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System Costs of Variable Renewable Energy in the European Union

Thibault ROY

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About the author:

Thibault Roy is a former student of the College of Europe, where he graduated in 2015 with a Master's degree in European Economic Studies, with Specialisation in European Economic Integration and Business. He holds another Master's degree in Corporate Strategy and Finance from Sciences Po Strasbourg. In the past, he worked for a Senator and several City Councillors in Strasbourg and interned with the United Nations Development Programme Multi-Partner Trust Fund Office in New York. He currently works as a Blue Book trainee at the Directorate-General for Energy of the European Commission, in the team of the Director-General.

Address for correspondence:

thibault.roy@coleurope.eu

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Abstract

To shift to a low-carbon economy, the EU has been encouraging the deployment of variable renewable energy sources (VRE). However, VRE lack of competitiveness and their technical specificities have substantially raised the cost of the transition. Economic evaluations show that VRE life-cycle costs of electricity generation are still today higher than those of conventional thermal power plants. Member States have consequently adopted dedicated policies to support them. In addition, Ueckerdt et al. (2013) show that when integrated to the power system, VRE induce supplementary not-accounted-for costs. This paper first exposes the rationale of EU renewables goals, the EU targets and current deployment. It then explains why the LCOE metric is not appropriate to compute VRE costs by describing integration costs, their magnitude and their implications. Finally, it analyses the consequences for the power system and policy options. The paper shows that the EU has greatly underestimated VRE direct and indirect costs and that policymakers have failed to take into account the burden caused by renewable energy and the return of State support policies. Indeed, induced market distortions have been shattering the whole power system and have undermined competition in the Internal Energy Market. EU policymakers can nonetheless take full account of this negative trend and reverse it by relying on competition rules, setting-up a framework to collect robust EU-wide data, redesigning the architecture of the electricity system and relying on EU regulators.

Keywords: Variable renewable energy, Integration costs, Distortion costs, EU electricity system, System costs

JEL codes: L51, L94, O52, Q20, Q42

List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
EC	European Commission
ENTSO-E	European Network of Transmission System Operators
IA	Impact Assessment
IEA	International Energy Agency
IEM	Internal Energy Market
IM	Internal Market
LCOE	Levelised Cost of Electricity
MS	Member State
NPV	Net Present Value
OECD	Organisation for Economic Cooperation and Development
RES	Renewable Energy Sources
TSO	Transmission System Operator
UK DECC	UK Department of Energy and Climate Change
VRE	Variable Renewable Energy
WACC	Weighted Average Cost of Capital

Glossary of Terms

Balancing costs: costs caused by the uncertainty of the power generation profile and its variability. Transmission system operators subsequently have to balance the network by relying of flexible thermal power plants.

Capacity credit: represents how much firm capacity can be taken out of the power system for every new unit of a new (variable) technology.

Capacity factor: corresponds to the average power generation per installed capacity unit of a technology.

Demand response: method to diminish or shift peak demand of electricity.

Demand-side management: includes energy efficiency and demand response. It aims at reducing electric consumption, continuously are on some periods (peak periods).

Electricity system: describes a web of generators (producers) and consumers of electricity linked by transmission and distribution networks.

Energy efficiency: describes methods enabling to perform the same activities while using less power.

Firm capacity: the amount of electricity that is guaranteed to be available at a given time.

Grid-related costs: Expenses for grid infrastructure and management due to the location specificity of the plants

Integration costs: costs that occur beyond the individual plant and are caused by the integration of renewables to the power system

Levelised cost of electricity: ratio of the costs incurred to build and operate a power-generating unit on the amount of electricity expected to be generated on the lifetime of this unit

Profile costs: expenses for additional thermal power due to adjusted utilization of thermal plants induced by the variability of the generation profile.

Renewable electricity sources: means non-fossil electricity sources: hydropower, wind, solar, geothermal, wave, tidal, etc.

Residual load: what remains of the power demand after subtraction of variable renewable energy sources' output.

Variable renewable energy: refers to non-dispatchable generation technologies that rely on fluctuating conditions (wind, sun, etc.)

"Any fact becomes important when it's connected to another."
— *Umberto Eco, Foucault's Pendulum*

1. Introduction

The EU wants to be a "world leader in renewables" (Cañete, 17 March 2015). The target, for 2030, is to increase the share of energy consumption from renewable energy to at least 27% at EU level. However, this target is costly. At EU level, the total cost of public interventions in energy, excluding transport, was €120-140 billion in 2012 (European Commission, 2014), the equivalent of Hungary 2012 GDP. Not surprisingly, the major part of public support goes to renewables with more than €10 billion each for solar and onshore wind. Thus, to reduce the financial burden during the transition, the European Commission (EC) gives fifteen action points in its February 25. Strategy for a "Resilient Energy Union" (2015b). It especially mentions its objective "to ensure that the 2030 EU target is met cost-effectively" (*Ibid.,* p.21).

Cost-effectiveness here links two concepts, policy *effectiveness* (realised growth) and *economic efficiency* (support paid compared to generation cost). The aim of this paper is to look at the second concept through a *system perspective*. The efficiency of each technology taken in isolation may be different from its efficiency when considering its *interactions* with the power system. The deployment of variable renewable energy (VRE) may indeed bring additional costs to the system. These costs may at the end of the day harm efforts to decarbonize our economies and fight against climate change, at EU and global level. In this regard, the calculation of costs needs to be as complete as possible. Policymakers would then be in position to draw conclusions on the state of policies and their impact on the power system.

Although the debate on the cost of VRE technologies is abundant and could suggest that all relevant issues have been addressed, there are still grey areas. VRE deployment has been a recent trend and the EU is the most advanced in the transition. As such, it cannot reflect on any historical reference or comparison with other regions. Furthermore, the technicality of VRE and the complexity of the European electricity system make assessments particularly difficult. It justifies a comprehensive analysis of VRE deployment and accompanying policies' economic effects.

Economists have developed several metrics to measure the costs of different electricity sources. The most widely used is the "Levelised Cost of Electricity" (LCOE). The LCOE is the ratio of the costs incurred to build and operate a power-generating unit on the amount of electricity expected to be generated on the lifetime of this unit (United Kingdom Government, 2013). It gives the assumed "total costs" (fixed and variable) of each MWh generated. Thus, it allows comparing variable sources of energy, renewables and non-renewables, despite their different cost structures (Ueckerdt et al., 2013).

Nonetheless, Joskow demonstrates that "levelised cost is a flawed metric for comparing [*intermittent generating units]* such as wind and solar with conventional dispatchable generating units technologies such as nuclear, coal and gas-combined-cycle" (2011, p.2). LCOE neglects costs *integration costs,* i.e. costs that occur beyond the individual plant and are caused by the integration of renewables to the power system. When added to direct generation costs, they form what Ueckderdt labels *system LCOE* (2013). *Technical specificities* of variable renewable energy (VRE) may induce significant integration costs, which affect not only VRE themselves but also *conventional generators*. If so, European policymakers may have to find methods in order to mitigate the costs of mitigation.

Most importantly, VRE deployment may harm the *economic efficiency* of the European *power system*. Taken together, all these costs are referred to as *system costs*. Their combined effects may require a massive EU power system overhaul. The cost of the transition could otherwise become unbearable for European citizens.

Therefore, the question that guides this paper is: ***"Should EU policymakers consider system costs of variable renewables?"***

The main finding of the paper is that the EU, by using the LCOE metrics, has greatly underestimated VRE direct and indirect costs. Until today, VRE deployment has meant more interventions by Member States and less competition in the market. The paper then proposes recommendations to reverse the trend that include more reliance on competition rules and a redesign of the European electricity system.

The paper is structured as follow. As a starting point, it describes the rationale of EU renewables goals EU targets and current deployment of renewables. Secondly, an analysis of VRE LCOE and integration costs is performed. In a third part, estimates of integration costs' drivers are confronted and the options to mitigate them are discussed. Lastly, the overall system costs of renewables are highlighted and conclusions for policymakers on a possible way forward are drawn.

2. The EU renewables target

Science has made it clear that climate change will have a negative impact on our economies and that carbon emissions are the major cause of climate deregulation. The EU has been at the forefront of efforts to mitigate greenhouse gas (GHG) emissions.
The Lisbon Treaty (2009, Article 194) sets out the EU's competence in energy policy and decarbonisation: "Union policy on energy shall aim [...] to promote [...] the development of new and renewable forms of energy." The EU has thus adopted EU-wide and national objectives. The Renewable Energy Directive 2009/28/EC has set mandatory national targets for achieving, by 2020, a reduction in GHG emissions of at least 20% below 1990 level. In addition, the EU 20-20-20 targets include goals of 20% of energy consumption sourced from renewables. The EU ambitions for 2030 are even greater with its goal to reduce GHG emissions by 40%.

Before analysing the deployment and associate costs of renewables, it is worthwhile making the distinction between *variable* or *intermittent* renewables – such as solar power and wind power – and "*non-variable*" or "*controllable*" renewables – for example hydroelectricity and biomass. The potential for more hydroelectricity in Europe is limited. Dams already occupy most of the favourable locations. Thus, the main effort is currently on wind and solar energy, both of them with a variable generation profile. Variable renewables are, according to the International Energy Agency, "based on sources that fluctuate during the course of any given day or season". Thus, "their output varies according to the variability of the resource" (IEA, 2008). Contrary to VRE units, thermal plants are labelled *dispatchable*. They can quickly be turned on and off to generate electricity whenever needed. They include gas-fired power plants, coal power plants and to a lesser extent nuclear plants.

It is particularly difficult to compute RES' costs. Nonetheless, approximations have been made. The EC estimated the additional cost of having 20% of renewable energy between €13bn and €18bn per year with growing costs every year (EC, 2008). Thus, in 2020 the extra cost would amount to €24 - €31bn. However, the ascertained cost of renewables sharply contradicts EC figures. In Germany alone, the total amount of subsidies in 2012 was around €20bn (Spiegel, 04 September 2013) with the barrel of oil around $100. It was translated into consumers electricity bill through a 20% surcharge (*Ibid.*). In 2014 alone, subsidies of €22-24bn to the VRE sector coincided with a record annual loss of €3.2bn for the German utility (power company) E.ON, which runs mainly on fuels (Euractiv, 2014 and Financial Times, 2015).

These figures first reveal that the direct cost of variable renewables might have been underestimated. Second, they also show that they have a negative disruptive effect on the traditional energy model and cause value losses to conventional power generation plants. These two facts may have been overlooked by EU policymakers, not because they have decided to ignore them, but more accurately because the valuation of costs may have been *partial* and may have been positively *biased* in favour of VRE.

3. System LCOE and the drivers of integration costs

Policymakers must necessarily rely on estimates to take cost-effective decisions. EU services have adopted the LCOE for its convenience to compare VRE and conventional sources. Thus, we first expose the LCOE method and its advantages.

These clarifications on the LCOE then bring us to its drawbacks. We demonstrate that it fails to take into account other VRE-specific *integration costs*. Policymakers may fall in the trap of thinking that the LCOE gives them a complete overview of costs for each technology, when they may actually get a very partial and reduced understanding of the drivers of variable RES costs and, subsequently, of their economic potential.
Additionally, this part facilitates the discussion on integration costs' mitigation options.

