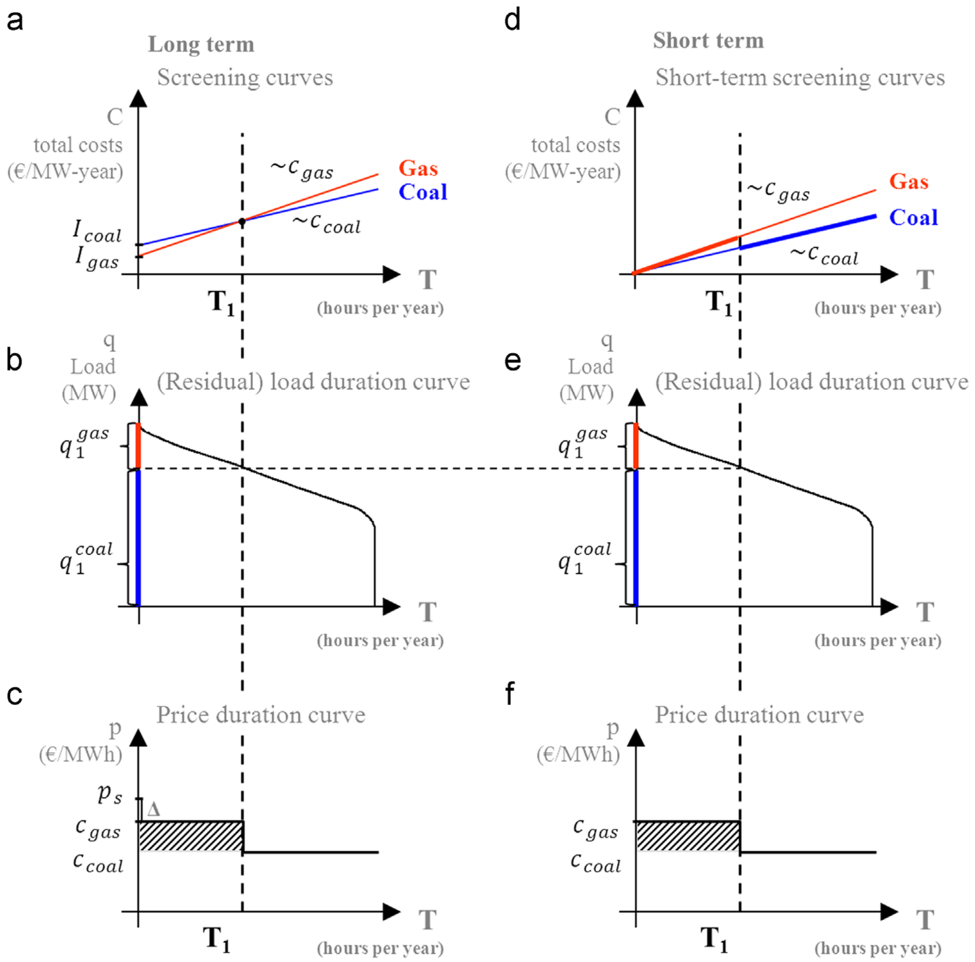

Fig. 2. Long-term equilibrium (left) and short-term equilibrium (right) described by screening curves (a, d), load duration curve (b,e), and price duration curve (c,f). In the short term, screening curves do not contain investment costs and the price duration curve does not contain scarcity prices p_s.

The markup Δ on specific (per MWh) variable costs c_{gas} can only be chosen to exactly cover the investment specific (per MW) cost I_{gas}. A gas power plant cannot further increase the scarcity price to make profit because other gas power plants would enter the market and bid lower prices until the rent vanishes. Hence, the scarcity price implies zero profits for gas power plants.

We now show that for the optimal capacity mix the scarcity price leads to zero profits also for coal power plants. At the intersection of the screening curves in Fig. 2a it holds:

$$c_{coal}T_1 + I_{coal} = c_{gas}T_1 + I_{gas} \tag{3}$$

$$\Leftrightarrow I_{coal} = (c_{gas} - c_{coal})T_1 + I_{gas} \tag{4}$$

$$\overset{(2)}{\Rightarrow} I_{coal} = (c_{gas} - c_{coal})T_1 + \Delta \tag{5}$$

The right hand side of the last equation is the annual income of one unit of coal capacity in the optimal capacity mix as indicated by the shaded area under the price duration curve (Fig. 2c). Hence, market income exactly covers the specific investment costs of coal capacity if the capacity mix is cost-minimal. One scarcity price leads to zero profits for both gas and coal power plants at the optimal capacity mix.

We now explain why this solution is the unique long-term market equilibrium. Let us assume the system's capacities deviate from their optimal values. Substituting gas for coal capacity would increase the width of the shaded area in Fig. 2c, resulting in profits for coal plants. Additional coal generators have an incentive to enter the market until profits vanish. Substituting coal for gas capacity would lead to negative profits and market exit. A decrease of total generation capacity would lead to profits via scarcity prices and subsequent market entry. An increase of total generation capacity would make scarcity pricing impossible, causing exit of suppliers. Thus the cost-minimal capacity mix and the corresponding PDC is the unique LTE. To conclude, in the long-term equilibrium load is covered at least costs and all power plants earn zero profits. This result can be generalized to more than two technologies.

In the following we define short-term profits and show that they are positive in the STE, as defined in Section 3.1. In the short term, capacities from the long-term equilibrium are given. Investment costs for those existing plants are sunk and hence short-term screening curves only contain variable costs and no investment costs (Fig. 2d). Coal is the least-cost technology at all full load hour values; however, its capacity is limited. The optimal dispatch does not change compared to the long-term equilibrium. Total capacity is not scarce and thus there is no scarcity price (Fig. 2f). We assume the "missing money" due to lacking scarcity prices is transferred to generators via other mechanisms, for example a capacity payment. Hence, gas plants sell electricity at marginal costs whenever they operate and do not earn any profits. On the other hand, coal power plants generate short-term profits when gas is price-setting. The specific rent per MW (shaded area in Fig. 2f) needs to be multiplied by the coal capacity q_1^{coal} to calculate the absolute short-term producer rent R_1^{coal}:

$$R_1^{coal} = (c_{gas} - c_{coal})T_1 q_1^{coal} \tag{6}$$

In contrast to the LTE, where profits are zero, in the short term some producers can extract short-term rents from their sunk investment.

3.3. Numerical model

To relax some of the assumptions of the analytical model, the calibrated Northwestern European numerical electricity market model EMMA has been developed. As the analytical model, it is deterministic, has an hourly resolution, assumes perfect and complete markets and can be used to derive both the LTE and the STE. However, it provides more details, such as a wider set of generation technologies, electricity storage, and international trade, features a large set of technical constraints, and accounts for fixed O&M costs. These features are discussed briefly in the following paragraphs. Equations are discussed in Hirth (2012) and the source code as well as input date are available under creative common license via Hirth (2013).

Generation is modeled as seven discrete technologies with continuous capacity: one fluctuating renewable source with zero marginal cost and exogenous dispatch (wind), five thermal technologies with economic dispatch (nuclear, lignite, hard coal, combined cycle and open cycle gas turbines), and electricity storage (pumped hydro). Dispatchable plants produce when the price is above their variable cost. The electricity price is the shadow price of demand, which is the marginal cost of increasing demand in a certain hour. This guarantees that the prices in the long-run equilibrium are consistent with the zero-profit condition for generators. Investments in all generation technologies is possible, but in the short-term nuclear investments are disregarded due to their long implementation time. Fixed O&M costs are taken into account, such that existing plants might be decommissioned for economic reasons after a policy shock.

In power systems, a large number of technical constraints affect the dispatch of plants. A few of the most important ones are implemented as side conditions in EMMA. A share of the thermal capacity is modeled as combined heat and power plants that sell heat as well as electricity. These plants are forced to run, even if prices are below their variable costs. Ancillary services such as regulating power are modeled as a spinning reserve requirement that forces dispatchable capacity equivalent to 20% of the yearly peak demand to be online at any point of time. While internal grid constraints are ignored, cross-border flows are limited by net transfer capacities.

Demand as well as wind generation time series are based on empirical 2010 data. Using historical time series ensures that crucial correlations across space, over time, and between parameters are captured. The model is calibrated to Northwestern Europe and covers Germany, Belgium, Poland, The Netherlands, and France. The model is linear, written in GAMS and solved by Cplex. It has been back-tested with historical data and is able to replicate dispatch decisions as well as prices in a satisfactory manner. Cost and technical parameters are consistent with empirical data, and were chosen such that today's capacity mix is roughly replicated in the long-term equilibrium (Fig. 3).

Both the analytical and the numerical model do not take into account internal grid investments and balancing power. Large-scale renewables deployment probably increases both grid and balancing costs (Hirth and Ziegenhagen, 2013), which we do not account for.

Similar market models have been used by DeCarolis and Keith (2006), Doherty et al. (2006), Olsina et al. (2007), Lamont (2008), Bushnell (2010), and Green and Vasilakos (2011) to numerically estimate long-term equilibriums of power markets. However, these authors do not discuss the short term nor distribution issues.

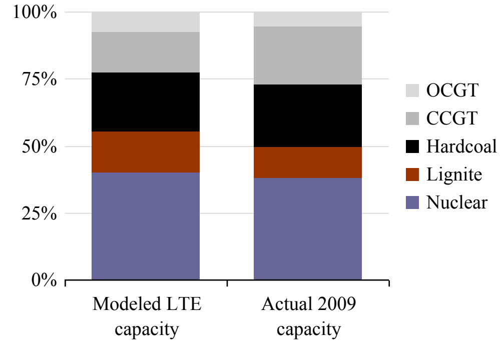

Fig. 3. Model long-term equilibrium capacity mix versus historical capacity mix in 2009 for the model region. The modeled LTE capacity mix resembles quite closely to the observed data.

4. Wind support

This section presents analytical and numerical model results of the redistribution effects of wind support schemes. As explained in Section 3.1, it is assumed that the electricity market is in its long-term equilibrium prior to the introduction of wind support, and effects take place in the short term. Distributional effects emerge because costs for the existing capital stock are regarded as sunk. Support policies are not modeled explicitly, but implicitly by exogenously increasing the amount of wind power. The costs of wind support are then calculated ex post as the gap between full costs and market income, assuming a perfect policy design that does not leave any rents to wind generators.

Renewable support policies have the effect of pushing additional low-variable cost capacity into the market relative to the long-term equilibrium. As a consequence, wind power replaces high-variable cost gas power plants when it is windy. Hence, during some hours coal is setting the price instead of gas power plants that become extra-marginal. In those hours the electricity price is reduced. In all other hours the electricity price remains unchanged. This implies that wind support never increases short-term rents of any existing generators. The reduction of producer rents leads to gains in consumer surplus. In addition, consumers are assumed to bear the economic costs of wind subsidies. The net effect of wind support on consumer surplus is thus a priori ambiguous and depends on the relative size of redistribution of producer surplus to the costs of subsidizing wind power.

4.1. Analytical results

Fig. 4 compares the short-term equilibrium of the electricity market prior (left) and after (right) the introduction of wind power. The left hand side is identical to the right hand side of Fig. 2. Additional wind capacity has no effect on the cost structure of dispatchable generators, thus the short-term screening curves do not change (a, d) and dispatchable capacity remains the same (capacity bars in c and d are identical). However, residual load (load net of wind generation) is reduced during windy hours, shifting the RLDC downwards (b, e). The RLDC also becomes steeper because load during the peak hour of the year remains virtually unchanged.[6] The amount of energy generated in dispatchable plants, the integral under the RLDC, is reduced. Thus full load hours of all dispatchable plants are reduced: existing capacity is utilized less – this is why Nicolosi (2012) calls the impact of wind on the RLDC the "utilization effect". Most importantly, the

[6] This is the case when the renewable technology has a comparable small capacity credit like wind power in Europe.

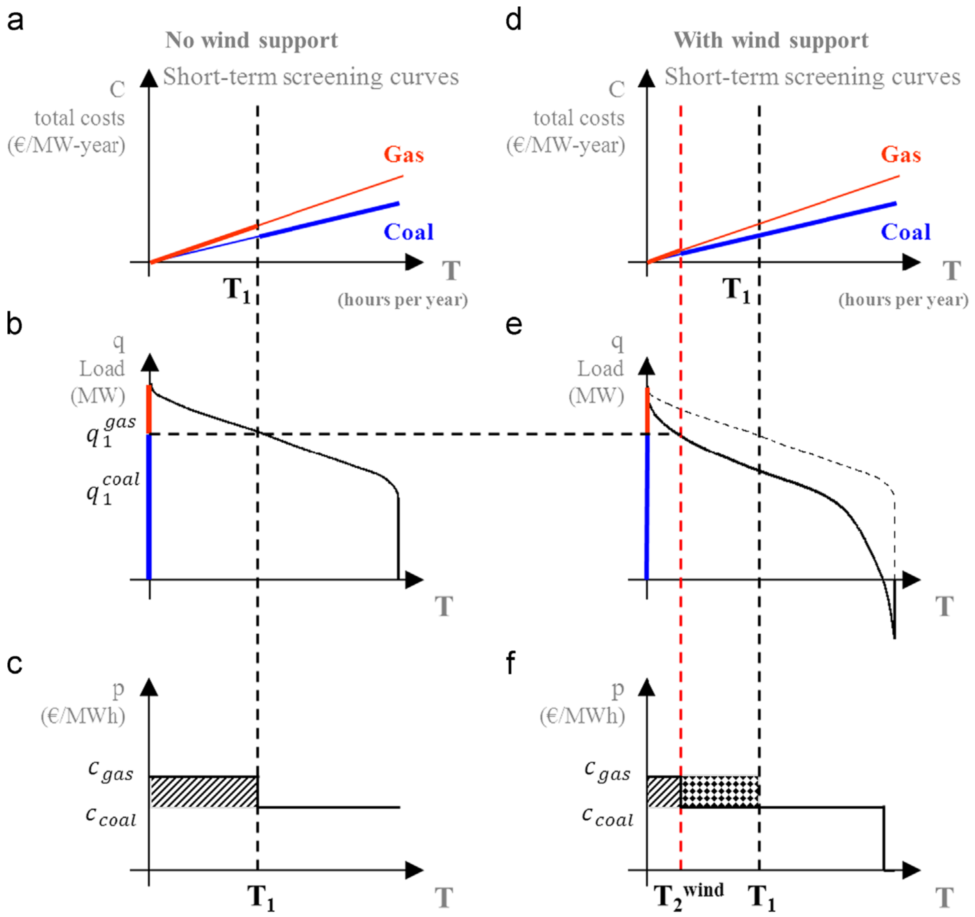

Fig. 4. Short-term screening curves, load duration curves, price duration curves without (left) and with wind support (right). Wind changes the residual load duration curve (b, e). Producer rents decrease with wind support (checkered area equals the reduction of specific coal rents).

PDC is shifted (c, f) to lower prices, because the number of hours where gas is price-setting is diminished.

The effect of wind support on incumbent generators is determined by the shift of the PDC. The short-term rents of gas plants remain zero even though less energy is generated, because they are price-setting whenever they operate. In contrast, coal power plants earn profits when gas is price-setting. Hence, coal power plants lose because the number of hours when gas is price-setting is reduced. The reduction of coal rents equals the change of total producer rents. The dotted area in Fig. 4f shows the loss of the specific (in € per MW) rent of coal capacity: $(c_{gas}-c_{coal})(T_1-T_2)$. The absolute decrease of R_1^{coal} (in €) is given by the coal capacity q_1^{coal} times the specific loss.

$$R_1^{coal}-R_2^{coal}=q_1^{coal}(c_{gas}-c_{coal})(T_1-T_2) \qquad (7)$$

The last factor depends on the deployment of renewable capacity while the others are constant: The shift of the PDC to lower prices drives redistribution due to renewable support.

A strong analytical result is that the rents of incumbent generators never increase due to wind support policies. Rents of the base load technology (coal) decrease, while rents of the peak load technology (gas) remain unchanged. The total effect is proportional to the reduction of hours in which gas is price-setting. Consumer rents increase by that amount minus the costs of wind support. The net effect on consumer surplus is ambiguous.

4.2. Numerical results

In the following, EMMA is used to derive additional details and quantifications in three directions. Firstly, redistribution flows are quantified and shown to be significant in size. Secondly, a wider set of dispatchable generation technologies is modeled, such that loosing and winning generators can be identified more specifically. Finally, the costs of optimal wind subsidies are estimated, and it is shown that for moderate amounts of wind power the net effect on consumer surplus is positive.

In the long-term equilibrium wind is absent, thus all incumbent generators are conventional. Table 1 presents the changes in producer and consumer surplus caused by an exogenous increase of the wind share from 0% to 30% of electricity consumption. Results are given per MWh of total annual consumption to facilitate comparison.[7] Short-term rents of conventional generators are in average reduced by 22 €/MWh. Nuclear rents almost vanish, coal rents are reduced by 80%, and gas rents by 70%. As indicated by the analytical model base load generators lose most, since their income is reduced during a relatively high share of hours.

The effect on electricity consumers is displayed in Table 1b. Consumers save 28 €/MWh in electricity expenditures, because 22 €/MWh are transferred from producers, and 6 €/MWh are saved due to lower fuel costs. On the other hand, consumers pay slightly more for heat, ancillary services, and grid fees. In addition, they have to bear the costs of incentivizing wind investments, which is 18 €/MWh. In sum, they receive a net benefit of 7 €/MWh. In other words, at 30% penetration rate the merit-order effect is larger than the cost increase due to wind subsidies. Despite wind power

[7] Thus results can be interpreted as normalized to a total electricity consumption of one MWh.

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Table 1
(a–c) Changes in short-term surplus of producers and consumers, and system costs changes when increasing wind penetration from zero to 30% (€/MWh). Previously existing generators lose, while gross benefits for consumers via the electricity price are larger than costs of subsidies, thus overall consumer surplus increases.

Incumbent producers (€/MWh)		**Consumers** (€/MWh)		**System costs** (€/MWh)	
Nuclear rents	−13	Electricity market	+28	Decrease in producers surplus	22
Coal rents	−9	Heat market	−2	Increase in consumer surplus	7
Gas rents	−1	AS market	−0.1		
		Interconnectors	−0.2		
		CO_2 taxes	/		
		Wind subsidies	−18		
Producer surplus	−22	Consumer surplus	+7	Increase in system costs	15

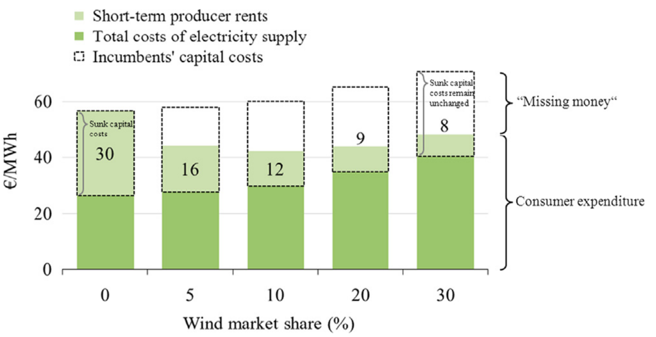

Fig. 5. Rents and costs at different wind penetration rates. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure. With increasing wind penetration, producer rents are transferred to consumers. At 10% wind market share, short-term consumer surplus is maximal. (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

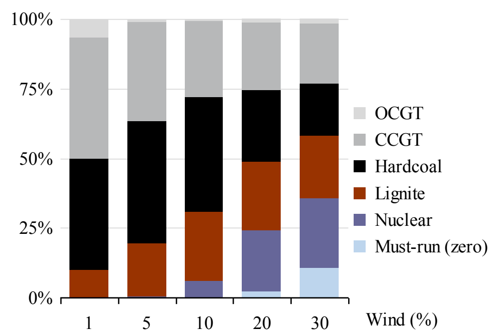

Fig. 6. Share of hours in which different technologies are price-setting. With higher wind penetration, the share of base load technologies increases. At 20% wind and above, prices drop to zero, when must-run constraints become binding.

being inefficient, pushing it into the market reduces net consumer costs by transferring surplus from producers. This is consistent with the findings of previous studies (Unger and Ahlgren, 2005; De Miera et al., 2008; Sensfuß et al., 2008; O′Mahoney and Denny, 2011; Gil et al., 2012).

System costs, the sum of negative surpluses, increase by 15 €/MWh (Table 1c). This is the net economic cost of wind power, ignoring all externalities.

The redistribution flows are economically highly significant: The surplus redistributed from producers to consumers due to wind subsidies is larger than the efficiency effect of this policy. Short-term profits are 30 €/MWh prior to the policy shock, thus they are reduced by more than 70%. Total long-term costs of electricity are 78 €/MWh, thus the loss in producer surplus is about 28% of total revenues of the industry.

Fig. 5 displays the costs of electricity supply and short-term producer rents at wind penetration rates between 0% and 30%. While total costs of electricity supply increase when more wind capacity is added to the system, incumbents' profits continuously fall. The latter effect is larger than the former, such that consumer expenditures are reduced. At a penetration rate of 10% consumers benefit the most. Prior to the policy shock, short-term rents were just sufficient to cover capital costs. Decreasing short-term producer rents are not sufficient to cover fixed costs ("missing money"). Conventional generators do not earn their expected rate of return, and might go bankrupt. Nonetheless, the "missing money" result does *not* imply that capacity payments are needed to restore allocative efficiency or secure supply. In our framework, energy-only markets with scarcity pricing provide sufficient incentives for new investments – it is only previously existing investments that are expropriated.

Fig. 6 shows how the price-setting technology shifts when adding more wind capacity to the system. This mechanism transfers producer rents to consumers via lower prices. As derived in Section 4.1, the additional capacity causes generators with lower variable costs to set the price more often. Without wind, gas plants set the price in 50% of all hours, and hard coal during most of the remaining time. At 30% wind penetration, the price drops to zero in 10% of all hours, and in an additional 50% of the hours the base load technologies lignite and nuclear set the price.

