

Integrating variable electricity supply from wind and solar PV into power systems

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Abstract

In contrast to energy supply from fossil and nuclear power plants, wind power and solar PV are *variable*. Their output is beyond human control, dependent on weather, and cannot always be supplied on demand. Variability causes “integration costs” that occur at a system level in addition to generation costs of variable renewable energy (VRE).

This thesis aims to improve the economic evaluation of VRE in particular with respect to their variability and corresponding integration costs. Its three main ambitions are contributing to the understanding of i) the economics of variability, ii) the modeling of variability and iii) the short-term costs and distributional effects induced by VRE. It thereby tries to bridge the gaps between three research strands that evaluate VRE: the integration costs literature, the marginal economic value literature and the integrated assessment model (IAM) literature.

First and most fundamentally, I present a framework for the economics of variability. It is based on a new definition of integration costs that, in contrast to previous definitions, relates to economic theory more clearly and captures all costs of variability. The framework reveals an important new component of integration costs, termed “profile costs”. They account for the low capacity credit of VRE, reduced utilization of dispatchable plants and over-produced VRE generation. Previous integration costs studies neglected some or all of these aspects, and could therefore not link to the marginal value literature. The link developed in this thesis shows two equivalent perspectives on integration costs: From a *cost* perspective the costs of integration are added to those of generation resulting in *system levelized costs of electricity* (System LCOE), while from a *value* perspective integration costs reduce the marginal economic value of VRE. The new concept of System LCOE broadens the cost perspective of integration costs studies such that it is equivalent to the economic literature on marginal value.

Both perspectives can be embedded in a welfare-economic setting: equivalent first-order conditions determine the optimal deployment of VRE. If the System LCOE of VRE drop below the average System LCOE of a purely conventional power system, more VRE deployment increases welfare. Production-based LCOE, the widely used conventional metric (and other indicators like grid parity), are misleading because they neglect variability. A situation where the LCOE of VRE are below those of conventional plants does not imply that VRE deployment is efficient or competitive. By contrast, the metric of System LCOE allows evaluating and comparing technologies, and could replace incomplete indicators. It retains the intuitive and familiar format of LCOE and, in addition, accounts for the complex interaction of VRE with the power system.

Based on this framework the thesis quantifies integration costs for wind. From a literature review and own modeling it is shown that (marginal) integration costs increase with

penetration and reach about 25–45¹ €/MWh at wind shares of about 30%. This is substantial compared to the average whole-sale electricity price or generation costs of wind of about 60 €/MWh. Integration costs for solar are of similar magnitude at high shares, mainly driven by profile costs, as indicated by comparing the integration challenges of wind and solar. Integration costs reduce the optimal and competitive share of VRE and can discourage high shares of VRE. However, the economic viability of VRE would increase if the full cost of conventional generation technologies were accounted for, foremost the climate change externality of fossil energy and the health risks of nuclear power. In addition, integration options might significantly reduce integration costs. This thesis helps identifying suitable integration options by revealing the most important integration challenges. A shift from capital-intensive base load plants to peak load gas plants substantially reduces profile costs. More fundamental changes in the energy system like a substantial change of demand patterns, long-distance transmission grid expansion or seasonal storage technologies could further reduce integration costs.

The second contribution of this thesis is the development of two approaches to improve the modeling of variability in IAMs based on the above insights into the economics of variability. The first approach suggests implementing System LCOE in IAMs to represent the full costs of VRE. Some IAMs already represent variability with simple cost penalties for VRE, yet System LCOE can improve this by providing cost penalties with a rigorous economic basis. System LCOE are system-dependent and thus need to be estimated with high-resolution models for a broad range of energy system configurations. To keep this parameterization manageable, variability aspects should be modeled explicitly in IAMs without using exogenous cost penalties, where possible. An option to achieve this is the second approach, which explicitly accounts for the most important integration costs component profile costs, by implementing residual load duration curves (RLDC) into REMIND-D, a multi-sector long-term model of the German economy. Hereby not only major integration challenges but also the optimal energy system's response can be modeled endogenously such as changes in the conventional capacity mix or the deployment of hydrogen and methane storage facilities (power-to-gas storage). If implemented into IAMs, both approaches could increase the credibility of mitigation scenarios results in particular the economic potential of VRE.

In its third contribution this thesis shows that in the short term, when VRE are driven by support policies, particularly high integration costs can be induced. These costs are not only imposed by VRE's variability but by an adverse combination of three aspects: variability, an unfavorable legacy power system, and a low capital turnover rate. This

¹ The higher values do neglect a number of integration options like the long-distance transmission, energy storage and changes in the temporal demand profiles.

might create a barrier to reaching the long-term optimal deployment of VRE. Redistribution effects intensify this potential lock-in effect. VRE support induces redistribution flows from conventional producers to electricity consumers, which can be larger than the net system cost increase due to VRE. This gives conventional generators the incentive to oppose VRE support. If large redistribution flows are not desired by society or single actors, they can present implementation barriers to specific policy instruments. Combining two policies, renewables support and carbon pricing, might allow policy makers to reduce redistribution effects. This would reduce implementation barriers even if the policy mix might not be the first-best policy to internalize externalities such as the climate change externality.

Zusammenfassung

Die Stromerzeugung aus Windkraft und Photovoltaik unterscheidet sich von fossilen und nuklearen Kraftwerken durch ihre Dargebotsabhängigkeit. Die Kraftwerksleistung von Wind und Solar schwankt in Abhängigkeit von Wetterbedingungen und kann nur begrenzt zur Deckung der aktuellen Stromnachfrage reguliert werden. Die Dargebotsabhängigkeit verursacht „Integrationskosten“ die zusätzlich zu den Stromgestehungskosten im Stromsystem anfallen.

Die vorliegende Doktorarbeit hat das Ziel die ökonomische Bewertung von Wind und Solar insbesondere im Hinblick auf deren Dargebotsabhängigkeit und Integrationskosten zu verbessern. Die drei wesentlichen Unterziele sind Beiträge zum Verständnis i) der Ökonomie der Dargebotsabhängigkeit von Wind und Solar, ii) der Darstellung von Dargebotsabhängigkeit in numerischen Modellen und iii) der mit Wind und Solar verbundenen kurzfristigen Kosten und Umverteilungseffekte. Hierbei wird versucht, die Lücken zwischen den folgenden drei Forschungssträngen zur Bewertung von Wind und Solar zu schließen: Forschung zu Integrationskosten von Wind und Solar, Forschung zu deren ökonomischen Wert und Forschung zu Klimaschutzszenarien mit sogenannten Integrated-Assessment-Modellen.

Zunächst präsentiere ich einen analytischen Rahmen für die Ökonomie der Dargebotsabhängigkeit. Er basiert auf einer neuen Definition von Integrationskosten, die im Unterschied zu früheren Definitionen einen klaren Bezug zu ökonomischer Theorie aufweist und alle Kosten der Dargebotsabhängigkeit umfasst. Der analytische Rahmen zeigt die Existenz einer neuen Integrationskostenkomponente: Profilkosten. Die Komponente erfasst den niedrigen Kapazitätsbeitrag von Wind und Solar, die Reduktion der Betriebsstunden von regelbaren Kraftwerken und potentiell überproduzierte erneuerbare Erzeugung. Integrationskostenstudien haben diese Aspekte bisher zum Teil oder komplett vernachlässigt und konnten daher nicht mit den Arbeiten zum ökonomischen Wert von Wind und Solar in Bezug gesetzt werden. Der Bezug, der in dieser Arbeit hergestellt wird, zeigt, dass es zwei Perspektiven auf Integrationskosten gibt: Von einer Kostenperspektive können Integrationskosten zu den Gestehungskosten addiert werden, so dass sogenannte systemische Gestehungskosten (System-LCOE) entstehen. Eine Wertperspektive verrechnet Integrationskosten als eine Reduktion des marginalen Wertes von Wind und Solar. Das neue Konzept System-LCOE erweitert die Kostenperspektive von Integrationskostenstudien, so dass sie äquivalent zur ökonomischen Literatur zum marginalen Wert ist.

Beide Perspektiven können in eine wohlfahrtsökonomische Betrachtung eingebettet werden: äquivalente Bedingungen erster Ordnung erlauben die Berechnung der optimalen Erzeugung aus Wind und Solar. Wenn die System-LCOE von Wind oder Solar unter die System-LCOE eines konventionellen Stromsystems fallen, erhöht ein weiterer Ausbau

von Wind oder Solar die Wohlfahrt. Ein Vergleich reiner Gestehungskosten (und anderer Indikatoren, z.B. Netzparität), deren Anwendung verbreitet ist, ist irreführend, da sie Integrationskosten außer Acht lassen. Wenn LCOE von Wind oder Solar unter die von konventionellen Anlagen sinken, heißt das nicht, dass Wind und Solar auch volkswirtschaftlich effizient oder wettbewerbsfähig sind. Im Gegensatz dazu erlaubt die System-LCOE-Metrik die ökonomische Bewertung und den Vergleich von verschiedenen Stromerzeugungstechnologien, und kann somit unvollständige Indikatoren ersetzen. Die neue Metrik erfasst die komplexe Wechselwirkung von Wind und Solar mit dem Stromsystem und behält gleichzeitig das intuitive und gewohnte Format von Gestehungskosten bei.

Auf Basis des entwickelten analytischen Rahmens werden Integrationskosten für die Stromerzeugung aus Windkraft quantifiziert. Mit einer umfassenden Literaturrecherche und neuen Modellergebnissen wird gezeigt, dass marginale Integrationskosten mit höheren Anteilen von Wind steigen und ungefähr 25–45² €/MWh bei einem Anteil von etwa 30% betragen. Diese Werte sind hoch im Vergleich zu typischen durchschnittlichen Börsenstrompreisen oder Gestehungskosten von Wind von etwa 60 €/MWh. Integrationskosten von solarer Stromerzeugung können ähnlich hoch sein, vor allem aufgrund von Profilkosten. Integrationskosten reduzieren den optimalen und wettbewerbsfähigen Anteil von Wind und Solar und könnten ein Hemmnis für hohe Anteile sein. Die ökonomische Attraktivität von Wind und Solar könnte jedoch steigen, wenn die vollen Kosten von konventionellen Erzeugungstechnologien berücksichtigt werden, vor allem die externen Kosten des Klimawandels aufgrund der Nutzung fossiler Energieträger sowie Gesundheitsrisiken bei der Nutzung der Kernenergie. Zudem können Integrationskosten durch den Ausbau von Integrationsoptionen gesenkt werden. Diese Arbeit hilft vielversprechende Integrationsoptionen zu finden indem die größten Herausforderungen bei der Integration bestimmt werden. So könnten Profilkosten durch einen strukturellen Wandel von kapitalintensiven Grundlastkraftwerken hin zu Mittel- und Spitzenlastkraftwerken wie Gaskraftwerken deutlich reduziert werden. Noch tiefgehendere Veränderungen des Energiesystems, wie eine Veränderung der zeitlichen Struktur von Nachfrageprofilen, weitreichende Übertragungsnetze oder Technologien zur saisonalen Energiespeicherung, könnten Integrationskosten weiter reduzieren.

Der zweite übergeordnete Beitrag dieser Arbeit ist die Entwicklung zweier Ansätze zur Verbesserung der Darstellung von Dargebotsabhängigkeit in Integrated-Assessment-Modellen. Der erste Ansatz schlägt vor, System-LCOE in die Modelle zu implementieren, um die vollen Kosten von Wind und Solar abzubilden. Einige Modelle

² Die höheren Werte lassen einige Integrationsoptionen außer Betracht, zum Beispiel weitreichende Übertragungsnetze, Stromspeichertechnologien und Veränderungen der zeitlichen Struktur der Stromnachfrage.

benutzen bereits einfache Kostenaufschläge für Wind und Solar. Die neue Metrik kann diese Ansätze verbessern, indem die Aufschläge ökonomisch fundiert werden. Da System-LCOE vom gesamten Energiesystem abhängen können, ist deren Abschätzung mit hoch-aufgelösten partiellen Modellen für einen großen Bereich von Systemkonfigurationen notwendig. Um den Parametrisierungsaufwand überschaubar zu halten, sollten jene Aspekte der Dargebotsabhängigkeit in Integrated-Assessment-Modellen explizit modelliert werden, bei denen das möglich ist. Der zweite Ansatz erlaubt eine solche explizite Modellierung von Profilkosten, der wichtigsten Komponente von Integrationskosten. Residuale Lastdauerkurven werden in REMIND-D, einem multisektoralen Modell zur langfristigen Entwicklung der deutschen Wirtschaft und Energieversorgung, implementiert. Hiermit können sowohl Integrationsherausforderungen als auch induzierte Systemanpassungen endogen modelliert werden. Die Systemanpassungen umfassen Veränderungen des konventionellen Kapazitätsmixes oder den Ausbau von Power-to-Gas, d.h. der Speicherung von erneuerbarem Strom als Wasserstoff oder Methan. Die Verwendung der beiden Ansätze in Integrated-Assessment-Modellen kann die Genauigkeit und Plausibilität von Klimaschutzszenarien, insbesondere optimalen Ausbaupfaden von Wind und Solar, erhöhen.

Der dritte Beitrag zeigt, dass in einer kurzfristigen Perspektive, wenn Förderinstrumente den Ausbau von Wind und Solar treiben, besonders hohe Integrationskosten entstehen können. Diese Kosten entstehen nicht nur aufgrund der Dargebotsabhängigkeit, sondern aufgrund einer ungünstigen Kombination von drei Aspekten: der Dargebotsabhängigkeit, eines für den Ausbau von Wind und Solar ungünstiges bestehendes Stromsystem, und einer niedrigen Erneuerungsrate des bestehenden Kapitals im Stromsystem. Daraus kann eine Barriere für einen langfristig optimalen Ausbau von Wind und Solar entstehen. Umverteilungseffekte verstärken diesen potentiellen „Lock-in-Effekt“. Förderinstrumente für Wind und Solar induzieren Umverteilungsströme von konventionellen Erzeugern hin zu Stromkonsumenten, die größer sein können als der Anstieg der Gesamtkosten des Stromsystems aufgrund von Wind und Solar. Dies könnte ein Anreiz für konventionelle Erzeuger sein, solche Förderinstrumente abzulehnen. Wenn Umverteilungseffekte von der Gesellschaft oder einzelnen Akteuren nicht erwünscht sind, können sie zu einem Hemmnis für die Einführung der zugrunde liegenden Instrumente sein. Eine Kombination aus mehreren Instrumenten, wie der Förderung von Wind und Solar und einer Bepreisung von CO₂-Emissionen, kann es politischen EntscheiderInnen erlauben, Umverteilung zu reduzieren. Das könnte Implementierungshemmnisse abbauen, auch wenn der resultierende Instrumentenmix nicht dem ökonomisch effizientesten Instrument entspricht, um Externalitäten wie den Klimawandel zu internalisieren.

1. Introduction

The first renewable energy technology I came in touch with in my life was a self-built solar cooker that I tested in Kenya during a study program in 2003/04. Back then I associated renewable energy with niche applications that are off-grid and small-scale. Since then the world has seen a dramatic expansion of renewable capacity that is mostly grid-connected and large-scale. This development was driven by a massive adoption of renewable support policies in meanwhile 127 countries (REN21 2013), which have the primary objective of mitigating climate change or more generally creating a sustainable energy supply. From 2005 until 2011 global annual growth rates for wind and solar power have been at 26% and 54%, respectively (IEA 2012). In 2012 new power generating capacity from renewables exceeded that of conventional fuels (fossil and nuclear) (REN21 2013). Market observers anticipate a continuous renewable expansion (IEA 2012) and 138 countries adopted policy targets for increased future shares (as of early 2013, REN21 2013).

However, power supply from wind and solar PV differs fundamentally from that of conventional power plants. Their power output is variable; it depends on weather conditions like wind speeds and solar irradiation and can therefore not be always supplied on demand. This variability imposes additional costs on the power system, termed “integration costs”. The economic impacts of wind and solar PV variability need to be carefully analyzed because they might form an economic barrier to their further expansion.

Today, 10 years after my off-grid cooking experience with solar energy, I present a thesis that seeks to understand the economic impacts of integrating high shares of wind and solar PV into power systems. I will argue that this understanding is crucial for identifying sensible transformation pathways towards a sustainable energy system.

The remainder of this introductory chapter starts with illustrating that limiting climate change requires a global energy transformation (section 1.1) with a prominent role of renewables in particular wind and solar PV (sections 1.2 and 1.1). Section 1.4 assesses the current state of knowledge on the evaluation of wind and solar under consideration of their variability. It carves out the need for research that leads to the overall objective of this thesis and its research questions (section 1.5). This section also sketches the structure of this thesis and introduces chapters 2 – 7.

1.1. Limiting climate change requires a global energy transformation

There is a broad scientific consensus that human activity causes climate change (IPCC 2007a, IPCC 2013, Cook et al. 2013). Continued greenhouse gas (GHG) emissions, foremost CO₂ emissions, will lead to a further global temperature increase, which is very likely to impose future costs on mankind (IPCC 2007b). Unmitigated climate change will

pose the risk of serious negative impacts to ecosystems and human societies, such as unprecedented heat waves, severe drought, and major floods in many regions (World Bank 2012). In addition, the Earth system has a number of “tipping elements”, i.e. large-scale (at least subcontinental) components that may be pushed into new regimes and consequently enhance global warming or its impacts once the global mean temperature crosses respective critical thresholds (Lenton et al. 2008). Important examples are the melting of the Greenland ice sheet, which would induce a long-term sea level of up to about 7m (Parry et al.), or the destabilization of the Indian Summer Monsoon rainfall, which could cause droughts and would endanger the agricultural productivity in one of the most populated regions of the world (Schewe and Levermann 2012). While uncertainties pertaining to the timing and scale of impact still abound, there is broad evidence that anthropogenic climate change is threatening the welfare and development of human societies.

Thus, reducing greenhouse gas (GHG) emissions to limit anthropogenic climate change is among the most important challenges of this century. Already in 1992 the international community agreed on the ultimate objective of a “stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system” (UNFCCC 1992). Meanwhile this objective is reflected in global and national temperature and mitigation targets. Temperature targets like the internationally agreed 2 °C target³ (UNFCCC 2010) impose a tight limit on cumulative future anthropogenic GHG emissions (Matthews and Caldeira 2008, Matthews et al. 2009, Meinshausen et al. 2009). As a consequence annual global emissions need to reverse their upward trend and decrease drastically to a close-to-zero level, or even become negative, if temperature change is to be limited. In order to achieve this, economic activity, in particular economic growth and development, would therefore need to decouple from emitting GHG emissions (Raupach et al. 2007, World Bank 2010).

Burning fossil fuels for energy supply causes over 60% of global GHG emissions and consequently is the main driver of anthropogenic climate change (UNFCCC 2013, IEA 2013a). At the same time energy economic scenarios of the future consistently indicate a further increase of global energy demand (Fisher et al. 2007). Thus, an almost full-scale decarbonization of the global energy systems is essential for mitigating climate change (Edenhofer et al. 2010, Luderer et al. 2012, Krey et al. 2013). This requires a profound transformation of the global energy systems that should start in the next years because further delay would have three implications: (i) an increase of mitigation costs⁴ compared

³ The “2°C target” refers to the long-term target of limiting the increase of global mean temperature to no more than 2°C relative to pre-industrial levels.

⁴ Note that mitigation cost estimates do not include benefits or co-benefits of reduced climate change.

to scenarios where immediate mitigation effort is possible (Rogelj, McCollum, Reisinger, et al. 2013, Luderer et al. 2014, Riahi et al. 2014, Kriegler, Tavoni, et al. 2014), (ii) a significant risk that the 2 °C target will not be achieved (Rogelj et al. 2011, Rogelj, McCollum, O'Neill, et al. 2013) and (iii) more generally an increase of achievable temperature targets (Luderer et al. 2013).

An infinite set of transformation pathways builds the solution space to the climate problem. Some scientists use numeric models, predominantly integrated assessment models (IAMs)⁵, to find those pathways that minimize the macroeconomic costs of achieving a prescribed climate target (i.e. mitigation costs). Such mitigation scenarios describe the deployment of different mitigation options including, most importantly, three classes of primary energy sources and corresponding technologies for low-carbon energy supply: (i) renewable energy sources (RES), (ii) fossil energy sources (or biomass) combined with carbon capture and storage (CCS) (IPCC 2005) and (iii) nuclear energy. Many assumptions over deeply normative choices enter these calculations such as social preferences for or against certain technologies or the discount rate. Since scientists have no mandate to decide on those assumptions, they should provide a range of scenarios based on different assumptions, making their impact on the results transparent. Such mitigation scenario analyses help policy-makers and the society in taking well-informed decisions on how to transform the energy system and solve the climate problem.

1.2. Renewables have a large potential for climate mitigation

Many mitigation scenario studies show that RES are a crucial mitigation option (Edenhofer et al. 2010, IPCC 2011, Krey and Clarke 2011, Luderer et al. 2012, GEA 2012, Luderer et al. 2013). IPCC (2011) shows in a comprehensive review that in the majority of scenarios RES become the dominant low-carbon supply option by 2050. As part of EMF 27, which is the most recent global model comparison exercise of mitigation scenarios from 17 global energy-economy climate models, Luderer et al. (2013) show that limiting the availability of the most important renewable sources wind, solar and biomass causes a substantial increase of mitigation costs, which exceeds the average cost increase in scenarios without CCS even if the latter is combined with a nuclear phase-out. Earlier studies calculate similar cost increases when restricting renewables and moreover find that CCS is of similar importance while nuclear is much less relevant (Edenhofer et al. 2010, Luderer et al. 2012, Tavoni et al. 2012).

There are more fundamental advantages of RES that are not considered in many economic scenarios. CCS and nuclear plants face sustainability concerns that are much more severe than those of RES. This reduces their social acceptance. Nuclear carries a risk of a catastrophic failure, has issues of radioactive waste disposal, might be linked to

⁵ IAMs are in detail explained in section 1.4.

proliferation of nuclear weapons and uranium for conventional reactors is limited (Ahearne 2011, Mez 2012, Kessides 2012). CCS faces limited geological storage reservoirs and therefore lacks sustainability in the long term. Moreover the risk of leakage of CO₂ from the disposal sites might withdraw its mitigation effect to some extent. Finally in the recent years CCS experienced setbacks concerning the progress of technological development and national legislation (von Hirschhausen et al. 2012). If a society considers these sustainability concerns essential, RES would suggest itself as the most important low-carbon technology.

It is worthwhile noting that while in the past the main argument for ambitious RES deployment targets and RES policy support schemes was mitigating GHG emissions, this broadened in the recent years. Other social objectives have gained importance such as energy security, job creation, reducing local environmental damage, poverty reduction and energy access (Borenstein 2012, GEA 2012, Edenhofer et al. 2013, Siler-Evans et al. 2013, IPCC 2011b, Sathaye et al. 2011). However, the positive contribution of RES to some of these objectives is controversial. For example Borenstein (2012) suggests that the distinct advantage of RES is its reduced local environmental impact and reduced GHG emissions and that energy security and job creation are no convincing arguments for policies that foster RES deployment. Besides this, other recent articles discuss a more general point. They suggest that in a real world with multiple objectives and multiple externalities it requires a careful design of multiple policy instruments to yield the welfare-optimal deployment of RES (Edenhofer, Hirth, et al. 2013, Edenhofer, Seyboth, et al. 2013, Edenhofer, Knopf, and Luderer 2013).

1.3. Wind power and solar PV are likely to play a prominent role

RES are very versatile. Various technologies allow human societies to access wind, solar, bio-, hydro, geothermal, and ocean energy (IPCC 2011a). None of these technologies is a “silver-bullet”, yet solar, wind and bioenergy are more likely to play a more prominent role than hydro, geothermal, and ocean energy (Krey and Clarke 2011, Luderer et al. 2013).

Even though Hydro power is currently the most significant non-biomass renewable energy source (IPCC 2011a, IEA 2013b), it plays only a modest role in most scenarios mainly due to their limited technical potentials (Kumar et al. 2011, Rogner et al. 2012). Moreover considering site-specific negative environmental and social impacts (Liu et al. 2013, Tajziehchi et al. 2013) would further reduce its economic potential. For geothermal energy the most optimistic EMF 27 models still show deployment levels well below those of wind, solar and even hydro power, albeit the model representation of geothermal power needs to be improved. Moreover, exploiting the geothermal potential to a large extent requires deep drilling (~10km depth) or enhanced geothermal systems (EGS), a technology that is still in a demonstration and pilot phase while its future availability and costs are uncertain (IPCC 2011a). The economic potential of ocean energy is highly

uncertain since there is no technology commercially available at present (IPCC 2011a). Hardly any IAM covers ocean energy technologies (Krey and Clarke 2011).

By contrast, IAM results show that bioenergy has a huge economic potential and its availability is crucial for climate mitigation for two reasons (Vuuren et al. 2007, Vuuren, Bellevrat, et al. 2010, Edenhofer et al. 2010, Luderer, Bosetti, et al. 2012, Luderer, Krey, et al. 2013, Rose et al. 2013). First, it allows generating negative emissions when combined with CCS. This allows for both compensating for more residual fossil fuel emissions and overshooting the long-term stabilization target in a transition phase, which takes some pressure off short-term emission reduction requirements until 2050 (see for example Krey et al. 2013). Second, due to its versatility biomass cannot only be used for electricity generation but also to produce liquids, hydrogen, gases, or heat for the non-electric part of the energy system. In fact the EMF scenarios show that biomass is the most important supply-side mitigation option for nonelectric part of the energy system, where mitigation options are scarce (Luderer, Krey, et al. 2013, Rose et al. 2013). Biomass is particularly utilized as liquid biofuels to substitute oil. It is unclear how much biomass potential remains economically efficient for the power sector. IAMs come to different results in this respect (Rose et al. 2013).

However, there are concerns, which make bioenergy appear to be a double-edged sword. Large-scale use of bioenergy can impose a number of negative externalities that are only partially considered in the scenario results analyzed above. Direct and indirect land use change can induce GHG emissions that could even over-compensate the direct mitigation effect of biomass (J. Fargione et al. 2008, J. E. Fargione, Plevin, and Hill 2010, Plevin et al. 2010, Creutzig, Popp, et al. 2012, Plevin R. J 2013). Moreover social and environmental issues such as food security, water availability, soil quality or biodiversity need to be carefully considered when evaluating biomass (Gerbens-Leenes, Hoekstra, and Meer 2009, Creutzig, von Stechow, et al. 2012, Edenhofer, Seyboth, et al. 2013). Thus, negative externalities of a large-scale bioenergy use are likely to limit the potential role of bioenergy in climate mitigation in particular its shares in the power sector.

By contrast, wind and solar energy face only minor sustainability concerns. Many mitigation scenarios show substantial electricity shares from wind and solar power in the long term. Luderer et al. 2013 present for the EMF27 model comparison that for all but one model renewables provide more than 35% of power supply in the second half of the century, and half of the models even have a renewables share of 59% or higher. In those scenarios with high overall RE deployment wind and solar PV contribute the major electricity share exceeding 40% in the second half of the century.

It is worthwhile noting that the power sector is a key sector for mitigation due to three reasons. First, its emissions share is high: Electricity and heat⁶ production caused 42% of the global CO₂ emissions from fossil fuel combustion in 2011 (IEA 2013a). Second, mitigation scenarios show consistently that the power sector decarbonizes earlier and more extensively than the non-electric energy demand, in particular than the transport sector (Luderer, Bosetti, et al. 2012, Luderer, Pietzcker, et al. 2012, Kriegler, Weyant, et al. 2014, Krey et al. 2013). This is mainly because there are many comparably cost-efficient mitigation options in this sector, while the non-electric part of the energy system strongly relies on biomass, energy efficiency and demand reductions. Third, by a partial electrification the heat and transport sector can make use of this mitigation potential. Hence, decarbonizing the power sector appears to be an indispensable step and can become the backbone of an energy transition towards a low-carbon economy.

In addition to scenario results, a prominent future role of wind and solar PV is also suggested by high current growth rates, market outlooks and ambitious policy targets for future electricity shares. The deployment of renewable energy sources is progressing rapidly, with worldwide annual growth rates for wind and solar power of 25.6% and 54%, respectively, from 2005 until 2011 (IEA 2012). In 2012 about half of the total electricity-generating capacity installed globally use RES, of which 39% is wind power and 26% is solar PV (REN21 2013). Market reports anticipate a continuous expansion of wind and solar PV (IEA 2012, REN21 2013) and 138 countries adopted policy targets for increased future shares of renewables (as of early 2013, REN21 2013). For example, Denmark has the target of 100% renewable energy in the energy and transport sectors by 2050. Germany formulated a target of an 80% RES share in the power sector by 2050. The EU Commission recently suggested a EU-wide binding target for final energy from renewables of at least 27% in 2030 (European Commission 2014) and in its “Energy Roadmap 2050” the Commission shows shares between 50-80% in 2050 (European Commission 2011). Other examples are a number of US states that introduced renewable portfolio standards (i.e. quota systems) requiring increased renewables’ electricity shares such as California and Colorado with 33% and 30% by 2030, respectively.

1.4. The challenge of integrating wind power and solar PV

Given the importance of wind and solar PV, policy makers typically pose crucial questions: What are their economic costs? When will wind and solar PV be competitive without subsidies? What is their welfare-optimal share? Reports and academic papers often respond by showing generation costs using a common metric for estimating and comparing the costs of generating technologies, namely levelized costs of electricity

⁶ The IEA does not report emissions from electricity and heat production separately. These emissions are partly linked due to combined heat and power generation.

(LCOE) (Karlynn and Schwabe 2009, IEA/NEA 2011, Nitsch et al. 2010, IPCC 2011, IRENA 2012, Kost et al. 2012, EIA 2013, IEA 2012). LCOE are the full life-cycle costs (fixed and variable) of a power generating technology per unit of electricity (MWh). Many analyses suggest or implicitly assume that wind and solar PV are competitive and economically efficient once their LCOE drop below those of conventional plants. However, this is wrong because it ignores one important issue.

The power output from wind and solar is determined by inherent natural variations of wind speeds or solar irradiation and can therefore not be supplied on demand. By contrast, the output of dispatchable plants such as thermal plants (gas, coal, biomass, geothermal), nuclear plants and most hydro plants can in principle be controlled. Because wind and solar are variable renewable energy sources (VRE) they interact differently with the power system than dispatchable plants and are more difficult to integrate. The fundamental reason behind this is that electricity unlike other goods needs to be generated and transmitted continuously to meet variable electricity demand at all times and locations.

While the integration of VRE faces no insurmountable technological barriers (IPCC 2011b) their deployment imposes additional costs at the system level, for example for additionally required distribution and transmission networks, short-term balancing services, more cycling and ramping of conventional plants and provision of firm reserve capacity. These costs are usually termed “integration costs” (Milligan and Kirby 2009, Hannele Holttinen et al. 2011, Milligan et al. 2011, Katzenstein and Apt 2012).

Neglecting or underestimating integration costs leads to biased conclusions regarding the above questions, i.e. the optimal share and competitiveness of VRE could be overestimated while the costs of a long-term transformation of the energy system could be underestimated. In fact if integration costs are high they could be a barrier to a transformation towards a system with high shares of wind and solar PV. Hence, it is crucial to understand the challenges and costs of integrating variable renewables and their impact on the cost-efficient deployment of wind and solar PV.

Unfortunately, accounting for short-term variability and renewables integration in models that focus on the long-term development of the energy system is difficult. There is a trade-off between model detail and scope due to numerical and complexity limits. The challenge is to bridge the scales that are relevant for both, the integration of wind and solar PV (hourly resolution or even less) and the long-term transition of the energy system (years to decades). Analogously the spatial dimension should ideally consider high detail (e.g. transmission lines and single generation units) and at the same time span a large geographical area, ideally even the global energy system, with all energy sectors and relevant macro-economic interactions. However, there is no model that features such high detail and wide scope at the same time to comprehensively evaluate VRE and their role in future power systems under the consideration of VRE integration. Instead there

are different approaches and corresponding scientific communities that apply models of different level of detail and scope.

Within the substantial body of literature on the economic evaluation of VRE I distinguish three main branches of literature: (i) the integrated assessment modeling literature, (ii) the integration costs literature and (iii) the marginal economic value literature. The corresponding communities to some extent contribute to the same research objective but their approaches differ in detail and scope. The approaches have specific merits and deficits and could in principle ideally complement each other. However, the corresponding scientific communities are hardly connected, i.e. they use different concepts, models and terminology and only rarely cite each other. I summarize these three distinct branches in the following.

(i) Integrated assessment modeling literature

IAMs are the predominant method for calculating mitigation scenarios and therein estimating the optimal deployment path of VRE. The multi-sector models have a long-term temporal and global spatial scope and aim at combining all drivers of climate change and mitigation options into a single modeling framework. They capture the key interactions between the energy, the economic and the climate system as well as general equilibrium effects and interaction within the energy system (heat, transport and power sector). Examples are GCAM (Calvin et al. 2009, Calvin 2011), IMAGE (Vuuren, Stehfest, et al. 2010), MESSAGE (Krey and Riahi 2009), TIAM (Loulou and Labriet 2008), MERGE (Manne, Mendelsohn, and Richels 1995), EPPA (Babiker et al. 2001), WITCH (Bosetti et al. 2006) and REMIND (Leimbach et al. 2010). However, the huge scope limits their level of detail. The models divide the world into 10–30 regions and use a temporal resolution for investment decisions of 5–10 years. Power demand and supply are aggregated and balanced in terms of annual averages, while in reality electricity demand, wind speeds, and solar radiation show significant variability on time scales of minutes to years. Increasing the temporal and spatial resolution to explicitly represent variability is not possible due to numerical limits. It needs a stylized representation of power sector variability and VRE integration.

Most IAMs use reduced-form approaches covering different aspects, but also having limitations and needing further development (Sullivan, Krey, and Riahi 2013, Luderer, Krey, et al. 2013, Baker et al. 2013). Luderer, Krey, et al. (2013) review 17 models with respect to their method of representing variability. Some models seem to be overly optimistic and thus underestimate the integration challenge. For example there are two models that ignore this issue entirely. Some models seem to be overly optimistic and thus underestimating the integration challenge for example two models that ignore this issue at all. By contrast, seven models limit the maximum generation share of wind and solar to e.g. 15% each, which can be considered as overly pessimistic because it implicitly assumes infinite integration costs at higher shares. As a more balanced approach four

models use a cost penalty per generated unit electricity from VRE that increase with penetration. To foster VRE integration eight models require stylized investment in specific integration options⁷ like gas-fired backup capacities, electricity storage or transmission infrastructure. Sullivan, Krey, and Riahi (2013) suggest an additional balance equation for “flexibility” to account for variability.

However, all these approaches have drawbacks. Most importantly, the economic foundation of the approaches is unclear. For some approaches this might be because they are motivated from a technical perspective; for other very stylized approaches the parameters lack an economic interpretation. Moreover, each approach focuses on specific aspects of variability while omitting others so that their completeness is unclear. And finally, these stylized representations are difficult to parameterize. Consequently, the representation of VRE needs to be improved to increase the credibility of model results and in particular to reduce the uncertainty when estimating the role of VRE for climate mitigation.

Note that beside IAMs there is another family of long-term models that narrow the scope to the energy or power sector of one world region, which makes room for an improved representation of variability. Sometimes they are termed “hybrid models” because they to some extent combine features of IAMs and the models of higher detail described later this section. Example that cover all energy sectors are PRIMES (applied in the EU Energy Roadmap 2050, European Commission 2011), TIMES (Loulou et al. 2005), MARKAL (Loulou, Goldstein, and Noble 2004), while other models focus on the power sector, such as ReEDs (Short et al. 2009), US-Regen (Blanford, Merrick, and Young 2013), LIMEs (Haller, Ludig, and Bauer 2012). The model’s spatial resolution increases to about countries or federal states, while using representative time slices or characteristic days or weeks implicitly increases their temporal resolution. However, these approaches in principle face the same drawbacks as the IAM approaches described above but to a lesser extent. The correlation of wind supply, solar supply and power demand, which is important for integration challenges, is hard to capture with a reasonable number of time slices or characteristic days. Instead it would need an about hourly temporal resolution to capture the most important aspects of VRE and integration issues as well as integration options such as most storage technologies (Nicolosi, Mills, and Wiser 2010). Consequently hybrid models are not detailed enough to explicitly represent the variability of VRE and comprehensively consider integration costs.

⁷ Inspired by (Sims et al. 2011) we use the term “integration options” as an umbrella term for all technologies and measures that reduce the integration costs of VRE.

(ii) Integration costs literature

The integration costs literature seeks to accurately calculate integration costs of VRE based on bottom-up techno-economic assessments (Gross et al. 2006, Smith et al. 2007, Milligan and Kirby 2009, DeCesaro and Porter 2009, GE Energy 2010, Hannele Holttinen et al. 2011). H. Holttinen et al. (2013) provide a blueprint for such integration studies and GE Energy (2012) shows a recent overview on a number of US studies.

These studies typically analyze a power system of one region or one balancing area with exogenously given generation and transmission capacities for one year. Their small temporal and spatial scope allows using high-resolution production cost modeling techniques with hourly to sub-hourly resolution that optimize the dispatch of in some cases even single generation units (dispatch or unit-commitment models) under consideration of technical constraints like ramping and cycling. Hence, variability of demand and renewable supply and its integration can be explicitly modeled.

Integration costs studies typically identify three characteristic properties of VRE that cause three integration costs components: balancing costs, grid costs and adequacy costs (GE Energy 2010, Sims et al. 2011, Hannele Holttinen et al. 2011, NEA 2012, H. Holttinen et al. 2013):

- *Balancing costs* occur because VRE supply is uncertain until realization. Forecast errors of VRE generation and short-term variability of VRE cause intra-day adjustments of dispatchable power plants and require operating reserves that respond on short notice. A categorization of operating reserves is given in Holttinen et al. (2012).
- *Grid costs* occur because the supply of VRE is location-specific, i.e. the primary energy carrier cannot be transported like fossil or nuclear fuels. Hence, costs occur due to additional transmission requirements.
- *Adequacy costs* reflect the low capacity credit of VRE i.e. that VRE supply energy while only slightly reducing the need for total generation capacity. Hence, backup capacities are required. Note that this cost category is controversial because VRE do not require additional capacity in the short term when introduced into a system. However, the term “backup capacity” refers to capacity that could be removed in the long term if VRE had a higher capacity credit.

Most integration costs studies focus on wind power. Integration costs estimates vary to some extent and their results are difficult to compare due to different methodologies. However, there is the general tendency that integration costs of wind are small compared to its generation costs or average whole-sale electricity prices. In a review Holttinen et al. (2011) show that additional balancing costs of wind amount to about 1–4 €/MWh at wind

shares of up to 30%. Additional grid costs vary from 50 €/kW to about 200 €/kW at 15% to 35% share, which equals to about 2–7 €/MWh⁸. Estimates for adequacy costs are sparse and controversial. NEA (2012) reports a cost range for several countries of about 3–7 €/MWh for a 30% share of wind. Other studies prefer to either only report capacity credits as an indicator without translating it into economic costs (Sims et al. 2011, Holttinen et al. 2011) or suggest refraining from this cost category at all (Smith et al. 2007, IEA 2014). If adequacy costs are not considered integration costs amount to about 3–11 €/MWh, which is low compared to LCOE of modern wind plants of about 60 €/MWh (Kost et al. 2012).

The integration costs studies show two types of deficits. The first is due to their limited scope. They mostly apply a short-term perspective where plant and grid capacities are given and fixed. Consequently they focus on system operation rather than capacity investment and hereby tend to neglect long-term transition effects and structural adjustments like a change of the capacity mix or demand patterns.

Second, there are also some important deficits of conceptual nature. While the properties of VRE are well-known and the term “integration costs” is widely used, there is no consensus on a rigorous definition and on how to comprehensively calculate total integration costs (Milligan et al. 2011). There are a number of only qualitative definitions of integration costs given in the literature such as “an increase in power system operating costs” (Milligan and Kirby 2009), as “the extra investment and operational cost of the nonwind part of the power system when wind power is integrated” (Hannele Holttinen et al. 2011), as “the additional cost of accommodating wind and solar” (Milligan et al. 2011), or as “comprising variability costs and uncertainty costs” (Katzenstein and Apt 2012). To overcome the lack of a rigorous definition integration studies typically operationalize integration costs as the sum of the above cost components: “balancing costs”, “grid costs”, and “adequacy costs”, while the latter category is very controversial. There is no consensus on how to consistently calculate each of these cost components such that they are comparable, and it is not clear if this enumeration is exhaustive. Consequently it is unclear whether the sum of levelized costs and integration costs actually represent the total economic costs of VRE. As a consequence, it is difficult to interpret integration costs estimates for an economic analysis of VRE. It is unclear how integration costs estimates for VRE help deriving their welfare-optimal deployment or how they relate to the marginal economic value of VRE, which is the focus of the third branch of literature.

⁸ This conversion assumes annual wind full-load hours of 2000, a discount rate of 7% and a grids' life time of 40 years.

(iii) Marginal economic value literature

The third research strand evaluates wind and solar PV by estimating their marginal economic value often as a function of their share (Martin and Diesendorf 1983, Grubb 1991, Hirst and Hild 2004, Lamont 2008, Borenstein 2008, Fripp and Wiser 2008, Gowrisankaran, Reynolds, and Samano 2011, Mills and Wiser 2012, Hirth 2013). The marginal economic value is an important concept in economic analysis: the intersection of marginal economic value and marginal (long-term) costs indicates the welfare-optimal amount of a generation technology. This link to economic welfare-theory is a key merit of this approach. While the integration costs literature is to some extent rooted in engineering, the marginal value literature is mainly written by economists.

Compared to dedicated integration costs studies the models use longer time horizons, capacity expansion and hereby to some extent consider system adjustments in response to VRE deployment. This comes at the costs of less detail. The models have a poorer representation of technical system constraints, such as ramping and cycling constraints of power plants or individual transmission grid lines. Nonetheless they explicitly account for variable demand and renewable supply by applying a high temporal resolution of typically hours while the spatial resolution typically is balancing areas or countries. Hereby they price in integration challenges without using the term “integration costs”. In fact the marginal value of VRE is impacted by their three characteristic properties (explained above) in case the underlying technical constraints are sufficiently represented.

However, in contrast to integration studies the effect of variability in marginal value studies is typically high. Studies find a strongly decreasing value of VRE at increasing penetration due to their variability (Grubb 1991, Hirst and Hild 2004, Mills and Wiser 2012, Hirth 2013). Mills and Wiser (2012) model for California that the value of wind decreases by 30% when its share increases from zero to 40% while that for solar reduces by more than 50% at a share of 30%. Hirth (2013) shows similar results for VRE for North-Western Europe: the value of wind decreases by about 25% to 55% at a share of 30% while that of solar reaches similarly low values already at a 15% share. Hirth also gives an extensive review on literature estimates of marginal economic values. The strong impact of variability on the economic value of VRE indicates that integration costs studies might not capture all economic impacts of variability.

The marginal value literature also has some methodical drawbacks due to limited detail and scope:

- 1) In contrast to integration costs studies they might miss some of the integration impacts that require a more detailed representation of technical system constraints. For example to accurately consider balancing costs forecast errors need to be modeled, which most models do not represent.

- 2) Because marginal value studies use partial equilibrium models of mostly only the power sector they neglect general equilibrium effects and interactions within the entire energy system.
- 3) Due to their limited scope they neglect some developments that can decrease the impact of variability and increase the marginal value of VRE, in particular a stronger linking of the heat and transport sector to the power sector via hydrogen from electrolysis, electric cars or power-to-heat technologies.
- 4) The studies often take VRE deployment as given exogenously, i.e. they do not calculate welfare-optimal shares of VRE. Only a few models also allow for endogenous deployment, which enables a direct estimation of optimal VRE shares (Lamont 2008, Hirth 2014).
- 5) The studies typically find that their results are highly sensible to exogenous parameters, such as CO₂ prices, conventional fuel prices, electricity demand and future cost reductions of VRE. Various assumptions for these lead to a range of estimates for marginal values and optimal shares.

The last four limitations become particularly obvious in comparison to IAMs. For deriving a consistent climate mitigation pathway that efficiently internalizes the climate externality with endogenous learning, optimal VRE deployment and general equilibrium effects, it requires models, like IAMs, with higher scope and endogenous learning and carbon pricing⁹.

⁹ For example via a cumulative long-term carbon budget, a carbon-tax path or coupling to a climate model.

Connecting the literature branches on evaluating VRE could resolve their deficits

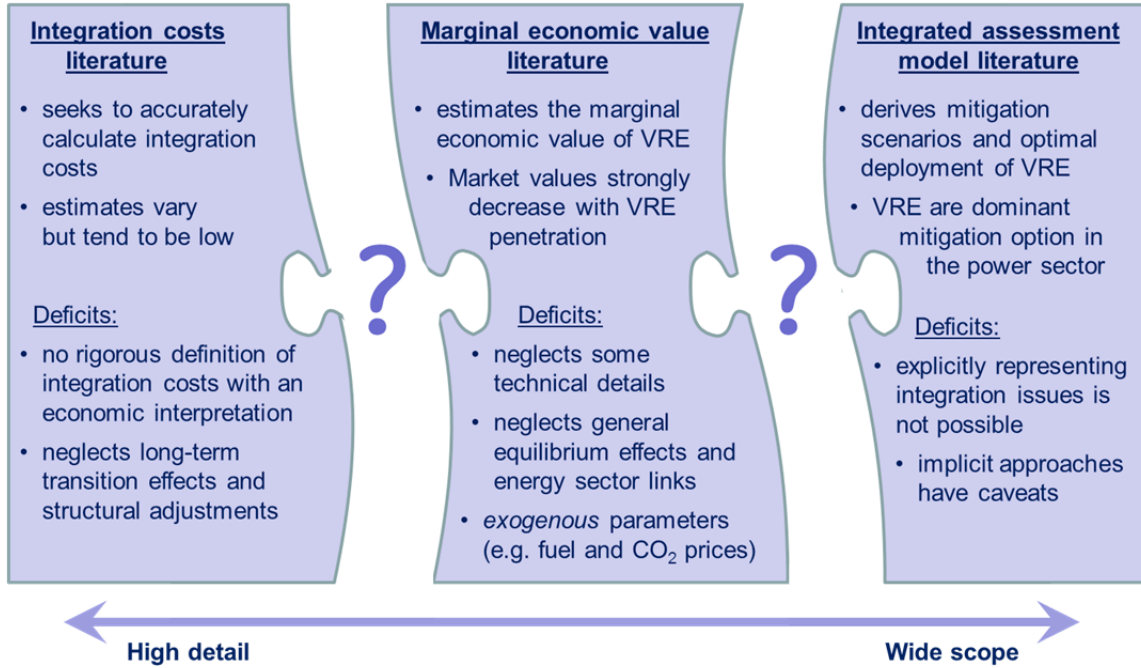


Figure 1: There are three literature branches on evaluating VRE with different detail and scope: integration costs, marginal economic value and integrated assessment model literature. Each branch has specific deficits that could be resolved if the branches could be connected.

To sum up, improving the representation of VRE is a key challenge for the IAM community. There are two more research strands evaluating VRE with much higher detail that could help advancing IAMs: the integration cost literature and the marginal value literature. However, both research strands are barely interlinked and use different concepts and terminology. Their results differ systematically and their relation is vague. There is no consensus on the economic impacts of variability or their magnitude and thus it is unclear how to parameterize IAMs.

Each of the three research strands has its merits, yet there are deficits of mostly methodical and conceptual nature (Figure 1). Better linking the three branches has huge potential for improving the respective approaches and their interplay. This thesis directly addresses their points of intersection and seeks to help resolving their deficits by building bridges between them. This would allow calculating robust mitigation scenarios and estimates of the economic potential of VRE under consideration of their integration challenges.

1.5. Thesis objective and outline

This thesis aims to improve the economic evaluation of wind and solar PV in particular with respect to their variability and corresponding integration costs. It covers a range of

relevant issues at the interface of the different literature branches and hereby seeks to establish crucial links that improve their respective approaches and results.

The thesis is structured along six main research questions that are addressed in chapters 2 to 7, each of which is published or under review in a peer-reviewed journal. Chapter 8 summarizes the main results of each chapter, draws research and policy implications and gives an outlook for further research. The remainder of this section introduces the chapters and their role in this thesis.

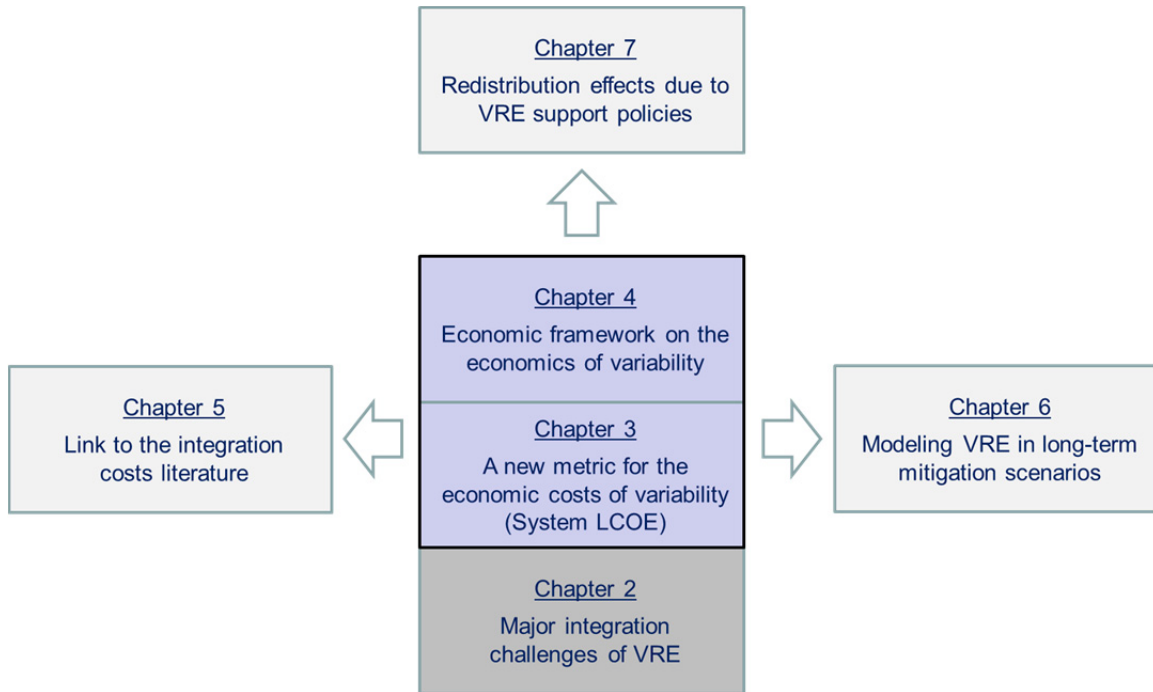


Figure 2: The interrelation of the six chapters. Chapter 2 builds the foundation, while 3 and 4 build the heart of the thesis. Chapters 5, 6 and 7 address important implications for related research fields. Figure 2 illustrates the interrelation of the six core chapters. Chapter 2 builds the foundation. It investigates major integration challenges that have been neglected in the integration costs literature. Chapters 3 and 4 are the actual heart of the thesis. They seek to understand the economics of variability and suggest a new economic metric System LCOE that aims to comprise the full costs of VRE. This requires a new definition of integration costs that links to the economic concept of the marginal value of VRE, which is also presented. The remaining chapters 5, 6 and 7 address important implications that explore links to related research fields. Chapter 5 focuses on connecting the two research strands on evaluating variable renewables: integration costs literature and the economic literature on the marginal value. Chapter 6 draws implications for how to model variability in IAMs. This can help improving the robustness of mitigation scenarios in particular with respect to the role of VRE. Finally while the previous chapters evaluate VRE with respect to total welfare or system costs, chapter 7

broadens this view to different actors in the power system and analyzes distributional flows when VRE support policies or carbon pricing are introduced.

In the following the chapters and their driving research questions are briefly introduced.

1. The foundation: What are the major integration challenges for variable renewables? (chapter 2)

This chapter analyzes three major integration challenges and their dependence on the penetration and mix of wind and solar, and on region (US Indiana and Germany). We focus on challenges that are determined by the temporal matching of demand with VRE supply: low capacity credit, reduced utilization of dispatchable plants and over-produced generation of VRE. These challenges induce the most important integration costs component “profile costs” (introduced and discussed in the chapters 3–5). We define challenge variables that represent the integration challenges based on residual load duration curves. These variables are quantified with a method only based on demand and VRE supply data and thus independent of model assumptions and scenario framings. This empiric approach helps identifying and understanding the key challenges of integrating VRE and can thus facilitate framing model analyses and interpreting their results. This chapter is a first step to understanding the impact of variability of wind and solar in this PhD thesis, on which the following chapters on the economic evaluation of VRE integration challenges build.

2. From integration challenges to integration costs: what are the economic costs of variability? What is an appropriate metric to compare power-generating technologies? (chapter 3)

This chapter introduces a new concept, System LCOE, which comprises all economic costs of VRE in a simple cost metric. The metric does not only contain generation costs (standard LCOE) but also reflects integration challenges that occur on a system level. Hereby the integration challenges studied in chapter 1 are translated into economic cost terms. For this purpose we develop a new mathematical definition of integration costs that comprises all costs of variability and that directly relates to economic theory. As a result System LCOE allow the economic comparison of generating technologies and deriving optimal quantities in particular for VRE. To demonstrate the new concept we quantify System LCOE from a simple power system model and literature values. This chapter moreover shows that System LCOE are equivalent to a marginal economic value or market value¹⁰ perspective. These two perspectives on evaluating VRE are further discussed in the next chapter.

