

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 qualified criticism particularly towards evaluating variable renewables like wind and solar power based on LCOE because it ignores integration costs that occur at the system level. In this paper we propose a new measure *System LCOE* as the sum of generation and integration costs per unit of VRE. For this purpose we develop a conclusive definition of integration costs. Furthermore we decompose integration costs into different cost components and draw conclusions for integration options like transmission grids and energy storage. System LCOE are quantified from a power system model and a literature review. We find that at moderate wind shares (~20%) integration costs can be in the same range as generation costs of wind power and conventional plants. Integration costs further increase with growing wind shares. We conclude that integration costs can become an economic barrier to deploying VRE at high shares. This implies that an economic evaluation of VRE must not neglect integration costs. A pure LCOE comparison would significantly underestimate the costs of VRE at high shares. System LCOE give a framework of how to consistently account for integration costs and thus guide policy makers and system planers in designing a cost-efficient power system.

Index Terms – renewable energy, integration costs, levelized costs of electricity, LCOE, environmental economics, power generation economics, wind power, solar power, electricity market, market integration

Highlights

- We propose a new metric *System LCOE* to determine the economic costs of wind and solar power.
- Integration costs of wind power can be in the same range as generation costs at moderate shares (~20%).
- Integration costs can become an economic barrier to deploying VRE at high shares.
- A significant driver of integration costs is the reduced utilization of capital-intensive conventional plants.
- An economic evaluation of wind and solar power must not neglect integration costs.

¹ The findings, interpretations, and conclusions expressed herein are those of the authors and do not necessarily

1. Introduction

The full life-cycle costs (fixed and variable) of a power generating technology per unit of electricity (MWh) are often called levelized costs of electricity (LCOE) or levelized energy costs (LEC). They are a common metric for calculating the costs of generating technologies in the power sector (for example Karlynn & Schwabe 2009; IPCC 2011; Borenstein 2011; Kost et al. 2012). One reason is that this metric allows comparing conventional plants with variable renewable sources (VRE) like wind and solar power, even though they have 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 that once LCOE of VRE dropped below those of conventional plants, VRE deployment should be competitive and economically efficient. However, there is qualified criticism towards this conclusion and the metric of LCOE itself.

Joskow (2011) shows that LCOE are a flawed metric for comparing the economic attractiveness of VRE with conventional dispatchable² generating technologies such as fossil, nuclear, or hydro plants. Moreover LCOE alone do not say anything about profitability or competitiveness. One main reason that Joskow points out 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 or generation profile. A LCOE comparison ignores this issue.

Joskow concludes that an economic evaluation of any power generating technology should be complemented by its market value, which is its revenue. If markets are perfect and complete, the market value of VRE equals their marginal economic value. VRE are competitive and economically efficient if their market value at least equals their levelized costs.

The deficits of a LCOE analysis and the importance of a market value perspective become more important with increasing shares of VRE. Hirth (2012b) shows that the market values of VRE in Europe significantly decrease with increasing VRE penetration because the electricity price decreases most in times of much VRE supply. Hence, competitiveness for higher shares of VRE will become more difficult than a LCOE comparison with conventional plants would imply. Mills and Wiser (2012) show similar results for California. The marginal economic value of solar PV, CSP (without thermal storage) and wind power drops when increasing the respective generation share. Grubb (1991) shows this effect in model results for the value of wind in England.

In this paper we propose an alternative approach to overcome the deficits of LCOE. As a starting point we interpret the reduction of VRE's market values as *integration costs*. If markets are perfect and complete the market value of VRE investors would incorporate all integration costs. In that sense we rephrase Joskow's criticism as follows: Levelized

² The output of dispatchable plants can be widely controlled, whereas VRE are subject to natural fluctuations.

costs are a flawed metric for economically comparing generation technologies because they neglect integration costs. We introduce a metric termed *System LCOE* that comprises both: generation costs and integration costs. System LCOE are the total levelized economic costs of a technology. They not only contain direct generation costs like standard LCOE but also reflect indirect costs that occur on the system level.

In contrast to standard LCOE the new metric allows to economically evaluate VRE. We show that a cost-optimal and competitive penetration level of VRE is given by the point where System LCOE of VRE equals the average System LCOE of a conventional system without VRE. Thus System LCOE can be helpful to policy makers and system planners to design and incentivize a cost-efficient power system, in particular because integration costs can be a large part of the costs of an energy transformation towards variable renewables.

Because System LCOE account for integration costs, unlike standard LCOE they cannot be calculated directly from plant-specific parameter. Rather, to calculate System LCOE one needs system-level cost data that can be either estimated from a model or recovered from observed market prices. In this paper we derive mathematical expressions for integration costs and System LCOE that can be applied to most models. For a proposal of how to estimate integration costs from market price data see Hirth (2012a)

System LCOE are an intuitive metric to understand and illustrate integration costs. We moreover suggest a decomposition of integration costs into different cost drivers that account for variability, uncertainty and location-specificity of VRE. This allows estimating the importance of different integration options like storage or transmission grid expansion. Furthermore the expression of integration costs per energy unit of VRE gives a simple parameterization of integration issues that can be implemented in large-scale models like integrated assessment models that lack the high temporal and spatial resolution to capture important power system effects that drive integration costs.

In general, 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 (see section 3). Thus we focus on integration costs of VRE in this paper.

The paper is structured as follows. In the next section we conceptually introduce System LCOE and rigorously define integration costs. Section 3 gives an overview on different drivers of integration costs. Section 4 shows quantifications of System LCOE based on a model analysis and literature estimates and section 5 derives implications for integration options. Finally, section 6 summarizes and concludes.

2. System LCOE and a definition of integration costs

To define System LCOE formally, we need a definition of integration costs. This section presents a rigorous definition of both concepts. Furthermore, it will be shown that System LCOE are the marginal economic costs of a VRE technology that determines its optimal deployment.

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 1, equation 1) as a function of the generation E_{vre} from VRE.

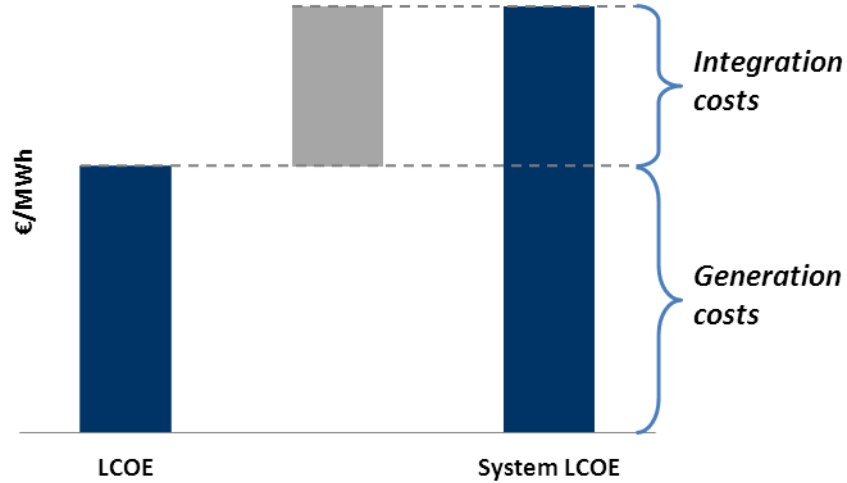


Figure 1: System LCOE of VRE are defined as the sum of their LCOE and integration costs per unit of VRE generation. They equal the marginal economic costs of VRE.

$$sLCOE_{vre} := \overline{LCOE}_{vre} + \Delta. \quad (1)$$

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

$$\Delta := \frac{d}{dE_{vre}} C_{int}. \quad (2)$$

The concept requires a clear definition of *integration costs* C_{int} . However, there is no agreement on how to calculate integration costs (Milligan et al. 2011). We suggest a rigorous way of how to do this.

We start with a qualitative definition of integration costs of VRE that is in line with several definitions in the literature (for example Milligan & Kirby 2009; Holtinen et al. 2011; Milligan et al. 2011; Katzenstein & Apt 2010). Integration costs of VRE are all additional system costs induced by VRE that are not directly related to their generation costs. This includes expenses for grids, balancing services, reserve requirements, and more flexible operation of thermal plants.

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 calculated 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*. All variables are a function of the VRE generation E_{vre} .

$$E_{resid} = \bar{E}_{tot} - E_{vre} \quad (3)$$

The total costs³ C_{tot} are divided into the generation costs of VRE C_{vre} and all other costs for the residual system C_{resid} .

$$\text{With VRE:} \quad C_{tot} = C_{vre} + C_{resid} \quad (4)$$

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

$$\text{Without VRE:} \quad C_{tot}(E_{vre} = 0) = C_{resid}(E_{vre} = 0). \quad (5)$$

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 (Milligan & Kirby 2009; Milligan et al. 2011). 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 identifying integration costs.

