System LCOE: What are the costs of variable renewables?

Falko Ueckerdt [a1] , Lion Hirth [ab], Gunnar Luderer [a], Ottmar Edenhofer [acd]

[a] *Potsdam Institute for Climate Impact Research, P.O. Box 601203, 14412 Potsdam, Germany*
[b] *Vattenfall GmbH, Chausseestraße 23, 10961 Berlin, Germany*
[c] *Chair Economics of Climate Change, Technische Universität Berlin, Germany*
[d] *Mercator Research Institute on Global Commons and Climate Change (MCC), Berlin, Germany*

Corresponding author: Falko Ueckerdt, ueckerdt@pik-potsdam.de, +49 331 288 2067

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.

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

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

[1] The findings, interpretations, and conclusions expressed herein are those of the authors and do not necessarily reflect the views of the Potsdam-Institute for Climate Impact Research or Vattenfall.

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 dispatchable[2] 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 (marginal[3] 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]. Hirst and Hild focus on operational aspects without capacity adjustments with a unit

[2] The output of dispatchable plants can be widely controlled, whereas VRE are subject to natural fluctuations.
[3] 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.

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 options[4].

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 2 conceptually introduces System LCOE, rigorously defines integration costs (section 2.1) and links these concepts to economic theory (section 2.2) and standard integration cost literature (sections 2.3 and 2.4). Section 3 demonstrates the concept by quantifying System LCOE based on simple modeling and literature estimates and derives implications for integration options (section 3.4). Finally, section 4 summarizes and concludes.

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 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 2.3) and an alternative interpretation of the new definition (section 2.4).

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.

[4] 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].

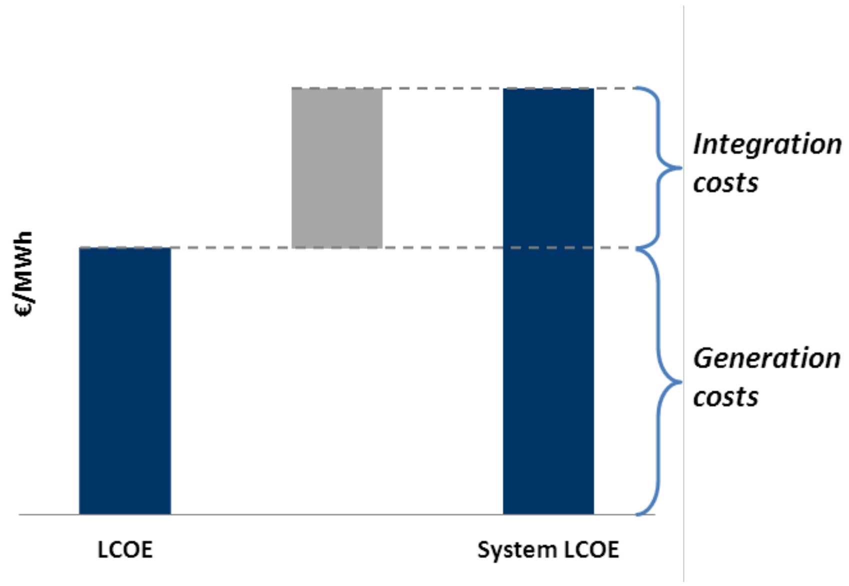


Figure 1: System LCOE of VRE are defined as the sum of their LCOE and integration costs per unit of VRE generation. They seek to comprise the total economic costs of VRE.

$$sLCOE_{vre} := \overline{LCOE}_{vre} + \Delta. \tag{1}$$

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

$$\Delta := \frac{d}{dE_{vre}} C_{int}. \tag{2}$$

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.

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 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 system[5]) of the power system when VRE are introduced.

[5] 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.

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 $\bar{E}_{\text{tot}}$ is partly supplied by the VRE generation E_{vre}. $\bar{E}_{\text{tot}}$ 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}.

$$E_{resid} = \bar{E}_{tot} - E_{vre} \tag{3}$$

The total costs[6] C_{tot} are divided into the generation costs of VRE C_{vre} and all other costs for the residual system C_{resid}.

$$With\,VRE: \qquad C_{tot} = C_{vre} + C_{resid} \tag{4}$$

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.

$$Without\,VRE: \qquad C_{tot}(E_{vre} = 0) = C_{resid}(E_{vre} = 0). \tag{5}$$

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 [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 *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* $C_{tot}(0)/\bar{E}_{tot}$.

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

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

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

[6] 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.

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

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.

