Renewables system integration –a system wide approach to cost and value

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MAIN MESSAGES

- The energy system is undergoing a radical transformation which goes far beyond renewables integration. Basing the analysis of system integration on total system costs and benefits allows us to assess the added value of different system configurations.
- Attempting to isolate technology specific integration costs is a very challenging exercise and is highly dependent on the methodology used.
- Instead of trying to add system integration cost to the generation cost (LCOE), policymakers and other stakeholders should assess the total system costs and benefits for the entire system for different scenarios. This will allow us to identify the investment needs, total operational costs and overall system value without the need to allocate costs to specific users/technologies.
- The total system cost and benefit approach avoids the challenging task of isolating and quantifying wind or solar specific system integration costs and does not require us to define a benchmark technology.
- Ideally, the comparison should be based on total system values, including benefits and added value from different system configurations. This would help to expose the numerous (environmental) benefits wind energy provides.
- The cost of a future energy system with a high share of variable renewables is highly dependent on the flexibility of the system. There are a number of no-regret measures that can deliver quick wins. Market design and cooperation between system operators are among the most important.

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1. UNDERSTANDING SYSTEM TRANSFORMATION COSTS

1.1. INTRODUCTION: WHY WE NEED TO TALK ABOUT SYSTEM TRANSFORMATION COSTS INSTEAD OF RENEWABLES INTEGRATION COSTS

In any power market, supply and demand need to match at any time. Current electricity markets and regulations have initially been designed based on the characteristics of inflexible power generation. With the increasing share of variable renewable energy, such as wind energy or solar PV, power systems need to become increasingly more flexible to respond to changes in supply and demand.

Experience shows, that power systems with a low share of variable renewables can integrate wind and solar energy without much attention to additional flexibility. Fluctuations in demand that these systems can cope with are generally larger than the fluctuations that the variable renewables bring to the system.

In power systems with higher shares of variable renewables, changes between load and residual load[1] become noticeable. But here as well, investment into additional flexibility is not yet the most important factor – upgrading operating practices and making better use of existing system resources usually suffice to achieve system integration of renewables.

But progressing towards meeting renewable energy targets implies greater swings in the net load. This prompts the need for a systematic increase in power system flexibility that goes beyond what can be supplied by existing assets, market rules and regulations.

This has led to an academic and policy discussion about understanding system integration cost associated with variable renewables. In many cases, the approach taken has been to calculate grid integration cost (see next section), and add them to the known generation cost (LCOE). The ultimate goal being to compare different technology costs including all their attributes.

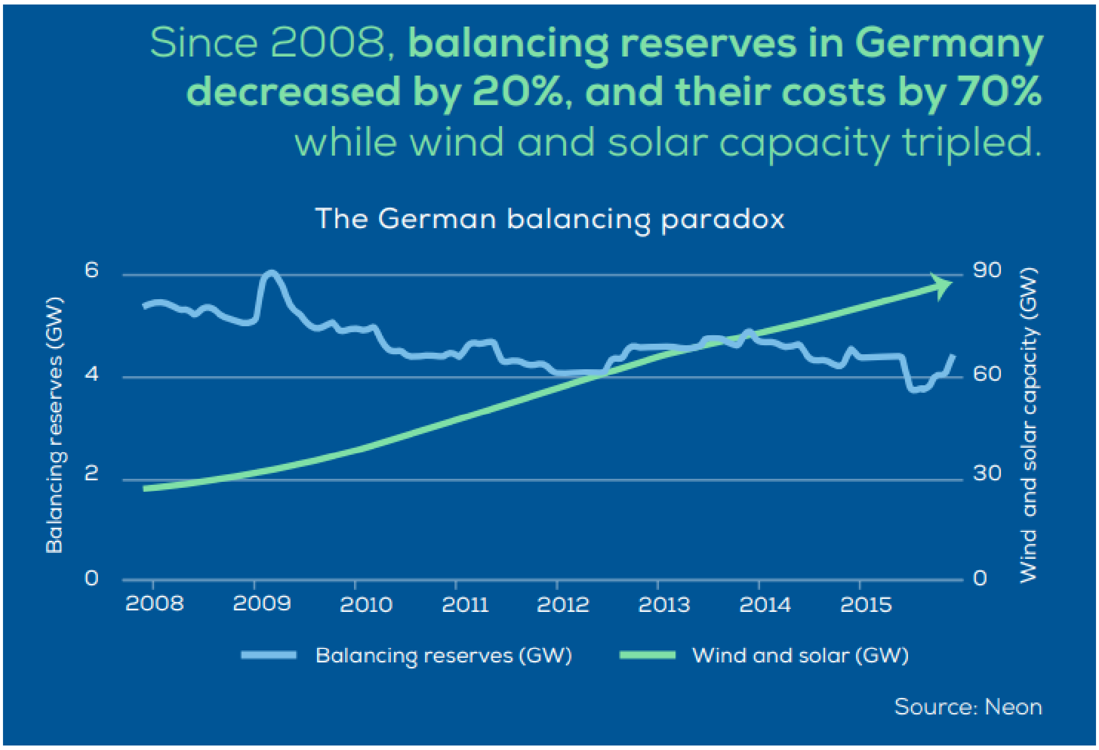
Policymakers who are faced with the question of transforming their energy systems tend to look into existing studies, trying to identify simple figures that they can add to the LCOE. Most of the studies (see annex) analysed present variable renewable integration costs, but their methodologies differ substantially leading to results that are often not suitable for comparison. In addition results are often driven by assumptions on the flexibility of the system and the reference technology used in the model.