¹⁰ The marginal value of a technology is defined as the marginal cost savings in the power system when adding a generation unit (MWh) of that technology. If markets are perfect and complete it equals the market value i.e. the investor’s average (per MWh) income from that technology.

3. Further generalization: What is an appropriate welfare-economic framework to evaluate variable renewables? How can integration costs be decomposed exhaustively and consistently and what is their magnitude? (chapter 4)

This chapter embeds the concept of System LCOE into a more generalized welfare-economic framework to analyze and quantify integration costs and to evaluate VRE. The framework consists of two equivalent perspectives on integration costs: A value perspective (marginal economic value) and a cost perspective (System LCOE). Furthermore, based on the fundamental characteristics of wind and solar power, temporal variability, uncertainty, and location-specificity, we suggest a decomposition of integration costs that exhaustively and consistently accounts for all costs that occur at the level of the power system. Finally, we significantly improve the quantification of integration costs shown in chapter 2 by reviewing 100+ published studies to extract estimates of integration costs and its components.

4. What is the link between the marginal value literature and the standard integration costs literature? (chapter 5)

There are two analytical approaches to evaluating the economic system impact of variable renewables: The first approach seeks to accurately calculate “integration costs” of VRE while the second analyses VRE by estimating their “marginal economic value”. However, the literature branches using each approach appear quite separated, using different concepts and terminology. This chapter shows how the conceptual insights derived in chapters 2 and 3 help connecting the two approaches on evaluating variable renewables. Hereby we hope to reveal stimulating links that may inspire future research. First, we show how former definitions of integration costs relate to the marginal value of VRE and second, we discuss the impact of different time horizons typically underlying both approaches and assumptions regarding the power system’s ability to adapt to VRE.

5. What are the implications for modeling VRE in IAMs? (chapter 6)

IAMs have a very wide scope, with a global perspective, a coverage of multiple sectors, a centennial perspective on mitigation challenges, and a representation of all major drivers of climate change and mitigation options. Inevitably, this limits the level of detail they can represent. As an example, the temporal resolution for investment decisions is typically 5 to 10 years. The temporal fluctuations of power demand and renewable supply relevant for the integration challenges occur on much shorter time scales. For the analysis of long-term transformation pathways, it is a crucial challenge to bridge all relevant time scales. To keep model complexity manageable, it needs a very stylized formulation of power sector variability and VRE integration. Building on the insights of chapter 2 to 4, chapter 6 introduces a new method of how to consider short-term temporal variability of VRE and power demand when modeling long-term climate change mitigation scenarios: the RLDC approach. As an example we apply the RLDC approach to REMIND-D, a long-term multi-sector model of Germany and analyze how it affects model results. The

core of the implementation is a representation of RLDC, which endogenously change depending on the penetration and mix of VRE. This allows for the simultaneous optimization of long-term investment and short-term dispatch decisions while accounting for short-term power sector variability.

6. What are the redistribution effects of VRE support and how do they compare to those of carbon pricing? (chapter 7)

The last chapter investigates and compares how energy and climate policies, namely the support for VRE and carbon pricing, redistribute wealth between different actors: electricity consumers and different electricity producers. While redistribution is seldom the focus of the academic literature in energy economics, it plays a central role in public debates and policy decisions. If policy makers want to avoid large redistribution they might prefer a mix of policies, even if CO₂ pricing alone is the first-best climate policy in terms of allocative efficiency. In other words, distinguishing between different actors and considering distributional effects might explain barriers to the implementation of first-best policies and help to identify feasible second-best policies.

2. Analyzing major challenges of wind and solar variability in power systems

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Abstract – Ambitious policy targets together with current and projected high growth rates indicate that future power systems will likely show substantially increased generation from renewable energy sources. A large share will come from the variable renewable energy (VRE) sources wind and solar photovoltaics (PV); however, integrating wind and solar causes challenges for existing power systems. In this paper we analyze three major integration challenges related to the structural matching of demand with the supply of wind and solar power: low capacity credit, reduced utilization of dispatchable plants, and over-produced generation. Based on residual load duration curves we define corresponding challenge variables and estimate their dependence on region (US Indiana and Germany), penetration and mix of wind and solar generation. Results show that the impacts of increasing wind and solar shares can become substantial, and increase with penetration, independently of mix and region. Solar PV at low penetrations is much easier to integrate in many areas of the US than in Germany; however, some impacts (e.g. over-production) increase significantly with higher shares. For wind power, the impacts increase rather moderately and are fairly similar in US Indiana and Germany. These results point to the need for a systems perspective in the planning of VRE, a further exploration of alternative VRE integration options, such as storage and demand side management, and the explicit consideration of integration costs in the economic evaluation of VRE.

2.1. Introduction

Future power systems will likely show a substantially increased share of renewable energy of which a large share will come from the variable renewable energy (VRE) sources wind and solar PV. This is indicated by the current high growth rates, future market trends, ambitious policy targets and support schemes, and scenario results.

The expansion of variable renewable electricity is progressing rapidly, with worldwide annual growth rates for wind and solar PV of 26% and 54%, respectively, from 2005 to 2011 [1]. In 2012 new power generating capacity from renewables exceeded that of conventional fuels (fossil and nuclear) [2]. In 2012 Denmark, Germany and Spain had a share of renewable electricity of 49%, 23% and 32%, respectively, with more than half being from wind and solar energy in each country [1], [3]. For the future policy makers have set renewable energy targets (in 138 countries) and adopted support schemes (in 127 countries) for a variety of reasons including climate-change mitigation targets, enhanced energy security and to reduce externalities such as air pollution [2]. For example, Denmark has a goal of 100% renewables in final energy consumption and Germany is

aiming for 80% in the power sector by 2050. The EU Commission recently suggested an EU-wide binding target of at least 27% renewables in final energy in 2030 [4] and in its ‘Energy Roadmap 2050’ it shows shares between 50-80% in 2050 (European Commission 2011). In the US, many states have introduced renewable portfolio standards that require increased renewable electricity shares. For example, California and Colorado have targets of 33% and 30% by 2030, respectively.

Many long-term integrated assessment scenarios and bottom-up resource assessment studies show that renewable energy has the potential to play an important role in achieving ambitious climate mitigation targets [5]–[10]. Scenario results summarized in [6] suggest that in the case of future policies to mitigate climate change in line with the globally-agreed long-term climate targets, renewable energy shares as a fraction of total primary energy consumption will increase from 13% to a range of 30%-80% by the middle of the century, with the uncertainty being mainly due to variations in assumptions as to which other low-carbon technologies will be available to complement renewables. The recent EMF27 model comparison [10] shows that for all but one model, renewables provide more than 35% of power supply in the second half of the century, and half of the models have a renewables share of 59% or higher. In those scenarios with high overall renewable deployment wind and solar PV contribute the major electricity share exceeding 40% in the second half of the century.

Achieving the high shares of wind and solar presented in many scenarios will require integration into global power systems. However, VRE differs from conventional power-generating technologies in that they exhibit characteristic properties that pose challenges to their integration. There is wide consensus that these challenges create no insurmountable technical barriers to high VRE shares, however, they cause additional costs at the system level, which are usually termed “integration costs” [6], [11]–[15]. There are slight differences in the way many studies classify the cost-driving VRE properties, but it is possible to categorize three specific properties of VRE: uncertainty, locational specificity, and variability [12], [14]–[18]. Integration studies often estimate the associated costs of these properties. We briefly go through the properties and elucidate their technical reason and relative importance.

First, VRE output is *uncertain* due to the limited predictability (forecast errors) of inherent natural variations of wind speeds or solar irradiation. This requires additional short-term balancing services and the provision of operating reserve capacity. Some studies review balancing costs estimates for wind and find that they are mostly below about 6€/MWh of wind which is about 10% of their levelized costs of generation [12], [19], [20].

Second, VRE output is *location-specific* because the primary energy carrier of wind and solar power cannot be transported like fossil or nuclear fuels and consequently additional costs for electricity transmission occur to meet spatially distributed demand. Estimates

for grid costs are scarce and there is no common method. It is estimated that annual transmission grid costs of € 1bn may be incurred to integrate 39% renewables in Germany's power sector by 2020 [21], translating to 10 €/MWh if the total cost is attributed to the increase in renewable generation. For the US, the National Renewable Energy Laboratory (NREL) estimates grid investment costs to integrate 80% renewable electricity (of which half are VRE) to be about 6 \$ per MWh of VRE [22]. Holtinen, et al. [12] review a number of European wind integration studies and shows a range of 50-200 €/kW at shares below 40%, which translates to 2-7 €/MWh¹¹. In summary, grid costs might be slightly higher than balancing costs but still small compared to generation costs of wind.

Third, the temporal *variability* of wind and solar has two impacts. The first one is increased ramping and cycling requirements of conventional plants because they need to adjust their output more often, with steeper ramps and in a wider range of installed capacity. This seems to be of minor importance. Studies estimate very low costs [20], [23], [24] or find that ramping and cycling requirements are easily met even at high shares of VRE [25]–[27]. However, even if power plants could perfectly ramp and cycle, variability would still impose an important second impact. Because electricity demand is fairly price-inelastic and electricity cannot easily be stored, demand needs to be covered at the time it arises. Thus, the temporal matching of VRE supply profiles with demand is crucial to their integration. Designated integration studies tend to neglect this impact and focus on balancing, grid, ramping and cycling, while other less technical and more economic studies implicitly account for it. They find a significant economic consequence: variability reduces the marginal value of wind from about 110% of the average electricity price to about 50-80% as wind increases from zero to 30% of annual electricity consumption [18], [28]–[30]. It is this aspect of variability that is the focus of this paper.

This paper contributes to understanding the impact of wind and solar variability on power systems, specifically, the impact of the temporal matching of VRE supply and demand profiles. The tool we use is the residual load duration curve (RLDC), which is usually applied for illustration purposes. RLDC is a purely physical concept, which only requires demand and VRE supply data, yet it captures the relation of the different temporal profiles of wind and solar supply and demand and delivers the relevant economic aspects of major integration challenges. We define three challenge variables that represent fairly independent impacts of variability on the structure of the RLDC. We aim to analyze and compare integration challenges by estimating these variables in a comprehensive analysis for different shares of wind and solar and for two regions, Germany and for a US region in Indiana. Only based on demand and VRE supply data, we derive essential insights that are independent of model assumptions and scenario framings. Our analysis is not meant

¹¹ Assuming a 7% discount rate and 2000 wind annual full load hours.

to be a surrogate for a model analysis. Instead, the results can help in understanding and framing model analyses. In addition, this study can aid in parameterizing integrated assessment models (IAMs) that cannot explicitly represent the short-term variability of wind and solar.

The paper is structured as follows. The next section introduces the method for defining integration challenges using RLDC. Section 2.3 provides results of our analysis and section 2.4 provides a discussion of our results and conclusions.

2.2. Method - capturing major integration challenges

An intuitively appealing technique for representing the load-matching properties of VRE and the induced challenges is provided by load duration curves (LDCs) and residual load duration curves (RLDC). These curves are mostly used for illustrative purposes and sometimes indirectly used as a model input [31]–[35]. We present here for the first time the application of RLDC as a direct quantitative tool for analyzing systems with arbitrary levels of penetration of both wind and solar PV, and demonstrate the intuitive clarity of this approach to thinking about VRE challenges.

We start by explaining the concept of RLDC. As a first preparatory step, we introduce the well-known concept of a load duration curve LDC, which is derived by sorting the load curve i.e. the time series of power demand for one year or longer (Figure 3) from highest to lowest values. The y-axis of a LDC indicates the minimum capacity required to cover total annual electricity demand, which is reflected by the area below the curve.

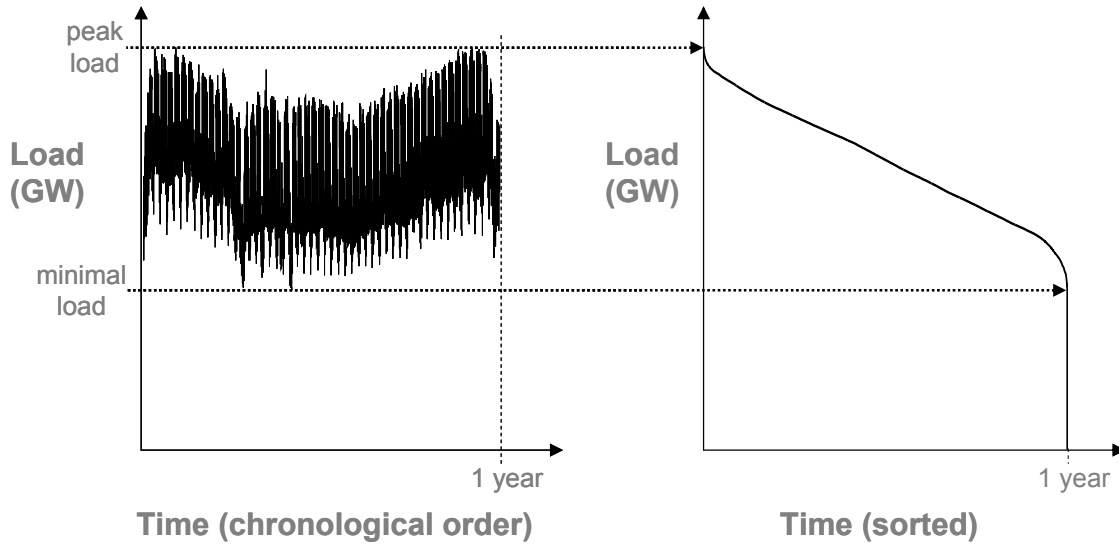


Figure 3 (schematic): The LDC (right) is derived by sorting the load curve (left) in descending order.

If a new source is added to the system, in our case wind and solar, the power generated from that source at each point in time can be subtracted from the load at that same time to arrive at a time series describing the residual load that must be supplied by the rest of the system (Figure 4). The RLDC is then derived by sorting this residual load curve in

descending order. The area between the LDC and the RLDC is the electricity generation from variable renewables (wind and solar). Note that the shape of the area does not indicate the temporal distribution of VRE supply, due to different sorting of load and residual load, yet this information is not relevant for our current purpose. Also ramping and cycling requirements are not captured, since that would require the chronological order of the residual load, which is lost in a duration curve.

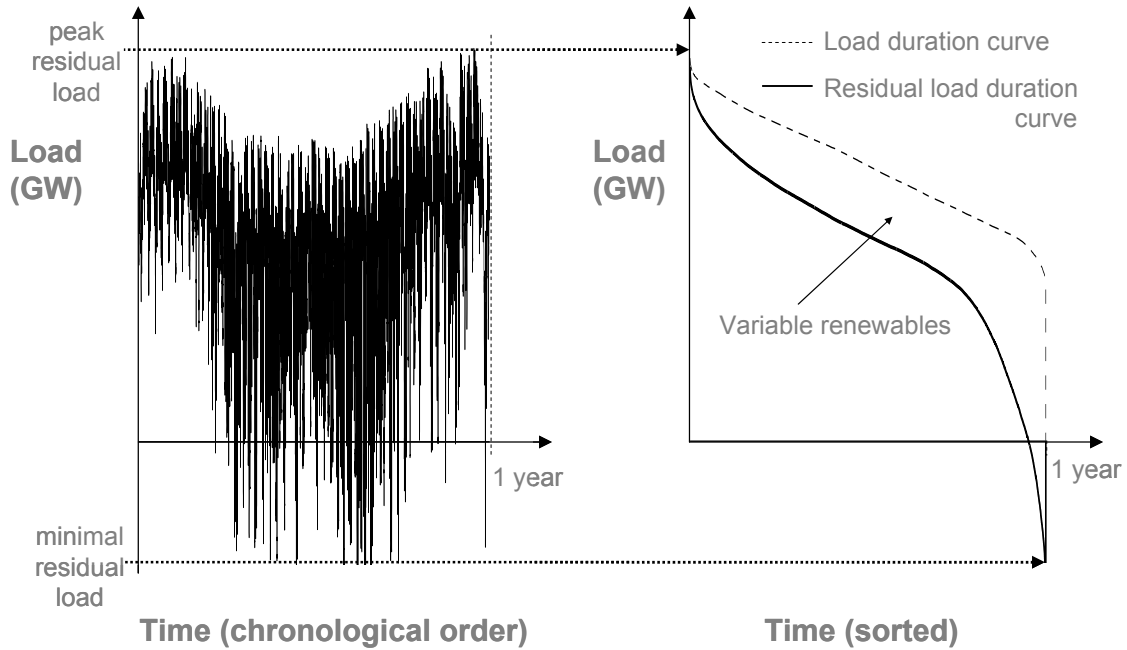


Figure 4: (schematic): The residual load curve (a time series) is derived by subtracting the time series of VRE from the time series of power demand (left). The RLDC (right) is derived by sorting the residual load curve in descending order. The area in between the RLDC and the LDC equals the potential contribution of VRE.

RLDC contain crucial information about the variability of wind and solar supply, as well as correlations with demand, thereby capturing three major challenges of integrating VRE into power systems, as shown in Figure 5, namely (i) low capacity credit, (ii) reduced full-load hours of dispatchable plants, and (iii) overproduction of VRE.

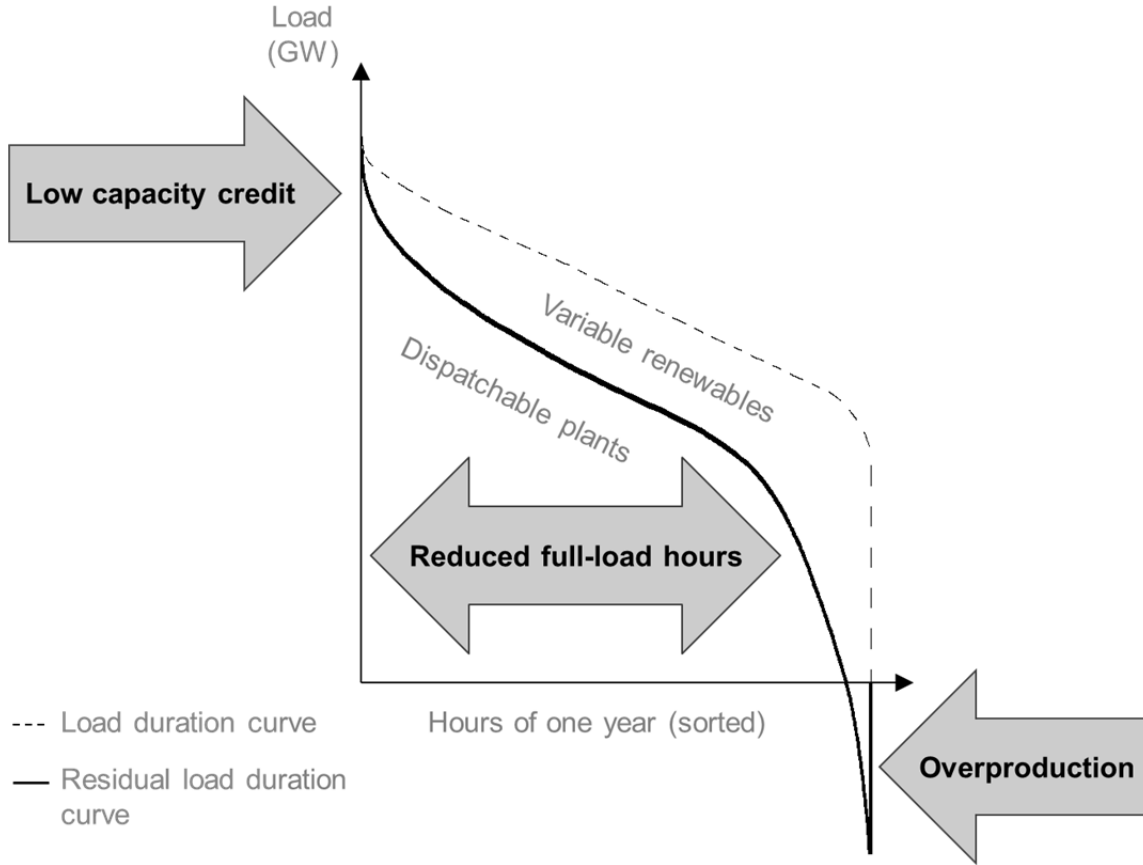


Figure 5: Residual load duration curves capture three main challenges of integrating VRE (illustrative). The utilization of conventional plants is reduced, while hardly any generation capacity can be replaced. At higher shares VRE supply exceeds load and thus cannot directly be used. Load and renewable feed-in data for Germany are used to derive the curves¹².

The RLDC not only *illustrate* the challenges of VRE but also allow for *quantifying* three “challenge variables” that represent the different and fairly independent integration aspects. We explain the challenges and their quantification used in the analysis:

- 1) **Low capacity credit:** Wind and solar contribute energy while only slightly reducing the need for total generation capacity, especially at high shares, due to a relatively low capacity value; consequently some firm capacity is required complementing VRE (including electricity storage or demand response mechanisms). In other words, the long-term capacity cost savings in a system are lower when adding VRE compared to adding a dispatchable plant. There are several similar qualitative definitions of capacity credit in the literature [36]–[38] that are in line with the following: The capacity value of a generator can be defined as the amount of perfect reliable capacity

¹² For wind and solar generation we use quarter hourly feed-in data from German TSOs for 2011. For power demand of Germany hourly data for 2011 is used from ENTSO-E.

(firm capacity) that can be removed from the system due to the addition of the generator, while maintaining the existing level of reliability. The capacity credit is the ratio of capacity value and the added capacity. Moreover there are different formal definitions, i.e. different methods of actually estimating the capacity credit [38]–[42]. Because we only want to rely on load and VRE supply data and to provide full transparency we follow an approximation method that was introduced by Garver [43] and has been shown to well-represent actual system performance. The method is based on the concept of Effective Load Carrying Capability (ELCC). The ELCC of a power plant represents its ability to increase the total generation capacity without increasing the existing level of reliability often measured in terms of *loss of load probability* (LOLP). In [43] an approximation for the ELCC is given, which has been used in many analyses to express the capacity value or capacity credit (see for example equation (13) in [42], or the appendix in [44]):

$$a = m \ln \left(\sum_i e^{LDC_i/m} / \sum_i e^{RLDC_i/m} \right) / C_{VRE} \quad (1)$$

where a is the capacity credit of the total VRE capacity C_{VRE} , LDC_i and $RLDC_i$ are the values of the (residual) load duration curve at a given instant i . The Garver capacity factor m was chosen for both regions to have a typical value of 4% of peak load [39], [44]. By considering the ratio of exponentials, the capacity credit as defined in Eq. (1) is to a large part determined by the difference between the peaks of the LDC and the RLDC, although there are contributions from the rest of the curves. Our work represents a first thorough treatment of capacity credit for a wide range of combinations of solar PV and wind power.

- 2) **Reduced full-load hours:** Wind and solar PV reduce the annual full-load hours (FLH) of dispatchable power plants; at high shares this is especially true for intermediate and baseload plants. The average utilization and therefore the life-cycle generation per capacity of existing and newly build plants is reduced and thus their specific generation costs (per MWh) increase. We operationalize this challenge by measuring the decrease in full-load hours of the RLDC at two heights as indicated in Figure 6. To capture the effect on intermediate load we chose a height equal to half of the peak load and to account for the reduction of baseload FLH we measure at the intersection with the x-axis. When T_{RLDC} and T_{LDC} are the inverse (residual) load duration curves the relative reduction at the two heights can be expressed as follows:

$$b = \frac{T_{RLDC}(0.5)}{T_{LDC}(0.5)} \quad (2)$$

$$c = \frac{T_{RLDC}(0)}{T_{LDC}(0)} \quad (3)$$

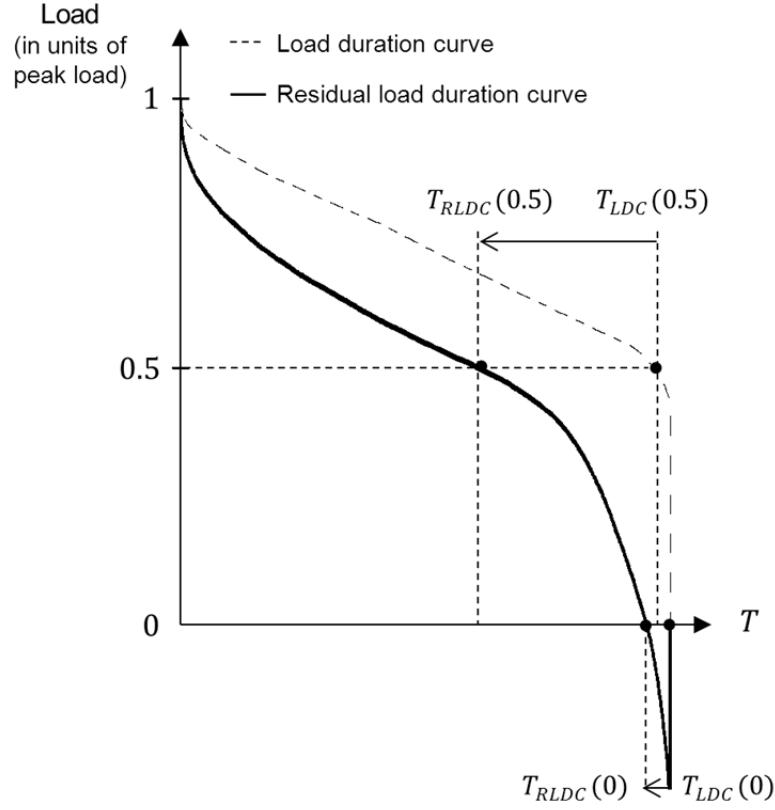


Figure 6: With VRE deployment the width of the RLDC is decreasing. We measure this effect at two heights relative to peak load: at half height and at the x-axis.

3) **Over-production of VRE:** At high generation shares there are hours in which combined wind and solar PV generation exceeds load, and thus production must be curtailed if it cannot be stored or transmitted. Hence, the effective capacity factor¹³ of VRE decreases and specific per-energy costs of VRE increase. We measure over-production as the share of potential total generation of wind and solar that exceeds domestic load. This equals the ratio of the negative part of the RLDC between the x-intercept T_0 and the maximum T_{max} of the data series (e.g. one year) to total potential variable renewable generation (G_{VRE}).

$$d = \int_{T_0}^{T_{max}} RLDC(T) dT / G_{VRE} \quad (4)$$

Note that our approach provides a simplified estimate of curtailment that can be derived from a pure data analysis without requiring detailed power system modeling. It may underestimate curtailment occurring in the real-world, because grid or

¹³ The capacity factor describes the average power production per installed nameplate capacity of a generating technology

minimum-load constraints of dispatchable power plants are neglected, or overestimate curtailment, because it does not account for the possibility of long-distance transmission or storage. Some studies focus on over-production. Ref. [45] uses a similar RLDC method and analyzes curtailment for New York State. For Germany, Ref. [46] estimates storage requirements to limit over-production to various levels and uses RLDC to illustrate the model results.

These three challenges impose costly redundancy on the system. We will show that the magnitude of these challenges depends on the renewable source (wind or solar), on the region and becomes more severe at higher shares. Note that all “challenge variables” are measured in average and not marginal terms *i.e.* the impacts are distributed across the total wind and solar penetration, rather than quantifying them for the last added unit of wind or solar. Marginal impacts can be much higher, for example the average capacity credit of all wind and solar plants is higher than that of the last unit, because the capacity credit always decreases with increasing penetration.

Furthermore, in this work we concentrate on the direct impact of variable renewable generation from solar PV and wind on the electrical system. In introducing the quantitative use of RLDC, we assume no possibility for long-distance transmission, and that there is no potential for demand-side management (DSM), storage, or other integration options. Hence, the results we present are effectively upper limits of the challenges to integration. The challenges are not to be seen as insurmountable barriers, but give insights as to how wind and solar PV might be efficiently deployed, and emphasizes the need for an integrated perspective on the integration challenge.

We look at two specific regions, Germany and the Midwestern United States, in some detail to illustrate the RLDC technique and show the regional diversity in results.

For Germany we use wind and solar generation from actual quarter-hourly feed-in data from German Transmission System Operators (TSOs) for 2011, which is publicly available on the respective websites¹⁴. To simulate higher penetrations we scale up the time series linearly. Hourly data for power demand in Germany in 2011 was downloaded from the ENTSO-E website¹⁵. The data was interpolated linearly to match the quarter hourly resolution of VRE generation. By spatially aggregating over the four different TSO zones in Germany we implicitly assume perfect domestic transmission (“copper plate assumption”). This is reasonable because Germany is already well interconnected and will be even better so after governmental plans are implemented [47]. Even though the data we analyze comes from Germany, it is to some extent representative for other European power systems due to typical load, solar and partly also wind patterns.

¹⁴ www.50hertz-transmission.net, www.tennetso.de, www.amprion.net, www.enbw.com

¹⁵ <https://www.entsoe.eu/data/data-portal/>

Hourly demand data for the US region (near Evansville, Indiana) are taken from documents filed with the Federal Energy Regulatory Commission¹⁶. Average demand in the chosen region was 750 MW during the year 2005, with average demand higher in the summer months, reaching a peak of 1291 MW. Demand data were interpolated to a ten-minute-interval basis to match the available solar data for the same region.

Solar data for the region are taken from the National Solar Radiation Database [48] and are based on both satellite measurements and ground-based meteorological data having the same long-term statistical properties as the measured radiation data sets with which they are validated for a relatively small number of sites. The data used for our analysis is the average global radiation (direct plus diffuse) on a horizontal surface, given in units of Wh/m². Using these data is equivalent to averaging over a large number of arrays that may not all be optimally sited, tilted, or oriented – total solar output for the region will be given by a multiplicative scaling factor of the global insolation for each hour.

Wind data for the same year for the same geographical region come from the Eastern Wind Integration and Transmission Study [49]. Wind speeds at various heights corresponding to chosen models of wind turbines are used to then aggregate data to the modeled power output of a wind park in that study area. For both wind and solar data several sites were selected, centered on the city of Evansville, to effectively find a regional average for each time step.

2.3. Results

In this section we present the results of the detailed analysis of challenge variables. Before discussing each variable in detail, we provide an overview of the results.

¹⁶ <http://www.ferc.gov/docs-filing/forms.asp#714>

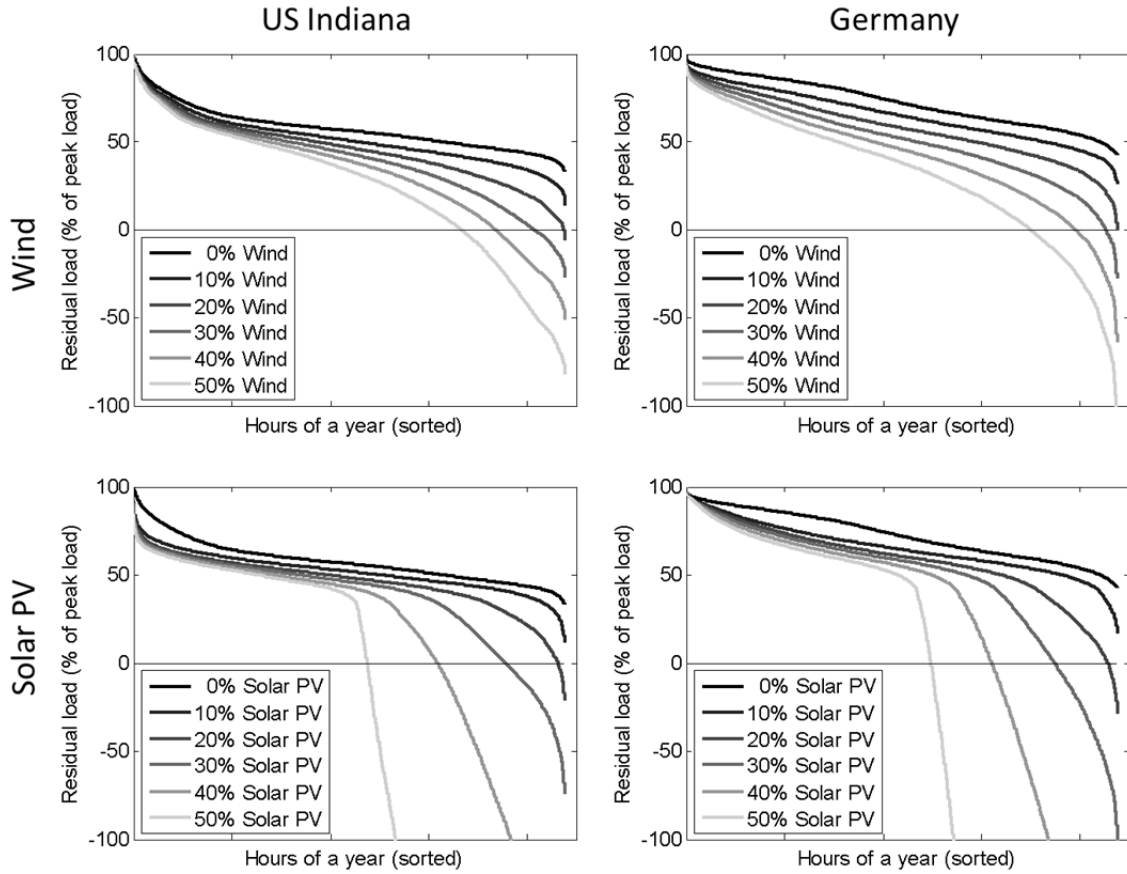


Figure 7: RLDC for wind and solar PV for Germany and US Indiana.

Figure 7 shows the RLDC for all four combinations of region and technology (wind and solar PV) for increasing shares (0% - 50%). For all combinations, the challenges (as illustrated in Fig. 3) become more severe at higher penetrations of final electricity consumption¹⁷. Although this overall tendency is the same there are some noticeable differences between wind and solar PV, and between the two regions considered. In Germany at low shares wind has a small capacity credit. The capacity credit of solar is even smaller, because solar PV contributes mostly to intermediate load (typically daytime in summer) rather than to peak load (typically winter evenings). At higher shares wind continuously tilts the RLDC while solar creates a kink in the RLDC so that at high shares most generation is over-produced. The US picture at low shares is the opposite: wind has a small capacity credit while solar contributes significantly to peak load. This is due to the more favorable correlation of peak demand occurring at summer days due the deployment of A/C systems with solar power supply. At higher shares the shapes become more similar to the results for Germany. The reason for the solar RLDC kink is that once

¹⁷ Throughout the paper “penetration” is the share of VRE in electricity consumption, i.e. overproduced VRE are not contributing to penetration.

summer day load is covered, further solar PV deployment mostly leads to over-production. The kink separates sun-intensive days (right side) from less sunny days and nights (left side).

We note as well that for increasing penetrations, and this is especially true for solar PV, the RLDC crosses the abscissa at points further to the left, meaning that the number of hours of operation for capacity usually designated as baseload is decreased. The implications of this characteristic are discussed below. On the other hand, it is also clear that even at very high penetrations, there is a remanent capacity and time of generation (i.e. total electrical energy) that must be supplied by the system beyond that which can be provided by VREs. This capacity fraction of system requirements will necessarily be provided by either conventional thermal capacity, non-variable renewables (e.g. hydroelectric power) and, to some extent, demand-side management and storage of over-produced VRE.

We now present each of the challenge variables in more detail, including combinations of wind and solar PV, as well as looking in more detail at regional variations.

The capacity credit

Figure 8 shows how the capacity credit depends on region, penetration and mix of wind and solar. The top panels in Figure 8 show all mixes of wind and solar while the line plots in the bottom panels focus on pure solar and wind capacity credits.

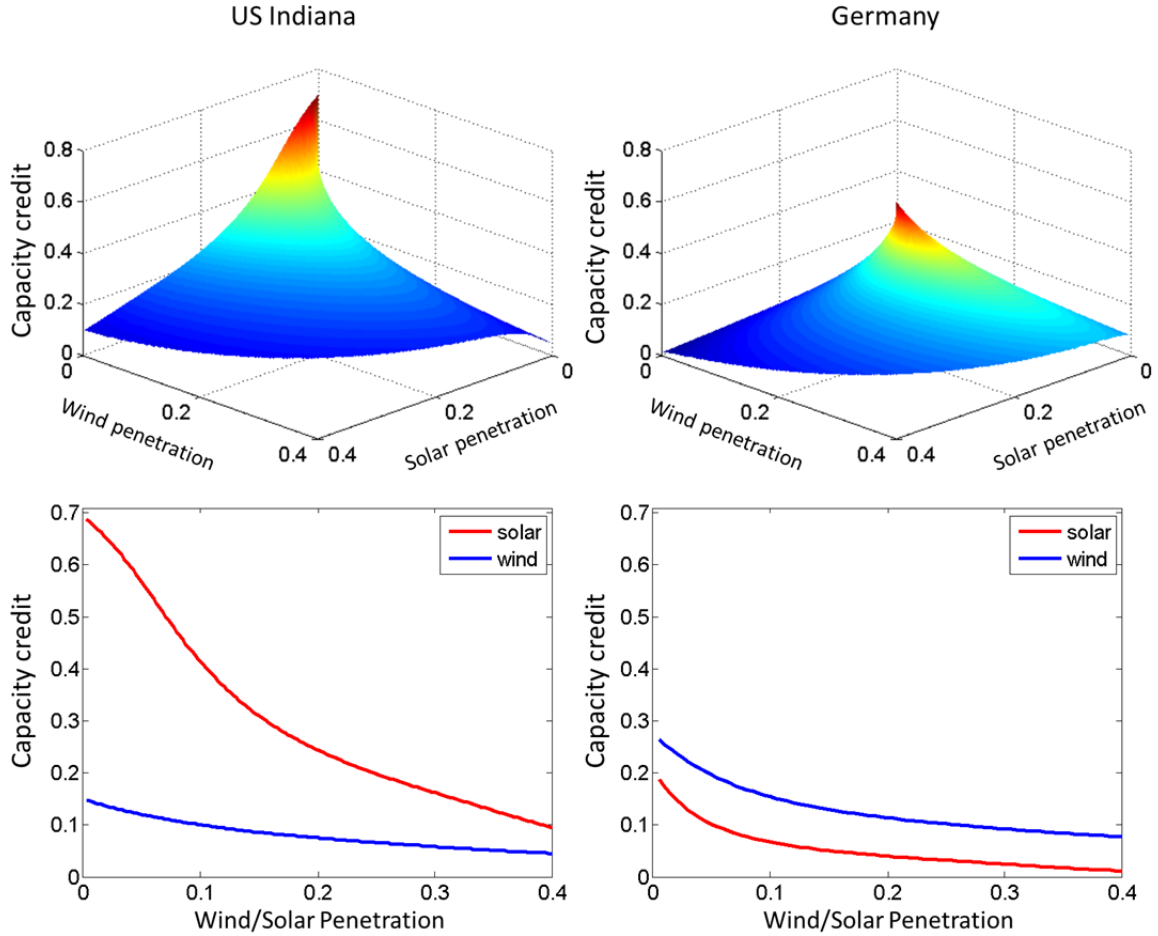


Figure 8: The capacity credit (defined in section 2.2) for different mixes and penetration of wind and solar PV for US Indiana (left) and Germany (right).

For most mixes the level of capacity credit is higher in Indiana than in Germany, mainly driven by a high capacity credit of solar of up to 70% for the first solar plants in the system. Apart from the overall level the dependency on the mix of wind and (especially) solar shows opposite patterns in the two regions. While the capacity credit of solar is high in Indiana it is low in Germany (~20% at low penetrations), where wind has a slightly higher capacity credit (~25%). Independent of the mix and region the capacity credit decreases rapidly with increasing penetration. However, a sensible mix of wind and solar PV can increase the capacity credit compared to a pure deployment of only wind or solar. For Germany the maximizing mix contains mainly wind power. Note again that here average values are displayed. Marginal values, *i.e.* the capacity credit of the last unit of wind or solar added, would decrease even more.

The large difference in solar capacity credits is explained with Figure 9, which shows average diurnal cycles for solar supply and load in both regions. More precisely it distinguishes between the average winter (December-February) and the average summer day (June-August).

The relation between the solar supply and load data is a free parameter and was chosen to best illustrate the findings. The load data is normalized such that the highest average load hour equals *one*. The solar data is normalized such that the summer supply peak equals the summer load peak.

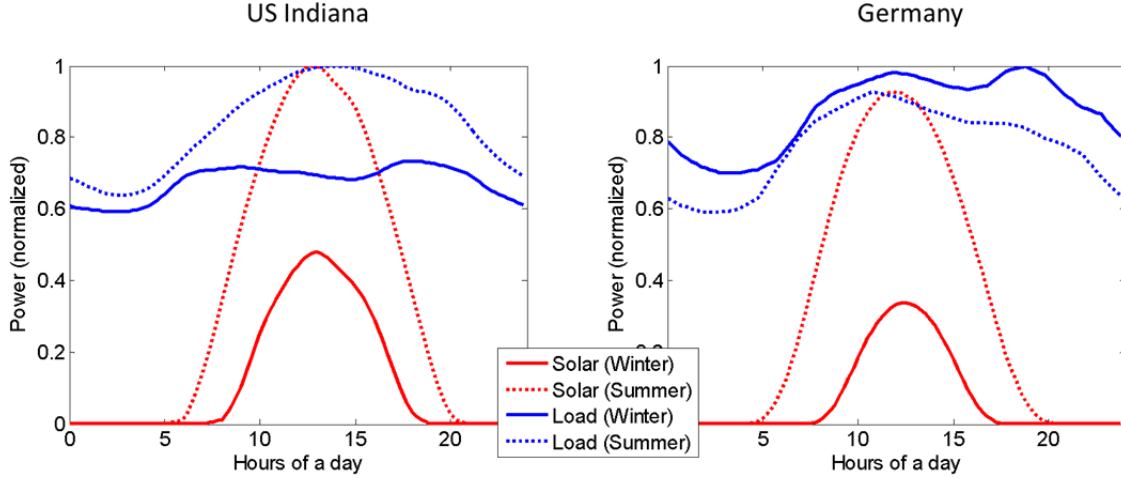


Figure 9: Average diurnal cycles for solar supply and load in US Indiana (left) and Germany (right) in winter (December-February) and in summer (June-August). The peaks of load and solar coincide in US Indiana while in Germany the load peak is in winter evenings when no sun is shining.

Solar PV has a low capacity credit in Germany because annual electricity demand in Germany peaks during winter evenings. Solar PV supply is highest during summer days and thus contributes to intermediate load at low penetrations (as shown in Figure 7). In Indiana as in most parts of the US power demand is highest during summer days due to the use of air conditioning. Consequently solar power supply is well-correlated with power demand. In particular demand peaks coincide (overlap) with significant solar supply and thus solar has a high capacity credit.

Wind generation does not show such regular patterns. It is more stochastic in the sense that the variance of wind output in an hour is very high compared to the mean value and compared to the variance of solar output. In other words, it is much harder to rely on wind power output. Hence, the matching of the average curves of wind and demand is not as important for wind. In US Indiana and Germany the capacity credit is similar even though seasonal demand patterns are different.

Literature results for capacity credits are in line with the above results. For wind plants there are many studies [12], typically showing a large range of capacity credit values from 10% to 35% for onshore wind plants at low penetrations that tend to decrease with higher wind shares. Literature on the capacity credit of solar PV is scarce.

Madaeni et al. show values ranging between 52% and 93% for the western US, depending on location and the plant's sun-tracking capability [42]. Perez et al. show estimations for different methods and diverse electric utility companies in the US [39]. In

those areas where summer peak load is much higher than in winter the capacity credit is in the range of 60% - 80% for low solar penetrations and decrease with higher penetrations. For the area of Portland, Oregon, for example, where summer and winter peak are about the same height, the preferred ELCC method gives a smaller capacity credit of about 33% and patterns resemble more closely those of the German data. This observation confirms that summer cooling demand drives the capacity credit of solar PV and thus its cost saving potential.

Reduced utilization of dispatchable plants

Figure 10 shows how the utilization of dispatchable plants is reduced for baseload plants (above) and intermediate load plants (below). The FLH of intermediate load plants are reduced even at low penetrations, while baseload FLH are affected at moderate and high penetrations. The overall picture is quite similar for both regions and fairly symmetric for wind and solar. We point to a few differences. Wind and solar affect baseload and intermediate load FLH in an opposite way. While wind tends to reduce intermediate load, solar has a larger effect on baseload. This asymmetry is larger for Germany.

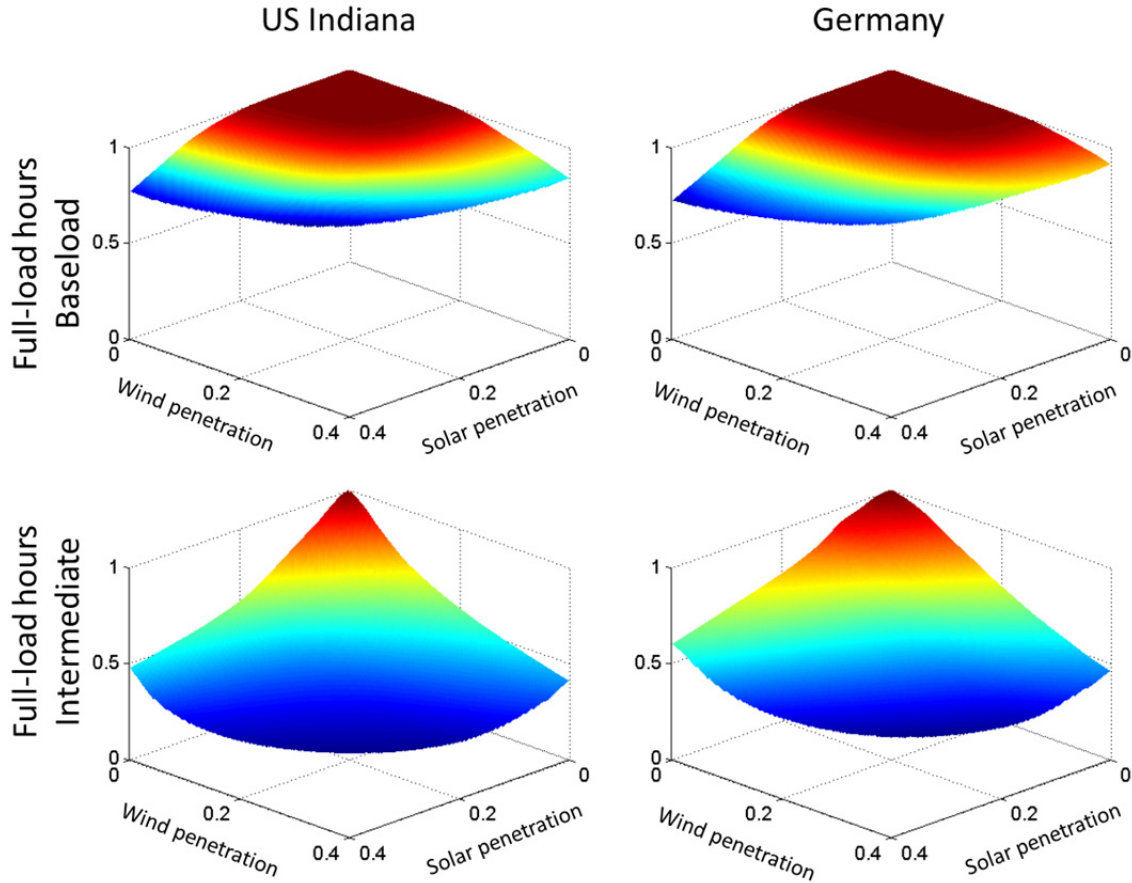


Figure 10: Two variables (defined in section 2.2) that describe the reduction of full-load hours with increasing penetration for different mixes of wind and solar PV for US Indiana (left) and Germany

(right). The above variable “Baseload” shows that at moderate penetration there is no residual load that needs to be supplied constantly. The below variable “Intermediate” shows that wind and solar reduce FLH at an intermediate height of the RLDC.

Note that the results for the intermediate load variable are sensitive to the chosen reference height on the RLDC. We have chosen an intermediate height of 0.5 (see section 2.2) to focus on the intermediate load parts of the RLDC with high FLH. Considering the FLH reduction at higher capacity levels would tend to evaluate the peak load part that is to a large extent already covered by the first challenge variable, capacity credit.

The corresponding system impact of those results depends on the dispatchable capacity mix and cost structure of existing and new plants. A system with high must-run generation (e.g. high minimum load of baseload plants or combined-heat and power plants without thermal storage) can face a major challenge when baseload FLH decrease. Wind and solar generation that would reduce baseload FLH might not be accommodated unless the system can be made more flexible, i.e. by reducing must-run generation. Moreover system costs increase if the existing and planned plants have high fixed costs like nuclear or to some extent coal plants. These plants typically have low variable costs and rely on a high utilization to recover their investment costs. In contrast a system with dispatchable plants with rather low fixed and high variable costs could better cope with reduced FLH.

As a consequence the “baseload” indicator shown in the upper plots in Figure 10 tends to be more important than the “intermediate” indicator shown in the bottom. In this respect solar PV might be more of a challenge than wind.

Over-production

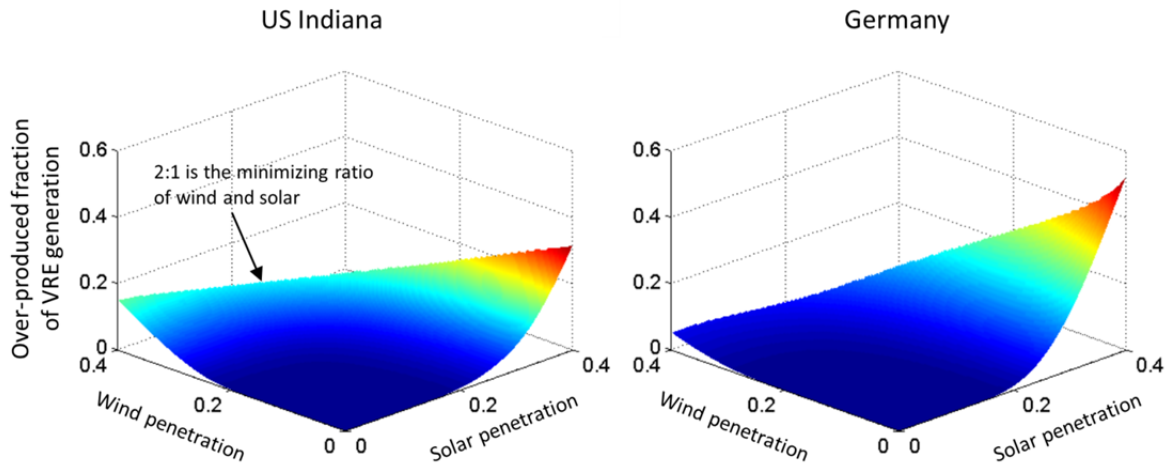


Figure 11: Over-production (defined in section 2.2) for different mixes and penetration of wind and solar PV for US Indiana (left) and Germany (right).

Figure 11 shows how the challenge variable over-production depends on region, penetration and mix of wind and solar. Over-production occurs above penetrations of

about 20%. For solar PV it increases stronger than for wind because once summer day load is covered, further solar PV deployment does mostly lead to over-production. This asymmetric effect is much stronger in Germany because of the unfavorable matching of solar supply and season load patterns (see above Figure 9). At solar penetrations of 40% above 40% of total solar generation would be over-produced, whereas over-production can be minimized if only wind power was deployed. For the US region there is a minimizing ratio of wind and solar PV of about 2:1 (as indicated by the arrow). This is in line with [45], which for New York State finds a minimizing ratio of 3:2.

2.4. Discussion and conclusion

In this paper we analyze three major challenges of integrating variable generation from wind and solar into power systems: the low capacity credit, reduced utilization of dispatchable plants and over-production. Using RLDC for this purpose is both a good heuristic tool and allows for quantitative analysis. We introduced corresponding challenge variables and estimate their dependence on region (US Indiana and Germany) and on penetration and mix of wind and solar. This basic, and at the same time informative, analysis provides insights into fundamental properties of the structural matching of demand with wind and solar supply.

Our results show that challenges associated with increasing wind and solar shares can become severe and consequently cannot be neglected in economic analyses and system planning. To a large extent these challenges depend on the penetration, mix of wind and solar, and regional circumstances. We summarize the results in the following five points:

- 1) All integration challenges increase with penetration independently of mix and region.
- 2) Some challenges, namely the over-production and the increasing reduction of the utilization of baseload plants, increase stronger for high shares of solar PV (>20%).
- 3) At low penetrations, solar PV is much easier to integrate in the US than in Germany. In particular it contributes a high capacity credit of up to 70%, while for Germany the capacity credit is low and vanishing with higher penetration.
- 4) For wind the challenges increase more modestly with increasing penetration than for solar. The capacity credit is relatively low even for low wind penetration.
- 5) The integration challenges of wind are fairly similar in US Indiana and Germany.
- 6) A sensible mix of wind and solar can mitigate some integration challenges such as increasing capacity credits or, for US Indiana, decreasing over-production.

These results show that the deployment and integration of VRE must be planned from a system perspective to account for the matching of wind and solar supply with demand.

The challenge variables are crucial system figures that depend on various parameters. The deployment of wind and solar should not purely be based on generation costs.

This work quantifies challenge variables for a broad range of boundary conditions. The next step should be translating these estimates into economic costs. This would require some kind of energy system model that accounts for existing capacities (generation and transmission). Moreover a time frame of the analysis needs to be defined in which new capacities are built and the system adjusts to the increasing share of variable generation from wind and solar. Such an analysis should consider potential mechanisms that might reduce integration challenges like energy storage, long-distance transmission and demand side management.