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.

$$C_{tot} \rightarrow min \tag{8}$$

$$\Rightarrow \frac{d}{dE_{vre}} C_{tot} = 0 \tag{9}$$

Using the definition of integration costs (equation 7) the total costs (equation 4) can be expressed as:

$$C_{tot} = C_{vre} + C_{int} + \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0). \tag{10}$$

Inserting this into the optimality condition (equation 9) gives:

$$\frac{d}{dE_{vre}} C_{vre} + \frac{d}{dE_{vre}} C_{int} + \frac{d}{dE_{vre}} \left(\frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \right) = 0. \tag{11}$$

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 2). The third summand can be simplified to $-C_{tot}(0)/\bar{E}_{tot}$ with equation 3. 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:

$$\overline{sLCOE}_{conv} := \frac{C_{tot}(0)}{\bar{E}_{tot}}. \tag{12}$$

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

$$\overline{LCOE}_{vre} + \Delta = \overline{sLCOE}_{conv} \tag{13}$$

$$\stackrel{(1)}{\Rightarrow} sLCOE_{vre} = \overline{sLCOE}_{conv} \tag{14}$$

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 2a and b illustrate these insights in schematic sketches. Figure 2a 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 3.2). The intersection of increasing System LCOE of VRE and average costs in a purely conventional system gives their optimal quantity E^* (Figure 2b or equation 14).

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}.

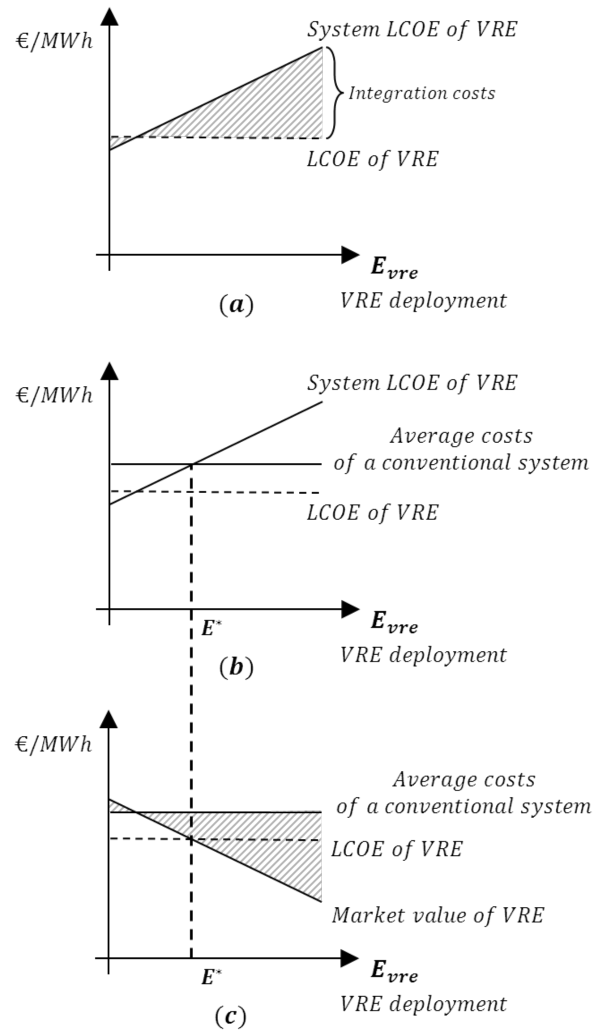


Figure 2: (a) System LCOE are the sum of LCOE and marginal integration costs (per MWh) while integration costs increase with VRE penetration. An optimal quantity E^* of VRE can be derived from (b) System LCOE or equivalently (c) the market value of VRE.

$$mv_{vre} := \frac{d}{dE_{vre}} C_{resid} \tag{15}$$

With this and equation 7 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 2c). 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].

$$\Delta \equiv \frac{d}{dE_{vre}} C_{int} = \frac{C_{tot}(0)}{\bar{E}_{tot}} - mv_{vre} \tag{16}$$

Inserting this into the optimality condition (equation 11) it can be rewritten.

$$mv_{vre} = \overline{LCOE}_{vre} \tag{17}$$

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 2c). Equation 14 and 17 are two formulations of the same optimality condition and thus both perspectives lead to the same optimal quantity (Figure 2b 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.

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 3, 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 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 3). In order to comprise *all* economic costs of variability and to allow drawing economic conclusions (like in section 2.2) this component needs to be accounted for. In [31] this component is termed *profile costs*.