This approach is misleading and does not make a good representation of technology value nor costs, which are furthermore coming down quicker than assumptions can be updated. In particular, this approach fails to quantify the (environmental) benefits that variable renewables bring to the power system. And assuming that system operation practices and market framework designs remain based on thermal dispatchable sources neglects that during the last few years, system operation practices and

[1] Residual load is equal to total load minus variable renewables production

market rules have improved significantly. This had led to cases where the cost of balancing[2] has sharply declined while at the same time variable renewables have quickly become large contributors to the power mix (see figure 1). Additional important reasons to take a total system cost approach are presented in chapter 2.

Figure 1. Balancing reserves use in Germany, Source: Neon



Against this background, **WindEurope believes it is more appropriate to talk about system transformation costs and benefits.** The power system, along with the transport and heating sectors are undergoing a radical transformation. Energy demand is increasingly electric, gas and power grids are being coupled to optimise the available low-carbon resources. Demand appliances are more and more based on power electronics. Cross-border trading through interconnectors is increasing. Displaced fossil-fuel based generation continues to lower carbon emissions and air pollution. Advanced variable renewable technologies are supporting their own system integration. All these new dynamics, along with the long-term decarbonisation and efficiency goals are forcing the energy system to transform. Such transformation goes far beyond an increase in the share of variable renewable in the system. Thus, investments for new infrastructure and new operational modes should not be exclusively allocated to the increasing share of renewables.

This paper discusses the traditional approaches to estimate costs associated with managing variable renewable energy sources and proposes a different way to address the analysis of system costs and benefits of power systems with increasing shares of renewable energy.

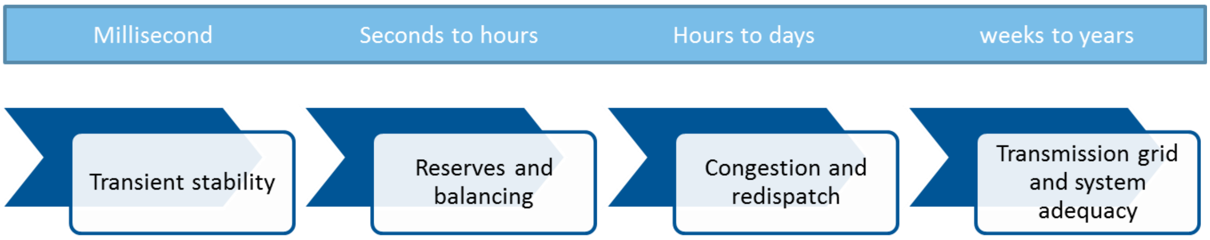
[2] https://windeurope.org/wp-content/uploads/images/about-wind/infographics/WindEurope-Infographic-System-Integration.pdf

The paper relies on the work done by the System Integration Unit of the International Energy Agency, IRENA and the international collaboration under the IEA Wind Task 25. WindEurope would like to acknowledge their contributions to this relevant debate.

1.2. HOW ARE SYSTEM INTEGRATION COSTS TRADITIONALLY DEFINED?

Electricity demand varies continuously over timescales from second, days, weeks, seasons, years. System operators and market mechanisms must ensure that demand is met at all times. To achieve this, system operators need to plan, procure and activate tools and existing resources in different timeframes. In certain instances, investment in new resources (e.g. grid and interconnectors) is required to achieve this goal in a most cost effective way. Figure 2 shows a simplified overview of these mechanisms based on different time scales.

Figure 2. Main mechanisms to balance demand and supply at all timeframes. Source: WindEurope



Traditionally, system integration costs refer to all the costs incurred to operate a power system in all timeframes, excluding the cost associated to generate the energy at the point of grid connection. The latter are normally referred to as generation costs or levelised cost of energy (LCOE). Most of the research has so far focused on estimating separate system integration costs by dividing them into components resulting from:

1. **Short term balancing and redispatch:** Balancing cost are incurred to match supply and demand in real time and the intra-day timeframe. These costs are incurred by the TSO when procuring and activating frequency control reserves. They can be divided into balancing energy and balancing capacity costs. Redispatch cost are those incurred by the TSO to ensure supply and demand can be met taking into account grid bottleneck and power flows. Congestion management and redispatch is generally activated by the TSO with contracted market players in the day ahead or intraday timeframe, who are willing to provide their flexibility at a negotiate prices (ramping up or down) or on direct order. Redispatch can also be done by dispatching down wind/solar power against a compensation.