Climate change mitigation policies will certainly require dramatically increased levels of electricity produced from variable renewable sources, as described at the beginning of this paper. Although the focus of this work is on the challenges to integration of VRE in the existing system, the potentially large negative externalities of anthropogenic climate change, together with the known negative externalities of current energy systems indicate that an energy system transformation will be necessary over the next few decades. The acceptance and success of this transformation will be enhanced if foreseeable consequences are examined carefully and early in the process such that options for avoiding problems can be developed in parallel with the ramp-up of VRE deployment.

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3. System LCOE: What are the costs of variable renewables?

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Abstract – Levelized costs of electricity (LCOE) are a common metric for comparing power generating technologies. However, there is criticism particularly towards evaluating variable renewables like wind and solar PV power based on LCOE because it ignores variability and integration costs. We propose a new metric System LCOE that accounts for integration and generation costs. For this purpose we develop a new mathematical definition of integration costs that directly relates to economic theory. As a result System LCOE allow the economic comparison of generating technologies and deriving optimal quantities in particular for VRE. To demonstrate the new concept we quantify System LCOE from a simple power system model and literature values. We find that at high wind shares integration costs can be in the same range as generation costs of wind power and conventional plants in particular due to a cost component “profile costs” captured by the new definition. Integration costs increase with growing wind shares and might become an economic barrier to deploying VRE at high shares. System LCOE help understanding and resolving the challenge of integrating VRE and can guide research and policy makers in realizing a cost-efficient transformation towards an energy system with potentially high shares of variable renewables.

3.1. Introduction

What are the costs of a transformation towards an energy system with high shares of variable renewables? When will wind and solar power be competitive without subsidies; and what is their cost-optimal share? Policy makers pose these crucial questions and reports and academic papers often respond using a common metric for estimating and comparing the costs of generating technologies, namely levelized costs of electricity (LCOE), [1]–[7]. LCOE are the full life-cycle costs (fixed and variable) of a power generating technology per unit of electricity (MWh). This metric allows comparing the generation costs of conventional plants with variable renewable sources (VRE) like wind and solar PV, despite their different cost structures. VRE exhibit high fixed costs and negligible variable costs, while conventional technologies have different fixed-to-variable-costs ratios. It is sometimes suggested or implicitly assumed that VRE deployment should be competitive and economically efficient once their LCOE dropped below those of conventional plants. However, there is qualified criticism towards this conclusion and the metric of LCOE itself.

Joskow shows that LCOE are a flawed metric for comparing the economic attractiveness of VRE with conventional dispatchable¹⁸ generating technologies such as fossil, nuclear, or hydro plants [8]. Note that earlier work already implicitly recognizes this point, [9]–[11]. LCOE alone do not say anything about competitiveness or economic efficiency. The main reason is that electricity is not a homogenous good in time, because demand is varying and electricity storage is costly. This is reflected by electricity prices, which fluctuate widely on time scales of minutes and hours up to seasons, depending on the current demand and supply situation. Hence, the value of VRE depends on the time when their output is produced. Since the output of wind and solar PV is driven by natural processes, the value of VRE is an intrinsic property associated with their variability patterns that determines their generation profile. An LCOE comparison ignores the temporal heterogeneity of electricity and in particular the variability of VRE.

To overcome the deficits of an LCOE comparison Joskow emphasizes basic economic principle that often seems forgotten: the economic evaluation of any power generating technology should consider both, *costs* and *value* of that technology. VRE are economically efficient if their LCOE (marginal¹⁹ costs) equal their marginal economic value. Moreover, they are competitive if LCOE are equal or below their market value, which is the revenue per unit generated by a technology. Assuming perfect and complete markets, the marginal economic value equals the market value and consequently economic effectiveness and competitiveness become congruent.

Note that in this paper we assume perfect markets because then the market and social planner solutions coincide. We apply this as a “reference case” because we want to contribute to understanding the fundamental economics of variable renewables and evaluate their economic costs from a system perspective. Admittedly, many distortions lead to deviations from this benchmark, like market power, information asymmetries and externalities. In particular the question whether the variability of wind and solar PV itself induces a new market failure is promising for further research, albeit it is beyond the scope of this paper.

The limitations of an LCOE analysis become even more severe in the future, because market values of VRE are decreasing with increasing VRE shares due to their variability, [9]–[16]. Mills and Wiser show decreasing values for wind and solar in California [12]. Hirth shows similar results for VRE for North-Western Europe including long-term model runs where generation and transmission capacities adjust in response to VRE [6].

¹⁸ The output of dispatchable plants can be widely controlled, whereas VRE are subject to natural fluctuations.

¹⁹ Note that the term “marginal costs” does not imply that only variable costs are considered. Instead “marginal costs” means the total costs (variable and investment) of an incremental unit of a technology.

Hirst and Hild focus on operational aspects without capacity adjustments with a unit commitment model and show that the value of wind drops significantly as wind power increases from zero to 60% of installed capacity [13]. Grubb shows this effect in model results for the value of wind in England [14]. Hence, competitiveness and economic efficiency for higher shares of VRE will become more difficult than an LCOE comparison would imply. This increases the need for an improved evaluation of VRE, for example by complementing it with market values.

In this paper we propose an alternative approach to correct the deficits of LCOE and facilitate a proper evaluation of VRE. We introduce a new concept, *System LCOE*, which seeks to comprise all economic costs of VRE in a simple cost metric instead of comparing costs and values. The metric should not only contain standard LCOE but also reflect the costs of variability that occur on a system level.

System LCOE partly build on integration cost studies that typically estimate the additional costs imposed on the system by the variability of wind and rarely also solar PV [15]–[25], [25]–[27], [28]. However, standard definitions of integration costs are motivated from a bottom-up engineering perspective and not linked to economic theory. That is why it is not clear how integration cost estimates relate to the economic efficiency or competitiveness of VRE. We want to fill this gap and mathematically derive a definition of integration costs with a direct economic link. On that basis System LCOE of a technology are defined as the sum of generation costs and integration costs per generation unit from that technology.

The main objective of System LCOE is that in contrast to standard LCOE their comparison should allow to economically evaluate VRE and other technologies. The new concept should be equivalent to the market value perspective that might alternatively be used to correct the caveats of an LCOE comparison. The task and context would then decide which perspective is more suitable. A simple cost metric like System LCOE would suggests itself for these three purposes:

- 1) The standard cost metric of LCOE is often applied to compare technologies (in industry, policy, and academic publications and presentations). System LCOE should correct the flawed metric while remaining this intuitive and familiar cost perspective.
- 2) A cost perspective is often applied by the integration cost literature that stands in the tradition of electrical engineering or power system operation. System LCOE should build on this branch and connect it with the economic literature on market values. Most importantly, this would provide an economic interpretation of integration cost estimates.
- 3) A cost metric that comprises generation and integration costs can parameterize long-term models in particular integrated assessment models (IAMs) and thus help to better represent the variability of VRE. Such an approach is sometimes already

applied in IAMs by introducing cost penalties that increase with wind deployment [29]. System LCOE would provide an improved parameterization with a rigorous economic foundation.

This paper focuses on conceptually introducing System LCOE and discussing its implications. Moreover, we roughly quantify the new metric for VRE, which is mainly done for demonstration purposes and not intended to be a final accounting. Hereby we illustrate the magnitude and shape of integration costs and compare the relative importance of different impacts of VRE. This allows drawing conclusions for suitable integration options²⁰.

In principle, all power generating technologies induce integration costs. However, because VRE interact differently with the power system than dispatchable plants they are much more difficult to integrate especially at high shares. Thus we focus on integration costs of VRE in this paper.

Note that because System LCOE account for integration costs, unlike standard LCOE they cannot be calculated directly from plant-specific parameter. Rather, to estimate System LCOE one needs system-level cost data that can be either estimated from a model or partly derived from observed market prices to the extent that real market prices reflect marginal costs. In this paper we derive mathematical expressions for integration costs and System LCOE that can be applied to most models.

The paper is structured as follows. Section 3.2 conceptually introduces System LCOE, rigorously defines integration costs (section 3.2.1) and links these concepts to economic theory (section 3.2.2) and standard integration cost literature (sections 3.2.3 and 3.2.4). Section 3.3 demonstrates the concept by quantifying System LCOE based on simple modeling and literature estimates and derives implications for integration options (section 3.3.4). Finally, section 3.4 summarizes and concludes.

3.2. System LCOE and integration costs

To define System LCOE formally, we need a definition of integration costs. This section presents a rigorous definition of both concepts. In section 3.2.2 we show that System LCOE determine the optimal deployment of VRE and the equivalence to the market value perspective. Furthermore we present implications for the decomposition of integration costs (section 3.2.3) and an alternative interpretation of the new definition (section 3.2.4).

²⁰ Inspired by [15] we use the term “integration options” as an umbrella term for all technologies that reduce integration costs. The alternative term “flexibility options” can be used as in [16] or [17].

We define System LCOE as the sum of the marginal integration costs Δ and the marginal generation costs \overline{LCOE}_{vre} of VRE in per-MWh terms (Figure 12, equation 5) as a function of the generation E_{vre} from VRE.

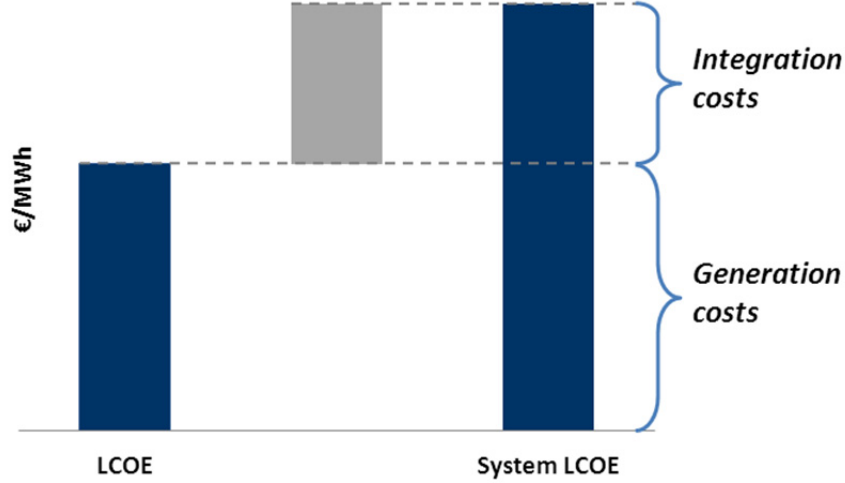


Figure 12: System LCOE of VRE are defined as the sum of their LCOE and integration costs per unit of VRE generation. They seek to comprise the total economic costs of VRE.

$$sLCOE_{vre} := \overline{LCOE}_{vre} + \Delta. \quad (5)$$

Marginal integration costs Δ are the increase of total integration costs C_{int} when marginally increasing the generation E_{vre} from VRE:

$$\Delta := \frac{d}{dE_{vre}} C_{int}. \quad (6)$$

The concept requires a clear definition of *integration costs* C_{int} . However, there is no agreement on how to estimate integration costs [18]. We suggest a rigorous way of how to derive a mathematical definition of integration costs in the next subsection.

3.2.1. A mathematical definition of integration costs

Integration costs have been defined as “the extra investment and operational cost of the nonwind part of the power system when wind power is integrated” [15, p.181] or equivalently “the additional cost of accommodating wind and solar” [14, p.51]. Integration studies usually operationalize this definition by estimating different cost components from bottom up, like “grid costs”, “balancing costs” and “adequacy costs” ([15], [17], [19], [21], [22], also see section 3.2.3). They assume that these components add up to total integration costs even though it is not clear if that is exhaustive. In contrast, we want to derive an expression for *total* integration costs and thus apply a top-down approach. We seek to formalize the following qualitative definition that is in line with the above definitions and the literature on VRE integration: Integration costs of VRE

are all *additional costs* in the *non-VRE part* (residual system²¹) of the power system when VRE are introduced.

However, it is difficult to determine the costs that are actually *additional*. In other words, applying the qualitative definition is challenging. Integration costs cannot be measured or estimated directly. Just modeling a single system state like the cost-optimal capacity mix and its dispatch is not sufficient. Instead, at least two power system states, *with* and *without VRE*, need to be compared to separate additional system costs.

For the *with VRE* case we assume that a power system's annual power demand \bar{E}_{tot} is partly supplied by the VRE generation E_{vre} . \bar{E}_{tot} is assumed here to be exogenously given without loss of generality for simplicity reasons. The resulting residual load E_{resid} needs to be provided by dispatchable power plants. Note, that we denote parameters with a *bar* while all variables are a function of the VRE generation E_{vre} .

$$E_{resid} = \bar{E}_{\text{tot}} - E_{vre} \quad (7)$$

The total costs²² C_{tot} are divided into the generation costs of VRE C_{vre} and all other costs for the residual system C_{resid} .

$$\text{With VRE:} \quad C_{\text{tot}} = C_{vre} + C_{resid} \quad (8)$$

Residual system costs include life-cycle costs for dispatchable plants, costs for reserve requirements, balancing services, grid costs and storage systems. In the *without VRE* case total system costs obviously coincide with residual system costs.

$$\text{Without VRE:} \quad C_{\text{tot}}(E_{vre} = 0) = C_{resid}(E_{vre} = 0). \quad (9)$$

Since integration costs of VRE are defined as not being part of generation costs of VRE, they should emerge from comparing the residual system costs C_{resid} *with* and *without VRE*. Unfortunately, the *absolute* difference of the corresponding residual power system costs does not only contain integration costs, but also the value of VRE generation mainly due to fuel savings [20], [18]. VRE consequently reduce residual costs: $C_{res}(E_{vre}) < C_{res}(0)$, which is not surprising since the total residual load decreases with VRE. Hence, a comparison of the absolute residual costs does not allow separating integration costs.

The crucial step is to not consider the *absolute* but the *specific* costs per unit of residual load. This resolves the problem of different absolute values of residual load *with* and

²¹ We use the typical term “residual system” for the non-VRE part of a power system by analogously to the term “residual load” that often describes total load minus VRE supply. Thus it encompasses other (residual) generation, grids, and system operation.

²² The total costs comprise all costs that are associated with covering electricity demand: Investment costs and the discounted life-cycle variable costs of plants, grid infrastructure and storage systems. The system is assumed to be in an economic equilibrium and the costs are treated in annualized terms.

without VRE. We define integration costs as the difference of *specific* costs (per MWh residual load) in the residual system times the residual load E_{resid} . *With* VRE the specific residual costs C_{resid}/E_{resid} typically increase compared to *without* VRE $C_{tot}(0)/\bar{E}_{tot}$.

$$C_{int} := \left(\frac{C_{resid}}{E_{resid}} - \frac{C_{tot}(0)}{\bar{E}_{tot}} \right) E_{resid} \quad (10)$$

$$= C_{resid} - \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \quad (11)$$

This mathematical definition comprises the additional costs in the non-VRE (residual) part of the system when introducing VRE and consequently complies with the qualitative definitions given above. System LCOE can be calculated by inserting this definition of integration costs in equation 6.

With this expression integration costs and System LCOE can be determined with any power system model that can estimate system costs *with* and *without* VRE. Moreover this concept can be applied for estimating integration costs of not only VRE but any *technology*. The corresponding base case would change accordingly to a *without that technology* case.

3.2.2. The economics of variability

We now show that the new definition of integration costs is rigorous because it allows determining the cost-optimal and competitive deployment of VRE and thus System LCOE can be interpreted as the marginal economic costs of an additional unit of VRE.

The cost-optimal deployment of VRE is reached when total costs of a power system are minimal when varying the share of VRE.

$$C_{tot} \rightarrow \min \quad (12)$$

$$\Rightarrow \frac{d}{dE_{vre}} C_{tot} = 0 \quad (13)$$

Using the definition of integration costs (equation 7) the total costs (equation 8) can be expressed as:

$$C_{tot} = C_{vre} + C_{int} + \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0). \quad (14)$$

Inserting this into the optimality condition (equation 13) gives:

$$\frac{d}{dE_{vre}} C_{vre} + \frac{d}{dE_{vre}} C_{int} + \frac{d}{dE_{vre}} \left(\frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \right) = 0. \quad (15)$$

The interpretation of the terms gives deep insights for the evaluation of VRE. The first summand are the marginal generation costs of VRE: $LCOE_{vre}$. The second summand are

the marginal integration costs of VRE: Δ (equation 6). The third summand can be simplified to $-C_{tot}(0)/\bar{E}_{tot}$ with equation 7. These are the average costs (per MWh) in a system without VRE. Note that conventional plants impose integration costs as well which have to be contained in total costs $C_{tot}(0)$ in addition to their generation costs. The third summand thus equals the average System LCOE of a purely conventional system:

$$\overline{sLCOE}_{conv} := \frac{C_{tot}(0)}{\bar{E}_{tot}}. \quad (16)$$

Using the new symbols the optimality condition (equation 14) reduces to:

$$\overline{LCOE}_{vre} + \Delta = \overline{sLCOE}_{conv} \quad (17)$$

$$\stackrel{(1)}{\Rightarrow} sLCOE_{vre} = \overline{sLCOE}_{conv} \quad (18)$$

This shows that the optimal deployment of VRE is given by the point where the System LCOE of VRE equal the System LCOE of a purely conventional system. Economic efficiency can be captured in a pure cost metric. The left-hand side can also be interpreted as the marginal economic costs of VRE on a system level, while the right-hand side can be interpreted as the value of VRE because it represents the opportunity costs of alternatively covering load with conventional generation. In other words VRE deployment is optimal where marginal economic costs of VRE intersect with their value, which is in line with economic theory.

Figure 13a and b illustrate these insights in schematic sketches. Figure 13a shows System LCOE of VRE depending on their deployment. Typically integration costs (shaded area) increase with higher deployment and can be negative in particular at small penetrations (compare results in section 3.3.2). The intersection of increasing System LCOE of VRE and average costs in a purely conventional system gives their optimal quantity E^* (Figure 13b or equation 18).

By adding integration costs to LCOE a new metric System LCOE could be developed, which can be used to derive the optimal and competitive quantity of VRE. In contrast standard LCOE are an incomplete metric for evaluating economic efficiency.

An equivalent perspective to account for integration costs and derive optimal quantities is a *market value perspective*. The market value mv_{vre} (or marginal economic value) of VRE can be defined as the marginal cost savings in the residual system when increasing the VRE deployment by a marginal unit dE_{vre} .

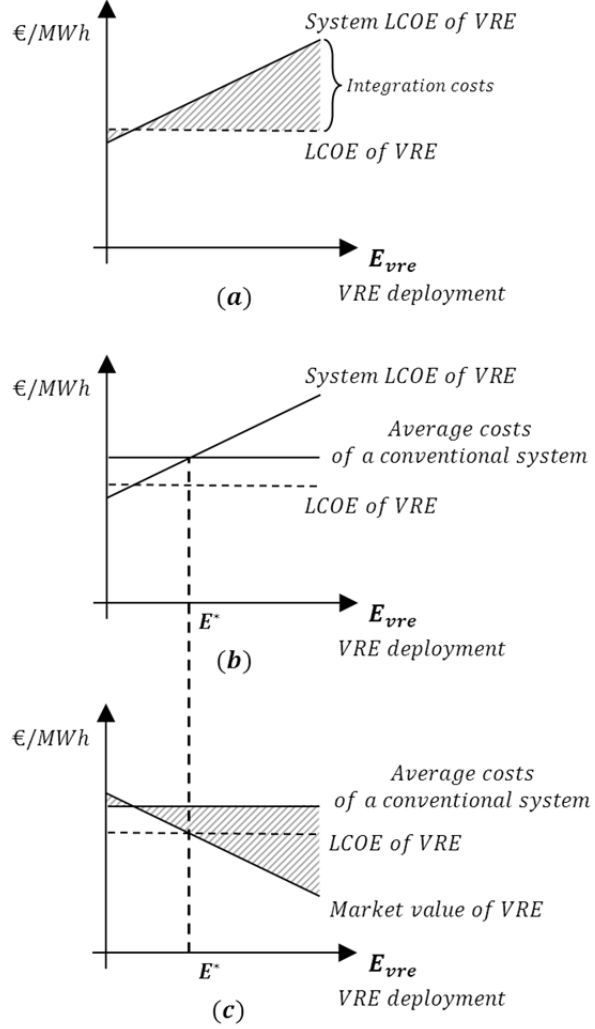


Figure 13: (a) System LCOE are the sum of LCOE and marginal integration costs (per MWh) while integration costs increase with VRE penetration. An optimal quantity E^* of VRE can be derived from (b) System LCOE or equivalently (c) the market value of VRE.

$$mv_{vre} := \frac{d}{dE_{vre}} C_{resid} \quad (19)$$

With this and equation 11 marginal integration costs can be expressed as the reduction of the market value compared to the average costs of a conventional system, which coincide with the annual load-weighted electricity price in a perfect market (illustrated in Figure 13c). This is reasonable because the reduction of the market value is driven by the variability of VRE and can thus be interpreted as the economic costs of variability. An illustrative example of how grid constraints and ramping requirements reduce the market

value of VRE are negative prices, which might be induced in particular in hours of high VRE supply [30]. Note that because the market value can be derived from empirical prices this perspective in principle allows the quantification of integration costs from market prices, at least to the extent that markets can assumed to be perfect [31].

$$\Delta \equiv \frac{d}{dE_{vre}} C_{int} = \frac{C_{tot}(0)}{\bar{E}_{tot}} - mv_{vre} \quad (20)$$

Inserting this into the optimality condition (equation 15) it can be rewritten.

$$mv_{vre} = \overline{LCOE}_{vre} \quad (21)$$

The market value of VRE decreases with increasing VRE penetration, [9]–[11], [13]–[16]. The optimal deployment of VRE is given by the point where the market value of VRE equals their marginal generation costs (Figure 13c). Equation 18 and 21 are two formulations of the same optimality condition and thus both perspectives lead to the same optimal quantity (Figure 13b and c). Both approaches equivalently resolve Joskow's concerns.

To sum it up, our definition of integration costs provides a link to economic theory that allows deriving optimal quantities of VRE. The new definition comprises all economic impacts of variability. Moreover it provides two equivalent ways of accounting for integration costs. They can be added to the generation costs of VRE (System LCOE), or expressed as market value reduction. Hereby our definition connects two branches of literature: the integration cost literature that stands in the tradition of electrical engineering and the economic literature on market (or marginal) value. In the remainder of this section we further explore how the new definition of integration cost relates to the standard integration cost literature.

3.2.3. Implications for decomposing integration costs

This subsection discusses the implications for decomposing integration costs and hereby relates the new definition of integration costs to standard definitions.

Integration cost studies typically decompose integration costs into three cost components, balancing costs, grid costs and adequacy costs ([15], [17], [19], [21], [22]) (see Figure 14, left bar).

Balancing costs occur because VRE supply is uncertain. Day-ahead forecast errors and short-term variability of VRE cause intra-day adjustments of dispatchable power plants and require operating reserves that respond within minutes to seconds. A further categorization of operating reserves is given in [23].

Grid costs are twofold. First, when VRE supply is located far from load centers investments in transmission might be necessary. Second, if grid constraints are enhanced by VRE the costs for congestion management like re-dispatch of power plants increase.

Adequacy costs reflect the low capacity credit of VRE. These costs occur because of the need for backup capacity (conventional plants, dispatchable renewable capacity or storage capacity) especially during peak-load times. Sometimes it is also called “capacity costs” [19]. Note that the term *backup* is controversial because VRE do not actually require additional capacity when introduced to a system [24]. However, the term refers to conventional capacity that could be removed in the long term if VRE had a higher capacity credit.

In contrast, the new definition of integration costs was derived from a top-down perspective without specifying its components so far (section 3.2.1). Comparing this definition to the standard cost components reveals a cost difference that corresponds to a further cost component that is covered by the new definition but has not been considered in standard integration costs (Figure 14). In order to comprise *all* economic costs of variability and to allow drawing economic conclusions (like in section 3.2.2) this component needs to be accounted for. In [31] this component is termed *profile costs*.

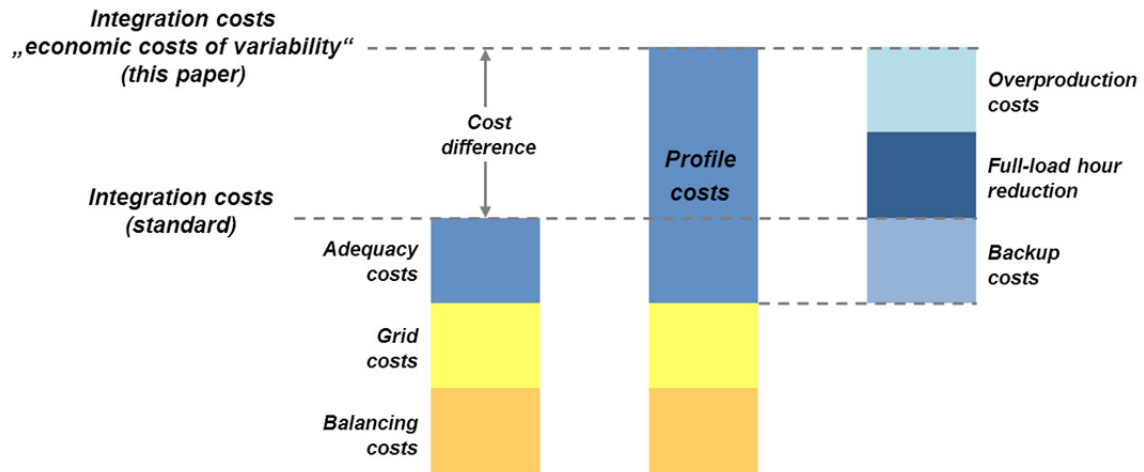


Figure 14: Integration costs as defined in this paper are higher than the sum of the standard cost components. Profile costs fill this gap and hereby complete the economic costs of variability. Profile costs can themselves be decomposed into overproduction, full-load hour reduction and backup costs, while the latter corresponds to standard adequacy costs. The integration cost definition in this paper extends the standard definition by also considering overproduction of VRE and full-load hour reduction of conventional plants.

One part of profile costs is already accounted for in the standard cost decomposition: adequacy costs belong to profile costs. In fact, profile costs can be understood as a more general conception of adequacy costs.

What are the fundamentals behind profile costs? Let us assume for a moment that VRE would not induce balancing costs because their variable output is deterministic and furthermore that power plants could perfectly ramp without additional costs – however,

the variability of wind and solar PV would still induce profile costs due to the load-matching properties of VRE which are determined by their temporal profile. VRE contribute energy while hardly reducing the need for total generation capacity in the power. Thus the average utilization of dispatchable power plants is reduced, which leads to inefficient redundancy in the system. This is illustrated in residual load duration curves²³ (RLDC). VRE unfavorably change the distribution of residual load (Figure 15). With high shares VRE cover base load rather than peak load. The RLDC becomes steeper. Compared to the hypothetical situation if wind and solar PV would not be variable, the specific costs in the residual system increase, which corresponds to the definition of integration costs.

Even though profile costs are also induced by variability they differ from grid and balancing costs in that they are more indirect. They do not correspond to direct cost increases in the residual system but occur as reduced value of VRE. However, these two categories are equivalent from an economic perspective. It makes no difference for evaluating VRE if they impose more balancing costs or if less capacity can be replaced due to a low capacity value of VRE when increasing their share. Hence, profile costs are very real and need to be considered just like balancing and grid costs. They do not necessarily need to be termed integration costs but they need to be accounted for in an economic evaluation. In this paper we term them integration costs to embrace all economic effects of variability.

We further decompose the profile costs into three main cost-driving effects (Figure 14 right bar, Figure 15). First, VRE reduce the full-load hours of dispatchable power plants mostly for intermediate and base load plants. The annual and life-cycle generation per capacity of those plants is reduced. Thus the average generation costs (per MWh) in the residual system increase. Second, VRE hardly reduce the need for backup capacity especially during peak load times due to their low capacity credit. This is usually referred to as adequacy costs. Because we suggest that adequacy costs can be understood in a more generalized way, we prefer using the term *backup costs* for costs due to backup capacity. And thirdly, at high shares an increasing part of VRE generation exceeds load and this overproduction might need to be curtailed. Hence, the effective capacity factor²⁴ of VRE decreases and specific per-energy costs of VRE increase. These costs could alternatively be expressed as a reduction of standard LCOE. However, since they depend on the system e.g. the temporal demand patterns or grid infrastructure we rather separate them from pure generation costs.

²³ The RLDC shows the distribution of residual load by sorting the hourly residual load of one year starting with the highest residual load hour.

²⁴ The capacity factor describes the average power production per installed nameplate capacity of a generating technology

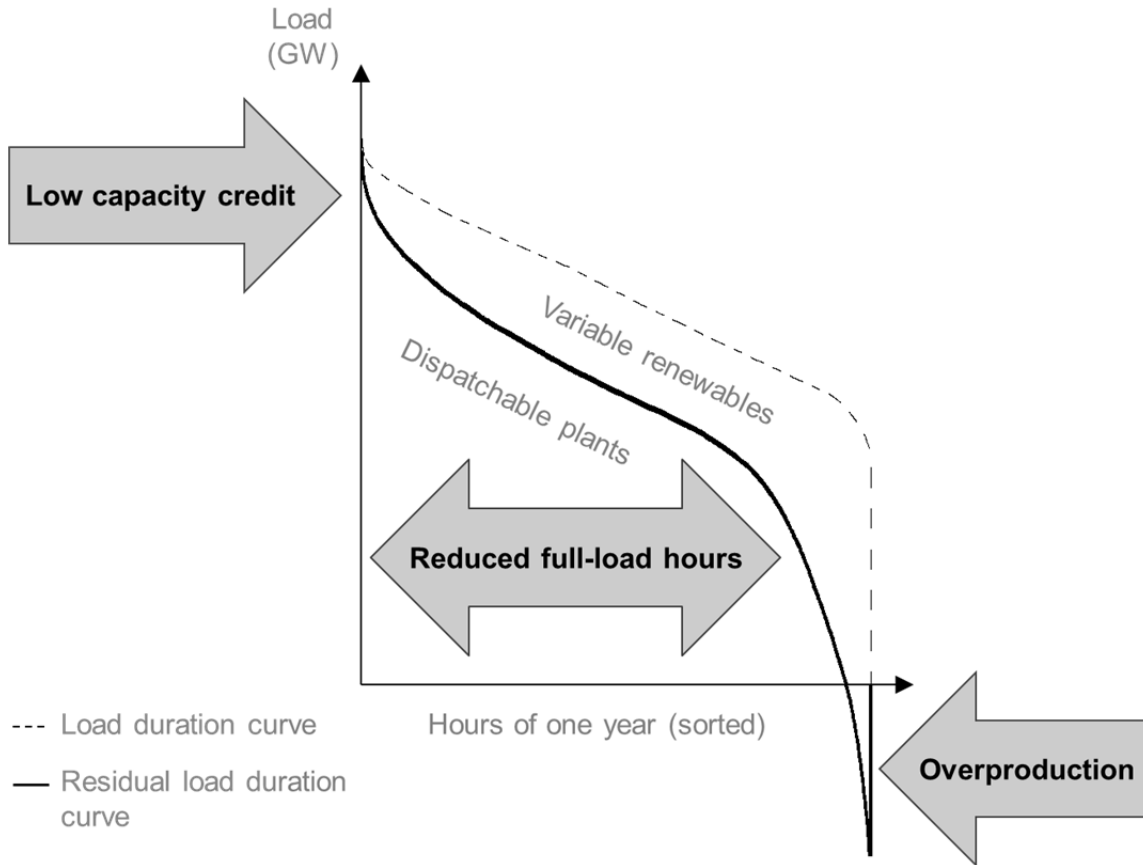


Figure 15 (illustrative): Residual load duration curves capture three main challenges of integrating VRE. While hardly any generation capacity can be replaced due to their low capacity credit, the full-load hours of conventional plants are reduced. At higher shares VRE supply exceeds load and thus cannot directly be used.

At higher shares these challenges get more severe. Figure 16 shows the development of RLDC with increasing shares of wind (left) and solar PV (right) for German data²⁵. The RLDC become even steeper. Although this overall tendency is the same for wind and solar PV generation there are some differences. Wind generation slightly reduces the annual peak load especially at low shares, while solar PV does not contribute during peaking hours at all. This is because electricity demand in Germany is peaking during winter evenings. Note that the capacity credit is system dependent. For a review of estimates for different systems and wind penetrations see [19]. Solar PV supply is highest during summer days and thus contributes to intermediate load at low penetrations. Once summer day load is covered, further solar PV deployment does mostly lead to overproduction. At high VRE shares the corresponding RLDC show a kink (Figure 16, right, arrow) that separates sun-intensive days (right side) from less sunny days and

²⁵ For wind and solar generation we use quarter hourly feed-in data from German TSOs for 2011. For power demand of Germany hourly data for 2011 is used from ENTSO-E.

nights (left side). Wind generation at low shares almost equally contributes to peak, intermediate and base load. With increasing shares it increasingly covers base load and causes overproduction because of the positive correlations of the output of different wind sites.

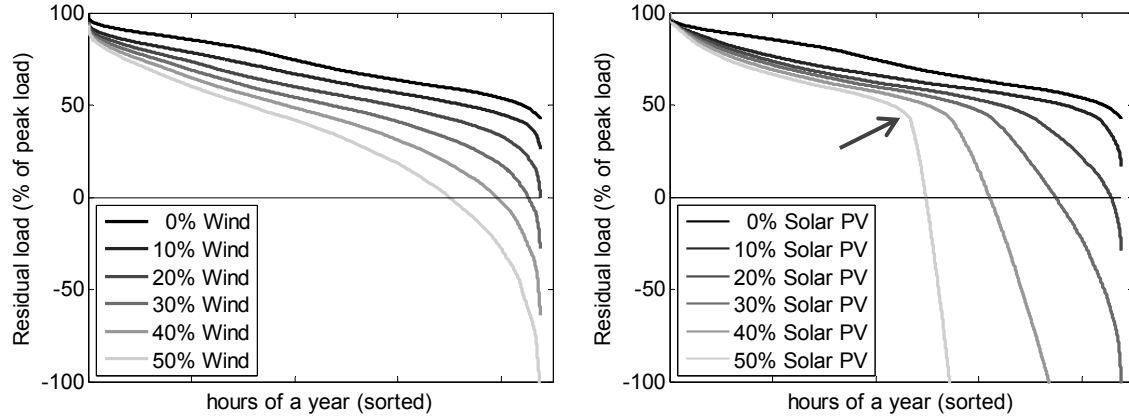


Figure 16: Residual load duration curves (RLDC) for increasing shares of wind (left) and solar PV (right) in Germany. With higher shares the RLDC continuously become steeper. Wind generation slightly covers peak load but increasingly contributes to intermediate and base load as well as to overproduction. Solar PV does not reduce peak capacity requirements. It covers intermediate load at low shares. With higher shares (>10%) additional solar generation mostly contributes to base load and overproduction.

Note that profile costs also include a further cost component induced by the so-called *flexibility effect*²⁶ [31]. It comprises additional costs from scheduled (i.e., planned) ramping and cycling of thermal plants when introducing VRE. In contrast, balancing costs cover all additional adjustments of the scheduled plants due to VRE uncertainty. In other words balancing costs would be zero if VRE were deterministic (perfect forecast) while the flexibility effect would still capture all costs due to ramping and cycling induced by the remaining deterministic variability of VRE.

Some definitions of “balancing costs” in the literature do not only capture uncertainty but also include the flexibility effect. In [19] for example they are defined as the “the operating reserve impact” (uncertainty) and the “impact on efficiency of conventional power plants for dayahead operation” (flexibility effect).

However, a number of studies find that the flexibility effect is very small compared to the other drivers of profile costs, for example [13], [14], [32]. In this paper we neglect the

²⁶ This term is inspired by [32].

flexibility effect and focus on the major part of profile costs that is induced by the three other mechanisms described above (Figure 15).

Based on the reflections in this subsection we can now decompose integration costs into balancing costs, grid costs and profile costs (Figure 17). System LCOE are defined by adding the three components of integration costs to standard LCOE that reflect generation costs (Figure 17).

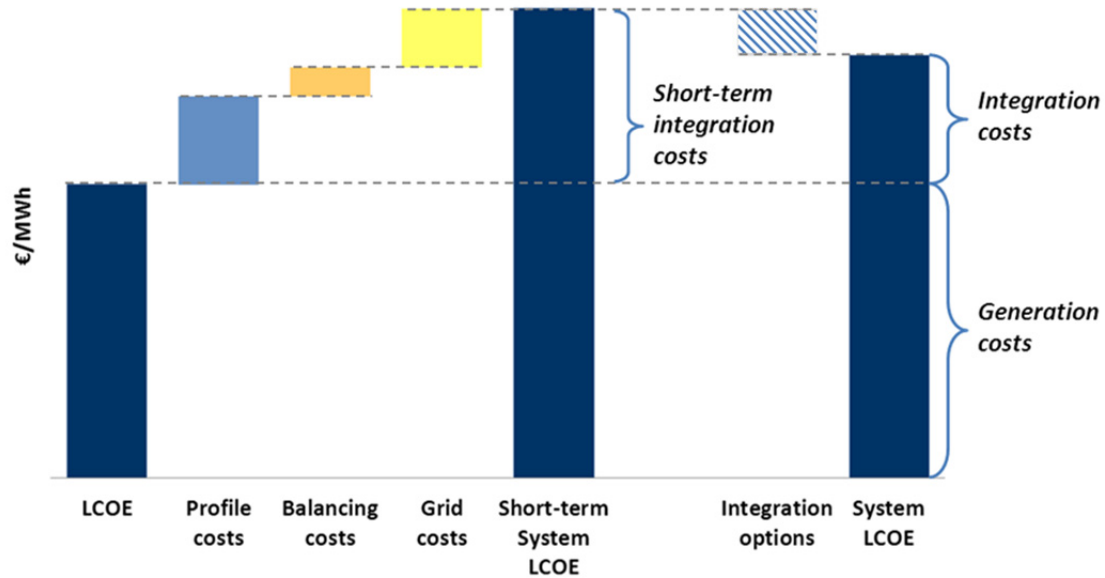


Figure 17: Integration costs are divided into three components: profile, balancing and grid costs. To some extent integration costs that occur in the short term can be reduced by integration options in the long term.

Note that in principle it does not need a decomposition to estimate total integration costs. This would require a model that fully accounts for all integration issues and options. However, such a “supermodel” does not exist. Instead by disaggregating integration costs models can specialize in deriving more accurate cost estimates for specific components. Doing so neglects any interaction of the components. Estimating the three components separately and assuming additivity is an approximation of the total integration costs. The standard decomposition and our extension seek for independent categories by structuring them along the three different properties of VRE. The interaction of these categories is an important field for further research.

Furthermore, integration cost estimates are typically derived by analyzing the impact of VRE on currently existing power systems with a fixed capacity mix and transmission grid. However, integration costs depend on time, more precisely on the deployment rate of VRE and on typical response times of the power system. Integration costs can be expected to decrease if the power system adapts in response to increasing VRE

penetration, which is usually beyond the scope of integration cost studies. In this paper we distinguish between two time perspectives, *short term* and *long term*²⁷ (as indicated in Figure 17):

- 1) The short-term perspective represents the start of a transition period after VRE have been introduced into a power system. It assumes fast deployment of VRE compared to typical relaxation times of the system defined by lifetimes and building times of power plants or innovation cycles of integration options like electricity storage. Hence, the power system has not yet adapted to VRE. Most importantly the dispatchable capacities remain unchanged when introducing VRE. Moreover, additional integration options like electricity storage or long-term transmission have not been installed yet. This perspective leads to short-term integration costs and short-term System LCOE which are higher than in a long-term perspective.
- 2) The long-term perspective assumes that the power system has fully and optimally adapted in response to VRE deployment. The power system transition is finished. From an economic point of view the system has moved to a new long-term equilibrium after it was shocked by exogenously introduced VRE. Thus dispatchable capacities adjusted and other integration options are in place if they are cost-efficient. Hence, short-term integration costs and short-term System LCOE have been reduced. System LCOE reflect the resulting (long-term) integration costs.

3.2.4. Determining integration costs with a benchmark technology

This fairly technical subsection has the objective to link the new definition from subsection 3.2.1 to a typical way of how integration costs are estimated in the literature. Moreover it gives an alternative interpretation of integration costs.

Many studies apply a *proxy resource* (we term it *benchmark*) to tease out integration costs ([26], [18]). The idea is that in the *without VRE* case a benchmark technology supplies the VRE energy without its variability and uncertainty to not impose integration costs. Consequently comparing the *with* and *without VRE* case extracts the pure integration costs of VRE. Here we reformulate our definition showing that an analog benchmark formulation is possible. Further we discuss how such a benchmark should be designed, theoretically or when realized in models, and show how typical difficulties of operationalizing it can be resolved by our definition of integration costs.

²⁷ The term “long term” refers to the standard economic term “long-term equilibrium” in which all investments are endogenous as if the power system was built from scratch (also known as green-field analysis). See for example [9], [25], [33], [34]. In analogy we use the term “short term” for an analysis with a given capital stock.

The second term in the definition of integration costs (equation 11) can be interpreted as the residual system costs C_{resid}^{BM} that would occur if the energy E_{vre} was supplied by an ideal benchmark technology (BM) that does not impose integration costs.

$$C_{resid}^{BM} := \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \quad (22)$$

$$= \left(1 - \frac{E_{vre}}{\bar{E}_{tot}}\right) C_{tot}(0) \quad (23)$$

The essential property of the benchmark is that the residual power system costs decrease in proportion to its generation E_{vre} (equation 23). Thus the specific costs in the residual system do not increase but remain constant. Because there are no additional costs in the residual system induced by deploying the benchmark, its integration costs are zero in line with the qualitative and mathematical definition.

$$\frac{C_{resid}^{BM}}{E_{resid}} = \frac{C_{tot}(0)}{\bar{E}_{tot}} = const. \quad (24)$$

Inserting the benchmark interpretation (equation 22) in equation 11 gives an equivalent definition of integration costs that might appear more intuitive and that reflects a typical way to estimate integration costs: Integration costs of VRE are the additional costs in the residual power system that VRE impose compared to an ideal benchmark.

$$C_{int} = C_{resid} - C_{resid}^{BM} \quad (25)$$

How should a benchmark technology be designed? An often used proxy for models is a perfectly reliable *flat block of energy* that constantly supplies the average generation of a VRE plant. The difference in costs of a system with this proxy compared to the VRE case clearly contains additional costs due to uncertainty of VRE and more flexible operation of thermal plants. However, integration studies point out that unfortunately the cost difference also contains the difference in fuel savings induced by the flat block compared to VRE ([20], [18], [26]). This is due to different temporal values of the energy provided by a benchmark and VRE determined by their respective temporal profiles.

While studies seek to adjust the benchmark technology in order to minimize this difference, our definition of integration costs suggests that the difference in energy values of VRE and a benchmark is part of integration costs. This is because the specific temporal profile of a VRE plant influences the costs in the residual system and might lead to additional costs, which per definition belong to integration costs. In fact, this effect leads to the new cost component *profile costs*, which was thoroughly discussed in section 3.2.3.

Concerning the choice of a suitable benchmark resource, we argue that there is no universal bottom-up realization of a benchmark that can be applied to any model²⁸. A benchmark that fulfills equation 22 and thus does not impose integration costs is model dependent. It depends on the representation of integration issues and the structure of the model and can be quite abstract or without any physical interpretation at all. We regard a benchmark as a helpful interpretation to create intuition, however an explicit modeling of a benchmark technology should be undertaken carefully, if at all. We suggest estimating total integration costs by modeling the power system *with* and *without VRE* and comparing the resulting specific residual system costs as expressed by equation 11.

Note that in the model applied in this paper (section 3.3.1) the appropriate benchmark interpretation is a proportional reduction of load. In a long-term perspective, when capacity mix adjustments are considered, this ideal generator decreases the costs in the residual power system in proportion to its generation and thus does not induce integration costs. The hypothetical output of this benchmark technology exhibits perfect spatial and temporal correlations with load. Perfect spatial correlations eliminate any additional grid costs, while full temporal correlations imply that no backup power plants or storage would be needed even at high shares. The time series of residual load would be reduced but retains its shape and stochasticity, so that residual power plants operate with the same ramping and reserve requirements, and their full-load hours (FLH) are conserved.

3.3. Quantification of System LCOE and integration costs

In section 3.2 we conceptually introduced System LCOE. In the following, we apply the concept and present quantifications based on model and literature results. We show shares of various drivers of integration costs and draw conclusions for integration options.

There is no model or study that fully accounts for all integration issues and options. Thus a single analysis can only give cost estimates for a limited range of integration aspects. Here we combine results of several studies and own modeling to gain a fairly broad picture of integration costs and System LCOE. We want to show how System LCOE in principle can help understanding and tackling the integration challenge. Thus we make no claims of presenting a complete literature review or using a state-of-the-art model. The quantifications should be understood as rough estimations of the magnitude and shape of integration costs. Moreover the results shed light on the relative importance of various cost drivers. The quantifications apply to thermal power systems²⁹ in Europe.

²⁸ This argument has been put forward by Simon Müller (International Energy Agency) in a personal correspondence.

²⁹ Thermal systems rely on thermal power plants like coal, gas and nuclear plants rather than hydro power generation.

3.3.1. Model description and literature estimates

The power system model applied here is tailor-made to quantify profile costs (section 3.2.3) while balancing and grid costs are parameterized from literature estimates (see end of this subsection). For steps toward a complete integration study that includes modeling balancing and grid costs see [17].

Profile costs are determined by the structural matching of demand and VRE supply patterns and almost independent from small-scale effects. Hence, quantifying them does neither require a high temporal or spatial resolution nor the representation of much technical detail of the power system. In order to isolate the profile cost component the model neglects other cost drivers of VRE, namely balancing and grid costs. Thus there are no technical constraints on the operation of power plants, like ramping and cycling constraints as well as no grid constraints modeled (“copper plate assumption”). As a result in this model integration costs as defined in section 3.2.1 are only made up of profile costs.

Integration costs can be reduced by integration options like long-distance transmission, storage or demand-side management technologies. Deriving an efficient mix of integration options needs a careful assessment considering the interactions of different integration options and significant uncertainties in technology development for example cost parameters of storage technologies. Such an analysis is beyond the scope of this paper. The only integration option that is modeled is the adaptation of the capacity mix of residual power generating technologies in response to VRE deployment. As a consequence the profile cost estimates mark an upper limit while the cost-efficient deployment of further integration options could potentially reduce profile costs.

We apply a standard method from power economics, [35]–[37]. It uses screening curves and a load duration curve³⁰ (LDC) (Figure 18). 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. Load is perfectly price-inelastic and deterministic.

The model minimizes total costs with endogenous long-term investment and short-term dispatch of five dispatchable power generation technologies (see Table 1 for technology parameters). In Figure 18 only three technologies are shown for illustrative reasons. Externalities are assumed to be absent. The cost minimizing solution corresponds to a market equilibrium where producers act fully competitive and with perfect foresight. A carbon price of 20 €/t CO₂ and a discount rate of 5% are applied.

³⁰ For the illustrations we use hourly data for German power demand in 2009 (ENTSO-E).

Table 1: For the model analysis the following technology parameters are used.

	Investment costs³¹ (€/kW)	Quasi-fixed costs (€/kW*a)	O&M costs (€/MWh_{el})	Fuel costs (€/MWh_{th})	Efficiency	CO₂ intensity (t/MWh_{th})
Open cycle gas turbine	600	7	2	25	0.3	0.27
Combined cycle gas turbine	1000	12	2	25	0.55	0.27
Hard coal power plant	1500	25	1	12	0.39	0.32
Nuclear power plant	4500	50	2	3	0.33	0
Lignite power plant	2500	40	1	3	0.38	0.45

For wind and solar PV generation we use quarter hourly feed-in data from German TSOs for 2011. For power demand of Germany hourly data for 2011 is used from ENTSO-E. Even though the load and renewable feed-in data belongs to Germany it is not our objective to specifically analyze the German situation. We rather want to give a general estimate of the order of magnitude and shape of integration costs for thermal systems³² with load and renewable profile patterns similar to those in Germany. This applies to most continental European countries.

³¹ Unplanned outages of plants cannot directly be considered in the model but are indirectly incorporated in the specific investment costs of each plant that were raised accordingly.

³² Thermal systems rely on thermal power plants like coal, gas and nuclear plants rather than hydro power generation.

Long-term perspective

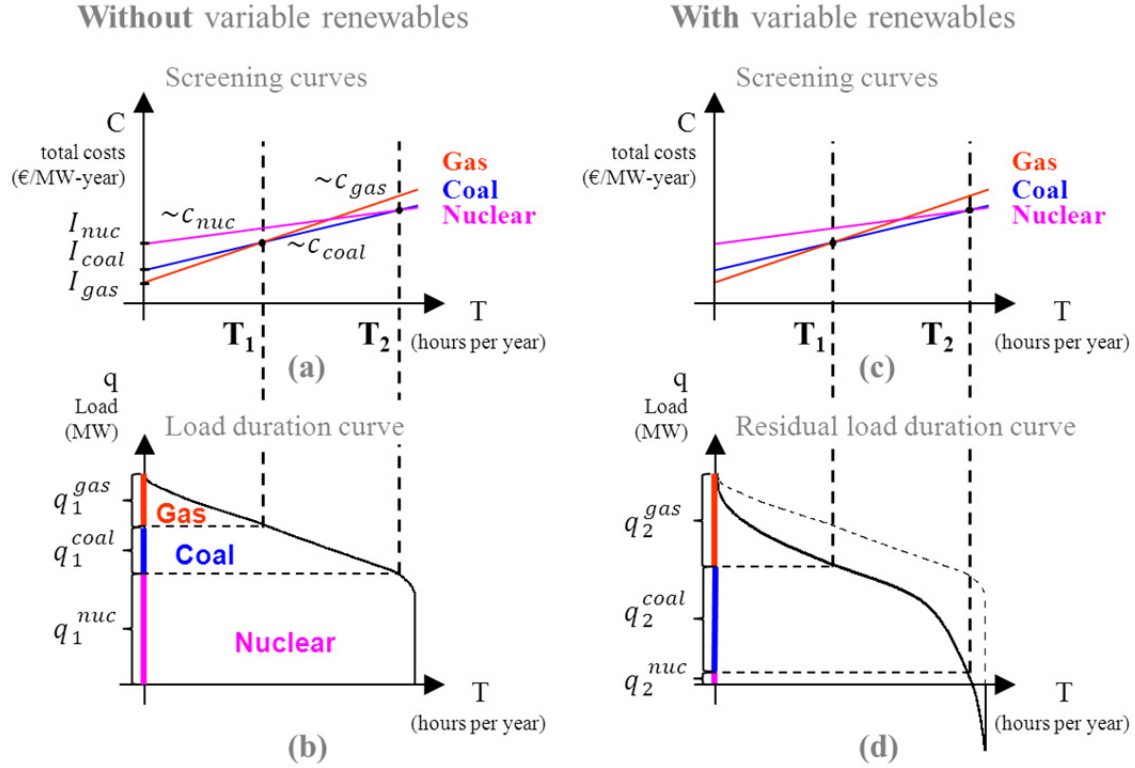


Figure 18 (illustrative): Long-term screening curves and load duration curves without (left) and with wind deployment (right). Wind changes the residual load duration curve (c, d). Thus capacities adjust towards lower fixed-to-variable-costs ratio (more gas capacity, less nuclear capacity).

That is why in the default scenario the German nuclear phase-out is not considered. In general there is no capacity constraint applied to any technology. Moreover it is assumed that the system is in its long-term equilibrium before VRE are deployed. Consequently the initial model state is characterized by cost minimizing capacities and dispatch without VRE and does not necessarily need to coincide with existing capacities. In the default scenario a carbon price of 20€/tCO₂ is applied.

When introducing VRE the system is displaced from its equilibrium. VRE change the LDC to a RLDC (Figure 18d). Its shape depends on the variability of the renewable sources and especially its correlation with demand. This captures profile costs as described in section 3.2.3.

1) Calculating total profile costs

Profile costs $C_{profile}$ are in this model given by applying the definition for integration costs (equation 11).

$$C_{profile} = C_{int} = C_{resid} - \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \quad (26)$$

Note that System LCOE are defined in marginal terms so that $\frac{d}{dE_{vre}} C_{profile}$ equals the cost component that is shown later in the results.

In equation 26 only two expressions need to be calculated: the total costs of the conventional part of a power system *with* and *without* VRE: $C_{resid}(E_{vre})$ and $C_{tot}(0) = C_{resid}(0)$. $C_{resid}(E_{vre})$ is given by integrating along the invers RLDC $T(q, E_{vre})$ and multiplying every full-load hour value T with the respective minimal screening curve value $c_{min}(T)$. q_{peak} is the peak demand marking the top of the RLDC.

$$C_{resid} = \int_0^{q_{peak}} T(q, E_{vre}) c_{min}(T(q, E_{vre})) dq \quad (27)$$

$$c_{min}(T) = \min(c_{gas}(T), c_{coal}(T), c_{nuc}(T)) \quad (28)$$

For the dispatchable costs without VRE $C_{resid}(0)$ the invers RLDC $T(q)$ needs to be replaced by the invers LDC. These equations represent the long-term perspective because capacities adapt in response to the transformation of the LDC to the RLDC.

In a short-term perspective capacities do not adjust after introducing VRE. The specific costs increase compared to a new long-term equilibrium because they do not follow the minimal screening curves but need to respect the existing capacities of the respective technologies q_{te} and the corresponding screening curves c_{te} (Figure 19 c, d). The two narrow shaded areas in Figure 19c indicate the screening curve difference between the long and the short-term perspective. Equation 27 accordingly changes to:

$$C_{resid}^{ST} = \sum_{te} \int_{q_{te,min}}^{q_{te,max}} T(q, E_{vre}) c_{te}(T(q, E_{vre})) dq \quad (29)$$

$q_{te,min}$ and $q_{te,max}$ mark where the capacity of each technology te is located on the q -axis in Figure 19b and d.