The crucial step to separating integration costs is to calculate the *specific* additional costs (per MWh) in the residual system when introducing VRE. *With VRE* the specific residual costs C_{res}/E_{resid} typically increase compared to *without VRE* $C_{tot}(0)/\bar{E}_{tot}$. We define integration costs as the *specific* additional costs in the residual system times the residual load E_{resid} .

$$C_{int} := \left(\frac{C_{resid}}{E_{resid}} - \frac{C_{tot}(0)}{\bar{E}_{tot}} \right) E_{resid} \quad (6)$$

$$= C_{resid} - \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \quad (7)$$

System LCOE can be calculated by inserting this definition of integration costs in the above equation 2.

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

We now show that the definition of integration costs is rigorous because the resulting System LCOE are the marginal economic costs of an additional unit of VRE that determine their optimal and competitive deployment. Using the definition of integration costs (equation 7) the total costs of a power system (equation 4) can be expressed as:

³ 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.

$$C_{tot} = C_{vre} + C_{int} + \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0). \quad (8)$$

The optimal deployment of VRE is reached when total costs are minimal when varying the share of VRE.

$$C_{tot} \rightarrow \min$$

$$\Rightarrow \frac{d}{dE_{vre}} C_{tot} = 0 \quad (9)$$

$$\stackrel{(8)}{\Leftrightarrow} \frac{d}{dE_{vre}} C_{vre} + \frac{d}{dE_{vre}} C_{int} + \frac{d}{dE_{vre}} \left(\frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \right) = 0 \quad (10)$$

The interpretation of the terms in the optimality condition (equation 10) gives deep insights in 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 . The third summand can be simplified with inserting equation 3: $-C_{tot}(0)/E_{tot}$. These are the specific system costs in a system without VRE. Conventional plants impose integration costs as well which are included in $C_{tot}(0)$ in addition to their generation costs. The third summand thus equals the average System LCOE of a purely conventional system:

$$\overline{sLCOE}_{conv} := \frac{C_{tot}(0)}{\bar{E}_{tot}}. \quad (11)$$

Using the new symbols the optimality condition (equation 10) reduces to:

$$\underbrace{\overline{LCOE}_{vre}}_{\text{marginal costs}} + \underbrace{\Delta - \overline{sLCOE}_{conv}}_{\text{direct value}} = 0. \quad (12)$$

(System LCOE)

The first two terms have been defined as System LCOE (equation 1). They equal the marginal economic costs of VRE. The last term can be interpreted as the direct value of VRE because it represents the opportunity costs of alternatively supplying energy with conventional generation. Hence, 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.

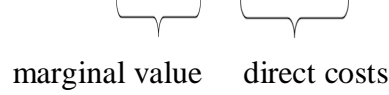
$$\text{System LCOE perspective:} \quad \overline{sLCOE}_{vre} = \overline{sLCOE}_{conv} \quad (13)$$

Another conclusive argument for the concept of System LCOE is its equivalence to a market value perspective. There are two equivalent ways of accounting for integration costs. They can be added to the generation costs of VRE (System LCOE), or subtracted from the direct value of VRE which gives the market value of VRE.

$$mv_{vre} := \overline{sLCOE}_{conv} - \Delta. \quad (14)$$

Inserting this into equation 12 gives an alternative formulation of the optimality condition.

$$\text{Market value perspective:} \quad mv_{vre} = \overline{LCOE}_{vre} \quad (15)$$



The optimal deployment of VRE is given by the point where their marginal economic value (market value) equals their marginal generation costs (direct costs). In perfect and complete markets the marginal economic value equals the private market value of VRE. Thus integration costs reduce the market revenues of VRE generators (Joskow 2011; Hirth 2012b; Mills & Wiser 2012).

If integration costs are internalized in this way, the resulting market incomes would incentivize the optimal generation capacity mix. Consequently, markets should be designed such that integration costs of all plants including conventional plants reduce their respective income. We disagree with Milligan et al. (2011) who conclude that integration costs of VRE should be shared because VRE's benefits are shared as well. We claim that socializing integration costs should not be a surrogate for a lack of internalizing of VRE's positive externalities. Instead, from an economic point of view, positive externalities should be internalized as well as integration costs in order to incentivize an economically efficient power system. For an overview of positive and negative externalities of renewables and a discussion of how to incorporate them see Borenstein (2011).

To sum up this section so far, we derived a sound expression for integration costs and used it to define System LCOE. We showed that this metric is conclusive because it equals the marginal economic costs of VRE and is equivalent to a market value perspective. In section 4 we show quantifications for System LCOE. In the remainder of this section we discuss an alternative but equivalent definition of integration costs that compares VRE with a benchmark technology to extract integration costs.

The second term in the definition of integration costs (equation 7) 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.

$$C_{resid}^{BM} := \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \quad (16)$$

$$= \left(1 - \frac{E_{vre}}{\bar{E}_{tot}}\right) C_{tot}(0) \quad (17)$$

The essential property of the benchmark is that the residual power system costs decrease in proportion to its generation E_{vre} (equation 9). Thus the specific residual system costs remain constant.

$$\frac{d}{dE_{vre}} C_{resid}^{BM} := -\frac{C_{tot}(0)}{\bar{E}_{tot}} = const. \quad (18)$$

Inserting the benchmark interpretation (equation 16) in equation 7 gives an equivalent definition of integration costs that might appear more intuitive: Integration costs of VRE are the additional costs in the residual power system that VRE impose compared to an ideal benchmark.

$$C_{int} = C_{resid} - C_{resid}^{BM} \quad (19)$$

The idea of using a benchmark for calculating integration costs is not new. DeCesaro & Porter (2009) and Milligan et al. (2011) distinguish two schools of thought. One applies a *proxy resource* (we term it *benchmark*) to supply the VRE energy without its variability and uncertainty in order to extracting the pure integration costs when comparing the *with* and *without VRE* case. The other school argues that there is no suitable proxy and that one needs to compare total system costs without applying a proxy in the *without VRE* case and consequently the value and integration costs of VRE cannot be entirely separated. In the following we discuss that both schools of thought are partly right, even though they seem to contradict each other. We show that our concept connects both perspectives.

The first school's motivation is to develop a model realization of a benchmark technology that does not impose integration costs. From a bottom-up perspective they try to design such a proxy resource without VRE characteristics like variability and uncertainty that would otherwise drive integration costs. An often used proxy is a perfectly reliable *flat block of energy* that constantly supplies the average generation of a VRE plant. The system cost difference of this proxy and VRE clearly contains costs of uncertainty and flexible operation of thermal plants. However, Milligan & Kirby (2009) and Milligan et al. (2011) point out that unfortunately the cost difference also contains the different energy values of both resources, which they do not regard as integration costs. That is in line with a branch of the integration cost literature that focuses on operational aspects and technical cost implications of VRE, like reserve or grid-related costs (for example Holttinen et al. 2011; DeCesaro & Porter 2009; Smith et al. 2007; Gross et al. 2006; Sims et al. 2011; GE Energy 2010).

However, we suggest that the difference in energy values of VRE and a benchmark resource should be seen as integration costs, following our definition (equation 6), because it increases the specific costs in the residual power system. We argue that in addition to rather technical costs a further cost component occurs due to the variability of VRE. Hirth (2012a) terms it *profile costs* (see section 3). These reflect the load-matching properties of the generation profile of VRE that determine their energy value and consequently account for the argument of Joskow (2011). Comparing residual system costs of the flat block proxy with the generation profile of VRE also includes *profile costs*, which we suggest is good, because they are part of the economic costs imposed by VRE.

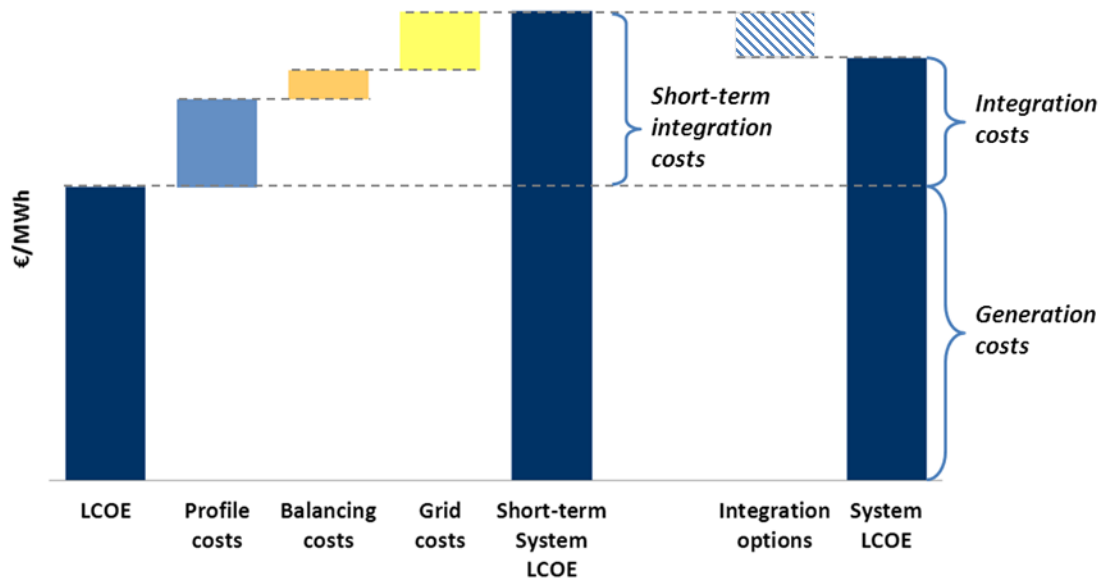
While, in principle we share the idea of using a benchmark to extract integration costs, we have two concerns. Firstly, the *flat block of energy* is not an ideal proxy because it imposes some integration costs itself, and thus the essential benchmark condition is not always fulfilled (equation 18). For example, the flat profile proxy is supplying base load energy. Increasing its share would increase the specific residual costs because the residual system would need to cover a higher fraction of peak load. To conclude, removing variability and uncertainty from VRE by converting its generation to constant output does not completely eliminate integration costs. Comparing VRE with the flat resource benchmark thus could underestimate integration costs of VRE.