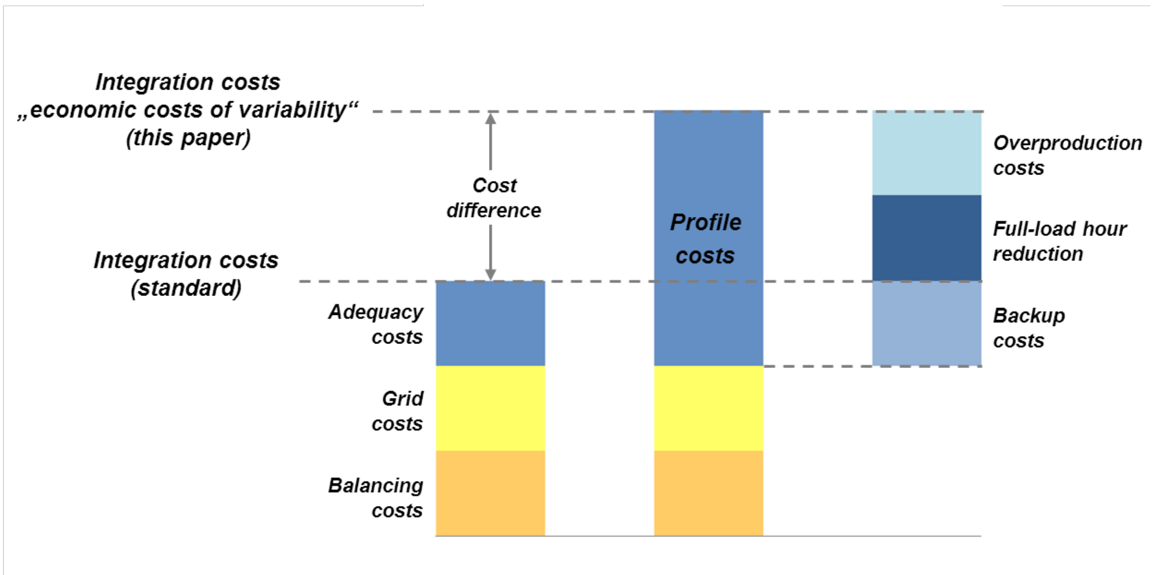


Figure 3: Integration costs as defined in this paper are higher than the sum of the standard cost components. Profile costs fill this gap and hereby complete the economic costs of variability. Profile costs can themself be decomposed into overproduction, full-load hour reduction and backup costs, while 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 curves[7] (RLDC). VRE unfavorably change the distribution of residual load (Figure 4). With high shares VRE cover base load rather than peak load. The RLDC becomes steeper. Compared to the hypothetic 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 3 right bar**,** 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 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 factor[8] 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.

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

[8] The capacity factor describes the average power production per installed nameplate capacity of a generating technology

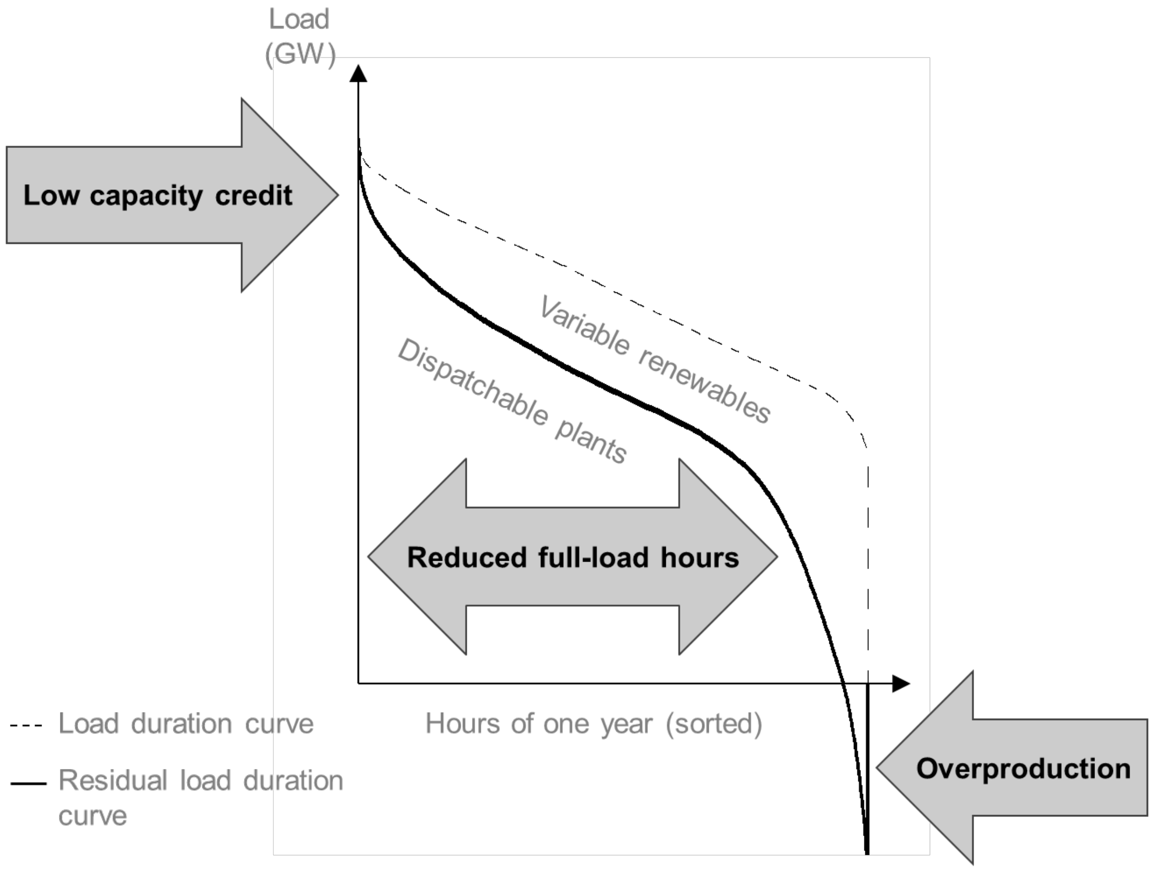


Figure 4 (illustrative): Residual load duration curves capture three main challenges of integrating VRE. While hardly any generation capacity can be replaced due to their low capacity credit, the full-load hours of conventional plants are reduced. At higher shares VRE supply exceeds load and thus cannot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

At higher shares these challenges get more severe. Figure 5 shows the development of RLDC with increasing shares of wind (left) and solar PV (right) for German data[9]. 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 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 the output of different wind sites.