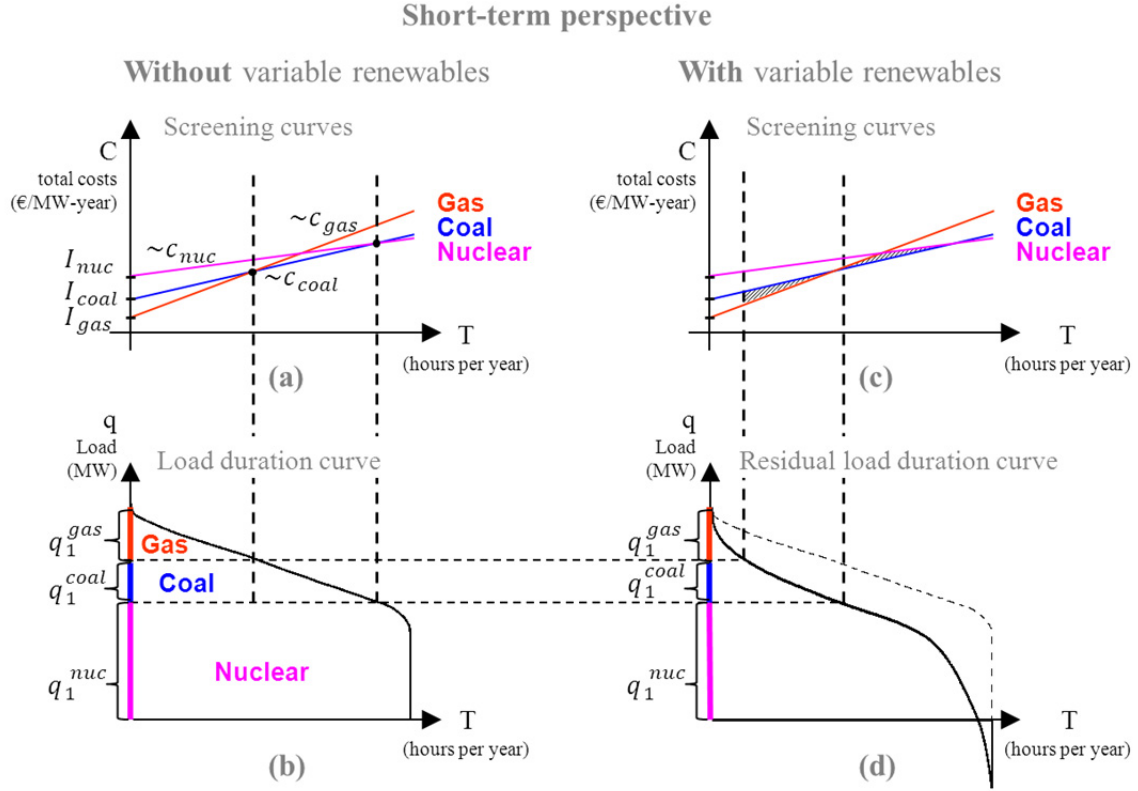


Figure 19 (illustrative): Optimal long-term capacities are derived without VRE (a, b). With VRE the LDC transforms to a RLDC (d). In the short-term perspective the capacities remain unchanged (b, d). Hence, specific costs increase because technologies operate in full-load hour ranges where they would not be cost-efficient if capacities could optimally adjust (c).

Note that our analysis only applies two temporal perspectives, the short and long term (compare section 3.2.3), while not considering the temporal evolution of the electric power system in between those two states.

II) Decomposing profile costs

After quantifying total profile costs we further decompose them into the three cost drivers shown in Figure 14 and Figure 15: overproduction costs, backup capacity costs and costs due to full-load hour reduction of conventional plants.

In our model overproduction occurs where VRE supply exceeds load. It equals the negative part of the RLDC. This fraction can thus be easily calculated from the load and supply data. Overproduction cannot directly be used to cover load and is spilled in the model. Hence, costs increase due to additional VRE capacity required to actually cover demand. Overproduction costs $C_{overprod}$ can be calculated from the overproduction rate γ which is the overproduced fraction of the generation of an incremental VRE unit.

$$C_{overprod} = \frac{\gamma}{1 - \gamma} \overline{LCOE}_{vre} \quad (30)$$

For example at an overproduction rate γ of 20% extra investment costs per MWh are one fourth of the LCOE of VRE. These costs can also be understood in comparison to an ideal technology that has the same LCOE as VRE (see section 3.2.4). The benchmark would not induce overproduction, because its supply has full correlation with load. Consequently to provide the same effective energy for covering demand VRE require more capacity costs. Note that overproduction and its costs are calculated in marginal terms. These numbers increase stronger than average terms, which are sometimes shown in the literature.

Similarly, we separate costs for backup capacity requirements due to a low capacity credit α_{VRE} of VRE. Again, the point of reference is the benchmark technology. Because of its full supply-demand correlations a benchmark would have a capacity credit α_{BM} of 100%. It could accordingly replace conventional plants and thus induce capacity cost savings. We assume that VRE replace open-cycle gas turbines with specific investment costs I_{OCGT} . By comparing the conventional capacity reduction of an incremental unit dq_{vre} of VRE to the benchmark we derive the difference in cost savings. This difference gives the cost component that is needed to backup VRE plants.

$$C_{backup} = (\alpha_{BM} - \alpha_{VRE})I_{OCGT}dq_{vre} \quad (31)$$

Note that in our simple model the capacity credit only corresponds to peak load reduction i.e. the difference of the maxima of the LDC and RLDC. For more sophisticated methods to calculating capacity credits see for example [38], [39].

The third cost component of profile costs due to the reduction of full-load hours is given by the residual cost share of profile costs after subtracting overproduction costs and backup costs.

$$C_{FLH} = C_{profile} - C_{overprod} - C_{backup} \quad (32)$$

III) Parameterizing balancing and grid costs

We parameterize balancing costs for wind power according to three literature surveys [19], [27], [31]. Therein balancing cost estimates are compiled from various studies for a range of penetration levels. A characteristic relation can be found even though there is some variance in the results. We parameterize balancing costs from about 2 to 4 €/MWh when increasing the wind share from 5% to 30%. Converting these average numbers into marginal terms the range increases to roughly 2.5 to 5 €/MWh. Because solar PV fluctuations are more regular and predictive they most likely induce even less balancing costs.

There are a few studies estimating grid costs of integrating VRE. An overview for grid reinforcement costs mainly due to added wind power can be found in [19]. At wind shares of 15-20% these costs are about 100 €/kW (~ 3.75 €/MWh³³). For Ireland the costs rise to 200 €/kW (~ 7.5 €/MWh) at 40% wind penetration [40]. For Germany annual transmission-related grid cost estimates are € 1 bn to integrate 39% renewable energy of which 70% is wind and solar generation [41]. This corresponds to 7.5 €/MWh VRE which is surprisingly consistent with the above literature values. We thus assume a linear increase of grid costs with increasing VRE share up to 7.5 €/MWh (average terms) which translate to about 13 €/MWh in marginal terms.

3.3.2. Results for System LCOE and integration costs

Figure 20 shows System LCOE and its components as a function of the final electricity share of wind power. Generation costs of wind are assumed to be constant and set to 60 €/MWh as currently realized at the best onshore wind sites in Germany [6]. Integration costs are given in marginal terms and composed of three parts: profile, balancing and grid costs. Short-term System LCOE are the costs of VRE that occur without adaptations of the residual power system. The shaded area shows cost savings that can be realized if residual capacities adjust to VRE deployment (compare Figure 17 in section 3.2.3). The solid line shows long-term System LCOE. Cumulative long-term integration costs are the area between generation costs (LCOE) and this line.

³³ This conversion assumes wind full-load hours of 2000, a discount rate of 7% and a grids' life time of 40 years.

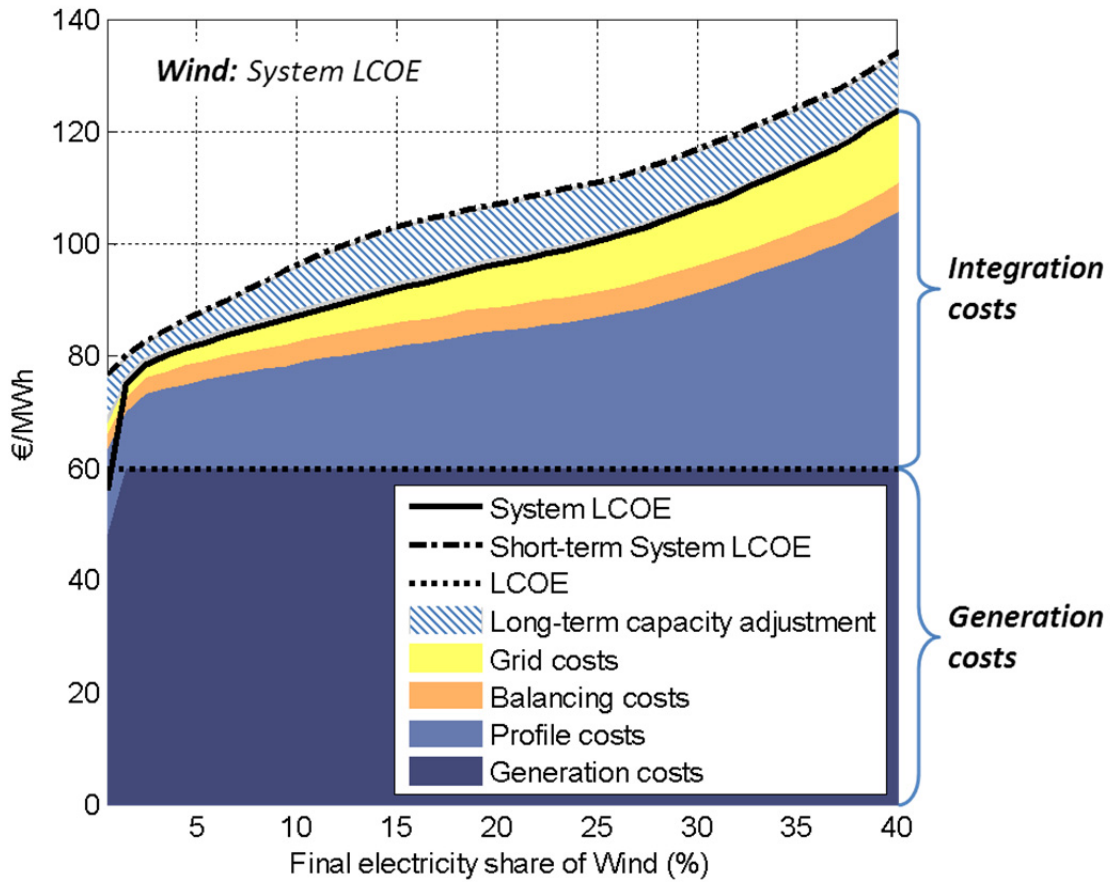


Figure 20: System LCOE for increasing shares of wind representing typical thermal power systems in Europe. Integration costs rise up to the order of magnitude of generation costs. Integration costs can thus become an economic barrier to large deployment of VRE.

We find four main results (Figure 20). First, at moderate and higher wind shares (>20%), marginal integration costs are in the same range as generation costs. At a wind share of 40% integration costs reach 60 €/MWh which equals the typical current wind LCOE in Germany. Second, integration costs significantly increase with growing shares. At low shares integration costs start at slightly negative values but steeply increase with further deployment. At moderate shares the curve is concave, at higher shares (>25%) the curve becomes convex. Third, profile costs are the largest component of integration costs, especially driving the convexity of System LCOE. Fourth, short-term System LCOE are larger than (long-term) System LCOE. Long-term adjustments of generation capacity can significantly reduce integration costs and are thus an important integration option.

These results have far-reaching implications. Growing marginal integration costs can become an economic barrier to further deployment of VRE even if their costs drop to low values and their resource potentials would be abundant. In case of a further reduction of generation costs due to technology learning the relative importance of integration costs

further increases. A barrier becomes more likely at high shares (>20%) where integration costs become convex. We will see that this is driven by VRE generation that needs to be discarded. DeCarolís and Keith schematically illustrate this convexity in [42]. This does not mean that there is an economic threshold to VRE deployment especially if integration options are applied (section 3.3.4).

Wind power would only be economically efficient (and competitive³⁴) without subsidies if its System LCOE is below the average costs (per MWh) of a purely conventional system (see section 3.2.2). We suppose that integration costs of conventional plants are small compared to those of VRE. Thus high shares of VRE might only be cost-efficient in the case of considerable CO₂ prices³⁵, strong nuclear restrictions or a complete phase out (like in Germany) or significant progress of integration options like long-distance transmission or storage.

Profile costs reach about 30€/MWh at a wind share of 30%. This model result is in line with other studies that show decreasing marginal values for wind. These reductions can be interpreted as profile costs if compared to the average annual electricity price.³⁶ To allow the comparison all literature values were normalized to an annual load-weighted electricity price of 70 €/MWh. Allowing for long-term adjustments Mills and Wiser [12] derive profile costs of 15-30 €/MWh for California at wind penetrations of 30-40% and Hirth [43] estimates 14-35 €/MWh at 30% penetration for North-Western Europe. Using dispatch models and not considering potential capacity adjustments Hirst and Hild [13] estimate profile costs of up to about 50 €/MWh at 60% capacity share (of peak load) and Grubb [14] shows results of 20-40 €/MWh at 40% wind penetration of total generation. A broad survey of about 30 studies estimates long-term profile costs at 15-25 €/MWh at 30% penetration [31].

Estimates for balancing and grids costs are much smaller than the results for profile costs. This implies that when evaluating variable renewables and their integration costs, profile costs should not be neglected. Moreover, integration options that reduce profile costs are particularly important for reducing the costs of an energy transformation towards VRE (section 3.3.4).

The economic barriers to the deployment of high shares of VRE might be alleviated by integration options like capacity adjustments of conventional generating technologies, long-distance transmission or electricity storage. On the one hand these options have a

³⁴ In case of perfect and complete markets.

³⁵ This assumes that carbon capture and storage (CCS) will not be a mitigation option.

³⁶ The effect of uncertainty was subtracted from the value reduction in those cases where it was considered in the original analysis.

reducing effect on integration costs. On the other hand their investment costs as well have an increasing effect on integration costs. In an economically efficient mix of integration options their investment costs can be considerably overcompensated by the reducing effect on integration costs. The dashed line in Figure 20 shows short-term System LCOE. It reflects short-term integration costs before the system adapts to the deployment of VRE. No integration options are newly installed in particular the dispatchable capacities remain unchanged when introducing VRE. For long-term System LCOE the only integration option explicitly modeled here are adjustments of the dispatchable capacities. These adjustments significantly reduce integration costs for all levels of wind deployment (shaded area). In section 3.3.4 we discuss various integration options and suggest that long-term capacity adjustments are among the most important integration option.

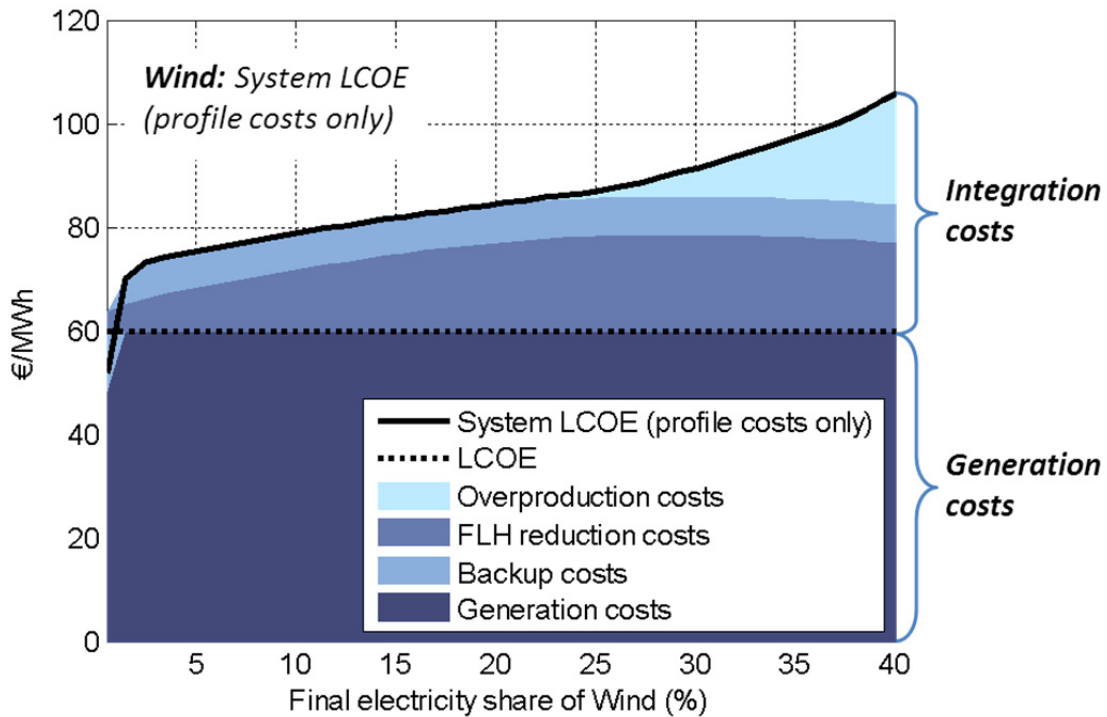
The integration cost savings from capacity adjustments correspond to profile costs. Hence, profile costs that occur in the short term are even higher than the long-term share shown in Figure 20. Adaptations of dispatchable plants drive down integration costs according to two mechanisms:

- 1) First, VRE reduce the average utilization (or full-load hours) of dispatchable power plants. Peak-load plants like gas turbines have lower specific investment costs and are thus more cost-efficient at low full-load hours. Hence, VRE shift the long-term optimal mix of residual capacities from base-load to mid-load and peak-load technologies. Because increasing wind shares continuously change the RLDC as shown in Figure 16 (left), the residual capacity mix continuously responds. Hence, the described mechanism reduces short-term integration costs at all levels of wind penetration.
- 2) Second, VRE can reduce overall capacity requirements. At low penetration levels wind power plants have a moderate capacity credit. In the short term this does not reduce costs because conventional capacities are already paid and their investment costs are sunk. In the long run when capacity needs to be rebuilt, VRE deployment can reduce the overall capacity requirement. However, already at moderate shares of wind, the marginal capacity savings of an added wind capacity is almost zero. Every newly installed wind plant needs to be fully backed up by dispatchable plants. Hence, in contrast to the first mechanism, integration cost savings due to overall capacity savings by VRE only occur at low levels of wind penetration.

3.3.3. A closer look on profile costs

Above we found that profile costs are the largest single cost component of integration costs. This component thus mainly determines the magnitude and shape of total integration costs. Here we further decompose the model results for profile costs to understand the underlying drivers and their relative importance. Moreover we extend the analysis to solar PV.

Figure 21 shows (long-term) profile costs and its components for wind power (above) and solar PV (below) as a function of the final electricity share. We disassemble profile costs into components according to three cost drivers introduced in section 3.2.3: Backup requirements due to a small capacity credit, reduced full-load hours of dispatchable plants and overproduction of VRE. For generation costs we assume 60 €/MWh for wind and 120 €/MWh for solar PV³⁷ [6].



³⁷ LCOE of 120 €/MWh for solar PV are already achieved in Spain and will probably be reached in Germany within the next years due to further technology learning.

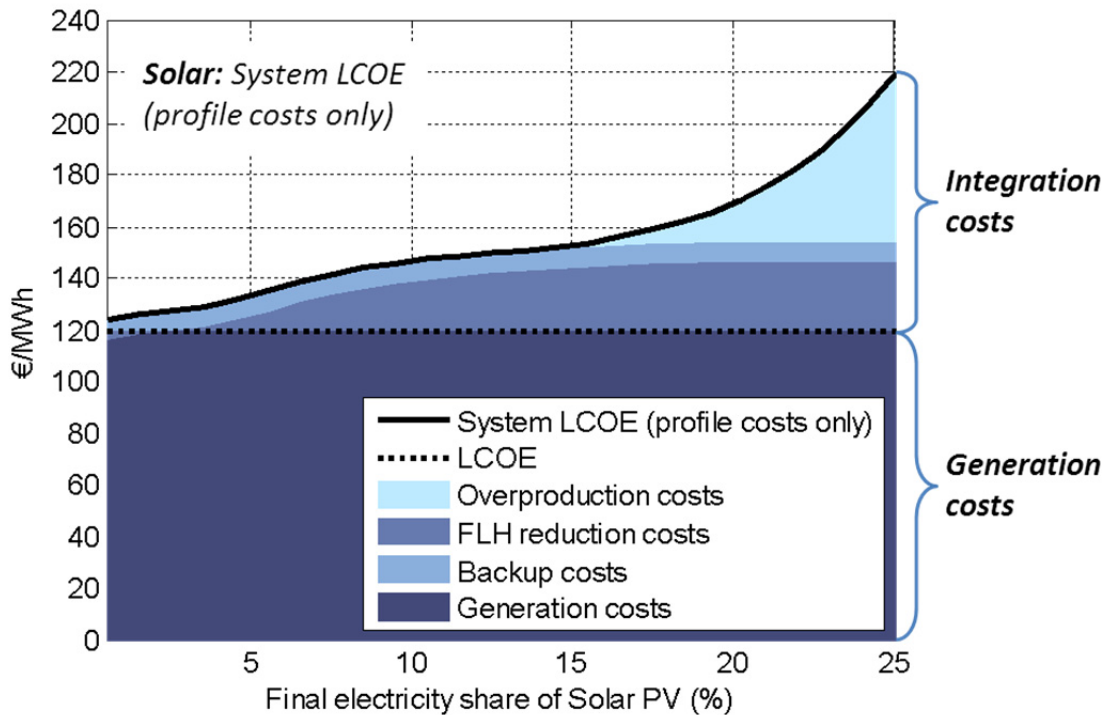


Figure 21: System LCOE (profile costs only) for increasing generation shares of wind (above) and solar PV (below) for Germany estimated with a power system model that is designed for calculating profile costs. These costs are decomposed into three cost drivers. The full-load hour (FLH) reduction of conventional plants is the largest cost driver at moderate shares, while overproduction costs significantly increase integration costs at high shares.

We find three main results that hold for wind and solar PV (Figure 21). First, the largest costs driver at moderate shares (10-20%) is the FLH reduction of conventional plants even though the residual capacity mix optimally adapts to VRE deployment. Fortunately, these costs are concave and saturate at higher shares. Second, with increasing shares overproduction costs occur and significantly grow. These costs drive the convex shape of integration costs. Third, backup requirements induce only minor costs that are constant for a wide range of penetration levels. Fourth, profile costs are negative at low shares.

While the rough magnitude and shape of profile costs are similar for wind and solar, there are some specific differences. Solar PV induces higher integration costs for moderate and high shares. At moderate shares profile costs are higher for solar PV than for wind due to higher FLH reduction costs. Overproduction costs for solar occur earlier (~15%) than for wind (~25%) and increase stronger. Once the load of summer days is covered with solar PV further solar deployment does mostly lead to overproduction. At very low shares (<2%) wind shows negative profile costs due to a high marginal capacity credit. In contrast, solar PV requires backup power at all penetration levels due to inappropriate matching of peak load at winter evenings and solar supply. However, at low shares (~5%) solar PV induces slightly less profile costs than wind. Diurnal correlations of solar supply

with load particularly reduce intermediate load and reshape the RLDC so that FLH reduction costs are smaller compared to wind.

3.3.4. Implications for integration options

The previous sections have shown that integration costs could significantly increase with penetration. However, there are a number of integration options that might effectively reduce integration costs and dismantle potential economic barriers to integrating VRE especially at high shares. However note that deploying integration options are not an end in itself. Most integration options are costly, and it is unclear to what extent these options are economically efficient. Deriving an efficient mix of integration options requires a careful analysis of a power system considering the complex interaction of variable renewables, other generating technologies and integration options as well as the relevant externalities (see for example [44]–[46]). This is beyond the scope of this paper. Instead here we derive basic implications for potential integration options from the quantification of System LCOE. This can assist further analyses by pointing out the most important options. Note that in the case of perfect and complete markets, in particular if all externalities of generating technologies are internalized market prices would incentivize all efficient integration options. Hence this section should not be understood as a list of what should be subsidized, but rather as a starting point for further research.

Capacity adjustments have been explicitly modeled in section 3.3.2 finding that shifting the residual capacity mix from base load to mid and peak load technologies can heavily reduce integration costs (profile costs).

Cross-border transmission and grid reinforcement is typically rated as a very important integration option. However, analyzing this integration option is complex because its potential to reduce integration costs of VRE in a country depends on the development of the generation mix in the neighboring countries. If the countries do not develop similar VRE shares reinforcing the grid connection would virtually reduce the VRE share in the resultant interconnected power system. Hence, marginal integration costs would then decrease as found in section 3.3.2. If on the other hand most neighboring countries increasingly deploy VRE, the cost-saving potential of transmission grids decreases because of high geographical correlations of VRE supply and power demand [6]. Moreover, long-distance transmission grids can indirectly decrease the generation costs of VRE significantly by allowing the access to the better renewable sites. Thus increased FLH of VRE would reduce the generation-side LCOE, though the integration costs would increase due to transmission grid costs.

We found in section 3.3.2 that profile costs are the largest component of integration costs. The matching of residual power demand and VRE supply gets worse with increasing shares. Any measure that can flexibly shift power demand or supply in time could improve this matching and would reduce integration costs.

If demand could be flexibly shifted over the course of a year at low costs, profile costs would be zero. That would mean that demand follows variable renewable supply to a large extent which is not realistic. However, it indicates the huge potential of demand-side management (DSM) in particular in the long term.

Analogously electricity storage has similar long-term potential by shifting electricity supply in time. To significantly reduce profile costs a storage system requires large and cheap reservoir to store huge amounts of electricity for longer times (weeks – seasons). For Germany a reinforced grid connection to the pumped-hydro storage plants in Austria and Switzerland as well as a grid extension to the Scandinavian hydro and pumped-hydro plants has potential to foster VRE integration. Chemical storage of electricity in hydrogen or methane in principle offers huge capacities and reservoirs. However, this option has a low total efficiency of 28-45% for the full storage cycle of power-hydrogen-methane-power and high costs for electrolysis and methanization capacities [47]. This drawback might be compensated by using renewable methane in the transport sector.

In principle, the links between the power sector and other sectors could be utilized to flexibilize demand and supply. Combined heat and power plants could easily be extended with thermal storage. In future, electric vehicles might offer storage and DSM possibilities.

3.4. Summary and conclusion

Due to the challenge of transforming energy systems policy makers demand for metrics to compare power generating technologies and infer about their economic efficiency or competitiveness. Levelized costs of electricity (LCOE) are typically used for that. However, they are an incomplete indicator because they do not account for integration costs. An LCOE comparison of VRE and conventional plants would tend to overestimate the economic efficiency of VRE in particular at high shares. In other words, LCOE of wind falling below those of conventional power plants does not imply that wind deployment is economically efficient or competitive. In this paper we have introduced a new cost metric to overcome this deficit. *System LCOE* of a technology are the sum of its marginal generation costs (LCOE) and marginal integration costs per generated energy unit.

We show that System LCOE can be interpreted as the marginal economic costs of VRE including the costs induced by their variability on a system level. That is why in contrast to a standard LCOE comparison the new metric allows the economic evaluation of VRE such as deriving optimal quantities while remaining an intuitive and familiar format. Only if System LCOE of VRE drop below the average System LCOE of a purely conventional system VRE are economically efficient and competitive.

The formalization of System LCOE required a new mathematical definition of integration costs that directly relates to economic theory while standard definitions lack such a link.

For that purpose we extended standard definitions by a new cost component *profile costs* that can be understood as a more general conception of standard adequacy costs. While adequacy costs only cover backup costs due to a low capacity credit of VRE, profile costs additionally account for the reduction of full-load hours of conventional plants and overproduction when VRE supply exceeds demand. Only because the new definition of integration costs contains profile costs it can be economically interpreted as the total costs of variability and consequently used to evaluate VRE.

We have shown that the cost perspective of System LCOE is equivalent to the established market value perspective where market value and LCOE of a technology are compared. The new definition of integration costs corresponds to a decrease of the market value of VRE with increasing shares. The concept of System LCOE hereby connects two literature branches: dedicated integration cost studies and economic literature on the value of VRE. This link hopefully stimulates future research like a more accurate estimation of VRE values with highly-resolved models typically used in integration studies.

Furthermore, to demonstrate how the concept can help understanding the integration challenge we quantified System LCOE for VRE in typical European thermal power systems based on model and literature results. As a central result we find that at wind shares above 20%, marginal integration costs can be in the same range as generation costs if integration options like storage or long-distance transmission are not deployed. Moreover, System LCOE and integration costs significantly increase with VRE penetration and can thus become an economic barrier to further deployment of wind and solar power. That does not mean that optimal shares of VRE are low in particular when negative externalities like climate change and further benefits of VRE are internalized. However, achieving high shares of VRE might need considerable carbon prices as well as strong nuclear capacity restrictions or significant renewables support.

Integration options could dismantle the economic barriers of deploying VRE by reducing integration costs. Quantifying different integration cost components that correspond to different impacts of VRE gave insights towards identifying the most crucial integration challenges and finding suitable integration options. We find that profile costs make up the largest part of integration costs. Grid reinforcement costs and costs for balancing due to forecast errors are comparably low. Hence, three integration options are in particular important because they reduce profile costs: firstly, adjusting the residual generation capacities to a mix with lower capital cost, secondly, increasing transmission capacity to neighboring power systems reduces integration costs strongly, in particular if those power systems do not develop similar shares of VRE and thirdly, any measure that helps shifting demand or supply in time like demand-side management and long-term storage.

Evaluating technologies and deriving cost-efficient transformation pathways requires a system perspective. Hereby System LCOE can serve as an intuitive metric yet accounting for the complex interaction of variable renewables, other generating technologies and

potentially integration options. This paper focused on introducing the concept and showing an initial application. In the future it can be further refined and estimated by more sophisticated models. Promising research directions are the interaction of different integration options and a refined consideration of the temporal evolution of the system adjusting in response to VRE deployment. Furthermore System LCOE estimates can provide a simple parameterization of integration costs for large-scale models like integrated assessment models that cannot explicitly model crucial properties of VRE and lack high temporal and spatial resolution.

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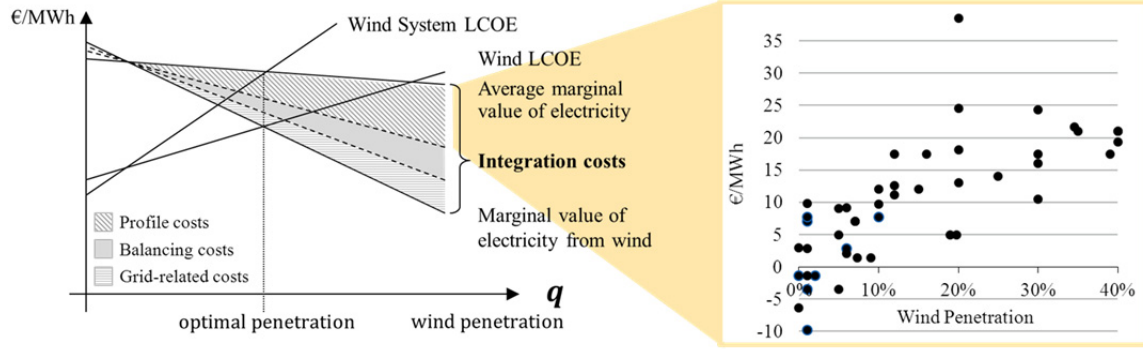
4. Integration costs revisited – An economic framework for wind and solar variability

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Abstract – The integration of wind and solar generators into power systems causes “integration costs” for grids, balancing services, reserve capacity, more flexible operation of thermal plants, and reduced utilization of the capital stock embodied in infrastructure. This paper proposes a valuation framework to analyze and quantify these integration costs. We propose a new definition of integration costs based on the marginal economic value of electricity that allows a welfare-economic interpretation. Furthermore, based on the principal characteristics of wind and solar power, temporal variability, uncertainty, and location-specificity, we suggest a decomposition of integration costs that exhaustively and consistently accounts for all costs that occur at the level of the power system. Finally, we review 100+ published studies to extract estimates of integration costs and its components. At high penetration rates, say a wind market share of 30-40%, integration costs are found to be 25-35 €/MWh, however, these estimates are subject to high uncertainty. The largest single cost component is the reduced utilization of capital embodied in thermal plant, which most previous studies have not accounted for.

Highlights:

- We propose a new definition of integration costs of wind and solar power.
- Our definition is based on the marginal economic value of electricity.
- We suggest a consistent, operationable, robust & comprehensive cost decomposition.
- Integration costs are large: 25-35 €/MWh at 30-40% wind, according to a lit review.
- A major driver is the reduced utilization of capital embodied in thermal plants.



Graphical Abstract - We propose defining “integration costs” as the gap between the marginal value of electricity and the marginal value of wind (or solar) power. This gap can be decomposed into profile, balancing, and grid-related costs (left). Reviewing the literature, we find that profile costs are the largest component, reaching 15-25 €/MWh at 30-40% penetration.

4.1. Introduction

As any other investment, the variable renewable energy sources (VRE)³⁸ solar and wind power occasion direct costs in the form of capital and operational expenses. These costs can be aggregated to average full costs, which in the power industry are often labeled “levelized energy costs” or “levelized costs of electricity” (LCOE). However integrating VRE into power systems cause additional costs at the system level, for example for 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 are usually called “integration costs” (Milligan & Kirby 2009; GE Energy 2010; Milligan et al. 2011; Holttinen et al. 2011; Katzenstein & Apt 2012; Holttinen et al. 2013). They need to be added to direct costs of wind and solar power to derive their total economic costs. Integration costs are relevant for policy making, since ignoring or underestimating those leads to biased conclusions regarding the welfare-optimal generation mix and the costs of system transformation.

Most studies identify three specific characteristics of VRE that impose integration costs on the power system (Milligan et al., 2011; Sims et al., 2011; Borenstein, 2012):

- 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, 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 the day before

³⁸ Variable renewables have been also termed intermittent, fluctuating, or non-dispatchable.

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. Integration costs occur because electricity transmission is costly and good VRE sites are often located far from demand centers.

While these properties of VRE are well-known and the term “integration costs” is widely used, it seems like there is no consensus on a rigorous definition and on how to comprehensively calculate total integration costs (Milligan et al. 2011). There are a number of only qualitative definitions of integration costs given in the literature.³⁹ According to our understanding it is thus unclear whether the sum of levelized costs and integration costs actually represent the total economic costs of VRE. As a consequence, it is difficult to interpret integration cost estimates for an economic analysis of VRE, for example calculating their welfare-optimal deployment or comparing LCOE across generation technologies. To overcome the lack of 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 aims at addressing these issues by making four contributions to the literature. First, we propose a definition of integration costs that has a rigorous welfare-economic interpretation so that total economic costs of VRE can be estimated including all costs of variability (section 4.2). Second, based on the different characteristics of VRE we suggest a decomposition of integration costs that is consistent, operational, robust and comprehensive (section 4.3). Third, we discuss the underlying technical constraints that explain integration costs and relate them to the established decomposition mentioned above. Specifically, we show that reduced capital utilization has a major impact and has been not accounted for in many previous studies (section 4.4). Fourth, we provide an extensive literature review of quantifications of all integration cost components (section 4.5). Additionally, section 6 explains briefly who bears costs under current market and policy design and identifies externalities. Section 4.7 concludes.

³⁹ They have been defined as “an increase in power system operating costs” (Milligan & Kirby 2009), as “the additional cost of accommodating wind and solar” (Milligan et al. 2011), as “the extra investment and operational cost of the nonwind part of the power system when wind power is integrated” (Holtinen et al. 2011), as “comprising variability costs and uncertainty costs” (Katzenstein & Apt 2012), or as “additional costs that are required in the power system to keep customer requirement (voltage, frequency) at an acceptable reliability level” (Holtinen et al. 2013).

4.2. Definition of integration costs

In this section we propose a new definition of integration costs that is rigorous and comprehensive. The idea of our definition is that integration costs should facilitate the economic evaluation of VRE like deriving their welfare-optimal deployment or comparing the levelized costs of different generation technologies. In that sense integration costs have a welfare-economic interpretation. In Hirth et al. 2013 we discuss the economics of variability more fundamentally.

Our definition of integration costs is derived from the marginal value of electricity from wind or solar power. The marginal economic value (benefit) of a generation technology $b'(q)$ is the incremental cost savings when adding a unit dq of this technology to a power system⁴⁰. Many studies show that the marginal value of VRE decreases with increasing VRE penetration (Lamont 2008, Borenstein 2008, Fripp & Wiser 2008, Nicolosi 2012, Mills & Wiser 2012, Hirth 2013a). It is a basic economic principle that the welfare-optimal deployment q^* of a technology is given by the point where marginal value and marginal costs $c'(q)$ coincide. The long-term marginal costs of a technology can be expressed as their LCOE (€/MWh). Hence, VRE like any technology, are optimally deployed when their marginal value equals their LCOE (Hirth 2013b).

$$b'(q^*) = c'(q^*) \quad (33)$$

The marginal value of VRE is impacted by the characteristic properties of VRE, variability, uncertainty, and location. At high penetration, VRE generators mainly produce during times of high supply, their forecast errors increase the system imbalance, and they are mainly located in regions of oversupply. These three factors on average reduce the marginal value of VRE. We define integration costs of wind i'_{wind} as the difference between the average load-weighted marginal value of electricity b'_{load} and the marginal value of wind b'_{wind} (Figure 22, left).

$$i'_{wind}(q) := b'_{load}(q) - b'_{wind}(q) \quad (34)$$

We define solar integration costs accordingly. Note that integration costs like all other figures are given in marginal terms per unit of VRE generation (€/MWh_{VRE}).

A key strength of this definition is that integration costs have a direct link to the economic evaluation of VRE. Integration costs reduce the marginal value of VRE and consequently their optimal quantity is reduced as well. In other words, it needs lower LCOE to reach a high optimal quantity of VRE. We refer to this way of accounting for integration costs and evaluating VRE as the *value perspective*.

⁴⁰ Assuming price-inelastic demand.

There is an alternative but equivalent perspective of how to understand integration costs. From a *cost perspective* marginal integration costs can be added to the LCOE of wind, resulting in the metric “system levelized costs of electricity” (system LCOE), (see Figure 22, right) (Ueckerdt et al., 2013).

$$sLCOE_{wind}(q) := LCOE_{wind}(q) + i'_{wind}(q) \quad (35)$$

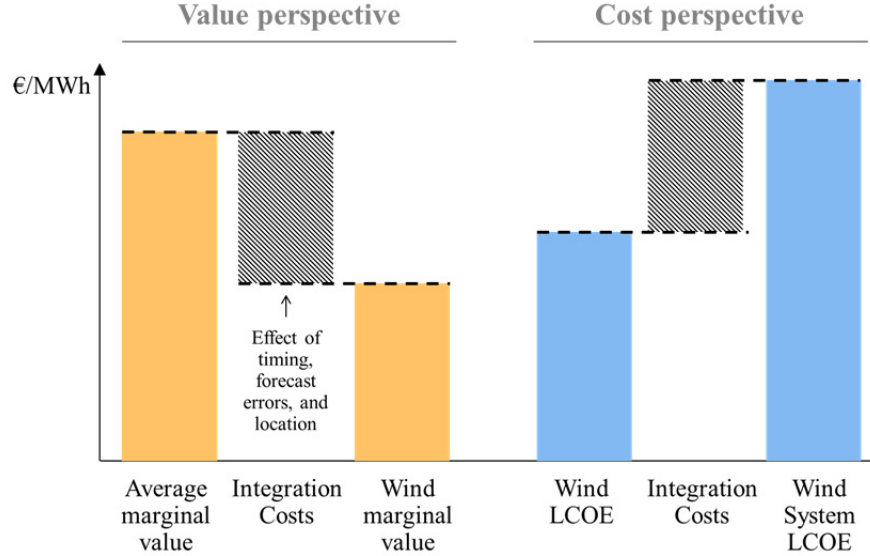


Figure 22: We define wind integration costs as the gap between its marginal value and the average (load-weighted) marginal value of electricity. The *value perspective* (left) is equivalent to the *cost perspective* (right). Integration costs of other generating technologies are defined accordingly.

In the cost perspective the above optimality condition can be analogously formulated: VRE, like any technology, are welfare-efficient when their system LCOE equals the average load-weighted marginal benefit of electricity. In that sense system LCOE represent the total economic costs of a technology.

$$sLCOE(q^*) = b'_{load}(q^*) \quad (36)$$

We have shown that they are two ways of accounting for integration costs. First, in a value perspective they reduce the marginal value of a technology, and second, in a cost perspective they can be added to the marginal costs (LCOE) of a technology. Figure 23 illustrates this duality. The welfare-optimal deployment q^* is equivalently given either at the intersection of marginal value and LCOE, or where system LCOE equal the marginal value of electricity. Since equation (36) holds for all generation technologies, in the long-term optimum, the system LCOE of all technologies are identical.

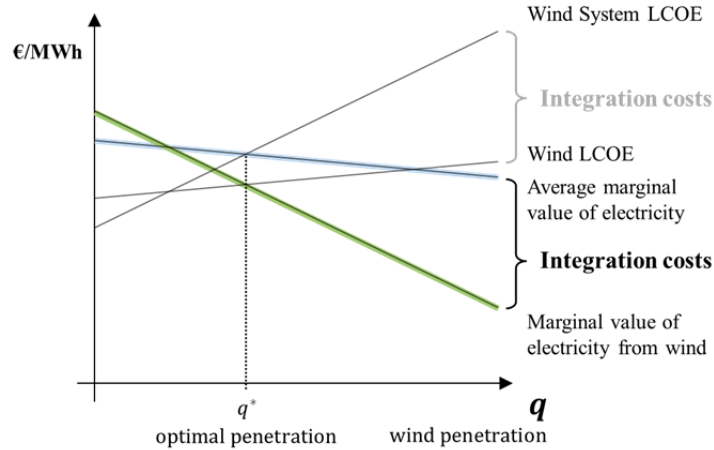


Figure 23: Integration costs can be defined as the reduction of the marginal value of VRE compared to the marginal value of electricity (value perspective). Or equivalently, they can be accounted for by adding them to the marginal generation costs (LCOE) of VRE leading to system LCOE (cost perspective). From both perspectives the welfare-optimal deployment q^* can be estimated at the intersection of marginal value and LCOE, or where system LCOE equal the marginal value of electricity.

Note that this straightforward welfare-theoretical interpretation is possible because we have defined integration costs in marginal terms. Our definition of integration costs features for crucial properties.

1. All generating technologies have integration costs, not only VRE.
2. Integration costs can be negative. Peaking plants have negative integration costs, and VRE have negative integration costs at low penetration if positively correlated with demand.
3. Integration costs are not constant parameters, but depend on a number of factors, including the VRE penetration rate, characteristics of the underlying power system, and assumptions on the ability of the power system to adapt to the introduction of VRE.

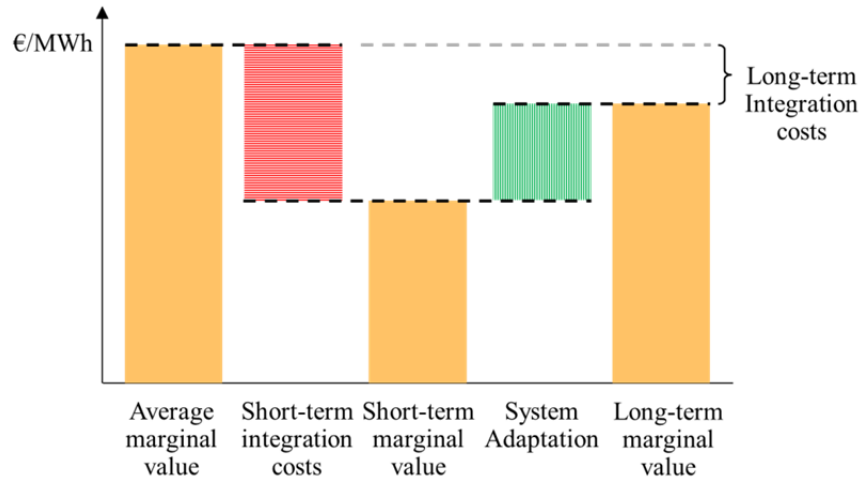


Figure 24: Integration costs depend on how the system adapts in response to VRE deployment. In the short term when the system does not adapt integration costs can be high (red area), while in the long term VRE can be better accommodated due to adaptation and thus long-term integration costs are smaller.

However, as mentioned above in point 3 integration costs depend on the range and magnitude of system adaptations in response to VRE deployment. Integration cost estimates are typically derived by analyzing the impact of VRE on currently existing power systems with a fixed capacity mix and transmission grid. This corresponds to a short-term perspective with rather high short-term integration costs (Figure 24). In contrast, in a long-term perspective the power system can fully and optimally adapt to better accommodate VRE. These potential changes comprise operational routines and procedures, market design, increased flexibility of existing assets, a shift in the capacity mix, transmission grid extensions and technological innovations. Hence, integration costs can be expected to reduce in the long term.

Under the assumption of complete and perfect markets, marginal values and marginal costs are identical to equilibrium prices. The marginal value of VRE equals the market value, which is the specific (€/MWh) revenue that an investor earns from selling the output on power markets, excluding subsidies like green certificates. In other words, it is the average annual price at which generation from that technology is traded. A technology is competitive when its market value at least equals LCOE. In perfect and complete markets economic efficiency and competitiveness are congruent. Through this link the new definition particularly allows estimating integration costs from market prices. In the next section we use market prices for defining different components of integration costs.

Note that under this assumption the average load-weighted marginal value of electricity b'_{load} is identical to the income of an ideal generator that does not feature forecast errors, follows load over time as if it was perfectly dispatchable, and has the same geographic distribution as load, and hence its integration costs would be zero.

4.3. Decomposition

Corresponding to the different characteristics of VRE (uncertainty, locational specificity, variability) we suggest a decomposition of integration costs that is consistent, comprehensive, operationable and robust.

We have shown in the previous section that our definition of integration costs in principle to evaluate VRE in economic assessments like deriving the optimal deployment. From that perspective, there is no need to disaggregate integration costs into components. However, disentangling total integration costs into components is warranted for three reasons. First, a decomposition allows the isolated estimation of single components with specialized models. Estimating the marginal value 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. Estimating individual components allows using existing models. Second, a decomposition allows evaluating and comparing the cost impact of different properties of VRE, helps identifying the major cost drivers and prioritizing integration options (e.g., storage, transmission lines, or forecast tools) to better accommodate VRE. And third, by decomposing integration costs the new definition can be connected to the standard literature that typically calculates integration costs as the sum of balancing, grid and adequacy costs.

Many published studies cite uncertainty, locational specificity, variability as the fundamental properties of VRE (Milligan et al., 2011; Sims et al., 2011; Borenstein, 2012). We suggest decomposing integration costs along these three properties and call the impact of uncertainty “balancing costs”, the impact of location “grid-related costs”, and the impact of temporal variability “profile costs” (Figure 25). We define them in the following in terms of prices:⁴¹

- *Balancing costs* are the reduction in VRE marginal value due to deviations from day-ahead generation schedules, for example forecast errors. These costs appear as the net costs of intra-day trading and imbalance costs. They reflect the marginal cost of balancing those deviations.
- *Grid-related costs* are the reduction in marginal value due to the location in the power grid. We define them as the spread between the load-weighted and the

⁴¹ We use prices for lingual clarity. Prices should be understood as marginal costs and values, which are independent on whether markets are perfect and complete.

wind-weighted annual price of 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 marginal value. We define them as the spread between the load-weighted and the wind-weighted system price of bidding periods 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.

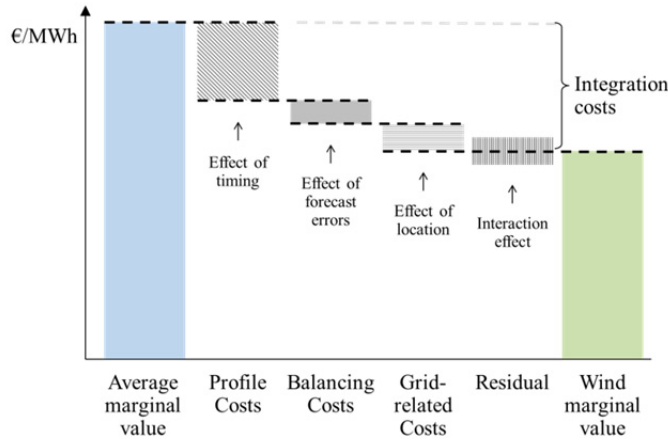


Figure 25: We decompose integration costs into three components, balancing, grid-related, profile costs. They correspond to the three characteristics of VRE uncertainty, locational specificity, and temporal variability.

These cost components interact with each other and we do not know the sign of the interaction term. Lacking further evidence, we set it to zero. We understand estimating the three components separately and adding them up as a first-order approximation of integration costs.

Our decomposition has four crucial properties:

1. Temporal variability, network constraints, and forecast errors can be evaluated *consistently* in a single framework. As a result the different cost components can be evaluated against each other. For example balancing costs of one €/MWh are equivalent to one €/MWh of grid-related costs because both have the same reducing effect on the marginal economic value of VRE. A comparison is shown based on a broad literature review in section 4.5.
2. The sum of the components approximately equals the total integration costs as defined in section². Hereby, all costs of variability at the system level are accounted for *comprehensively* so that integration costs have direct and clear relevance for the economic evaluation of VRE. In contrast, adding previous

integration cost estimates to LCOE does not provide this welfare-economic link (section 4.4.4).

3. The decomposition allows *operationalizing* integration costs. An accurate estimation of integration costs with one model or dataset might not be feasible because it would require a “super model” that captures all characteristics of VRE and its system impacts. The decomposition enables an estimation because each component can be separately estimated with models that capture the relevant VRE characteristic and the respective cost-driving mechanisms. For example, power market models can be used to estimate profile costs (Hirth 2013) and observed imbalance prices can be used to estimate balancing costs (Obersteiner et al. 2010).
4. It is *robust* in the sense that quantification of each component can be either derived from observed market prices or from modeled shadow prices, to the extent that models can be regarded as realistic and markets can be treated as being complete and free of market failures.

The next section investigates the techno-economic mechanisms behind each cost component. After doing so, we compare this decomposition to the integration cost categories often used in previous studies (4.4.4).

4.4. The technical fundamentals behind integration costs

In section 4.2 we have proposed a definition of integration costs derived from the marginal economic value of a generation technology and in section 4.3 we have suggested a decomposition of integration costs into balancing, grid-related, and profile costs. These three cost components have been defined in terms of prices. However, prices are nothing else than a monetary evaluation of underlying technical constraints and opportunity costs. This section discusses the fundamental constraints that cause integration costs. We will discuss profile costs in most detail, since those have received least attention in the literature.

4.4.1. Balancing costs

Balancing costs are the marginal costs of deviating from generation schedules, for example because forecast errors. They are reflected in the price spread between day-ahead and intra-day / balancing (real-time) markets.

There are three fundamental technical reasons that jointly cause balancing costs: i) frequency stability of AC power systems requires supply and demand to be balanced at every time with high precision; ii) thermal gradients cause wear and tear of thermal plants, implying that output adjustment (ramping and cycling) are costly, and ramping constraints make costly part load operation necessary for spinning reserve provision; iii) the forecast errors of wind (and solar) generators are positively correlated because weather is correlated and generators 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 a second and minor reason for balancing costs. Electricity contracts are specified as constant quantities over certain time periods such as 15 or 60 minutes. Balancing costs arise not only due to forecast errors, but also to balance the small variations within these dispatch intervals (intra-schedule variability). Note that costs from scheduled (i.e., planned) ramping and cycling are not balancing costs, but the flexibility effect, which is a component of profile costs (section 4.4.3).

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

- The absolute size of the VRE forecast error, itself depending on
 - installed VRE capacity.
 - the relative size of individual forecast errors, which is determined by the quality of forecast tools (Foley 2012). Some analysts argue that solar can be predicted more easily, hence balancing costs would be lower for solar than for wind.
 - the correlation of forecast errors between VRE generators, which is a function of the geographic size of the balancing area: a larger area typically reduces and hence reduces the absolute size of VRE forecast errors (Giebel 2000).
- The correlation of VRE forecast errors with load forecast errors.
- The capacity mix of the residual system. Specifically, hydro power can typically deliver balancing services at lower costs than thermal plants (Acker et al. 2012).
- The design and liquidity of the intra-day market (Holttinen 2005, Weber 2010).
- The design of the balancing markets and the determination of the imbalance price (Vandezande et al. 2010, Obersteiner et al. 2010, Hirth & Ziegenhagen 2013).

4.4.2. Grid-related costs

Grid-related costs are the marginal costs of transmission constraints and losses. They are reflected in the price spread between locational prices. Locational prices can be implemented as nodal or zonal spot prices, or as locational grid fees. If much VRE capacity is installed in a region, for example because of good wind resources and cheap land, the relative electricity price in that region is *ceteris paribus* lowered. The resulting reduction of income from VRE electricity sales are 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 wind speeds and solar radiation, 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.

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 with cheap land and 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.
- Transmission constraints.
- The cost of transmission expansion.
- The design of locational price signals to electricity generators, such as nodal prices, zonal prices, differentiated grid fees, and cost-based re-dispatch.

Typically solar power 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 (Nordic region, several regions in the U.S.).