2. **Grid expansion and reinforcement costs:** Cost associated to the upgrade of the transmission and distribution infrastructure. These costs can be well separated from other costs and are generally recovered through network charges that all electricity consumers bear. In certain cases like in the UK, offshore power producers need to factor the cost of transmission (until the closer connection point onshore) under their bidding price. At European level, the Ten Year Network Development Plan reflects the transmission infrastructure needs for the whole of Europe. Additional Infrastructure

development has several benefits, such as reduction of re-dispatching measures and curtailments, lowering (and convergence of) market prices due to increased cross-border competition and trade, exchange of balancing capacity and energy or sharing of balancing reserves and overall lower system operation costs. As it is not possible to allocate specific costs to a single technology (e.g. wind or solar PV), these cost are generally either socialised or recovered through imbalance charges.

3. **Profile or capacity cost due to change in the generation mix**. Costs incurred to ensure the system will have enough capacity to deal with tight adequacy situations (e.g. winter periods with very high demand due to cold and large plants outages). These costs are not always explicit. When they are, they are generally reflected in capacity remuneration mechanisms; otherwise they are part of network charges. Since conventional generators can suffer unforeseen outages and variable renewable energy has a low capacity value, system operators need to size their systems with over capacity. Since the system operator does not own the generation units, it needs to make sure this capacity is available at times of system shortages, with associated costs. Having this capacity may be considered as adequacy cost (capacity can also be offered by consumers in the form of demand response).

There are a number of other costs that might fall in the previous categories. For instance the cost of dealing with energy efficiency losses in the transmission and distribution of electricity, ancillary services such as black start capabilities or some contracts for reactive power provision. These costs are generally recovered though the network charges.

1.3. CALCULATING SYSTEM INTEGRATION COSTS FOR A SINGLE TECHNOLOGY ALONE IS CLOSE TO IMPOSSIBLE

While analysing generation costs (LCOE) for specific technologies is well established and common methodologies exist, the research community[3] (e.g. IEA Wind Task 25) agrees that calculating the system integration cost for a single technology alone (e.g. wind energy) is not appropriate and virtually impossible. Any attempt to isolate the cost of variability necessarily relies on models that use additional assumptions to strip away the impact of variability from all other impacts variable renewables bring to the power system. The primary impact is that variable renewable power plants generate electricity at very low short-run marginal cost and displace other generators when they are added to a power system, all else being the same (in the model). One thus needs to introduce a theoretical benchmark technology. This benchmark functions as the non-variable renewable technology. Calculating system integration costs requires comparing two cases: one which uses VRE and another using a benchmark technology. Because non-variable renewables is not defined as such, the choice for such a benchmark is discretionary. This is one of the critical underlying factors explaining the controversial debate on integration cost and the sometimes large disparity between estimates.

[3] System Integration Costs- a Useful Concept that is Complicated to Quantify? 15th Wind Integration workshop, October 2018

Balancing and redispatch cost

It is straightforward to calculate system balancing cost. Mostly by quantifying the cost of using balancing, operating reserves and redispatch mechanisms. This includes both the sizing and the actual use of those reserves or balancing market in real time to maintain the system balance. But identifying how much of this cost is due to variable renewables is challenging because real-life imbalances aggregate uncertainty and short-term variability of load and all generation. Increasing variable renewables shares could lead to larger sizing of balancing reserves, and thus one would think that such additional cost should be attributed solely to variable renewables. However, as the German example above shows (Figure 1), balancing costs have reduced – in parallel to the increase of variable renewables. Furthermore variable renewables bring a reduction of system operating costs (due to lower use of fuels from other generators that are displaced and lower spending on $CO2$-emissions allowances).

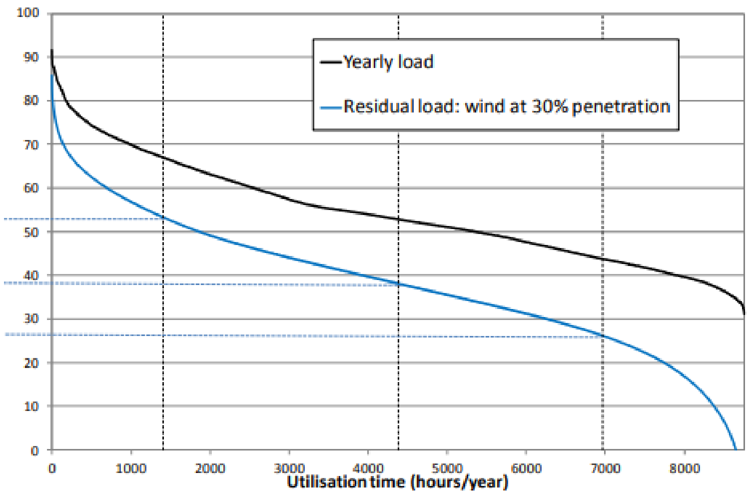
It is essential to understand that improving operational practices and market design leads to significant reduction of balancing and redispatching costs. Making such "soft" improvements becomes necessary before considering investments in hardware.