[9] 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.

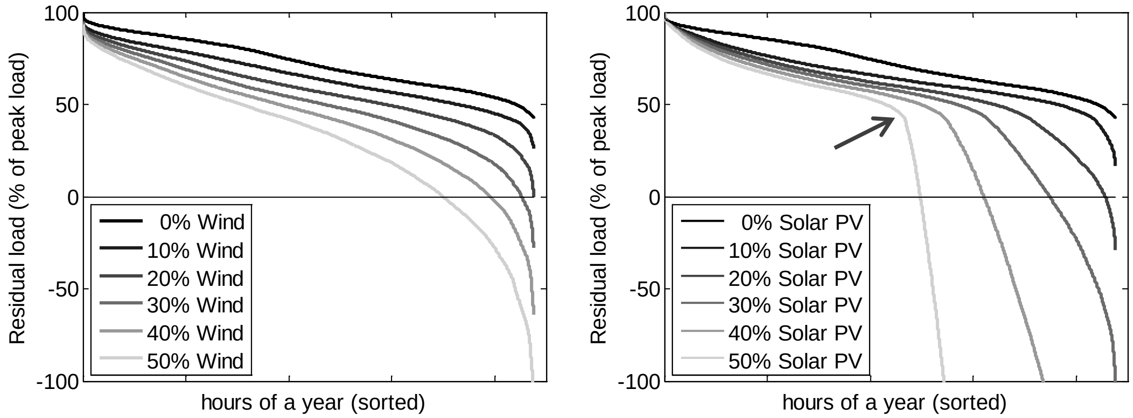


Figure 5: Residual load duration curves (RLDC) for increasing shares of wind (left) and solar PV (right) in Germany. With higher shares the RLDC continuously become steeper. Wind generation slightly covers peak load but increasingly contributes to intermediate and base load as well as to overproduction.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

Note that profile costs also include a further cost component induced by the so-called *flexibility effect*[10] [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 flexibility effect and focus on the major part of profile costs that is induced by the three other mechanisms described above (Figure 4).

Based on the reflections in this subsection we can now decompose integration costs into balancing costs, grid costs and profile costs (Figure 6). System LCOE are defined by adding the three components of integration costs to standard LCOE that reflect generation costs (Figure 6).

[10] This term is inspired by [32].

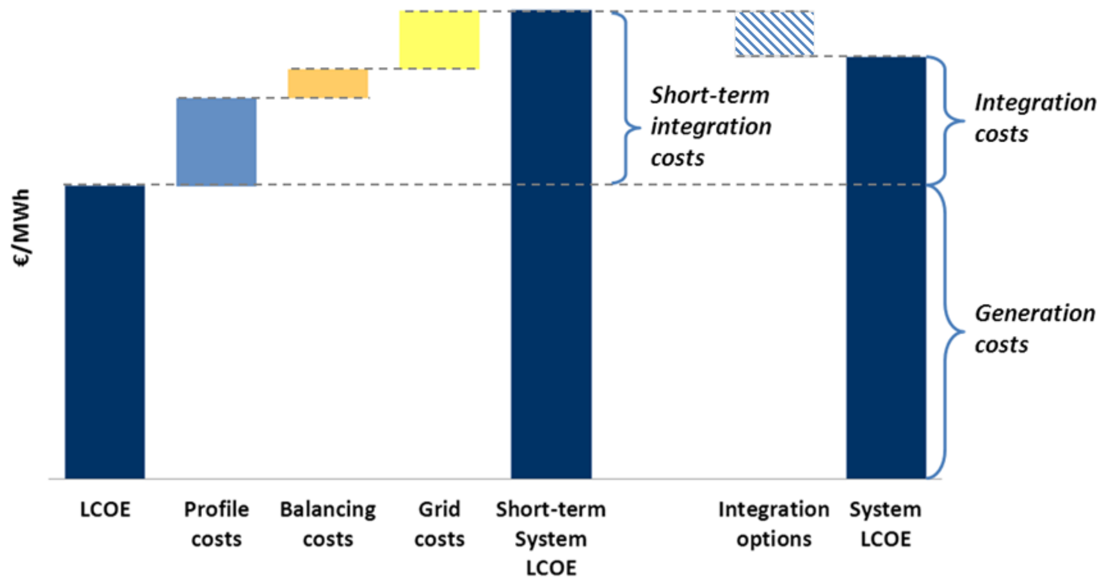


Figure 6: Integration costs are divided into three components: profile, balancing and grid costs. To some extent integration costs that occur in the short term can be reduced by integration options in the long term.

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*[11] (as indicated in Figure 6):

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.

[11] 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.

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.

2.4.Determining integration costs with a benchmark technology

This fairly technical subsection has the objective to link the new definition from subsection 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.