4.3. *Findings and discussion*

Several findings emerge from our analytical and numerical analysis of redistribution effects of wind support policies. Triggering significant amounts of wind investments will always reduce the electricity price. This implies a redistribution of surplus from incumbent generators to consumers. Thus wind support policies can be seen as a mechanism to transfer rents from producers to consumers. This is possible only if investments are sunk. Transfers are large relative to system cost effects and relative to other benchmarks. Base load generators lose relatively more than peak load generators. At moderate penetration rates (up to at least 30%) consumers benefit even if they pay the wind subsidies. Consumer surplus is maximized at around 10% wind share. Other types of renewables such as offshore wind power and solar power are more costly than onshore wind. Subsidizing those technologies could have a negative net effect on consumers, since the costs of subsidies might be larger than redistributed producer rents.

5. CO_2 pricing

This section presents analytical and numerical model results of the redistribution effects of carbon pricing. As in Section 4, we do not model the carbon policy explicitly, but just its consequence: the existence of a CO_2 price signal. The price of CO_2 could be implemented via a price or a quantity instrument, both forms are equivalent in the present models. It is assumed that neither emission rights are allocated freely to emitters nor is there any other compensatory transfer to generators.

Carbon pricing increases the variable costs of CO_2-emitting plants. This increases the electricity price whenever these technologies are marginal generators. In all other hours, the electricity price remains unchanged. This implies that carbon pricing never decreases the short-term rents of carbon-free generators, while the effect on emitting generators depends on their relative carbon intensity and their location in the merit order. The increase in average electricity price leads to losses in consumer surplus. However, consumers are assumed to receive the revenue from carbon pricing as a lump-sum transfer. The net effect of pricing carbon on consumer surplus is thus a priori ambiguous.

5.1. Analytical results

In this subsection we will show that the net effect on producers as a whole depends on the initial generation mix and the CO_2 price level.

Fig. 7 shows short-term screening curves for different CO_2 prices. Fig. 7a displays a price of zero and is identical to Fig. 2b. With higher carbon prices, the variable costs of emitting technologies increase and thus the short-term screening curves pivot around their vertical intercepts. This effect induces changes of short-term profits. Six qualitatively different CO_2 price regimes can be identified (Fig. 7a–f):

(a) Without CO_2 pricing costs and rents are $(c_{gas}-c_{coal})T_1 q_1^{coal}$ as derived in Section 3.
(b) An increasing CO_2 price causes the screening curve of coal to pivot faster than the screening curve of gas. Coal rents decrease in proportion to the decreasing variable cost gap $(c_{gas}-c_{coal})$, while capacities as well as dispatch remain unchanged.
(c) At a sufficiently high CO_2 price, the two screening curves coincide.[8] Capacities remain unchanged, and dispatch is arbitrary since both technologies feature identical variable costs. Total producer rents are zero because the price always equals the variable costs.
(d) Further increasing the CO_2 price increases the variable costs of coal above those of gas. The coal screening curve is steeper and above the gas curve. While capacities remain unchanged, now the dispatch changes ("dispatch fuel switch"): gas plants now cover base load. While coal plants do not earn any profits, gas plants generate rents when coal power plants are price-setting.
(e) At an even higher CO_2 price, the screening curve of coal touches the screening curve of new gas power plants even though the latter also contains investment costs.[9] At this point, new base load gas is as expensive as old base load coal ("investment fuel switch"). The rents of gas power plants reach a maximum.
(f) At higher CO_2 prices, the end of the short-term coal screening curve lies above the long-term gas screening curve. Now, it is efficient to replace coal plants that operate with full load hours higher than T_2 by new gas plants.[10] Only old gas plants generate rents. These rents remain at the level they reached in (e). This regime is further discussed in the remainder of this subsection and shown in Fig. 9.

Fig. 8 summarizes the development of short-term rents (in €) of coal and gas power plants when the carbon price increases. It illustrates that rents shift from coal power plants to gas power plants. The change of total producer rents (coal and gas) depends on the initial capacity mix of coal and gas, as we formally show later this section.

In detail we discuss regime (f) because it includes a multitude of relevant policy-induced effects. Fig. 9 compares the short-term equilibrium of the electricity market prior (left) and after (right) the introduction of a carbon price. The short-term screening curves in Fig. 9a and d change according to the development illustrated in Fig. 7f. Variable costs of coal are above those of gas, thus the coal screening curve is above the gas curve for existing plants. The dispatch is transposed: coal is shifted to peak load, existing gas power plants cover base load (Fig. 9e). Coal rents vanish, while incumbent gas plants generate profits when coal is price-setting (Fig. 9f).

Moreover investments in new gas power plants are profitable because screening curves of new gas power plants and existing coal power plants intersect (Fig. 9d). All coal power plants that would operate at full load hours higher than T_2 are replaced. The remaining coal power plants operate at lower full load hours. New gas plants are assumed to have the same efficiency parameters as old plants, thus the dispatch of old and new gas does not need to be distinguished.

Hence all gas plants have the same specific income (in € per MW) indicated by the shaded area (Fig. 9f): $(c_{coal}^{CO_2}-c_{gas}^{CO_2})T_2$. The absolute rents (in €) of old gas are derived by multiplying with the old gas capacity:

$$R_2^{gas} = (c_{coal}^{CO_2}-c_{gas}^{CO_2})T_2 q_1^{gas} \tag{8}$$

T_2 is given by the intersection of new gas power plants and existing coal power plants intersect:

$$c_{coal}^{CO_2} T_2 = c_{gas}^{CO_2} T_2 + I_{gas} \tag{9}$$

When inserting this into Eq. (8) and it follows:

$$R_2^{gas} = I_{gas} q_1^{gas} \tag{10}$$

Total gas rents R_2^{gas} depend only on the fixed costs of gas investments and their initial capacity. They do not further increase with growing CO_2 price. This is one of our major analytical results. One MW of existing gas capacity receives short-term rents that exactly equal the costs of constructing new capacity. Thus the sunk nature of capital can be understood as entrance barrier that allows investors to generate profits.

To calculate the total effect of carbon pricing on the total producer rents we need to calculate the coal rent before the policy. When the CO_2 price is zero coal power plants earn their maximum rent R_1^{coal} this can be calculated by inserting Eq. (4) into Eq. (6):

$$R_1^{coal} = (I_{coal}-I_{gas}) q_1^{coal} \tag{11}$$

Now we compare total producer rents (the sum of coal and gas plants), assuming realistically that coal plants are twice as capital intensive as gas plants ($I_{coal}=2I_{gas}$). Thus from Eqs. (10) and (11) it can be followed that the change in total producer rents (in €)

[8] The short-term screening curves coincide at a carbon price of 65 €/t CO_2, assuming fuel costs of 25 €/MWh_{th} (gas) and 12 €/MWh_{th} (coal), efficiencies of 48% (gas) and 39% (coal), carbon intensities of 0.24 t/MWh_{th} (gas) and 0.32 t/MWh_{th} (coal).

[9] This happens at about 80 €/t CO_2, with the same efficiency assumptions and investment costs of 100 €/kWa (gas).

[10] It is assumed that new gas power plants have the same costs and the same efficiencies as old ones.

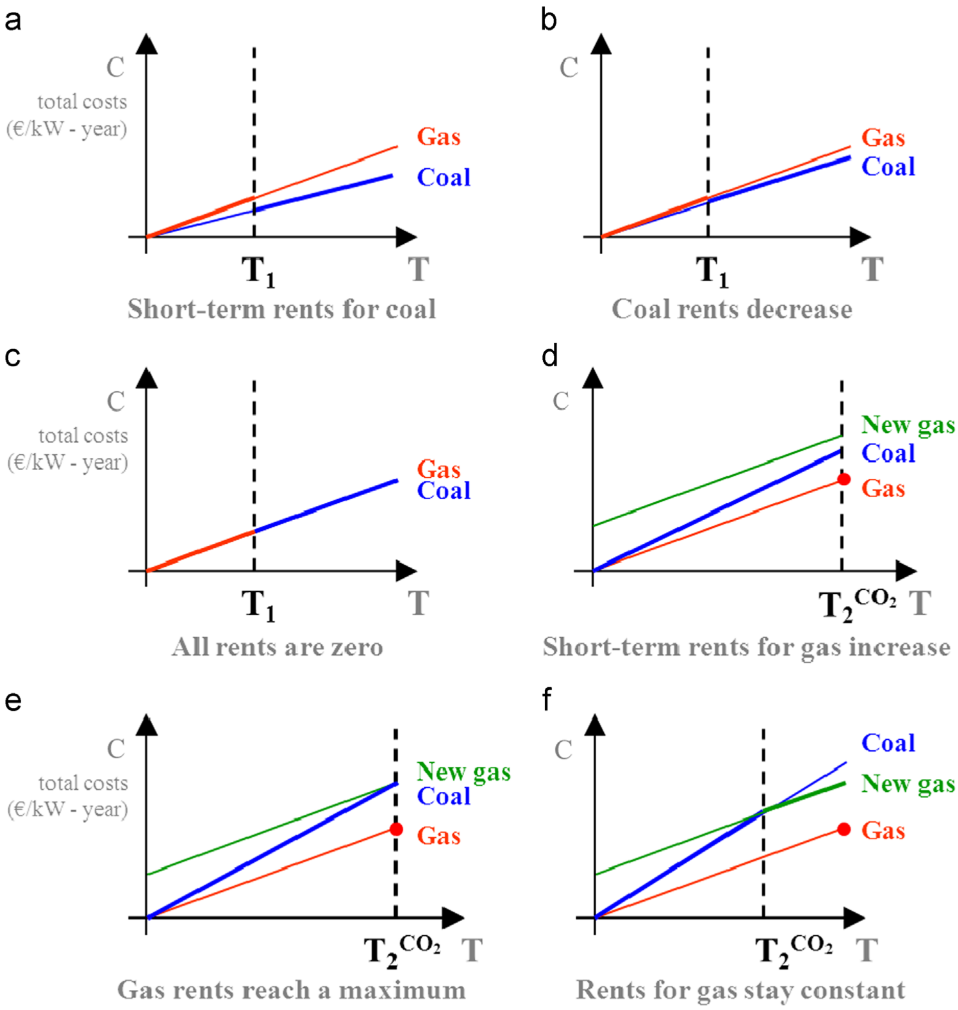

Fig. 7. Short-term screening curves for coal and gas power plants. The CO_2 price increases from figure a to f, and thus the short-term screening curves pivot further around their vertical intercepts. Six qualitatively different CO_2 price levels can be identified.

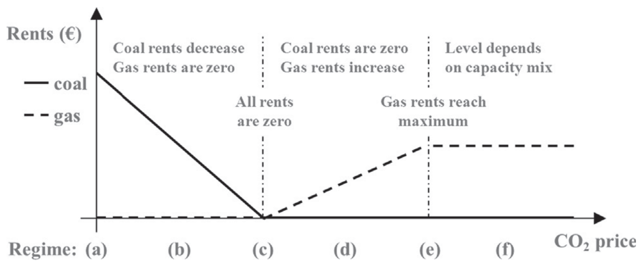

Fig. 8. Rents of gas and coal power plants change with increasing CO_2 price. Six regimes (a–f) can be distinguished. Coal rents decrease to zero, while gas rents increase to a maximum level. The gas rents in regime (e and f) could be above or below the coal rents in (a), depending on the initial capacity mix (see result derived below).

depends only on the initial capacity mix:

$$R_2^{gas} - R_1^{coal} = I_{gas}(q_1^{gas} - q_1^{coal}) \qquad (12)$$

If there is more low-carbon gas than carbon-intensive coal capacity in the initial mix the total producer rents will increase with high CO_2 prices. This is a surprisingly simple condition and one of our main analytical model results.

To conclude, increasing the CO_2 price leads to redistribution flows between the two producers. The initial rents of coal power plants vanish. Rents of gas power plants occur after a certain threshold and increase up to a certain level that is determined by the rental capital costs of new gas plants. The resulting change of the total producer rents depends on the CO_2 price and the initial mix of existing capacity.

In this analytical model, it requires both very high CO_2 prices and more initial gas than coal capacity to increase total producer rents. If we add a low-carbon base load technology like nuclear power to the model, it can be shown that CO_2 pricing increases producer rents under a much wider set of parameters. While these results are not shown analytically due to space constraints, they are discussed in the following subsection.

5.2. Numerical results

Table 2 presents the changes in producer and consumer surplus caused by an exogenous increase of the carbon price from zero to 100 €/t as modeled in EMMA. A CO_2 price of 100 €/t has a similar system cost impact as supporting wind power to reach a market share of 30% and is in that sense a similarly “strong” policy intervention. The surprising result: despite full auctioning, overall short-term producer rents increase. This is one of our major numerical results.

Nuclear power, while not being affected on the cost side, gains from increased electricity prices and can more than double short-term profits. On the other hand, coal plants lose most of their short-term profits. Gas rents increase their initially low profits by

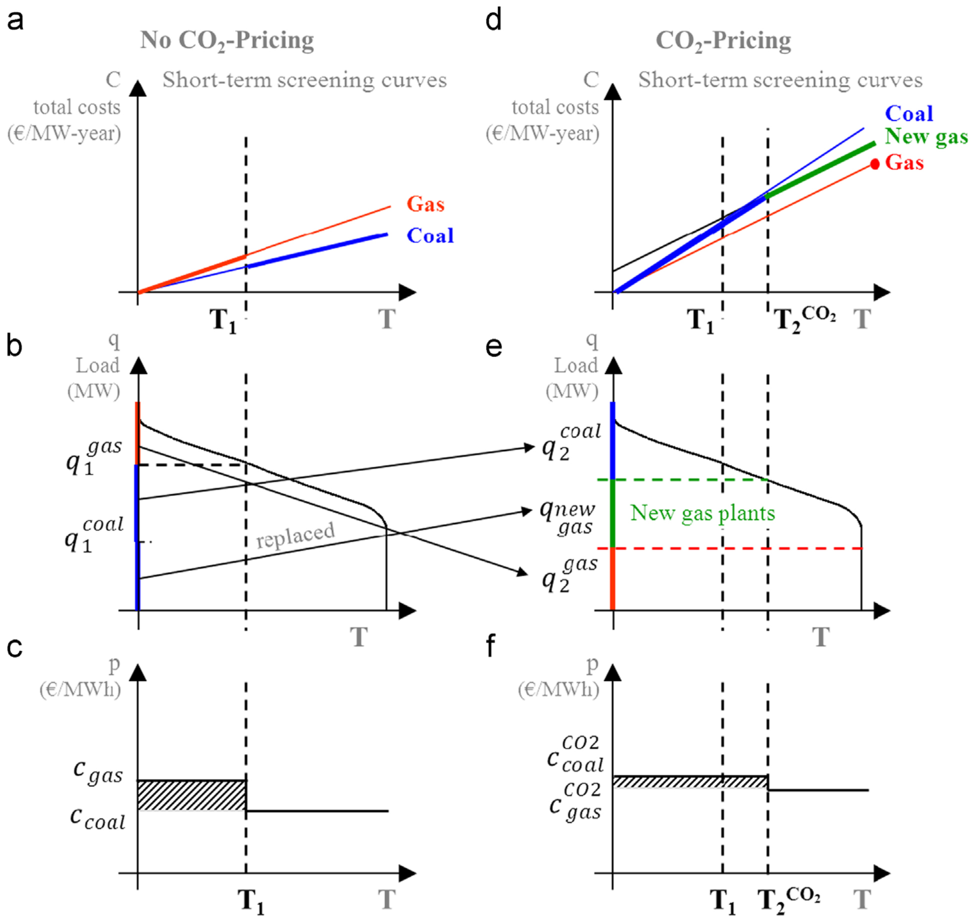

Fig. 9. Short-term screening curves, load duration curves, price duration curves without (left) and with CO_2 pricing (right). Coal rents disappear, while gas rents appear. New gas power plants are built.

Table 2
(a–c) Changes in short-term surplus of producers and consumers, and system costs changes when increasing the CO_2 price from zero to 100 €/t (€/MWh). Producers gain and consumers lose.

Incumbent producers (€/MWh)		**Consumers** (€/MWh)		**System costs** (€/MWh)	
Nuclear rents	+21	Electricity market	−43	Increase in producer surplus	12
Coal rents	−10	Heat market	−6	Decrease in consumer surplus	29
Gas rents	+0	AS market	−0		
		Interconnectors	−0		
		CO_2 taxes	+20		
		Wind subsidies	/		
Producer surplus	+12	Consumer Surplus	−29	Increase in system costs	17

15%. If large-scale new nuclear investments would be possible in the short run, nuclear profits would be limited by new investments. The finding that overall producer rents increase is consistent with some previous studies, for example Martinez and Neuhoff (2005) and Chen et al. (2008).

Consumers have to pay 43 €/MWh more for electricity, and have to bear higher costs for district heating, ancillary services, and grids as well. On the other hand, they receive a lump-sum carbon revenues of 20 €/MWh. Overall, consumer surplus is reduced by 29 €/MWh. System costs increase by 17 €/MWh.

As in the case of wind support, the transfers between economic actors due to carbon pricing are large in size. The surplus redistributed from consumers to producers is larger than the efficiency effect of this policy. Short-term profits are 30 €/MWh prior to the policy shock, thus they are increased by about 40%. In contrast to wind support and as indicated by the analytical model, carbon pricing also leads to massive redistribution between different generation technologies, from carbon intensive to low-carbon generators. According to our estimates, nuclear power plants more than double their profits.

If emission allowances would be allocated freely to producers instead of being auctioned, this would increase producer rents by another 20 €/MWh. Thus the rents generated by increasing spot prices are of the same order of magnitude as the rents generated from entirely free allocation. This is surprising, since free allocation is widely discussed as a transfer mechanism, and the electricity market received much less attention in the public and academic debate.

Not only a carbon price of 100 €/t, but also lower price cause significant transfers. Fig. 10 displays the costs of electricity, suppliers' expenditures for CO_2, and short-term producer rents at carbon prices between zero and 100 €/t. The sum of these three components equals consumer expenditure for electricity. Short-term producer rents increase continuously, driven by increased

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nuclear profits. Recall that the effect of CO_2 pricing on total producer rents was found to be dependent on the initial capacity mix in Section 5.1. Empirically, the increasing rents of low-carbon producers overcompensate for decreasing rents of carbon-intensive generators, because of the significant amount of installed nuclear power in the long-term equilibrium derived in Section 3.3. In contrast to the effect of wind support consumer expenditures continuously increase even if revenues from the carbon market are transferred to the consumers.

In contrast to wind support, carbon pricing has very different effects across countries: because of large existing nuclear capacity in France, producer rents double when introducing a CO_2 price of 100 €/t. At the same time they remain constant in Germany, because of the large carbon-intensive incumbent lignite fleet. This dependency of the capital mix on the overall producer rents empirically confirms a qualitative result of the analytical model.

Fig. 11 compares the merit-order curve without a CO_2 price with that at 100 €/t. The change in the merit-order curve is the fundamental reason for income transfers from consumers to producers via higher electricity prices. At high carbon prices, lignite plants would have higher variable costs than hard coal and CCGTs, but due to economic reasons they are decommissioned. The underlying reason for nuclear to increase short-term profits is that carbon pricing drives up the gap between nuclear and fossil plants. As in Fig. 9f, the carbon price is high enough to incentivize new investments, in this case lignite CCS, CCGTs, and wind power.

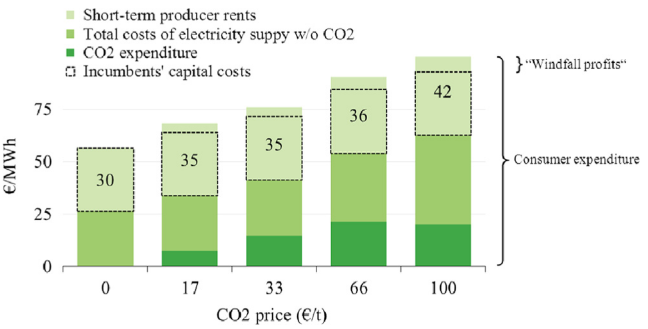

Fig. 10. Rents and costs at different CO_2 prices. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure, but CO_2 expenditure of fossil plants (dark green) is recycled to consumers via lump-sum payments. Short-term rents increase with higher carbon prices over and above what is needed to recover capital costs ("windfall profits"). (For interpretation of the references to color in this figure legend, the reader is referred to the web version of this article.)

5.3. Findings and discussion

The findings from modeling short-term effects of carbon pricing analytically and numerically can be summarized as follows. Even without free allocation of emission permits, pricing carbon can increase the surplus of electricity producers. If that is the case or not, depends on the initial capacity mix prior to the policy shock. Specifically, if the infra-marginal capacity is mainly low-emitting, producers as a whole benefit and consumers lose (via increasing electricity prices). If the infra-marginal capacity is mainly carbon intensive, producers lose and consumers can benefit (via tax or auction revenues).

At realistic cost parameters and under the given European electricity mix, numerical model results show increasing overall producer rents at carbon prices of up to 100 €/t. Even at a moderate carbon price of 17 €/t, profits increase by almost 20% under full auctioning. Furthermore, this policy induces large transfers from carbon-intensive to low-carbon generators. The overall gain in producer surplus is large, in the same order of magnitude as the transfer due to free allocation of emission permits. Furthermore, the different initial capacity mixes in European countries lead to significant cross-border transfers, the largest flowing from coal-intensive Germany to nuclear-intensive France.

6. Policy mix

Comparing the two policy instruments with respect to their redistribution effect reveals a striking difference. While the system cost effect of each policy as well as the size of redistribution between consumers and producers is comparable in size, the directions of flows are opposite. CO_2 pricing transfers economic surplus from consumers to producers while wind support does the opposite. Moreover, CO_2 pricing leads to dramatic profit transfers from carbon-intensive to low-carbon producers, while wind support policies make all incumbent producers lose.