Secondly, we generalize that there is no universal bottom-up realization of a benchmark that can be applied to any model⁴. In that we agree with the second school of thought. A benchmark that fulfills equation 11 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. Instead, integration costs should be calculated by modeling the power system *with* and *without VRE* and comparing the resulting specific residual system costs.

In the model applied in this paper (appendix A.2) the appropriate benchmark interpretation is a proportional reduction of load. The hypothetical output of this benchmark technology exhibits perfect spatial and temporal correlations with load. Perfect spatial correlations eliminate any additional grid-related 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. An overview of different drivers of integration costs

In the previous section we derived a formal expression for integration costs and System LCOE. In this section we give an overview of different drivers of integration costs. When quantifying System LCOE in section 4 we distinguish the integration costs drivers introduced here. In particular we discuss *profile costs* one important driver that corresponds to Joskow’s criticism toward the metric of LCOE that we referred to in the introduction (Joskow 2011).



⁴ This argument has been put forward by Simon Müller (International Energy Agency) in a personal correspondence.

Figure 2: Integration costs are divided into three components: profile, balancing and grid-related costs (Hirth 2012a). To some extent integration costs that occur in the short term can be reduced by integration options in the long term.

Integration costs can be decomposed according to three intrinsic properties of VRE: variability, uncertainty and location-specificity (Sims et al. 2011, Hirth 2012a). As illustrated in Figure 2 Hirth assigns cost components accordingly: profile costs, balancing costs and grid-related costs. These components comprehensively add up to integration costs.

Profile costs occur because wind and solar PV are variable. In particular at higher shares this leads to increasingly inappropriate load-matching properties. Backup capacities are needed due to a low capacity credit⁵ of VRE. The full-load hours of capital-intensive dispatchable power plants decrease while these plants need to ramp up and down more often. Moreover VRE supply might exceed demand and is thus overproduced. A closer look on profile costs is taken below.

Balancing costs occur because renewable supply is uncertain. Day-ahead forecast errors of wind or solar PV generation cause unplanned intra-day adjustments of dispatchable power plants and require operating reserves that respond within minutes to seconds.

Grid-related 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.

System LCOE are defined by adding the three components of integration costs to standard LCOE that reflect generation costs (Figure 2). We distinguish between two time perspectives: *short term* and *long term*:

- 1) The short-term perspective represents the transition period after VRE are introduced into the power system. It reflects 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.
- 2) The long-term perspective assumes that the power system has fully adapted to VRE. 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. Hence, short-term integration costs and short-term System LCOE have been reduced. System LCOE reflect the resulting (long-term) integration costs.

⁵ The capacity credit of a technology indicates how much firm capacity can be removed from the system in relation to a newly installed unit of this technology.

In this paper we pay special attention to profile costs because it corresponds to Joskow’s argument (Joskow 2011). We further decompose profile costs into different drivers. In section 4 we quantify profile costs and associate cost shares to its drivers.

Profile costs can be further subdivided due to two implications of variability of renewables (Figure 3).

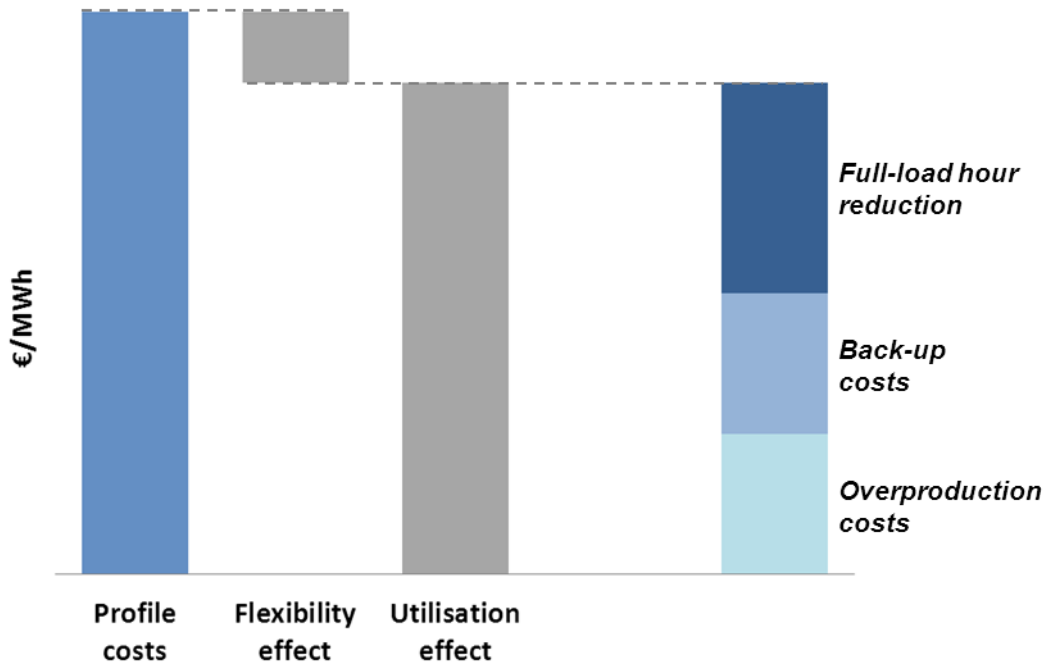


Figure 3: Profile costs can be divided in two parts: flexibility effect and utilization effect. The utilization effect can be further subdivided into costs for full-load hour reduction of conventional plants, backup costs and overproduction costs.

On the one hand, variability of VRE makes it harder and more expensive for a power system to follow residual load. Nicolosi (2012) calls this the *flexibility effect*. Even if there was no uncertainty (perfect forecast) VRE output would increase the volatility and variance of residual load. The dispatchable plants in the residual power system would need to adjust their output more often, with steeper ramps and in a wider range of installed capacity.

On the other hand, even if power plants could perfectly ramp without additional costs, variability would still induce profile costs. VRE contribute energy while hardly reducing the need for total generation capacity in the power system (reflected in the low capacity credit of VRE). Thus the average utilization of dispatchable power plants is reduced (reflected in decreasing full-load hours). This *utilization effect* (Nicolosi 2012) leads to inefficient redundancy in the system and higher specific costs compared to the hypothetical situation if wind and solar would not be variable. This is illustrated in residual load duration curves⁶ (RLDC). VRE unfavorably change the distribution of residual load

⁶ The RLDC shows the distribution of residual load by sorting the hourly residual load of one year starting with the highest residual load hour.

(Figure 4). With high shares VRE cover base load rather than peak load. The RLDC becomes steeper. This effect is driven by the temporal distribution of VRE or more precisely by the correlation of variable demand and VRE supply. Thus profile costs (more specifically the *utilization effect*) account for the criticism of Joskow (2011) towards the use of LCOE for evaluating VRE. In contrast, conventional plants hardly impose profile costs if they are optimally deployed in a power system, because they have a high capacity credit and their output can be adjusted more flexibly.

Nicolosi (2012) concludes that costs caused by the *flexibility effect* are small compared to the *utilization effect*. Grubb (1991) also suggests for England that the effect of ramping and cycling constraints is negligible. CONSENTEC (2011) finds that ramping constraints are not binding even at high shares of VRE in Germany. In this paper when calculating profile costs we neglect the *flexibility effect* and focus on the *utilization effect*.

We further decompose the *utilization effect* into three main cost-driving effects (Figure 4). 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 reserve capacity especially during peak load times due to their low capacity credit. 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 factor⁷ of VRE decreases and specific per-energy costs of VRE increase.