4.4.3. 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. As a thought experiment, let us 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. Still, VRE variability would have economic consequences, which are reflected in varying spot prices and (often) in lower average income for VRE generators than for an average generator (Hirth 2013).

One reason for this gap is the cost of adjusting output of thermal plants. As mentioned in section 4.4.1, 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 Nicolosi (2012), we call this the “flexibility effect.” The flexibility effect covers only planned ramping and cycling. Uncertainty-related ramping and cycling such as balancing power provision are reflected in balancing costs.

We illustrate the flexibility effect using German residual load data, which we scale to reach VRE penetration between 0% and 40% (Figure 26).⁴² Increasing the VRE share to 40% increases the number of “system cycles”, the sum of upward ramps during one year over peak load, from 100 to 150. This means, the average plant cycles twice as often. Assuming cycling costs of 100 €/MW per cycle, this results in marginal costs of 3 €/MWh_{VRE} (Figure 27). Hence, the economic impact of cycling is relatively small, which is confirmed by the literature review in section 4.5.3.

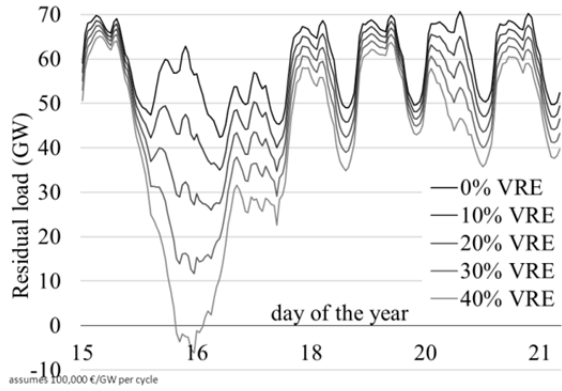


Figure 26: Residual load curves during one week. One can see how residual ramps increase at high VRE shares.

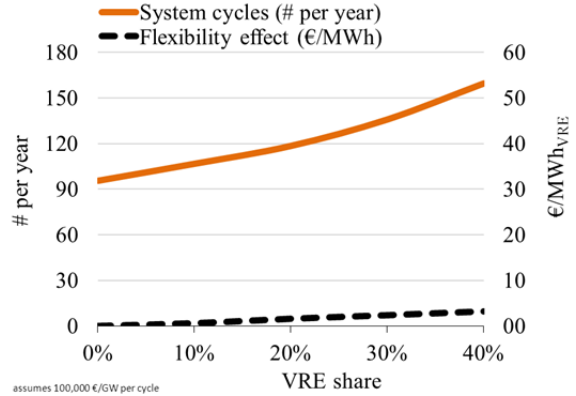


Figure 27: The flexibility effect, based on simple residual load scaling and assuming 100 €/MW per cycle.

Continuing the thought experiment, let us assume that all plants can ramp and cycle at zero cost, hence the flexibility effect disappears. Still, at high penetration the average income of VRE generators will be lower than that of an average generator. In other words, profile costs occur. In the following, we will show that these costs are caused by a reduced utilization of thermal plants.

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. Because the merit-order curve is upward-sloping, electricity prices are an increasing function of residual load. Hence, VRE generates increasingly in times of low prices and their average specific revenue decreases. VRE’s impact 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 (Figure 28). The y-intercept of the RLDC shows the required thermal capacity, not accounting for planning reserves. The integral under the RLDC is the energy produced by this thermal capacity. The average utilization

⁴² 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.

of the thermal capacity is given by ratio of y-intercept to integral. With increasing VRE penetration this ratio decreases.

We illustrate the size of the utilization effect with German data. As VRE penetration grows to 40%, the average utilization of the thermal system decreases from 70% to 47% (Figure 29, Table 2). Assuming thermal capital costs of € 200/kW_a, this implies costs of 44 €/MWh_{VRE}, about 15 times more than cycling costs at this penetration level. In reality, the thermal capacity mix will adjust and the long-term utilization effect will be smaller. However, the literature review of section 4.5.3 supports the finding that the capital cost-driven utilization effect is the single most important integration cost component.

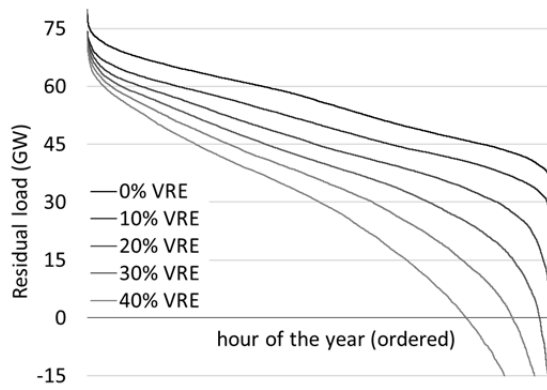


Figure 28: Residual load duration curves for one year. The average utilization of the residual generation fleet decreases.

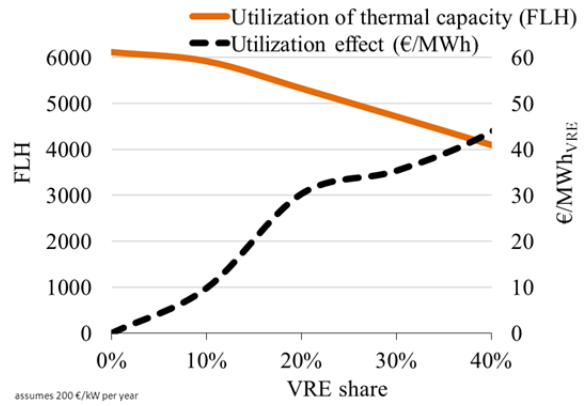


Figure 29: The utilization effect, based on simple residual load scaling and assuming thermal capital costs of 200 €/kW_a.

Table 2: Utilization of the residual generation capacity at increasing shares of VRE.

VRE share (% of consumption)	0%	10%	20%	30%	40%
Installed VRE capacity (GW)	0	36	72	110	154
Potential VRE generation (TWh)	0	49	97	149	208
Curtailment (TWh _{VRE})	0	0	0	2	13
Thermal capacity (GW)	80	74	73	73	72
Thermal generation (TWh)	489	440	391	342	293
Utilization of residual capacity (%)	70%	68%	61%	54%	47%
Utilization of residual capacity (FLH)	6100	6000	5300	4700	4100
Utilization effect (€/MWh_{VRE})	0	10	30	35	44

*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.

Figure 30 offers another perspective on the utilization effect, using the same data: it displays the share of capacity that runs at different full load hours. While without VRE almost two thirds or installed capacity run base load, at 50% penetration rate only 4% of residual capacity run base load. This increases average generation costs, since levelized electricity costs strongly decrease with increasing utilization, even under optimal technology choice (Figure 31).

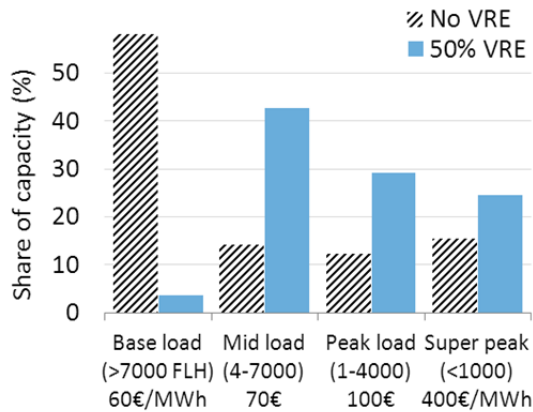


Figure 30: Utilization of residual capacity without renewables and at 50% penetration. The share of capacity that runs base load is reduced from 58% to 14%. The amount of capacity that runs mid, peak, or super peak load increases not only relatively, but also absolutely.

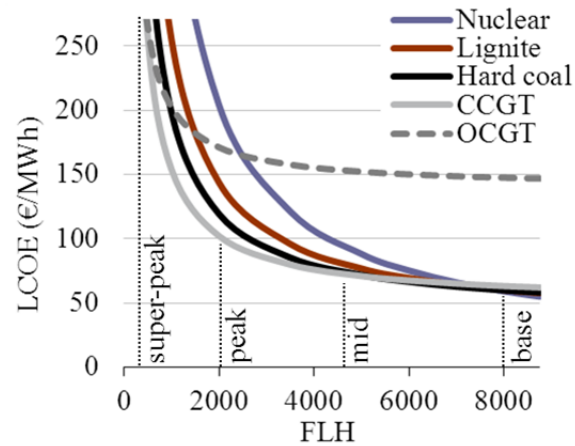


Figure 31: Average costs for different technologies at different full load hours. While base load plants (7000 FLH) supply electricity for around 65 €/MWh, super peakers (500 FLH) cost 250 €/MWh.

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 affected by many factors:

- VRE penetration rate. Profile costs increase with penetration, mainly because the utilization of residual capacity decreases (Hirth 2013).
- The distribution of VRE generation profiles. A flatter 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 (Borenstein 2008, Gowrisankaran et al. 2011, Nicolosi 2012, Mills & Wiser 2012).
- The geographic size of the market. A larger market leads to a flatter (more constant) aggregated VRE generation profile because of geographical smoothening (Giebel 2000).

- The correlation of VRE generation with demand. Positive correlation leads to negative profile costs at low penetration. An obvious example is solar's diurnal correlation with demand.
- The shape of the merit-order curve: the steeper the curve, the larger the utilization effect. In the long term, the shape of the merit-order curve is determined by how differentiated available technologies are in terms of fixed-to-variable cost ratio.
- The intertemporal flexibility of the power system, both on the supply (e.g., storage) and the demand side (e.g., demand response). Especially, reservoir hydro power has a large impact. This technology allows shifting generation over time, hence "flattens" out residual load (Rahman & Bouzguenda 1994, Mills & Wiser 2012, Nicolosi 2012, Hirth 2013).

Wind integration studies often account for the costs of grid extensions, balancing services, and cycling of thermal plants. Our findings indicate that it is at least equally important to also account for the reduced utilization of thermal generators and their capital costs – something usually not done in the literature.

4.4.4. The utilization effect in the integration cost literature

Integration studies typically do not account for costs due to the utilization effect. That is because these costs conceptually differ from grid and balancing costs: grid and balancing costs are additional system costs in the strict sense of increased expenses, e.g. for higher fuel consumption, maintenance, or grid infrastructure. Integration studies focus on calculating this kind of *additional* costs imposed by VRE and try to identify the costs that are caused by variability. In contrast, the utilization effect does not directly increase expenses but induces costs that appear as a reduction of the "energy" value of VRE. The utilization effect increases with VRE penetration, because thermal capacity idles more and more, increasing the specific cost of residual generation - but of course costs do not increase relative to the case of no VRE. Hence, the utilization effect does not create additional costs, but reduces the cost savings that new VRE capacity creates.

From an economic perspective these two categories of "incremental expenses" and "diminishing value" are equivalent (Ueckerdt et al. 2013b). Economically, both are opportunity costs. It makes no difference for evaluating VRE if more balancing costs are imposed or if less peak capacity can be replaced by VRE when increasing their share.

However, many integration studies cover a specific aspect of reduced utilization: the low capacity credit of VRE (Ensslin et al. 2008, Amelin 2009, recall also Figure 28 and Table 2). Integration cost studies regularly estimate *adequacy costs*⁴³, motivated by the need for

⁴³ Sometimes it is also called "capacity costs".

firm capacity to ensure generation adequacy. Hereby the studies expand their focus away from only calculating “incremental expenses”: VRE do not actually require additional capacity when introduced to an existing system. However, adequacy costs refer to capital intensive dispatchable capacity that could be removed in the long term if VRE had a higher capacity credit. Similarly, profile costs refer to dispatchable capacity that could be utilized better if VRE would follow load.

While adequacy costs only cover firm capacity costs due to a low capacity credit of VRE, the utilization effect additionally accounts for the reduction of full load hours of capital-intensive conventional plants and overproduction when VRE supply exceeds demand. These three cost impacts are all determined by the same driver: the temporal coincidence of VRE generation and load. Hence, profile costs and the utilization effect can be understood as a more general conception of standard adequacy costs.

To conclude on section 4.4, thermal power systems with distributed loads and meshed transmission networks, such as many continental European markets, probably feature high profile, but only moderate balancing and grid-related costs. Hydro power systems with constrained grids such as the Nordic region probably feature low profile and balancing costs but significant grid-related costs. Profile, balancing, and grid-related costs can be quite different for different VRE technologies.

4.5. Quantifications from the literature

One merit of the decomposition of the framework proposed in sections 4.3 and 4.4 is that cost components can be estimated separately, and that they can be estimated from models or market prices. We reviewed more than 100 studies on solar and wind integration, of which about half could be used to extract quantifications of balancing, grid-related, and profile costs. The estimates vary significantly in methodology, rigor, and specifications of the power systems. Model-based estimates are reliable only to the extent that models can be regarded as realistic and estimates from market data to the extent that markets can be treated as being complete and free of market failures. Also, studies often use slightly different definitions.

4.5.1. Balancing costs

There are three groups of studies that provide balancing cost estimations: wind integration studies, academic publications based on stochastic unit commitment models, and empirical studies based on market prices. We discuss these publications in turn and summarize findings in Figure 32.

A number of meta-studies have reviewed wind integration studies. Gross (2006) reports costs to be below 3 £/MWh in most cases. Surveying six American studies, Smith et al. (2007) report balancing costs between 0.7-4.4 \$/MWh. DeMeo et al. (2007) find costs between 3-4.5 \$/MWh for penetration rates around 30%, but find one outlier of 9

\$/MWh. The most recent survey is provided by Holttinen et al. (2011), who estimate balancing costs at 20% penetration rate to be between 2–4 €/MWh in thermal power systems and less than 1 €/MWh in hydro systems. In several of the reviewed studies, balancing costs arise mainly because wind power raises reserve requirements. The findings are consistent with an early study by Grubb (1991a), who estimates balancing costs to be around 3.6% of the value of electricity, based on the statistical properties of wind forecast and reserve costs.

A second set of studies derives 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 and more expensive plants have to be scheduled than under perfect foresight. Mills & Wiser (2012) estimates wind balancing costs to be between 2–4 \$/MWh at penetration rates up to 30%, and solar PV balancing to be somewhat more expensive. 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 of balancing costs, we calculate average, not marginal, balancing costs by dividing the cost increase by wind generation. Tuohy et al. (2009) find average wind balancing costs of about 3 €/MWh at 34% penetration in Ireland and Ummels et al. (2007) find costs for The Netherlands to be “small”. Gowrisankaran et al. (2011) report costs for Arizona solar to be 8 \$/MWh.

The third group of studies does not use models, but evaluates wind forecast errors at observed imbalance prices. Such market-based evaluations are of course limited to historical conditions, such as quite low penetration rates. Holttinen (2005) reports balancing costs in Denmark to be 3 €/MWh. If intraday markets would have 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 very high interconnector capacity. Pinson et al. (2007) 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. Obersteiner et al. (2010) use Austrian, Danish, and Polish data. They find balancing costs often reduced by biased forecasts, because day-ahead and short-term markets are not arbitrage-free. The authors find balancing costs of close to zero in Denmark, 6 €/MWh in Austria, and 13 €/MWh in Poland. Holttinen & Koreneff (2012) 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, implying that intraday trading would have been inefficient. Katzenstein & Apt (2012) estimate balancing costs in ERCOT to be 2–5 €/MWh for a small group of turbines.

Assessing German imbalance prices for this study, we find balancing costs for wind between 1.7–2.5 €/MWh during the last three years, using TSO forecasts.

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 (Hirth & Ziegenhagen 2013). Moreover, day-ahead forecasts are sometimes biased, either because of imperfect forecast methodology, or because it pays off for wind generators to sell less than the expected output on day-ahead markets if upward and downward variations are priced asymmetrically (Pinson et al. 2007, Vandezande et al. 2010).

The literature is quite heterogeneous both in terms of methodologies and results. However, as Figure 32 shows, virtually all estimates are below 6 €/MWh even at very high penetration rates in thermal power systems, and several estimates are well below that number. The estimates above 6 €/MWh are market-based estimates of systems where imbalance prices contain punitive mark-ups and probably do not reflect the marginal costs of balancing. All estimates for hydro systems are below 2 €/MWh. A list of studies and estimates can be found in the appendix.

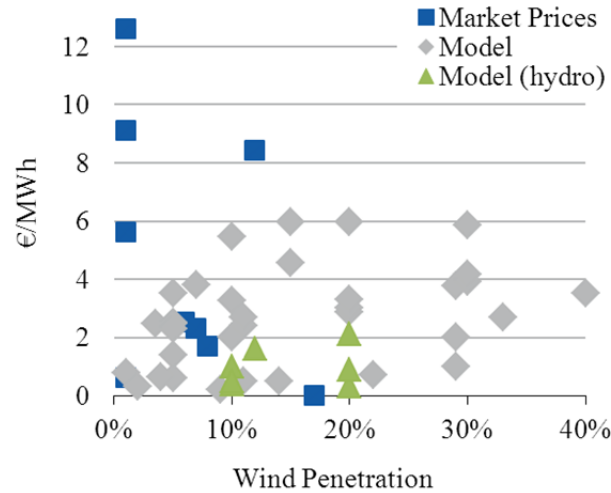


Figure 32: Balancing cost estimates for wind power from market prices (squares) and model prices (diamonds). Three market-based studies report very high balancing costs, all other estimates are below 6 €/MWh. Surprisingly, while individually studies often find balancing costs to increase with penetration, this is not the case for the whole population of studies. Studies of hydro-dominated systems show very low balancing costs (triangles). A list of studies can be found in the appendix.

VRE do not only increase the demand for balancing, but can also supply balancing services (Kirby et al. 2010, Bömer 2011, Speckmann et al. 2012, and Hirth & Ziegenhagen 2013). While this is a possible additional income stream for VRE, it will not be considered here due to lack of robust quantifications.

4.5.2. 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 or other factors drive the need for grid investments.

DENA (2010) estimates the transmission-grid related costs to integrate 39% renewables in Germany by 2020 to be about € 1bn annually. If that is attributed to the increase in renewable generation, it translates to about 10 €/MWh. NREL (2012) estimates grid investment costs to support 80% renewables (of which half are VRE) to be about 6 \$/MWh. Holttinen et al. (2011) 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 translates to 2-7 €/MWh.⁴⁴ However, all these estimates are average costs and do not represent the impact on the marginal value of wind and solar electricity.

Hamidi et al. (2011) 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. Schumacher et al. (2013), model locational marginal prices in Germany to evaluate wind power. They find 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 marginal value is close to zero - both for solar and wind.

Some studies use empirical locational electricity prices to estimate grid-related costs. Brown and Rowlands (2009) estimate the market value of solar power in Ontario to be 20-35 \$/MWh higher in large cities than the system price. Lewis (2010) finds similarly large differences for different locations in Michigan. However, the data provided by these two studies does not allow calculating the impact of spatial price variations on the marginal value of electricity from VRE. Evaluation locational prices in Texas, Schumacher et al. (2013) find, surprisingly, the value of wind power to be slightly increased by its location. Hence, grid-related costs are negative. The reason is that electricity price in Western Texas are above state average.

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 price area where many future wind projects are planned, and the Stockholm region, where most load is located, has been 0.8 €/MWh. In addition, there are

⁴⁴ At a 7% discount rate and 2000 wind full load hours.

geographically differentiated grid fees for generators.⁴⁵ If those are summed up, grid-related costs are in the order of 5 €/MWh.

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

4.5.3. Profile costs

We discuss the flexibility effect and the utilization effect separately. Costs estimates of the *flexibility effect* are rather scarce. Most of those few find the cost of hour-to-hour variability to be very small. Based on an analytical approach, Grubb (1991a) estimates variability cost to be 0.2-0.3% of the value of wind electricity. Smith et al. (2007) find slightly higher values of 0.4 \$/MWh to 1.7 \$/MWh and Hirst & Hild (2004) report 0.2 \$/MWh to 2 \$/MWh.

A number of studies come to the conclusion that the flexibility effect is very small without providing cost numbers. Nicolosi (2012) finds the utilization effect to be much larger than the flexibility effect. Consentec (2011) concludes that ramping constraints are not binding even at high penetration rates in Germany. Similarly, Lannoye et al. (2012) 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 marginal value of VRE generators. This finding is consistent with the simple calculations in section 4.4.3.

Many studies implicitly report estimates of the *utilization effect*. Hirth (2013) provides an extensive quantification, based on a literature survey, market price-based regression analysis, and numerical modeling, hence we keep the discussion here short. Based on that study, Figure 33 summarizes profile cost estimates from some 30 publications. 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. As expected, dispatch models without endogenous investment find mostly higher costs at high penetration, since they do not model the adaptation of the residual system (short-term models). Long-term models that account for changes in the capacity mix show lower costs. A list of references can be found in the appendix.

⁴⁵ Spot prices from nordpoolspot.com, retrieved 2012/10/2. Grid fees from personal communication with Svenska Kraftnät.

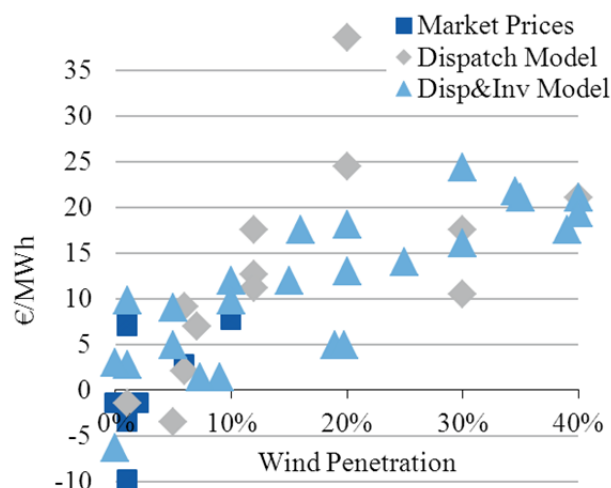


Figure 33: Wind profile cost estimates from about 30 published studies (updated from Hirth 2013). Studies are differentiated by the way they determine electricity prices: from markets (squares), from short-term dispatch modeling (diamonds), or from long-term dispatch and investment modeling (triangles). To improve comparability the system base price has been normalized to 70 €/MWh in all studies. A list of studies can be found in the appendix.

Summing up all three integration cost components result in costs of roughly 25-35 €/MWh at about 30-40% penetration rate in thermal power systems at an average electricity price of 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 the integration costs, about two thirds are profile costs.

4.6. 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. This is a question of policy and market design and will be discussed (briefly) in this section.

As we have defined integration costs as the difference between a generator's marginal value and the average value of electricity, "paying for integration costs" does not necessarily imply a transfer of money, but can well happen by receiving reduced income from electricity sales. If all generators receive the marginal value of their generation as income, there are no externalities and the social and private value of electricity coincide. Under this condition one might say that "integration costs are borne by those who cause them". Hence, the question of integration cost allocation boils down to the question if electricity prices reflect marginal costs and values.

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 and imbalance prices, and grid-related costs would appear as differentiated locational spot prices.

In the real word, all this is typically not the case:

- 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 (Fischedick et al. 2011, Borenstein 2012).
- There is disagreement of energy-only markets can appropriately price capacity via scarcity prices (Boiteux 1960, Crew et al. 1995, Cramton & Ockenfels 2011).
- Market power distorts electricity prices and reduce average VRE income (Twomey & Neuhoﬀ 2010, Mountain 2013).
- Given the long investment cycles, power markets can be out of equilibrium for extended time periods after shocks (Sensfuß 2007, Ueckerdt et al. 2013b, Hirth & Ueckerdt 2013).
- Balancing prices in most markets 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 (Vandezande et al. 2010, ENTSO-E 2012, Hirth & Ziegenhagen 2013).
- Many power systems lack locational price signals. Spot prices are often settled in larger geographical bidding areas, grid fees are not locational differentiated, and grid-related 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 a potential bias from externalities. Second, for a first-best 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.

4.7. Summary and conclusion

This paper proposes a valuation framework for variable renewables and offers a new perspective on “integration costs”. Integration costs are those costs that occur not at the level of the wind turbine or solar panel, but elsewhere in the power system. We suggest to define them as the gap between the average marginal value of electricity and the marginal value of electricity from wind (or solar). This definition is rigorous, comprehensive, and has a welfare-economic interpretation in the sense that the sum of generation and integration cost (System LCOE) of each generation technology is identical in the long-term optimum. Moreover, we propose a decomposition of integration costs along three characteristic properties of VRE: uncertainty, locational inflexibility, and temporal variability. We believe this decomposition to be comprehensive, robust, consistent, and operationable. We then review 100+ published studies to extract quantitative estimates of these cost components.

These studies vary considerable in definitions, methodology, regional focus, and quality, so results need to be interpreted careful. 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. Hence, electricity from wind power is worth only 35-45 €/MWh under those conditions. Integration costs increase direct generation costs by 35-50%.
- This implies ignoring integration costs in welfare or cost studies strongly biases results (see also Hirth 2013b).
- Size and composition of integration costs depends on the power system and VRE penetration: integration costs can be negative at low (<10%) penetration, generally increase with penetration and are smaller in hydro than in thermal systems.
- In thermal systems with high VRE shares, the utilization effect causes 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 integration cost studies do not mention this effect.
- Balancing costs and the flexibility effect, which receive much attention in the debate, are at best moderate in size. What is needed for VRE-rich power systems

is maybe technical flexible plants (ramping and cycling capabilities), certainly and more urgently economical flexible plants (low capital costs).

- System adaptations can significantly reduce all types of integration costs. It is important for analysts to be explicit about the time horizon and boundary conditions of studies.

This framework proposal and quantification are by no means final. We hope to have contributed to the consolidation of the field, but there is much need for further research. By defining integration costs based on the marginal value, we make a first step in linking the standard integration literature and the marginal cost literature. Further exploring this link is promising research to develop a common understanding of the respective concepts, assumptions, and ends. Empirical research is required to investigate the interaction of the proposed integration cost components. More studies with common definitions and rigorous methods are needed to increasing robustness of quantitative estimates. Specifically, models that allow for changes of the capacity and other system adaption need to be developed and deployed to estimate high-penetration integration costs.

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Appendix

Table 3: Balancing cost literature

Prices	Reference	Technology	Region	Balancing cost estimates (at different market shares)
Market prices	Holttinen (2005)	wind	Denmark	2.8 €/MWh or 12% of the base price (12%)
	Pinson et al. (2007)	wind	Netherlands	3.7 €/MWh or 13% of the base price (small)
	Obersteiner et al. (2010)	wind	Austria	8% of the Base price (small)
			Denmark	close to zero (17%)
			Poland	18% of the Base price (small)
	Holttinen & Koreneff (2012)	wind	Finland	0.6 €/MWh
	<i>this study</i>	wind	Germany	1.7 – 2.5 €/MWh
Model results	Grubb (1991)	wind	UK	3.6% of value of electricity (5%)
	Gross et al. (2006), survey	wind	several UK studies	0.5 – 3 £/MWh (5-40%)
			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%)
	DeMeo et al. (2007), survey	wind	several US systems	3-4.5 \$/MWh for penetration rates around 30%, but find one outlier of 9 \$/MWh
	Mills & Wiser (2012)	Wind	California	3-5% of the base price
	Gowrisankaran et al. (2011)	solar	Arizona	8 \$/MWh (30%)

Model results for hydro systems)	Holttinen et al. (2011) , survey	wind		2-3 €/MWh (10-20%)
			Finland	1.4 – 3.3 €/MWh (5-20%)
			UK 2007	0.2-0.5 €/MWh (9-14%)
			Ireland	2.3 – 3.8 €/MWh (5-7%)
			Colorado	2.3 – 3.4 (15-25%)
			Minn. 2006	0.3 €/MWh (2%)
			California	3.5 €/MWh (5%)
			PacificCorp	2.4-2.7 €/MWh (11%)
			Germany	1-2 €/MWh (29%)
			Denmark	0.5 – 0.7 (11-22%)
			Finland	
Model results for hydro systems)	Garribble & Leahy (2013)	wind	Ireland	2.7 €/MWh
Model results for hydro systems)	Holttinen et al. (2011)	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%)
Model results for hydro systems)	Carlsson (2011)	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.

Table 4: Profile cost literature

Prices	Reference	Technology	Region	Value factors estimates (at different market shares)
Historical Prices	Borenstein (2008)	Solar	California	1.0 – 1.2 at different market design (small)
	Sensfuß (2007), Sensfuß & Ragwitz (2011)	Wind	Germany	1.02 and 0.96 (2% and 6%)
		Solar		1.33 and 1.14 (0% and 2%)
	Frapp & Wiser (2008)	Wind	WECC	0.9 – 1.05 at different sites

Prices from Dispatch Model				(small)
	Brown & Rowlands (2008)	Solar	Ontario	1.2 based on system price (small)
	Lewis (2010)	Wind	Michigan	0.89 – 1.14 at different nodes (small)
	Green & Vasilakos (2012)	Wind	Denmark	<i>only monthly value factors reported</i>
	Grubb (1991a)	Wind	England	0.75-0.85 (30%) and 0.4-0.7 (40%)
	Rahman & Bouzguenda (1994)	Solar	Utility	<i>only absolute value reported</i>
	Rahman (1990), Bouzguenda & Rahman (1993)			
	Hirst & Hild (2004)	Wind	Utility	0.9 – 0.3 (0% and 60% capacity/peak load)
	ISSET et al. (2008), Braun et al. (2008)	Solar	Germany	<i>only absolute value reported</i>
	Obersteiner & Saguan (2010)	Wind	Europe	1.02 and 0.97 (0% and 6%)
	Obersteiner et al. (2009)			
	Boccard (2010)	Wind	Germany	.87 – .90 (6-7%)
			Spain	.82 – .90 (7-12%)
			Denmark	.65 – .75 (12-20%)
	Green & 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 & Wang (2011)	Wind	PJM	1.05 (5%)
Dispatch & Investment Model	Martin & Diesendorf (1983)	Wind	England	<i>only absolute value reported</i>
	Swider & 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	<i>no prices reported</i>
	Gowrisankaran et al. (2011)	Solar	Arizona	0.9 and 0.7 (10% and 30%)
	Mills & 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%)
Hirth (2013a)	Wind	Europe	1.1 (0%) and 0.5-0.8 (30%)

These publications usually do not use terms “profile cost” or “utilization effect”. Output was re-calculated to derive yearly value factors. Value factors were then re-calculated to profile costs assuming a load-weighted electricity price of 70 €/MWh. Source: Hirth (2013)

5. Integration Costs and Marginal Value: Connecting two perspectives on the economics of variable renewables

This chapter is submitted for publication to *Renewable Energy* as: Ueckerdt, F., Müller, S., Hirth, L., Nicolosi, M.: “Integration Costs and Marginal Value: Connecting two perspectives on the economics of variable renewables”.

Abstract – There are two analytical approaches to evaluating the economic effects on power systems at growing shares of variable renewables: The first approach seeks to accurately calculate the “integration costs” of VRE while the second analyses VRE by estimating their “marginal economic value”. However, the two literature branches using each approach appear quite separated, using different concepts and terminology. This paper aims to elucidate two conceptual links between both branches. First, how do “integration costs” relate to the “marginal value” of VRE? Second, what are the analytical consequences of each considering different time horizons and making different assumptions regarding the power system’s ability to adapt to VRE deployment? We discuss that integration costs are defined as the additional costs imposed on the system when adding VRE due to characteristic VRE properties such as their variability, while the marginal value of VRE equals opportunity costs, which are net avoided costs. The marginal value decreases at higher VRE penetration due to two effects: to increasing integration costs and to diminishing avoided costs. This link allows a welfare-economic interpretation of integration cost estimates and resolves some of the problems associated with calculating integration costs and disaggregating these into components. Concerning the second question we suggest a categorisation into three different levels of system adaptation and relate those to different time horizons. System adaptation can significantly help the deployment of VRE. Hence, economic assessments of VRE that consider only short-term costs should be treated with care. Incorporating the temporal evolution and potential adaptations of the power system into evaluating VRE is crucial to determining efficient transformation pathways towards an energy system with possibly high shares of variable renewables.

5.1. Introduction

There are two analytical approaches to evaluating the economic system impact of variable renewables, the “integration cost approach” and the “marginal value approach”. However, the literature branches using each approach appear quite separated, providing little cross-references, using different concepts and incompatible terminology. While we acknowledge that the two approaches have a different focus, we believe there is significant room for synergies and learning from each other. This paper aims to elucidate some of the conceptual links between the two approaches. We put both approaches into context, by working out differences and relating findings from one branch to the other. Hereby we hope to reveal stimulating links that may inspire future research.

The first approach seeks to accurately calculate “integration costs” of variable renewable energy sources (VRE), such as wind and solar power. Integration costs have been defined as “an increase in power system operating costs” [1], as “the extra investment and operational cost of the nonwind part of the power system when wind power is integrated” [2], as “the additional cost of accommodating wind and solar” [3], or as “comprising variability costs and uncertainty costs” [4]. 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 modelling techniques [1], [2], [5]–[8]. Ref. [9] provides a blueprint for such integration studies. In particular studies commissioned by electric utilities in Northern America usually include calculations of integration costs (see [10] for an overview, a number of US studies can be accessed online⁴⁶). Most integration studies are published in journals with an engineering focus or as non-peer-reviewed reports. Acknowledging the significant diversity within this group, we find this group of studies similar enough to group it under the term “integration cost literature”.

Calculating integration costs is done by setting up different scenarios, one including variable resources and one without them or at a lower share. Differences in production costs are noted and allocated to variable generation using different techniques. However, problems frequently arise with isolating integration costs from other differences between the two scenarios. More specifically, these differences are often dominated by fuel costs savings, which need to be accounted for correctly to identify integration costs [3]. Most integration studies focus on the operational timescale and do not account for long-term investment effects.

The second approach analyses VRE by estimating their marginal economic value [11]–[16]. These studies identify and estimate the marginal economic value of electricity from wind and solar power. 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. We label this group of studies “marginal value literature”. While the integration cost literature is to some extent rooted in engineering and closely connected with real-world system operation, the marginal value literature is mainly written by economists.

Studies of marginal value regularly assume price-inelastic demand, and calculate the marginal value of VRE as the reduction of (long-term) costs of the power system due to VRE’s introduction. The models applied in the marginal value literature are typically closer to models used in economics and consider longer time horizons. Models tend to have a poorer representation of technical system constraints than dedicated integration

⁴⁶ via <http://www.uwig.org/opimpactsdocs.html>

cost analyses. Marginal value studies typically find a decreasing value of VRE at increasing penetration (Fig. 1). A key merit is that this perspective provides a link to economic welfare-theory: the welfare-optimal share of generation technologies can be derived by comparing their marginal economic value (per MWh) to their levelized cost of electricity (LCOE). Moreover, in the case of perfect and complete markets the (social) marginal value coincides with the (private) market value, the specific revenue that plant owners receive from power markets. To the extent this assumption holds, the marginal value of VRE can also be derived from empirical market prices [16]–[19]. However, given issues of market power and price distortions, such results need to be interpreted with great care.

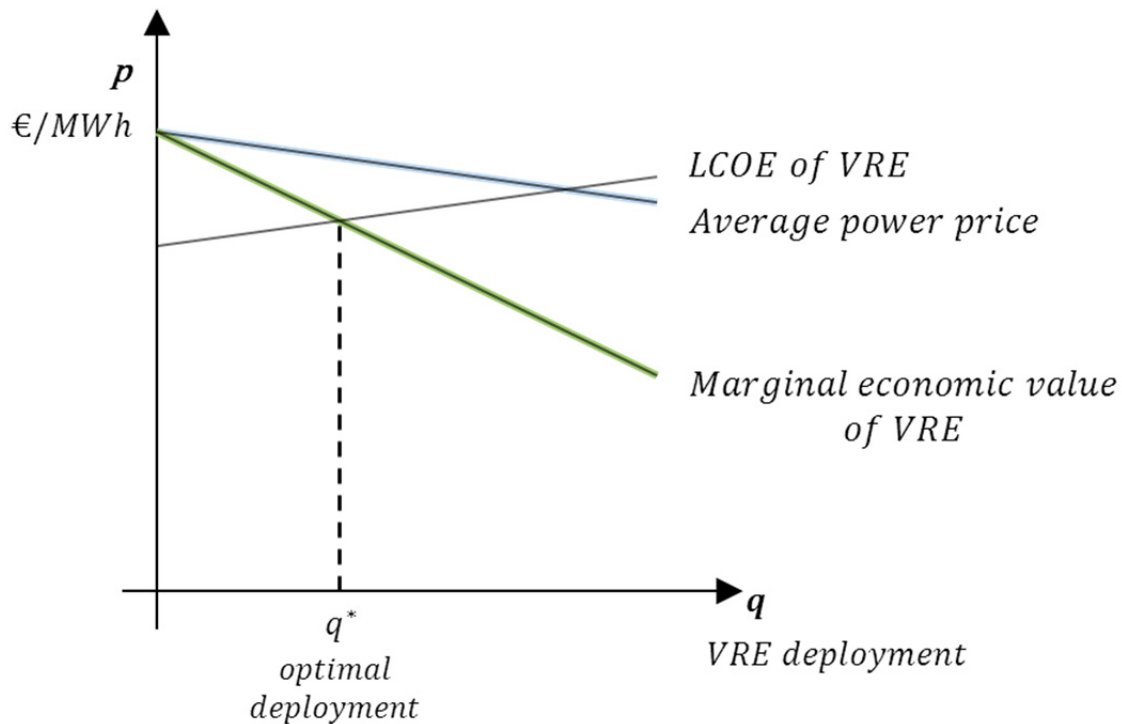


Figure 34: The marginal economic value of VRE typically decreases compared to the average power price with increasing VRE deployment. The welfare-optimal deployment q^* of VRE or any generation technology can be derived by comparing their marginal economic value (per MWh) to their levelized costs of electricity (LCOE).

We relate both approaches to each other with respect to the two issues that have caused misunderstanding and confusion in the past. We begin by asking the fundamental question: How do “integration costs” relate to the “marginal value” of VRE? In a next step, we focus on a second key difference. We investigate the importance of the different time horizons typically underlying both approaches and consequently assumptions regarding the power system’s ability to adapt to VRE deployment.

5.2. Integration costs and marginal value

“Integration cost literature” and “marginal value literature” both investigate the economic impact of wind and solar power variability on power systems and markets. The first branch seeks to accurately calculate “integration costs” of VRE while the second branch analyses VRE by estimating their “marginal economic value”. Hence, both ask the same overarching research question, but using different concepts. How do these concepts differ from and relate to each other?

A first key difference is that the integration cost literature aims to identify additional costs imposed on other actors by some of VRE’s properties (e.g. variability and uncertainty). Additional costs are understood strictly as an increase of expenses, e.g. for higher fuel consumption, CO₂ emissions, maintenance, or investment in more flexible plants or grid infrastructure. These costs are often categorized into “balancing costs”, “grid costs”, and “adequacy costs”. These components are sometimes added up to total integration costs, which typically increase with higher penetrations. However, there is no general agreement on a rigorous definition that also includes a procedure to calculate each of the different components. More specifically, the notion of additionality requires comparing VRE with a reference technology. The definition of an appropriate reference technology is remarkably challenging [3].

In contrast, the marginal value of VRE depends on the additional costs imposed on other actors, but not only: it also depends on the avoided costs that VRE deployment entails, such as saved fuel, CO₂, or avoided capital costs. The marginal value of VRE equals opportunity costs, which is avoided costs minus additional costs. While the additional costs of incremental VRE generation typically increase, marginally avoided costs diminish with growing penetration. Accordingly, the decrease of the marginal economic value with increasing VRE shares can be attributed to two effects: to increasing additional costs and to diminishing avoided costs (Fig. 2). This helps to link the two concepts “integration costs” and “decreasing marginal value”. From a pure economic perspective it makes no difference whether additional costs increase or avoided costs decrease, e.g. for deriving the welfare-optimal deployment of VRE. That is why typically the literature on marginal value does not explicitly distinguish between the two effects or relate their results to integration costs.

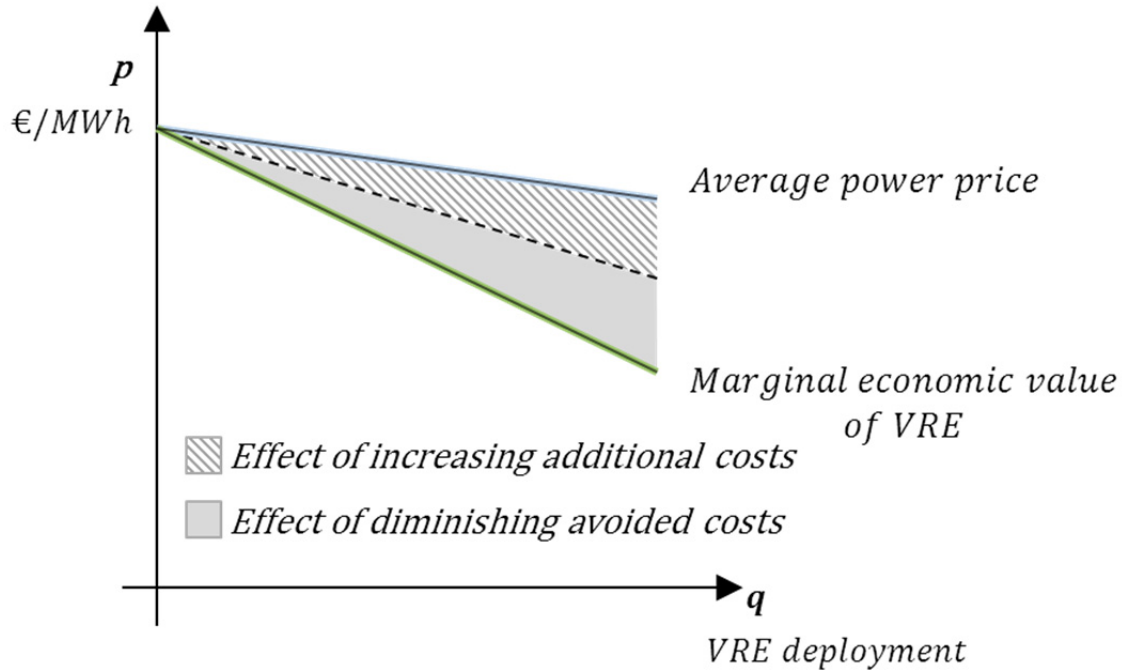


Figure 35: The decrease of the marginal economic value of VRE compared to the average power price can be attributed to two effects: increasing additional costs and diminishing avoided costs.

Through the link between integration cost and marginal value both worlds can stimulate each other. The remainder of this section discusses different possible synergies regarding: the economic interpretation of integration costs, marginal value estimates that are quantified by high-resolution production cost modelling techniques and thus consider integration cost components more comprehensively and accurately as well as implications for the definition of integration costs and its components.

The “marginal value literature” shows that integration cost estimates alone are not sufficient to derive welfare-optimal shares of VRE. They need to be complemented by diminishing avoided costs. Note that we do not want to imply that the integration cost literature actually intends to calculate welfare-optimal shares of VRE; however, a welfare-economic interpretation of integration costs adds relevance to their estimates and might inspire future research. For example integration cost estimates can support the welfare-economic evaluation of VRE as follows. While in principle marginal value estimates account for integration costs, the underlying economic models often neglect or only roughly treat some technical aspects that require high model detail e.g. effects related to uncertainty and short-term variability. Parameterising such cost components via integration cost studies or conducting a model coupling with highly resolved models can provide an improved basis for a welfare evaluation of VRE.

Moreover, the close relation of increasing additional costs (integration costs) and diminishing marginal value of VRE explains and partly resolves problems when trying to

calculate integration costs. While integration cost studies seek to only calculate additional costs, there are difficulties with separating those costs from avoided costs i.e. benefits of VRE like fuel savings when comparing a power system with and without VRE [1], [3], [7]. The reason for this difficulty becomes clearer considering the difference between avoided and additional costs. To separate integration costs from avoided costs some integration studies compare VRE to a proxy technology that does not show output variability but that leads to the same avoided costs. However, both, additional and avoided costs are affected by the variability of VRE and consequently their separation might not be possible in a stringent way. If that is true, a more fundamental reconsideration of the concept of integration cost might be needed to fully capture all relevant economic effects.

Some integration cost studies already consider one important driver behind diminishing avoided costs by coming up with a quasi-cost component: adequacy costs. Adequacy costs are meant to capture the costs of installing “back-up” capacities that supposedly complement VRE generation if peak load coincides with low VRE generation. However, adequacy costs are actually no additional costs since simply adding VRE capacity to a system does not require additional thermal capacity. In fact, it corresponds to the other effect shown above, i.e. VRE help avoiding costs to the extent that VRE capacity reduces the need for other generation capacity. This benefit is expressed via the capacity credit of VRE. However, the capacity credit of additional VRE capacity diminishes with increasing VRE deployment. While the first VRE plant might have a significant capacity credit, it decreases when increasing the VRE share because the output of additional VRE plants is positively correlated to existing VRE plants. Integration cost studies often reflect this in increasing requirements for back-up capacity and hereby invent an integration cost category that is somewhat artificial.

These problems of conceptual definition and operationalization call for a cautious use of the term “integration cost”. We suggest using one of the following two definitions: the term could either be used in a narrow sense to encompass only additional costs such as balancing and grid costs. This notion of integration costs would not include adequacy. However, these costs would still be difficult to isolate properly and lack a direct welfare-economic interpretation. Alternatively, integration costs can be defined as the reduction in net marginal value of VRE between two different penetration levels, which includes both increasing additional costs and diminishing avoided costs. In previous publications we have done the latter and defined integration costs in a wider sense [20], [21]. This wider definition of integration costs contains a new cost component apart from balancing and grid costs: Profile costs, which can be understood as generalized adequacy costs. Profile costs summarise all effects that arise from the temporal profile of VRE generation, disregarding its uncertainty or locational aspects. This captures the effects often described by adequacy costs as well as costs of short-term variability i.e. costs of additional ramping and cycling in the absence of VRE generation uncertainty. However,

in this context “cost” captures all effects that negatively impact the value of VRE generation, which is different from the standard “integration cost” concept. This definition of integration cost as reduction in marginal value allows interpreting integration costs as all economic costs of variability.

5.3. Time horizon and system adaption

In section II we compared the core concepts of the integration cost and the marginal value approach and related them to each other. Now we focus on a second key difference: both schools of thought typically differ with respect to the time horizons they apply in their analyses. Integration cost studies typically accurately analyze the impact of VRE on the currently existing system with a fixed capacity mix and primarily fixed transmission system, while the marginal value literature often studies the effect of VRE in the rather long term with less technical detail, where the capacity mix (and sometimes demand structure and the general transmission grid topology) are allowed to adjust to higher VRE shares. Of course there are exceptions from this tendency: some integration cost studies operate in the long-term, and some marginal value papers study the short term. However, some of the differences between results within each school of thought can be explained by the application of different time horizons.

In general, integration costs can be expected to decrease if the power system is allowed to adapt in response to increasing VRE penetration. Similarly, the marginal value can be expected to increase due to system adaptation.

Power systems can adapt in a multitude of ways to increasing VRE penetration. Operational routines and procedures can be changed; market design can adapt; existing assets can be modified to operate more flexibly or tailored to meet other changes in operating conditions; the capacity mix can undergo a structural shift; the transmission grid can adjust; and more profound technological innovations can take place (ordered roughly by increasing time that is needed). The main reason for changes to take time is the limited natural capital turnover rate, as a result of the comparably long technical lifetime of sunk investments in physical infrastructure.

How much integration costs (or the marginal value) differ between a not adapted and an adapted system depends on three factors: the degree to which existing assets complement VRE, the system’s long-term adaptation potential; and the system’s natural capital turnover rate relative to the speed of VRE deployment. For example, if VRE are introduced very slowly relative to the natural rate of turnover of the power system, the system might remain continuously perfectly adapted during the transformation process and integration costs stay at minimum levels. If on the other hand VRE are rapidly introduced to a power system with a low turnover rate that does not complement VRE well (e.g. large share of inflexible assets such as base load thermal plants), integration costs will be higher.

The different types of potential system adaptations can be regarded as different degrees of freedom along which a system can adapt. In energy system modelling, degrees of freedom correspond to control variables that can endogenously change when introducing VRE. The possible degrees of freedom increase when considering longer timescales. The longer the time horizon, the more fundamental become the changes i.e. the number and range of degrees of freedom increase.

In this paper we distinguish between three different levels of system adaptation (Table 1). We show that these levels are loosely connected to three time horizons, i.e. the listing starts with changes that might be available at earlier time scales. However, timescale should not be thought of as strictly calendric, but as the degree to which there is an opportunity to replace none, some or all assets of the system.

1) In the short term (hours to months), the load structure and elasticity as well as physical assets of the power systems cannot be changed. Only production decisions are endogenous. Consequently the operation of existing assets is adjusted to accommodate VRE generation.

2) In the medium term (months to few years), power plants can be decommissioned, to the extent that VRE carry capacity credit. Thus fixed O&M costs are additionally saved. Note that investment costs of existing assets are sunk so that no further cost savings are induced. Furthermore, these existing assets can be modified to operate more flexibly as well as demand can be shifted more flexibly within short time scales (<days). Furthermore, market design can be adopted.

3) In the long term (years to decades), VRE deployment might also induce rather structural changes because all existing assets can be replaced. Investment costs are no longer sunk. The capacity mix can shift, e.g. base load plants can be replaced by mid-merit and peaking plants. Moreover the transmission grid infrastructure can adjust. As a result investment costs can additionally be saved. Load patterns significantly change depending on the temporal and spatial profile of VRE supply. Moreover, technological innovations can take place in particular regarding flexibility options like seasonal storage, long-distance transmission as well as improved linkages between power and heat and transport sector.

Table 5: Three levels of system adaptation.

	Time horizon		
	1) Short term	2) Mid term	3) Long term
Potential adaptations	only operations can adjust (investments sunk)	assets can be decommissioned; Existing assets and demand can be modified to adjust more flexible	structural changes; e.g. a shift towards peak load plants; the network infrastructure adjusts; load pattern change; new technologies (e.g. flexibility options like storage) are developed
Cost savings (avoided costs)	→ VRE may induce fuel and carbon cost savings	→ in addition, fixed O&M costs can be saved	→ in addition, capital and further fuel costs can be saved; higher share of VRE can be utilized
Additional costs (integration costs in a narrow sense)	→ VRE may induce higher balancing and grid-related costs	→ balancing and grid-related costs can be reduced	→ additional costs for flexibility options; balancing and grid-related costs can be further reduced

In each of the three temporal perspectives the marginal value of VRE can be calculated for increasing deployment and its reduction can be interpreted as integration costs (in the wider sense). In a short-term perspective integration costs are higher than in a long-term perspective at equal VRE shares. This is because short-term integration costs are not only determined by the inherent properties of VRE. Given that assets cannot be changed short term, costs critically depend on the properties of the legacy energy system. The degree to which a short-term perspective is appropriate to assess VRE integration impacts depends on the speed of VRE deployment relative to the natural capital turnover rate of the system (typical investment time scales, building and live times of assets). Where VRE deployment outstrips capital turnover, costs are equally driven by the properties of the legacy system. For example if sunk investments in conventional technologies did not anticipate a rapid VRE deployment, a lower value of VRE will be reflected in reduced market prices and the corresponding decrease in the value of existing assets.

From an economic perspective, VRE generators – as any other generator – should be remunerated according to the value of their generation. This would ensure that integration costs are borne by the causal VRE generators. This would incentivize investments that increase the value of VRE for example in wind turbines that have a temporal profile that better matches demand and thus reduces operating costs of conventional plants.

Similar considerations seem to be the rationale for thinking of integration costs as a tariff that is assessed to recover the increased costs of conventional generators, balancing authorities or other entities [3], [22], [23]. Such tariffs would need to be based on a number of cost-causation principles, first and foremost: “Those individuals who cause costs to the system should pay for those costs” [3, p. 56], [22, p. 6]. This in turn requires an attribution of integration costs to causal generators. However, short-term integration costs cannot be fully attributed to VRE. As explained above, these costs are not only a result of VRE-inherent characteristics. Disentangling the drivers of short-term integration costs (VRE properties, legacy system properties) is difficult if possible at all.

Considering that, terming the short-term system costs when introducing VRE as integration costs may be somewhat misleading. We suggest the term *transformation costs*, defined as the difference between integration costs with and without system adaptations when comparing short-term and a long-term marginal value results. The grey area in Figure 36 shows such transformation costs. The residual part (shaded area) that remains after full adaptation might be termed integration costs (in a wider sense). Following this reasoning, in the short term, both transformation and integration costs occur, while in the long term integration costs would be specific to the properties of VRE would only induce integration costs.