3.1. LCOE

> "The Commission services consider the LCOE method as best practice" (EC, 2013, p.19)

The LCOE of a particular technology is "the discounted lifetime cost of ownership and use of a generation asset, converted into an equivalent unit of cost of generation in [€/MWh]" (UK Department of Energy and Climate Change, 2013, p.6). It is the net present value of "the ratio of the total costs of a generic plant (including both capital and operating costs), to the total amount of electricity expected to be generated over the plant's lifetime" (Ibid., p.6). The components of LCOE are concisely described below.

1) Investment costs (I_t): pre-development costs and capital expenditure costs.

2) Operations and maintenance costs (OM_t): relating to labor, regular maintenance, insurance, repair, regulatory fees, etc.
3) Fuel costs (F_t): They apply to thermal power plants.
4) Decommissioning and waste storage costs: for nuclear power plants.
The costs are then divided by the power generation over the unit lifetime.

The LCOE metric enables to compute the lifecycle cost of a plant or its “cradle to grave” costs. Ueckerdt et al. emphasise that it “allows comparing conventional plants with variable renewable sources like wind and solar power, even though they have very different cost structures” (2013, p.2). The formula enables it. Thanks to a discounting method $(1+r)^t$, it gives the net present value (NPV) of costs that occur at different moments in time.

$$LCOE = \frac{\Sigma_{t=1}^{n} \frac{Investment\ c. + Operations\ \&\ Maintenance\ c. + Fuel\ c. + Decommissioning\ \&\ waste\ c.}{(1+r)^t}}{\Sigma_{t=1}^{n} \frac{Power\ generation}{(1+r)^t}}$$

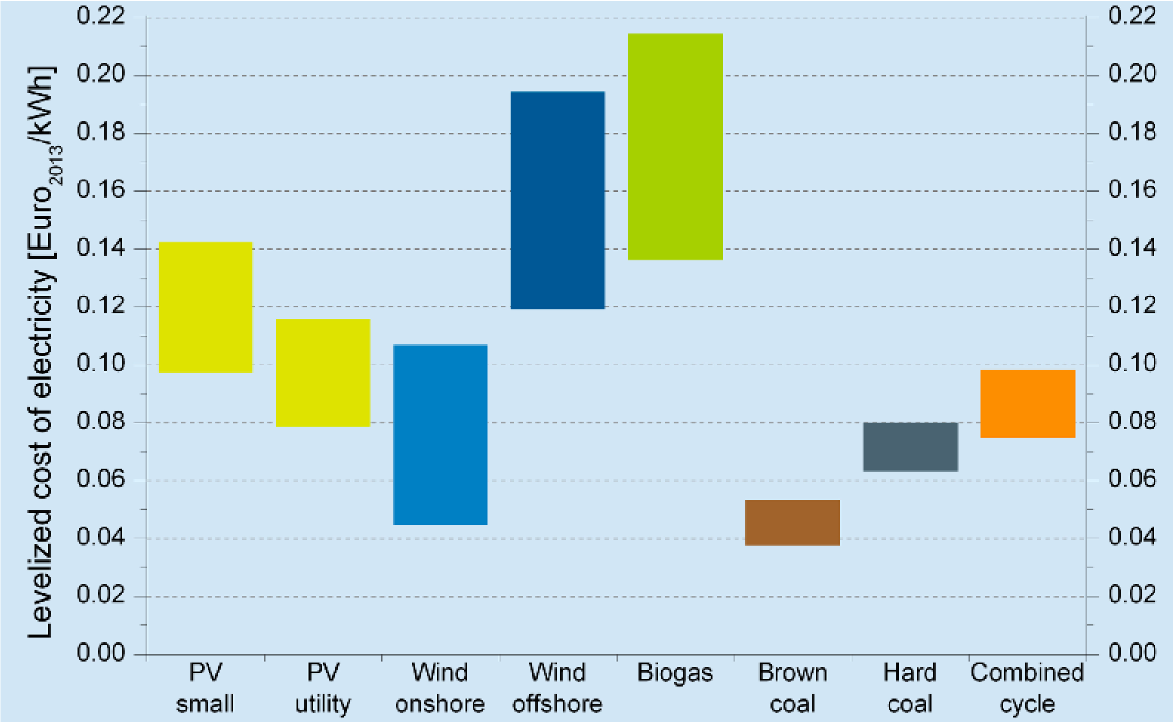
As an example, gas requires relatively low up-front fixed investment costs but annual operations and maintenance costs are far from being negligible, especially when fuel prices climb. On the contrary, RES may be more capital-intensive, depending on the installed capacity. They may ask for more fixed investment costs on day one. But their variable operations costs are lower as they run on a free “fuel”: wind and sun for example.

The Fraunhofer Institut has computed in 2013 the LCOE of RES and conventional power plants in Germany (See *Graph 1*). One can see that coal is overall the cheapest technology. Combined cycle is already more expansive and in the same cost ranges as wind onshore. Solar costs are higher but still lower than the costs per MWh of wind offshore.

Indeed, Joskow (2011) demonstrates that the LCOE is a flawed metric for comparing the competitiveness or *economic attractiveness* of various technologies. The inherent mistake of LCOE is that it takes electricity as a homogeneous good, which means “power supply from different fuels and technologies is perfectly substitutable” (Ueckerdt et al, 2013, p.17).
The reason lies first in the different generation profiles between VRE and conventional power plants. Thermal plants are dispatchable, the network operator can control their power delivery and adjust it almost whenever it wants. Supply adapts to the demand. Joskow demonstrates that “conventional generators are typically dispatched when the wholesale market price for power exceeds their short-run marginal cost of generating electricity” (2011, p.7). On the contrary, VRE have intermittent generation profiles, driven by natural elements. Network operators cannot dispatch power when the market asks for it, i.e. when the price is higher. Supply cannot adjust to demand. As a result, the economic value of power generated by variable RES is lower.
A further proof to that argument is that private firms do not plan their investment decisions based on LCOE. They take revenues into consideration because their evaluations are market-based.

Even more worryingly for VRE players, their increasing market share will further depress the price as they generate at more or less the same periods, when wind is blowing and sun is shining. It will lead to oversupply and further price reduction.

Graph 1: LCOE of renewable energy technologies and conventional power plants at locations in Germany in 2013



Source: Fraunhofer Institut, 2013, p.16

As Joskow points out, “the extension and use of levelised cost comparisons to intermittent generation has been a mistake and tends implicitly to overvalue intermittent generating technologies compared to dispatchable alternatives” (2011, p.4). The LCOE metric is adapted for dispatchable power plants, not intermittent. However, government agencies actually use it for their procurement programs and auctioning processes, regardless of technologies’ economic merits (*Ibid*).

Hence, it is worth searching for a more adapted metric. It would enable policymakers to take decisions based on better-adjusted benchmarks.

3.2. Integration costs and system LCOE

> “RES specificities, such as production variability and low-predictability, zero marginal-cost of generation, and strong site-specificity, result in a set of technical and economic challenges” (Henriot and Glachant, 2013, p.2)

Ueckerdt et al. put emphasis on system LCOE, “the total levelised economic costs of a technology” (2013, p.3). The system LCOE metric combines LCOE and integration costs, which are “all additional costs induced by VRE that are not directly related to their generation costs” (*Ibid*, p.4).

Integration costs comprise three main additional costs to LCOE following “three intrinsic properties of VRE: *variability*, *uncertainty* and *location-specificity*” (Ueckerdt et al., 2013, p.10). These three costs are shown in *Table 1*.
A distinction should be made between balancing costs and grid-related costs on the one side and profile costs on the other side. The first two are *direct* or *additional* costs to the system. Indeed, the highest the penetration of variable RES, the more the need to build and manage the network. The third refers to “*diminishing cost savings* in the non-VRE system when increasing the VRE share.” (Edenhofer et al., 2015, p.13).

Table 1: The three types of integration costs.

Name of cost	**Cause**	**Induced costs**	**Nature of costs**
1. Balancing costs	*Uncertainty* of the generation profile	(1) Reserve requirements and (2) more flexible operation of thermal plants	*Additional* (the deployment of variable RES cause higher expenses)
2. Grid-related costs	*Location-specificity* of the plants	Additional expenses for grid infrastructure and management	*Additional*
3. Profile costs	*Variability* of the generation profile	Expenses for additional thermal power due to adjusted *utilization* of thermal plants	*Diminishing cost savings*

Source: Ueckerdt et al., 2013

The uncertainty of the generation profile causes balancing costs. The weather can hardly be predicted with full certainty. It means the inflow of power from variable RES is hardly predictable more than a few hours in advance as well. It induces costs: reserves of coal and gas to counterbalance a momentary lack of power (1) and more start-up and shutdowns operations on conventional power plants (2). This is the cost of non-reliability.

Grid-related costs also are a direct additional burden. They are due to the location-specificity of variable RES and can be valued as “the additional investments in the transmission grid after the integration of a given target of renewables with respect for those required for an “equivalent” system without renewables” (ILEX, 2002, p. 147). VRE generators are currently not fully held responsible for these costs. Edenhofer et al. (2015) qualify integration costs' three drivers as *transmission capacity infrastructure*, *transmission losses* and *varying resource quality and land prices*.

1. *Transmission capacity infrastructure*: refers to investments in extension *of* and connection *to* the grid (A) as well as grid reinforcement (B). With variable RES, “the average distance between production and consumption increases” (Groebel, A., for the EC (2013), p.4) and the power lines intermittently have to carry a surcharge of electricity.
2. *Transmission losses*: transportation of power mechanically creates losses. The largest the distance between generation and consumption of power, the largest the loss. Wind parks are far away from conglomerations and thus face power losses.

3. *Varying resource quality and land prices*. The geographical footprint of variable RES is higher than the one for a conventional power plant. Put together with NIMBY ("not in my backyard") issues, variable RES are either located far from urban centres or face higher land costs.

Beyond *additional* rather *technical costs*, there are "*diminishing cost savings* in the non-[*VRE*] system when increasing the VRE share" (Edenhofer, 2015, p.13). These "profile costs" are the most complex to account for but they are also the ones with the largest negative disruptive effect on the European power system and the functioning of the Internal Energy Market (IEM).

The term "profile costs' refers here to the costs induced by the *generation profile* of *variable* RES: their *variability*, i.e. *intermittency* creates three kinds of costs.