⁷ The capacity factor describes the average power production per installed nameplate capacity of a generating technology

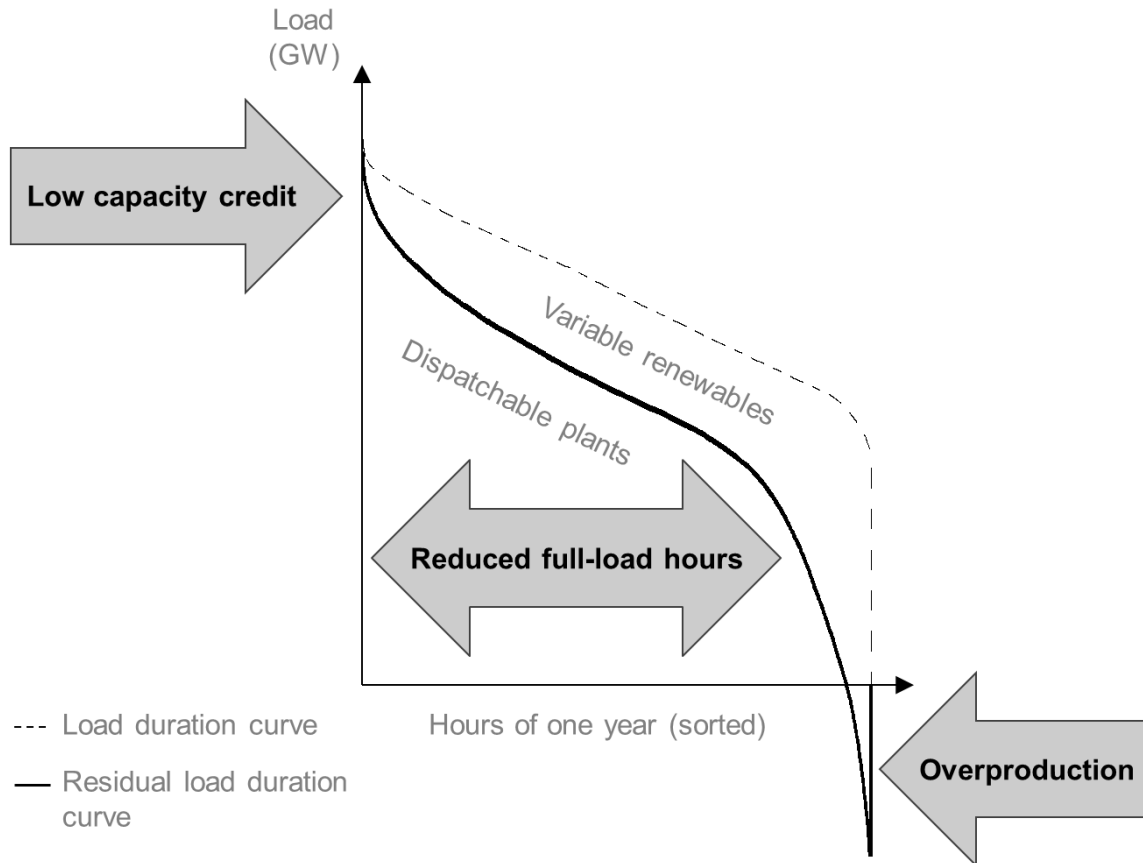


Figure 4: Residual load duration curves capture three main challenges of integrating VRE (illustrative). Full-load hours of conventional plants are reduced, while hardly any generation capacity can be replaced. At higher shares VRE supply exceeds load and thus cannot directly be used.

At higher shares these challenges get more severe. Figure 5 shows the development of RLDC with increasing shares of wind (left) and solar PV (right) for German data⁸. 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 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. 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 5, right, arrow) that separates sun-intensive days (right side) from less sunny days and 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 different wind sites.

⁸ 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.

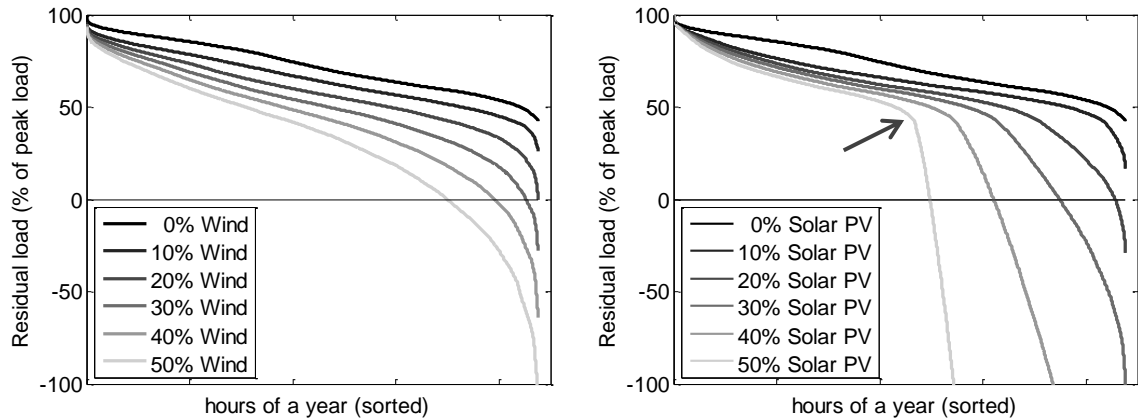


Figure 5: Residual load duration curves (RLDC) for increasing shares of wind (left) and solar PV (right) in Germany. With higher shares the RLDC continuously become steeper. Wind generation slightly covers peak load but increasingly contributes to intermediate and base load as well as to overproduction. 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.

4. Quantification of System LCOE

In section 2 we conceptually introduced System LCOE. In the following, we present quantifications based on model and literature results. We show shares of various drivers of integration costs that have been identified in the previous section. Profile costs are studied in particular.

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 make no claims of being complete, but rather want to show how System LCOE in principle can help understanding and tackling the integration challenge. 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 systems⁹ in temperate climate.

The power system model applied here is tailor-made to quantify profile costs that occur due to the *utilization effect* (previous section). For that purpose it minimizes total costs with endogenous investment and dispatch of five dispatchable power generating technologies. When calculating the profile cost component we neglect grid constraints, electricity storage and international trade as well as technical constraints on the operation of power plants, like ramping and cycling constraints. Electricity demand is perfectly price-inelastic and deterministic. The only integration option that is modeled is the adaptation of the capacity mix of residual power generating technologies. German load and renewable in-feed data and a carbon price of 20€/tCO₂ is used. A detailed description

⁹ Thermal systems rely on thermal power plants like coal, gas and nuclear plants rather than hydro power generation.

of the model and of how System LCOE are calculated can be found in the appendix (A.2 and A.3).

Figure 6 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 (Kost et al. 2012). Integration costs are given in marginal terms and composed of three parts. Profile costs are calculated with the model described above. Balancing costs are parameterized according to three literature surveys (Holttinen et al. 2011; Gross et al. 2006; Hirth 2012a). Grid costs are taken from Holttinen et al. (2011) and DENA (2010). The parameterization from the literature is described in the appendix A.5. 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 2 in section 3). The solid line shows long-term System LCOE. Cumulative long-term integration costs are the area between generation costs (LCOE) and this line.