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.

$$C_{resid}^{BM} := \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \tag{18}$$

$$= \left(1 - \frac{E_{vre}}{\bar{E}_{tot}}\right) C_{tot}(0) \tag{19}$$

The essential property of the benchmark is that the residual power system costs decrease in proportion to its generation E_{vre} (equation 19). 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.

$$\frac{C_{resid}^{BM}}{E_{resid}} = \frac{C_{tot}(0)}{\bar{E}_{tot}} = const. \tag{20}$$

Inserting the benchmark interpretation (equation 18) in equation 7 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.

$$C_{int} = C_{resid} - C_{resid}^{BM} \tag{21}$$

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 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 model[12]. A benchmark that fulfills equation 18 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 7.

Note that in the model applied in this paper (section 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.

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

3. Quantification of System LCOE and integration costs

In section 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 systems[13] in Europe.

3.1. Model description and literature estimates

The power system model applied here is tailor-made to quantify profile costs (section 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 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 curve[14] (LDC) (Figure 7). A screening curve represents the total costs per kW-year of one generation technology as a function of its full-load hours. Its y-

[13] Thermal systems rely on thermal power plants like coal, gas and nuclear plants rather than hydro power generation.
[14] For the illustrations we use hourly data for German power demand in 2009 (ENTSO-E).

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 7 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 CO_2 and a discount rate of 5% are applied.

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

	Investment costs[15] (€/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	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 systems[16] with load and renewable profile patterns similar to those in Germany. This applies to most continental European countries.

[15] 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.

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

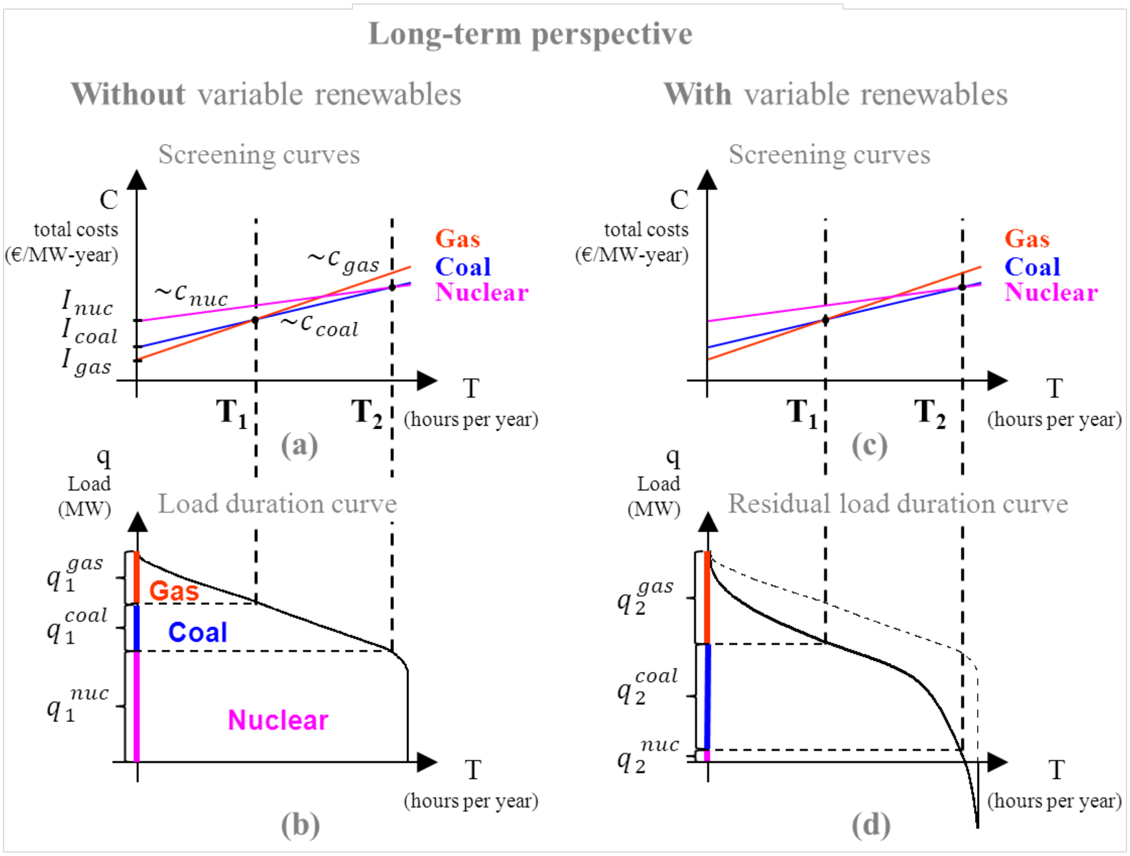


Figure 7 (illustrative): Long-term screening curves and load duration curves without (left) and with wind deployment (right). Wind changes the residual load duration curve (c, d). Thus capacities adjust towards lower fixed-to-variable-costs ratio (more gas capacity, less nuclear capacity).

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€/tCO_2 is applied.

When introducing VRE the system is displaced from its equilibrium. VRE change the LDC to a RLDC **(**Figure 7d**)**. Its shape depends on the variability of the renewable sources and especially its correlation with demand. This captures profile costs as described in section 2.3.