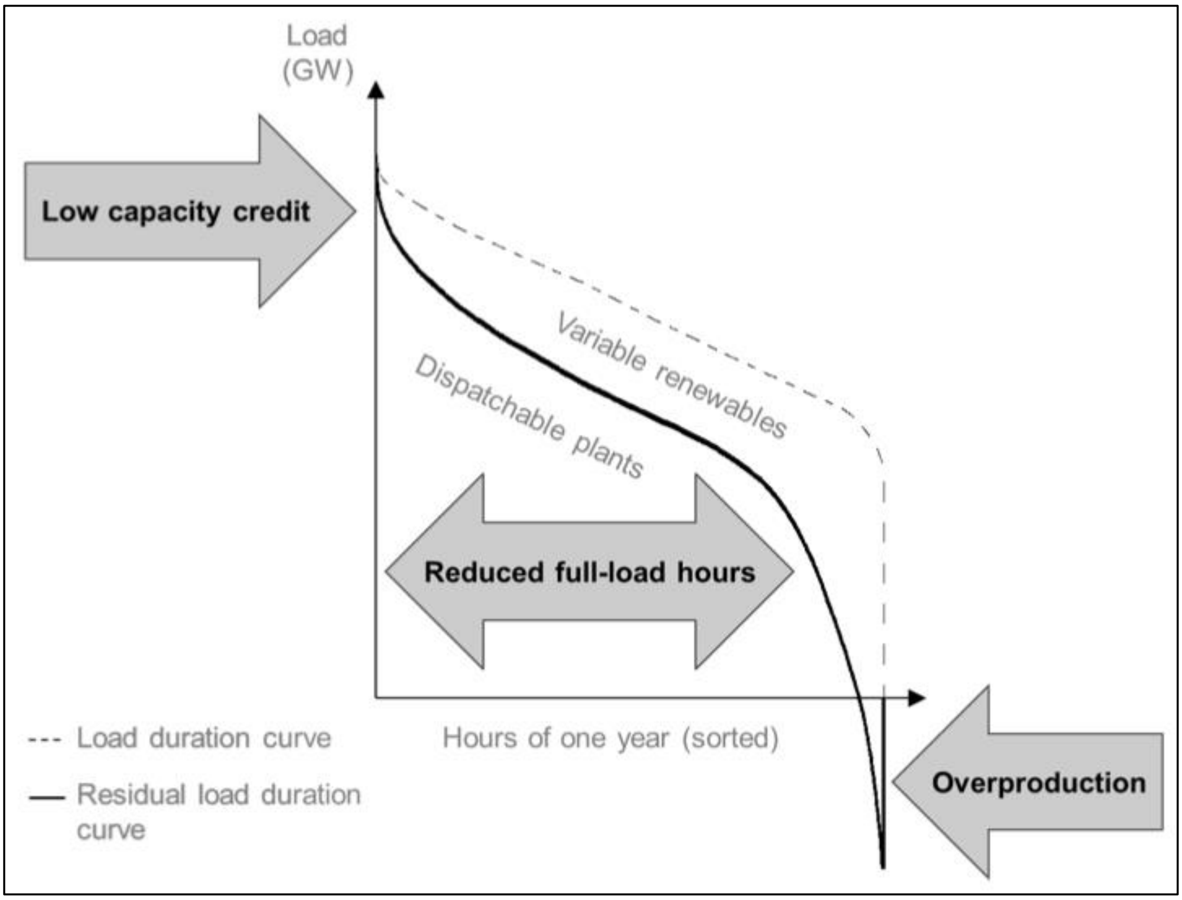
1. *Full-load hour reduction (FLH reduction)*: when VRE units generate electricity, they replace conventional power plants because they benefit from their close-to-zero marginal costs. As a result, dispatchable power plants produce less electricity during their lifetime, i.e. they earn less revenue while their investment costs remain identical. Mechanically, their LCOE per MWh increases.
2. *Back-up costs*: VRE have a low *capacity factor*, i.e. a low percentage of power generation over their lifetime per installed capacity, less than 35% for wind power and less than 25% for solar (Ueckerdt et al., 2013). In addition, their generation profile does not match fluctuations in demand. They cannot adapt to the needs. But the power system requires *adequacy*, i.e. "the ability of the system to satisfy demand at all times, taking into account the fluctuations in supply and demand" (OECD IEA, 2012, p.17). It explains VRE low *capacity credit*, the capacity credit indicating "how much firm capacity can be removed from the system in relation to [*the* installation of] a new unit of this technology" (*Ibid*, p.10). According to the OECD, it "rarely exceed[*s*] 10% of total capacity and decline with rising shares […] in electricity production" (*Ibid.*, p.30). Thus, for every MWh of VRE capacity installed, the power system needs to maintain almost the same capacity of dispatchable power.

All these complex *technical* properties would be less of a problem if the market could find *economically efficient* solution. In a market without distortions, the natural outcome of supply and demand properties would be that dispatchable power plants would be sufficiently remunerated for the *residual power* they generate when VRE do no produce sufficiently. In reality, utilities with dispatchable power plants face a *missing money* issue in particular because of regulated prices.. They cannot rely solely on the value of electricity they sell on the market to cover fixed and marginal costs.

3. *Overproduction costs*: Ueckerdt et al. (2013, p.12) point out that "at high shares an increasing part of VRE generation exceeds load and this overproduction might need to be curtailed. Overproduction can result in negative hourly pricing or, as the EC mentions, "even in negative daily average baseload electricity prices" (2014d, p.8)

Ueckerdt et al. expose profile costs: FLH reduction, back-up capacity needs and overproduction costs (See *Graph 2*). The arrow on the bottom right hand corner shows overproduction. The arrow in the middle represents FLH reduction: with VRE penetration, conventional power plants run during less hours. Nonetheless, "hardly any generation capacity can be replaced" (Ueckderdt et al., 2013, p.13), because of the low capacity credit of VRE (arrow on the upper left hand-corner).

Graph 2: Three main challenges of integrating VRE



Source: Ueckerdt et al., 2013, p.13

The worrisome factor common to these three challenges is the reduced utilization of sunk capital, for thermal plants (full load hour (FLH) reduction) as well as for VRE (overproduction). Even more worrying, Hirth explains that this cost component "has not been accounted for in most previous studies" (2015, p.1).

As explained above, the question is not whether integration costs exist. They do. A more relevant question for policymaking purposes would be:

- Are integration costs significant compared to LCOE?

If the answer were yes, the following question would be:

- Do they change the comparative cost-effectiveness of technologies? 1) Between the different variable RES technologies? 2) In comparison with other technologies (nuclear, coal, CCGT).

If no to 1) and 2), policymakers may consider other decarbonisation options such as a reduction in electricity demand. Indeed, it would mean that changing the power mix and targets would not prevent an increase in the overall transition cost. If yes to 1) or 2), policymakers should pay close attention to changes in the merits of each technology and prevent from favouring one over another (technology neutrality).

4. Estimations of integration costs and implications

4.1. Estimation of integration costs

> "A number of challenges were not addressed at the time of the 2009 climate and energy package […] The management challenges linked to the introduction of renewables, including dealing with the variable supply of certain renewables (e.g. wind and solar) were also not fully considered" (EC, 2013, p.6)

There is, unfortunately, no such thing as a simple calculation of integration costs. Ueckerdt et al. demonstrate that "it is difficult to determine the costs that are actually *additional* […] Integration costs cannot be measured or calculated directly" (2013, p.4). A key reason is that "integration costs not only depend on the characteristics of VRE technologies but also on the power system in which they are integrated, and the power system's flexibility to adapt" (Ueckert et al., 2013, in Hirth, 2015, p.5).

Complexity leads to debate. According to Ueckerdt et al. (*Ibid),* there are issues with methods used to compute integration costs. As an example, some researchers use a *benchmark* technology, a *flat block of energy*, without integration costs. They then compare the cost of producing electricity with this technology to the cost of producing the same amount of electricity with VRE. Their goal is to extract "the pure integration costs" (*Ibid*, p.8). But the integration costs-free benchmark is biased because it also creates integration costs itself. As Ueckderdt et al. mention, the benchmark technology generates base-load power. Consequently "increasing its share would increase the specific residual costs because the residual system would need to cover a higher fraction of peak load" (*Ibid*). Instead, they propose to follow another method and argue "integration costs should be calculated by modelling the power system *with* and *without* VRE and comparing the resulting specific residual system costs" (*Ibid*, p.9). Thus, the graphs used in this analysis follow this method.

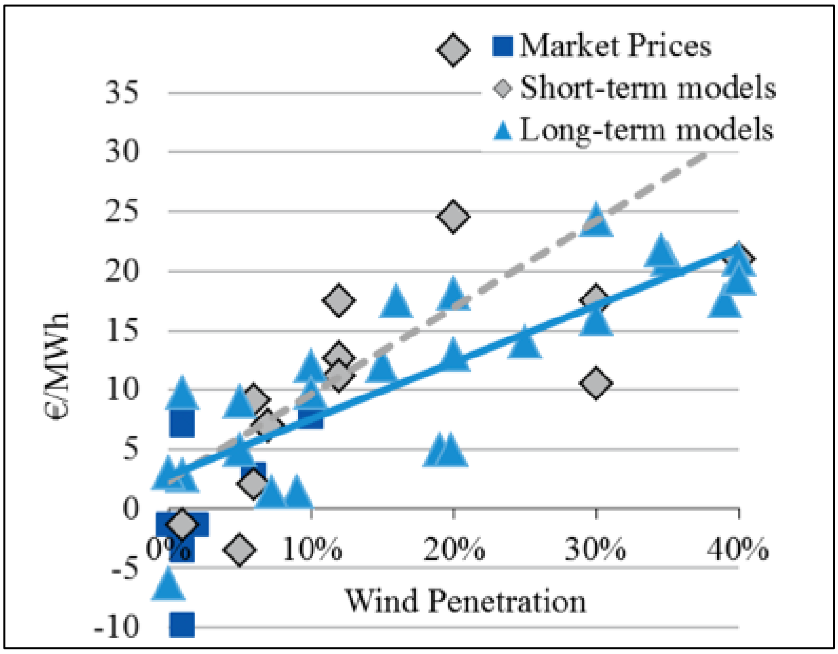
Literature on integration costs is very recent. The section above (4.1.1) has showed that schools of thought disagree on the appropriate computation methods. Furthermore, estimations are scarce and results diverge a lot, but some studies have nonetheless been conducted. Based on them we first examine here each cost individually. Secondly we compile these integration costs and compare them to LCOE.

Balancing costs may receive too much coverage in the literature. Their marginal importance is minimal compared to other cost drivers. Estimates consistently show a cost of less than €5/MWh, even with penetration of VRE above 40%. Policymakers should therefore pay less attention to them.

Literature on *grid-related costs* is missing. Quite surprisingly, the EC was already considering paying full attention to them in 2008. Nonetheless, there has not been much progress since. A handful of studies have been conducted (gathered in particular by Holtinen et al., (2011) but they report average costs, not the marginal cost impact of VRE on the grid. Hirth (2012) translates them to between €5 and €10/MWh. It depends naturally on the type of area. In the densely populated continental Europe, Grid-related costs may be lower than in Nordic countries with long distances between generation and consumption.

Finally, we present here estimates of *profile costs*. Based on thirty studies reviewed, Hirth graphically represents the costs. He finds a range of €15-25MW/h at 30-40% market share (*Graph 3*).

Graph 3: Wind profile costs.



Source: Hirth, 2012, p.19

Profile costs are twice as important as balancing and grid-related costs combined. Another factor to take into consideration is that the highest the penetration of VRE, the more profile costs per MWh escalate too. This property is shared with integration and balancing costs and should concern policymakers. Indeed, on this point integration costs diverge with LCOE, which remain constant are may even decrease with further deployment thanks to the learning curve effect.