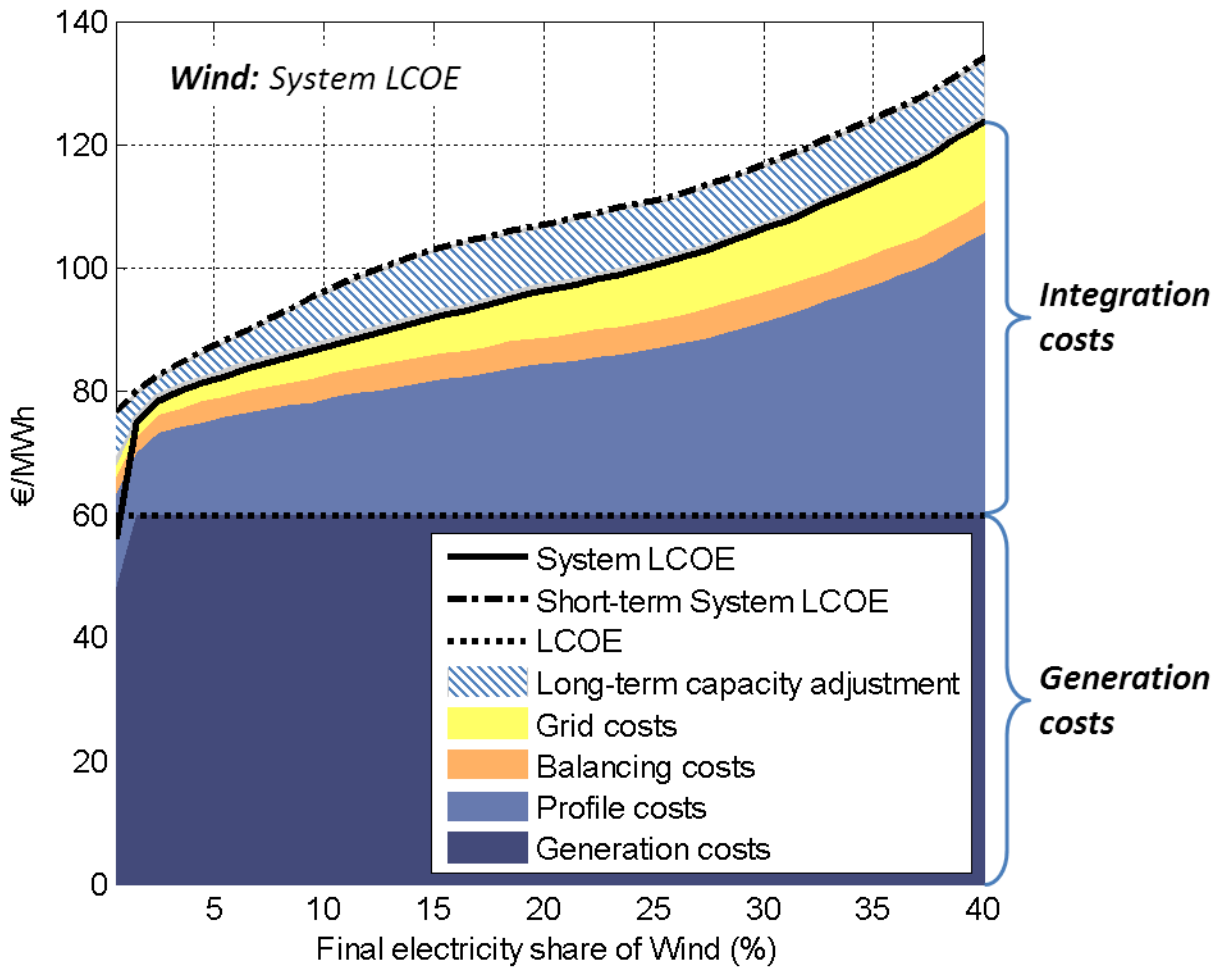


Figure 6: System LCOE for increasing shares of wind representing typical thermal power systems in Europe. Integration costs rise up to the order of magnitude of generation costs. Integration costs can thus become an economic barrier to large deployment of VRE.

We find four main results (Figure 6). 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 Europe. 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. A barrier becomes more likely at high shares (>20%) where integration costs become convex. In case of a further reduction of generation costs due to technology learning the relative importance of integration costs further increases.

Within the last years wind plants got close to having less generation costs than average conventional plants. To conclude that new wind power plants will soon be competitive and economically efficient is wrong. For determining the economically efficient share of wind one would need to take their System LCOE as a reference value for a comparison. A pure LCOE analysis is misleading. Integration costs need to be considered in any socio-economic cost-benefit analysis or welfare optimization.

Wind power would only be economically efficient (and competitive¹⁰) without subsidies if its System LCOE is below the average System LCOE of a purely conventional system (see section 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 prices¹¹ and strong nuclear restrictions or a complete phase out (like in Germany).

Profile costs reach about 30€/MWh at a wind share of 30%. This model result is in line with other studies that show decreasing market values for wind.¹² In a broad survey of about 30 studies Hirth (2012a) estimates long-term profile costs at 15 €/MWh - 35 €/MWh at 30% penetration. In Mills & Wiser (2012) the long-term value of wind in California drops from 70 to 40 \$/MWh when increasing the share to 40%. For England Grubb (1991) finds that the value of wind decreases by 20 to 60% when increasing the share up to 40%. 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

¹⁰ In case of perfect and complete markets.

¹¹ This assumes that carbon capture and storage (CCS) will not be a mitigation option.

¹² The studies use a different benchmark that corresponds to the base price of electricity instead of the load-weighted electricity price. To precisely compare the results the numbers of this paper need to be reduced by 5% -10%.

reduce profile costs are particularly important for reducing the costs of an energy transformation towards VRE (section 5).

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 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 6 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 5 we discuss various integration options and suggest that long-term capacity adjustments is among the most important integration option.

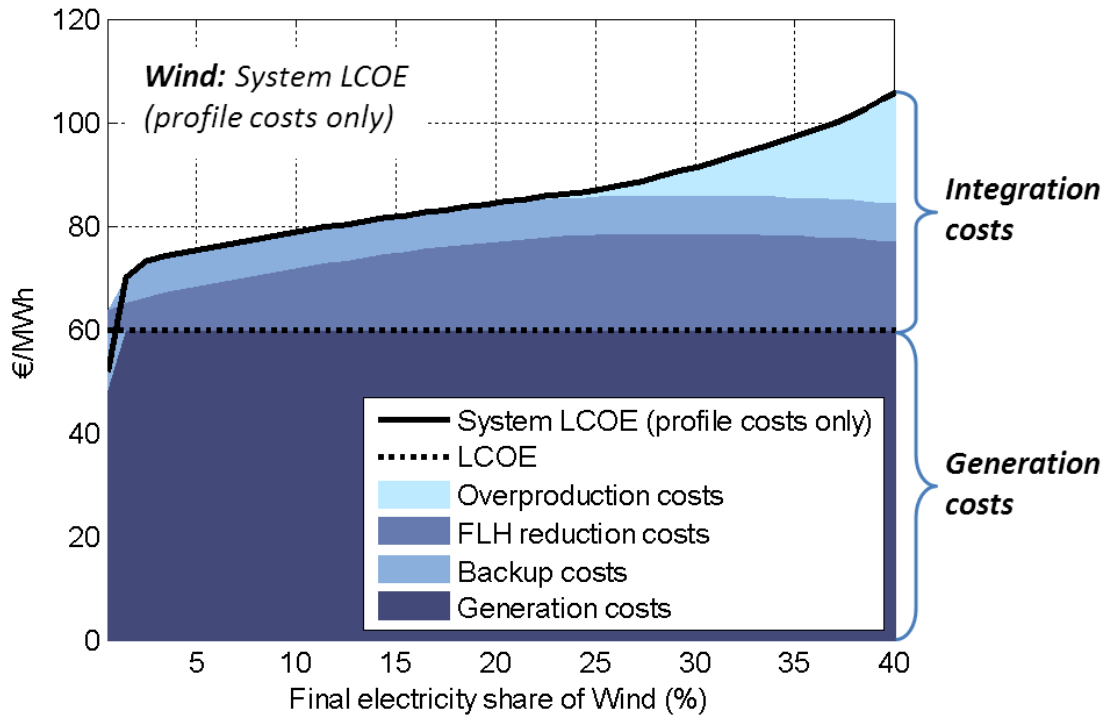
The integration cost savings from capacity adjustments correspond to profile costs. Hence, profile costs that occur in the short term are even higher than the long-term share shown in Figure 6. Adaptations of dispatchable plants drive down integration costs according to two mechanisms:

- 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 5 (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.

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. This decomposition is described in the appendix A.4. Moreover we extend the analysis to solar PV.

Figure 7 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: 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 PV¹³ (Kost et al. 2012).



¹³ 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.

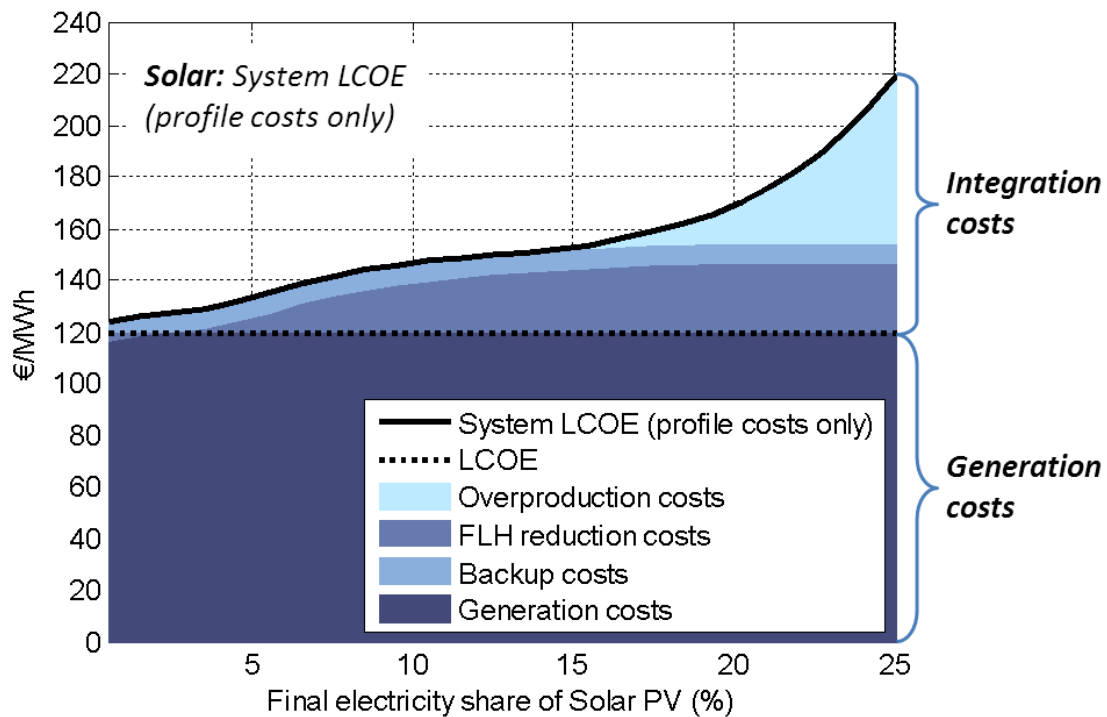


Figure 7: System LCOE for increasing generation shares of wind (above) and solar PV (below) for Germany calculated with a power system model that is designed for calculating profile costs. These costs are decomposed into three cost drivers. The full-load hour (FLH) reduction of conventional plants is 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 (Figure 7). 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.