I) Calculating total profile costs

Profile costs $C_{profile}$ are in this model given by applying the definition for integration costs (equation 7).

$$C_{profile} = C_{int} = C_{resid} - \frac{E_{resid}}{\bar{E}_{tot}} C_{tot}(0) \qquad (22)$$

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 22 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 $T(q, \mathrm{E_{vre}})$ 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.

$$C_{resid} = \int_0^{q_{peak}} T(q, E_{vre}) c_{min}\big(T(q, E_{vre})\big)\, dq \tag{23}$$

$$c_{min}(T) = min(c_{gas}(T), c_{coal}(T), c_{nuc}(T)) \tag{24}$$

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 8 c, d). The two narrow shaded areas in Figure 8**c** indicate the screening curve difference between the long and the short-term perspective. Equation 23 accordingly changes to:

$$C_{resid}^{ST} = \sum_{te} \int_{q_{te,min}}^{q_{te,max}} T(q, E_{vre}) c_{te}(T(q, E_{vre}))\, dq \tag{25}$$

$q_{te,min}$ and $q_{te,max}$ mark where the capacity of each technology te is located on the q-axis in Figure 8b and d.

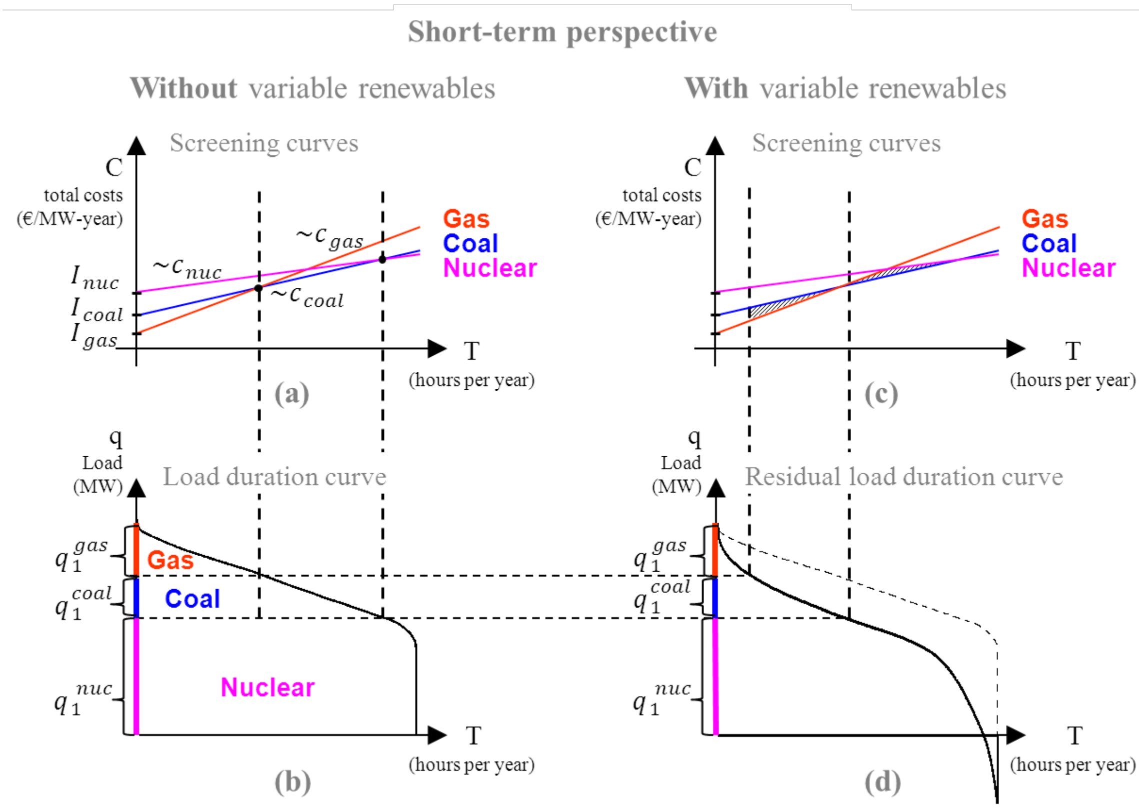


Figure 8 (illustrative): Optimal long-term capacities are derived without VRE (a, b). With VRE the LDC transforms to a RLDC (d). In the short-term perspective the capacities remain unchanged (b, d). Hence, specific costs increase because technologies operate in full-load hour ranges where they would 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 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 3 and Figure 4: 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.

$$C_{overprod} = \frac{\gamma}{1-\gamma}\overline{LCOE}_{vre} \tag{26}$$

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 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.

$$C_{backup} = (\alpha_{BM} - \alpha_{VRE}) I_{OCGT} dq_{vre} \tag{27}$$

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.

$$C_{FLH} = C_{profile} - C_{overprod} - C_{backup} \tag{28}$$

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 €/MWh[17]). 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

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

increase of grid costs with increasing VRE share up to 7.5 €/MWh (average terms) which translate to about 13 €/MWh in marginal terms.

3.2. Results for System LCOE and integration costs

Figure 9 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 6 in section 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.