Comparing these costs to the average cost of electricity production without VRE reveals their importance: in 2005, the average cost (addition of fixed costs, variable costs and fuel costs) was €73/MWh in the Euro'10 (EC Impact Assessment, 2011, p.80). Furthermore, the LCOE of wind is getting close to this number in some favourable locations. We can even go one step further and assume the wind LCOE to be €73/MWh in these locations. If we add integration costs presented above – totalling around €30/MWH - system LCOE are above €100/MWh, *representing a cost increase of more than 40%.*

The aforementioned complexity of integration costs and the lack of data limit the implications we can draw. Nonetheless, there are lessons to be drawn:

1) Integration costs are not negligible compared to LCOE. System LCOE is a relevant metric to compare the economic efficiency of technologies.
2) Integration costs and consequently system LCOE rise with a growing share of VRE. It means that they could become "an economic barrier to further deployment of wind and solar power" (Ueckerdt et al., 2013, p.22).
3) Literature on integration costs is too scarce, especially on grid-related and profile costs. A research agenda would be needed.
4) Profile costs represent the lion's share of integration costs.

4.2. Implications of integration costs

First of all, integration costs and related system LCOE change the merit of technologies.

Integration costs may be more important for some VRE technologies than for others. Hirth compiles his findings on four technologies in a (See *Table 2*). As expressed before, balancing costs are either low or moderate for all technologies. Grid-related present more interest as they vary a lot. They are negative for solar PV with a low penetration rate (less than 10%) and they become only moderately positive with additional deployment (above 10%). On the contrary, grid-related costs of offshore wind are high because of the distance from consumers and the high-technicality required in building and maintaining transmission lines under the sea. Not surprisingly, profile costs are the most difficult to account for. First, solar profile costs are extremely dependent on penetration rate. In continental Europe, at high shares, a consequent percentage of power generated is lost in overproduction (summer days) and the consumed power covers mainly baseload. The reason is that peak demand occurs generally in winter and around 6pm, when the sun is not shining anymore.

Table 2: Different VRE technologies in comparison.

	Solar PV	Solar thermal	Wind onshore	Wind offshore
Profile costs	extremely dependent on penetration rate	extremely dependent on penetration rate	very dependent on penetration rate	dependent on penetra-tion rate
Balancing costs	low	low	moderate	moderate
Grid-related costs*	negative / low	high	moderate	high

* Assuming solar PV is installed close to consumers, onshore wind at intermediate distance to consumers, and solar thermal and offshore wind far from consumers.

Source: Hirth, 2012, p.26

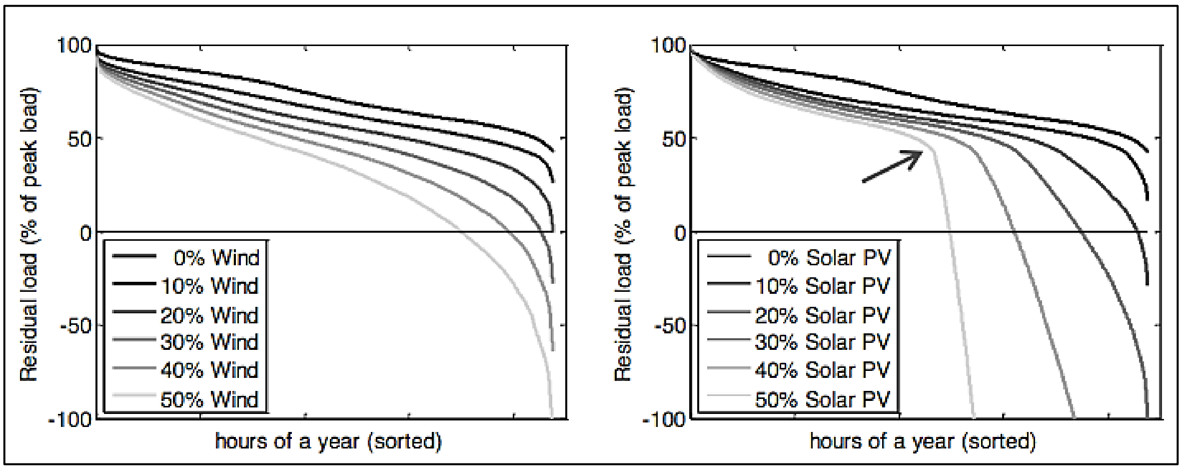
There are debates on the contribution of wind to respectively peak load, intermediate load and base load. Based on modelling (Graph 4, below), Ueckerdt et al. believe that wind covers more peak and intermediate load than solar as one can see that the RLDC for wind (left) is less steep than for solar (right).

Ueckerdt et al. justly remark, “the decomposition of integration costs helps estimating the importance of different options” (2013, p.20). We derive implications for long-term mitigation strategies. We review here *integration options* that can *mitigate the cost of climate change mitigation*. Indeed, Hirth points out that “integration costs not only depend on the characteristics of VRE technologies but also on the power system into which they are integrated, and the power system’s flexibility to adapt” (Hirth, 2015, p.5).

The four main options to deal with flexibility are:

1. On generation (*supply*): a) *adjustment of the residual capacity mix* b) *interconnections* c) *storage*.
2. On consumption (*demand*): *demand-side management* (DSM)

Graph 4: RLDC for increasing shares of wind (left) and solar PV (right) in Germany.



Source: Ueckdert e et al., 2013, p14

1. a) *Adjustment of the residual capacity mix*: it may be the most promising tool. The FLH reduction of thermal power plants results in higher investment costs per MWh. Thus, it is necessary to direct investments to plants with low sunk costs (gas) that would cover mid and peak load.
However, this assumption is in contradiction with the short-run effect induced by VRE. Lower prices and residual load hit technologies with high variable costs such as gas turbines (Henriot and Glachant, 2013).

b) *Interconnections*: the possibility to dispatch power from one MS (with a given mix) to another (with a different mix) would reduce the need to maintain plants solely to cover peak capacity. It would reduce imbalances between supply and demand.

c) *Storage*: short-term storage (pumped hydro, batteries) is another tool to accommodate intermittency.

The three supply-side options also change the value of power generated by VRE. It is compiled in *Table 3*. Overall, they are beneficial for VRE value and as such, its competitiveness.

Table 3: Mitigation options and the value of VRE power.

Change	Value factor	Dominating Chains of Causality
Interconnectors ↑	↑ (LT) ↑/↓ (MT)	Long term: smoothening out of wind generation across space; Mid term: German wind suffers from low prices set by French nuclear
Storage ↑	–	Small impact of wind because of small reservoirs; Negative impact on solar at low penetration rates, positive at high rates
Plant Flexibility ↑	↑↑	Reduced must-run generation leads to higher prices especially during hours of high wind supply

Source: Hirth, 2013, p.30

2. *Demand-side management*: demand response especially, with a system of incitation, smart grids and smart meters would increase the capacity credit of VRE. Consumers' demand would better adapt to (variable) supply.

Overall, taking into account integration cost backs the *EU economic rationale to push for more cross-border interconnections, efforts on storage and DSM*. It may also trigger more debates on nuclear long-term economic value and its (in)compatibility with high shares of VRE. The EU has not sufficiently tapped into the four options' economic potential. However, these options also have a cost.

Thus, it is not clear yet how the options will develop and interact. There is a need to develop a framework that would compare their cost-efficiency and model cost-efficient policies. It is extremely challenging to compare system LCOE or to conduct economic analyses "such as calculating [*VRE*] welfare-optimal deployment [*or*] conducting cost-benefit analyses" (Hirth, 2015, p.3). EU policymakers should try to consider how they could consolidate integration costs into regulatory impact assessments.

In a nutshell, *the more VRE are deployed, the more their integration costs rise and the more policymakers will have to deal with this increasingly heavy burden.* In a market with perfect competition and completeness, integration costs would be perfectly internalised by VRE. It would lead to a cost-efficient deployment of VRE - and other low-carbon or not - technologies. However, the European power market is not a perfect and complete market.

5. Market distortions and system costs

Current MSs policies supporting VRE deployment distort the market and may impose an additional toll on the power system that we call *distortion costs*. We then define *system costs as the addition of LCOE*, *integration costs and distortion costs*. The graphical representation below (*Figure 1*) fully expresses their extent and ramifications. These costs naturally overlap and interact with each other. For example, both high VRE LCOE and integration costs often serve as a justification for MSs' intervention.

We thus define system costs differently than Ueckerdt et al. (2013) who equate integration and system costs, as showed in *Figure 2*. In our view, LCOE and integration costs form system LCOE. If we add to system LCOE market distortion costs, it leads to system costs. It enables us to gather all the costs in one concept, i.e. to have the whole picture of the toll renewables may cause to the electric system. We believe it will facilitate discussions on the welfare effect of VRE and supporting policies. The goal would indeed be to enable more complete impact assessments of VRE's costs and benefits.

Figure 1: Components of system costs

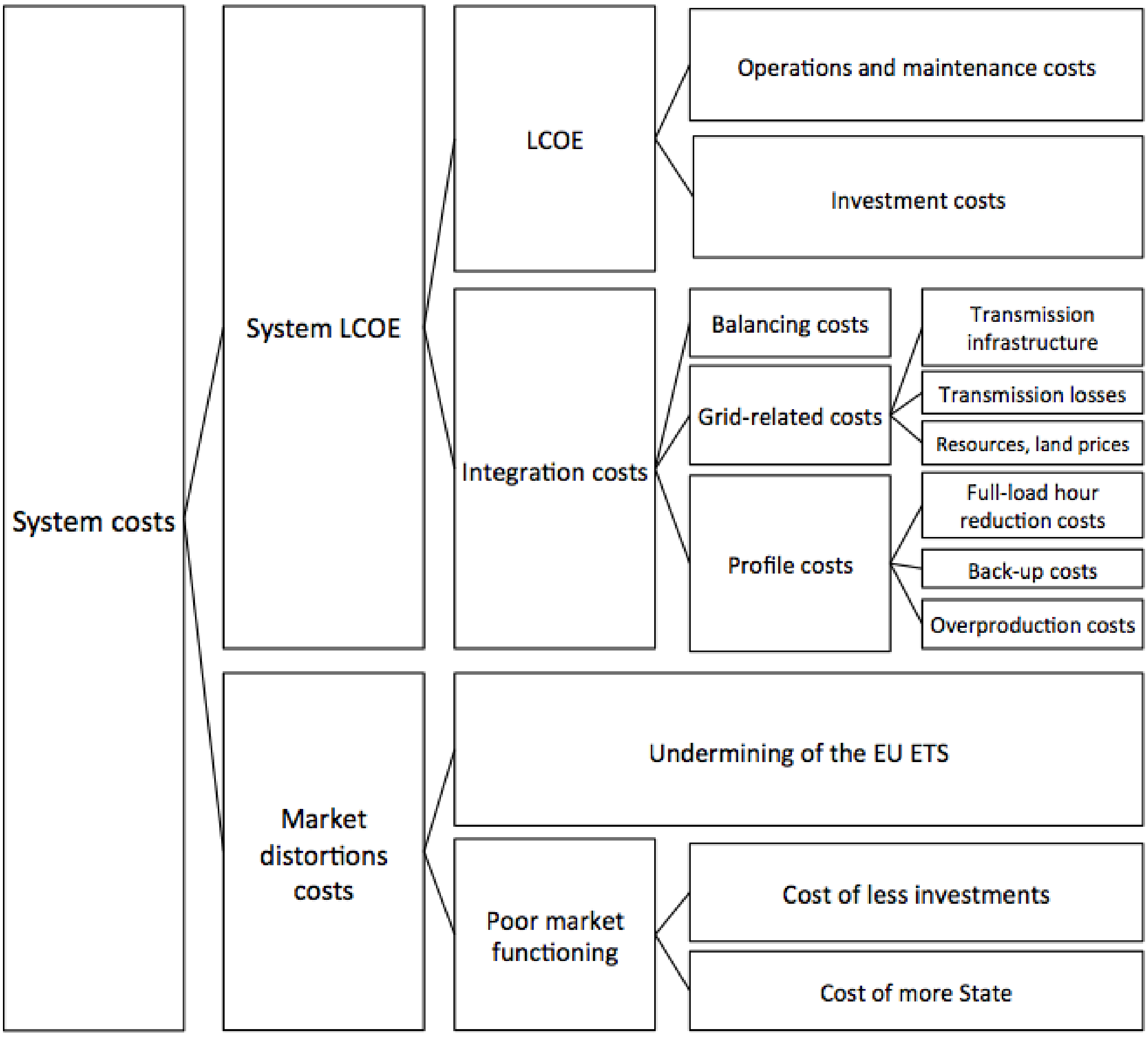
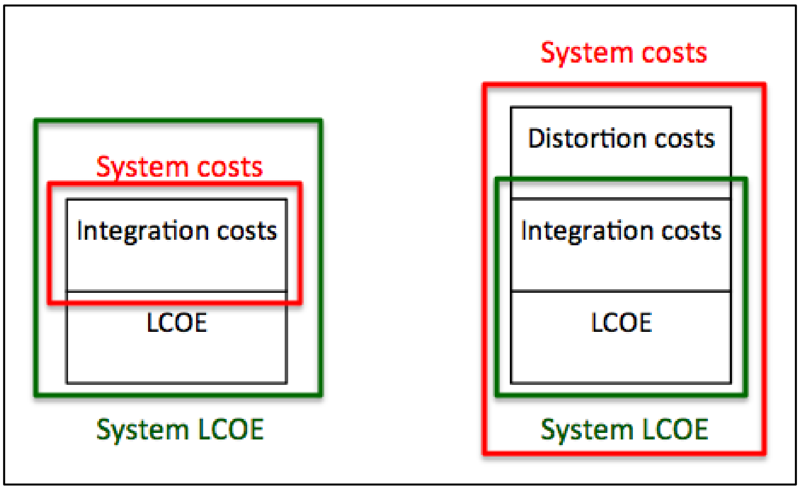