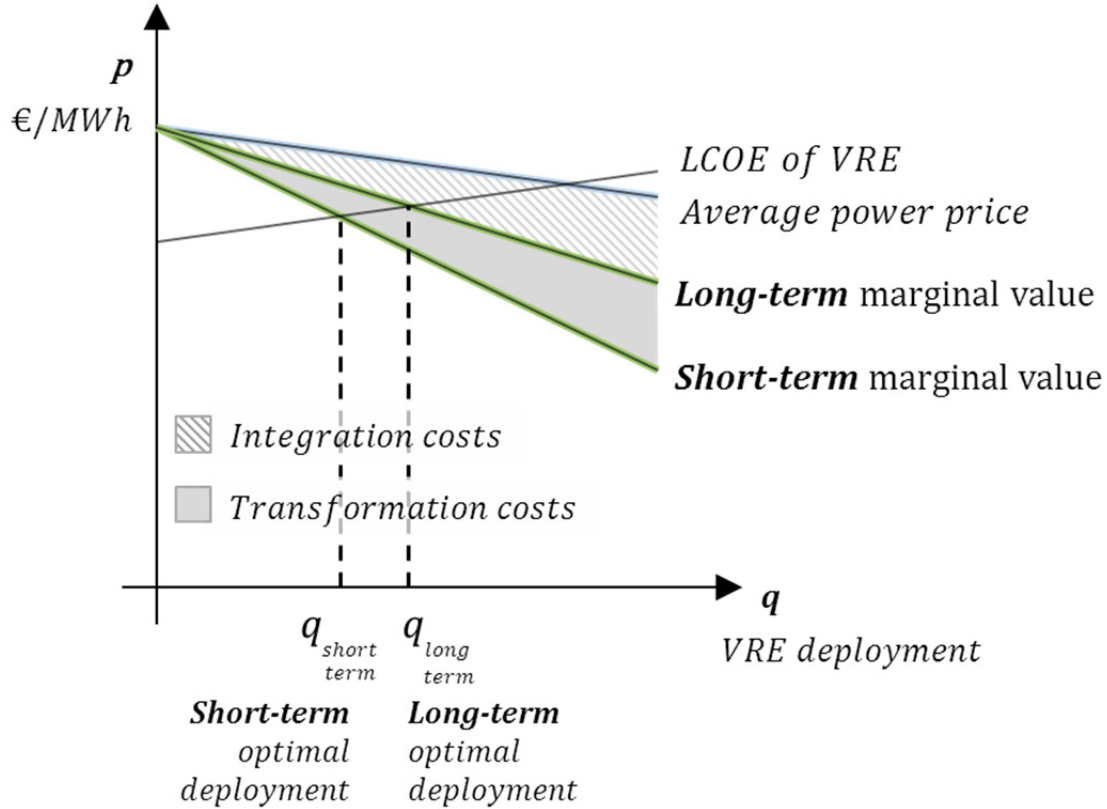


Figure 36: The decrease of the marginal value of VRE is higher in the short term compared to the long term. We term the difference transformation costs since they are induced by properties of the legacy system. Integration costs (in a wider sense) are the marginal value reduction in the long term. Different time perspectives lead to different optimal deployment levels. Considering the higher optimal deployment in the long term, short-term deployment may exceed its optimal short-term value.

This has implications for the optimal deployment pathways of VRE. Fig. 3 illustrates that the optimal deployment of VRE for each temporal perspective is defined by the intersection of LCOE with the corresponding marginal value curve. Each intersection represents a static equilibrium neglecting that the system evolves in time. Because transformation costs disappear in the long term, the long-term optimal quantity is higher than in a short-term perspective where potential system adaptations are neglected. The short-term optimal deployment is not dynamically efficient i.e. an optimal pathway might require higher VRE deployment than a short-term analysis would suggest to eventually reaching the optimal long-term deployment of VRE. In other words, if investment decisions are solely taken from a short-term perspective, the long-term adjustment and long-term optimal deployment might not materialize.

A critical variable in this regard is the speed of VRE deployment relative to the capital turnover rate of the system. Where deployment of VRE occurs quickly compared to capital turnover, the marginal value of VRE will remain closer to the short-term

perspective. Where VRE deployment is slow compared to the rate of capital turnover, the value of VRE will be closer to the long-term perspective. As such, power systems with a high capital turnover rate (dynamic power systems) thus have an opportunity to deploy VRE cost effectively at a faster rate than systems with a lower turnover rate (stable systems).

In stable systems VRE deployment is often fostered by introducing support policies and the conventional system will have little opportunity to adjust to rapidly increasing VRE shares. In cases where the legacy system does not complement VRE well, high transformation costs can result. This may hamper the adoption of optimal policy instruments and thus could create a potential barrier to reaching the long-term optimal deployment of VRE. In that sense an adverse combination of VRE properties, legacy system and low capital turnover could cause a ‘lock-in’ into power systems dominated by conventional plants. Note that distributional effects might even enhance such a lock-in situation. Ref. [24] shows that VRE support policies might induce redistribution flows from conventional producers to electricity consumers which can be large relative to net system cost increases.

To conclude, this section shows the importance of system adaptations and the time horizon when calculating integration costs and evaluating VRE. System adaptations can significantly ease the integration of VRE and consequently short-term should be treated with care. Any analysis should be explicit about the temporal perspective applied and aware about its effect on the results. Importantly, an optimal deployment pathway of VRE might be higher than a purely short-term analysis would suggest. Hence, incorporating the temporal evolution and potential adaptations of the power system into evaluating VRE is crucial to determining efficient transformation pathways. Moreover, shedding more light on potential short-term barriers to VRE deployment and policy instruments that resolve them is another promising research direction.

5.4. Conclusion

There are two analytical approaches to evaluating the economic system impact of variable renewables, the “integration cost approach” and the “marginal value approach”. The first approach seeks to accurately calculate “integration costs” of VRE while the second analyses VRE by estimating their marginal economic value. However, the literature branches using each approach appear quite separated, using different concepts and terminology. The objective of this paper was to elucidate some of the conceptual links between the two approaches. For this purpose we worked out differences and related their concepts to each other. We hope that linking both approaches stimulates future research.

First, we asked the fundamental question: How do “integration costs” relate to the “marginal value” of VRE? The integration cost approach seeks to calculate additional

costs imposed on the system when adding VRE, while the marginal value of VRE equals opportunity costs, which are avoided costs minus additional costs. The marginal value decreases at higher VRE penetration due to two effects: increasing integration costs and diminishing marginally avoided costs. We hope that this link helps both research strands to refine their approaches and results. Integration cost estimates can now be interpreted such that they can support a welfare-economic evaluation of VRE. We show that the link also explains and resolves some of the problems when trying to calculate integration costs and decomposing them into their components. We infer that the term “integration cost” needs to be cautiously defined and used. The term could be either applied *in a narrow sense* containing only additional costs such as balancing and grid costs, but not include adequacy. However, these costs would still be difficult to isolate properly and lack a direct welfare-economic interpretation. Alternatively, integration costs *in a wider sense* can be defined as the reduction in marginal value of VRE, which comprises both increasing additional costs and diminishing marginally avoided costs (including adequacy costs).

In a second step, we discussed the importance of different time horizons typically underlying both approaches as well as assumptions regarding the power system’s ability to adapt to VRE deployment. We suggest a categorisation into three different levels of system adaptation and relate these levels to different time horizons: short, mid and long term. System adaptations can significantly reduce integration costs and the marginal value can be expected to increase. This increases the long-term optimal share of VRE. Short-term costs can exceed long-term costs due to legacy system properties and should be carefully interpreted. In particular they should not entirely be attributed to VRE. Moreover, a purely short-term perspective is likely to underestimate the optimal VRE deployment. Incorporating the temporal evolution and potential adaptations of the power system into evaluating VRE is an important research direction; in particular including the effects of the capital turnover rate of the power system as a whole (stable vs dynamic systems). This would allow determining efficient transformation pathways towards an energy system with possibly high shares of VRE while accurately accounting for their variability and all available flexibility options.

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6. Representing power sector variability and the integration of variable renewables in long-term climate change mitigation scenarios: A novel modeling approach

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Abstract – We introduce a new method for incorporating characteristics of short-term temporal variability of power demand and variable renewable energy sources (VRE) when modeling long-term climate change mitigation scenarios: the RLDC approach. The core of the implementation is a representation of residual load duration curves (RLDC), which change endogenously depending on the share and mix of VRE. The approach captures both major integration challenges of VRE and the energy system’s response to growing VRE shares without a considerable increase of the numerical complexity of the model. In addition, the approach allows for an endogenous representation of power-to-gas storage and the simultaneous optimization of long-term investment and short-term dispatch decisions of non-VRE plants. As an example, we apply the RLDC approach to REMIND-D, a long-term energy-economy model of Germany, which is based on the global model REMIND-R. Including variability results in significantly more non-VRE firm capacity and reduces the generation of VRE in 2050 by about one-third in both baseline and ambitious mitigation scenarios. Explicit modeling of variability increases mitigation costs by about one fifth, but power-to-gas storage can alleviate this increase by one third. We conclude that implementing the RLDC approach in a long-term multi-sector model would allow improving the robustness and credibility of scenarios results, such as mitigation costs estimates and the role of wind power and solar PV.

6.1. Introduction

There is broad evidence that anthropogenic climate change is threatening the welfare and development of human societies [1]–[3]. Combustion of fossil fuels is the main driver of anthropogenic climate change, causing over 60% of global greenhouse gas emissions [4], [5], which is why climate change mitigation requires a transformation of the global energy systems towards low-carbon technologies. Identifying mitigation scenarios that minimize the macroeconomic costs (so-called mitigation costs) of achieving a prescribed climate target requires long-term numerical energy-economy models that capture the key interactions between the energy, the economic and the climate system, as well as interactions within the energy system (heat, transport and power sector).

Most mitigation scenarios show that the power sector decarbonizes earlier and more extensively than the non-electric energy part of the energy system [6]–[9]. Electricity can be supplied by a number of comparably low-cost mitigation options such as renewable

energy sources, carbon capture and storage and nuclear power, while supplying non-electric energy demand with low greenhouse gas emissions relies strongly on biomass. Electrification is an important mitigation strategy for the transport and residential heating. The power sector appears to be a centerpiece for climate change mitigation. The Special Report on Renewable Energy Sources and Climate Change Mitigation [10] and the recent EMF27 model comparison [11] confirm that wind power and solar PV are important mitigation options. In many mitigation scenarios these two technologies contribute substantial generation shares in the second half of the century, thereby helping to decarbonize the power sector.

However, long-term energy-economy models have a deficit that leads to inaccurate or even biased scenario results: Typically, they only have a crude representation of power sector variability, which needs to be improved in particular to give an accurate account of the economics of variable renewable energy sources (VRE) [11], [12]. This includes both variable power demand as well as VRE like wind and solar and their integration into energy systems. Variability shapes the economics of the power sector. As demand is inherently variable and electricity cannot be stored easily a heterogeneous mix of power-generating technologies is optimal, rather than a single technology [13]–[17]. If a model does not represent the variability of demand there is a tendency to bias the results towards more base-load technologies and underestimates the total costs of the power system. In addition, neglecting the variability of VRE intensifies this bias. Variability of VRE imposes costs on the power system as a whole. These costs are often termed integration costs and can be substantial at high VRE generation shares [18], [19]. Consequently, the economic value and optimal deployment of VRE strongly decrease due to their variability [20]–[24]. For wind this amounts to 25–35 €/MWh at a share of 30–40%, according to an extensive literature review [19]. For a fundamental analysis of the impacts of power sector variability (demand and VRE) on the economics of electricity see Ref. [25].

Accounting for short-term power sector variability in models that focus on the long-term development of the energy system is difficult, because there is a trade-off between model scope and detail due to numerical and complexity limits. Long-term energy-economy models have a very wide scope, i.e. coverage of multiple sectors, a centennial perspective on mitigation challenges, often a global perspective, and a representation of the major drivers of climate change and mitigation options. Inevitably, this limits the level of detail they can represent. Many models use a temporal resolution for investment decisions of 5–10 years. Power demand and supply are aggregated and balanced in terms of annual averages. By contrast, real electricity demand, wind speeds, and solar radiation show significant variability on time scales of minutes to years. For the analysis of long-term transformation pathways, it is a crucial challenge to bridge all relevant time scales. Numerical constraints prohibit increasing the resolution of long-term energy-economy models to a degree that would allow for an explicit representation of variability. To keep

model complexity manageable, one needs a lean, yet accurate representation of power sector variability and VRE integration.

Most long-term energy-economy models use stylized representations covering different aspects of variability. However, these representations have limitations and require further refinement [11], [26], [27]. Ref. [11] contains a review of 17 long-term energy-economy models with respect to their method to represent VRE variability, which we discuss briefly in the following. Two of these models have no dedicated representation of variability, but represent the imperfect substitutability between different power sources using constant elasticity of substitution (CES) production functions. Such an approach is highly stylized, and tends to preserve power supply structures as observed today, making it difficult to explore the types of transformative changes required for low stabilization.

The other models considered in [11] have one or more explicit constraints to represent VRE integration challenges. Eight models limit the maximum generation share of wind and solar, e.g. to 15% each. This can be regarded as overly pessimistic because detailed studies for many regions and experience with high VRE shares indicate that VRE integration poses no insurmountable technical barrier [28]. Four models use a somewhat more advanced approach by introducing an integration costs penalty per generated unit electricity from VRE that increases with the VRE share in generation mix. This has three drawbacks. First, cost penalties lack an economic basis because they do not build on a rigorous definition that ensures that the cost additions comprise all economic costs of variability. Ref. [18] introduces a definition that could help in improving these approaches. Second, cost penalties would need to be parameterized carefully with a high-resolution model. This is challenging because integration costs are system-dependent and the parameterization would need to cover a large number of different scenarios. Third, solely applying such an implicit measure neglects changes in the non-VRE part of the energy system in response to VRE deployment, for example shifts in the capacity mix of non-VRE generation technologies.

An approach in which fixed investments in specific integration options like firm capacity from gas-fired power plants, electricity storage or transmission infrastructure are required is represented in eight models. However, there are again three drawbacks. First, it is unclear if these approaches comprise all aspects of variability: A single integration option does not mitigate all aspects of variability. Even with a model representation of a number of integration options there might be a residual impact of variability that is not captured. Second, these approaches are again difficult to parameterize: The optimal deployment of a specific technical requirement depends on several evolving properties of the overall energy system, such as the mix and share of VRE, the non-VRE capacity mix, and the deployment of other integration options. Third, by preselecting specific integration options and parameterizing their deployment the model loses the opportunity to find a cost-effective way to cope with variability endogenously.

A more novel approach, implemented in the MESSAGE model [26] introduces an additional balance equation for “flexibility”, in which flexible generation from an endogenous mix of dispatchable plants and electricity storage technologies balances flexibility requirements from variable demand and VRE supply. The parameterization does not build on technical parameters or a rigorous definition, but is derived from a limited ensemble of scenarios of a generic unit-commitment model with six nodes. It is unclear to what extent the approach represents power-sector variability for other regions and system configurations. A challenging simplification is that the MESSAGE approach tries to capture most aspects of variability in a single constraint. A further refinement might entail a more comprehensive parameterization and potentially a differentiated representation of different aspects of variability, for example by finding specific “flexibility” constraints for different time scales of load balancing.

The research community that uses long-term energy-economy models works on consolidating the different approaches and developing best practices. Explicit modeling of some aspects of variability, implicit representations of other aspects using exogenous parameters, and/or soft-coupling with high-resolution models can be part of the solution. In correspondence to the above limitations of the prevalent approaches we suggest three criteria that a sound representation of variability should fulfill. First, it should be comprehensive, i.e. it should represent the most important aspects of demand and renewable supply variability. Second, it should be robust, i.e. its parameterization should be valid for a broad range of different energy system configurations. To this end the representation should either build on a rigorous definition of economic impacts of variability or on physical constraints that capture variability such that the correct economic impacts are induced. Third, a representation should be flexible, i.e. it should allow for an endogenous choice of different integration options, including adjustments of the non-VRE part of the energy system.

This paper presents a novel modeling approach for representing variability in long-term energy-economy models that aims at meeting these criteria. It is based on a model representation of residual load duration curves⁴⁷ (RLDC) that changes depending on the model-endogenous share and mix of VRE. RLDC are a purely physical concept only requiring demand and VRE supply data without using exogenous cost parameters, yet it delivers the economic impact of both the major aspects of demand and VRE supply variability. RLDC reflect the temporal distribution of demand and residual demand⁴⁸, which determines the cost-efficient mix of non-VRE power plants. Changes of the RLDC

⁴⁷ The RLDC is derived by subtracting the time series of VRE power supply from the time series of power demand and then sorting the resulting curve in descending order. See a more detailed introduction in the appendix A.1.

⁴⁸ Residual demand is the power demand after subtracting VRE supply.

with increasing VRE shares induce potential shifts in the non-VRE capacity mix. Moreover, RLDC capture so-called “profile costs”, which depend on the temporal matching of VRE supply profiles with (residual) power demand. While profile costs can be even negative at low shares, e.g. for solar PV in many US regions, profile costs are the largest cost impact imposed by VRE variability at higher shares of VRE ($>15\%$) ([19], [29]), i.e. they tend to be substantially larger than costs related to additional balancing or grid requirements of VRE.⁴⁹ Ref. [29], [30] show that RLDC capture the three main drivers of profile costs: a low capacity credit and resulting requirements for firm capacity, reduced utilization of the capital embodied in dispatchable plants⁵⁰, and over-produced VRE generation. There are several integration options that reduce profile costs [29]. Apart from a shift towards less capital-intensive dispatchable plants the RLDC approach covers endogenous investment in seasonal energy storage via hydrogen and methane (power-to-gas storage). This provides some flexibility to mitigate the challenges and corresponding costs of power sector variability. In addition, the approach contains model equations that in a stylized way account for minimum load and operating reserve requirements.

In this paper we describe the RLDC approach and demonstrate its impact on the results of REMIND-D, a long-term energy-economy model for Germany ([31], [32]). There are two reasons why we use this model. First, the German government has both adopted an ambitious climate-change mitigation target and agreed on a nuclear phase out; at the same time, the share of VRE has risen considerably in the past two decades and carbon capture and storage (CCS) as a mitigation option faces serious acceptance concerns. Hence, the potential role of renewables, in particular wind and solar PV, in climate change mitigation is crucial and its variability can be expected to have a major impact on future mitigation scenarios. Second, REMIND-D is a single-region version of the global state-of-the-art integrated assessment model REMIND-R [33]. Stylized representations of power sector variability are particularly relevant for global models because their wide scope limits the level of model details. Since REMIND-R has a very similar model structure and equations the implementation can easily be transferred from REMIND-D.

The paper is structured as follows. Section 6.2 describes the RLDC approach including a model representation of power-to-gas storage. Section 6.3 discusses the impacts on model results by comparing runs with and without the new approach. Section 6.4 concludes.

⁴⁹ The reason is that the supply of additional VRE plants is correlated with the existing VRE plants and thus the matching with residual demand gets unfavorable at higher VRE shares.

⁵⁰ In principle, the utilization is reduced for all dispatchable plants; however, for capital-intensive base-load plants this is particularly costly.

6.2. Method

This Section describes the RLDC approach. Section 6.2.1 presents the core: a representation of load duration curves (LDC) and RLDC in long-term energy-economy models. Section 6.2.2 suggests two complementary elements: a constraint that accounts for minimum load requirements of thermal plants, and a constraint that requires operating reserves for sufficient flexible generation (introduced in Ref. [26]). Finally, in Section 6.2.3 we demonstrate how the approach allows a representation of power-to-gas storage in which renewable over-production is stored as hydrogen or methane.

6.2.1. The RLDC approach

The preparatory step for the RLDC approach is implementing an approximation of the LDC. In principle this is already done in some long-term energy-economy models, [11]. While typically a step function is used, here we suggest a representation that also contains a triangular part to more accurately approximate the shape of the LDC. Hereby the LDC is reduced to three parts: A base load box, an intermediate load triangle⁵¹, and a peak capacity margin (Figure 37). The approximation is derived from regional demand data such that the deviation between the linear pieces and the actual LDC data is minimized and the integral of the original LDC is conserved. The capacity margin provides additional firm capacity to assure reliability in case of contingency events, e.g. outages of plants or grid connections. The specific margin depends on region-dependent industry standards. We apply a U.S. standard reserve margin of 20% of peak load [26].

⁵¹ Note that these terms are indicative and do not necessarily match other definitions of base, intermediate or peak load.

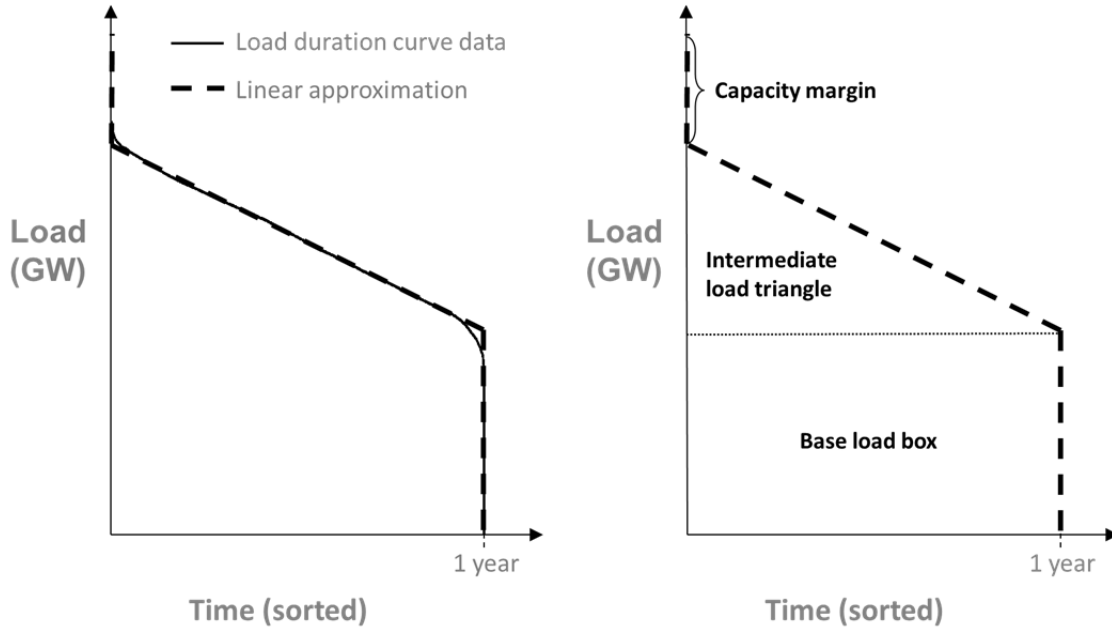


Figure 37: The LDC is approximated by a linear function (left). Three different parts build up the load: A base load box, an intermediate load triangle, and a capacity margin. (schematic illustration)

With growing VRE shares, dispatchable power plants merely cover residual load: The RLDC depends on the share and mix of wind power and solar PV, and the linear approximation in the model changes accordingly (Figure 38). The change in the RLDC induced by VRE is controlled in terms of four parameters (C_{box} , C_{Δ} , C_{peak} , v_{box}), which are functions⁵² of the generation shares of wind power and solar PV. Prior to model optimization, the function parameters are derived from a data analysis based on VRE supply and power demand data.

⁵² The function form is third degree polynomials with two variables (wind and solar share) and mixed terms.

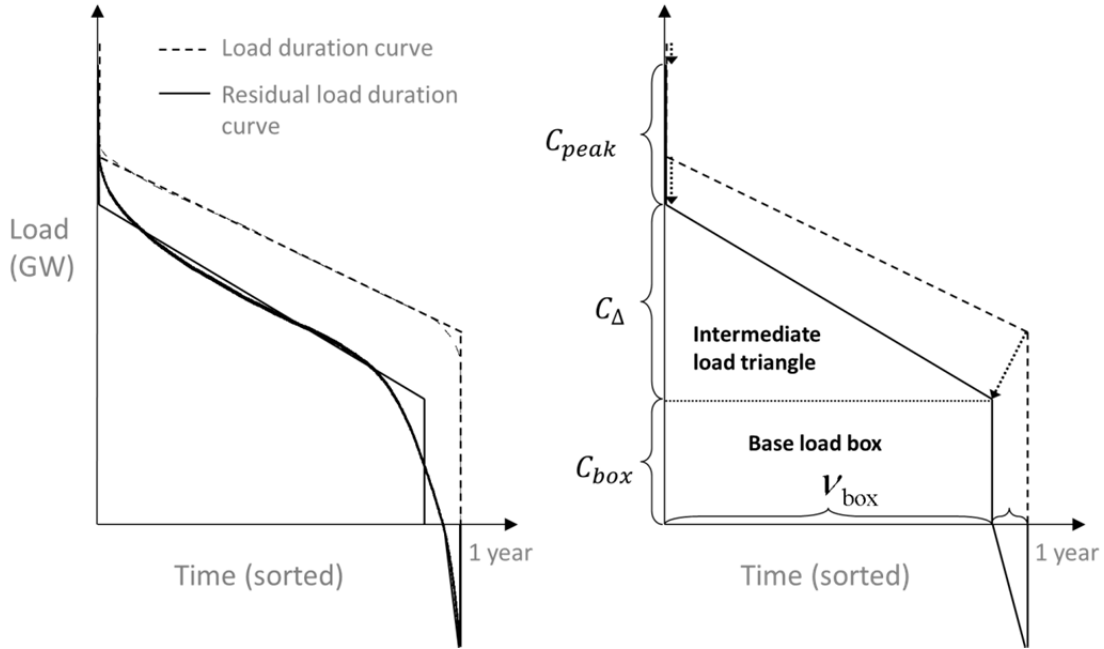


Figure 38: The RLDC is approximated by a box and a triangle (left). This is implemented into the model as a transformation of the original LDC (right). The transformation is controlled by the change of four parameters parameters (C_{box} , C_{Δ} , C_{peak} , v_{box}) that are functions of the VRE generation share and mix of VRE power. (schematic illustration)

By endogenizing the RLDC changes we enable the model to anticipate the resulting long-term effects, i.e. VRE contribution to total capacity, the reduced utilization of dispatchable plants and the over-produced VRE generation. Analogously, when investing in dispatchable power plants, the model considers the long-term capacity requirements for covering base load, intermediate load and the capacity margin, as well as the long-term development of annual full load hours (FLH) (i.e. capacity factors⁵³) over the lifetime of the dispatchable plants. Note that as a part of this also the total peak capacity requirements are fulfilled, which has been formulated in a single model equation in Ref. [26].

The RLDC approach allows for the simultaneous optimization of investment as well as operation decisions in the power system under the consideration of short-term variability: Every unit of installed capacity of a dispatchable technology can in principle operate in each part of the three parts of the RLDC (base, intermediate and capacity margin). In every time step (typically 5 to 10 years) the overall installed capacity of a technology is split cost-efficiently among the three parts of the RLDC. The FLH of each generating unit in this time step depend on the part of the RLDC where the unit is operating. While in

⁵³ The capacity factor of a generating technology is a number between 0 and 1 given by the relation of its full-load hours compared to the total hours of one year.

principle every generation technology can contribute to covering each part of load, the specific economic characteristics of the heterogeneous technologies suggest typical operation decisions. For example, nuclear and coal plants (in particular lignite) have high specific investment costs and low variable costs, thus require high operating hours, and will operate predominantly in the base-load part, in contrast to gas turbines, which will mainly be dispatched to cover peak load. For each part of the RLDC model equations balance the respective electricity and capacity demand and supply (see Appendix A.2).

The above approximation uses an intermediate load triangle. Alternatively, the RLDC can also be approximated with three boxes as illustrated in Figure 39 (left). Analogously to the above formulation these boxes would change endogenously with growing VRE shares. This approximation is less accurate but might ease the implementation due to two reasons. First, it avoids some equations of higher order that are needed to properly dispatch capacities in the intermediate load triangle (see Appendix A.2). Second, the boxes could be implemented similarly to a small number of representative time slices like in the model LIMES [34], [35] or ReEDS [36], [37]. The novel development is a change of heights and widths of the time slices depending on VRE shares (Figure 39, right).

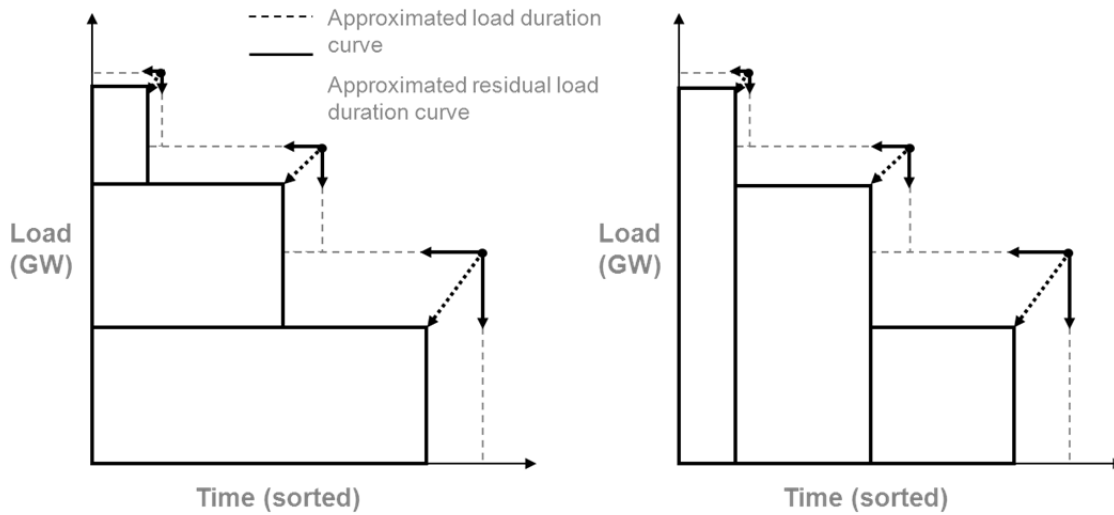


Figure 39: Using boxes as an approximation of the RLDC is less accurate but might be easier to implement. In a vertical formulation (right) the RLDC approach might benefit from experience made with representative time slices.

6.2.2. Additional elements

An additional element of the RLDC approach is a “minimum load box”. There are different reasons why VRE will not be able to cover total power demand in a single moment. First, thermal generators have a limited flexibility of reducing their output. There is a minimum load each plant unit must supply before it has to shut down, which imposes some time lag until it can supply again. Second, the provision of ancillary services like frequency control requires operating reserves that are necessary to maintain

the security of power systems. These dispatchable capacities need to run at partial load to be able to increase their output on short notice. Third, combined heat and power (CHP) plants might need to generate power even in situations of over-produced VRE because of required heat generation. As a result a minimum amount of dispatchable capacity remains supplying throughout the year even in situations when demand could actually be fully met by VRE. The height of this continuous band of dispatchable generation is sometimes referred to as “grid flexibility” or “system flexibility” [38], [39], [40]. We incorporate this in a “minimum load box”, which is a fourth part of the RLDC. The height of the minimum load box (h_{min}) is a parameter, which is uncertain and depends on the future development of minimum load values of individual power plants, the capability of VRE to contribute to ancillary services, and the flexibilization of CHP plants such as the installation of thermal storage facilities; here we estimate this height to be 10% of peak load (Figure 40). The “minimum load box” increases the over-produced amount of VRE (shaded area) and allows some dispatchable plants to run at a constant output throughout the year.

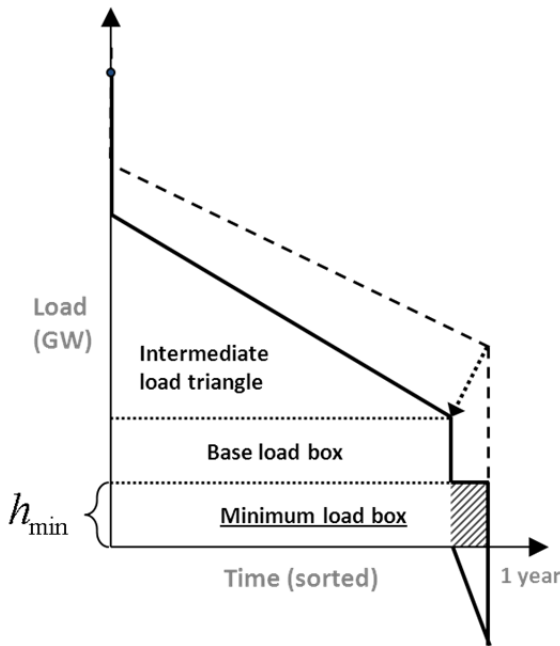


Figure 40: A minimum load box accounts for limited system flexibility, which requires some supply from dispatchable capacities throughout the year.

The RLDC approach can be combined with approaches that represent other (minor) aspects of variability. The approach does not focus on representing operating reserve requirements to provide flexible generation accounting for increased balancing, ramping and cycling requirements of VRE, yet the minimum load box partly addresses this issue. Ref. [26] introduces an operating reserve constraint, which balances flexibility contributions and requirements across all generating technologies and demand. This additional model equation can complement the RLDC approach.

6.2.3. Power-to-gas storage

The RLDC approach allows for modeling power-to-gas storage endogenously. The suggested model realization of power-to-gas storage consists of an electrolysis process that transforms over-production from VRE supply to hydrogen, followed by a potential second step in which hydrogen can be further transformed to methane. A key determinant for the profitability of power-to-gas is the amount of available over-production and its frequency distribution. Both depend on the VRE share and mix and can be derived directly from geometric shape of the RLDC. This is illustrated in Figure 41. The model endogenously chooses an electrolysis capacity. The shaded area equals the resulting amount of over-production that is input to electrolysis. The width of this area is given by the frequency distribution of over-production and determines the FLH of the electrolysis. Hydrogen can be directly used e.g. in the transport sector, fed into the natural gas grid (on a limited scale), or alternatively be transformed to methane. The latter option requires CO₂ as an input, which can be provided from biogas fermentation or synthesis. Power-to-gas storage can be represented within the RLDC approach because the operation of the electrolysis is independent of the chronological order of the residual load, which is lost in an RLDC. By contrast, other short-term storage technologies and demand-side management would change the RLDC in a more complex way also depending on the mix of wind power and solar PV. Representing these technologies requires further refinement of the approach.

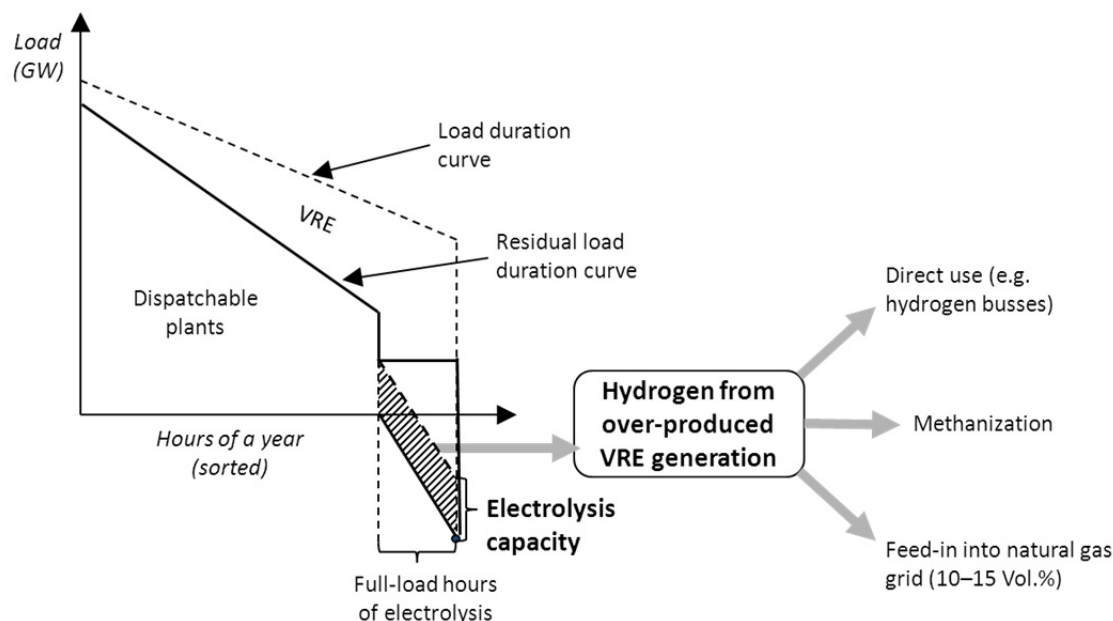


Figure 41: The representation of RLDC allows implementing power-to-gas storage via hydrogen and methane.

6.3. Application of the RLDC approach in REMIND-D

For a first application of the RLDC approach we use the REMIND-D model, which is described in Section 6.3.1. In Section 6.3.2 we investigate the impact on scenario results of modeling power sector variability with the RLDC approach.

6.3.1. Model and data

REMIND-D is a long-term energy-economy model for Germany; a detailed description of the model and the calibration data is available in Ref. [31]. The equations are derived from the global model REMIND-R [41], [42]. REMIND-D finds the welfare-optimal mitigation pathways until 2050, considering technological mitigation options in the power, heat and transport sector. The optimal solution is calculated by an inter-temporal, non-linear optimization algorithm, assuming perfect foresight and accounting for endogenous technological learning. Hereby, it combines a Ramsey-type growth model that reflects general macroeconomic dynamics and a detailed bottom-up energy system module. Model complexity, the global scope and long time horizon limits the temporal resolution for investment decisions to 5 years. For this reason, short-term power sector variability must be accounted for in a stylized way. The model is used as a first application of the RLDC approach.

For parameterizing the RLDC approach in REMIND-D we use wind and solar generation data from actual quarter-hourly feed-in data from German Transmission System Operators (TSOs) for 2011, which is publicly available on the respective websites⁵⁴. To simulate higher VRE shares we scale up the time series linearly, which is an approximation that tends to overestimate the correlation of VRE supply. Hourly data for power demand for the German power system in 2011 was downloaded from the ENTSO-E website⁵⁵. The data was interpolated linearly to match the quarter hourly resolution of VRE generation. By spatially aggregating over the four different TSO zones in Germany we implicitly assume perfect domestic transmission (“copper plate assumption”). The variability of offshore wind power supply is parameterized with wind onshore data due to a lack of offshore wind data.

6.3.2. Results: impacts of modeling variability in REMIND-D

We compare the REMIND-D model outputs with and without the new RLDC approach. In the latter model version variability and integration challenges are neglected entirely. We examine both the direct impact of variability on the deployment of VRE as well the indirect effect on the residual system like dispatchable generation and storage

⁵⁴ www.50hertz-transmission.net, www.tennetso.de, www.amprion.net, www.enbw.com

⁵⁵ <https://www.entsoe.eu/data/data-portal/>

requirements. Moreover we determine broader impacts like the mitigation cost penalty due to variability and separately estimate the effect of power-to-gas storage.

In order to focus on the RLDC approach, we use a predefined scenario. All results shown here apply the boundary conditions of the ‘continuation’ scenario in [32], which enforces a set of trends in the electricity and transport sector. Nuclear power plants are phased out according to legislation and carbon capture and storage (CCS) is assumed to be unavailable because of its poor prospects in Germany [33]. Coal power plants are allowed to retire before the end of their technical lifetime if cost-efficient, e.g. due to high CO₂ prices, in contrast to Ref. [32], in which this is rated unlikely. We show results for the baseline scenario, where no carbon budget is applied, and for a standard ambitious mitigation scenario, i.e. achieving the German policy target of 80% emissions reduction in 2050 relative to 1990.

The RLDC approach is implemented including the additional elements of a minimum load box and the operating reserves constraint introduced in Ref. [26]. A first result is that the latter constraint, if parameterized according to Ref. [26], is not binding in any scenario, i.e. that even though the RLDC approach focuses on capturing profile costs, it tends to provide sufficiently flexible generation. The main reason is that an RLDC with high VRE shares induces a shift towards typical peak- and mid-load capacities such as gas or biomass plants, which not only reduces profile costs but also provide enough flexible generation, in contrast to base-load plants like coal plants that are characterized by supplying less flexibility.

The direct impact of the RLDC approach on modeled VRE generation levels is shown for the baseline scenario (Figure 42, left) and the standard mitigation scenario (Figure 42, right). The consideration of variability with the RLDC approach substantially reduces the power generation from VRE, by 35% in the baseline scenario and by 27% in the mitigation scenario in 2050. The shaded areas show sensitivity results for the VRE generation with 20% higher and lower VRE capital costs. In the mitigation scenario, varying the costs of VRE does only slightly change deployment levels, since there are hardly alternative mitigation options in the power sector to reach the ambitious reduction target if both nuclear and CCS are constrained. The strong effect of the RLDC approach is mainly induced by over-production. However, this can be used for producing hydrogen via electrolysis.

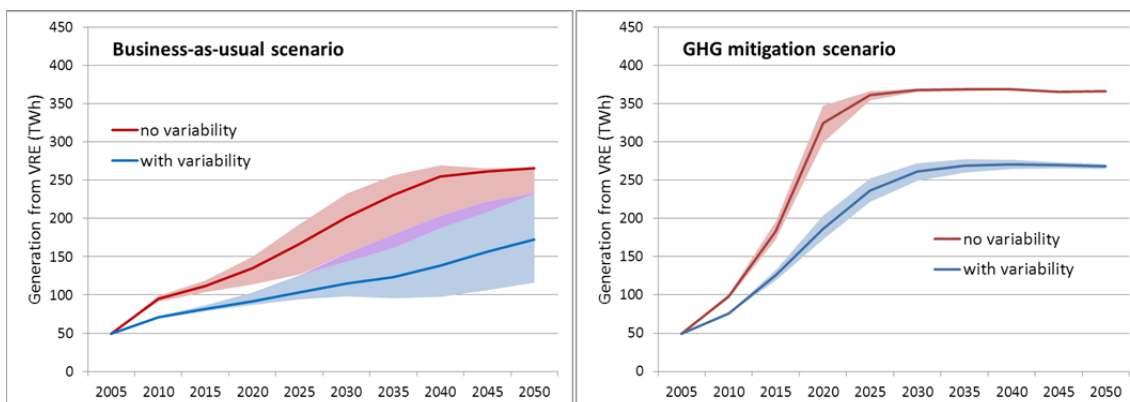


Figure 42: Representing variability with the RLDC approach substantially reduces the power generation from VRE, by 35% in the baseline scenario and by 27% in the mitigation scenario in 2050. The shaded areas show sensitivity results for the VRE generation with 20% higher and lower VRE capital costs.

In the mitigation scenario up to 25% of VRE generation cannot directly be used in 2050 because it exceeds demand or interferes with dispatchable minimum load requirements. Figure 43 (left) shows that this amounts to up to 90TWh of annual potential curtailment, of which over 80% are input to power-to-gas storage, with endogenous capacity of roughly 40GW of hydrogen electrolysis and 2GW of methanization. Due to efficiency losses the 90 TWh of curtailed electricity production is decreased by 46% to an actual stored energy 49 TWh (35TWh hydrogen, 14TWh methane) (Figure 43, right).

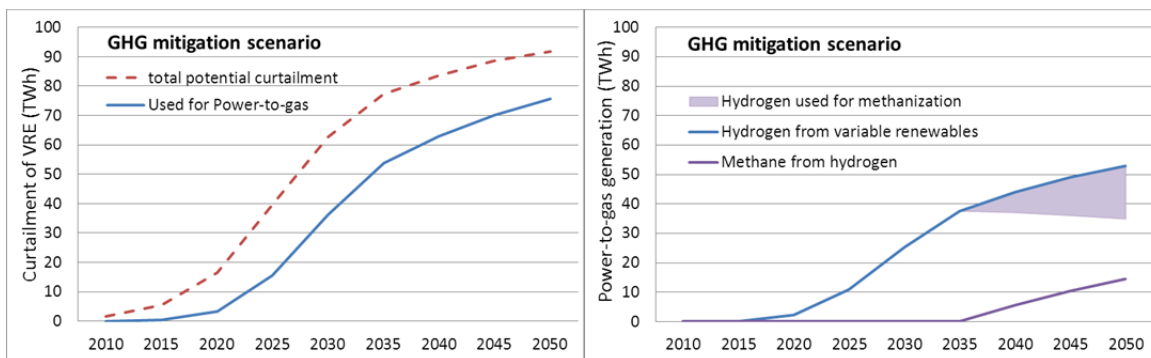


Figure 43: A high fraction of total curtailment of VRE can be used for power-to-gas storage (left). A small fraction of hydrogen is transformed into methane (right).

Comparing electricity generation and the non-VRE capacity mix for the mitigation scenario with and without the RLDC approach gives insights as to the indirect effect of variability, i.e. how the non-VRE system changes due to variability of demand and VRE. Figure 44 shows that the share of VRE generation in 2050 reduces from 72% to 55% with the RLDC approach, with the difference being made up by more dispatchable generation. Total power generation decreases because power demand is price-elastic and the costs of power generation increase with power sector variability. Dispatchable renewables like biogas, hydro-power and geothermal plants are used to a considerable extent, increasing

the total share of renewables to 90% in 2050. In contrast to the case without RLDC, a small share of fossil generation from combined-cycle gas plants remains in the power system, because there is no option to decarbonize a certain fraction of the RLDC due to inappropriate matching of VRE supply with residual load at high VRE shares and limited potential of dispatchable renewable energy sources. These combined-cycle gas plants replace coal power plants that are decommissioned before the end of their technical lifetime, driven by decreasing FLH for dispatchable plants and a high CO₂ price (85 €/t CO₂ in 2020). These gas plants also provide sufficient flexibility to meet the operating reserve constraint.

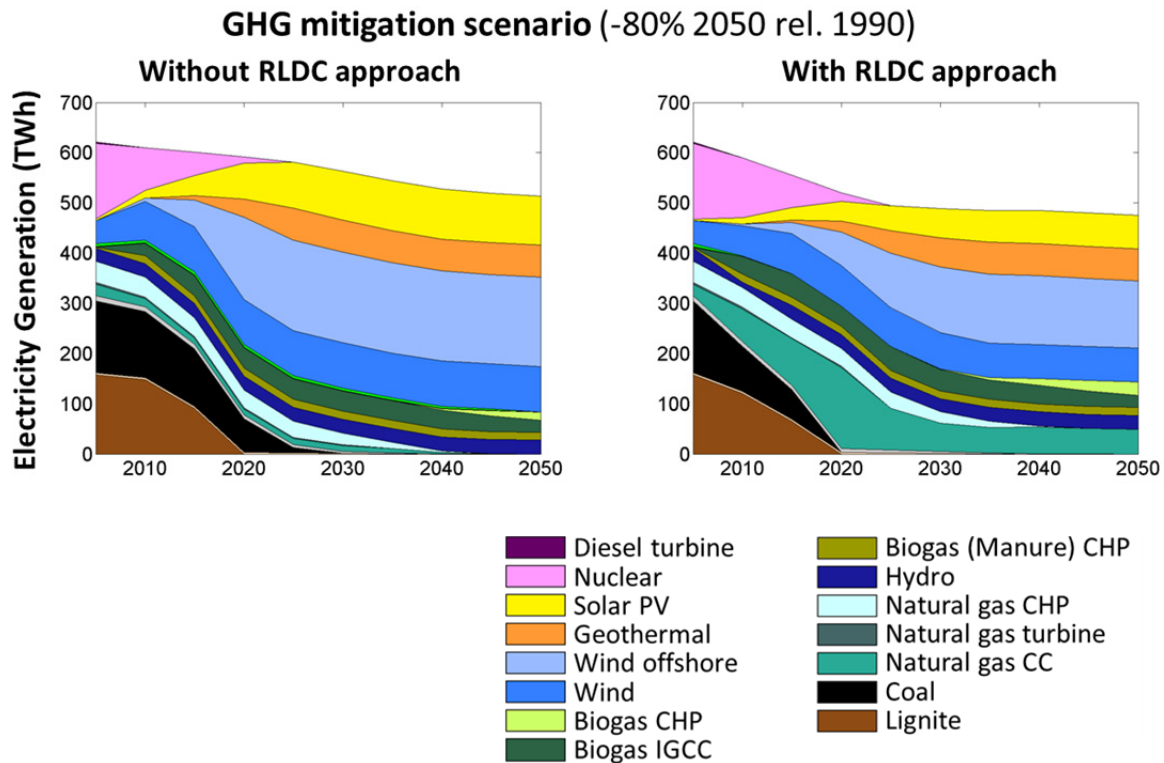


Figure 44: The development of the electricity generation mix without (left) and with (right) the RLDC approach, keeping all other scenario characteristics unchanged.

Figure 45 shows the development of the capacity mix for non-VRE capacities. With the RLDC approach, required generation capacity in 2050 is three times higher than in the case without RLDC even though the total electrical energy generation is slightly reduced. Combined-cycle gas plants and gas turbines (open cycle gas plants) are cost-efficient options to provide firm capacity due to their low specific-investment costs.

This significant increase of total installed generation capacity is caused by a more accurate reflection of demand variability in particular peak demand situations and the low capacity credit of VRE with the RLDC approach. Without the new approach, REMIND-D does not account for power sector variability, which is tantamount to assuming that power demand and supply are homogenous in time [25]. This corresponds to a situation

in which power demand is constant and VRE provide base-load electricity and reduce capacity requirements as if they could supply constant power output. This bias underestimates strongly real capacity requirements in particular in power systems with high VRE shares. In the shown scenario without the RLDC approach, installed firm capacity could only serve about 35% of peak capacity. Moreover, gas power plants are discriminated against because their specific value for covering peak load is not reflected when neglecting variability.

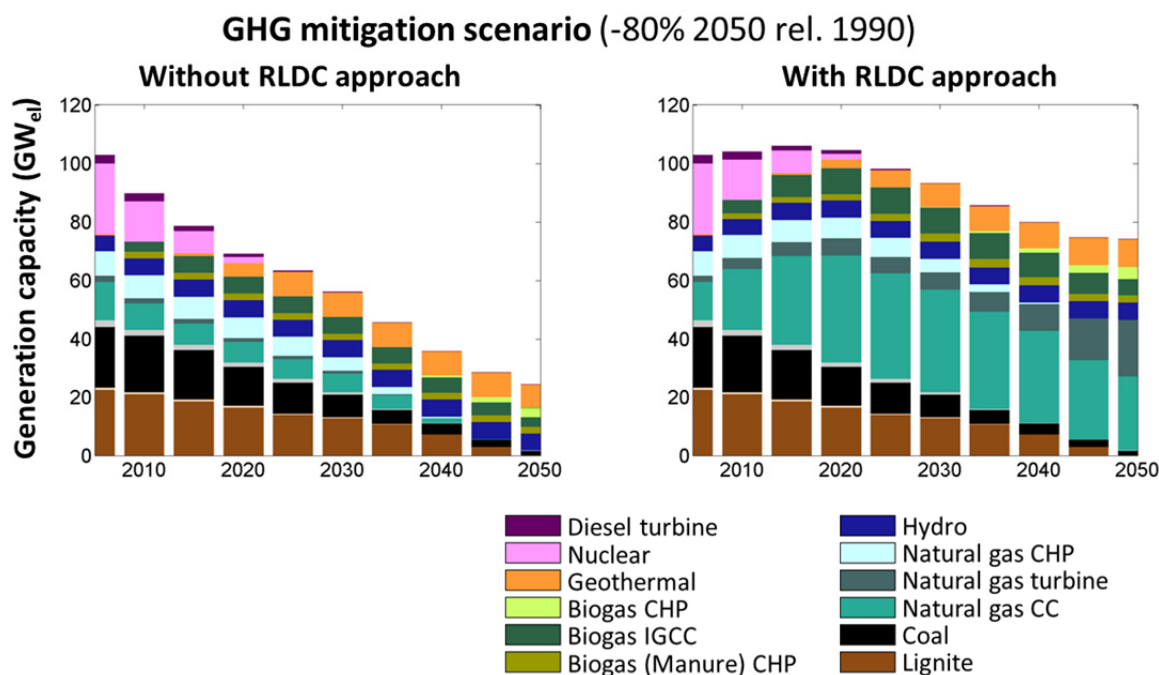


Figure 45: The development of the non-VRE capacity mix without (left) and with (right) the RLDC approach.

With the RLDC approach, mitigation becomes more expensive because the important mitigation option VRE incurs additional integration costs on a power system level. Also, the mitigation effect of a unit VRE capacity is reduced. The power generation from VRE needs to be partly curtailed or transformed by costly power-to-gas storage with limited efficiency, while more dispatchable plants and generation are required to provide capacity and operating reserves.

Figure 46 shows the mitigation costs of the ambitious mitigation scenario, in terms of cumulative discounted consumption losses over the period 2010-2050, compared to the baseline scenario. Here we also analyze a model version with an intermediate implementation step: a representation of RLDC but without power-to-gas storage. From left to right we add elements of the novel method resulting in three different mitigation cost figures. With the RLDC but without power-to-gas storage, mitigation costs increase from 1.20% to 1.41%. Thus, introducing variability enlarges mitigation costs by 18%. This is a considerable increase given that the technology portfolio remains unchanged

and the new equations only affect the power sector. On the other hand the consideration of variability fundamentally reshapes the operation and planning of the power system and limits renewable energy, which is the only low-carbon energy supply option in these scenarios. Power-to-gas storage can reduce this increase by about one third, with mitigation costs amounting to 1.34% consumption losses under implementation of the full RLDC approach. The impact of variability on mitigation costs might further decrease with the availability of more alternative mitigation options in the power sector such as nuclear power or CCS, as well as with increased flexibility options such as demand-side management and large-scale transmission, which would change the RLDC due to the spatial aggregating of VRE supply and demand.