It is plausible to assume that policy makers try to avoid transferring surplus to conventional generators. Indeed, during the last years there have been fierce debates on "excessive returns" and "windfall profits" in the context of emission trading and renewables support schemes in several countries. On the other hand, reducing generators' short-term rents too much might leave them in a situation where they cannot pay back their sunk investments and go bankrupt, which might be undesirable from a policy maker's perspective as well. Given that CO_2 pricing increases producer rents and wind subsidies reduce them, a mix

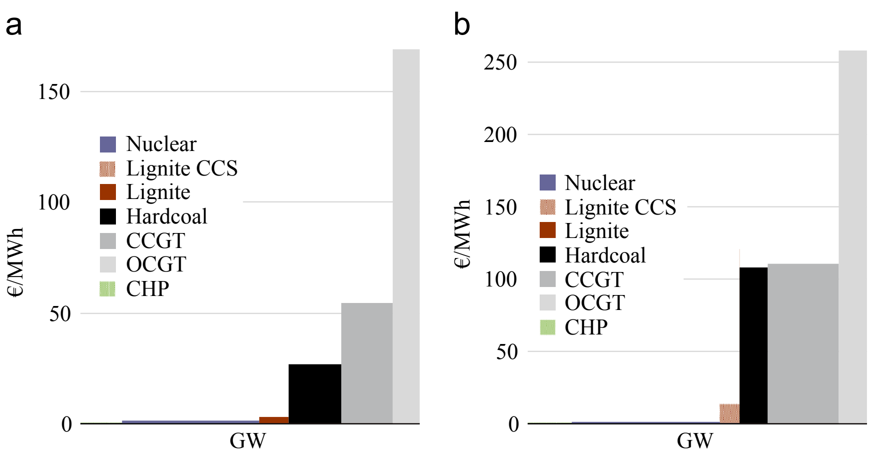

Fig. 11. (a) and (b) The merit-order curve of dispatchable plants without carbon pricing (left) and at 100 €/t CO_2. The y-axis shows bidding price that takes into account start-up costs.

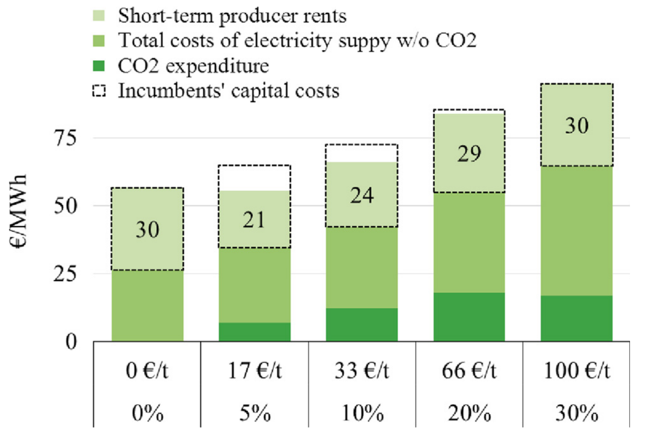

Fig. 12. Rents and costs with a mix of policies. The policy mix represents a path which leaves rents roughly unchanged.

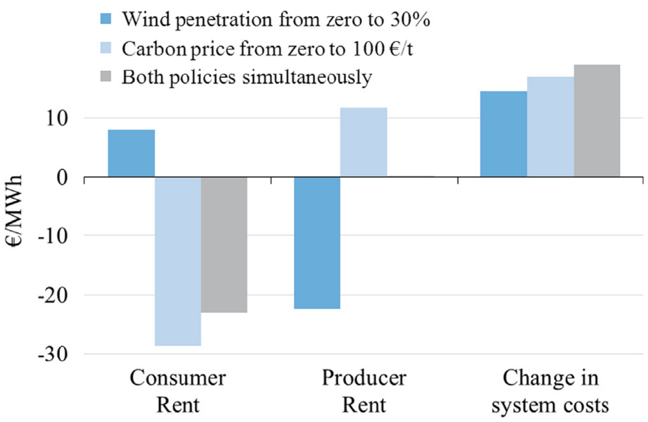

Fig. 13. Change in consumer rent, producer rent, and system costs due to wind support (30%), carbon pricing (100 €/t) and a combination of the two policies. A policy mix reduced the impact on profits virtually to zero.

of both instruments allows mitigating CO_2 emissions without changing conventional generators' rents too much. Figs. 12 and 13 display the compound effect of a mix of both policies. For example, introducing a CO_2 price of 100 €/t and a wind target of 30% simultaneously leaves conventional rents virtually unchanged.

7. Conclusion

This paper discusses wealth redistribution between producers and consumers caused by carbon pricing and renewable support via the electricity market. We have developed a framework to consistently evaluate both policies and have applied both a theoretical and an empirical model to it.

We find that redistribution flows are large relative to the system cost impact of these policies. The two policies induce diametrically opposed redistribution flows: renewable support transfers rents from consumers to producers, while CO_2 pricing does the opposite. In the case of renewables support, transfers are large enough to make consumers benefit from moderate levels of wind subsidies even if they pay for subsidies. Suppliers as a group benefit from carbon pricing, even if they pay for emission allowances, but there are large transfers from carbon intensive to low-carbon generators.

In the economic literature on power markets and electricity policy, energy and climate policies have the primary purpose of internalizing external effects. Distributional consequences are seldom the focus of academic research and usually only briefly discussed in the literature. In real world policy making, in contrast, redistribution effects are often hotly debated. Given the size of transfers, we find, this is not surprising.

Furthermore, our findings help explaining two stylized facts of energy policy: the attitude of certain actors towards specific policies, and the existence of a mix of policies in many countries. Our findings suggest that conventional generators should push for carbon pricing, while consumers should prefer renewable support. These attitudes can indeed be found in current European debates on energy policy.

It is often found that carbon pricing is the first-best climate policy. The existence of renewable support policies is often explained with other externalities like learning spill-overs. We offer an alternative interpretation of this policy mix: undesirable distributional consequences might prevent the implementation of carbon pricing alone and additionally require renewable support. Specifically, we show that combining carbon pricing with renewables support allows policy makers to keep producer rents unchanged. In general, understanding redistribution effects helps policy makers designing a policy mix that reduces implementation barriers.

Future research could expand the analysis in five directions: First, redistribution between jurisdictions is important for policy making. This could be analyzed specifically in the context of heterogeneous national policies. Second, the interaction of redistributive effects of renewables support and CO_2 pricing with existing and new policies merits attention. Third, we have not touched upon redistribution between different consumer groups and between producing firms (not only fuels), which certainly matters. Forth, we have ignored the efficiency impact of both policies in terms of internalization of externalities. Examining the potential trade-off between efficiency and redistribution would be interesting. Finally, our assumption on perfect power markets could be relaxed, and redistribution under market power analyzed.

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Chapter 7

Balancing Power and Variable Renewables. A Glimpse at German Data *

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Inka Ziegenhagen

*under revision at *Renewable & Sustainable Energy Reviews*.

Balancing Power and Variable Renewables

A Glimpse at German Data

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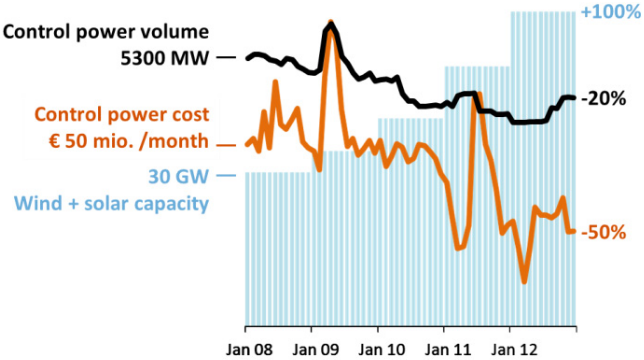
Abstract – Balancing power (regulating power, control power) is used to quickly restore the supply-demand balance in power systems. Variable renewable energy sources (VRE) such as wind and solar power, being stochastic in nature, *ceteris paribus* increase the need for short-term balancing. Their impact on reserve requirements is heavily discussed in academic and policy circles and often thought to be large. The paper contrasts a literature survey and model results with descriptive statistics of empirical market data from Germany, providing surprising insights: all models predict VRE to increase balancing reserve requirements - however, despite German VRE capacity doubled during the last five years, balancing reserves decreased by 20%, and procurement cost fell by 50%. Other factors, such as increased TSO cooperation and the recession, must have overcompensated for the growth of renewables. To the extent this specific German experience can be generalized, we interpret this as an indication that balancing power is not necessarily a major barrier to VRE integration at moderate penetration rates. Next to reserve requirements, the paper discusses two additional links between renewables and balancing systems: the supply of balancing power by renewables; and the role of the imbalance price as incentive for forecast improvements. Reviewing these three links, the paper also provides a comprehensive overview of balancing systems.

Key Words – balancing power; control power; regulating power; variable renewables; wind power; solar power; market design; renewables system integration | *JEL* – D42, L94, Q48

Highlights

- Wind and solar power, being variable in nature, increase short-term balancing needs.
- However, while VRE capacity doubled in Germany, the balancing reserve fell by 20%.
- There are (at least) two more links between variable renewables and balancing:
- Variable renewables can supply balancing services, if market design is appropriate.
- Variable renewables' forecast quality is incentivized by the imbalance price.



Graphical Abstract – Surprisingly, since 2008 German balancing reserve decreased by 20%, and costs by 50%, while VRE capacity doubled. There are many factors besides renewables that impact balancing systems, and renewables have more effects on balancing than just increasing reserve requirements.

The findings, interpretations, and conclusions expressed herein are those of the authors and do not necessarily reflect the views of Vattenfall or the Potsdam-Institute. Corresponding author: Lion Hirth, Vattenfall GmbH, Chausseestraße 23, 10115 Berlin, lion.hirth@vattenfall.com, +49 30 81824032.

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1. Introduction

Electricity generation from variable renewable electricity sources (VRE) such as wind and solar power has grown rapidly in the past years and is expected to continue to grow. The fact that these generators are distributed, non-synchronous, and weather-dependent cause specific challenges when integrating them into power systems (Grubb 1991, Holttinen et al. 2011, IEA 2014). With increasing amounts of VRE, in many countries market and system integration has become a major public policy debate. This paper explores a specific aspect of this debate: the interaction of wind and solar with balancing power systems. The mostly frequently discussed link is that VRE, being inherently stochastic and subject to forecast errors, increases the need for balancing power. While there is in principle wide agreement on this nexus, there is no consensus on the size of the impact. However, there are two additional links between VRE and balancing power: VRE generators can supply balancing services; and the balancing system provides the economic incentive for improving forecasts. These three channels are inter-dependent and interact with each other. Hence, this paper takes a holistic view and discusses all three interfaces. We believe only such a comprehensive review of topics allows fully understanding the challenge and developing consistent policy recommendations.

The aim of this paper is to stimulate and structure the discussion on the interaction between VRE and balancing power that is ongoing among academics, regulators, system operators, traditional market participants, and VRE generators. Specifically, it aims at providing practitioners with an overview of topics, guide them through the literature, and summarize policy proposals. We hope to show that balancing is a smaller obstacle to renewables than often believed; that wind and solar do not only consume but can also provide balancing services; and that there are significant possibilities to further increase the economic efficiency of balancing systems.

Balancing power is used to stabilize the active power balance on short time scales. In AC power systems, the demand-supply balance has to hold at every instant of time to ensure frequency stability. Frequency stability is important because the laws of electromagnetic induction cause frequency to increase if supply exceeds demand, which can mechanically destroy rotating machines such as generators. Since all machines in the power system are affect simultaneously, such a contingency can be very costly. Technical procedures and economic institutes have evolved to prevent frequency instability, the most important of which being 'balancing power'[2]. Balancing power is used to physically balance deviations, such as VRE forecast errors, on short time scales of seconds to few hours. This paper provides an overview of European balancing power systems and markets in the context of the increasing role of wind and solar power.

Electricity generation from VRE sources has been growing rapidly during the last years, driven by technological progress, economies of scale, and deployment subsidies. Global solar PV capacity has reached 100 GW, a ten-fold increase since 2007; wind power capacity surpassed 280 GW, a three-fold increase since 2007 (REN21 2013). During the past years, $ 250 bn p.a. were invested in renewables, more than 90% of which into wind and solar power (IEA 2013). Several power systems now accommodate very high VRE shares, including Denmark (30%), Spain (23%), Ireland (17%), and Germany (15%), according to IHS (2013). The IEA projects that by 2016 renewables will surpass natural gas and become second-largest electricity source after coal. Within five years, global wind capacity will double and solar PV capacity triple. In the long-term VRE are expected to grow further, being one of the major options to mitigate greenhouse gas emissions (IEA 2012, GEA 2012). Fischerdick et al. (2011), Luderer et al. (2013) and Knopf et al. (2013) summarize model comparisons according to which the share of VRE will at least ten-fold under ambitious decarbonization, but will also increase four-fold until 2050 without climate policy. Hence system integration will remain challenging and it is understandable that balancing power receives much attention from academics, practitioners, and policy makers.

[2] There is a multitude of names for this service, and indeed inconsistent nomenclature is a major problem in this area. We use here the internationally most common generic term "balancing power". European transmission system operators have used the term "control power" (UCTE 2009), but are replacing it by "operational reserves" (ENTSO-E 2012b). In Germany and Nordic countries, "regulating power" is more commonly used. Other names include balancing reserve, frequency control, and reserve power. Certain types of balancing power are sometimes used synonymously, such as regulation, load following, contingency reserves, frequency containment, frequency restoration, or replacement reserve.

This paper identifies and discusses three major links between VRE and balancing systems. Each link has been discussed previously in the literature, but to the best of our knowledge this is the first attempt of a comprehensive account of the interactions between VRE and balancing power. Firstly, and most obviously, VRE forecast errors increase the need for balancing. Specifically, an increasing amount of capacity has to be reserved for balancing purposes (left part of Figure 1). But, secondly, VRE generators can also supply balancing services. This requires policies and markets to be designed appropriately (bottom). Finally, the financial penalty for forecast errors, the imbalance price, determines the size of forecast errors. If set rightly, the imbalance price can stimulate more accurate forecasting and VRE generators to behave more system-stabilizing (right). These three channels are inter-dependent and subject to repercussions. For example, passive balancing can substitute active balancing, the imbalance price impacts forecast errors and hence the reserve requirement, and balancing power auction design affects the imbalance price. In a nutshell, the balancing system is a system and needs to be analyzed as one.

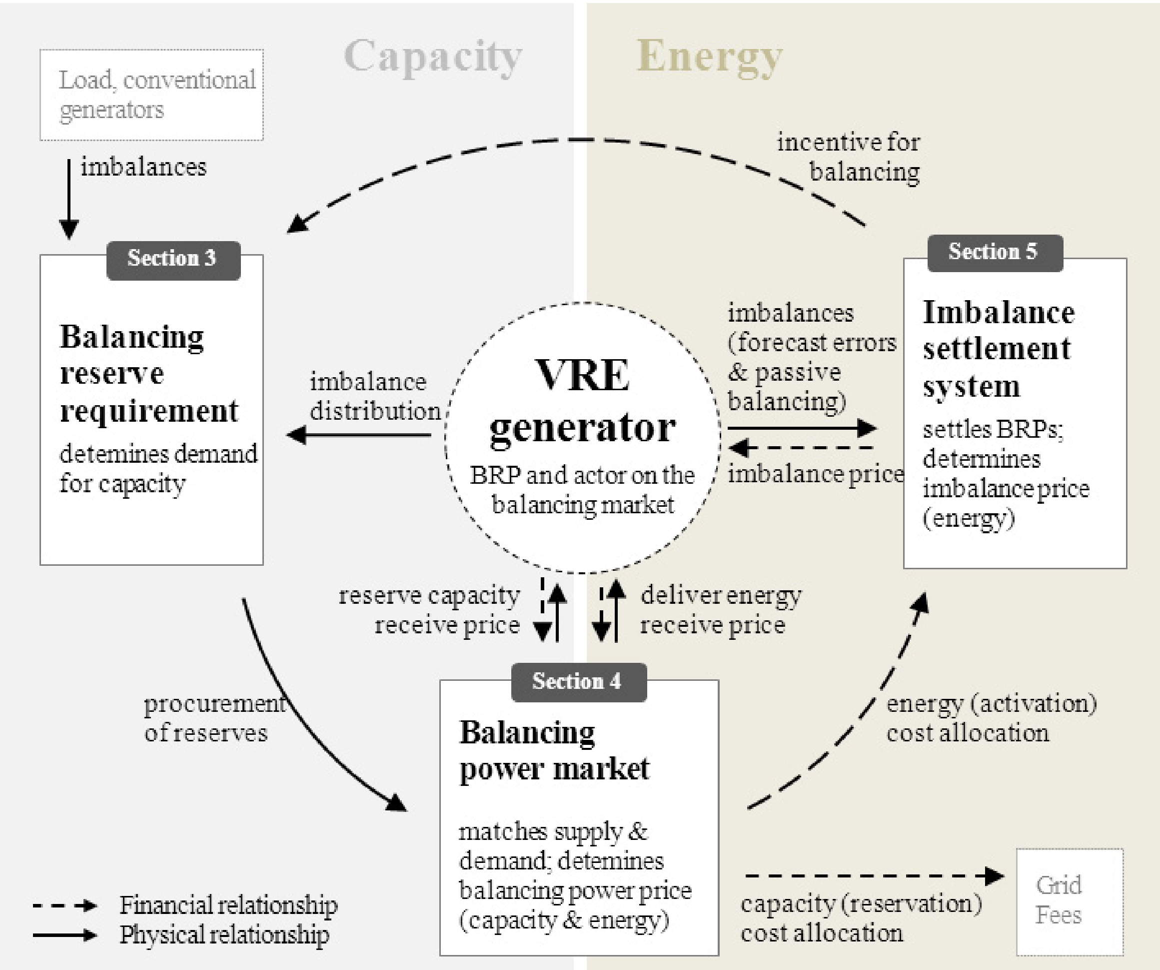

Figure 1. The three links between VRE and the balancing system. Each link will be discussed in one section of this paper.

This paper is comprehensive not only in the sense that all three links are covered, but also in terms of methodology. We provide a condensed yet comprehensive and accessible overview of European balancing systems and the state of the art of academic research on the role of VRE along the three links. For one link, the impact of VRE on balancing reserve requirements, we present new model results. Throughout the paper, we complement theoretical findings with analyses of German market development. German VRE capacity has doubled since 2008 and now exceeds 60 GW or 70% of peak load. Surprisingly, during this period, balancing reserves volumes and costs could be *reduced* by 20% and 50%, respectively. We believe it is important to validate theoretical and model results with empirical observations, and believe this is a crucial contribution of this study. Germany is an interesting case not only because of high and fast growing VRE penetration, but also because of data availability, cooperation between system operator cooperation, and market design reforms. We study

German markets and policies in detail, but most observations and recommendations apply to other European markets, and, albeit to a lesser degree, to U.S. power systems.

This paper builds on and relates to several branches of the literature. First, there are studies that estimate the balancing costs of VRE, from market data (Obersteiner et al. 2010, Holttinen & Koreneff 2012, Katzenstein & Apt 2012) or from cost modeling (Grubb 1991, Gowrisankaran et al. 2011, Mills & Wiser 2012, Garrible & Leahy 2013). Holttinen et al. (2011) and Hirth et al. (2013) survey the literature. While most model-based assessments report costs of 1-5 €/MWh, the market-based studies report a wider range and sometimes much higher costs. We explain this inconsistency in section 5 with the fact that current pricing rules often do not reflect marginal costs. Second, there exist a number of papers on balancing systems. Rebours et al. (2007a, 2007b), TenneT (2011), ENTSO-E (2012a), Ela et al. (2011a), and Cognet & Wilkinson (2013) provide international comparisons. Vandezande et al. (2010) discusses economic aspects of market design. Kristiansen (2007) and Bang et al. (2012) provide a comprehensive survey of the Nordic balancing system and Ela et al. (2011a, 2011b) and NERC (2012) of American systems. We add to this literature by addressing the role of VRE and providing a more comprehensive assessment of the interactions. We also supplement theory with market data; in that sense, this study is more empirical than these publications. Finally, there are studies that study individual aspects, such as the impact of VRE on balancing reserves. We will discuss this literature throughout the paper.

This article focuses on electricity, but the natural gas market features a similar system of balancing energy to which many of the general arguments apply (KEMA & REKK 2009, ACER 2011).

The empirical findings of this article are based on descriptive statistics of the German market. Being a case study, causal interpretations and generalizations to other countries have to be drawn carefully. However, we do believe some conclusions can be drawn. Overall, we find that the impact of VRE on balancing power is less dramatic than sometimes believed. VRE growth has had moderate impact on volumes and costs of balancing power at best. Other factors, such as efficiency gains from market integration, have overcompensated for VRE growth, and there is room for further efficiency improvements. Moreover, we find that current balancing power design constitutes a prohibitive entry barrier for VRE, and suggest it should be adopted to allow participation of all actors. Finally, we find that currently the imbalance price does not reflect the marginal costs of balancing, and argue that it should.

The paper is organized as follows. Section 2 gives an overview of balancing systems. Section 3 discusses how the reserve requirement is determined. We show that despite significant VRE growth, German reserves were significantly reduced. Section 4 covers balancing power markets, where these reserves are procured. We suggest how VRE participation in balancing power provision could be stimulated. Section 5 addresses the other side of the balancing system: imbalance settlement. We argue that prices should reflect marginal costs to provide an efficient signal for VRE forecasting, and that passive balancing should complement balancing power markets. Section 6 concludes.