Figure 2: System costs.
Definition (left) and personal perspective (right)



Whether EU policymakers should consider distortion costs depends on two questions: first, are these costs important? Second, if yes, can the EU address the causes? Distortion costs are manifold, complex and as such almost unquantifiable. Nevertheless, the OECD IEA rightly explains that "the fact that […] they are difficult to quantify in an explicit manner does not mean that they do not exist" (2012 p.104). Identifying them will already have a positive effect on how policymakers design both power system and climate strategies.

5.1. VRE and the market

We first expose some economic concepts and EU energy history to start our analysis. Edenhofer et al. (2013, p.1) identify the starting point of any policy: "to choose a particular weighting of public policy objectives based on value judgments, i.e. a social welfare function". EU energy policy has several goals but the most important are climate change mitigation, competitiveness and energy security. We focus here on the first two, which we believe go hand in hand. In his mission letter to the Commissioner for Climate Action to Energy Miguel Arias Cañete, Jean-Claude Juncker reaffirmed the need "to ensure we reach our climate goals in a cost-effective way" (EC, 1 November 2014). In fact, competition precisely assures the most cost-effective allocation of resources. At the end of the day, it reduces energy bills for consumers.

In a perfect market, competition leads to productive efficiency, i.e. the optimal use of resources. However, productive efficiency does not integrate (negative) externalities such as carbon emissions. These externalities are not internalised by polluting power plants. Consequently, the market potential of VRE is lower than its economic potential for social welfare (Ueckerdt et al., 2013). There is a market failure that as to be remedied remedy, which is why governments and the UE implement policies to bridge the gap between the market and the economic potential. If these externalities were properly internalised, allocative efficiency would lead to a better allocation of resources.

As for productive efficiency, the EU's main effort has been since the 1990s to bring more competition into the energy sector. It has developed the Internal Market for energy - in particular electricity - with its three "energy packages". In addition, the EU has developed a market for pollution - the EU Emissions Trading System - to address the carbon externalities. The aim was to internalize the negative externality of carbon emissions and bring allocative efficiency.

We claim that recent trends have actually weakened allocative efficiency. Each MS has adopted renewables support schemes, causing several distortions to the market, both in terms of power mix and prices. The EC recognizes that *"the impact of a large number of national support schemes for renewables on market integration was underestimated"* (EC, 2013, p.6)

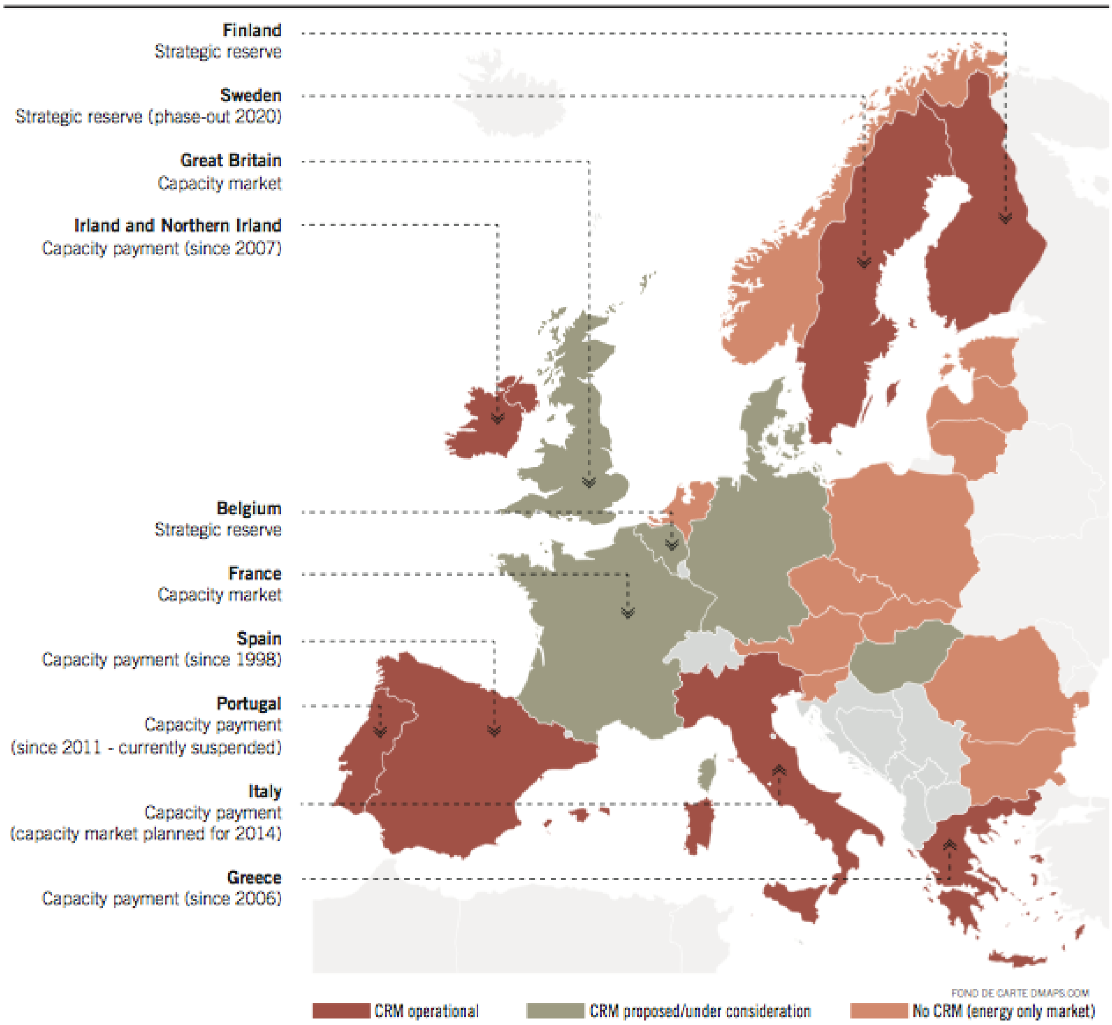
Climate policies have been adopted to address a market failure: the negative externality of CO_2 emissions. it may nonetheless be replacing this market failure with a government failure, the distortion of competition in the IM. We expose these concerns in the following section.

The "visible hand" of EU MSs (Finon, 2013) is partly responsible for distortions. However, the EU may also have shot itself in the foot with its binding national targets for

2020 and its lax behaviour on State-aids. To reach these targets, national governments have implemented multiple support policies.

In addition, the distortion of price signal and the inherent issues with WRE (integration costs due to variability, uncertainty, location specificity, etc.) have conducted governments to support thermal power plants operations. For example, capacity mechanisms have been developed "to secure adequate electricity generation when there is a real risk of insufficient electricity generation capacity" (EC, April 9th 2014). *Figure 3* shows both the accumulation of national mechanisms for capacity and the induced divergences in the IEM.

Figure 3: National measures to preserve capacity adequacy.



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Source: National Regulatory Authorities (2013), in Capacity Remuneration Mechanisms and the Internal Market for Electricity (Agency for the Cooperation of Energy Regulators, 2013), p.8

Finally, other types of state-aids have further undermined competition in the IM with abuses on exemptions. VRE for example have been exempted from the costs they cause to the system or from energy taxes. As a whole, this return to the States is fragmenting the IM and breaking the European energy playing field.

VRE generation is not an externality in itself but it creates external costs. We expose them by analysing their interaction with the EU ETS.

The EU ETS may be stamped "the most important piece of EU environment legislation" (Genoese and Egenhofer, 2014, p.1). Operational since 2005, it is the world's largest market for the trade of GHG emissions allowance; it mainly concerns large polluting installations, i.e. power plants and factories. As a "cap-and-trade" mechanism, it first sets a limit or "cap" on the total emissions that can be realised every year. In addition, it fixes individual caps for companies and distributes allowances accordingly. The cap is reduced every year in line with EU targets.
The rationale for such a cap and trade mechanism is that it is considered the most cost-effective method to curb emissions. The scarcity of allowances translates into a price of carbon. Companies can then exchange their allowances or "rights to pollute". It creates efficiency as "it ensures that the market price of carbon is equal to the lowest marginal abatement cost amongst all controlled sources" (Egenhofer, 2013, p.2). Companies (emitters) search for the least costly options cut emissions. They take into account the *opportunity cost* of using allowances and prepare investment plans accordingly (*Ibid*).
Thus, the EU shall be moving towards a market with more efficiency and less distortions. It is unfortunately not the case because of *interaction effects*.

> "With overlapping policies […] one can no longer point to allowance prices as an accurate reflection of marginal abatement costs" (Fischer and Preonas, 2010, p.31)

The EU ETS is not the only mechanism. Renewables support schemes were meant to be temporary, but they now seem to be well settled in the current power system. Their overlapping with the ETS creates two interaction effects:

1) Carbon price depression
2) Change in carbon abatement attributable to each policy

We concentrate on the first one. The second one is difficult to assess: based on modelling, Weigt et al. find that "abatement resulting from any given injection of RE generation depends on the carbon content and the merit order of the displaced generation" (2012, p.28).