In appendix A.1 we show these System LCOE model results from a market value perspective to illustrate the equivalence of both concepts.

5. Implications for integration options

Integration options that effectively reduce integration costs can dismantle potential economic barriers to integrating VRE especially at high shares. From the quantification of System LCOE we now derive implications for potential integration options. The decomposition of integration costs helps estimating the importance of different options like adjusting the residual capacity mix, transmission grid reinforcement, demand-side management (DSM) and electricity storage.

Capacity adjustments have been explicitly modeled when quantifying System LCOE (section 4). Shifting the residual capacity mix from base load to mid and peak load technologies can heavily reduce integration costs. Typical peak load plants like gas turbines feature lower specific investment costs. The overall residual capacity costs are reduced. Thus the costs due to reduced full-load hours can be mitigated in a system with adjusted capacities. We find that this is a very important integration option.

The model applied in section 4 does not take into account cross-border transmission and grid reinforcement. 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. This is a highly relevant integration option because marginal integration costs decrease significantly with lower penetration levels. With electricity exports overproduction of VRE can be reduced and FLH of dispatchable plants can be increased. The effect of reducing peak capacity requirements due to power imports might be low because of high load correlations. In his model analysis Nicolosi (2012) assumes that Germany will remain having a higher VRE share than most of its neighbors. He finds a strong increasing effect of grid extension on the market value and consequently integration costs decrease. 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 (Hirth 2012b). 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 4 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.

Demand-side management (DSM) could in particular reduce the capacity requirements for covering peak load. Peak load in the RLDC becomes narrower with increasing VRE share (Figure 4). This increases the potential capacity savings by DSM because less load would need to be shifted to reduce peak load than without VRE. This option could increase the VRE's capacity factor and thus reduce costs for backup capacity already at lower shares of VRE. With increasing shares the additional cost saving effect of DSM would decrease. This is because VRE mostly contribute to base load in these regimes. To reach a further capacity reduction more load would need to be shifted and the time scales

for shifting load would increase. Hence, DSM might not be an option for significantly increasing the FLH of base and mid load plants or reducing curtailment.

There are a number of energy storage technologies that could help reducing integration costs. At present, the only commercial option is pumped-hydro storage where surplus power during low-demand or high-renewable-supply periods is used to pump water from a lower to an upper reservoir. Unfortunately, the potential of pumped-hydro storage in most European countries is very limited. For example the installed German capacity of 7.6GW is not expected to significantly increase. These storage plants have small reservoirs that can provide maximum output for about six to eight hours. These operating time scales are suitable to meet the diurnal fluctuations of solar. Solar supply can be shifted towards the evening where usually higher load needs to be covered. This would increase the full-load hours of dispatchable plants and potentially decrease solar overproduction and could reduce the evening peak of demand. However, the overall potential of reducing integration costs of solar PV is small mainly due to the limited reservoirs. For wind the potential is even smaller, because wind fluctuations are less regular and occur on higher time scales. These arguments are confirmed in a model-based analysis of market values for wind and solar (Hirth 2012b). A sensitivity study varies the capacity of pumped-hydro storage and shows a small effect for wind and a considerable effect for solar PV.

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 (Sterner 2009) and high costs for electrolysis and methanization capacities. 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.

6. Summary and conclusion

LCOE are often used to compare power generating technologies. However, they are an inappropriate metric especially for evaluating variable renewables (VRE) because they do not account for integration costs. 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 (MWh). We formally derive conclusive expressions for System LCOE and integration costs. In an alternative but equivalent definition integration costs are interpreted as the cost difference of VRE in comparison to an ideal benchmark technology that does not induce any integration costs. An important feature of the concept of System LCOE is that it can be relatively easy applied in most energy system models to consistently derive

integration costs and System LCOE. Furthermore, we quantify System LCOE for VRE in typical European thermal power systems based on a model and literature results. Integration costs are decomposed according to different cost-driving effects of VRE. Quantifying the resulting cost components gives insights towards identifying the most crucial integration challenges and finding suitable integration options.

As a central result we find that at wind shares above 20%, marginal integration costs are in the same range as generation costs. 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. A comparison shows 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. Profile costs are mainly driven by the reduction of full-load hours of conventional plants induced by VRE that hardly reduce overall capacity requirements. Moreover at high shares an increasing part of VRE generation exceeds load. This overproduction might need to be curtailed and thus reduces the value of VRE.

In contrast to standard LCOE the new metric System LCOE allows to evaluate VRE economically. System LCOE are the marginal economic costs of VRE. Only if System LCOE of VRE drop below the average System LCOE of a purely conventional system they are economically efficient and competitive. This implies that an economic evaluation of VRE must not neglect integration costs. A standard LCOE comparison of VRE and conventional plants would overestimate the economic value of VRE at high shares. In other words, LCOE of wind falling below those of conventional power plants would not imply that wind deployment is economically efficient or competitive. The results for System LCOE suggest that this becomes increasingly difficult with high shares of VRE. It would need considerable carbon prices and strong nuclear restrictions or significant renewables support that internalizes their positive externalities. To conclude, System LCOE can guide policy makers and system planners in designing a cost-efficient power system.

The concept of System LCOE is equivalent to a market value perspective. In a perfect and complete market the marginal market value of VRE is equal to the marginal economic value of VRE. Thus the market revenues of VRE generators would be reduced by integration costs. Integration costs of all plants including conventional generators should be internalized in this manner in order to incentivize an economically optimal generation capacity mix and dispatch. However, our results suggest that integration costs are significantly higher for VRE because an optimized mix of dispatchable capacities hardly induces profile costs, while these are the largest cost component for VRE.

Integration options could dismantle the economic barriers of deploying VRE by reducing integration costs. Firstly, we find that the adjustment of the residual generation capacity mix when introducing VRE is an important integration option. VRE reduce the utilization of conventional plants. This means that a shift from capital-intensive base to mid and peak load technologies with low specific investment costs reduces integration costs, more precisely profile costs. Secondly, increasing transmission capacity to neighboring power systems reduces integration costs strongly, but only if those power systems do not develop similar shares of VRE. In that case reinforcing the grid connection would virtually reduce the VRE share in the resultant interconnected power system. Hence, grid

interconnections are an important integration option because integration costs decrease with lower shares. Thirdly, any measure that helps shifting demand or supply in time would reduce the profile costs. Demand-side management could in particular reduce peak load and compensate for the small capacity credit of VRE. Pumped-hydro storage might reduce integration costs for solar PV. For efficiently integrating wind, storage options would need to have larger reservoirs. An important option seems to be a reinforced connection of thermal systems with hydro-dominated systems in the Alps and Scandinavia.

Integration costs cause a significant part of the costs of moving towards power systems with high shares of variable renewables. The different generating technologies and integration options strongly interact. To evaluate technologies and derive cost-efficient pathways one needs to take a system perspective. However, there is no single model that fully accounts for all costs and options. It needs a number of complementing studies to cover all aspects and develop a complete picture of the costs of variable renewables and integration options. System LCOE can support this analysis in three different ways.

Firstly, the concept helps understanding the integration challenge by determining the magnitude and shape of integration costs. Moreover, integration costs can be decomposed into different cost drivers to estimate their relative importance. Hereby, System LCOE help to properly frame models and scenarios. Secondly, System LCOE can be used as a diagnostic tool for understanding and illustrating model results in particular with regard to the total costs of VRE. Thirdly, System LCOE 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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A. Appendix

A.1. Quantification of market values

Figure A.1 shows model results for long-term market values for deployment of wind (above) and solar PV (below) as a function of the potential generation share¹⁴. These results correspond to the scenarios shown from a System LCOE perspective in Figure 7 (section 4). The model is described in section A.2. Market values of wind and solar strongly decrease with growing shares. The market value of a benchmark technology without integration costs (introduced in section 2) equals the load-weighted electricity price of 52 €/MWh. The gap between the market value of VRE and the benchmark value corresponds to integration costs. Here, integration costs only consist of profile costs, because other cost drivers are neglected in the model. At low shares profile costs are positive, because supply is positively correlated with demand, for solar PV due to its diurnal pattern and for wind power due to positive seasonal correlation. Profile costs are decomposed into its components.