2. Fundamentals of balancing systems

This section explains the principles of balancing systems. We clarify the roles of different actors and present an overview of the types of balancing power used in Europe, focusing on the area of the Union for the Co-ordination of Transmission of Electricity (UCTE).[3]

2.1. Roles and responsibilities

We define the *balancing system* as the set of technical and economic institutions that have evolved to maintain and restore the short-term active power balance in integrated electricity systems. Other ancillary services, such as reactive power compensation or transmission congestion management, are not within the scope of this article. The balancing system comprises two economic mechanisms, the

[3] As organization, the UCTE has been replaced by "ENTSO-E Regional Group Continental Europe". We stick with the former name for convenience.

'balancing power market' to acquire balancing power and the 'imbalance settlement system' to settle the imbalances financially.

Two geographic entities exist in the balancing system: the synchronous system (interconnection) and several balancing areas (control areas) within the synchronous system. The synchronous system, a geographic area usually of the size of several countries, is characterized by a common steady state-frequency; power imbalances induce the frequency to deviate from its nominal value. Balancing areas are regions, usually of the size of countries, for which one system operator is responsible. Balancing systems are meant to balance both the synchronous system and each balancing area. Specifically, they are intended to stabilize two variables at their nominal value: the frequency of the synchronous area; and each balancing area's imbalance (area control error).

In European balancing systems, there exist three four of actors: transmission system operators, balance responsible parties, suppliers of balancing power, and regultors. *Balance responsible parties* (BRPs) or 'program responsible parties' are market entities that have the responsibility of balancing a portfolio of generators and/or loads. BRPs can be utilities, sales companies, and industrial consumers. They deliver binding schedules to system operators for each quarter-hour of the next day,[4] and are financially accountable for deviations from these schedules.

Transmission system operators (TSOs) operate the transmission network and are responsible to balance injections and off-take in their balancing area. TSOs activate balancing power to physically balance demand and supply if the sum of BRP imbalances is non-zero. Specifically, TSOs have four obligations:

1. determine the amount of capacity that has to be reserved for balancing, ex ante (section 3)
2. acquire the required balancing power reserves and determine the price paid for capacity and energy, ex ante (section 4)
3. activate balancing power in moments of physical imbalance, real time
4. determine the imbalance price, and clear the system financially, ex post (section 5).

Suppliers of balancing power reserve supply capacity, and deliver energy once activated by the TSO. They are obliged to deliver energy under pre-specified terms, for example within a certain time frame and with certain ramp rates. Suppliers are traditionally mostly generators, but can also be consumers. Typically suppliers of balancing power receive a capacity payment (€/MW per hour)[5] because capacity reservation occasions opportunity costs, and/or energy payment (€/MWh) since activation is costly.

Regulators determine the balancing power market design. They also monitor market power, and prescribe the pricing formula of the imbalance price.

2.2. Types of balancing power

Characteristics, classification, and nomenclature of balancing power vary across power systems. Moreover, since there exist multiple sources of imbalances with different characteristics (see section 3.1), in most power systems several different types of balancing power are employed simultaneously. The different balancing power types can be distinguished along several dimensions: operating vs. contingency reserve; spinning vs. stand-by reserve; reserves that balance a balancing area vs. reserves that balance the synchronous system; time of activation (fast v. slow); way of activation (manual v. automatic); positive (upward) and negative (downward).

In the UCTE, balancing power is called 'control power', and three different types are used: primary control, secondary control, and tertiary control (minute reserve). They differ in purpose, response time, and the way they are activated (Table 1). Primary control power (PC) can be fully deployed within 30 seconds. Being a shared resource within the UCTE, it is not activated by TSOs but by locally

[4] Schedules are usually submitted one day in advance, but can be adjusted until about one hour ahead of delivery. In some markets, schedules can be adjusted after delivery by swapping volumes between BRPs in so-called "day after" markets, see section 5.2. Some markets feature half-hourly schedules, such as France.

[5] This is the price of reserving capacity per MW and per hour, which is not identical to the price for delivering one MWh of electrical energy. TSOs report prices usually in €/MW per day, €/MW per week, or €/MW per month. Market actors sometimes use €/kW per year. We report all capacity prices as €/MW per hour (€/MWh). Note that despite having the same unit, these capacity prices have nothing to do with energy prices.

measured frequency deviation. PC can be classified as a fast, automatic, spinning reserve that is used to balance the synchronous system both up- and downwards.

Secondary control power (SC) has to be available within five minutes after activation. It is activated automatically and centrally by TSOs each four seconds. SC is used to supplement PC for frequency restoration, and to re-balance the respective balancing area (UCTE 2009, P1 and A1). SC can be supplied by some stand-by hydro plants, but is mainly provided by synchronized thermal generators. Hence, it is an automatic reserve that balances both the synchronous system and the balancing area up and down; to a large extent, it is a spinning reserve. Tertiary control power (TC) is used to replace SC over time. It is either directly activated or in schedules of 15 minutes. Activation is a manual decision usually based on current and expected deployment of SC. TC is mostly supplied by stand-by generators. UCTE (2009) and Rebours et al. (2007a) provide more technical details.

Table 1: Types of Control Power in the UCTE

	Primary Control	**Secondary Control**	**Tertiary Control (Minute Reserve)**
Response Time	30 s, direct (continuously)	5 min, direct (continuously)	15 min, direct or schedule
System	UCTE	UCTE and balancing area	UCTE and balancing area
Control Variable	Frequency deviation from 50 Hz	Balance of the control area; Frequency deviation	Amount of $SC^{+/-}$ activated
Activation	Based on local frequency measurement	Centralized (TSO); active call through IT	Centralized (TSO); active call through phone / IT
Suppliers (typically)	Synchronized generators, (large consumers)	Synchronized generators, stand-by hydro plants, large consumers	Synchronized and fast-starting stand-by generators, large consumers
Reserved Capacity	3000 MW in UCTE (600 MW in Germany)	Decided by TSO (2000 MW in Germany)	Decided by TSO (2000 MW in Germany)

2.3. The European target model for balancing power systems

To integrate European power markets, the European Union aims at harmonizing and integrating European balancing systems and markets. If implemented as planned, the European balancing system and all of its markets will significantly change in the coming years. Important actors in this process are EU institutions (commission and council), energy regulators (Agency for the Cooperation of Energy Regulators ACER) and TSOs (European Network of Transmission System Operators for Electricity ENTSO-E). On 15 topics, ACER has published ‘Framework Guidelines’ based on which ENTSO-E drafts ‘Network Codes’. These codes then enter the EU Comitology process after which they become legally binding. ENTSO-E (2013c) provides an overview of the process.

One of the 15 areas is ‘Balancing Energy’, another is ‘Load-frequency Control and Reserves’. In both cases, Framework Guidelines are finalized (ACER 2012a, 2012b) and Network Codes are currently drafted (ENTSO-E 2013a, 2013b).[6] Mott MacDonald & SWECO (2013) provide an impact assessment of the Balancing Energy Framework Guideline. The guidelines introduce ‘frequency containment’ and ‘frequency restoration’ reserves as common terminology for all European synchronous systems, which will replace PC, SC, and TC. With the present, we aim at supporting the implementation process by providing information on market design and price impacts to stakeholders and a wider audience.

[6] For overviews on the status of Balancing Energy Network Code, see www.acer.europa.eu/Electricity/FG_and_network_codes/Pages/Balancing.aspx and www.entsoe.eu/major-projects/network-code-development/electricity-balancing/ and for the status of the Load-frequency Control and Reserves Network Code see www.entsoe.eu/major-projects/network-code-development/load-frequency-control-reserves/.

3. Calculating the balancing reserve requirement

This section discusses the impact of VRE on balancing reserve requirements. First, we explain which variables cause system imbalances and how the reserve is determined from their joint probability distribution. Second, we quantify the impact of VRE on balancing reserves, summarizing the published literature and presenting new model results. Third, we show that in the German case, history seems to prove theory wrong: while VRE capacity increased, balancing reserves could be reduced. We propose a few explanations for this apparent paradox. Finally, we suggest a number of policy options that we derive from the literature, theoretical considerations, and our analysis of market data.

TSOs determine the amount of capacity to be reserved as balancing power ex ante. The methodologies they use vary across types of balancing power and between TSOs (Holttinen et al. 2012). There are stochastic (probabilistic) or deterministic approaches to estimate the reserve requirement. Probabilistic approaches explicitly account for the distribution function of the system imbalance, keeping it balanced with a certain security level. They require detailed knowledge about sources of imbalances, their probability distribution, and their correlation. Deterministic approaches require the reserve to be large enough to cover a certain event, such as the largest credible contingency (*N-1* criterion). They do not account for less severe events, their probability, or correlation between imbalances. Whether stochastic or deterministic, TSOs can either use historical data to determine the reserve for longer time periods such as one year (static dimensioning) or update the reserve requirement more frequently depending on the current or expected status of the system (dynamic dimensioning).

In continental Europe, reserve requirements are regulated in UCTE (2009). It prescribes a common European deterministic-static approach for PC, reserving 3000 MW to compensate the loss of two large nuclear reactors connected to the same bus bar. UCTE suggests a number of approaches for SC and TC dimension, but leaves the decision to TSOs. As a consequence, the amount of SC+TC reserves vary widely – from 5% of average load in France to 14% in Belgium (Cognet & Wilkinson 2013). German TSOs use a static-probabilistic approach, which we will discuss in the following.

3.1. Determining the reserve requirement via statistical convolution

Several factors cause active power imbalances in power systems. One way to categorize them is to distinguish stochastic from deterministic processes (Table 3).[7] Stochastic processes are unplanned outages (contingencies), and load and VRE forecast errors. Deterministic processes are the deviations between the stepwise (discrete) schedules and continuous physical variables. These *schedule leaps* exit for generation, consumption, and interconnectors.

Table 2: Variables that cause system imbalances

	Stochastic	Deterministic
Thermal and Hydro Generation	unplanned plant outages	Schedule leaps
VRE Generation	forecast errors	
Interconnectors	unplanned line outages	
Load	forecast errors	

Tripping plants induce a shortage and hence require only positive balancing. The probability of outages is a function of plant characteristics (technology, fuel, age) and the frequency of start-stops. The owner of the tripped plant is obliged to replace the missing capacity after one hour. Forecast errors of load and VRE can be positive or negative. Forecasts improve as the prediction horizon shortens. If intra-day markets are liquid, it is only the errors of the latest forecast that requires balancing power. The imbalance price provides the economic incentive for BRPs to reduce forecast errors (section 5).

[7] This has nothing to do with stochastic / deterministic estimation methodologies for reserve dimensioning, but addresses the nature of the underlying process.

Next to these inherently stochastic processes, there is a deterministic source of imbalances: deviations resulting from the way contracts are designed in liberalized electricity markets. Schedules are specified as discrete step functions in intervals of 15 minutes. However, physical demand and supply changes smoothly (Figure 2). The differences between physical and scheduled values are called 'schedule leaps.' These leaps require substantial balancing. Figure 3 shows that schedule leaps are large and that deviations are largest around full hours, indicating that many BRPs use hourly instead of quarter-hourly schedules (see Weißbach & Welfonder 2009, Consentec 2010).

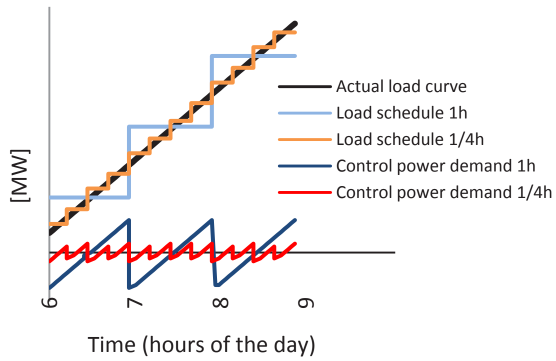

Figure 2. Discrete schedules cause imbalances (illustration). Quarter-hourly schedules cause smaller imbalances than hourly schedules.

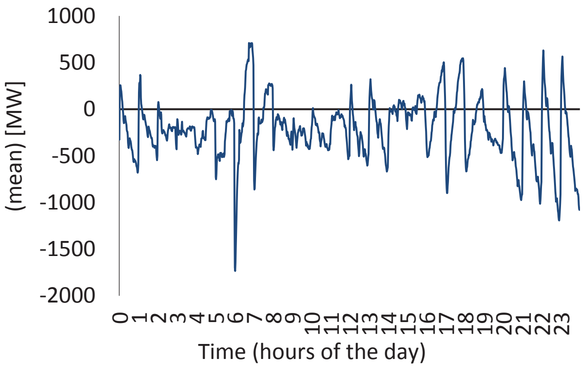

Figure 3. Average German system imbalance for every minute of the day during the year 2011 (4s-data from TSOs). One can identify clear patterns just before and after full hours. These schedule leaps are quite large compared to the sum of reserves of about 4.5 GW.

The German TSOs use a probabilistic approach to determine SC and TC capacities, sometimes called the 'Graf/Haubrich approach' (Consentec 2008, 2010, Maurer et al. 2009). In probabilistic approaches, the balancing area imbalance, the sum of all individual imbalances, determines the reserve requirement. In statistical terms, the balancing area imbalance follows the joint distribution of the individual factors' distribution functions.

To determine the joint distribution function, the individual density functions of all random variables are estimated, either from historical data or theoretical considerations. The German TSOs consider empirical data of the previous twelve months. The size of the balancing area crucially determines the correlation between individual BRP's imbalances and hence the individual distribution functions. A larger balancing area with a higher number of more diverse loads leads to a more narrow distribution of load forecast errors. The same applies to VRE generators. Having estimated each factor's density, the joint density distribution is then derived by statistical convolution, assuming all factors to be statistical independent (see Braun et al. 2013 for supporting evidence). Finally, positive and negative reserves are set in a way that the integral of the density function equals a pre-defined security level (Figure 4). The German regulator has recently increased the level to 99.95% (Consentec 2010). In those care occasions during which imbalances exceed balancing reserves, TSOs support each other with ad hoc measures.

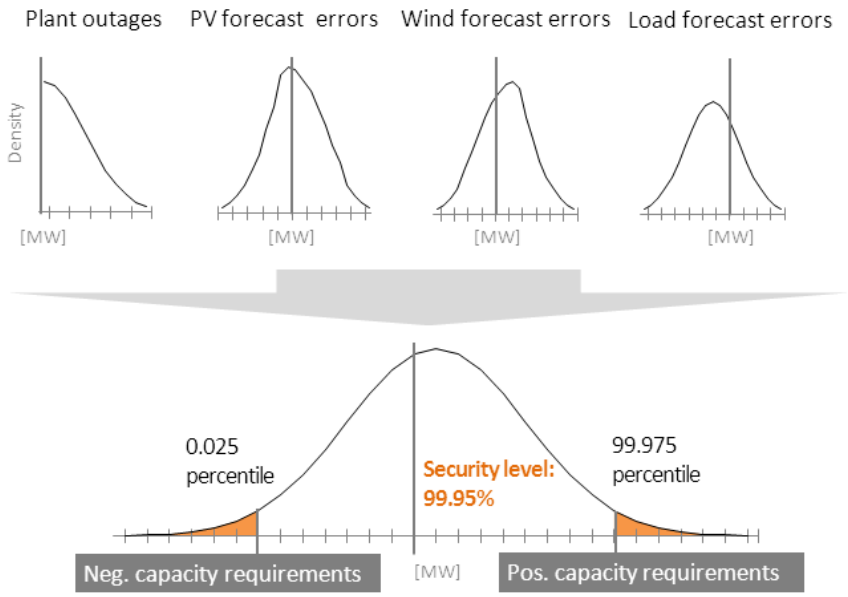

Figure 4. Convolution of different sources of imbalance to derive the joint distribution function. The 0.025% and the 99.975% percentile of that function determine the required amount of reserves.

3.2. The impact of VRE on reserve requirements

If VRE forecast errors are uncorrelated to other factors, additional wind and solar capacity *ceteris paribus* increases the size of balancing reserves. Many studies have estimated the impact of VRE on balancing power reserve requirements. UKERC (2006) and Holttinen et al. (2011) provide surveys of the literature. Holttinen et al. report that in predominately thermal power systems, most studies find a reserve increase of 2-9% of the installed wind capacity. DLR et al. (2012) report about 4% of additional VRE capacity in Germany if wind and solar are mixed, assuming significant improvements in forecast quality. De Vos et al. (2012) restrict their analysis to wind power, ignore other drivers of imbalances. Accordingly, they find wind to have a very large impact, increasing the requirement by 30% of installed capacity. This stark difference shows how important it is not to study individual imbalances, but the system's imbalance.

Ziegenhagen (2013) provides a convolution-based assessment of the impact of VRE on reserve requirements. She finds that reserve requirements are increased by 6% of installed wind or solar capacity, assuming a moderate reduction of forecast errors by 30%. This number is reduced to 4% if both technologies are built out simultaneously. Without forecast improvements, such a mixed expansion would increase reserve needs by 6.5% - if forecast errors are improved by 60%, the impact on reserves would be reduced to 1.5%. Up to 100 GW of additional capacity Ziegenhagen estimates the impact of reserve requirements to be roughly linear (Figure 5). Significant forecast improvements seem to be not unrealistic (Freedman et al. 2013, Siefert et al. 2013).

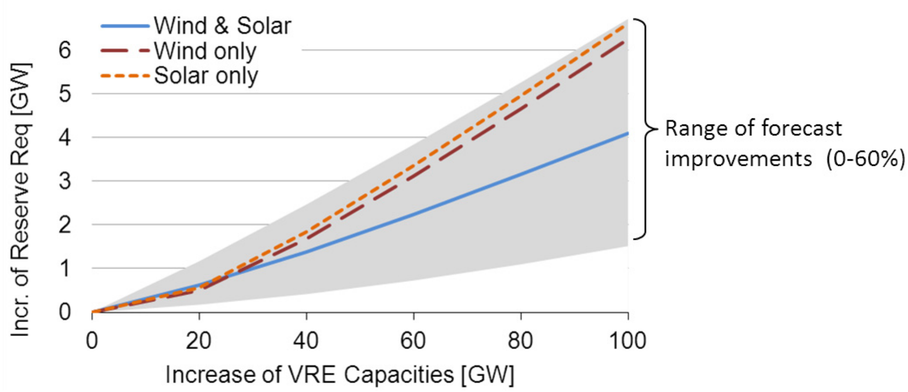

Figure 5. The impact of on balancing reserve requirement as estimated by Ziegenhagen (2013).

While there is no consensus in academic literature about the size of VRE's impact on balancing reserves, there is no doubt that more VRE capacity increases that reserve requirement. In the following, we review empirical market data from Germany, which seems to prove theory wrong.

3.3. The German experience: A paradox?

Since 2008, combined German VRE capacity has grown from 30 GW to 64 GW, compared to peak load of 80-90 GW. The share of VRE in energy terms increased from 7% to 11%. During the same time, TSOs *reduced* balancing reserves by 20% (Figure 5). This empirical fact seems to contradict common sense as well as the theoretical findings presented in section 3.2.

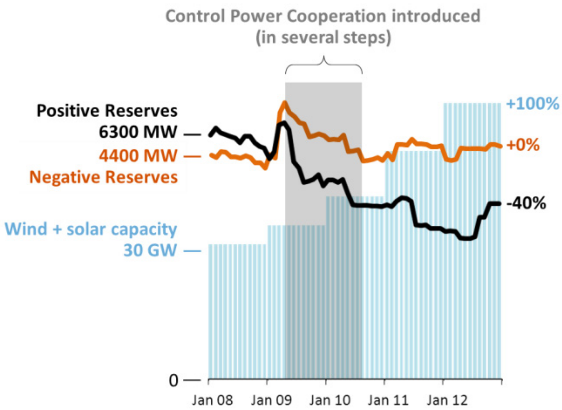

Figure 6. Balancing reserves and VRE capacity in Germany. Despite the installed capacity of wind and solar power doubling since 2008, the demand for balancing power decreased. One reason was the cooperation between TSOs introduced in 2009/10.

Of course these descriptive statistics do *not* imply that wind and solar power reduce the balancing reserve requirement. However, it shows that during the past five years, in Germany variable renewables have not been the dominant driver for reserve requirements; other factors must have overcompensated for the capacity increase. There are several candidates: wind and solar forecasts might have become better; TSOs might have become more cost-conscious and decreased additional internal security margins; load forecasts might have become better; and the cooperation of TSOs probably helped. A quantitative assessment of these drivers is beyond the scope of this paper, but would be a promising direction of future research.

During 2009/10 the German TSOs established a 'control power cooperation' (*Netzregelverbund)*. Today, both reserve dimensioning and activation is done jointly such that Germany can be treated almost as a single balancing area (Zolotarev et al. 2009, Zolotarev & Gökeler 2011). Since 2012, the Danish, Dutch, Swiss, Belgium, and Czech TSOs have joined the 'International Grid Control Cooperation'. At this stage, the members outside Germany cooperate in terms of SC activation, but dimension reserves individually. This 'bottom-up' regional cooperation process develops in parallel with the 'top down' framework guideline process described in section 2.3.

In academic and policy circles, there seems to be widespread believe that wind and solar power have become major drivers for balancing power. This is reflected in the fact that there are numerous published studies that assess this relationship. Surprisingly, to the best of our knowledge, there is no ex-post estimation of impact of the *Netzregelverbund* or studies that otherwise explain the decrease of balancing reserve in Germany, nor are we aware of studies that quantify the impact of larger balancing areas in general. Similarly, while a lot of research addresses VRE forecasts, very little is written about load forecasting.

This market analysis shows that reserve dimension is not a question of VRE alone, but of many more factors. Future studies should not assess the impact of VRE in isolation, but take these other factors into account. Germany's historical experience also shows that is can be possible to decrease balancing reserves while increasing VRE capacity, if system operation is organized more efficiently.

3.4. Policy options: advancing reserve calculations

There are possibilities to further increase the economic efficiency of reserve dimensioning. One option that the literature suggests is to calculate reserve requirements dynamically, that is, as a function of the current or expected system conditions (Holttinen et al. 2012). For example, if a wind front is expected to arrive the next day, more reserve can be procured than for a calm day. Dynamic dimensioning is currently under assessment in Switzerland (Abbaspourtorbati & Zima 2013) and Germany[8].