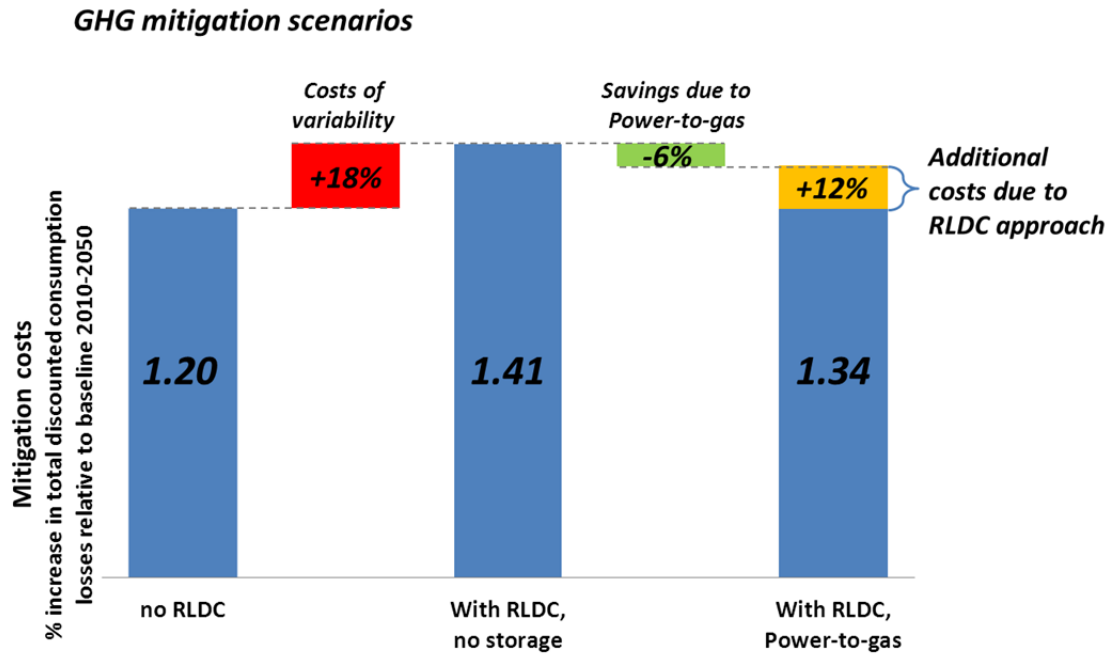


Figure 46: Mitigation costs in terms of cumulative discounted consumption losses compared to the respective baseline scenarios. Considering variability enlarges mitigation costs by 18%. Power-to-gas storage can reduce this increase by one third.

6.4. Summary and conclusion

Improving the representation of power sector variability is among the highest priorities for the further refinement of integrated energy-economy climate models used for analyzing long-term climate change mitigation scenarios. Our novel approach can serve as an appropriate model representation of power sector variability because of three main merits. It firstly covers the most important variability impacts, secondly is valid for a broad scenario space with different energy system configurations and thirdly provides flexibility of choosing among multiple pathways of integrating VRE. In an application for the model REMIND-D, the substantial impact of the approach on model results confirms that power sector variability matters. Thus, implementing the RLDC approach in a long-

term multi-sector model would improve the robustness and credibility of mitigation scenarios. In particular, it would foster a more accurate estimation of mitigation costs and the role of VRE in low-carbon transformation scenarios.

The novel approach incorporates power demand and supply variability through the use of RLDC. RLDC are a purely physical concept based only on demand and VRE supply data, yet deliver the economic impact of the most important aspect of variability of demand and supply. The unfavorable matching of the temporal profiles of VRE supply with demand results in so-called profile costs due to lower utilization of dispatchable power plants. These profile costs can be substantial at high VRE shares and tend to be higher than integration costs for additional grid and balancing requirements of VRE ([19], [29]). More specifically, for a broad range of shares of wind and solar PV the novel approach represents a number of cost-driving aspects of power sector variability such as firm capacity requirements, the reduction of FLH of non-VRE plants, over-production of VRE and minimum load and operating reserve constraints. Hereby, the modeled energy system can endogenously adjust in response to increasing VRE deployment, namely via a shift in the non-VRE capacity mix, deployment of power-to-gas storage or curtailment of over-produced VRE generation.

We demonstrate the RLDC approach with REMIND-D [31], [32], a long-term energy-economy model for Germany. The impacts on the results are substantial. With the RLDC approach implemented, power generation from VRE reduces by 35% in the baseline scenario and by 27% in an ambitious mitigation scenario in 2050. The model requires significantly more non-VRE capacity, in particular gas-fired plants. The consideration of variability changes key macro-economic figures: Mitigation costs increase by 18%. The availability of power-to-gas storage can reduce this increase by one third.

The RLDC approach as presented here has important limitations. First, short-term storage technologies and demand-side management cannot yet be represented because their impact on the RLDC is very complex. Second, finding a representative RLDC parameterization of a large world region requires some kind of aggregation and will neglect some spatial heterogeneity. Third, the approach does not allow for an accurate accounting of additional grid and balancing costs of VRE. Many of these limitations can be overcome. Developing commensurate refinements is the subject of further research. The endogenous representation of RLDC can be complemented with other elements, such as implementing cost parameters for detailed variability aspects (e.g. grid and balancing costs), or exogenous deployment of integration options like short-term storage or demand-side management that are derived from high-resolution models.

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Appendix

A.1. Residual load duration curves

This section briefly introduces LDC and RLDC. Electricity demand is variable (see Figure 47, left) and price-inelastic (in the short-term) and consequently electricity providers need to adjust generation instantly. Variable demand also implies that power plants differ in their annual FLH. This can be illustrated with a LDC, which is derived by sorting the load curve i.e. the time series of power demand for one year or longer (Figure 47) from highest to lowest values. The maximum of a LDC indicates the capacity required to cover total annual electricity demand, which equals the area below the curve. The curve is shaped by the temporal distribution of variable demand, which determines the potential FLH of power-generating plants.

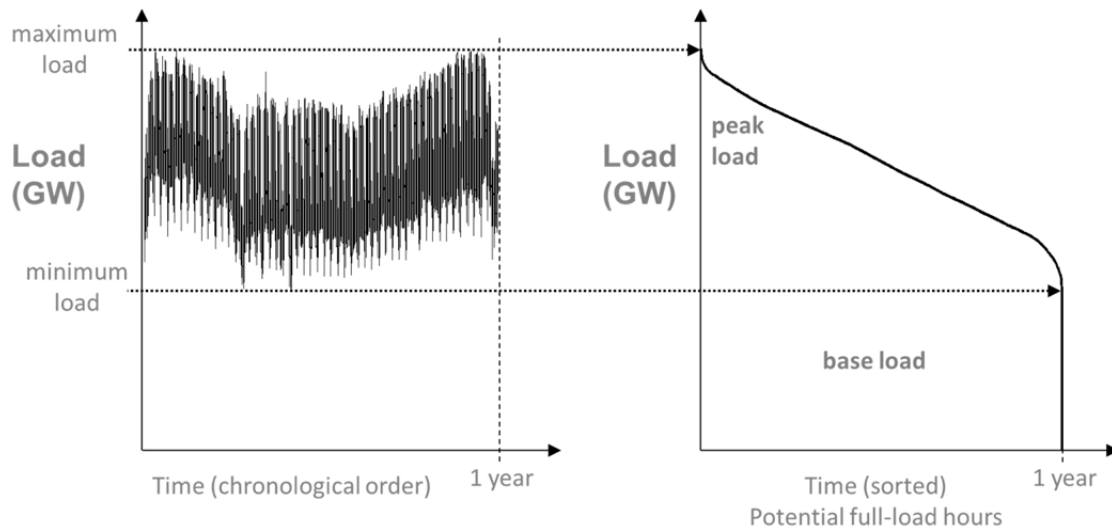


Figure 47 (schematic): The LDC (right) is derived by sorting the load curve (left) in descending order.

The residual load curve is a time series that is derived by subtracting the time series of VRE from the time series of power demand (Figure 48, left side). The RLDC is then derived by sorting the residual load curve in descending order (Figure 48, right side). The area between the LDC and the RLDC is the potential electricity generation from VRE. Note that the shape of the area does not indicate the temporal distribution of VRE supply,

due to different sorting of load and residual load, yet this information is not relevant for the RLDC approach. RLDC are shaped by the temporal distribution of residual demand and hereby determine the potential FLH of dispatchable plants, which are crucial to the optimal technology mix in a power system. In that sense RLDC replace the LDC in a situation with VRE.

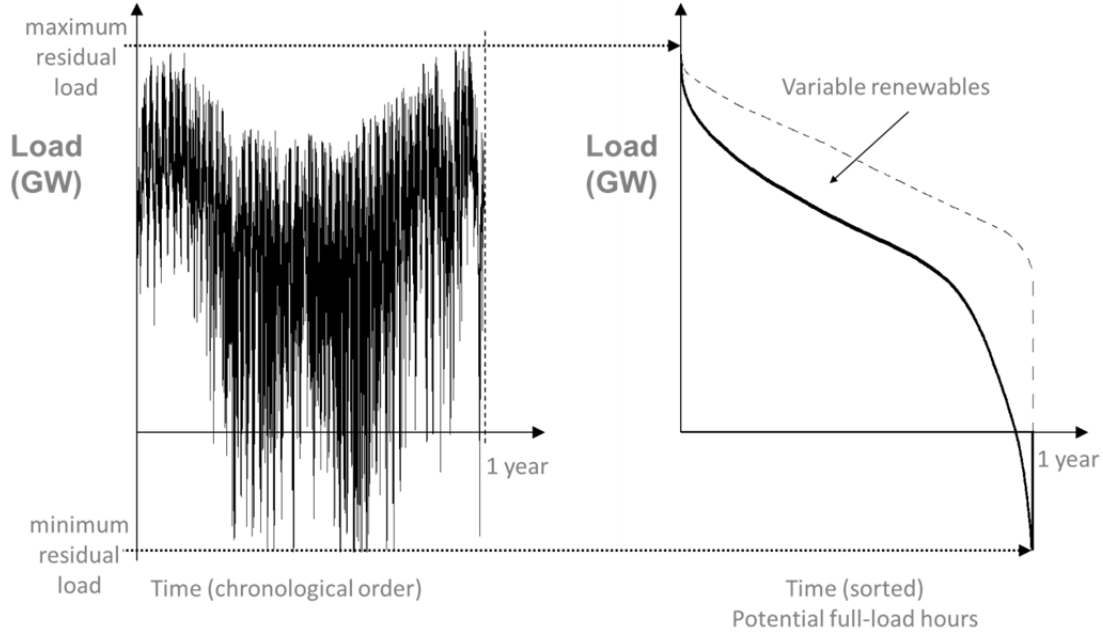


Figure 48 (schematic): The residual load curve (a time series) is derived by subtracting the time series of VRE from the time series of power demand (left). The RLDC (right) is derived by sorting the residual load curve in descending order. The area in between the RLDC and the LDC equals the potential contribution of VRE.

A.2. Equations of the RLDC approach

In the following we show the core equations of the RLDC approach. All equations are valid for each time step, i.e. every variable depends on the time, which is not shown here. For every non-VRE power generating technology te the respective total installed capacity $C_{tot,te}$ is decomposed into three parts ($C_{box,te}$, $C_{\Delta,te}$, $C_{peak,te}$) that operate in the three different parts of the RLDC: the base load box, the intermediate load triangle, and the peak capacity part (Figure 49, left).

$$C_{tot,te} = C_{box,te} + C_{\Delta,te} + C_{peak,te} \quad (37)$$

When adding all the capacity units that operate in one part of the RLDC, e.g. for base load $C_{box,te}$, this should equal the total capacity demand for this RLDC part, e.g. C_{box} .

$$C_{box} = \sum_{te} C_{box,te} \quad (38)$$

There are two more analogous equations for C_{Δ} and C_{reserve} . In addition there are two balancing equations for the generation in the base load G_{box} and intermediate load part G_{Δ} .

$$G_{\text{box}} = C_{\text{box}} v_{\text{box}} = \sum_{te} C_{\text{box},te} v_{\text{box}} \quad (39)$$

$$G_{\Delta} = \frac{1}{2} C_{\Delta} v_{\text{box}} = \sum_{te} C_{\Delta,te} v_{\Delta,te} \quad (40)$$

The capacity factors v for the different parts of the RLDC endogenously depend on the generation share and mix of VRE. As a consequence the RLDC approach is non-linear and cannot be applied in purely linear models. The capacity factor of units that operate in the base load part v_{box} , is independent of the specific technology te . By contrast the capacity factors in the intermediate load part $v_{\Delta,te}$ is different for different technologies te . This is because the capacities need to cover the triangle shape as illustrated in Figure 49 (right). Each capacity $C_{\Delta,te}$ has an average capacity factor $v_{\Delta,te}$ and covers a range of capacity factors from $v_{\Delta,te}^{\min}$ to $v_{\Delta,te}^{\max}$ as calculated in equations (41) and (42).

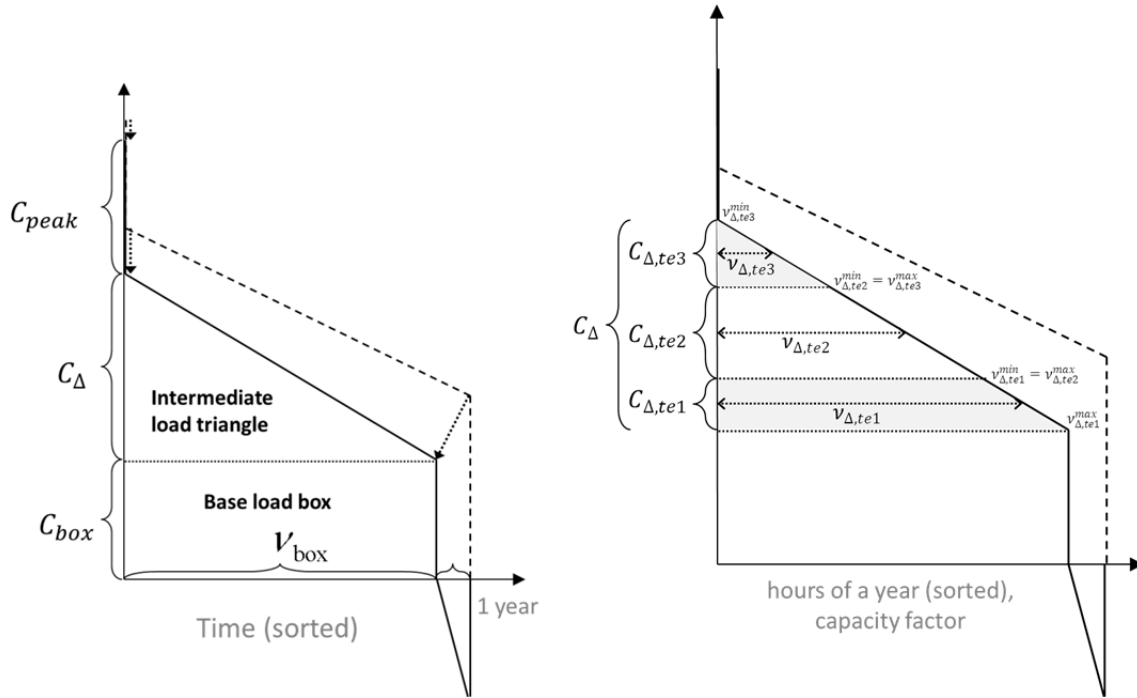


Figure 49: Four parameters describe the RLDC shape (left). The capacity units $C_{\Delta,te}$ that operate in the intermediate load triangle have different capacity factors $v_{\Delta,te}$ in order to cover the triangle shape (right).

$$v_{\Delta,te}^{min} = v_{\Delta,te} - \frac{1}{2} C_{\Delta,te} \frac{v_{box}}{C_{\Delta}} \quad (41)$$

$$v_{\Delta,te}^{max} = v_{\Delta,te} + \frac{1}{2} C_{\Delta,te} \frac{v_{box}}{C_{\Delta}} \quad (42)$$

The order of the capacities in the intermediate load triangle is endogenously chosen in the optimization. It can change between different time steps of the scenario, because it is driven by changing fuel costs and carbon prices. That is why it needs a few more equations to ensure that the capacities cover a triangle. An RLDC can be interpreted as a cumulative distribution function. The triangle part can be described with a constant density function $f(v) = C_{\Delta}/2$ because capacity is distributed uniformly over the capacity

factors 0 to v_{box} . We now use the moments of this density function to make sure that the variables $v_{\Delta,te}^{min}$ and $v_{\Delta,te}^{max}$ are chosen such that the corresponding capacities $C_{\Delta,te}$ cover the intermediate load triangle. The moments k can be generally defined with the expectation operator E :

$$E(v^k) = \frac{\int_0^{v_{box}} v^k f(v) dv}{\int_0^{v_{box}} f(v) dv} \quad (43)$$

These moments can be expressed in terms of $v_{\Delta,te}^{min}$ and $v_{\Delta,te}^{max}$ by decomposing the integrals like this:

$$\int_0^{v_{box}} v^k f(v) dv = \sum_{te} \int_{v_{\Delta,te}^{min}}^{v_{\Delta,te}^{max}} v^k f(v) dv \quad (44)$$

Now the moments can be set such that the corresponding density function is uniform: $f(v) = C_{\Delta}/2$. Hereby equation 44 simplifies to:

$$v_{\Delta,te}^{max^{k+1}} - v_{\Delta,te}^{min^{k+1}} = v_{box}^{k+1} \quad (45)$$

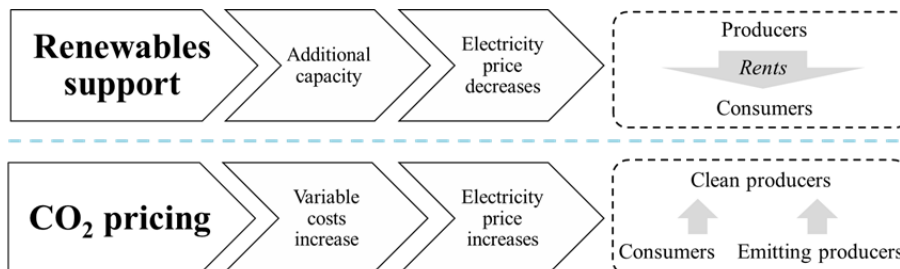
It is sufficient to fix the first 2 to 4 moments to cover the triangle shape, i.e. implementing equation 45 for $k = 1 \dots 2(3 \text{ or } 4)$.

7. Redistribution Effects of Energy and Climate Policy: The Electricity Market

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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 CO₂ 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. CO₂ 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 CO₂ pricing alone is the first-best climate policy in terms of allocative efficiency.

- CO₂ 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



Renewable support redistributes economic surplus from incumbent producers to consumers. CO₂ pricing does the opposite, but affects carbon-intensive and low-carbon technologies differently.

7.1. 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 CO₂ 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 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 CO₂. In Europe CO₂ pricing was implemented via an emission trading scheme in 2005, and several countries, regions, and states have followed. During the last eight years, the European carbon price has fluctuated between zero and 30 €/t, with official expectations of prices between 100 €/t and 300 €/t by 2050.⁵⁶

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.

CO₂ pricing increases the variable costs of carbon-emitting plants. Whenever such generators are price-setting, CO₂ 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 CO₂ 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 CO₂ pricing, using an analytical (theoretical) and the numerical (empirical)

⁵⁶ 2050 targets are taken from the Energy Roadmap 2050 (European Commission 2011).

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 CO₂ 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 CO₂ 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. CO₂ 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 CO₂ 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 7.3 presents the analytical framework and introduces the models. Section 7.4 discusses the effects of wind support, section 7.5 those of carbon pricing, and section 7.6 the compound effects of both policies. Section 7.7 concludes.

7.2. 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. (2013) 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, Ragwitz, and Genoese 2008) and Spain (de Miera, Gonzalez, and Vizcaino 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) and Gil, Gomez-Quiles, and Riquelme (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 CO₂ 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 CO₂ certificates. In addition, Burtraw and Palmer (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 CO₂ 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 CO₂ prices, and a more stringent CO₂ 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 CO₂ 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.

7.3. 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.

7.3.1. Framework

In a long-term equilibrium (LTE) on perfect and complete markets with free entry, profits (rents, producer surplus) are zero.⁵⁷ 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.⁵⁸ 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

⁵⁷ 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.

⁵⁸ 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 labelled 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.

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 to 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 (Figure 50). 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 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.

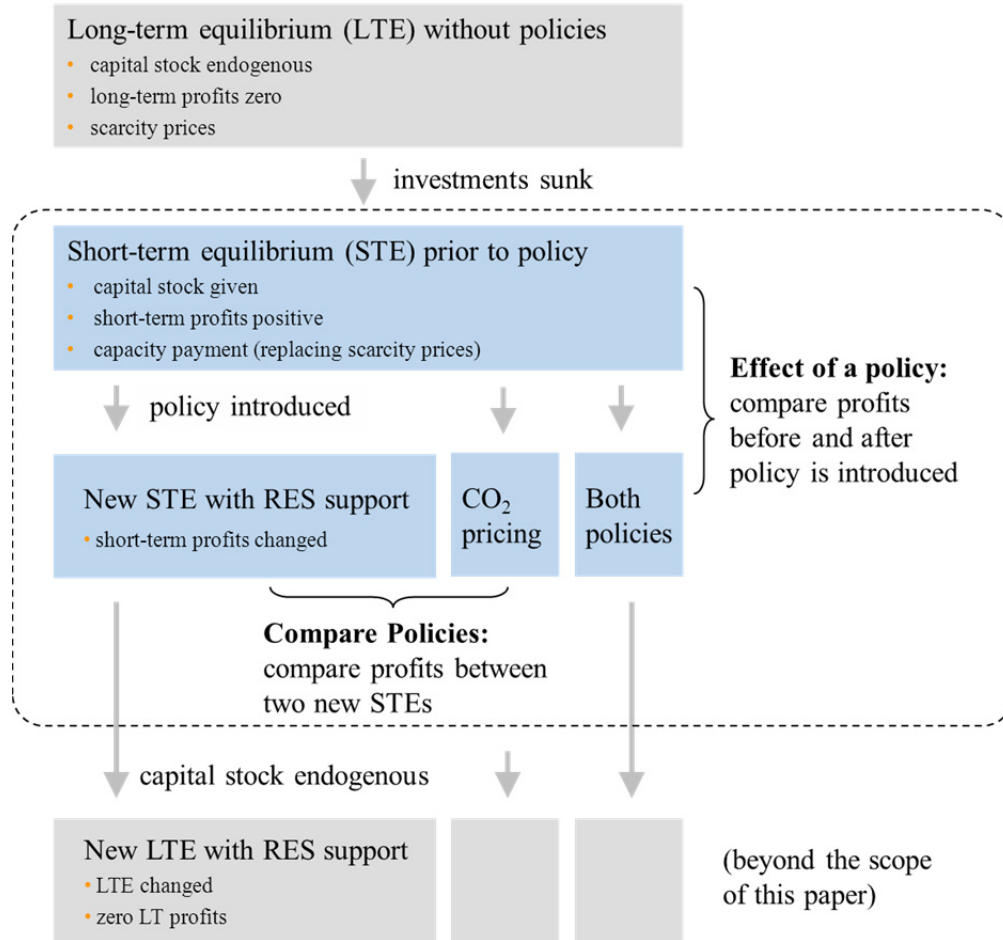


Figure 50: This framework allows to consistently studying different policies with an analytical and a numerical model. Starting from a long-term equilibrium with no policy, two short-term equilibriums (STE) are compared: the STE prior to policy with a STE with a newly introduced policy.

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 AG et al. 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.

7.3.2. 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 7.4.1 and 7.5.1.

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 7.3.3). 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 curve⁵⁹ (LDC), and a price duration curves (PDC) that is derived from the first two (Figure 51a, b, 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 support⁶⁰ reshapes the LDC, while CO₂ pricing pivots the screening curves. Before introducing policies in sections 7.4 and 7.5, 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).

⁵⁹ For the illustrations we use hourly data for German power demand in 2009 (ENTSO-E).

⁶⁰ We use quarter hourly feed-in data from German TSOs for 2009.

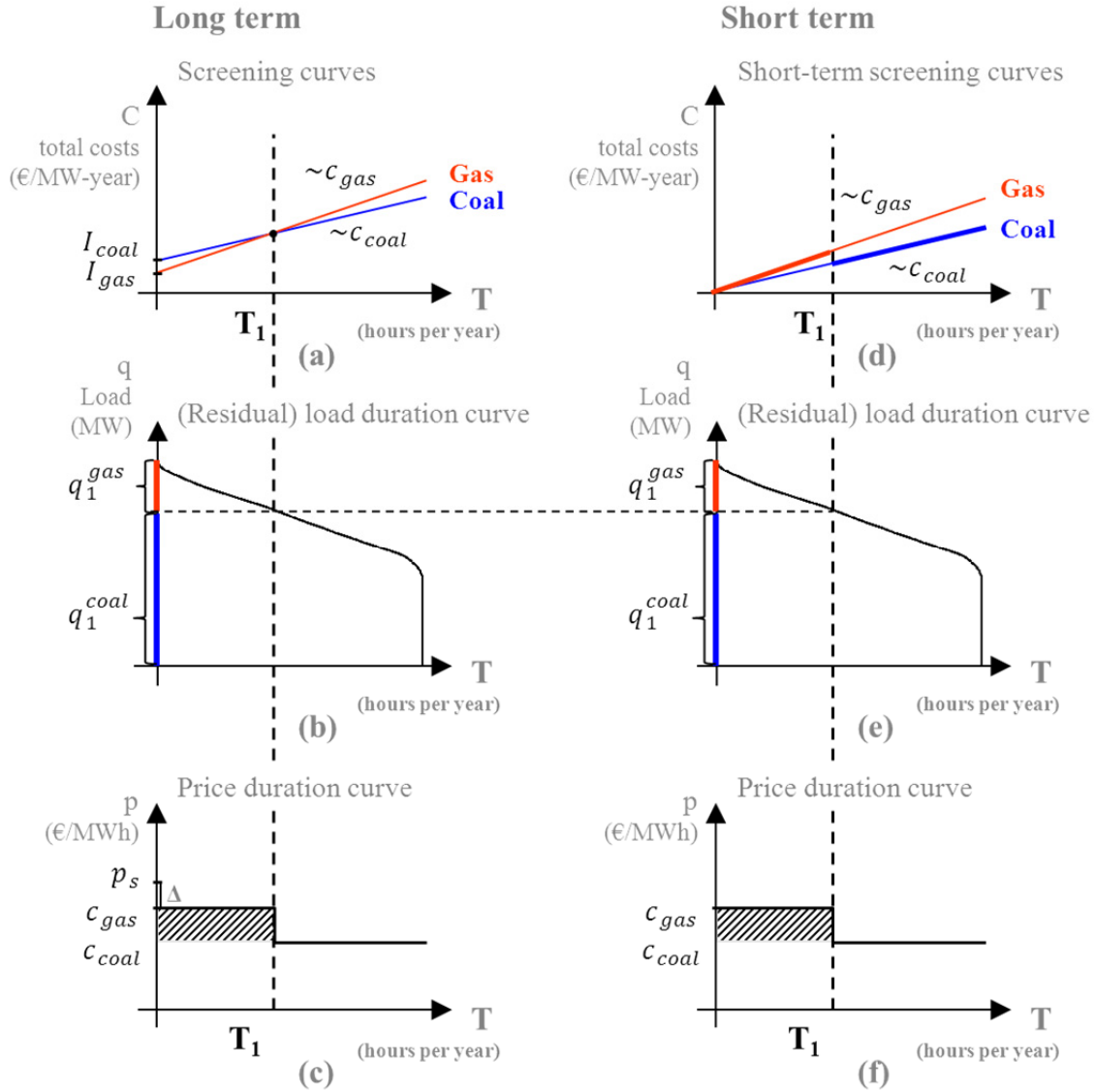


Figure 51: Long-term equilibrium (left) and short-term equilibrium (right) described by screening curves (a,d), load duration curve (b,e), and price duration curve (c,f). In the short term, screening curves do not contain investment costs and the price duration curve does not contain scarcity prices p_s .

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 (Figure 51c). 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.

$$p_s = c_{gas} + \Delta \quad (46)$$

$$\Delta = I_{gas} \quad (47)$$

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 Figure 51a it holds:

$$c_{coal}T_1 + I_{coal} = c_{gas}T_1 + I_{gas} \quad (48)$$

$$\Leftrightarrow I_{coal} = (c_{gas} - c_{coal})T_1 + I_{gas} \quad (49)$$

$$\stackrel{(2)}{\Rightarrow} I_{coal} = (c_{gas} - c_{coal})T_1 + \Delta \quad (50)$$

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 (Figure 51c). 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 Figure 51c, 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 7.3.1. 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 (Figure 51d). 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 (Figure 51f). 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 Figure 51f) needs to be multiplied by the coal capacity q_1^{coal} to calculate the absolute short-term producer rent R_1^{coal} :

$$R_1^{coal} = (c_{gas} - c_{coal})T_1 q_1^{coal} \quad (51)$$

In contrast to the LTE, where profits are zero, in the short term some producers can extract short-term rents from their sunk investment.

7.3.3. 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 (2012a) and the source code as well as input data 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 (Figure 52).

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 DeCarolís 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.

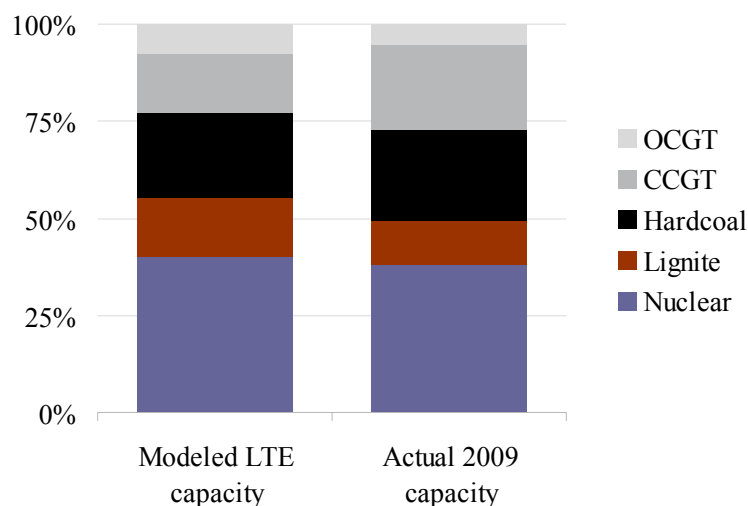


Figure 52: Model long-term equilibrium capacity mix versus historical capacity mix in 2009 for the model region. The modeled LTE capacity mix resembles quite closely to the observed data.

7.4. Wind Support

This section presents analytical and numerical model results of the redistribution effects of wind support schemes. As explained in section 7.3.1, 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.

7.4.1. Analytical Results

Figure 53 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 Figure 51. 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 unchanged⁶¹. 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 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 Figure 53f 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.

$$R_1^{coal} - R_2^{coal} = q_1^{coal}(c_{gas} - c_{coal})(T_1 - T_2) \quad (52)$$

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.

⁶¹ This is the case when the renewable technology has a comparable small capacity credit like wind power in Europe.

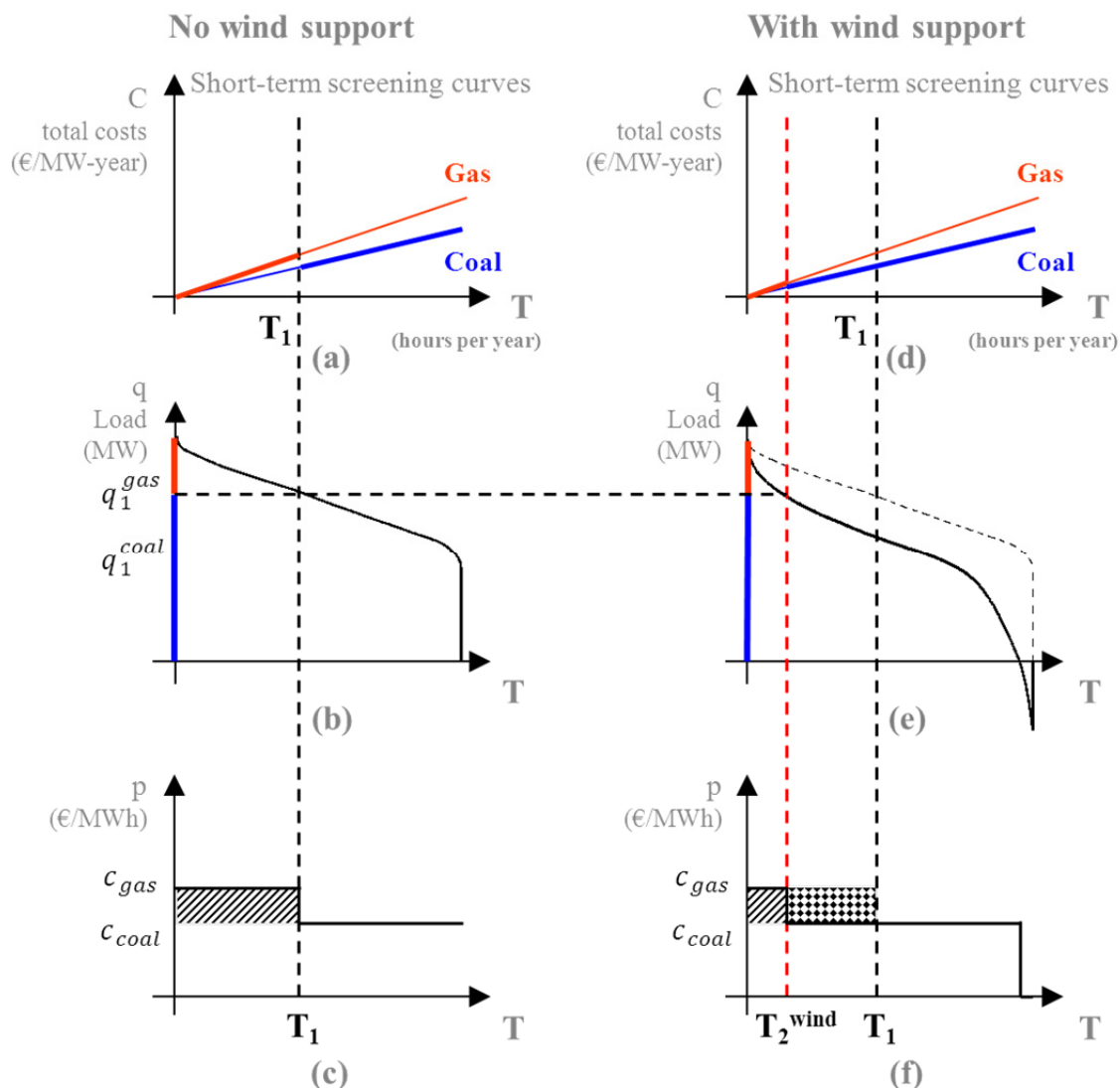


Figure 53: Short-term screening curves, load duration curves, price duration curves without (left) and with wind support (right). Wind changes the residual load duration curve (b, e). Producer rents decrease with wind support (checkered area equals the reduction of specific coal rents).

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.

7.4.2. 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 zero to 30% of electricity consumption. Results are given per MWh of total annual consumption to facilitate comparison.⁶² 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 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, Gomez-Quiles, and Riquelme 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.

⁶² Thus results can be interpreted as normalized to a total electricity consumption of one MWh.

Incumbent Producers (€/MWh)		Consumers (€/MWh)		System Costs (€/MWh)	
Nuclear Rents	- 13	Electricity market	+ 28	Decrease in	22
Coal Rents	- 9	Heat market	- 2	producers surplus	
Gas Rents	- 1	AS market	- 0.1	Increase in	7
Producer Surplus	- 22	Interconnectors	- 0.2	consumer surplus	
		CO ₂ taxes	/	Increase in system	15
		Wind subsidies	- 18	costs	
		Consumer Surplus	+ 7		

Table 1a-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.

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.

Figure 54 displays the costs of electricity supply and short-term producer rents at wind penetration rates between zero 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.

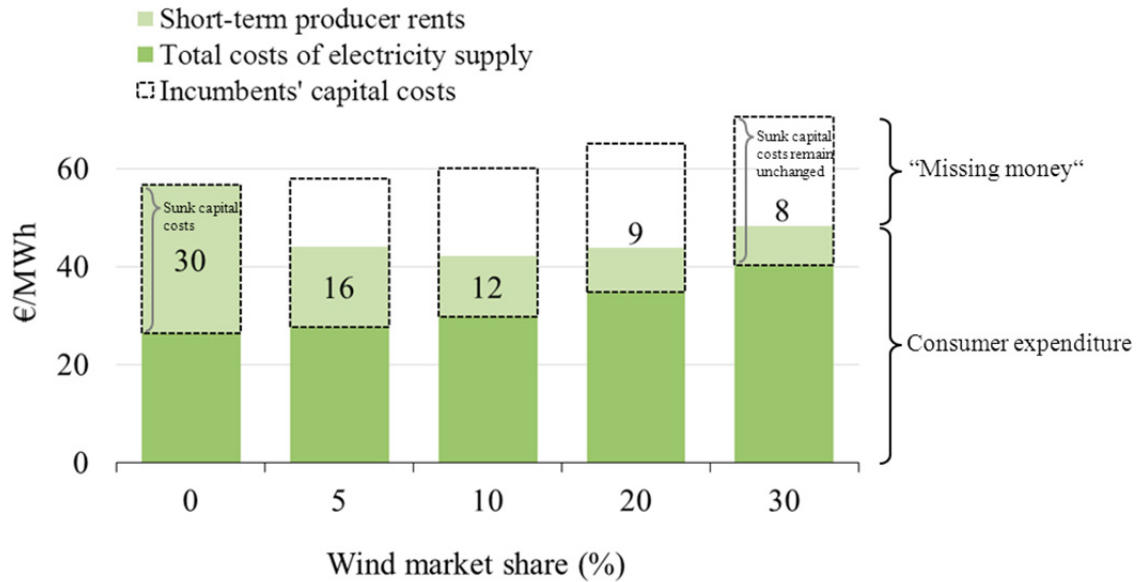


Figure 54: Rents and costs at different wind penetration rates. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure. With increasing wind penetration, producer rents are transferred to consumers. At 10% wind market share, short-term consumer surplus is maximal.

Figure 55 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 7.4.1, 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.

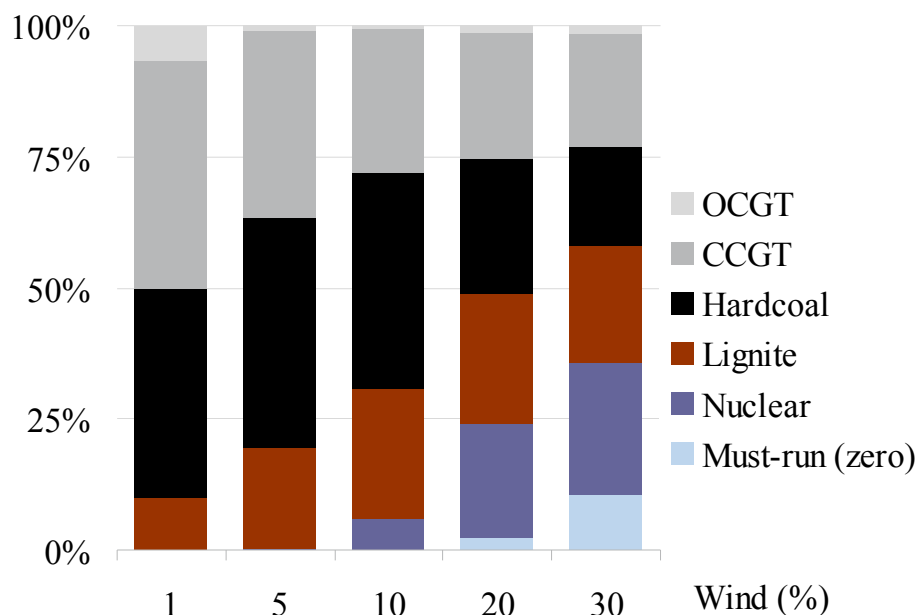


Figure 55: Share of hours in which different technologies are price-setting. With higher wind penetration, the share of base load technologies increases. At 20% wind and above, prices drop to zero, when must-run constraints become binding.

7.4.3. 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.

7.5. CO₂ Pricing

This section presents analytical and numerical model results of the redistribution effects of carbon pricing. As in section 7.4, we do not model the carbon policy explicitly, but just its consequence: the existence of a CO₂ price signal. The price of CO₂ 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 CO₂-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.

7.5.1. 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 CO₂ price level.

Figure 56 shows short-term screening curves for different CO₂ prices. Figure 56a displays a price of zero and is identical to Figure 51b. 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 CO₂ price regimes can be identified (a-f).

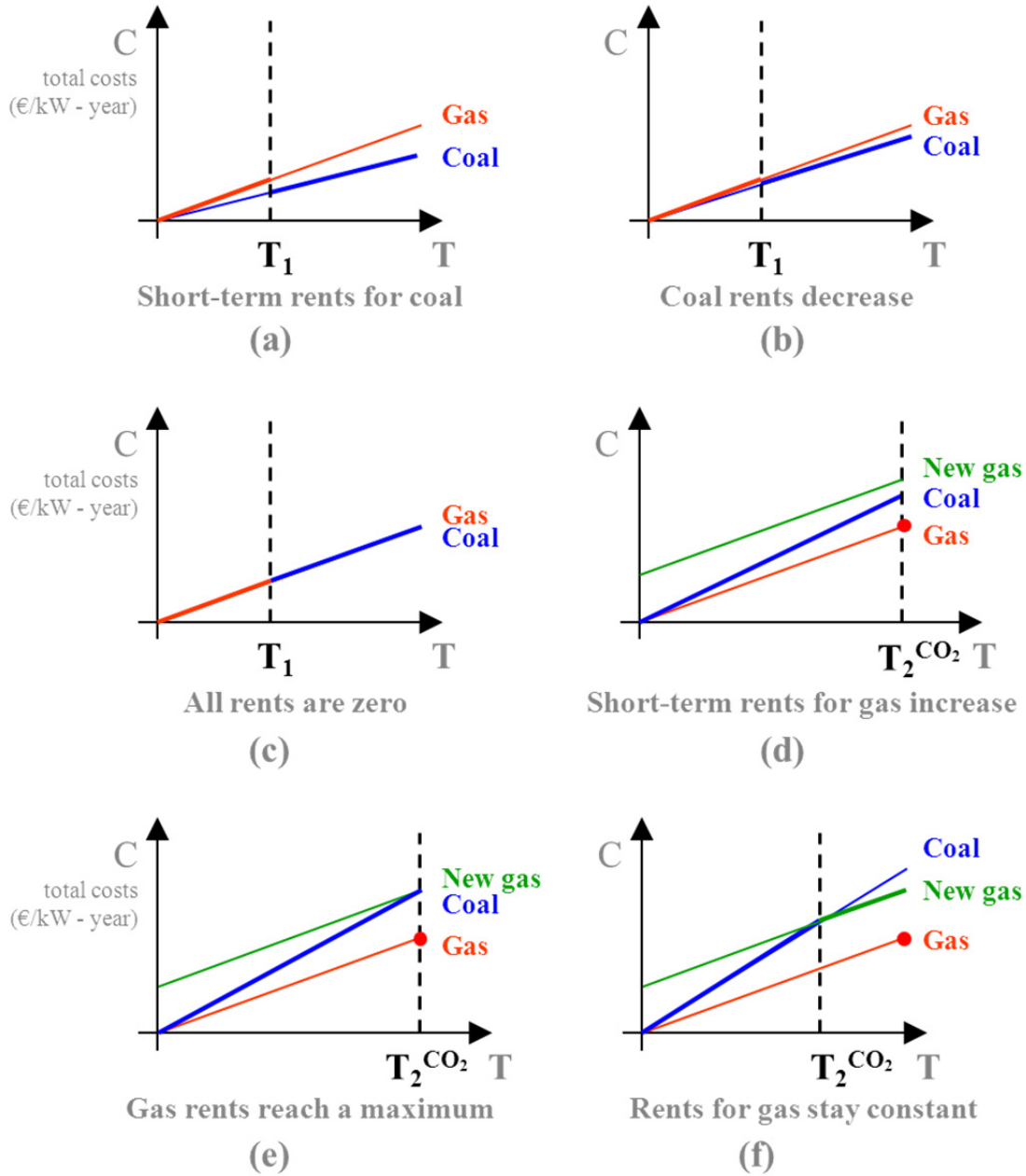


Figure 56: Short-term screening curves for coal and gas power plants. The CO₂ price increases from Figure a to f, and thus the short-term screening curves pivot further around their vertical intercepts. Six qualitatively different CO₂ price levels can be identified.

- (a) Without CO₂ pricing costs and rents are $(c_{gas} - c_{coal})T_1 q_1^{coal}$ as derived in section 7.3.
- (b) An increasing CO₂ 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 CO₂ price, the two screening curves coincide.⁶³ 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 CO₂ 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 CO₂ price, the screening curve of coal touches the screening curve of new gas power plants even though the latter also contains investment costs.⁶⁴ 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 CO₂ 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.⁶⁵ 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 Figure 58.

⁶³ The short-term screening curves coincide at a carbon price of 65 €/t CO₂, 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).

⁶⁴ This happens at about 80 €/t CO₂, with the same efficiency assumptions and investment costs of 100€/kW_a (gas).

⁶⁵ It is assumed that new gas power plants have the same costs and the same efficiencies as old ones.

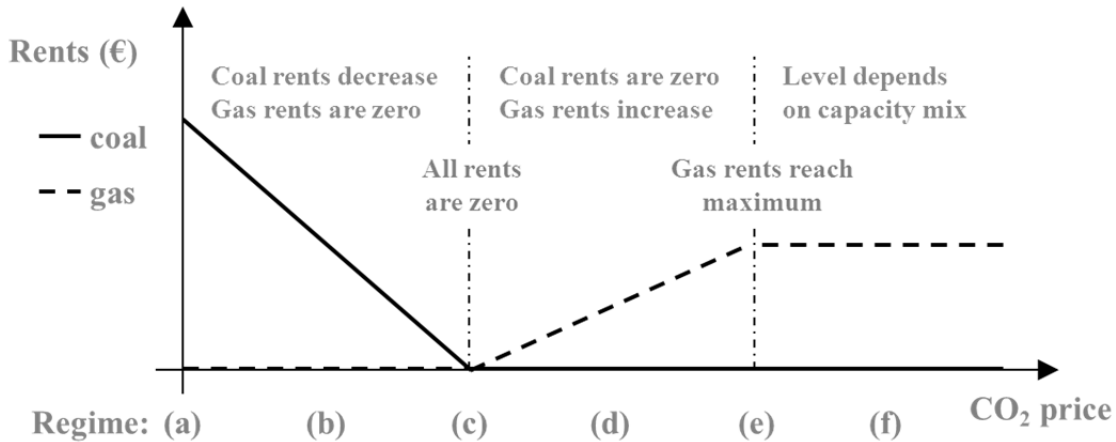


Figure 57: Rents of gas and coal power plants change with increasing CO₂ price. Six regimes (a-f) can be distinguished. Coal rents decrease to zero, while gas rents increase to a maximum level. The gas rents in regime (e) and (f) could be above or below the coal rents in (a), depending on the initial capacity mix (see result derived below).

Figure 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. Figure 58 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 Figure 58 (a, d) change according to the development illustrated in Figure 56f. 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 (Figure 58e). Coal rents vanish, while incumbent gas plants generate profits when coal is price-setting (Figure 58f).

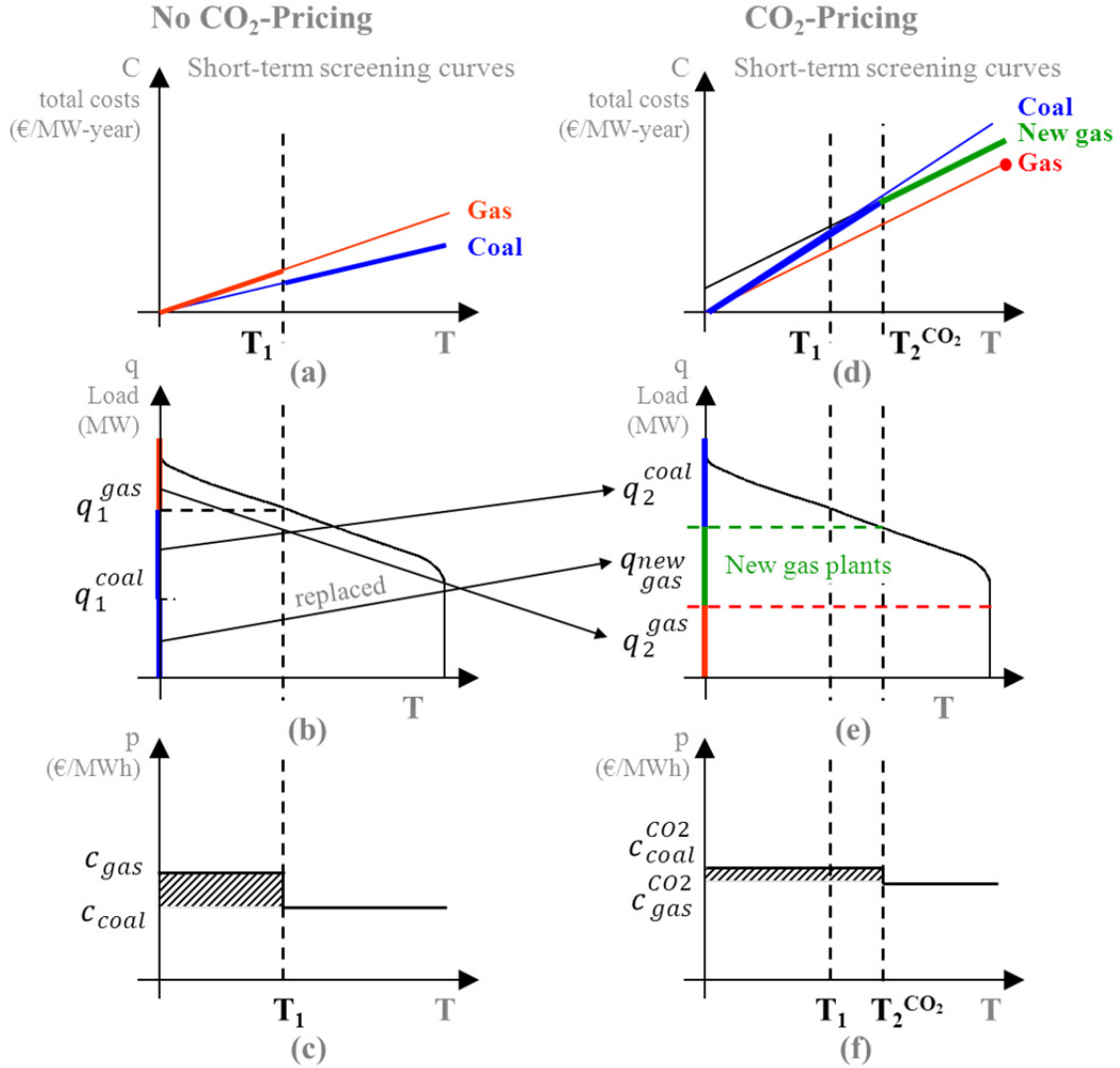


Figure 58: Short-term screening curves, load duration curves, price duration curves without (left) and with CO₂ pricing (right). Coal rents disappear, while gas rents appear. New gas power plants are built.

Moreover investments in new gas power plants are profitable because screening curves of new gas power plants and existing coal power plants intersect (Figure 58d). 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 (Figure 58f): $(c_{coal}^{CO_2} - c_{gas}^{CO_2})T_2$. The absolute rents (in €) of old gas are derived by multiplying with the old gas capacity:

$$R_2^{gas} = (c_{coal}^{CO_2} - c_{gas}^{CO_2})T_2q_1^{gas} \quad (53)$$

T_2 is given by the intersection of new gas power plants and existing coal power plants intersect:

$$c_{coal}^{CO_2}T_2 = c_{gas}^{CO_2}T_2 + I_{gas} \quad (54)$$

When inserting this into equation 53 and it follows:

$$R_2^{gas} = I_{gas}q_1^{gas} \quad (55)$$

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 CO₂ 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 CO₂ price is zero coal power plants earn their maximum rent R_1^{coal} this can be calculated by inserting equation 49 into equation 51:

$$R_1^{coal} = (I_{coal} - I_{gas})q_1^{coal} \quad (56)$$

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 equations 55 and 46 it can be followed that the change in total producer rents (in €) depends only on the initial capacity mix:

$$R_2^{gas} - R_1^{coal} = I_{gas}(q_1^{gas} - q_1^{coal}) \quad (57)$$

If there is more low-carbon gas than carbon-intensive coal capacity in the initial mix the total producer rents will increase with high CO₂ prices. This is a surprisingly simple condition and one of our main analytical model results.

To conclude, increasing the CO₂ 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 CO₂ price and the initial mix of existing capacity.

In this analytical model, it requires both very high CO₂ 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 CO₂ 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.

7.5.2. 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 CO₂ 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 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.

Incumbent Producers (€/MWh)		Consumers (€/MWh)		System Costs (€/MWh)	
Nuclear Rents	+ 21	Electricity market	- 43	Increase in	12
Coal Rents	- 10	Heat market	- 6	producer surplus	
Gas Rents	+ 0	AS market	- 0	Decrease in	29
				consumer surplus	
<hr/> Producer Surplus		Interconnectors	- 0	<hr/>	
	+ 12	CO ₂ taxes	+20	Increase in	17
		Wind subsidies	/	system costs	
		<hr/>			
		Consumer Surplus	- 29		

Table 2a-c: Changes in short-term surplus of producers and consumers, and system costs changes when increasing the CO₂ price from zero to 100 €/t (€/MWh). Producers gain and consumers lose.

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. Figure 59 displays the costs of electricity, suppliers' expenditures for CO₂, 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 nuclear profits. Recall that the effect of CO₂ pricing on total producer rents was found to be dependent on the initial capacity mix in section 7.5.1. 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 7.3.3. In contrast to the effect of wind support consumer expenditures continuously increase even if revenues from the carbon market are transferred to the consumers.