From a market perspective the decreasing market value can be explained as follows. VRE have roughly zero variable costs. Their supply is driven by weather conditions and fairly independent from whole-sale prices. Whenever VRE supply they reduce market-clearing prices. Hence, they reduce their own revenues especially at high deployment levels.

¹⁴ The potential generation share is defined as the relation of annual VRE production including surplus energy and total annual electricity demand.

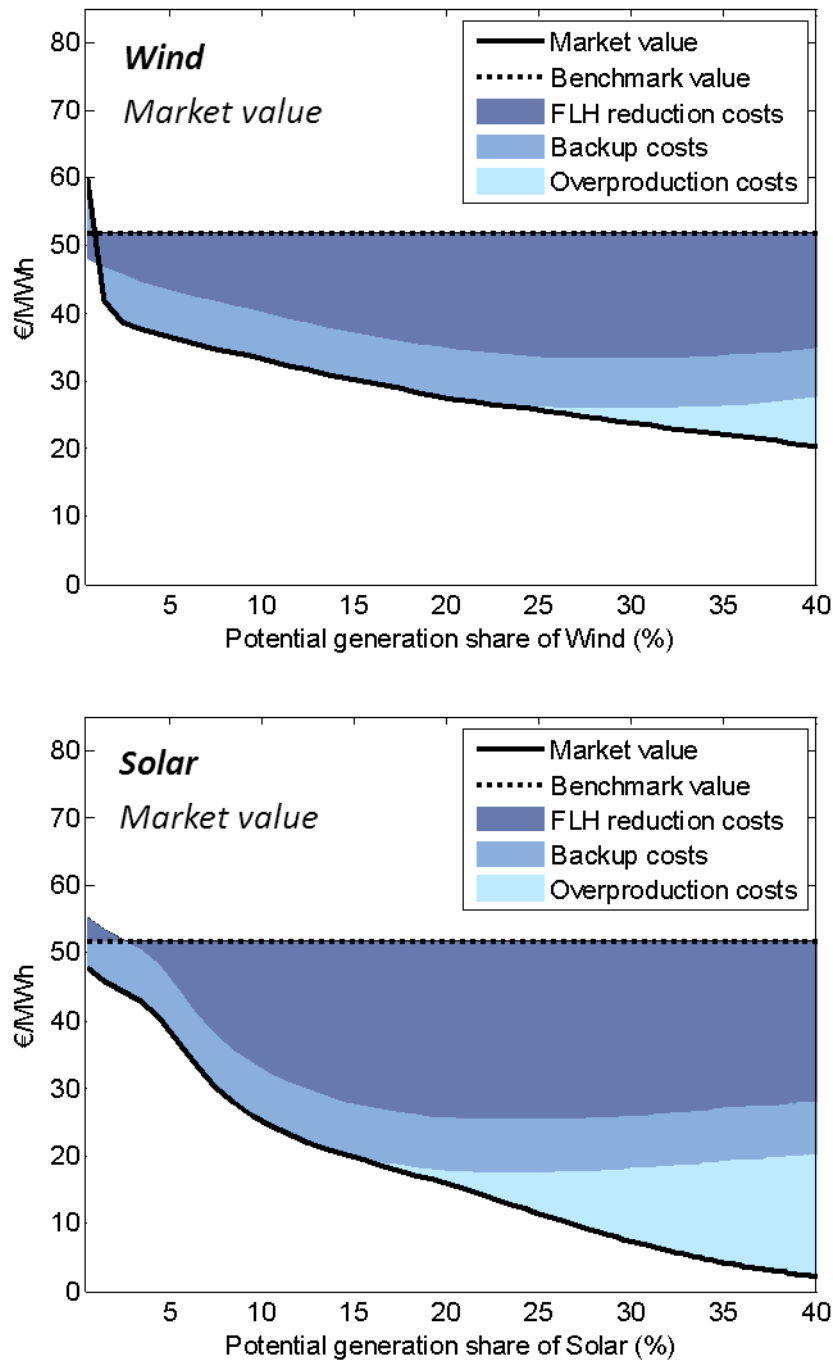


Figure A.1: Market values significantly decrease for increasing shares of wind (above) and solar PV (below) due to inappropriate load-matching properties that induce profile costs.

The low value at high shares is caused by the variability of wind and solar PV and their inappropriate load-matching properties. Hence, decreasing market values reflect the decreasing economic value of VRE and are not caused by false market design or market failure as sometimes suggested, for example in Kopp et al. (2012) and Winkler & Altmann (2012).

Decreasing market values can have drastic impacts on the profitability and competitiveness of VRE. Without subsidies the market value needs to cover the investment costs given by the LCOE of VRE. Only because LCOE of VRE drop below those of conventional plants does not mean that VRE reach competitiveness. If a society or policy makers want more VRE than a competitive market would incentivize, policy instruments e.g. renewable subsidies are needed. Due to integration costs the total costs of an energy transformation towards VRE is significantly more expensive than a pure LCOE analysis would imply.

Note, that the applied model does not represent integration options other than adjustments of generation capacities. Flexibilizing electricity demand or renewable supply by demand-side management, electricity storage, transmission infrastructure and other integration options would somewhat increase the market value of VRE.

A.2. Model description

This section describes a tailor-made model of the power sector for calculating profile costs that are caused by the *utilization effect* (see section 3).

We extend a classical method from power economics (Stoft 2002, Green 2005) that uses screening curves, a load duration curve¹⁵ (LDC), and a price duration curves (PDC) that is derived from the first two (Figure A.2 a, 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. We assume marginal pricing where prices equal variable costs of the marginal capacity ($c_{technology}$). Scarcity prices p_s occur in peak demand hours when capacity is scarce.

¹⁵ For the illustrations we use hourly data for German power demand in 2009 (ENTSO-E).

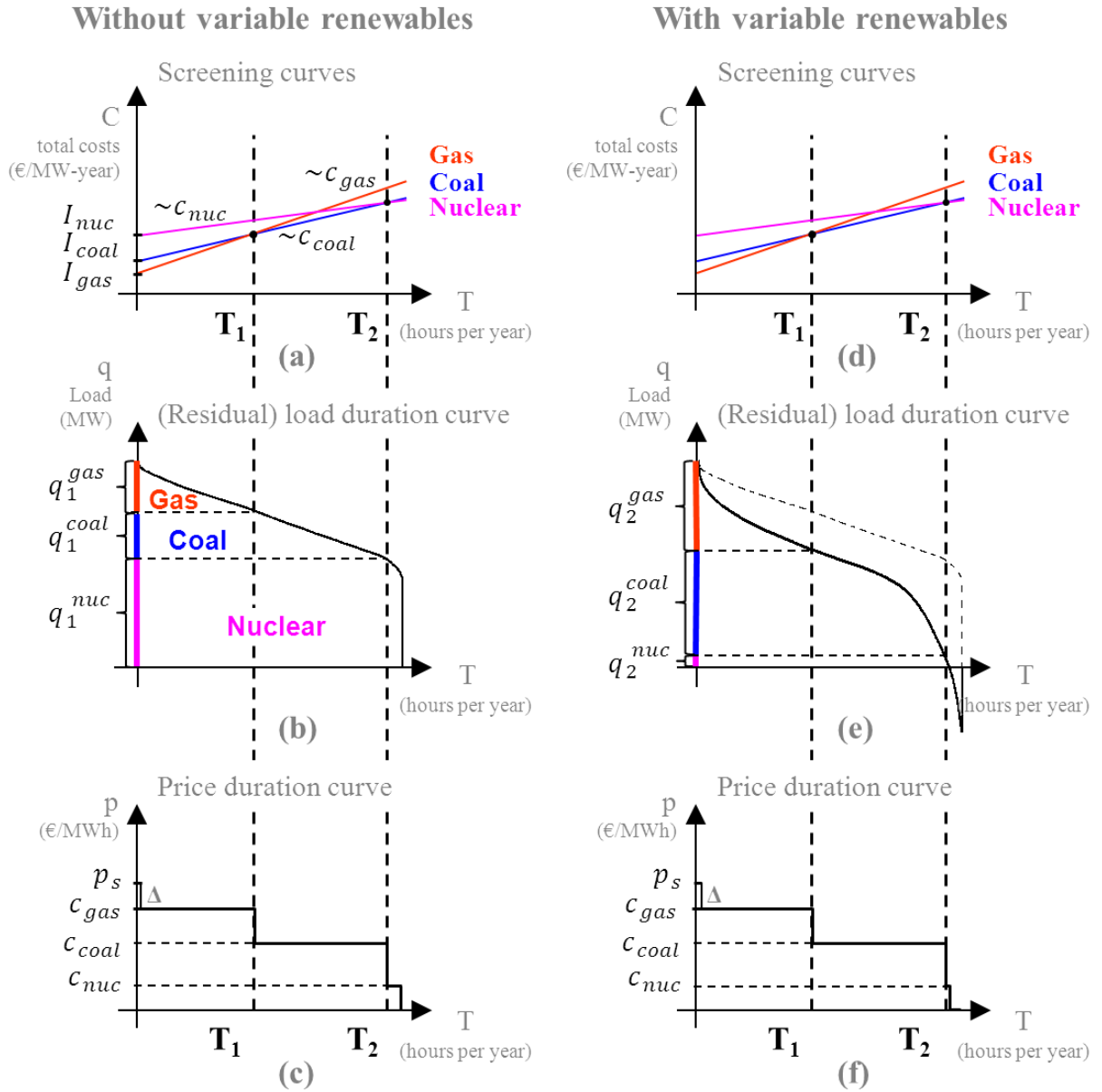


Figure A.2: Long-term screening curves, load duration curves, price duration curves without (left) and with wind support (right). Wind changes the residual load duration curve (c, d). Thus capacities adjust towards lower fixed-to-variable-costs ratio (more gas, less nuclear).