German data shows that schedule leaps cause significant deterministic imbalances (recall Figure 3). Reserving capacity as balancing power is a means to respond to *surprising* events. Schedule leaps are known to occur every day at the same time, hence one should not hold expensive spinning reserve for compensation, but look for cheaper approaches: others have suggested smoothing the transitions between schedules via regulation; shortening dispatch intervals (Weißbach & Welfonder 2009, Pérez-Arriga & Battle 2012); or introducing a dedicated ramping product (Milligan et al. 2009). However, we propose rely on price mechanism and use passive balancing. That is, to incentivize BRPs to stabilize the system via the imbalance price (see section 5.4). Such a solution seems to be cost-efficient, since no capacity has to be reserved and no capacity price has to be paid.

A third possibility of improvement concerns price-elastic dimensioning (Müsgens et al. 2011). Price-elastic dimensioning means that the amount of capacity reserved should reflect the price of capacity. When capacity reservation is cheap, it is probably welfare-improving to procure more reserves, thereby increasing the security level. These three suggestions complement each other and could be implemented simultaneously.

This section has discussed reserve sizing. After determining how much capacity is needed, TSOs procure reserves on balancing power markets. We will elaborate on German balancing markets in turn.

4. Balancing power market

Since TSOs do not own generation assets, they procure reserves on balancing power markets. Depending on the type, suppliers of balancing power receive a payment for capacity and/or energy, hence the price is a two-part tariff. While energy prices for positive balancing are always positive, they can be positive or negative for negative balancing (suppliers sometimes get paid for reducing output).

While the technical characteristics of different balancing power types are harmonized throughout the UCTE (Table 1), balancing power market design is national. A wide range of institutional setups exist, ranging from supply obligation for generators with or without compensation, and mandatory offers by generators, to free bidding. While almost all wholesale electricity prices feature marginal pricing, pay-as-bid pricing is common on balancing power markets. Wholesale markets are bilateral markets with multiple buyers and sellers, in contrast, balancing power is only demanded by the TSO, hence it is a single-buyer market.

Rebours et al. (2007b), ENTSO-E (2012a) and Cognet & Wilkinson (2013) compare market rules internationally. TenneT (2011) compares of the Dutch and the German market. Ela et al. (2011b) discusses American market design. Van der Veen (2013) discusses market design in the context of European balancing power market integration. In the following, we will summarize on the German market design, report on recent market development, argue that VRE can cost-efficiently supply negative balancing, and identify entry barriers for VRE that prevent market participation up to this point.

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[8] Starting in April 2013, the German TSO TenneT and research institute IWES develop approaches for dynamic dimensioning in Germany. www.iwes.fraunhofer.de/de/Presse-Medien/Pressemitteilungen/2013/dynamische-bestimmung-des-regelleistungsbedarfs-im-stromnetz.html

4.1. German balancing power market design

German balancing power market design is prescribed by the regulator and has been subject to frequent changes. Shortly after the liberalization of spot markets, balancing power markets were created in 2001, when bilateral contracts were replaced by public auctions. Since late 2007, the four German TSOs use a common procurement platform.[9] Table 5 summarizes auction design as it is in effect since mid-2011, after the latest reform.

TSOs have a perfectly price-inelastic demand for balancing power. Bidders have to prove that they can deliver balancing power according to technical requirements (Table 1) before bidding ('prequalification'). All auctions are pay-as-bid auctions (see Morey 2001, Chao & Wilson 2002, Müsgens et al. 2011). Bids are accepted based on their capacity price (*Leistungspreis*) only; activation is done according to the energy price (*Arbeitspreis*). Hence, there are two independent merit-orders. PC and SC are tendered for a week, TC for each day. PC is a symmetric (bi-directional) base product, which means both upward and downward regulation has to be provided for an entire week. SC is tendered separately as positive and negative reserves for peak and off-peak periods. TC is auctioned in blocks of four hours, separately for negative and positive. Hence, there are four SC products and twelve TC products per auction. Minimum bid sizes apply, but generators can be pooled. The number of prequalified suppliers has increased during the past years. Today, unconventional suppliers such as municipal utilities, industrial consumers, aggregators, and foreign generators are pre-qualified for all three control power types.[10] However, as we will argue in 4.4, the current market rules constitute an entry barrier for VRE generators, who could, as we argue in 4.3, efficiently supply balancing services.

Table 3: Balancing power market design in Germany.

	Primary Control	Secondary Control	Tertiary Control
Auction Period	week	week	day
# of Products	1 (base, symmetric)	4 (pos/neg; peak/off-peak)	12 (pos/neg; blocks of four hours)
Contract Duration	week	week (peak/off-peak)	four hours
Capacity Payment	yes	yes	yes
Energy Payment	no	yes	yes
Minimum Bid	1 MW	5 MW	5 MW
# of Suppliers	14	17	35

4.2. Market development

The price of balancing power differs across types. The average 2012 capacity price in Germany varied between 1 and 12 €/MW per hour.[11] Positive TC was cheapest while negative SC was most expensive. Maybe surprisingly, negative balancing was on average three to four times as expensive as positive. The sum of the four SC products was priced similarly to PC (Figure 7), which confirms the impression that both goods are close technical substitutes (Table 1). Prices are very volatile and price spikes occur.[12]

The balancing power capacity market had a size of about € 400 million in 2012.[13] For the TSOs, this is the cost of capacity reservation. We estimate activation costs to be € 200-300 million, hence capacity

[9] At least four studies discuss the impact of this market design reform: Riedel & Weigt (2007), Growitsch & Weber (2007), Müller & Rammerstorfer (2008), and Haucap et al. (2013).

[10] List of prequalified bidders, www.regelleistung.net/ip/action/static/provider. In April 2013, the batter company Younicos announced to build a 5 MW Li-On Battery to provide PC, www.younicos.com/de/mediathek/pressemeldungen/013_2013_04_29_WEMAG.html.

[11] We report capacity prices in €/MWh (Euro per MW and hour), not to be confused with energy payments, which are also denoted in €/MWh (Euro per MW-hour).

[12] During the Christmas week, 460 €/MWh was paid for negative SC.

[13] We have compiled all individual bids 2008-12 and calculated the capacity-weighted price.

payments are about two thirds of the total costs for balancing. Relative to the wholesale market for electrical energy (€ 25 billion), balancing is a small niche, featuring only 2.5% of its turnover (Figure 8). Of a private household's electricity bill, balancing services account for not more than 0.7%. For other countries, Rebours et al. (2007b) report the balancing system to cost 0.5-5% of the wholesale market for electrical energy, consistent with the numbers reported here. Cognet & Wilkinson (2013) find a similarly wide range of costs across European markets. This is an important finding: balancing power is cheap compared to the total cost of the power system. In a sense, even if balancing is regarded as a problem for VRE deployment, economically, it is a small problem.

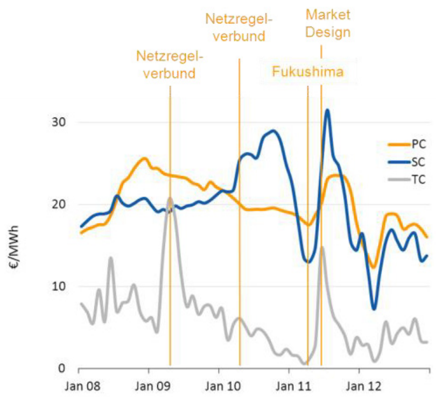

Figure 7. Capacity prices per MW and hour since 2008. The four SC products and the 12 TC products are aggregated to symmetrical base products in order to make prices comparable. The introduction of the control power cooperation, the phase-out of seven nuclear reactors, and the 2011 market design reform significantly affected prices.

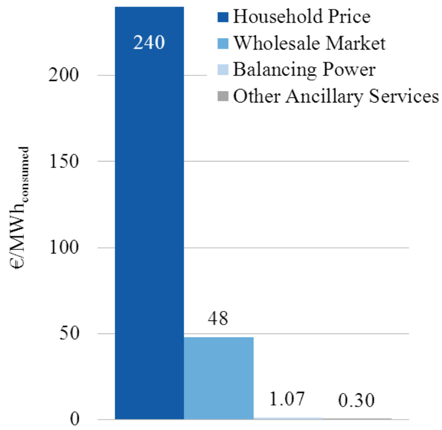

Figure 8. The cost of balancing power provision is very small when compared to the wholesale market for energy or the retail prices. Source: own calculations, Bundesnetzagentur (2012).

Since 2008, prices decreased significantly. Prices for positive balancing decreased much more than for negative balancing. PC prices fell by 20%, SC by 30%, and TC prices by 50%. In conjuncture with decreasing tendered quantities, this caused the market size to contract 30-60% (Figure 9). The aggregated costs of balancing power provision fell by 50%. Figure 10 sums up the development of reserve requirements and costs since 2008. While VRE capacities doubled, volumes decreased by 20% and costs by 50%. Again, this does not indicate a causal relationship - in contrast, it indicates that there is *not* a one-to-one relationship: apparently VRE do not necessarily dominate balancing cost development, even during times of strong built-out.

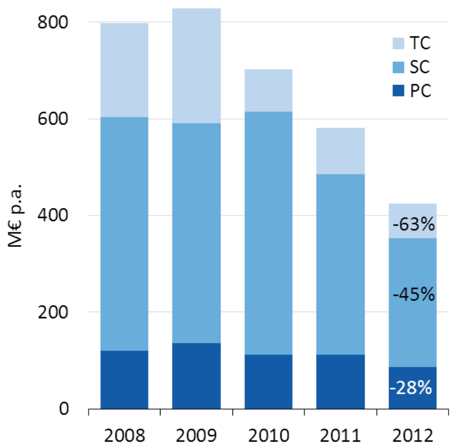

Figure 9. The market size of balancing power. The overall market size has contracted by 50% since 2008, with tertiary control decreasing most.

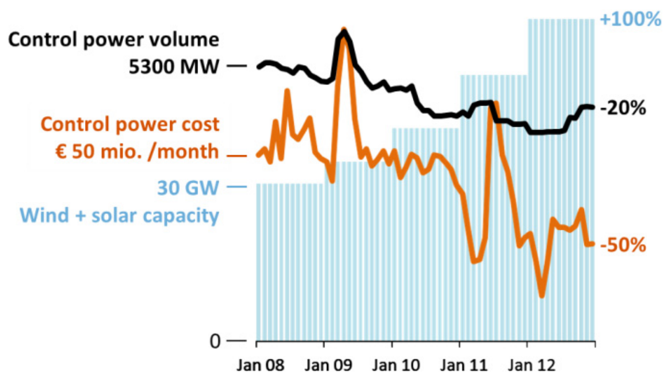

Figure 10. VRE capacity, reserves volumes, and reserve costs.

Explaining the historical price movement is not trivial. Since 2008, the balancing power market was affected by a number of shocks, which all potentially have influenced price development.

- Demand fell (section 3.3)
- Balancing markets became more competitive (Table 3), possibly triggered by market design changes and regulatory intervention (Growitsch et al. 2010, Heim 2013)
- Several supply shocks hit the market, such as the nuclear phase-out and the recession which has caused generation capacity oversupply
- Variable renewable capacity doubled, but at the same time forecasts were improved and a reform of the renewable support scheme in early 2012 exposed most renewables to imbalance price signals (section 5.3)
- Intra-day markets became more liquid and 15-minute trading was introduced, offering balancing options outside the balancing market
- Lower margins on spot markets changed opportunity costs for thermal plants

A more rigorous evaluation of the price development, such as multivariate regression analysis, is beyond the scope of this paper, but would be a promising direction of further research. Taken together, overcapacity, demand reduction, and market entry might jointly explain the strong overall price decrease. The price increase of negative versus positive balancing power can be explained by reduced margins on the spot market. The price spike during spring 2011 is related to the phase-out of seven nuclear reactors after the Fukushima accident. The price spike of TC prices in spring 2009 is connected to a shift of balancing power demand from SC to TC. Heim (2013) discusses the role of market power during the 2008-11 price increase for negative SC.

In the following, we point out what drives the costs of thermal plants to reserve capacity for balancing, and argue that because of this cost structure, VRE would be an efficient supplier of balancing.

4.3. The opportunity costs of reserve provision: why VRE should participate

We will argue that VRE generators are well equipped to provide downward balancing reserves during times they generate electricity. We then show that a thermal plant's opportunity costs of reserving balancing capacity is a function of the spot price - and that costs are high at very low spot prices. In other words: whenever VRE generate much electricity, they can provide balancing reserves at low cost, and thermal plants can supply only at high cost. This is a strong argument to encourage VRE generators to participate in balancing power markets.

Wind and solar power are technically well suited to ramp down very quickly, without significantly increasing maintenance costs or affecting life-time (Kirby et al. 2010, Bömer 2011, Speckmann et al. 2012, Bossanyi & Ghorashi 2013). In contrast, ramping of thermal plants causes boiler, tubes and turbines to change temperature, causing fatigue. While VRE generators can supply downward balancing at virtually no cost, they are not well suited to provide upward balancing: given their low marginal costs, operating below generation possibilities would occasion higher opportunity costs in terms of foregone profits on the spot market than for thermal plants (Figure 11, Figure 12).

The opportunity costs of reserve provision are determined by the foregone profit from sales on the spot market. They depend on i) the status the generator would be in otherwise, ii) spot market spreads, iii) ramping costs, and iv) part-load efficiency losses. Opportunity costs are different for positive and negative balancing. A generator that is in the money can provide negative balancing power at zero cost. To provide positive spinning reserves, the generator has to operate constantly below its rated capacity, resulting in reduced electricity sales and part-load efficiency losses. A generator that is out of the money has to remain online despite making losses; hence its opportunity costs are avoided losses.

Ignoring ramping costs and part-load efficiency, the opportunity costs of providing positive spinning reserve, C_+, can be written as a function of the spot price p, the plant's variable cost c, minimum load P_{min} and the amount of balancing power the plant can deliver, P_+.

$$C_+ = \begin{matrix} (p-c) & \text{if } p > c \\ -(p-c) \cdot P_{min}/P_+ & \text{if } p < c \end{matrix} \qquad (1)$$

The opportunity costs of providing negative reserve, C_-, can be written as this:

$$C_- = \begin{cases} 0 & \text{if } p > c \\ -(p-c)\cdot(P_{min}+P_-)/P_- & \text{if } p < c \end{cases} \tag{2}$$

Figure 11 and Figure 12 show illustrative opportunity costs of providing positive and negative reserves for combined cycle gas turbines (CCGT), hard coal-fired, lignite-fired plants, and wind power. They ignores any dynamic effects such as ramping or cycling costs, part-load efficiency losses, portfolio effects, and the fact that balancing power is provided for more than one hour. Under realistic parameters and 2012 European market prices for commodities these plants have variable costs of around 50 €/MWh, 33 €/MWh, 21 €/MWh, and zero. If spot prices are at these levels, generators are indifferent to produce or not, and opportunity costs for positive balancing are zero (Figure 11). At lower or higher prices, they are positive. VRE has always highest opportunity costs, except at very low prices, because it has lowest variable costs. In contrast, VRE's opportunity costs for negative balancing (Figure 12) are always zero. At low spot prices, the opportunity costs of thermal plants become positive. Importantly, during wind and sunny hours, VRE generation depresses the spot price, driving up the opportunity costs of thermal plants to provide negative balancing power. In other words, in these hours VRE generators are able to supply, and thermal generators have high costs. In those hours it would be efficient to use VRE for downward balancing.

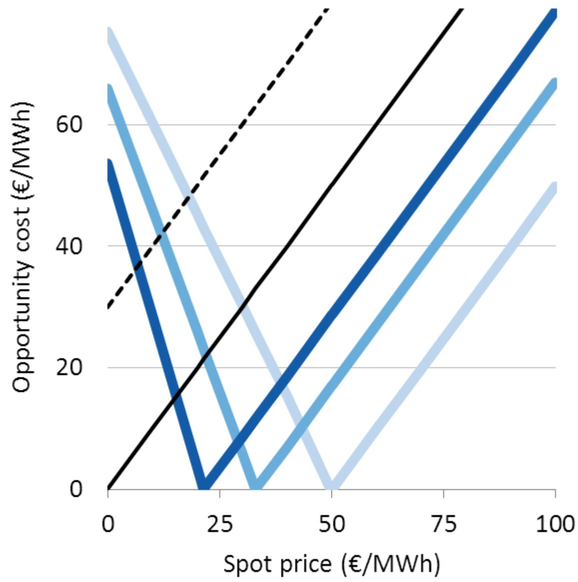

Figure 11. Opportunity costs of providing positive balancing reserves. Depending on the price, technologies with low or with high variable costs have lower opportunity costs.[14]

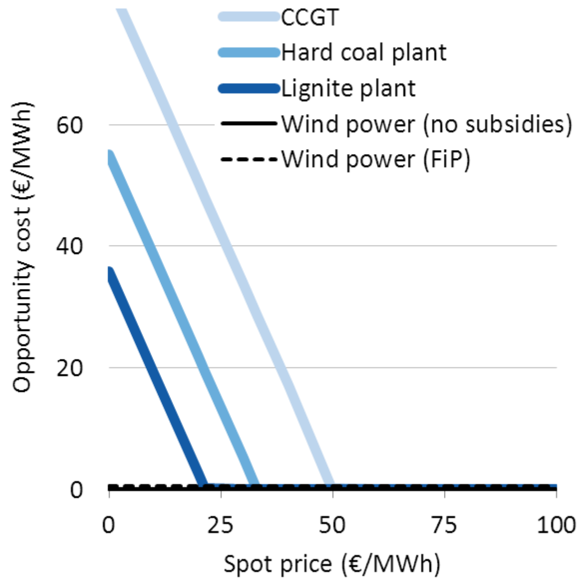

Figure 12. Opportunity costs of providing negative balancing reserves. Technologies with lower variable costs have lower opportunity costs. Plants that are in the money have zero opportunity costs.

4.4. Policy options: lowering entrance barriers

Above we have argued that VRE can efficiently supply negative balancing whenever they generate. However, despite the German renewable support system allows VRE to participate in balancing markets since 2012[15], wind and solar power seem not to participate on the market in significant volumes (Köpke 2013). Next to practical implementation issues (Speckmann 2013, Jansen et al. 2013),

[14] Gas price 25 €/MWh, hard coal price 10 €/MWh, lignite price 3 €/MWh, CO_2 10 €/t, efficiencies for CCGT 55%, hard coal 40%, lignite 35%, min load CCGT 30%, hard coal 40% , lignite 50%, control range 20%.

[15] Under the feed-in-tariff, VRE generators are not allowed to participate. Under the feed-in-premium, which covers now more than half of all capacity, they are.

the reason seems to be the design of balancing power markets that constitutes a prohibitive entry barrier.

The ability of VRE to provide negative balancing power is limited to times when the primary energy is available. The current market design constitutes a barrier to VRE participation, since it requires providing PC and SC for a full week. Over that time horizon, VRE forecasts are very uncertain, and only rarely weather conditions are stable during such a long time. Shorter auction periods are necessary for VRE participation. In the case of solar power, another detail of the market design prevents participation: solar power is available in large amounts between 10 a.m. and 6 p.m. However, current market rules require provision around the clock (PC) or from 8 a.m. to 8 p.m. (SC). Shorter contract durations are a necessary condition for solar power to supply these services.

We believe that daily auctions in steps of hours, in line with in the day-ahead sport market auction, would be a good solution. As a side benefit, it also improves the efficiency of thermal plant dispatch (Just 2010, Müsgens et al. 2012). As a side benefit, this would reduce must-run of thermal plants, keeping up the spot price and mitigating the market value drop of VRE (Hirth 2013, 2014). There are no costs beyond transaction costs, which could be greatly reduced if the power exchange instead of a proprietary platform is used for procuring balancing power.

Alternatively or in addition, energy bids could be accepted after the capacity auction is closed, as already done in Denmark (energinet.dk 2008) and The Netherlands (TenneT 2011). TenneT argues that this feature is a key reason for lower balancing costs in The Netherlands than in Germany. This would augment the existing balancing market with an energy-only balancing market. Alternatively, passive balancing could be fostered (5.4).

In addition, there are two proposals that would increase efficiency, but not affect VRE specifically. Borggrefe & Neuhoff (2011) have proposed condition bids. Conditional bids are joint bids on spot and balancing power markets, for example offering negative balancing for those hours where plants are in the money. Kahn et al. (2001) and Müsgens et al. (2011) argue that pay-as-bid pricing should be replaced by uniform pricing as it is more robust against uncertainty, reduces information asymmetry among firms, and mitigates market power.

5. Imbalance Settlement System

VRE forecast error *ceteris paribus* increase the need for balancing reserves. If the regulator gets "the prices right" and sets up the balancing power market accordingly, VRE generators can supply balancing power. There is a second way how the balancing system provides economic incentives to VRE generators: the imbalance settlement system and, as part of it, the imbalance price. We use 'imbalance settlement' or 'imbalance market' as an umbrella term for processes in the balancing system that take place after activation of balancing power. This involves two closely connected steps: the determination of the imbalance price and the allocation of remaining costs or profits. The imbalance price is the price that BRP have to pay for being out-of-balance and is paid per MWh deviation from the submitted schedule (€/$MWh_{deviation}$). This section discusses imbalance settlement, pricing rules, and two ways the imbalance price can work as an incentive: forecast improvements, and passive balancing.

5.1. The German Imbalance Settlement System

Imbalance price mechanisms are nationally regulated and differ along several dimensions: two-price or one-price systems; price derived from the cost of balancing or the spot price; capacity cost included or not; average or marginal pricing; cost-based pricing or punitive mark-ups; non-discriminatory pricing or a differentiated price for generators and loads (Vandezande et al. 2010, Borggrefe& Neuhoff 2011, ENTSO-E 2012a).