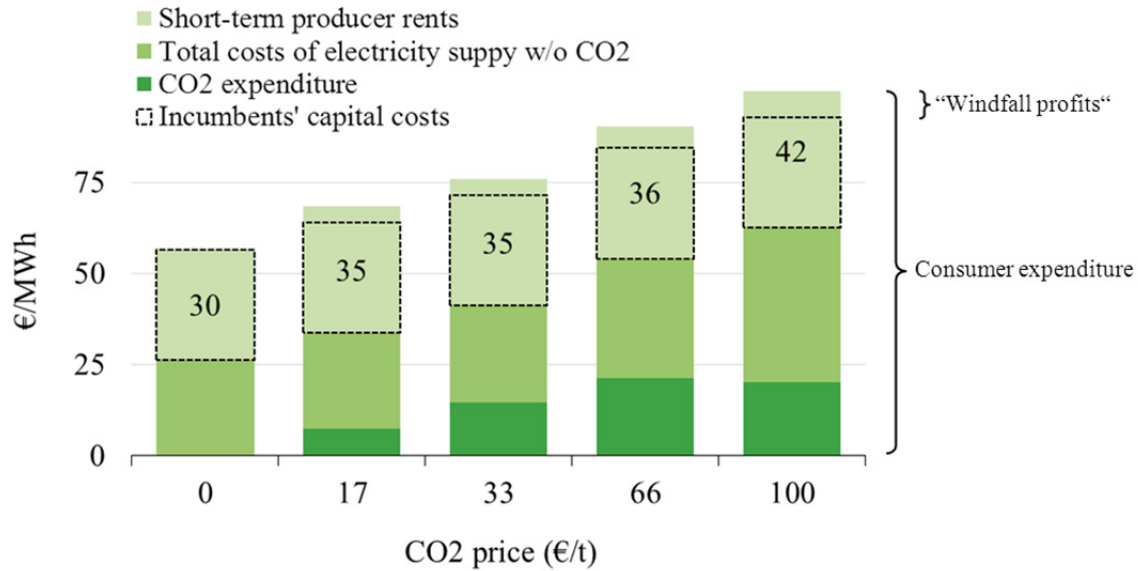


Figure 59: Rents and costs at different CO₂ prices. Numbers label short-term producer rents (light green). The sum of the colored bars is consumer expenditure, but CO₂ expenditure of fossil plants (dark green) is recycled to consumers via lump-sum payments. Short-term rents increase with higher carbon prices over and above what is needed to recover capital costs (“windfall profits”).

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 CO₂ 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.

Figure 60 compares the merit-order curve without a CO₂ 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 Figure 58f, the carbon price is high enough to incentivize new investments, in this case lignite CCS, CCGTs, and wind power.

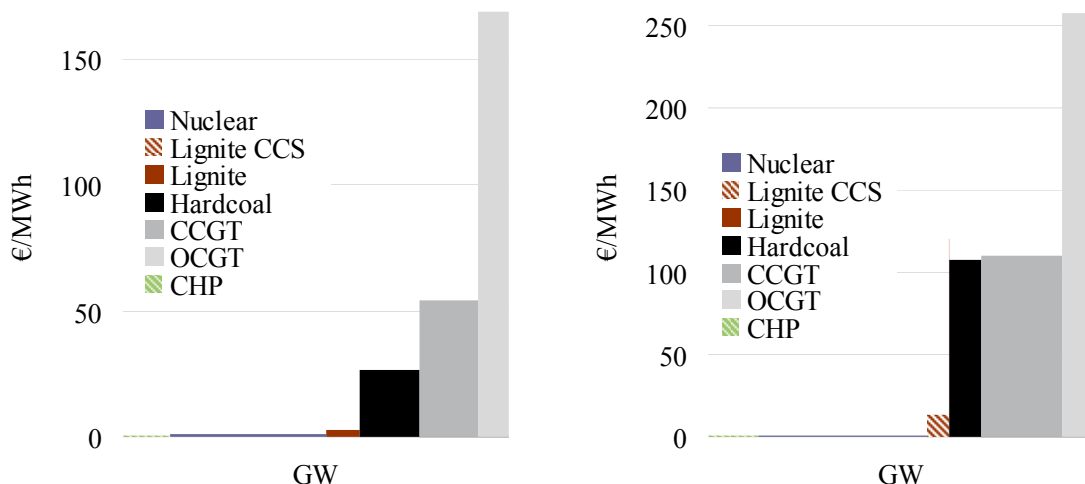


Figure 60a-b: The merit-order curve of dispatchable plants without carbon pricing (left) and at 100 €/t CO₂. The y-axis shows bidding price that takes into account start-up costs.

7.5.3. 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.

7.6. 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. CO₂ pricing transfers economic surplus from consumers to producers while wind support does the opposite. Moreover, CO₂ 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 CO₂ pricing increases producer rents and wind subsidies reduce them, a mix of both instruments allows mitigating CO₂ emissions without changing conventional generators' rents too much. Figure 61 and Figure 62 display the compound effect of a mix of both policies. For example, introducing a CO₂ price of 100 €/t and a wind target of 30% simultaneously leaves conventional rents virtually unchanged.

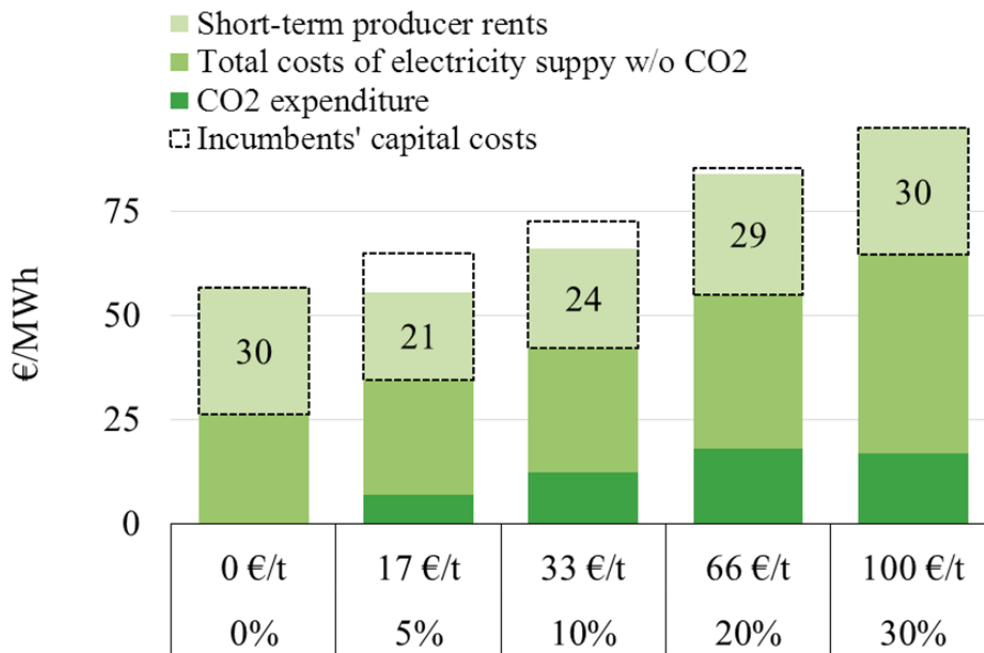


Figure 61: Rents and costs with a mix of policies. The policy mix represents a path which leaves rents roughly unchanged.

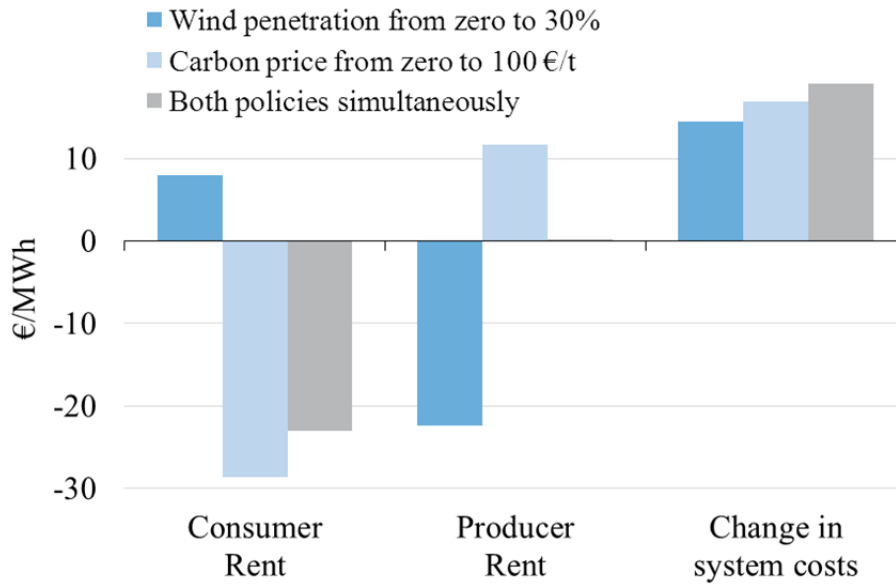


Figure 62: Change in consumer rent, producer rent, and system costs due to wind support (30%), carbon pricing (100 €/t) and a combination of the two policies. A policy mix reduced the impact on profits virtually to zero.

7.7. 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 producers to consumers, while CO₂ 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 spillovers. 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 CO₂ 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. Fourth, 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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8. Synthesis and Outlook

Wind and solar PV are important long-term mitigation options, as IAM scenarios indicate. Their deployment has grown rapidly in the recent years and many countries have further adopted high deployment targets. However, in contrast to conventional generating technologies their output is *variable* in time and space. This causes challenges when integrating VRE into current and future power systems. Due to their coarse temporal and spatial resolution, IAMs cannot explicitly account for the variability of wind and solar PV and corresponding challenges. The implicit approaches that are currently used in many models have drawbacks, which reduce the robustness of their results. Improving the representation of variability and integration challenges is thus a major challenge for the IAM community. This requires insights and parameterizations from analyses that apply sufficient resolution to explicitly account for their variability. As introduced in section 1.4 there are two more research strands in addition to the IAM literature that evaluate VRE with much higher detail and could help advancing IAMs: the integration costs literature and the marginal value literature. However, both those research strands are barely interlinked and use different concepts and terminology. Consequently their results differ and their relation is unclear. Connecting all three research strands has huge potential for both, improving their individual approaches as well as combining their results to generate new insights.

This thesis explored new links between the research strands to enable a more robust evaluation of wind and solar PV under the consideration of their variability and the resulting integration challenges. These links are discussed in detail in the context of the academic conclusions in section 8.2. Implication for policy makers are concluded in section 8.3. Section 8.4 discusses the limitations of the results presented in this thesis and suggests further research directions. The next section 8.1 presents the main findings from the chapters 2 to 7 following the research questions posed in section 1.5.

8.1. Summary

This section summarizes the findings from the core chapters 2 – 7. It is structured along the six research questions formulated in section 1.5.

1. The foundation: What are the major integration challenges for variable renewables? (chapter 2)

Highlights:

- Three major challenges of integrating VRE into power systems are the low capacity credit, reduced utilization of dispatchable plants and over-production
- RLDC are a suitable heuristic tool allowing for quantitative analysis of integration challenges only based on demand and VRE supply data

- To a large extent the integration challenges depend on the penetration, mix of wind and solar, and region
- All integration challenges increase with penetration, irrespective of mix and region.
- For wind, the challenges increase more modestly with penetration than for solar.
- At low penetrations, solar PV is much easier to integrate in US Indiana than in Germany, while the challenges of integrating wind are fairly similar in both regions

This chapter investigated three major VRE integration challenges that are determined by the temporal matching of demand with supply patterns of VRE: low capacity credit, reduced utilization of dispatchable plants and over-produced VRE generation. Chapters 3 and 4 have shown that these challenges induce the most important integration costs component “profile costs”.

We demonstrated that RLDC are an appropriate tool for illustrating and quantifying the integration challenges. We found variables that represent the challenges. These variables were estimated for a large range of parameters, namely mix and penetration of wind and solar power in two regions (US Indiana and Germany).

We found that all integration challenges increase with penetration independently of mix and region. They can become significant at higher VRE shares (>20%) and thus should be considered in economic analyses and system planning. To a large extent they depend on the penetration and mix of wind and solar, and on the region. For wind the challenges increase more modestly with penetration than for solar, in particular over-production and the reduction of the utilization of baseload plants. At low penetrations, solar PV is much easier to integrate in the US than in Germany because during hot summer days peak supply of PV correlates favorably with peak demand, while for Germany the capacity credit is very low and rapidly vanishing with increasing penetration. The challenges of integrating wind are fairly similar in US Indiana and Germany. The wind capacity credit is relatively low even for low penetration.

The results showed that the deployment and integration of VRE must be planned from a system perspective to account for the matching of VRE supply with demand. The challenge variables are crucial system figures that depend on various parameters. The deployment of wind and solar should not purely be based on generation costs.

This work quantified challenge variables for a large range of wind and solar mixes and penetration and its regional dependence. The next step should be translating these estimates into economic costs. This requires a sensible concept of integration costs.

2. From integration challenges to integration costs: what are the economic costs of variability? What is an appropriate metric to compare power-generating technologies? (chapter 3)

Highlights:

- We proposed a new metric *System LCOE* that allows comparing power-generating technologies
- We derived a new definition of integration costs that comprises all economic costs of variability and has a direct economic interpretation
- We showed the equivalence of a cost perspective (System LCOE) and market value perspective
- At high shares, integration costs of wind power can be in the same range as generation costs of wind power, if storage, long-distance transmission and demand-side management are not available
- A significant driver of integration costs is the reduced utilization of capital-intensive dispatchable plants (profile costs)

The last chapter gave insights into major integration challenges of wind and solar without translating them into cost terms. However, policy makers demand for economic metrics to compare power-generating technologies and infer about their economic efficiency or competitiveness. The standard cost metric LCOE, which is widely used, is incomplete and misleading because it neglects integration costs. We proposed a new metric System LCOE that comprises generation costs as well as integration costs. For this purpose, we derived a new definition of integration costs that captures all costs of variability. In contrast to the standard understanding of integration costs, which is mainly rooted in engineering, this new definition directly relates to economic theory. System LCOE retain the intuitive and familiar format of LCOE, while allowing for an economic evaluation of generating technologies, in particular for VRE. In other words, Systems LCOE allow comparing the economic efficiency of power-generating technologies and deriving optimal quantities. Only because LCOE of wind drop below those of conventional plants, does not imply that wind generators are economically efficient or competitive. By contrast, if System LCOE of wind drop below the average System LCOE of a purely conventional system, wind is economically efficient and competitive. We showed that the cost perspective of System LCOE is equivalent to a market value perspective. This was further discussed in chapter 4.

The new economic definition of integration costs introduced here reveals a new component of integration costs termed profile costs. It can be understood as a more general conception of the standard cost component adequacy costs. While adequacy costs only cover backup costs due to a low capacity credit of VRE, profile costs additionally

account for the reduction of full-load hours of conventional plants and overproduction when VRE supply exceeds demand. These three integration challenges (low capacity credit, reduced FLH, overproduction) have been analyzed in a comprehensive parameter study in chapter 2. Only because the new definition of integration costs contains profile costs it can be economically interpreted as the total costs of variability and consequently used to evaluate VRE. The relation between the new and the standard definition of integration costs was discussed in detail in chapter 5.

Because the concept of System LCOE is equivalent to the market value perspective one may ask why the new metric is useful. System LCOE and the corresponding “cost perspective” suggest themselves for these three purposes:

- A cost perspective is very intuitive and thus often applied (in industry, policy, and academic publications and presentations) when comparing power-generating technologies, in particular to infer about their competitiveness. System LCOE can replace the misleading metric of LCOE that has been typically used for this purpose.
- A cost perspective is often applied by the “integration costs literature” in the tradition of electrical engineering or power system operation. System LCOE connects this research strand with the economic literature on marginal value and hereby provides a welfare-economic interpretation of integration costs estimates.
- Implementing System LCOE in long-term or multi-sector models particularly integrated assessment models (IAMs) can help to better represent the variability of VRE. Such an approach is sometimes already applied in IAMs by introducing rough estimates as cost penalties that increase with wind deployment (Luderer, Krey, et al. 2013). System LCOE can provide an improved parameterization due to its rigorous definition that comprises all economic costs of economic variability.

We quantified System LCOE for VRE in typical European thermal power systems based on model and literature results. Most importantly, at wind shares above 30%, marginal integration costs can be in the same range as generation costs, if integration options like storage or long-distance transmission are not deployed. At a wind share of 30% integration costs are about 45 €/MWh and can be added to generation costs of about 60 €/MWh. With higher VRE penetration integration costs significantly increase. Moreover, we found that profile costs are the largest component of integration costs, while grid-related costs and balancing costs due to forecast errors are comparably low.

Integration options could reduce integration costs. Three integration options are in particular important because they tackle profile costs: (i) adjusting the residual generation capacities to a mix with lower capital cost, (ii) increasing transmission capacity to neighboring power systems, in particular if those power systems do not develop high shares of VRE and (iii) any measure that helps shifting demand or supply in time such as

demand-side management and long-term storage. In a simple model it was shown that the first option reduces integration costs by about 20% at wind shares of 30%.

We concluded that integration costs tend to be underestimated in the literature and can become an economic barrier to further deployment of VRE. That does not necessarily imply that optimal shares of VRE are low, in particular when negative externalities of conventional plants and benefits of VRE are internalized. However, achieving high shares of VRE might need considerable policy intervention like very high carbon prices or significant policy support.

3. Further generalization: What is an appropriate welfare-economic framework to evaluate variable renewables? How can integration costs be decomposed exhaustively and consistently and what is their magnitude? (chapter 4)

Highlights:

- We provided a welfare-economic framework that unifies two equivalent perspectives on integration costs: System LCOE and marginal economic value
- We suggested a consistent, operationable, robust and comprehensive cost decomposition of integration costs
- We improved the estimation of integration costs from chapter 3 with an extensive literature review
- We found that integration costs are substantial: 25–35 €/MWh for wind at a generation share of 30–40%
- We confirmed that profile costs are high, while costs for balancing and grid are much lower in size

This chapter embedded the concept of System LCOE into a more generalized welfare-economic framework to evaluate VRE and in principle also other technologies. The framework consists of two equivalent perspectives on integration costs: A cost perspective (System LCOE) and a value perspective (marginal economic value). In the value perspective, integration costs are defined as the decrease of the marginal value of VRE with increasing share. This definition is equivalent to the definition developed from a cost perspective in chapter 3. Both perspectives have a direct welfare-economic interpretation, i.e. a long-term welfare optimum is characterized by two equivalent conditions: The sum of generation and integration costs (System LCOE) of each generation technology is identical, or equivalently, the marginal value of each technology equals its LCOE.

In chapter 3 we already revealed a new cost component “profile costs”. This cost component is now embedded in an exhaustive decomposition of integration costs, which is structured along the three fundamental characteristics of wind and solar power, namely

temporal variability, uncertainty, and location-specificity. The decomposition allows the isolated estimation of single components with specialized models. This is essential because directly estimating *total* integration costs would require a “super model” that accounts for all characteristics and system impacts of VRE, and such a model does not exist. Instead, with the decomposition total integration costs can be estimated by summing up separate estimates of the three cost components. Moreover, the decomposition allows comparing the cost impact of different properties of VRE, which helps identifying the major cost drivers and prioritizing integration options to better accommodate VRE.

Chapter 4 presented a broader and thus more robust quantification of integration costs compared to the estimates shown in chapter 3. In a literature review various estimates of integration costs and its components were extracted and carefully synthesized. The results are in line with the estimates from chapter 3:

- Integration costs are substantial at high deployment: in thermal systems wind integration costs are about 25–35 €/MWh at 30–40% penetration
- Size and composition of integration costs depend on the power system and VRE penetration: (marginal) integration costs can be negative at low (<10%) penetration, generally increase with penetration and are smaller in hydro than in thermal systems
- In thermal systems with high VRE shares, profile costs constitute more than half of total integration costs. This confirmed the importance of the integration challenges analyzed in chapter 1.

4. What is the link between the marginal value literature and the standard integration costs literature? (chapter 5)

Highlights:

- We explored two links between the marginal value literature and the integration costs literature
 - First, we explored in detail how the two concepts “integration costs” and “marginal value” of VRE relate
 - Second, we discussed the impact of system adaptations and different time horizons typically underlying both approaches
- We investigated that an adverse combination of VRE properties, an unfavorable legacy power system and a low capital turnover rate could cause a “lock-in” into power systems dominated by conventional plants

Chapter 5 further elucidated the connection between two research approaches and corresponding literature branches that both seek to evaluate VRE: the “integration costs approach” and the “marginal value approach”. We built on the chapters 2 and 3 and

worked out differences and related the concepts of both approaches to each other. We focused on two links that might inspire future research. First, how do “integration costs” relate to the “marginal value” of VRE? Second, what is the impact of different time horizons typically underlying both approaches and assumptions regarding the power system’s ability to adapt to VRE deployment?

We discussed that in the integration costs are typically defined as the additional costs imposed on the system when adding VRE, while the marginal value of VRE equals opportunity costs, which are avoided costs minus additional costs. The marginal value decreases at higher VRE penetration due to two effects: increasing integration costs and diminishing avoided costs. This means that increasing integration costs decrease the market value, while there is a second separate driver (diminishing avoided costs), which has the same economic effect. This link allows for a welfare-economic interpretation of integration costs estimates even though it needs the second driver to evaluate VRE. This is why chapter 2 and 3 introduced a new definition of integration costs that also includes diminishing avoided costs in a new cost component *profile costs*. This allows using integration costs to directly evaluate VRE and it partly resolves problems that are reported in the integration costs literature when trying to calculate integration costs or their components. Moreover, we inferred that the term “integration cost” needs to be cautiously defined and used.

Concerning the impact of different time horizons we suggested a categorization into three different types of system adaptations and related those to three temporal perspectives (short, mid and long term). Integration costs studies typically accurately analyze the impact of VRE from a short-term perspective, i.e. in currently existing systems with a fixed capacity mix and transmission system (legacy system). By contrast, the marginal value literature often studies the effect of VRE in the rather long term with less technical detail, where the capacity mix (and sometimes demand structure and the transmission grid topology) is assumed to adjust to higher VRE shares. We pointed out that assumptions on the time horizon have a strong impact on the results of evaluating VRE. System adaptations can significantly foster the deployment of VRE by reducing integration costs and raising their marginal value. An adverse combination of VRE properties, an unfavorable legacy power system and a low capital turnover rate could lead to high short-term costs and could cause a “lock-in” into power systems dominated by conventional plants. Hence, short-term costs estimates of VRE should be treated with care and not solely attributed to VRE. Any analysis should be explicit about the temporal perspective applied and aware of its effect on the results. Incorporating the temporal evolution and potential adaptations of the power system into evaluating VRE and calculating integration costs is an important research direction. This would allow determining efficient transformation pathways towards an energy system with possibly high shares of VRE while accurately accounting for their variability and integration options.

5. What are the implications for modeling VRE in IAMs? (chapter 6)

Highlights:

- We introduce the RLDC approach, which accounts for short-term variability of power demand and VRE in long-term climate change mitigation scenarios
- We demonstrate the impact of the RLDC approach with REMIND-D, a long-term multi-sector model of the German economy
- Variability reduces the generation of VRE in 2050 by 35% in a business-as-usual scenario and by 27% in an ambitious mitigation scenario
- Variability increases mitigation costs by 18%, but power-to-gas storage can alleviate this increase by one third

Improving the representation of power sector variability is among the highest priorities for the further refinement of integrated energy-economy climate models used for analyzing long-term climate change mitigation scenarios. This chapter introduced the RLDC approach – a method of how to consider short-term temporal variability of VRE and power demand when modeling long-term climate change mitigation scenarios, in particular with IAMs. The approach features three main merits. It firstly covers the most important variability impacts in particular profile costs, secondly is valid for a broad scenario space with different energy system configurations and thirdly provides flexibility of choosing among multiple pathways of integrating VRE.

In an application for the model REMIND-D, the substantial impact of the approach on model results confirms that power sector variability matters. Considering variability reduces the deployment of VRE by 35% in the baseline scenario and by 27% in an ambitious mitigation scenario in 2050. The model requires significantly more non-VRE capacity, in particular gas-fired plants. The consideration of variability changes key macro-economic figures: Mitigation costs increase by 18% compared to a model version in which variability is not taken into account. Power-to-gas storage can reduce this increase by one third.

The specific merits of the RLDC approach and its impact on model results suggest that using this method in a long-term multi-sector model would improve the robustness and credibility of mitigation scenarios. In particular, it would foster a more accurate estimation of mitigation costs and the role of VRE in low-carbon transformation scenarios. However, the RLDC approach has important limitations. For example, the approach does not allow for an accurate accounting of additional grid and balancing costs of VRE. Developing commensurate refinements is the subject of further research. The endogenous representation of RLDC can be complemented with other elements, such as an implementation of cost parameters (such as System LCOE) for grid and balancing costs.

6. What are the redistribution effects of VRE support and how do they compare to those of carbon pricing? (chapter 7)

Highlights:

- VRE support and carbon pricing have strikingly different impacts on rents
- VRE support schemes (quota systems or feed-in tariffs) decrease producer surplus (of conventional plants) and increase consumer surplus
- Carbon pricing (emissions trading or carbon taxes) has the opposite effect: producer surplus increases, and consumer surplus decreases
- We develop an evaluation framework and model these impacts theoretically and quantify them for North-Western Europe
- Redistribution of wealth is found to be significant in size

While the previous chapters evaluated VRE with respect to total welfare or system costs, this last chapter estimated and discussed redistribution flows between producers and consumers induced by two policy instruments VRE support and carbon pricing.

We found that redistribution flows can be large relative to the additional total system costs induced by the policies. For a numerical model analysis for North-Western Europe we showed that the two policies induce diametrically opposed redistribution flows: VRE support transfers rents from consumers to producers, while CO₂ pricing does the opposite. If wind support is efficiently chosen to just equal their LCOE, transfers are large enough to make consumers benefit even if they pay for the wind subsidies (assuming perfect retail markets). Suppliers as a group benefit from carbon pricing, even if they have to pay for emission allowances, while in the group there are large transfers from carbon-intensive to low-carbon generators. These results were found based on a newly developed framework to consistently estimate redistribution effects of policies. This framework has then been applied in both a theoretical and a numerical model.

The potentially large redistribution effects might be barriers to transforming a power system towards low CO₂-emissions and high shares of VRE. We concluded that economic research should not only focus on the overall efficiency or welfare effects of policies. Understanding redistribution effects helps policy makers designing a policy mix that reduces implementation barriers even if such a mix might not be the first-best policy to internalize externalities. Such trade-offs between efficiency and redistribution are a promising research direction.

8.2. Research synthesis

This thesis helped connecting the three research strands on evaluating VRE: the integration costs literature, the marginal economic value literature and the integrated assessment modeling literature. I presented new concepts, methods and quantitative

results at the interface of the existing research strands. Figure 63 illustrates how selected achievements of this thesis bridge the gaps between the three strands.

This thesis links three literature strands to improve the evaluation of VRE and integration costs

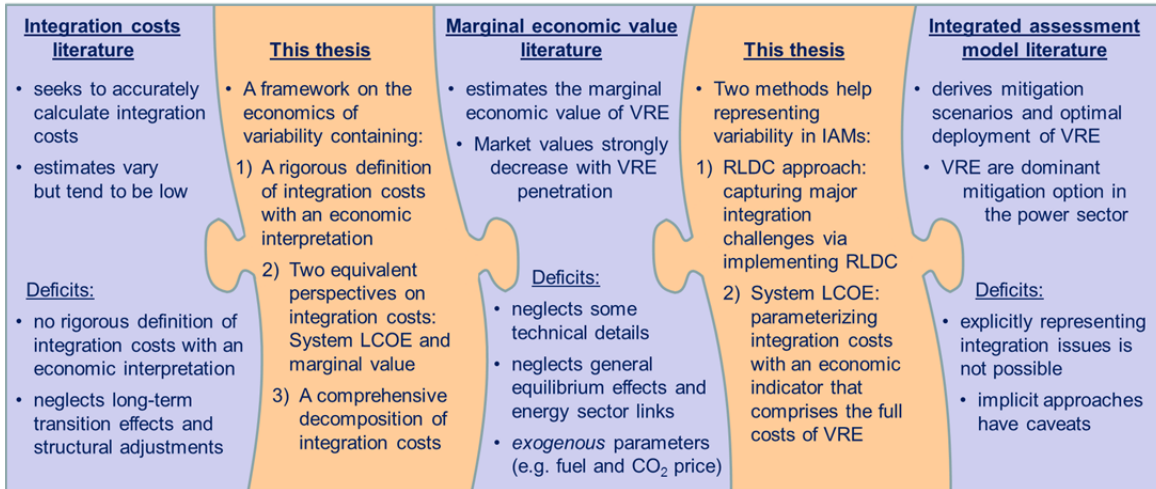


Figure 63: This thesis bridged the two gaps between the three literature strands on evaluating VRE. First, it presented a framework for the economics of variability and second, it proposed two methods that help representing variability in IAMs. This improves the understanding of the economic impacts of variability and their representation in mitigation scenarios.

Bridging the integration costs literature and the marginal value literature

So far the two literature branches have been hardly interlinked. They use different concepts and terminology and it was to a large extent unclear how their approaches and results related to each other. Studies from the integration costs literature did not enable a welfare-economic evaluation of VRE. Specifically, their definitions of integration costs did not allow for an economic interpretation of integration costs estimates. Their studies typically apply a bottom-up engineering perspective focusing on different aspects of variability. Until now it remained unclear if such assessments of variability impacts are complete and how the resulting cost estimates can be embedded in an economic evaluation of VRE. By contrast, the marginal value literature economically evaluates VRE and sometimes calculates welfare-optimal deployment levels. Studies from this strand account for variability without explicitly calculating integration costs. Even though they represent less technical detail than integration costs studies they calculate a stronger impact of variability. However, it was to a large extent unclear how the approaches and results of both research strands relate to each other.

At the core of bridging both strands this thesis suggested a new framework for the economics of variability. It consists of three elements: (1) A new definition of integration costs, (2) two equivalent perspectives – System LCOE and marginal value – of how to account for integration costs, and (3) a comprehensive economic decomposition of integration costs. These elements are described in the next three paragraphs.

- 1) The framework is based on a new definition of integration costs that is more comprehensive and rigorous than previous definitions. In contrast to previous approaches, the definition captures all costs of variability and relates directly to economic theory. The new definition revealed an important new component of integration costs that we term “profile costs”. Profile costs can be defined as the additional system costs induced by the imperfect temporal matching of VRE supply with electricity demand, which results in a low capacity credit, reduced utilization of dispatchable plants and over-produced VRE generation. These costs occur in an indirect way because they reduce the value of VRE but do not impose additional costs when VRE are added to an existing system.⁶⁶ That is why profile costs were often neglected or underestimated in the integration costs literature, which focused solely on additional costs, while the marginal value literature in principle accounted for all variability aspects that reduced the value of VRE. This explains why the two literature branches systematically differed when estimating the impact of variability.
- 2) The core of the framework are two equivalent perspectives on integration costs: From a *cost* perspective integration costs are added to the generation costs of VRE (System LCOE) while from a *value* perspective integration costs reduce the marginal economic value of VRE. Both perspectives have a direct welfare-economic interpretation, i.e. equivalent first-order conditions determine the welfare-optimal deployment of VRE. Previous integration costs studies were incomplete in their accounting of costs, and could therefore not be related to the marginal value literature. The concept of System LCOE introduced in this thesis (Chapter 3) broadened the cost perspective of integration costs studies such that it is equivalent to the economic literature on marginal value.
- 3) The framework further proposed a comprehensive decomposition of integration costs along the three crucial characteristics of VRE: profile costs reflect temporal variability, grid-related costs reflect spatial variability, and balancing costs reflect short-term uncertainty of VRE supply. Since there is no “super model” accounting for all variability aspects that could calculate total integration costs, specialized models are required to calculate specific cost components. Hereby highly-resolved integration costs models can derive estimates for e.g. balancing or grid costs that can be combined with profile cost estimates from the marginal value literature. Total integration costs can then be approximated as the sum of these components.

⁶⁶ For example, the low capacity credit of VRE does not require additional back-up capacity in the short term because there is enough capacity in an existing system. However, costs occur in the long run when conventional capacity needs to be rebuilt that otherwise could have been removed if VRE had a higher capacity credit.

Using the new definition of integration costs and its decomposition allowed combining the results of both, the integration costs and the marginal value literature. Estimating total integration costs from an extensive literature review and own quantifications with a stylized model showed that they are large: 25–45⁶⁷ €/MWh at wind share of about 30%, with increasing (marginal) costs for higher shares. Integration costs for solar are of similar magnitude at high shares as indicated by comparing the integration challenges of wind and solar. Moreover, we found that profile costs are the largest component of integration costs, while grid-related costs and balancing costs are comparatively low. This was a surprising result because the latter received more attention in the integration costs literature and the public debate. Hence, when evaluating VRE their full integration costs should be considered, in particular their profile costs.

Moreover, this thesis showed that integration costs depend strongly on the time horizon underlying the analysis and on the consideration of system adjustments. Integration costs studies typically apply a short-term perspective, i.e. they typically add VRE to an existing system with fixed generation and transmission capacities. The marginal value literature often uses a long-term perspective, in which the power system can adjust with higher VRE shares. System adaptations can significantly ease the deployment of VRE by reducing integration costs, and raising their marginal value. Hence, any analysis should be explicit about the temporal perspective applied and aware about its effect on the results. Short-term costs of VRE, which partly occur due to an unfavorable legacy power system and a low capital turnover rate, should be treated with care. Neglecting system adaptations can lead to misleading conclusions when determining efficient transformation pathways towards an energy system with possibly high shares of VRE.

Bridging the marginal value literature and the integrated assessment modeling literature

Importantly, the representation of VRE in IAMs needed to be improved. Since numerical constraints prohibit increasing their temporal and spatial resolution to a degree that would allow for an explicit description of variability, it needed a stylized representation that captured the major impacts of variability. Marginal value studies account for these impacts. However, they do not explicitly calculate integration costs estimates or carve out the economic impact of variability in a way that could serve as a stylized parameterization to IAMs.

This thesis presented two approaches of how to use the insights of the marginal value literature to improve the representation of VRE in IAMs: (1) System LCOE and (2) the RLDC approach.

⁶⁷ The higher values do neglect a number of integration options like the long-distance transmission, energy storage and changes in the temporal demand profiles.

- 1) This thesis introduced a new metric System LCOE, which comprises generation and integration costs of VRE. In a next step this metric can be implemented in IAMs to represent the full costs of VRE including the costs of variability. Some IAMs already represent variability with cost penalties for VRE; albeit their economic basis is unclear. System LCOE can improve these approaches by providing a rigorous welfare economic motivation and parameterization. To estimate System LCOE high-resolution numerical models are necessary. Because System LCOE are system specific (they depend on the mix of power supply technologies), ex-ante estimates might not be suitable for a broad range of IAM regions and scenarios. A parameterization needs to be carefully conducted. Ideally it would need an iterative process of soft coupling of an IAM and a highly-resolved partial model to derive consistent scenarios. System LCOE could be estimated on a region-specific basis and resultant IAM results should be fed back to the partial model to verify the ex-ante estimate. To keep this complex parameterization manageable, some aspects of variability should be modeled explicitly, where possible.
- 2) The RLDC approach allowed for an explicit representation of the most important integration costs component: profile costs. This thesis has shown that even though RLDC are a purely physical concept, which only requires demand and VRE supply data, it delivers the correct economic impact of major integration challenges. By implementing RLDC into the multi-sector long-term model REMIND-D these challenges and corresponding costs could be directly represented without using exogenous cost parameters. Moreover the system's response to those challenges could be modeled endogenously, such as changes in the conventional capacity mix or the deployment of hydrogen and methane storage facilities. More detailed aspects of variability like grid-related and balancing costs could be implemented by adding a reduced-form formulation of System LCOE. A comprehensive representation of variability in an IAM would likely be a model-specific combination of different explicit and implicit elements.

The two approaches pave the way for a sound representation of variability, which would resolve one of the most important limitations of IAMs. This would increase the credibility of essentially all scenario results, and in particular two key figures: the economic potential of VRE and mitigation costs estimates.

8.3. Policy implications

Five highly policy-relevant conclusions can be drawn from the results presented in this thesis:

- 1. Because integration costs are significant they can become an economic barrier to high deployment levels of wind and solar power.**

A core result of this thesis was that integration costs of wind and solar can be substantial compared to the average whole-sale electricity price or generation costs of wind. They increase significantly with VRE penetration. An extensive literature review and own modeling showed that at a wind share of about 30% integration costs are about 25–45⁶⁸ €/MWh (sections 3.3.2 and 4.7). This new result was based on an integration costs concept that captures both the direct technology costs (e.g. additional costs for grid or balancing) as well as the indirect costs induced by diminishing economic value of VRE due to temporal variability, so-called profile costs. Profile costs are the additional system costs induced by the imperfect temporal matching of VRE supply with electricity demand, which results in a low capacity credit, reduced utilization of dispatchable plants and over-produced VRE generation. The new concept of integration costs comprises all costs of variability and thus has a clear economic interpretation that can be used to determine the optimal deployment of VRE.

Because integration costs are significant they can become an economic barrier to high deployment levels of wind and solar power. Integration costs reduce the cost-efficient and competitive share of VRE compared to the hypothetical situation without variability. That is why an analysis that neglects variability is misleading. For example, LCOE of VRE dropping below those of conventional plants is not a sufficient condition for cost-efficiency or competitiveness of wind or solar power.

However, welfare-optimal shares of VRE and their mitigation potential might still be high for three reasons. First, negative externalities of all generation technologies should be fully internalized, foremost the climate change externality. High carbon prices would reduce the economic efficiency of freely emitting carbon-intensive power plants (without CCS). Competing low-carbon options including nuclear, CCS and biomass plants face other sustainability and social acceptance concerns that need to be considered. Second, positive contributions of VRE to achieving social objectives other than climate change mitigation, for example reduced local environmental impacts or energy access, might to some extent compensate for high integration costs and lead to increased welfare-optimal shares. In a real market with decentralized actors it thus requires the internalization of all externalities, negative and positive, to realize the welfare-optimal share of VRE. Third, learning-by-doing and economies of scale might further reduce the generation costs of wind power and solar PV, in case these effects are not compensated because new VRE plants need to be built at poorer sites with lower annual FLH.

In case some externalities are not internalized, e.g. because sufficiently high carbon prices are not feasible or desired, reaching high VRE shares might require significant and continuous financial support, such as feed-in-tariffs or quota systems, also in the next

⁶⁸ The higher values do neglect a number of integration options like the long-distance transmission, energy storage and changes in the temporal demand profiles.

decades to reach their socially optimal share. This is because integration costs are to a large extent reflected in real market prices and reduce the market value of VRE, i.e. the specific market income of a VRE investor. If VRE plants would gain no subsidies and would thus need to cover their costs only from market incomes, integration costs might significantly reduce their competitive shares to a socially sub-optimal level.

In case society aims for high VRE targets that exceed the socially optimal share, VRE would also need permanent financial support, even if their LCOE are below those of conventional plants. This is not because power markets work inefficiently and thus it is no question of market design as sometimes suggested (Kopp, Eßer-Frey, and Engelhorn 2012, Winkler and Altmann 2012) and partly argued in the public debate. On the contrary, in a perfect market it would require a financial support scheme to push VRE above an optimal level.

2. A system perspective is required for evaluating VRE.

The economics of power systems are coined by multiple interdependencies between different power technologies on different temporal and spatial scales, and depend on market design and policy environment. As a consequence, a systems perspective is required to perform an economic evaluation of power-generating technologies and to derive cost-efficient transition pathways to a low-carbon energy system. In particular, the challenge of integrating VRE depends on penetration and mix of wind and solar, on the existing power system and its potential to adapt, as well as on regional demand and VRE supply patterns.

Hence, conventional production-based LCOE (and other indicators like grid parity) are an incomplete and misleading metric to evaluate and compare technologies, because they neglect integration costs occurring on a system level. By contrast, the new metric System LCOE allows an unbiased analysis because it comprises generation costs as well as integration costs.

The approaches of System LCOE and marginal value are equivalent. However, the main merit of using System LCOE is that it takes a cost perspective. Comparing costs is very intuitive and thus often applied in industry, policy, and academic publications and presentations when evaluating power-generating technologies, in particular to infer about their competitiveness. System LCOE can replace the incomplete metric of LCOE, because it remains an intuitive metric yet accounting for the complex interaction of variable renewables, other generating technologies and potentially integration options.

An economic evaluation of VRE should take a system perspective that accounts for both variability of VRE and a potential adaptation of the non-VRE part of the power system. This thesis supports future analyses with its new insights into the economics of variability and, based on this, innovative methodical approaches for incorporating variability in long-term multi-sector models.

3. Integration options might significantly reduce integration costs and hereby reduce economic barriers.

Integration options are measures and technologies that can reduce integration costs or equivalently increase the value of VRE and hereby further mitigate barriers to VRE deployment. Some integration options are already considered in some of the reviewed studies and own analyses, such as changes in the conventional capacity mix, some storage technologies or an increase of transmission capacity. Adapting the residual non-VRE capacity mix has a large effect. In a simple model, integration costs could thereby be reduced by about 20% at wind shares of 30% (section 3.3.2). More specifically, a shift from capital-intensive base load plants to peak load gas plants substantially reduces profile costs. However, integration costs tend to remain substantial.

Other fundamental changes in the energy system have not been considered when calculating integration costs in this thesis. These integration options could further reduce the integration costs estimates. Examples are demand side management (DSM), long-distance transmission grid expansion or seasonal storage technologies like power-to-gas storage (Sterner 2009) or large-scale pumped hydro storage. A substantial potential role of power-to-gas was indicated in a model analysis of the German energy system: In an ambitious mitigation scenario with high shares of VRE, power-to-gas storage could reduce an increase of mitigation costs due to power sector variability by about one third (section 6.3.2).

This thesis helped identifying suitable integration options by revealing the most important integration challenges. We found that profile costs constitute the largest part of integration costs. Grid reinforcement costs and costs for balancing due to forecast errors are comparably low. Three integration options are in particular important because they reduce profile costs: firstly, adjusting the non-VRE generation capacities to a mix with lower capital cost, secondly, increasing transmission capacity to neighboring power systems reduces integration costs strongly, in particular if those power systems do not develop similar high shares of VRE and thirdly, any measure that helps shifting demand or supply in time like demand-side management and electricity storage. For reducing profile costs significantly, electricity needs to be shifted in time scales of weeks to seasons. This indicates that it needs storage systems with high reservoirs at preferably low costs. Pumped-hydro storage has high potential in some regions such as Scandinavia or the Alps. Power-to-gas storage in principle offers huge reservoirs in many power systems because electricity can be transformed into hydrogen or methane, which can be stored in the existing gas infrastructure and used in all energy sectors. In general, the links between the power sector and other sectors could be utilized to shift demand and supply in time. Combined heat and power plants could easily be extended with thermal storage. In future, electric vehicles might offer storage and DSM possibilities.

The future role of these options is unclear. On the one hand in principle they could significantly decrease integration costs. For example profile costs could be reduced to zero if demand could be flexibly shifted over the course of a year at low costs, i.e. demand would follow VRE supply to a large extent. On the other hand there might be a limit for the system's ability to change. For example, electricity demand will most likely never be perfectly elastic. Fundamental changes take time and thus will probably not unfold their full potential until the medium term (~2030). Furthermore deploying integration options and reducing integration costs is not an end in itself. Integration options cause costs, which need to be compared with their value added to the system. There is no scientific consensus on which and to what extent integration options are economically efficient. Deriving an optimal mix of integration options requires a comprehensive analysis of a power system considering the complex interaction of VRE, other generating technologies, potential fundamental system changes and the relevant externalities. This was beyond the scope of this thesis and thus the integration costs estimates herein represent no final results.

4. Variability should be considered in market design and policy instruments.

From an economic perspective integration costs should be internalized i.e. be reflected in market prices such that they are borne by the causal (VRE) generators. This would remunerate those generators with low integration costs and thus incentivize both an efficient deployment of VRE and integration options that lower integration costs. While temporal variability (i.e. profile costs) is well-reflected in many markets, spatial variability is not due to missing locational price signals. Also balancing systems could be more market-oriented and in most markets VRE generators do not bear the full costs of their uncertainty. Governments and regulatory agencies should shape the design of power markets such that they better internalize integration costs. Note that this thesis did not indicate a fundamental reason why markets should not function even at high shares of VRE, yet the appropriateness of energy-only markets for VRE-dominated power systems is an open question.

Moreover, also policy instruments should be designed such that they account for variability. In particular renewable support schemes should not be independent of market prices and thus should not remunerate every generated unit homogeneously like standard feed-in tariffs. Also if renewable generators are subsidized, it needs to be ensured that price signals shaped by integration costs reach the subsidized investor for incentivizing a reduction of integration costs. Feed-in premiums are advanced in this respect because they tie the remuneration to the varying actual market price of electricity. The premium could be chosen such that only those VRE generators are profitable that do not impose more than a specific amount of integration costs. This could, for example, lead wind generators to invest in wind turbines that have a profile that better matches with demand.

5. In the short term, VRE deployment can induce high costs and redistribution flows.

It is important to distinguish short-term from long-term effects when introducing VRE into a system. In the short term, when VRE are driven by support policies, particularly high integration costs are induced. These costs are not only imposed by variability but by an adverse combination of three conditions: variability, an unfavorable legacy power system, and a low capital turnover rate of the power system. These short-term system costs decrease when the power system transforms in response to increasing VRE penetration (that is why in chapter 5 they were also termed transformation costs). However, because of system inertia due to a limited capital turnover rate, this transition can take several decades. During the transition period the system costs remain high, which might hinder the optimal adoption of policy instruments and thus could create a potential barrier to reaching the long-term optimal deployment of VRE. In that sense path dependency and system inertia could cause a “lock-in” into a power system dominated by conventional plants.

Distributional effects might even intensify this lock-in effect. When introducing VRE support the resulting short-term costs are distributed unequally among the non-VRE generators and consumers. VRE investors only pay their private generation costs (LCOE), which are in some way covered by a combination of support scheme remunerations and potentially market revenues. Short-term costs are reflected in a decreasing whole-sale electricity price and consequently reduce the income of conventional producers. By contrast, consumers benefit from reduced whole-sale electricity prices (assuming perfect retail markets). For wind power, chapter 6 showed that consumers can be better off even if they pay the wind subsidies. Hence, VRE support induces redistribution flows from conventional producers to electricity consumers, which can be larger than the net system cost increase induced by VRE. This gives conventional generators the incentive to lobby against VRE support schemes. If large redistribution flows are not desired by society or single actors they can induce implementation barriers to specific policy instruments. By contrast, CO₂ pricing (emissions trading or carbon taxes) can increase aggregated producer surplus, even without free allocation of emission allowances; however, not all types of producers benefit. Combining the two policies VRE support and carbon pricing allows policy makers to reduce redistribution effects. This can reduce implementation barriers even if the policy mix might not be the first-best policy to internalize externalities such as the climate externality.

8.4. Limitations and further research

This thesis improved the economic evaluation of VRE and the understanding of integration costs in a broad range of aspects, yet the results are by no means final. Many further research directions arise. I point to the most important ones.

- A large part of the thesis had a conceptual focus. Some of the new concepts and approaches were only applied in simple models for demonstration purposes. They should be applied in more comprehensive and sophisticated models. System LCOE and integration costs (based on the new definition) should be calculated with a more realistic high-resolution energy system model. These models should develop towards a “super model” that captures all aspects of variability. As such a model does not yet exist, the new decomposition of integration costs could be applied to estimate single cost components with specialized models and sum them up to total integration costs. Hereby the two approaches of integration costs studies and the marginal value literature should be combined, building on their link explored in this thesis. Further exploring this link is promising research because more studies with common definitions and rigorous methods are needed to increase the robustness of the estimates.
- When quantifying integration costs integration options need to be more comprehensively represented. While the concepts presented in this thesis in principle account for integration options, only a few options were considered when applying the concepts for quantifications. Foremost deep structural changes of energy systems with high shares of VRE should be modeled in future analyses such as substantial changes of demand patterns, long-distance transmission grid expansion, seasonal storage technologies and a strong integration of the different energy sectors. This might considerably decrease integration costs estimates.
- A sensible representation of power sector’s variability in IAMs is among the highest priorities in IA modeling. System LCOE can be implemented in IAMs to represent the full costs of VRE. To estimate System LCOE high-resolution numerical models are necessary. A parameterization needs to be carefully conducted, because System LCOE depend on many boundary conditions such as the technology mix in the energy system, fuel prices or regions. Ideally it would need an iterative process of soft coupling of an IAM and a highly-resolved partial model to derive consistent scenarios. To keep this complex parameterization manageable, some aspects of variability should be modeled explicitly, where possible. The RLDC approach explicitly accounts for the most important integration challenges without using exogenous cost penalties. It has been refined and demonstrated in the REMIND-D model and is thus ready to be implemented in global IAMs. Structural shifts in the conventional capacity mix and seasonal energy storage via hydrogen and methane could be included, yet a sensible consideration of other integration options remains an open question. The RLDC approach could be ideally complemented by a reduced-form formulation of System LCOE that covers detailed aspects of variability like grid-related and balancing costs. A sound representation of variability would likely be a model-specific combination of different explicit and implicit elements.

- Moreover it is an open and promising research question whether variability of wind and solar PV enhances existing or induces new market failures. Even without VRE there is disagreement on whether energy-only markets can appropriately price capacity via scarcity prices (Boiteux 1960, Crew, Fernando, and Kleindorfer 1995, Cramton and Ockenfels 2012). This thesis indicated no fundamental reason why markets should not function even at high shares of VRE.
- This thesis provided understanding and estimates of short-term integration costs and distributional flows induced by VRE policies. These costs can be high due to VRE properties, an unfavorable legacy power system dominated by conventional plants, and a low capital turnover rate of the system. Redistribution flows, in particular, can be a barrier to implementing or maintaining VRE support policies. A policy mix can reduce redistribution flows and decrease barriers even if that is not the first-best policy to internalize externalities. Economic research should not only focus on the overall efficiency or welfare effects of policies. Investigating the trade-offs between efficiency and reducing redistribution is a promising research direction. In view of potential short-term barriers to VRE deployment a guiding research question could be: What are efficient policy instruments that avoid a conventional lock-in and pave the way for reaching the long-term optimal deployment of VRE?

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Nomenclature

CCS	Carbon Capture and Sequestration	System LCOE	System Levelized Costs of Electricity
EGS	Enhanced Geothermal Systems	TSO	Transmission system operator
ENTSO-E	European Network of Transmission System Operators for Electricity	VRE	Variable renewable energy sources
EU	European Union		
FLH	Full-load hours		
GAMS	General Algebraic Modeling System		
GHG	Greenhouse Gas		
IAM	Integrated Assessment Model		
IPCC	Intergovernmental Panel on Climate Change		
LCOE	Levelized Costs of Electricity		
LDC	Load duration curves		
PV	Photovoltaic		
REMIND	Regionalized Model for Induced Technological Change		
RES	Renewable energy sources		
RLDC	Residual load duration curves		

Statement of Contribution

The six core chapters 2–7 of this thesis are the result of collaborations between the candidate and his principle advisor, Prof. Dr. Ottmar Edenhofer, and his direct supervisor, Dr. Gunnar Luderer, and other colleagues. The candidate has made significant contributions to the contents of all six chapters, from conceptual design, to technical development and implementation, and writing. This is specified below. Chapters 1 and 8 were outlined and written by the candidate and Gunnar Luderer, Olivia Serdeczny, Steffen Brunner and Ulrike Kornek provided helpful comments.

Chapter 2 The candidate, Robert Brecha and Gunnar Luderer were jointly developing the research design of the article. Robert Brecha and the candidate were jointly conducting the technical analyses and writing the article. The article was coordinated by the candidate.

Chapter 3 The candidate initiated, coordinated and wrote the article. The research design was developed jointly by the candidate, Lion Hirth, Gunnar Luderer and Ottmar Edenhofer. Helpful comments were provided by Lion Hirth, Gunnar Luderer and Ottmar Edenhofer. More comments from a number of people are gratefully acknowledged in the chapter.

Chapter 4 The research design was developed jointly by the candidate, Lion Hirth and Ottmar Edenhofer. Lion Hirth and the candidate wrote the article. Lion Hirth coordinated the article and was responsible for the literature review and the quantification section. The theoretical sections were developed jointly by Ottmar Edenhofer, Lion Hirth, and the candidate. Comments and support from various parties are gratefully acknowledged in the article.

Chapter 5 The candidate, Simon Müller, Lion Hirth and Marco Nicolosi were jointly developing the research design and jointly writing the article. The candidate was coordinating the article.

Chapter 6 The candidate coordinated and wrote the article. The research design was developed jointly by the candidate, Robert Brecha, Gunnar Luderer, Patrick Sullivan, Nico Bauer. Eva Schmid developed the model REMIND-D on which the analysis is based. Diana Böttger contributed to the refinement of the presented method with validation runs conducted with a dispatch model.

Chapter 7 The candidate and Lion Hirth were jointly developing the research design and jointly writing the article. Lion Hirth initiated and coordinated the article. He was responsible for the numerical model results, while the candidate provided the analytical model analysis. Comments and support from various parties are gratefully acknowledged in the article.

Tools and Resources

This section lists the tools and resources that were used by the author to complete this thesis.

Modeling: The numerical modeling performed by the author made use of the General Algebraic Modeling System (GAMS), version 22.7.2 (Brooke et al., 1988) and the CONOPT3 solver, version 3.14S, for non-linear programs (Drud, 1994), or using The MathWorks' MATLAB, version 6.5 release 13 (MATLAB, 1998).

Data Processing: Model output was analyzed and illustrated using The MathWorks' MATLAB, version 6.5 release 13 (MATLAB, 1998), Microsoft Excel 2010, and Microsoft PowerPoint 2010.

Typesetting: This document was written with Microsoft Word 2010. The style sheet was provided generously by Steffen Brunner.

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