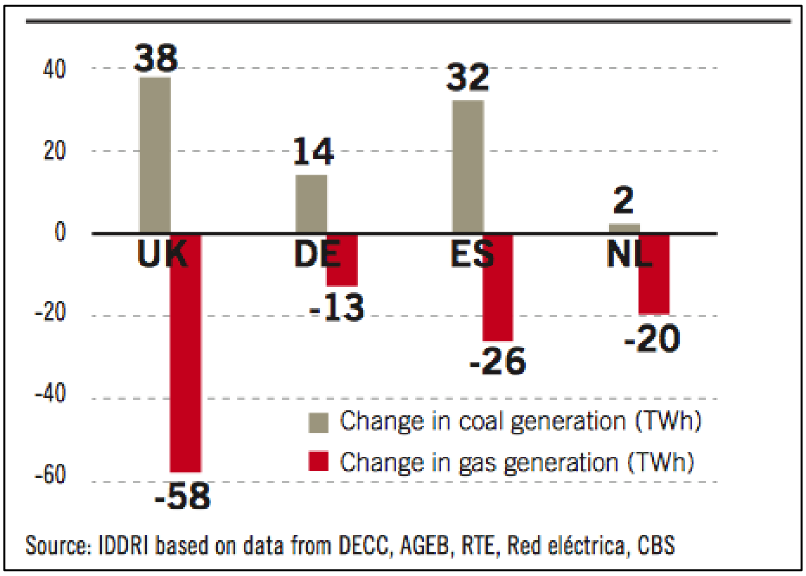
We illustrate this fact with the "*avoided emissions*" perspective developed by Frank (2014).

Avoided emissions perspective

The question, when considering investments in VRE, should be "which kind of technology will this new unit of VRE replace?" Frank rightly explains that "avoided emissions of a new plant or much higher if it displaces a baseload coal plant rather than a natural gas combined cycle plant [*or a nuclear power plant]* during off-peak hours" (2014, p.3). As coal is cheaper than gas, it crucially depends on a sufficiently high price of carbon that Frank calls "break-even carbon price" (*Ibid*, p.19) Hence the need for less distortions from renewables support schemes.

Current short-term trends in Europe demonstrate the worrying displacement of gas by coal (See *Graph 5*). IDDRI shows in four countries (the UK, Germany, Spain and The Netherlands) that coal generation has been growing between 2010 while gas generation has been plummeting.

Graph 5: Change in electricity generation from gas and coal between 2010 and 2012 (TWh)



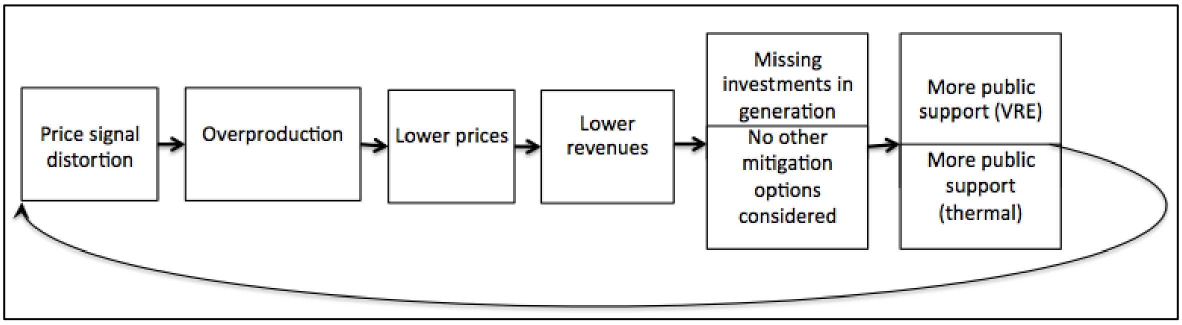
Source: IDDRI, 2014, p.7

Lessons from Frank's apply to the first effect. As a matter of fact, the main problem with the two instruments is that they have the same objective, which is to reduce CO2 emissions. Weigt et al. show that "[*as]* a cap is already in place to achieve this same objective, no additional reduction occurs. The negative waterfall effect is that support schemes lead to higher generation from carbon-free VRE; it reduces demand for allowances; it depresses CO2 price; finally, remaining conventional power plants and polluting factories have less financial incentives to reduce their pollution.
It is recognized by a majority of economists that the ETS would lead to cost-effective decisions, but the support schemes undermine its cost-effectiveness. First, they are not technology neutral; they favour certain technologies and discourage others. Second, because of the overall price reduction, they displace investment decisions in certain *technologies* that would have taken place with a higher CO_2 price. Third, because they are national, they shift emissions from one country to another and lead to sub-optimal *geographic allocation* of decisions in the EU. Finally, they cause *uncertainty* on the future carbon price.

As a whole, support schemes blur the price signal, both for VRE and conventional power. Initial distortions create a vicious circle. We represent in a simplified way thanks to *Figure 4*. With financial support (for example a feed-in tariff) and priority access to the grid, VRE distorts the price coordination function. More VRE units are deployed but the residual system has no time to adapt to its generation, which leads to overproduction. Higher supply with the same demand creates lower prices and consequently lower revenues. In addition, both VRE and conventional companies require public financial support to keep running.

This additional public support further distorts the market price signal. At the end of the day, both VRE technical characteristics (low marginal costs) and support policies weaken economic efficiency.

Figure 4: Support schemes and price signal distortion



Signal distortions have repercussions at different levels of the power market. We argue here that VRE and related policies bring additional system costs also because the market architecture is not adapted to them. Hiroux and Sagan expose them for the deployment of wind: "i) if wind power producers are exposed to wrong signals, their reaction to signals would be inefficient and ii) if the conventional market participants are exposed to wrong signals, their reaction to signals would be inefficient as well" (2008, p.15). To illustrate it, we present some issues related to flexibility (*Table 4*).

Table 4: Support schemes and market signals.

	Market design creating distortions	**Consequences**
Day-ahead and intraday markets	-Price cap -Too long gate closure delays	Increase the reliability cost and the problem of adequacy -Penalize VRE
Balancing markets	-Lack of balancing responsibility -Lack of liquidity	-VRE generators overuse balancing services -Abuse of market power

Source: inspired by Hiroux and Saguan, 2008, p.18

Let us precise that day-ahead markets conclude trade the day before the physical delivery of electricity and intraday markets function during the day of operation (European Network of Transmission System Operators, ENTSO-E). With VRE units, the RLDC becomes steeper during some hours of the day (peak hours). It means that in addition to VRE, the system needs power generation from thermal (peak) plants. Their service should be remunerated accordingly. But the price cap sends the wrong signal. It might lead to more costly outcomes such as controlled rolling blackout (Hiroux and Saguan, 2008).

Another issue with day-ahead and intraday markets is that the gate closure is too far from real time. VRE market participants cannot trade the power they generate sufficiently close to real time (*Ibid*). They are penalized.

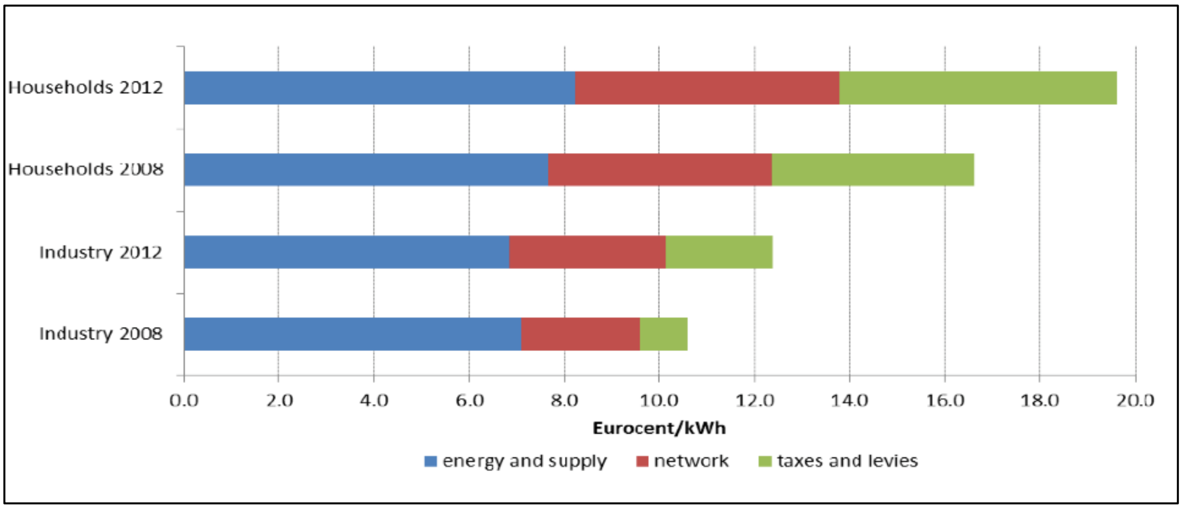
Finally, the current power system does not VRE participants responsible enough for their toll on balancing requirements. According to ENTSO-E, "balancing refers to the situation after markets have closed (gate closure) in which a TSO acts to ensure that demand is equal to supply, in and near real time" (2014). Because of the variability, VRE units deployment requires much more balancing services. However, if not charged enough for the service, they may abuse it. On the contrary, a lack of liquidity and competition may induce incumbents to abuse their market power and distort the price signal. Hence the need for an integration of balancing market.

In this regard, TSOs should work more in common structure, ideally through ENTSO-E. In this regard, the interaction between a *European* network (ENTSO-E) and *regional* initiatives should be carefully analysed, all the more so since regional schemes have already emerged. As an example, in Central Europe the TSO Security Cooperation of eleven TSOs fosters the security of the power grids for around 170M citizens. This cooperation at regional level could be a first step towards fully harmonized EU rules.

To conclude, we have demonstrated that VRE create additional distortion costs through the interaction of policies targeting the same goal, a weakened market and a rigid market structure. These three points call for action from EU policymakers. The first of all for self-power preservation for the EU may be losing grip on MSs' energy policies.

As a result of these distortions, electricity costs in the EU are rising faster than GDP (EC, 2013). Despite an overall decline of *wholesale* electricity prices, the price for consumers and industries is heavier because the network and taxes components represent more and more of the total price. *Graph 6* illustrates it. Electricity prices for households in 2012 was due for more than half to taxes, levies and network fees. According to the Commission, "costs are likely to increase up to 2020, due to rising fossil fuel costs coupled with necessary investment in infrastructure and generation capacity" (EC, 2014a, p.13).

Graph 6: Electricity price evolution by component in the EU 2008-2012.