The German imbalance pricing mechanism is imposed by the Bundesnetzagentur and has been adjusted several times during the past years. Since May 2010, there is a common imbalance price for the four German balancing areas (*Ausgleichsenergiepreis,* reBAP). The imbalance price is based on the average costs of activated balancing energy, and settled for time intervals of 15 minutes, corresponding to BRP schedules. The costs for capacity reservation are socialized via grid fees on a pro-rata (€/MWh) basis. The system is designed to be cost-neutral in the sense that all activation costs are borne by unbalanced BRPs. As the energy payment on the balancing power market is subject to pay-as-bid pricing, the imbalance price is generally different from the energy price activated suppliers receive. The costs for capacity reservation are socialized via grid fees.

Germany follows a one-price system, hence short and long BRPs are settled with the same price. The relevant economic incentive is the *imbalance spread*: the difference between imbalance price and the corresponding day-ahead price. Usually, unbalances BRPs on the 'wrong' side, increasing the system imbalance, pay an imbalance spread, while BRPs that are on the 'right' side earn a spread.

TSOs publish imbalance prices only with a backlog of several months. BRPs trade imbalances on the so-called 'day after' market. In a one-price system this does not affect expected costs; it is merely done to reduce uncertainty.

Apparently the German regulator perceived the imbalance spread as too low to provide a sufficiently strong incentive for BRP to avoid imbalances (Bundesnetzagentur 2012a, Consentec 2012). As a consequence, a punitive mark-up was introduced in late 2012.[16] Since then, the price includes a mark-up of at least 100 €/MWh if more than 80% of all balancing power is activated. In 2010/11, this condition was fulfilled in only in 0.5% of all quarter hours. However, it is these extreme situations that determine the reserve requirements (see subsection 3.1).

5.2. Imbalance Prices in Germany

Figure 13 displays all 70.000 quarter-hourly imbalance prices for the years 2011 and 2012 as a function of the corresponding physical area imbalance. It also displays the average imbalance price and the imbalance spread. The associated figures are presented in Table 4.

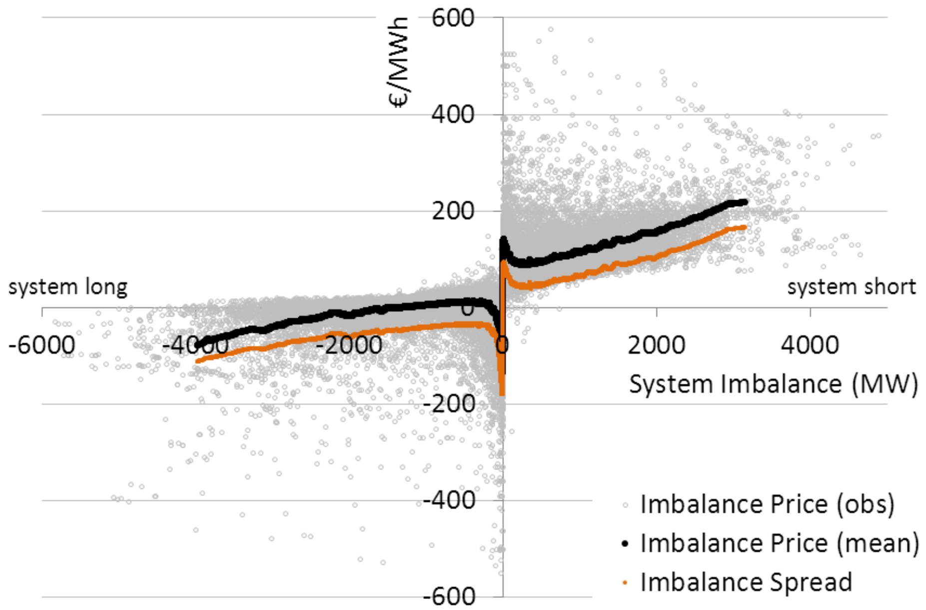

Figure 13. German system imbalance and imbalance price 2011-12 (70.000 quarter-hourly observations). At an imbalance of 2000 MW (positive balancing power needed), the imbalance price was 150 €/MWh on average, 100 €/MWh above the corresponding day-ahead spot price.[17] The high spreads around zero arise from the fact that the imbalance price is calculated in 15-minute intervals, while activations of SR is done at shorter time scales, such that within one interval there might be both negative and positive reserves activated. In such intervals there might be significant costs, but small net activation, resulting in high absolute imbalance prices.

[16] Bundesnetzagentur BK6-12-024, www.bundesnetzagentur.de/DE/DieBundesnetzagentur/Beschlusskammern/1BK-Geschaeftszeichen-Datenbank/BK6/2012/BK6-12-001bis100/BK6-12-024/BK6-12-024_Beschluss_2012_10_25.pdf

[17] www.amprion.net/ausgleichsenergiepreis; www.epexspot.com

The positive correlation between the system imbalance and the imbalance price indicates that overall, the pricing mechanism provides an economic incentive goes in the right direction. When the system was long, long BRPs lost in average 50 €/MWh, since they had paid 46 €/MWh on the day-ahead market, and received -4 €/MWh as imbalance price. When the system was short, the imbalance spread was 61 €/MWh. In less than one percent of all quarter-hours the imbalance spread provided a perverse incentive to BRP, being negative in times of system undersupply or positive in times of system oversupply.

Surprisingly however, the imbalance price was only 40 €/MWh on average, while the day-ahead spot market price was 47 €/MWh. Hence, during these years, it would have been profitable – albeit unlawful – for a BRP to be constantly short. In other words, in 2010/11 the imbalance market and the day-ahead market were not free of arbitrage opportunities. In one price systems, imbalances are only costly if correlated to the system imbalance: a normally distributed imbalance that was uncorrelated with the system imbalance paid an average imbalance spread of zero.[18]

Table 4: Imbalance prices and incentive to BRPs

	Average	System long (60% of all hours)	System short (40% of all hours)	System very long (<-2000MW) (4% of all hours)	System very short (>2000MW) (2% of all hours)
Imbalance price*	40 €/MWh	-4 €/MWh	109 €/MWh	-32 €/MWh	186 €/MWh
Day-ahead price*	47 €/MWh	46 €/MWh	48 €/MWh	41 €/MWh	52 €/MWh
Imbalance spread*	**-7 €/MWh**	**-50 €/MWh**	**61 €/MWh**	**-73 €/MWh**	**134 €/MWh**

*Time-weighted average.

Along with physical imbalances (Figure 3), the imbalance spread shows a characteristic pattern during the day: there are deterministic spreads before and after each full hour, driven by schedule leaps (Figure 14). We will argue below that BRPs should be allowed to respond to these price incentives.

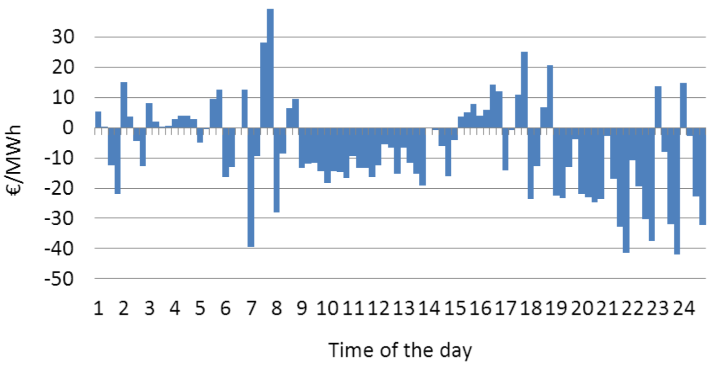

Figure 14. The quarter-hourly imbalance spread during the day. There is a clear pattern around the schedule leaps when residual load ramps are steep in the morning and late evening hours.

5.3. The Balancing Price as Incentives for Accurate VRE Forecasts

TSOs and regulators often view the imbalance price primarily from a cost allocation perspective: the price is set in a way that the costs of balancing energy are allocated, and no profits or losses remain with the system operators. However, from an efficiency perspective, the crucial role of the imbalance price is that it constitutes the incentive to BRPs to avoid imbalances.

BRPs can reduce imbalances by improving forecasts, shifting from hourly to 15 min scheduling, trading more actively on intra-day markets, and dispatch asset more accurately. Rational BRPs invest in such imbalance management measures only up to the point where the marginal costs of reducing

[18] A simulation of hundred normally distributed imbalances resulted in an average imbalance spread of 0.01 €/MWh.

their imbalances reach the imbalance spread. For static and dynamic efficiency, the imbalance price should reflect the marginal economic costs of solving imbalances by means of balancing power. For optimal resource allocation, these marginal costs are identical to the marginal costs of avoiding imbalance.

Setting the incentive right might be more relevant for VRE than for other BRPs. Relative to their output, imbalances are larger than for other generators. In addition, forecasting methodologies are relatively young and progressing quickly. Both for static and dynamic efficiency it is important that VRE generators see the true costs of forecast errors via unbiased price signals.

However, it is not only the imbalance pricing scheme that matters, renewables support policy also needs to transmit incentives to investors. Until the feed-in-tariff, German VRE generators were isolated from imbalance prices. Under the feed-in-premium, generators are not only allowed to participate on balancing power markets, but were also exposed to the imbalance price.

5.4. Passive and Active Balancing

When TSOs deploy balancing power, they *actively* balance the system. The price paid for this service is the capacity and the energy payment for balancing power. Similarly, the imbalance price provides the incentive to BRPs to *'passively'* balance the system. Hence, TSOs can either actively balance the system ordering adjustments via contracted balancing power, or passively balance the system via sending imbalance price signals to BRPs. This is also called 'self-balancing'.

Preconditions for effective passive balancing are on the one hand a timely publication of the imbalance price and on the other hand the legal possibilities for BRPs to respond by unbalancing their portfolio 'on purpose'. Traditionally, the Dutch TSO has used this mechanism quite heavily (TenneT 2011), while the German TSOs have followed a philosophy of active balancing. In fact, it is illegal for BRPs to unbalance on purpose - even if they would stabilize the system. The German regulator and TSOs want BRPs to stick to their schedules, and not respond to price incentives.

In fact, passive balancing is a close substitute for active balancing. Fostering passive balancing could be an alternative to open balancing power markets for VRE. But passive balancing can only respond on time scales of several minutes. Hence, it cannot replace balancing power to quickly offset stochastic disturbances. However, often imbalances last for hours or days, for example due to extreme weather, and passive balancing could play an important role. Moreover, deterministic imbalances – such as schedule leaps – could be efficiently targeted by passive balancing.

5.5. Policy Options

There are three major sources of inefficiency in the German imbalance market: practical and legal barriers to passive balancing, average pricing, and the allocation of capacity costs via grid fees. We discuss each in turn.

Passive balancing should be encouraged. First, it needs to be made legal, and second, the imbalance price needs to be published quickly. In France, Benelux, and UK prices are published within less than one hour (ENTSO-E 2012a). The price signal itself should be published, not only indicative physical imbalances, as TSOs have recently started to publish.

Efficient resource allocation requires the imbalance price to be based on the *marginal* cost of balancing energy provision, not the average cost. The combination of pay-as-bid auctions on the balancing power market and average pricing on the imbalance market leads to inefficiently low imbalance prices. Hence, either pay-as-bid payment should be replaced by marginal pricing (there are more reasons to do this see 4.4), or the imbalance price should be based on marginal activation costs.

Similarly, economic theory suggests that capacity costs should not be socialized, but borne by those BRPs that caused the need for reservation (Vandezande et al. 2010). A pragmatic approach could be to allocate these costs via the imbalance price, which would increase the imbalance spread by about 20

€/MWh.[19] If reserves are dimensioned to cover the loss of the largest unit, as it the case for PC, one might consider to allocate capacity costs to this unit.

Both average pricing and socializing capacity cost cause the imbalance spread to be currently *inefficiently low*. Hence, they constitute a positive externality; the incentives that BRPs receive to balance their portfolios are too weak. Specifically, the incentive for VRE generators to improve forecasts is too weak.

6. Concluding remarks

This paper has discussed three interfaces between variable renewables and the balancing system: the impact on reserves, participation of VRE generators on balancing markets, and the incentives provided by the imbalance settlement systems. These links interact and need to be considered holistically to account for the entire option space for policy makers. Take the example of passive balancing: allowing for BRPs to respond to price signals might render balancing power market reforms unnecessary, and could reduce the need for additional reserves to balance future wind and solar capacities.

Being a study of the German case, one has to be careful with generalizations. Moreover, we present descriptive statistics, such that statements on quantitative impacts necessarily remain untested hypothesis. However, we believe to be able to draw four broad findings from this study. Firstly, the balancing reserve requirement depends on a multitude of factors. Wind and solar power forecast errors power are only one of several important drivers. Secondly, while German VRE capacity doubled since 2008, reserves were reduced by 20%. This indicates that other factors can be quantitative more important than even strong VRE growth. One can interpret this as an indication that balancing power is not necessarily a major barrier to VRE integration at moderate penetration rates. Thirdly, the design of balancing power markets determines the incentives for VRE generators to provide balancing power themselves. Current market design constitutes a major barrier for participation. Finally, the design of imbalance settlement systems determines the incentives for BRPs for balancing their portfolios. Specifically, it sets the incentives for VRE generators to forecast accurately. Currently, the incentives for accurate forecasting are too low.

Throughout the paper we have also suggest a number of policy options. We propose to switch to dynamic dimensioning and price-elastic reserve procurement. In the balancing power market, entry barriers for variable renewables should be lowered to stimulate participation. Specifically, we recommend shifting to daily auctions and hourly contracts; to reduce transaction costs, the power exchange should be used for procurement. Moreover, we recommend switching from pay-as-bid to marginal pricing. In the area of imbalance settlement, we emphasize the role of the imbalance price as price signal. Today, the imbalance price is often understood as a cost allocation mechanism, but we believe it should be treated as a price signal. Passive balancing should be encouraged and prices should be published close to real time. Moreover, we recommend including the costs of capacity reservation in the imbalance price.

[19] In 2011, the costs for positive and negative capacity reservation (excluding PC) were € 160 million and € 310 million, respectively. The amount of energy activated was 7 TWh and 18 TWh (Bundesnetzagentur 2012b). Allocating capacity costs via imbalance prices would have increased the imbalance spread by about 20 €/MWh, both in periods of undersupply and oversupply.

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Chapter 8

Findings and Conclusions

Chapter Eight: Findings and Conclusions

Electricity is a peculiar economic good, being at the same time perfectly homogenous and significantly heterogeneous along three dimensions - time, space, and lead-time. Electricity's heterogeneity is rooted in its physics. As an implication, the economics of wind and solar power are affected by their variability. The impact of variability can be expressed in terms of the marginal value: for example, at 30% penetration, electricity from wind power is worth 30-50% less than electricity from a constant source. Expressed differently, wind power's variability increases generation costs by 20-35 €/MWh, or, expressed still differently, the optimal share of wind power would be three times as high if winds were constant. This value drop (or cost increase) stems mainly from the fact that the capital embodied in thermal plants is utilized less. Welfare analyses of VRE need to take electricity's heterogeneity into account to avoid optimistically biased estimates. These are, in very short, the main findings of this thesis.

The remainder of this chapter provides a somewhat more elaborated summary of results from the six articles. It synthesizes findings, draws conclusions, and indicates promising directions of future research. The first section summarizes my impressions regarding the status of the literature in the field. Section two reports the conceptual findings from this thesis, and section three quantitative results. Section four discusses methodological conclusions for modeling. Section five derives policy implications. Directions for future research are pointed out throughout the chapter.

1. *The literature is scattered*

The literature on the economics of wind and solar power variability is divided among at least two separate schools of thought, the 'integration cost literature' and the 'marginal value literature'. These two literature branches use separate concepts, incompatible terminology, and different modeling methodologies. Moreover, the two strands are rather inward-looking, with little references to the other school of thought. Specifically, the integration cost literature has been quite silent about the economic meaning and the implications of their estimates. Obviously, such a separation of fields is unsatisfactory and inefficient.

More generally, in my perception the field lacks a culture of reviewing the literature. Most articles, including those published in peer-reviewed journals, do not provide a rigorous discussion of previous publications. Often, merely a handful of well-known publications are enumerated. Dedicated literature review articles that cover both the integration cost and the marginal value literature are almost absent. Such reviews would be especially helpful if they do not only synthesizing the state of the art, but also clarifying terminology, and provide unified frameworks for further research. As a consequence of the weak review culture, some early seminal contributions seem to be almost forgotten. Several decades ago, Stephenson (1973), Martin & Diesendorf (1983), and Grubb (1991) have provided crucial insights to the economics of wind and solar integration, yet these contributions are seldom acknowledged, and many recent papers lag behind these landmark papers in terms of understanding, scope, and methodology. Finally, much of the relevant literature is not published in peer-reviewed journals, including key contributions such as GE Energy (2010), Mills & Wiser (2012), Nicolosi (2012), or NREL (2012). It is widespread practice that German studies for policy advice refer mostly to German studies, and are not being published in English language. In total, almost half all documents surveyed for this dissertation is grey literature. The field would certainly benefit from more journal publications in terms of rigor and accessibility.

For future research, authors should review the entire field, not only their narrow community. Editors and reviewers should enforce the provision of thorough literature reviews. Founding bodies of studies should encourage authors to submit manuscripts to academic journals and to publish in English. Specifically, dedicated literature surveys are highly warranted. Editors and reviews should welcome the submission of literature survey manuscripts.

2. *Conceptual findings*

The most fundamental finding of this doctoral thesis is that *variability matters*. It matters in the sense that that ignoring variability in economic assessments of wind and solar power almost always biases results, and the bias is often quite large. Based on ECONOMICS OF ELECTRICITY and FRAMEWORK, this section first argues that that many commonly used assessment tools are flawed because electricity is heterogeneous, and then synthesizes the valuation framework developed in these papers, which does account for heterogeneity.

a) The implication of homogeneity for economic assessment

The marginal value, or price, of one MWh of electricity can vary by several orders of magnitude. It varies between moments in time, locations in the grid, and with respect to lead-time between contract and delivery. We have identified this 'three-dimensional heterogeneity' as the fundamental property of electricity as an economic good. It is rooted in the physical laws of electromagnetism that disallow storage and hence inhibit arbitrage over time, affect transmission and hence restrict arbitrage over space, and limit flexibility and hence inhibit arbitrage over lead-time.

Heterogeneity has a number of important implications. First, electricity from different generators has a different economic value, as it is produced at different times, at different locations, and under different degrees of flexibility. Economically, electricity from wind turbines is only imperfectly substitutable with electricity from coal plants. In other words, they produce different electricity goods. Second, commonly used indicators such as 'levelized electricity costs' (LEC) and 'grid parity' are incomplete measures for economic efficiency of generation technologies. These indicators ignore value differences, hence they implicitly assume electricity to be a homogenous good. Third, the relative value (or price) of electricity from a certain technology decreases with its market share. This is true for all generators, including wind and solar power. At high penetration, VRE will have a relatively low economic value, relative compared to both today's value and to the value of more dispatchable power sources. Ignoring this effect in welfare and competitiveness studies introduces a bias towards optimism regarding wind and solar power.

An important application where such bias can be introduced is assessment based on multi-sector models, such as integrated assessment models (IAMs). These models have a low spatial and temporal resolution, and accordingly cannot represent heterogeneity explicitly. If not parameterized carefully, IAM-based estimates of optimal VRE deployment are biased.

b) A valuation framework

Based on this analysis, this thesis has developed a consistent and comprehensive 'toolbox' for economic assessment of power generating technology that is also applicable to variable renewables and accounts for their specific characteristics. The toolbox contains concepts, methods, and terminology. We have labelled this toolbox a *valuation framework*. This framework comprises several building blocks: the derivation of unbiased first-order conditions for optimal quantities of wind and solar power in the presence of heterogeneity; a definition of variability and variability costs; a new metric that expresses value differences in terms of costs; proposals for indicators and modelling; a new definition of integration costs; the decomposition of variability costs into three components; accounting for system inertia and system adaptation; and empirical estimates of these cost components from models and markets.

Optimality requires the long-run marginal costs of electricity supply from each generation technology to coincide with *its marginal value*. This condition can be expressed in terms of different electricity goods. Defining the *cost of variability* as the difference in marginal value to a reference electricity good, we have derive the metric *System LCOE* as the sum of generation cost and these variability cost. Often, academic, policy, and industry documents compare the LCOEs of different technologies, implicitly or explicitly suggesting that a lower LCOE indicates efficiency or competitiveness. This is not the case. In fact, comparing LCOEs from different technologies has quite little economic meaning at all, since marginal costs of producing different economic goods are compared. The framework suggests a remedy: if technologies are to be compared in terms of per-unit costs, System LCOE should be used instead. This allows inference on competitiveness and efficiency.

Not only for simple comparisons, also for IAM modeling, might it be convenient to present value differences in terms of costs differences. In the past, 'integration costs' have been used for that purpose. We have shown that the standard definition of integration costs cannot be used to compare the economics of technologies, and proposed to define integration costs "in a broad sense" along our definition of variability costs. This definition is more rigorous than previous definitions and has a straightforward welfare-economic interpretation. According to this definition, all technologies are subject to integration costs, and integration costs can be positive as well as negative.

Much previous research has focused on certain aspects of VRE variability, such as forecast errors, or the need for grid extensions. The conceptual chapters of this thesis have proposed a pragmatic approach to consistently compare such individual aspects in economic terms. Variability costs are decomposed into profile, balancing, and grid-related costs, each of which can be individually assessed and quantified. We have shown that, while forecast errors and grid constraints matter, they are not the largest economic impact of variability. Rather, the most important economic consequence of wind and solar variability is reduced utilization of the capital embodied in the residual power system, mainly in thermal plants. A convenient feature of this decomposition is that each component can be quantified from model results or market data, as will be reported in the following section.