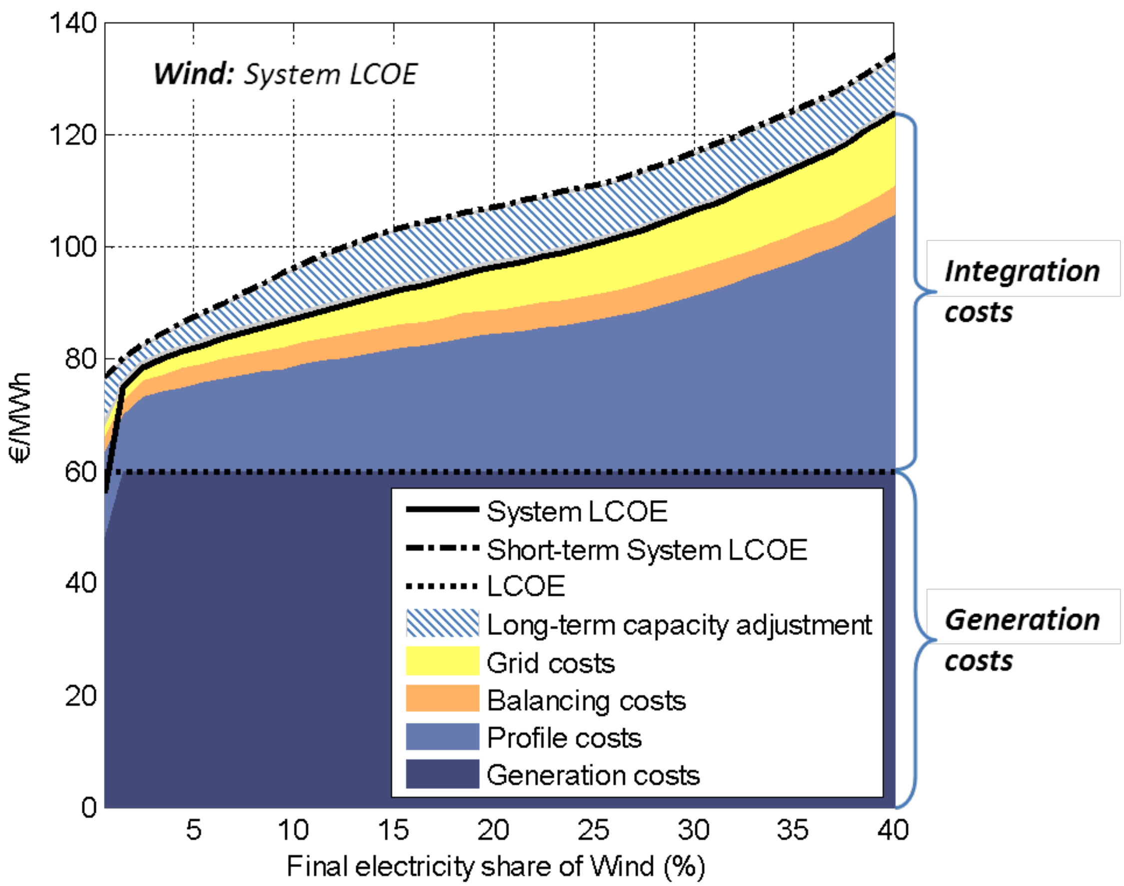


Figure 9: System LCOE for increasing shares of wind representing typical thermal power systems in Europe. Integration costs rise up to the order of magnitude of generation costs. Integration costs can thus become an economic barrier to large deployment of VRE.

We find four main results (Figure 9). 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. DeCarolis 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 3.4).

Wind power would only be economically efficient (and competitive[18]) without subsidies if its System LCOE is below the average costs (per MWh) of a purely conventional system (see section 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 CO_2 prices[19], 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.[20] 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

[18] In case of perfect and complete markets.
[19] This assumes that carbon capture and storage (CCS) will not be a mitigation option.
[20] The effect of uncertainty was subtracted from the value reduction in those cases were it was considered in the original analysis.

particularly important for reducing the costs of an energy transformation towards VRE (section 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 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 9 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 3.4 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 9. Adaptations of dispatchable plants drive down integration costs according to two mechanisms:

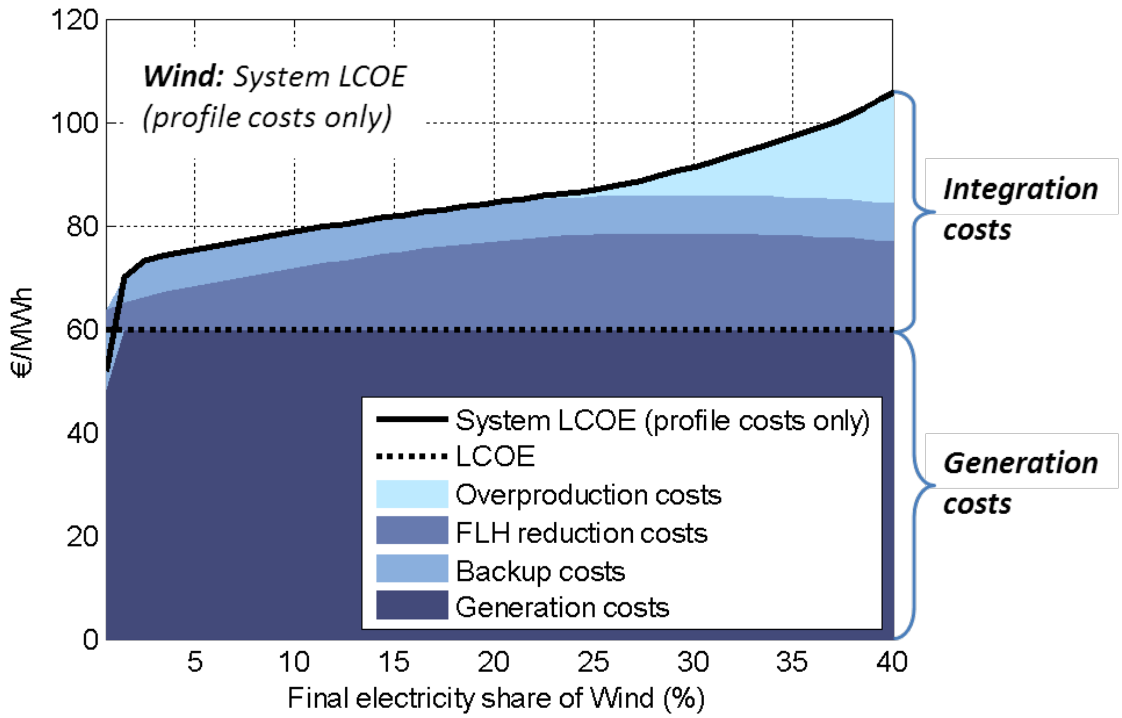
1) First, VRE reduce the average utilization (or full-load hours) of dispatchable power plants. Peak-load plants like gas turbines have lower specific investment costs and are thus more cost-efficient at low full-load hours. Hence, VRE shift the long-term optimal mix of residual capacities from base-load 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 responses. 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. 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 10 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 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 PV[21] [6].



[21] 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.

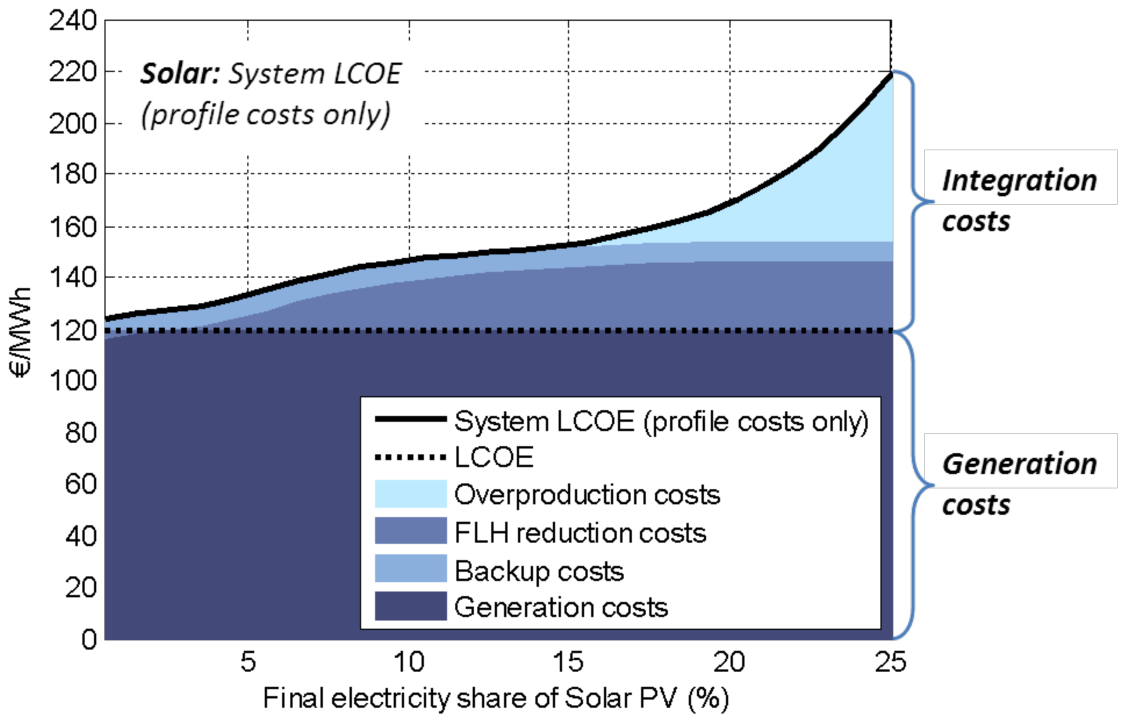


Figure 10: System LCOE (profile costs only) for increasing generation shares of wind (above) and solar PV (below) for Germany estimated with a power system model that is designed for calculating profile costs. These costs are decomposed into three cost drivers. The full-load hour (FLH) reduction of conventional 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 10). 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.

3.4. 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 extend 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 3.2 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 3.2. 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 3.2 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 extend 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.

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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