Source: EC, 2014a, p.6

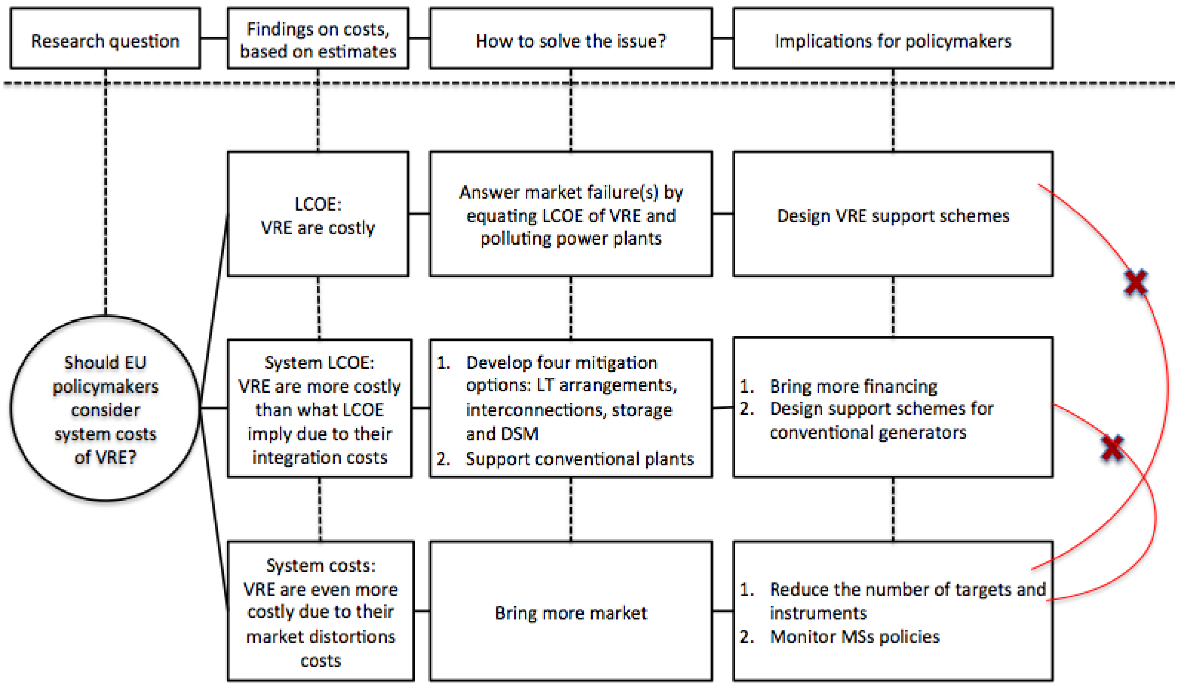
In addition the "price differential with external competitors (with the main exceptions of Japan and Korea) is increasing" (*Ibid*, p.13). Loss of competitiveness may be *another additional* cost provoked by VRE deployment.

5.2. Pertinence of system costs

We expose these outcomes because they show the negative effects associated with the deployment of VRE, inappropriate policies and power system design. Indeed, the research question was not "should EU policymakers consider *the different costs* of VRE". We focused on *system costs* for we wanted to see if the power system had been impacted. It has clearly been. We draw a figure that represents our findings expressed above (See *Figure 5)*. It characterizes interactions between the three main cost drivers of VRE and the system as a whole.

The starting point is that the VRE *LCOE* is still higher than for thermal power plants. To solve this issue, MSs support VRE through various *policy schemes*. It creates *market distortions*. In addition, the *specificities* of VRE induce *integration* costs. Integration costs ask for dedicated public policies, which add to distortion costs. The figure shows that *LCOE, integration costs and distortion costs are intermingled*. If national and EU policymakers consider solely LCOE, they will increase the burden on integration costs and distortion costs. Similarly, if they design support schemes for conventional generation, they further increase distortion costs and undermine competition on the IEM. On the contrary, we can view this graph from another (extreme) angle. If policymakers consider solely distortion costs, they will stop to support VRE, which means climate targets will not be reached.

Figure 5: System costs in the EU, considerations for policymakers.



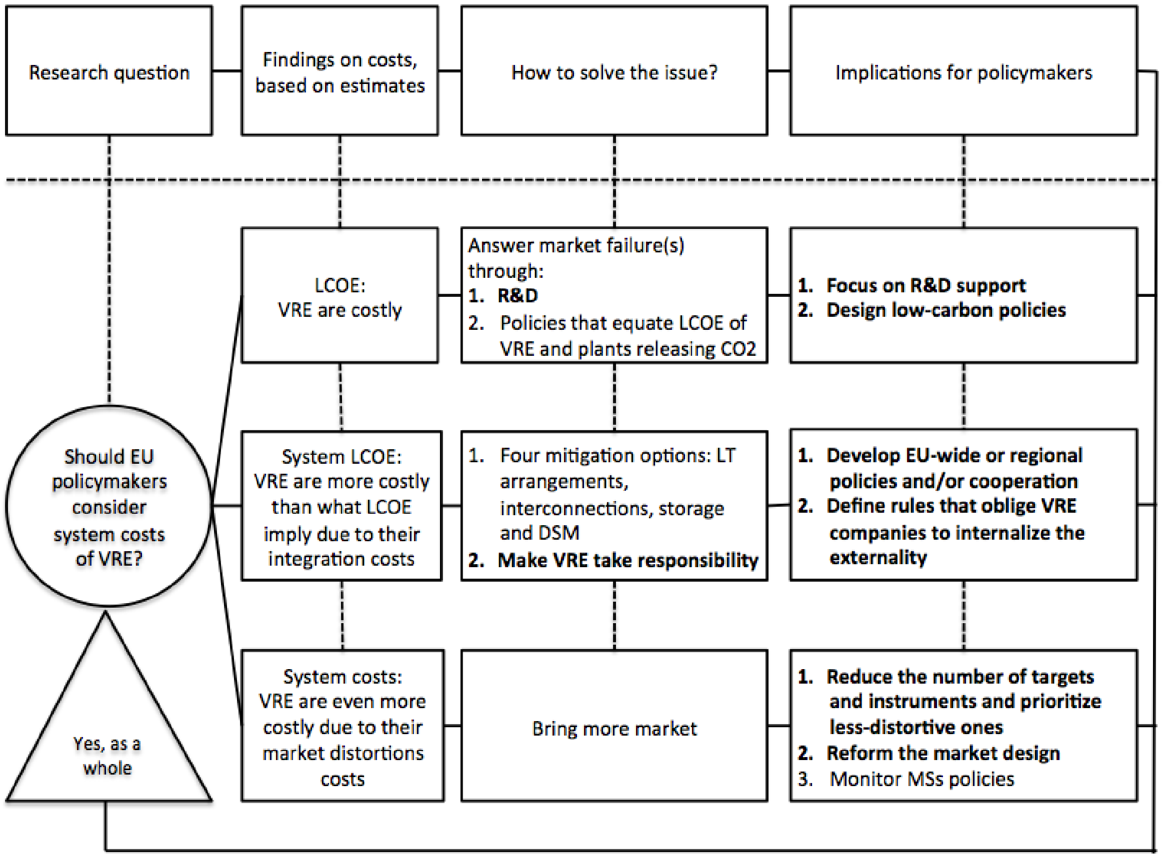
These interactions effects between levels of costs and policies demonstrate the *relevance of the system costs concept*. With the current European market design, these three kinds of costs are currently reinforcing each other. The whole is – negatively - higher than the sum of its parts.

It should lead EU policymakers to consider power system design options that address the three ladders of system costs *together*. These options exist. We bring them up concisely as an extension to our aforementioned findings.

5.3. Recommendations for EU policymakers

The analysis has demonstrated that policymakers cannot disregard the cost of VRE and support schemes. It implies a second step, which is the necessity to redesign the power system. In other words, by considering the system costs concept, they should use it as a compass in their decision-making process.
There are *system solutions*. We add them in bold to the previous figure (See *Figure 6*): focus on research and development to reduce VRE's LCOE and answer market failure, define EU-wide rules that would oblige VRE companies to internalize their negative externalities, etc. Discussing their respective merit in details would depart from the research question so we limit our analysis to a concise overview of challenges that EU policymakers should consider.

Figure 6: System costs and system solutions



They are exposed throughout the sections “A need for more information”, “A need for policy debate”, “Who should be responsible for cost calculation?”, “Options to address VRE externalities” and finally “Who should be responsible for market design?”

A need for more information

First of all, information is missing. Methods for LCOE computations exist but it becomes blurrier with integration costs because there is no possible historical comparison. Distortion costs and system costs as a whole are even problematic. The OECD clearly identifies the issue when stating, “by definition, externalities are difficult to quantify, which is precisely the reason why they are “external” to traditional cost accounting conventions, which for good reason apply to the perimeter of the enterprise.” (2011, p.104). However, policymakers are not CEOs as they deal with both private and public costs. Thus, we would recommend them to favour research on the various cost components and their interactions and include in in impact assessments. It would provide understanding of the responsibility of each technology and policy support.

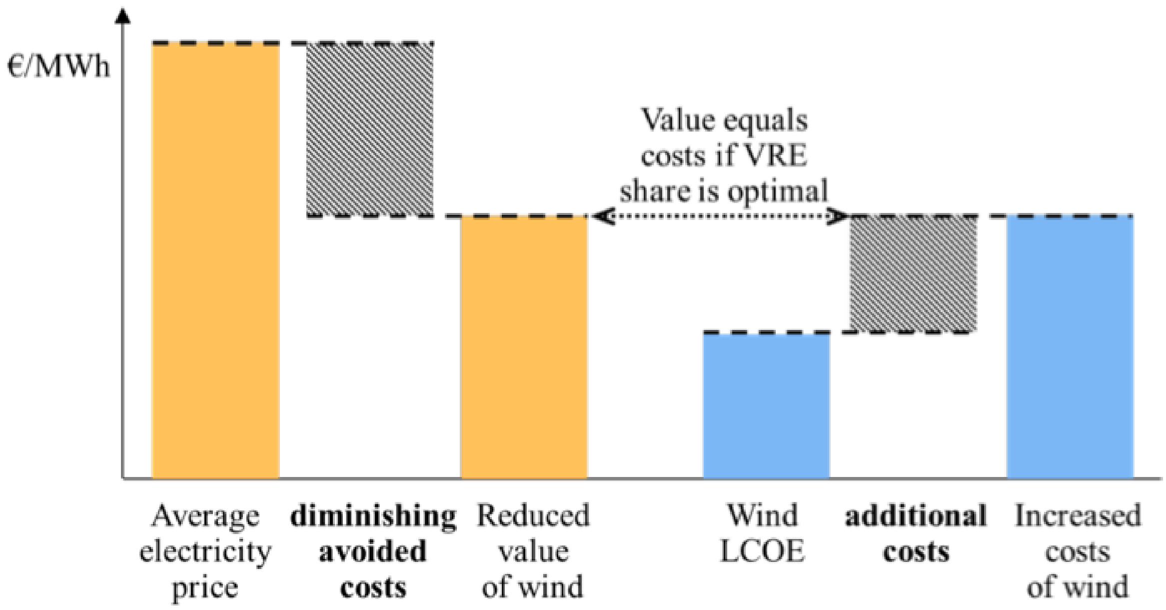
To give a recent example of incomplete valuation induced by lack of information and awareness, Ecofys conducted in 2014 for the EC an analysis of “Subsidies and Costs of EU energy”. Its goal was “to provide the European Commission with a complete and consistent set of data on energy (electricity and heating), generation and system costs and the historical and current state of externalities and interventions in each Member State of the EU and for the EU overall” (p.2). As can be read, it mentions “system costs”, “externalities” and “the EU overall”, but it then does not approach any of the system costs associated with VRE. To close the discussion, it concludes its very short overview of system costs (less than half a page) with a rather laconic statement: “even if system costs might increase in future, the contribution from energy supplied in 2012 is considered to be negligible. In addition, most of these costs should be reflected in the market in future, for example through imbalance costs for plant operators. As such they would not be defined as external costs” (*Ibid*, p.16). We provide this example to show that there is a substantial lack of *information on* and *consideration of* system LCOE as well as distortion costs.