3. *Quantitative findings*

This section summarizes quantitative estimates on the impact of variability that are derived from MARKET VALUE, OPTIMAL SHARE, FRAMEWORK, and REDISTRIBUTION. The impact of variability is expressed in form of three different metrics: as its effect on the marginal value of wind and solar power, as the effect on their optimal deployment level, and as additional (integration) costs. Estimates are mainly derived from numerical modeling results, but also from market data estimates and a broad review of the literature. First, long-term estimates are reported, and then transitional effects are discussed.

a) *Long-term (lasting) effects*

The following paragraphs report results from EMMA runs, first benchmark (point) estimates and then uncertainty ranges. These are in the following complemented with evidence from the literature to derive a consolidated "impact matrix" that compares the impact of different aspects of variability. Finally, the impact of different policy drivers is identified.

The first and foremost quantitative result of this study is that the marginal value of both wind and solar power in thermal power systems is significantly reduced by increasing market shares of the respective technology. At low penetration levels, the marginal value of both technologies is comparable to a constant source of electricity, or even higher. In other words, integration costs are absent – or even negative. At 30% market share, the long-term marginal value of wind power is reduced to about 0.6 of that of a constant source. Solar reaches a similar reduction already at 15% penetration. Variability has a larger impact on solar than on wind power, because solar generation is more concentrated. These numbers can be equivalently expressed as integration cost mark-ups. If the average electricity price is 70 €/MWh, the value drop is equivalent to a cost increase of 30 €/MWh. These findings can also be expressed in optimal deployment levels: this study estimates the optimal wind share in Northwestern Europe to be around 20% – without variability, optimal deployment would be three times as high. In other words, studies that optimize the generation mix but ignore variability might introduce a bias of 200%. These results are based on EMMA modeling of thermal power systems, and are consistent with empirical market data and previous studies. In hydro systems, the marginal value at high penetration is generally higher (hence integration costs are lower, and optimal deployment is higher).

These findings are subject to significant model and parameter uncertainty. The following figures displays the parameter uncertainty derived from a large number of EMMA sensitivity runs.[1] Figure 1 shows the marginal value drop for wind power from profile costs, ignoring balancing and grid-related costs. At 30% penetration, the marginal value is estimated to be in the range of 0.5 to 0.8 (point estimate 0.7). Figure 2 shows the optimal market share, ignoring grid-related costs. At 50 €/MWh generation costs, 30% below current cost levels, the optimal share is estimated to be between 1% and 45% (point estimate 20%); however, 80% of all model runs fall in the range of 16% to 25%.

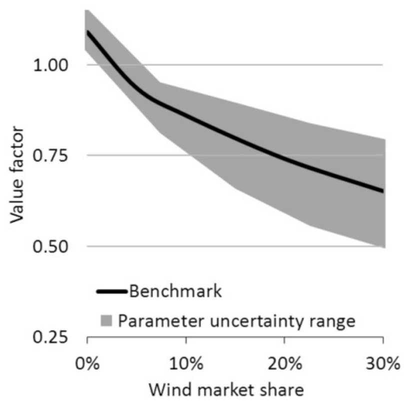

Figure 1. Parameter uncertainty of marginal value. The shaded area indicates the upper and lower extremes of mid- and long-term runs. Source: own work, adopted from MARKET VALUE.

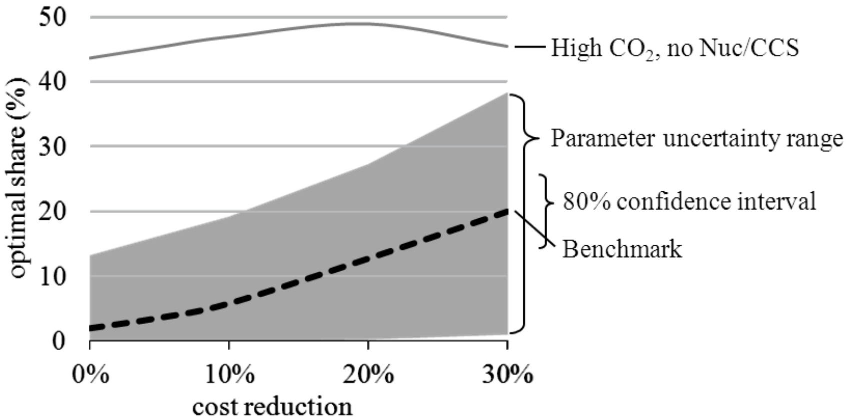

Figure 2. Long-term optimal wind shares in the benchmark run and the range of all sensitivities. The range does not include the noNucCC run at 100 €/t, where the optimal wind share is above 40%. Source: own work, adopted from OPTIMAL SHARE.

These model runs apply to Northwestern Europe and are subject to the model assumptions that underlie EMMA. About 100 previously published studies have been reviewed to validate these estimates and increase robustness, and historical market data has been assessed. From studies and EMMA model results, subjective confidence intervals are condensed that represent the 80% probability range of parameters. Deriving these ranges is based on significant subjective judgment regarding quality of different studies, applicability of methodologies, and relevance of case study regions. Table 1, the impact matrix, summarizes the impact of variability as expressed as marginal value drop, integration cost mark-up, and optimal deployment reduction by each variability component.

Table 1: The impact of variability on the economics of onshore wind power.

Impact metric		**Marginal value**	**Integration costs**	**Optimal deployment**
Impact of variability		- 30-50%	+ 20-35 €/MWh	-50%-points (from 70% to 20% share)
Of which	**… profile**	- 20% to -35%	+ 15-25 €/MWh	45%-points
	… balancing	- 4% to -10%	+ 3-6 €/MWh	8%-points
	… grid-related	- 0% to -15%	+ 0-10 €/MWh	?
Wind assumptions		30-40% wind penetration	30-40% wind penetration	wind LEC 50 €/MWh
System assumptions		predominately thermal power system; ca. 70 €/MWh long-term equilibrium base price		

Numbers are aggregated from different numerical modeling results and a large number of published studies. Ranges roughly represent 80% confidence intervals. Extreme values of cost components do not sum up, as extremes are unlikely to occur simultaneously. Weighting studies adding up the three components contains significant subjective judgment. Source: own work, based on FRAMEWORK, MARKET VALUE, and OPTIMAL SHARE.

[1] These uncertainty ranges only represent parameter uncertainty. Figure 5 below displays findings from previous studies. These results capture both parameter and model uncertainty.

The relative size of the three components is one of the most important, and maybe most surprising, finding of this study: in thermal systems with high VRE shares, profile costs cause more than half of all integration costs. It is not forecast errors, which receive most of the public and academic attention, but the temporal generation profile of wind power that reduces its value. The profile has such a strong impact because it reduces the utilization of thermal capacity. In other words: the largest integration cost component is the reduction of utilization of the capital embodied in the power system. This is insofar surprising, as most integration cost studies do not even mention this effect. Balancing costs and ramping costs, which receive much attention in the debate, are at best moderate in size.

Prices, policies, and technology strongly affect the market value of VRE. While some of these impacts are as expected, others come at a surprise. Take the example of carbon pricing: many observers suggest that CO_2 pricing has a positive and significant impact on VRE competitiveness. Many European market actors argue that during the 2020s, renewable subsidies should be phased out, and expect VRE to continue to grow, driven by carbon prices. We compare the impact of a low CO_2 price (0€/t) and a high price (100 €/t) to a moderate price (20 €/t). As expected, a low price leads to low wind value. Yet, a high price *also* leads to a lower wind value. The reason for this surprising impact lies in competing low-carbon technologies: most low-carbon technologies, such as nuclear power and carbon capture plants, are base load technologies with very high investment, but very low variable costs. Baseload capacity reduces the marginal value of VRE, as it can deliver electricity at low cost, once it is built. Carbon prices below 40 €/t do not trigger any nuclear or CCS investments, such that up to that point carbon pricing has a positive impact of VRE via higher costs of emitting plants. Beyond 40 €/t, the baseload investment effect dominates the emission cost effect. Hence, in some cases, a higher CO_2 prices *reduces* optimal wind deployment. Table 8 summarizes the effects of the price and policy shocks on the relative value of wind power.

Table 2: Divers of the marginal value of wind power

Change	**Value factor**	**Dominating Chains of Causality**
CO_2 price ↓	↓	Steeper merit-order curve due to lower variable costs of coal
CO_2 price ↑	↓	Steeper merit-order curve due to investment in nuclear and CCS
CO_2 price ↑ & Nuc/CCS ↓	↑↑	Flatter merit-order curve due to higher variable costs of coal; Overall price increase
Coal price ↑	↑	Flatter merit-order curve in the range hard coal – gas; Partly offset by lignite investments
Gas price ↑	↓	Steeper merit-order curve due to higher variable costs of gas; Lignite and hard coal investments reinforce this effect
Interconnectors ↑	↑	smoothening out of wind generation across space;
Storage ↑	–	Small impact of wind because of small reservoirs; Negative impact on solar at low penetration rates, positive at high rates
Plant Flexibility ↑	↑↑	Reduced must-run generation leads to higher prices especially during hours of high wind supply

Source: own work, adopted from MARKET VALUE.

Figure 3 shows the impact of drivers in terms of optimal deployment. It summarizes the optimal long-term share of wind power in Northwestern Europe under all tested parameter assumptions. Several drivers have only limited impact, but some drivers have a large effect. Maybe most surprising is the role of carbon prices. High CO_2 prices can either reduce the optimal wind share to very low levels (if they trigger investments in nuclear power), or double the optimal share over and above 40% (if no nuclear or carbon capture and storage investments are allowed). This is consistent with the impact on marginal value discussed above.

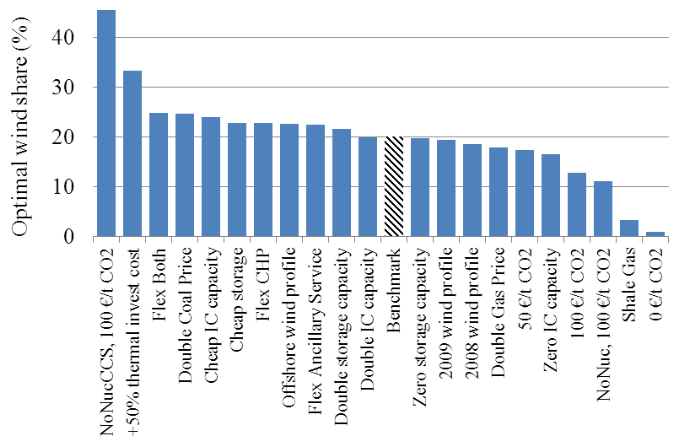

Figure 3: The impact of different drivers on the optimal deployment of wind, assuming wind generation costs of 50 €/MWh. The total range is 1-45%; this is the parameter uncertainty range mentioned above. Source: own work, reproduced from OPTIMAL SHARE.

b) Short-term (transitional) effects

Until the power market has converged to its long-term equilibrium, the introduction of VRE capacity and its variability has a number of short-term or transitional effects. On the one hand, power markets adopt, also in terms of market design. A good example is the adjustment of balancing systems to accommodate VRE forecast errors. On the other hand, the marginal value drops to low levels, before recovering in the long term. Finally, the introduction of renewables causes significant wealth redistribution between consumers and incumbent power generators.

The economics of VRE depends not only on the variability itself, but also on many parameters of the residual power system: the thermal capacity mix, the transmission grid, market design, and much more. When quantifying the economic impact of high shares of wind and solar power, studies take very different assumptions about the power system to adapt to the introduction of large quantities of VRE. Power systems can adapt in a multitude of ways to increasing VRE penetration: operational routines and procedures can be changed; market design can adopt; existing assets can be modified to operate more flexibly or under otherwise changed conditions; the capacity mix can shift; the transmission grid can adjust; technological innovations can take place like integration options (roughly ordered by time that is needed). Because of *inertia*, for example the sunk investments in physical capital, these adjustments take time. Since life-time of physical assets is very long in the electricity sector, power markets can actually be out of equilibrium for extended periods of time after the swift introduction of significant amounts of VRE.

An example of adjustments of market design to higher shares of VRE is the balancing system. As argued in BALANCING POWER, there are three interfaces between renewables and the balancing system: the increased the need for balancing services due to VRE's inherent forecast errors; the supply of balancing services by VRE generators; and the incentive for dynamically improving forecast technologies that the balancing system provides. These three channels are inter-dependent and interact with each other. System adaptation in form of appropriate balancing power market re-design (short contract durations, close-to-real time trading, marginal pricing, passive balancing) can greatly reduce balancing costs.

In general, integration costs can be expected to decrease if the power system is allowed to adapt in response to increasing VRE penetration, and the marginal value can be expected to increase (Figure 4). The size of system adaptation depends on the system adaptation potential, speed of system adaptation, speed of introduction of wind and solar power. Hence, different assumptions on system flexibility can explain a good share of the difference in findings of previous studies. Figure 5 shows that studies that hold the residual capacity mix fix estimate the marginal value to drop by one percentage point per percentage point increase of wind market share. Studies that allow the capacity mix to adopt report a drop of only 0.6 percentage points. In other words, studies that account for system adaptation report lower integration costs. Generally, it is important for analysts to be explicit about the time horizon and boundary conditions of studies. Specifically, high VRE shares should only be evaluated with tools that allow significant system flexibility, especially an endogenous capacity mix (see section 4).

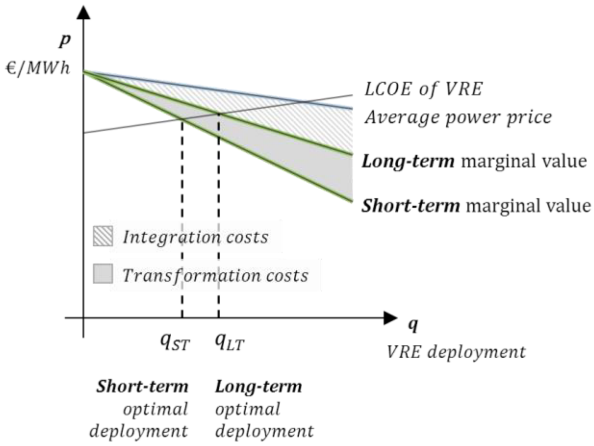

Figure 4: The decrease of the marginal value of VRE is steeper in the short term compared to the long term and the optimal share is lower. Source: Ueckerdt et al. 2013.

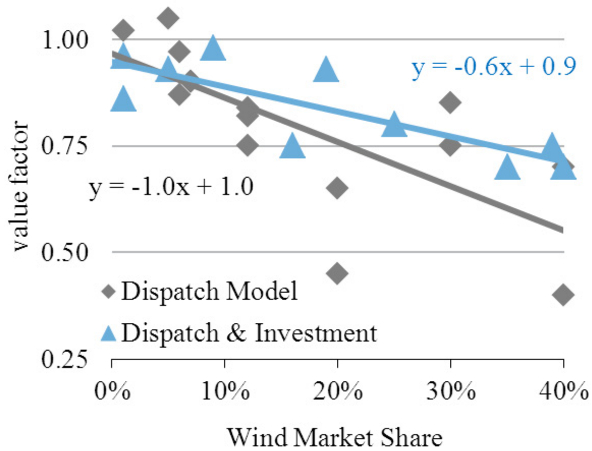

Figure 5: Short-term (dispatch) and long-term (dispatch & investment) models result in quite different marginal value estimates at high penetration. Source: Own work based on the literature reviewed in FRAMEWORK.

In the short term, before the system has settled at the long-term equilibrium, significant amounts of wind investments will always reduce the electricity price. This implies not only a low market value for wind power, but also significant redistribution of economic surplus from incumbent generators to consumers. We find that this redistribution effect can be quite large, reducing producers' short-term profits by 75% at 30% wind penetration (Figure 6). According to our estimation, wind support transfers enough producer rents to consumers to make those better off even if they pay the costs of subsidies.

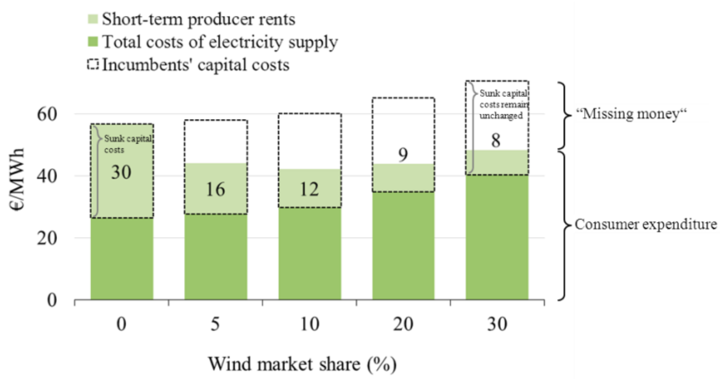

Figure 6: Rents and costs at different wind penetration rates. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure. With increasing wind penetration, producer rents are transferred to consumers. At 10% wind market share, short-term consumer surplus is maximized. Source: own work, reproduced from REDISTRIBUTION.

4. *Methodological conclusion*

These findings lead to a number of methodological conclusions and point at possibilities to develop models further. First and foremost, they show that variability matters in economic analysis of the electricity sector. Ignoring electricity's heterogeneity leads to a large bias in results, and tools that treat electricity as a homogenous good should not be used to assess electricity generation. Second, several of the reported findings are surprising or even counter-intuitive at first glance. This underlines the necessity for rigorous analytical methods that can challenge intuition and conventional wisdom. Electricity sector research and policy advice should use calibrated models for assessments. In the following, I discuss methodological conclusions and directions for future research for low-resolution and high-resolution models.

Macroeconomic models with coarse temporal and spatial resolution, such as integrated assessment models, cannot represent variability explicitly with sufficient detail to capture even the largest effects. First, not only renewables, but all power generation technologies need to be modelled in a way that accounts for their different marginal value. Second, IAM development should prioritize those aspects that have the largest impact on model results, which are often profile costs. Third, to estimate integration costs, tools other than IAMs are needed, such as high-resolution numerical or econometrical models. From such models, System LCOE can be estimated and implemented to IAMs to represent variability. That would give the common method of using cost-penalties for VRE a rigorous welfare-economic foundation. However, its ex-ante calculation with a partial model might not be suitable for a broad range of IAM regions and scenarios. Consequently, it could be estimated on a region-specific basis and model results should be fed back to the partial model to verify the ex-ante estimate. To reduce the need for such an iterative model coupling, where possible, some aspects of variability could be modeled explicitly. For instance, endogenous residual load duration curves could address a large part of profile costs. More detailed aspects like grid-related and balancing costs could be implemented by adding reduced-form formulations. A sound representation of variability would likely be a model-specific combination of different explicit and implicit elements. However, much remains to be understood, and representing the electricity sector rigorously in IAMs is a promising direction of further research.

The findings of section 2 and 3 provide compelling arguments to use high-resolution models for economic assessments of the electricity sector, such as power market models. Of course, power market models such as EMMA have limitations as well. On the one hand, they cannot capture macroeconomic phenomena like endogenous technological learning or general equilibrium effects. These features can probably be only incorporated via soft-coupling with macro models. On the other hand, power market models themselves should be equipped with a number of features if used for assessing the economics of VRE at high penetration. Specifically, they should

1. feature a fine temporal resolution, such as hours
2. account for operational inflexibilities of power systems, such as balancing power provision and combined heat and power generation
3. cover a large geographic area, not only one country, and allow for imports and exports
4. take into account the legacy of the existing capital stock, especially existing power plants
5. model investments endogenously, hence allow for an adaptation of the capacity mix and permit investors to earn capital costs back in the long term
6. use wind, solar, and load time series as input data that features realistic statistical properties, such as the first and second moment, auto-correlation, and correlation between variables
7. approximate the impact of forecast errors and balancing power
8. approximate the transmission grid and account for congestion
9. provide a realistic representation of hydro reservoirs, capturing flexibilities and constraints

The model that was used in this study, EMMA, performs quite well on the first seven criteria, but scores low on network and hydro modeling. Hence estimates from EMMA should be interpreted for thermal systems only, and need to be amended for grid-related costs.

For future research, EMMA, or comparable models, could be extended in several directions. A more thorough modeling of specific flexibility options is warranted, including a richer set of storage technologies, demand side management, long-distance interconnections, and heat storage. A special focus should be paid to the existing hydro reservoirs in Scandinavia, France, Spain and the Alps. More generally, integrated modeling of hydro-thermal systems and integrated modeling of both transmission constraints and power plants investments are promising fields of model development. For certain research questions, representing existing policies and model the interaction of policies can be quite crucial. Developing numerically feasible approaches to incorporate internal transmission constraints intro long-term power market models is another promising research direction.

5. Policy conclusions

These findings lead not only to methodological conclusions, but also suggest a number of policy implications. Bearing in mind significant parameter uncertainty (recall section 3) and model limitations (section 4), such conclusion need to be drawn cautiously. However, I believe seven broad robust conclusions can be drawn, each of which also indicates promising directions of future research.

Firstly, onshore wind power will most likely become an important source of electricity and play a much larger role than today. The numerical results point at the important role of wind power as a competitive electricity generation technology in Northwestern Europe. The long-term point estimate of a 20% generation share implies an increase from today by as much as three-fold. Wind power will most likely become a cornerstone of Europe’s electricity supply. Policy makers, system operators, and investors should take that into account when design policies and markets, planning transmission and distribution grids, and investing in long-living generation assets. Each of these areas provides a range of relevant research question, for example appropriate balancing power and intraday market design for significant wind shares.

Secondly, having said this, results also indicate that the market value of VRE steeply declines with penetration. It follows, that very high renewable shares of 80-100%, as targeted by some governments (recall Chapter One), will probably not be materialized without large-scale subsidies. Even under very strong VRE cost reductions and a very favorable mix of policies we have not found a case where the share of VRE rises above 60%. High carbon prices alone do not make wind and solar power competitive at high penetration rates, as they trigger low-carbon base load investments. For Europe, that means that even if CO_2 prices pick up again, subsidies cannot be phased out during the 2020s if ambitious renewable targets are to be reached. This relates directly to the fierce discussion around policy targets for 2030 that currently takes place in Brussels. For the long-term decarbonization of the power sectors, researchers as well as policy makers should take the possibility of a limited role for solar and wind power into account and should not disregard other greenhouse gas mitigation options too early. Future research should study policy interaction more thoroughly, especially the repercussions of renewable support, CO_2 pricing, and technology-specific policies for nuclear and CCS.