The model minimizes total costs with endogenous long-term investment and short-term dispatch of five dispatchable power generation technologies (see appendix A.6 for model parameters). It neglects grid constraints, electricity storage, international trade and dynamic aspects, like ramping and cycling constraints. Electricity demand is perfectly price-inelastic and deterministic. Externalities are assumed to be absent. We model energy only markets with marginal pricing. The cost minimizing solution corresponds to a market equilibrium where producers act fully competitive and with perfect foresight.

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. 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 systems¹⁶ with load and renewable profile patterns similar to those in Germany. This applies to most continental European countries.

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. Its shape depends on the variability of the renewable sources and especially its correlation with demand. The resulting effect on the residual capacity mix and its total costs can be analyzed two temporal perspectives: *long term* and the *short term*.

- 1) Within a *long-term perspective* it is assumed that the power system has moved into its new long-term equilibrium. Dispatchable capacities adjust to VRE and an energy system transition is finished.
- 2) Within a *short-term perspective* we analyze the transition period. The dispatchable capacities remain unchanged when introducing VRE. It reflects fast deployment of VRE compared to typical relaxation times of the system defined by e.g. lifetimes of power plants or building times.

Figure A.2 shows sketches of two long-term results, *without* and *with VRE*. Here only three technologies are shown for illustrative reasons. In general the RLDC is steeper than the LDC (Figure A.2 e). Hence, the full-load hours of dispatchable plants are reduced. In the long term plants with high specific investment costs like nuclear are replaced by plants with a lower fix-to-variable-costs ratio e.g. more gas power plants (Figure A.2 e). Whenever VRE supply exceeds demand the RLDC becomes negative. Thus the PDC shows zero prices at the right edge (Figure A.2 f). Besides that the PDC remains unchanged.

A.3. Calculating System LCOE

For quantifying System LCOE we need to calculate integration costs as derived in section 2 (equation 7). For this purpose it only needs expressions for the total costs of the conventional part of a power system *with* and *without VRE*: $C_{res}(E_{vre})$ 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.

¹⁶ Thermal systems rely on thermal power plants like coal, gas and nuclear plants rather than hydro power generation.

$$C_{resid} = \int_0^{q_{peak}} T(q, E_{vre}) c_{min}(T(q, E_{vre})) dq \quad \text{A.1}$$

$$c_{min}(T) = \min(c_{gas}(T), c_{coal}(T), c_{nuc}(T)) \quad \text{A.2}$$

For the dispatchable costs without VRE $C_{resid}(0)$ the invers RLDC $T(q)$ needs to be replaced by the invers LDC.

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 A.3 c).

$$C_{resid}^{ST} = \sum_{te} \int_{q_{te,min}}^{q_{te,max}} T(q, E_{vre}) c_{te}(T(q, E_{vre})) dq \quad \text{A.3}$$

With these expressions System LCOE and market values can be calculated using equations 1, 2, 7 and 14.

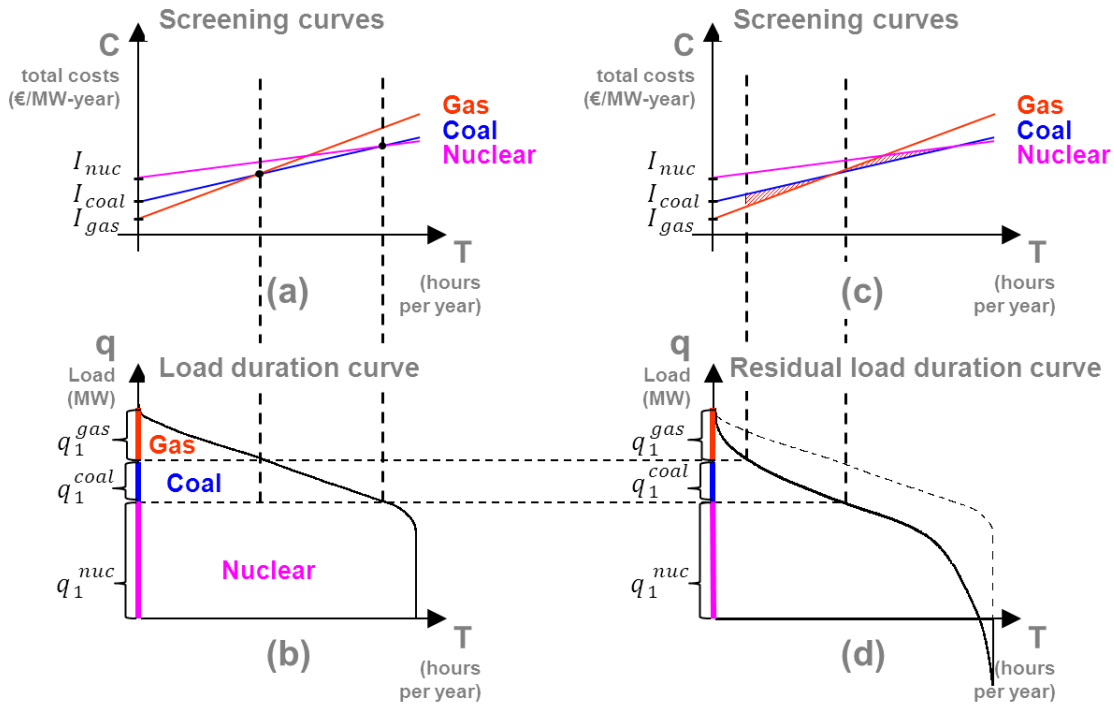


Figure A.3: Optimal long-term capacities are derived without VRE (a, b). With VRE the LDC transforms to a RLDC (d). In the short-term perspective the capacities remain unchanged (d). Hence, specific costs increase because technologies operate in full-load hour ranges where they would not be cost-efficient if capacities could optimally adjust (c).

A.4. Decomposing profile costs

In Figure 7 (section 4) we show a decomposition of profile costs into three components: 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 this

model. Hence, costs for additional VRE capacity occur in comparison to the ideal technology that provides the same effective energy (see section 2). The benchmark would not induce overproduction, because its supply has full correlation with load. Note that overproduction and its costs are calculated in marginal terms. These numbers increase stronger than average terms, which are often shown in the literature.

Similarly, we separate costs for backup capacity requirements. Again, the point of reference is the benchmark technology. Because of its full supply-demand correlations a benchmark would have a capacity credit of 100%. It could accordingly replace conventional plants (open-cycle gas turbines) and thus induce capacity cost savings. By comparing the peak reduction 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.

Costs due to the reduction of full-load hours are given by the residual cost share of profile costs after subtracting overproduction costs and backup costs.

A.5. Balancing and grid costs

Holttinen et al. (2011), Gross et al. (2006) and Hirth (2012a) compile balancing cost estimates from various studies at different 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 2.5-5€/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-related costs of integrating VRE. Holttinen et al. 2011 give an overview for grid reinforcement costs mainly due to added wind power. At wind shares of 15-20% these costs are about 100 €/kW (~3.75 €/MWh¹⁷). For Ireland the costs rise to 200 €/kW (~7.5 €/MWh) at 40% wind penetration (All Island Grid Study 2008). For Germany DENA (2010) calculates annual transmission-related grid costs of € 1 bn to integrate 39% renewable energy of which 70% is wind and solar generation. 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 into 13 €/MWh in marginal terms.

A.6. Model parameters

For the model analysis the following default parameters are used.

Technology parameter

	Investment costs (€/kW)	Quasi-fixed costs (€/kW*a)	O&M costs (€/MWh _{el})	Fuel costs (€/MWh _{th})	Efficiency	CO ₂ intensity (t/MWh _{th})
Open cycle gas turbine (OCGT)	600	7	2	25	0.3	0.27

¹⁷ This conversion assumes wind full-load hours of 2000, a discount rate of 7% and a grids' life time of 40 years.

Combined cycle gas turbine (CCGT)	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

Further parameter

	CO ₂ price (€)	Discount rate
Default value	20	0.05