A need for policy debate

Information leads to transparency and accrued transparency would trigger a fruitful debate. Knowing the true magnitude of costs will enable a balanced comparison with “system-related benefits” of climate policies (Ragwitz, 2015) such as co-benefits, synergies, etc. EU regulatory impact assessments should, in our view, include VRE-specific costs in a way or another. We provide here insights on inclusion options.

We have showed the limited of the LCOE method. To take integration costs into accounts, two “schools” have been emerging. The first, that we have described, adds integration costs to LCOE. The second takes a value perspective. It considers that costs are equivalent to a loss of value. We would, following Hirth et al. advice to adopt a *mixed* perspective, that is, add grid-related costs and balancing costs to LCOE and retrieve profile costs from the market value. Indeed, profile costs represent “diminishing avoided costs” (2015, p.13). Hirth et al. represent it on a figure (See *Figure 7*). As they explain, “VRE deployment is optimal when […] value and costs coincide” (*Ibid*, p.14).

Figure 7: A mixed value and cost perspective.



Source: Hirth et al., 2015, p.14

In addition to the mixed perspective on *electricity* costs we would recommend policymakers to combine it with the *avoided emissions* one. Frank convincingly explains "renewables incentives should be based not on output of renewable energy but on the reduction in CO2 emissions by renewable energy. They are not the same thing" (20 May 2014). It would allow a fair comparison between all costs and benefits of each VRE technology, according to the power system where it is deployed.

We believe policymakers should address one question, "is the deployment of VRE compatible with the idea of a single playing field for all actors?"

Henriot and Glachant identify two schools of thought with two distinct solutions. The first is the "melting pot" – with same rule for everyone -, the second the "salad bowl" - distinct rules (2013). The first perspective states, "once competitiveness of RES will have been achieved, RES could be considered as active units exposed to the same rules as conventional generators" (*Ibid*, p.4). According to the first school, the market will reach equilibrium by itself. Conversely, the second argues that more arrangements are needed because of fundamental VRE characteristics such as variability (Finon and Roques, 2012) or lack of dynamic pricing (Ambec and Crampes, 2010). There are two issues with the second perspective.

1) More state-aid may mean further price distortions, which leads to further problems.

2) Uncoordinated MSs policies will further undermine the IEM.

We believe applying the first school's proposals may lower productive and allocative efficiency.

The first school may nevertheless also have its limitations. Hiroux and Sagan (2008, p.14) expose the transaction costs (cost of participating in the market) problem when they state that with VRE integration to the market "the producers have to understand the complex electricity market architecture and have to be able to understand and react to different signals sent through the markets." Indeed, VRE generators are often small players compared to conventional ones and these transaction costs associated to competition in the

market may be prohibitive. However, we believe they can associate to the market through learning by doing.
To conclude on policy debate, it once more proves the need to conduct empirical and quantitative analysis, which would enable to assess each policy option.

How to know, however, who should have the mandate to steer these debates and be responsible for cost calculation? We hint below at this issue.

Who should be responsible for cost calculation?

Let us start with another question: *who is currently responsible for cost calculation?* It is a simple question, which unfortunately does not bring a simple answer. Figures on prices and cost components of electricity can originate from national statistics agencies, transmissions system operators (TSOs), national regulatory agencies (NRAs), the Agency for Cooperation of Energy Regulators (ACER), the Council of European Energy Regulators or intergovernmental organisations such as the IEA.

This state-of-play is harmful to European citizens. The lack of consistency of current information provides a very weak basis for policy formulation. Indeed, the Commission explains that "data on the tax exemptions and other subsidies offered by Member States […] is currently patchy." (2014, p.9) In this context, regulation cannot be evidence-based. It leads to negative externalities that justify a need to act in common at EU level.

The EC has recently taken positive steps. It published in 2014 its first "Report on energy prices and costs" and is preparing a second report for 2016. It will hopefully go one step further. The Task Force on the Future of Energy Statistics, initiated by the EC and launched in 2013, came up with conclusions in January 2015, among them "the inclusion of national […] electricity household prices fata in the legal framework of data collections of Eurostat." (2015d, p.4). In June of this year, the Energy Council on the implementation of the Energy Union called "call[*ed*] on the European Commission to help to ensure greater transparency in the composition of energy costs and prices by means of appropriate monitoring, while avoiding unnecessary burden." (p.4). In our view, the optimum outcome would be cooperation between Eurostat and ACER, which would collect data from NRAs based on a harmonised framework.

Options to address VRE externalities

Whatever the result of this debate, the power system design needs to evolve. We evoke solutions that would bring more coherence and competition at EU level and ultimately reduce system costs. Thanks to its competency on competition policy, the EC has made important progress. The recent "Guidelines on State-aid for environmental protection and energy 2014-2020" (EC, 2014b) are an important leap forward.

1) Objectives and instruments. Less is more

Less objectives and instruments will bring fewer distortions. Regarding public policy objectives (in addition to climate change mitigation, "energy security", "green jobs and growth", etc.) their multiplication may be a threat for the IEM as they may justify additional measures.

Regarding instruments, they should evolve toward more market compatible ones. Two "best-practice examples are the auctioning (or "tendering") of VRE generation and the creation of markets for competition between capacity remuneration mechanisms (CRM) and DSM for adequacy. Finally, policies should be technologically and geographically neutral to let the market make efficient decisions. As such, the point 3.9.2. of the State-aid Guidelines, "Need for state intervention", represents a positive movement.

We do not plead for the disappearance of support but advocate greater focus.

- On *less-mature technologies*: encourage R&D that will bring dynamic efficiency and technological spillovers. As an example, at EU level SETIS (Strategic Energy Technologies Information System) promotes basic research and demonstration projects.
- On "*instruments that effectively bring new emissions in under the cap*" (OECD, 2011, p.10). Supporting electric batteries for vehicles would increase demand for electricity, increase the ETS carbon price and reduce emissions.

Finally, the main instrument has to remain the EU ETS. Recently, favourable decisions have been adopted such as the harmonisation of allocation at EU-wide level, the auctioning of allowances and the future creation of market stability reserve (MSR, operational from 2021).

2) Internalise VRE externalities

> "The main challenge is […] not a technical but a rather an economic one. It is not to find technical solutions, but rather to ensure that stakeholders have the right incentives to develop these technical solutions" (Henriot and Glachant, 2013, p.2)

A more efficient EU policy for climate change mitigation also requires the internalisation of *all* negative externalities created by polluting plants (internalisation through the price of carbon) *and on VRE units* (internalisation of variability, uncertainty and location-specificity).

Thus, we advocate two measures.

- First, adjust and harmonize *network codes*: provide *locational signal* through *nodal pricing* (individual prices reflect incremental marginal costs). Potential investors would better consider the trade-off between the location generation potential and grid costs.
- Second, impose *balancing responsibilities*: the Guidelines already mention it when stating "beneficiaries are subject to standard balancing responsibilities, unless no liquid intra-day markets exist" (2014, C200/25) With these responsibilities, VRE players are held responsible for the shifts in generation profiles. They integrate it in their investment decisions as they bear the full cost of their investment decisions

However, accrued internalisation of negative externalities de facto increases costs for generators. They may be unable to enter the market. It is all the more true since the current price of carbon, stuck below €10 a tonne, does not bring any incentive in cutting emissions. It has to be recognized that only a strong carbon price can enable a positive internalization process and stop the IEM fragmentation.

The question is, how can a fragmented governance lead to a clear-cut policy? Governance should be centralised to make sure Europe develops a coherent power system design.

Who should be responsible for market design?

We believe that the “subsidiary test” justifies EU intervention. Following recent judgements by the European Court of Justice (ECJ) connected to the old “Meroni doctrine”, it appears that EU institutions are getting the legal backing to delegate power to regulatory agencies. Until recently, the Meroni case was seen as preventing the EU from doing so.

In addition, there is a clear need to act in common on energy issues, to remedy the negative externalities caused by the IEM fragmentation and avoid 180% policy turns. On the second point indeed, the EU, with its slow and consensus-based model, ensures commitments are kept. On the contrary, there is often a risk that a MS will suddenly change its policies, as Spain has illustrated with its retroactive cut of renewables subsidies.

The current framework is a (positive) outcome of the Third Energy Package, which entered into force in 2009. It established an agency (ACER) but did not give it real decision-making powers. MSs, through comitology at the Council, can still block the adoption of EU-wide measures. They can oppose a decision that would potentially endanger a “national champion”.

Thus, there is a need for both formal decision-making mechanisms and formal supervision on cross-border issues. ACER should gain regulatory independence to bridge the regulatory gap caused by currently intertwined competencies. This evolution will happen. The question is “at which speed?” The rapidity of the process will depend on MSs and NRAs’ will. We welcome in this perspective the EC’s decision to publish, by the end of 2016, a revised “ACER regulation” with the goal of strengthening the agency.

To conclude, a system costs perspective will help both policymakers and regulators in addressing current challenges associated with the electricity market design. We hope that the EC will fully apprehend the magnitude of these costs and their interactions and that it will integrate them in future policies.

6. Conclusion

The EU has clearly underestimated the costs associated with the shift towards low-carbon power generation. Although VRE investment and operation costs (LCOE) have been dropping, they still lack cost-competitiveness compared to thermal power plants and this will not change overnight. In addition VRE technical particularities cause additional costs to the power system and the low market value of VRE power already reflects these integration costs.

VRE’s impossibility to compete on the market has induced other costs, as the EU and MSs crucially need further deployments of VRE to achieve their targets and VRE generators apparently crucially need public support schemes to expand. Renewables support schemes are not temporary anymore and their well-established presence in all EU MSs fragments the IEM. States do not even use the back door to reaffirm their grip on the energy stage.
Another cost to the system caused by VRE units comes from their close-to-zero variable costs, which depresses the wholesale price. Intermittent renewable, without being able to provide necessary adequacy and reliability, turn the conventional power system into a

residual one. The consequence is that the power system still needs thermal power plants and that MSs start to remunerate them for their services. All these public interventions engender weakened competition and negative interaction effects.

To conclude, we have highlighted the reasons why EU policymakers should not overlook the situation. First, because each cost taken individually is not negligible, secondly because system costs are reinforcing each other in the current power market design and thirdly because there is still some room for manoeuvre. Obliging both VRE and conventional players to internalize their negative externalities could, at least partly, answer concerns on the seemingly unavoidable trade-off between reinforced competition and VRE deployment. As a result, competition rules, regulations and a strengthened ETS could enable the EU to restore the European electricity playing field. In addition, EU institutions and MSs should work on setting-up a framework of robust EU-wide data collection. Finally and to build on the initial policy research question, *policymakers* should aim at lowering system costs of variable renewables by giving more power to a *European regulator*.

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