Thirdly, there are a number of integration options that help mitigating the value drop of VRE: transmission investments, flexibilizing thermal generators, and advancing wind turbine design could be important measures. In contrast, electricity storage is found to play only a limited role. Future research should assess integration options in more detail, based on appropriate numerical modeling. Another research direction is to study technological change of energy technologies and assess potential research externalities and remedies: how to efficiently incentivize the technology development of integration options?

Fourthly, such mitigation measures will develop if and only if incentives are set rightly. Hence, it is important to “get the prices right” - wholesale, balancing power, and imbalance prices need to reflect marginal costs and marginal benefits to provide efficient incentives. Since most VRE generators are subsidized, it is also important to “get the policies right”, to provide the right incentives to stimulate turbine development, for example. Future research needs to address how policy instruments can be designed to transmit price signals, and how prices can reflect the true marginal costs of flexibility and grid constraints.

Fifthly, we find that variable renewables need mid and peak load generators as complementary technologies. Biomass as well as highly efficient natural gas-fired plants could play a crucial role to fill this gap. On the other hands, low-carbon base load technologies such as nuclear power or CCS do not perform well with high shares of VRE. This is not because such plants are technically inflexible, but because they are capital intensive. It is true that technically flexible plants (ramping and cycling capabilities) are needed for VRE-rich power systems. However, such flexibility is rather cheap. What is more important is having *economical* flexible plants (low capital costs). Future research should plumb the potential of low-carbon, low-capex technologies and study the power market interactions between biomass and VRE.

Sixthly, we have shown that rapid expanding VRE deployment is problematic, for two reasons. On the one hand, the short-term marginal value of electricity is lower than the long-term value, and the long life-time of physical assets imply that power systems need significant time to adapt to shocks. Pushing in capacity too fast devalues capital that is sunk in physical assets. On the other hand, this in fact expropriates incumbent generators and might undermine long-term trust of investors. For both reasons, VRE should not be up-scaled too fast.

Finally, we have shown that not only efficiency, but also redistributive consequences of introducing renewables are significant. Combining carbon pricing with renewables support allows policy makers to keep producer rents down. This could be an explanation for the existence of subsidies for renewables. Redistribution merits further attention, including redistribution between jurisdiction and without the heterogeneous group of electricity consumers. More fundamentally, on the one hand researchers should state more explicitly if the phenomenon they study is one of efficiency of one of distribution. On the other hand, studies would become more policy-relevant if *both* efficiency and distribution outcomes are assessed.

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Chapter 9

Appendix

Appendix

Appendix A: Ad campaign of German utilities

Figure 1: Ad campaign of German utilities in 1993. Source: Die Zeit, 30.7.1993, page 10.

Appendix B: EMMA model formulation

B.1 Total System Costs

The model minimizes total system costs C with respect to a large number of decision variables and technical constraints. Total system costs are the sum of fixed generation costs $C^{fix}_{r,i}$, variable generation costs $C^{var}_{t,r,i}$, and capital costs of storage C^{sto}_{r} and transmission $C^{trans}_{r,rr}$ over all time steps t, regions r, and generation technologies i:

$$\begin{aligned} C &= \sum_{r,i} C^{fix}_{r,i} + \sum_{r,i,t} C^{var}_{t,r,i} + \sum_{r} C^{sto}_{r} + \sum_{r,rr} C^{trans}_{r,rr} \\ &= \sum_{r,i} \left(\hat{g}^{inv}_{r,i} \cdot \left(c^{inv}_{i} + c^{qfix}_{i} \right) + \hat{g}^{0}_{r,i} \cdot c^{qfix}_{i} \right) + \sum_{t,r,i} g_{t,r,i} \cdot c^{\mathrm{var}}_{i} + \sum_{r} \hat{s}^{inv}_{r} \cdot c^{sto} + \sum_{r,rr} \hat{x}^{inv}_{r,rr} \cdot \phi_{r,rr} \cdot c^{NTC} \end{aligned} \quad (1)$$

where $\hat{g}^{inv}_{r,i}$ is the investments in generation capacity and $\hat{g}^{0}_{r,i}$ are existing capacities, c^{inv}_{i} are annualized specific capital costs and c^{qfix}_{i} are yearly quasi-fixeded costs such as fixed operation and maintenance (O&M) costs. Balancing costs for VRE technologies are also modeled for as fixed costs, such that they are not affecting bids. Variable costs are the product of hourly generation $g_{t,r,i}$ with specific variable costs c^{var}_{i} that include fuel, CO_2, and variable O&M costs. Investment in pumped hydro storage capacity $\hat{s}^{io,inv}_{r}$ comes at an annualized capital cost of c^{sto} but without variable costs. Transmission costs are a function of additional interconnector capacity $\hat{x}^{inv}_{r,rr}$, distance between markets $\phi_{r,rr}$, specific annualized NTC investment costs per MW and km c^{NTC}.

Upper-case C's denote absolute cost while lower-case c's represent specific (per-unit) cost. Hats indicate capacities that constrain the respective flow variables. Roman letters denote variables and Greek letters denote parameters. The two exceptions from this rule are initial capacities such as $\hat{g}^{0}_{r,i}$ that are denoted with the respective variable and zeros in superscripts, and specific costs c.

There are eleven technologies, five regions, and 8760 times steps modeled. Note that (1) does not contain a formulation for distribution grids, which contribute a significant share of household electricity cost.

B.2 Supply and Demand

The energy balance (2) is the central constraint of the model. Demand $\delta_{t,r}$ has to be met by supply during every hour and in each region. Supply is the sum of generation $g_{t,r,i}$ minus the sum of net exports $x_{t,r,rr}$ plus storage output $s^{o}_{t,r}$ minus storage in-feed $s^{i}_{t,r}$. Storage cycle efficiency is given by η. The hourly electricity price $p_{t,r}$ is defined as the shadow price of demand and has the unit €/MWh. The base price $\overline{p}_{r}$ is the time-weighted average price over all periods T. Note that (2) features an inequality, implying that supply can always be curtailed, thus the price does not become negative. The model can be interpreted as representing an energy-only market without capacity payments, and $p_{t,r}$ can be understood as the market-clearing zonal spot price as being implemented in many deregulated wholesale electricity pool markets. Since demand is perfectly price-inelastic, cost minimization is equivalent to welfare-maximization, and $p_{t,r}$ can also be interpreted as the marginal social benefit of electricity.

$$\delta_{t,r} \le \sum_i g_{t,r,i} - \sum_{rr} x_{t,r,rr} + \eta \cdot s^o_{t,r} - s^i_{t,r} \qquad \forall t,r \qquad (2)$$
$$p_{t,r} \equiv \frac{\partial C}{\partial \delta_{t,r}} \qquad \forall t,r$$
$$\bar{p}_r \equiv \sum_t p_{t,r} \Big/ T \qquad \forall r$$

Generation is constraint by available installed capacity. Equation (3) states the capacity constraint for the vRES technologies $j \in i$, wind and solar power. Equation (4) is the constraint for dispatchable generators $m \in i$, which are nuclear, lignite, hard coal, CCGT, and OCGT as well as load shedding. Note that technology aggregates are modeled, not individual blocks or plants. Renewable generation is constraint by exogenous generation profiles $\varphi_{t,r,j}$ that captures both the variability of the underlying primary energy source as well as technical non-availability. Availability $\alpha_{t,r,k}$ is the technical availability of dispatchable technologies due to maintenance. Dispatchable capacity can be decommissioned endogenously via $\hat{g}^{dec}_{r,k}$ to save on quasi-fixeded costs, while vRES capacity cannot. Both generation and capacities are continuous variables. The value factors $v_{r,j}$ are defined as the average revenue of wind and solar relative to the base price.

$$g_{t,r,j} = \hat{g}_{r,j} \cdot \varphi_{t,r,j} = \left(\hat{g}^0_{r,j} + \hat{g}^{inv}_{r,j}\right) \cdot \varphi_{t,r,j} \qquad \forall t,r,j \in i \qquad (3)$$
$$g_{t,r,k} \le \hat{g}_{r,k} \cdot \alpha_{t,r,k} = \left(\hat{g}^0_{r,k} + \hat{g}^{inv}_{r,k} - \hat{g}^{dec}_{r,k}\right) \cdot \alpha_{t,r,k} \qquad \forall t,r,m \in i \qquad (4)$$
$$v_{r,j} \equiv \sum_t \varphi_{t,r,j} p_{t,r} \Big/ \sum_t \varphi_{t,r,j} \Big/ \bar{p}_r \qquad \forall r,j \in i$$

Minimizing (1) under the constraint (3) implies that technologies generate if and only if the electricity price is equal or higher than their variable costs. It also implies the electricity price equals variable costs of a plant if the plant is generating and the capacity constraint is not binding. Finally, this formulation implies that if all capacities are endogenous, all technologies earn zero profits, which is the long-term economic equilibrium (for an analytical proof see Hirth & Ueckerdt 2012).

B.3 Power System Inflexibilities

One of the aims of this model formulation is, while remaining parsimonious in notation, to include crucial constraint and inflexibilities of the power system, especially those that force generators to produce at prices below their variable costs (must-run constraints). Three types of such constraints are taken into account: CHP generation where heat demand limits flexibility, a must-run requirement for providers of ancillary services, and costs related to ramping, start-up and shut-down of plants.

One of the major inflexibilities in European power systems is combined heat and power (CHP) generation, where heat and electricity is produced in one integrated process. High demand for heat forces plants to stay online and generate electricity, even if the electricity price is below variable costs. The CHP must-run constraint (5) guarantees that generation of each CHP technology $h \in m$, which are the five coal- or gas-fired technologies, does not drop below minimum generation $g^{min}_{t,r,h}$. Minimum generation is a function of the amount of CHP capacity of each technology $k_{r,h}$ and the heat profile $\varphi_{t,r,chp}$. The profile is based on ambient temperature and captures the distribution of heat demand over time. CHP capacity of a technology has to be equal or smaller than total capacity of that technology (6). Furthermore, the current total amount of CHP capacity in each region γ_r is not allowed to decrease (7). Investments in CHP capacity $k^{inv}_{r,h}$ as well as decommissioning of CHP $k^{dec}_{r,h}$ are possible (8), but only to the extent that total power plant investments and disinvestments take place (9), (10). Taken together, (6) – (10) allow fuel switch in the CHP sector, but do not allow reducing total CHP capacity. For both the generation constraint (5) and the capacity constraint (7) one can derive shadow prices $p_{t,r,h}^{CHPgene}$ (€/MWh) and $p_{r}^{CHPcapa}$ (€/KWa), which can be interpreted as the opportunity costs for heating energy and capacity, respectively.

$$g_{t,r,h} \geq g_{t,r,h}^{min} = k_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} \qquad \forall t,r,h \in m \qquad (5)$$

$$k_{r,h} \leq \hat{g}_{r,h} \qquad \forall r,h \qquad (6)$$

$$\sum_h k_{r,h} \geq \gamma_r = \sum_h k_{r,h}^0 \qquad \forall r \qquad (7)$$

$$k_{r,h} = k_{r,h}^0 + k_{r,h}^{inv} - k_{r,h}^{dec} \qquad \forall r,h \qquad (8)$$

$$k_{r,h}^{inv} \leq \hat{g}_{r,h}^{inv} \qquad \forall r,h$$

$$k_{r,h}^{dec} \leq \hat{g}_{r,h}^{dec} \qquad \forall r,h \qquad (9)$$

$$p_{r,t}^{CHPgene} \equiv \frac{\partial C}{\partial g_{t,r,h}^{min}} \qquad \forall r,t \qquad (10)$$

$$p_{r}^{CHPcapa} \equiv \frac{\partial C}{\partial \gamma_r} \qquad \forall r$$

Electricity systems require a range of measures to ensure stable and secure operations. These measures are called ancillary services. Many ancillary services can only be or are typically supplied by generators while producing electricity, such as the provision of regulating power or reactive power (voltage support). Thus, a supplier that committed to provide such services over a certain time (typically much longer than the delivery periods on the spot market) has to produce electricity even if the spot prices falls below its variable costs. In this model, ancillary service provision is implemented as a must-run constraint of spinning reserves (11): an amount σ_r of dispatchable capacity has to be in operation at any time. We set σ_r to 10% of peak load plus 5% of VRE capacity of each region, a calibration based on Hirth & Ziegenhagen (2013). Two pieces of information were used when setting this parameter. First, market prices indicate when must-run constraints become binding: if equilibrium prices drop below the variable cost of base load plants for extended periods of time, must-run constraints are apparently binding. Nicolosi (2012) reports that German power prices fell below zero at residual loads between 20-30 GW, about 25-40% of peak load. Second, FGH et al. (2012) provide a detailed study on must-run generation due to system stability, taking into account network security, short circuit power, voltage support, ramping, and regulating power. They find minimum generation up to 25 GW in Germany, about 32% of peak load.

In the model it is assumed that CHP generators cannot provide ancillary services, but pumped hydro storage can provide them while either pumping or generating. For a region with a peak demand of 80 GW, at any moment 16 GW of dispatchable generators or storage have to be online. Note that thermal capacity of 8 GW together with a pump capacity of 8 GW can fulfill this condition without net generation. The shadow price of σ_r, $p_{t,r}^{AS}$,is defined as the price of ancillary services, with the unit €/KW$_{online}$a.

$$\sum_k g_{t,r,k} - \sum_h \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} + \eta \cdot s_{t,r}^{o} + s_{t,r}^{i} \geq \sigma_r \qquad \forall t,r \qquad (11)$$

$$\sigma_r = 0.1 \cdot \max_t \left(d_{t,r}\right) + 0.05 \cdot \sum_j \hat{g}_{r,j}^{inv} + \hat{g}_{r,j}^{0} \qquad \forall r \qquad (12)$$

$$p_r^{AS} \equiv \frac{\partial C}{\partial \sigma_r} \qquad \forall r$$

Finally, thermal power plants have limits to their operational flexibility, even if they do not produce goods other than electricity. Restrictions on temperature gradients within boilers, turbines, and fuel gas treatment facilities and laws of thermodynamics imply that increasing or decreasing output (ramping), running at partial load, and shutting down or starting up plants are costly or constraint. In the case of nuclear power plants nuclear reactions related to Xenon-135 set further limits on ramping and down time. These various non-linear, status-dependent, and intertemporal constraints are proxied in the present framework by forcing certain generators to tolerate a predefined threshold of negative contribution margins before shutting down. This is implemented as a "run-through premium" for nuclear, lignite, and hard coal plants. For example, the variable cost for a nuclear plant is reduced by 10 €/MWh. In order not to distrort its full cost, fixeded costs are duly increased by 87600 €/MWa.

B.4 Flexibility options

The model aims to not only capture the major inflexibilities of existing power technologies, but also to model important flexibility options. Transmission expansion and electricity storage can both make electricity systems more flexible. These options are discussed next.

Within regions, the model abstracts from grid constraints, applying a copperplate assumption. Between regions, transmission capacity is constrained by net transfer capacities (NTCs). Ignoring transmission losses, the net export $x_{t,r,rr}$ from r to rr equals net imports from rr to r (13). Equations (14) and (15) constraint electricity trade to the sum of existing interconnector capacity $\hat{x}^{0}_{r,rr}$ and new interconnector investments $\hat{x}^{inv}_{r,rr}$. Equation (16) ensures lines can be used in both directions. Recall from (1) that interconnector investments have fixed specific investment costs, which excluded economies of scale as well as non-linear transmission costs due to the nature of meshed HVAC systems. The distance between markets $\delta_{r,rr}$ is measured between the geographical centers of regions.

$$x_{t,r,rr} = -x_{t,rr,r} \qquad \forall t,r,rr \qquad (13)$$

$$x_{t,r,rr} \le \hat{x}^{0}_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t,r,rr \qquad (14)$$

$$x_{t,rr,r} \le \hat{x}^{0}_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t,r,rr \qquad (15)$$

$$\hat{x}^{inv}_{rr,r} = \hat{x}^{inv}_{r,rr} \qquad \forall r,rr \qquad (16)$$

The only electricity storage technology applied commercially today is pumped hydro storage. Thus storage is modeled after pumped hydro. Some storage technologies such as compressed air energy storage (CAES) have similar characteristics in terms of cycle efficiency, power-to-energy ratio, and specific costs and would have similar impact on model results. Other storage technologies such as batteries or gasification have very different characteristics and are not reflected in the model. The amount of energy stored at a certain hour $s^{vol}_{t,r}$ is last hour's amount minus output $s^{o}_{t,r}$ plus in-feed $s^{i}_{t,r}$ (17). Both pumping and generation is limited by the turbines capacity $\hat{s}_r$ (18), (19). The amount of stored energy is constrained by the volume of the reservoirs $\hat{s}^{vol}_r$, which are assumed to be designed such that they can be filled within eight hours (20). Hydrodynamic friction, seepage and evaporation cause the cycle efficiency to be below unity (2). The only costs related to storage except losses are capital costs in the case of new investments $\hat{s}^{inv}_r$ (1).

$$s_{t,r}^{vol} = s_{t-1,r}^{vol} - s_{t,r}^{o} + s_{t,r}^{i} \qquad \forall t,r \tag{17}$$

$$s_{t,r}^{i} \le \hat{s}_r = \hat{s}_r^{0} + \hat{s}_r^{inv} \qquad \forall t,r \tag{18}$$

$$s_{t,r}^{o} \le \hat{s}_r = \hat{s}_r^{0} + \hat{s}_r^{inv} \qquad \forall t,r \tag{19}$$

$$s_{t,r}^{vol} \le \hat{s}_r^{vol} = \left(\hat{s}_r^{0} + \hat{s}_r^{inv}\right) \cdot 8 \qquad \forall t,r \tag{20}$$

The model is written in GAMS and solved by Cplex using a primal simplex method. With five countries and 8760 times steps, the model consists of one million equations and four million non-zeros. The solution time on a personal computer is about half an hour per run with endogenous investment and a few minutes without investment.

B.5 Alternative Problem Formulation

In short, the cost minimization problem can be expressed as

$$\min \quad C \tag{21}$$

with respect to the investment variables $\hat{g}_{r,i}^{inv}, \hat{s}_r^{io,inv}, \hat{x}_{r,rr}^{inv}, \hat{x}_{r,rr}^{dec}, k_{r,h}^{inv}, k_{r,h}^{dec}$, the dispatch variables $g_{t,r,i}, s_{t,r}^{i}, s_{t,r}^{o}$, and the trade variable $x_{t,r,rr}$ subject to the constraints (2) – (20). Minimization gives optimal values of the decision variables and the shadow prices $p_{t,r}, p_{r,t}^{CHPgene}, p_{r,t}^{CHPcapa}, p_r^{AS}$ and their aggregates $\overline{p}_r, v_{r,j}$.

Statement of Contribution

This thesis was written by the author of this thesis in collaboration with his adviser, Prof. Dr. Ottmar Edenhofer. The author of the thesis has made significant contributions to all chapters from conceptual design, to model development, numerical implementation, structuring and drafting the text, and correspondence with journals and referees. The following paragraphs detail the contribution of the author to the six core chapters of this thesis and acknowledges major contributions of others.

Chapter 1 and 8

The author was solely responsible for drafting the Introduction and Conclusion chapters. Meike Riebau, Brigitte Knopf, Eva Schmid, Dania Röpke and Alice Färber provided helpful comments. Eva Schmid supported the compilation of the PDF file. Thank you!

Chapter 2 (ECONOMICS OF ELECTRICITY)

The research design was developed and implemented jointly by the author, Ottmar Edenhofer, and Falko Ueckerdt. Falko Ueckerdt and the author structured and wrote the article. Handling was done by the author. Michael Pahle, Brigitte Knopf, and Eva Schmid provided helpful comments, further comments are acknowledged in the chapter.

Chapter 3 (FRAMEWORK)

The research design was developed jointly by the author, Ottmar Edenhofer, and Falko Ueckerdt. Falko Ueckerdt and the author wrote the article. Handling was done by the author. The author was responsible for the literature review and the quantification section. The theoretical sections were developed jointly by Ottmar Edenhofer, Falko Ueckerdt, and the author. Comments and support from various parties are acknowledged in the chapter.

Chapter 4 (MARKET VALUE)

The author was sole responsible for the chapter throughout all stages of research and writing. Comments and support from various parties are acknowledged in the chapter.

Chapter 5 (OPTIMAL SHARE)

The author was sole responsible for the chapter throughout all stages of research and writing. Comments and support from various parties are acknowledged in the chapter.

Chapter 6 (REDISTRIBUTION)

The research design was developed jointly by the author and Falko Ueckerdt. The author handled the article and was responsible for the numerical model results. The analytical model was provided by Falko Ueckerdt. Comments and support from various parties are acknowledged in the chapter.

Chapter 7 (BALANCING POWER)

The author was responsible for handling the article, and was responsible for the paragraphs related to empirical market development. Research design and article structure were developed jointly with Inka Ziegenhagen, who also provided model results from her Master thesis. Comments and support from various parties are gratefully acknowledged in the chapter.

Tools and Resources

The main computational tool used in this thesis is the numerical power market model EMMA. The model has been developed for this thesis and is documented in the Appendix. Model code and all input parameters are freely available under CC-BY-SA 3.0 license. They can be requested from the author, and are available as supplementary material of Hirth (2013). EMMA is implemented in the "General Algebraic Modeling System" (GAMS) and has been solved using the linear program solver CPLEX.

Data analysis was done in Microsoft Excel 2010 and Stata 13. Graphs were created in Microsoft PowerPoint 2010, for typesetting of all chapters Microsoft Word 2010 was used.