Profile or capacity cost due to change in the generation mix

Tackling the impact that variable renewables have on the generation capacity mix and required power system investments has proven to be the most challenging. Early approaches focussed exclusively on contribution of variable renewables to meeting peak demand (deterministic approach); but they have important shortcomings. By focussing only on the moment of peak demand, impacts during other hours are left out of consideration. In fact resources need to cover residual load[4] at all times. Considering the effects that weather and economic and social activity have on the load, it is most suitable to understand variability related impacts. Despite important differences from system to system, the residual load duration curve at high and growing levels of variable renewables typically exhibits three properties: 1) Residual peak demand reduces less quickly than residual minimum demand; 2) Residual demand becomes negative at some point while residual peak demand does not reduce further or reduces very slowly; 3) as a consequence, the residual load duration curve between maximum and minimum demand becomes steeper. This is represented in Figure 3.

[4] Residual load= total load – variable renewable generation

Figure 3. Residual load share with more variable renewables in the system. Source: IEA



In this case, the non-variable renewables power plant fleet would experience a falling utilisation rate: the need for capacity remains high (high peak demand), while the need for energy continues to fall (falling minimum demand). While the overall cost of meeting the residual demand will fall (as there is less demand to be covered by the non variable renewables fleet), the specific cost of meeting this residual demand (expressed per MWh) from non- variable renewables generation increases. The main driver for this increase is the fixed costs of power plants, which need to be 'spread' over a lower amount of MWh generation. Appropriately accounting for this effect has arguably been the biggest source of controversy and confusion regarding economic effects[5].

Defining which should be the future power system load is challenging. Peak demand in the future might occur in a different times of day or year, depending on a multiplicity of climate factors, electrification of end uses, energy storage and energy efficiency and demand side management programmes. This could make the net-load shape less challenging to meet. This will depend largely on whether new demand behaviours are smartly managed to follow available generation. The degree of demand response in a system will have huge implication on the estimated cost. Also, an optimised interconnected system joining larger areas can flatten the (net-load) curve, making it also less challenging to meet.

Grid expansion and reinforcement costs

Grid costs can be reasonably well isolated from other cost impacts. Transmission grid planning includes power flow and dynamic/transient analyses to assess if the grid is sufficient to cope with both temporary disturbances and significant failures. It should be noted that this system integration cost component is not a cost by definition. Adding solar or wind power at a favourable location can relieve grid congestions, resulting in a negative need for grid expansion and therefore negative system integration cost. This of course is not always the case as new wind farms are often far away from load centres, particularly in the case of offshore wind.

System operators in Europe do not publish grid reinforcement costs for any technology/cause for grid upgrade. This is because it is extremely difficult, if not impossible to allocate a cost of an asset that is used by all users to one single cause to build that asset.

[5] The Power of Transformation- Wind, Sun and the economics of flexible power system, IEA, 2014

Most of grid capacity additions are due to an increase of electric load rather than wind energy supply - visible from the European system operators' transmission planning work (TYNDP). The current move towards road transport electrification and electrification of heating in buildings and industry will require transmission and, especially, distribution upgrades[6].

The benefits of higher grid capacity are multiple, including lower electricity prices for consumers (as there is more capacity to trade from low to high prices areas) and reduced congestions and redispatch costs. But given the fact it takes many years to develop them, innovative alternatives are needed to cope with the changing system. This includes clear system designs where distributed generation is closely connected to electric charging points. Hybrid power plants such as wind + PV and or Wind + storage can also help optimise the use of the infrastructure, making the upgrades less costly.

The big question regarding grid costs is not how to calculate them, but rather how to allocate them. New wind farms that require a connection to the public grid should not be charged the full cost of the infrastructure as other grid users will benefit from infrastructure in the future. There should be a level-playing field for all generation technologies concerning the bearing of costs. This is why it is important to socialise the grid cost among energy consumers[7].

[6] Breaking New Ground, WindEurope, September 2018. https://windeurope.org/about-wind/reports/breaking-new-ground/

[7] Position paper on network tariffs and grid connection regimes, EWEA, 2016

2. TOTAL SYSTEM COST AND BENEFITS APPROACH

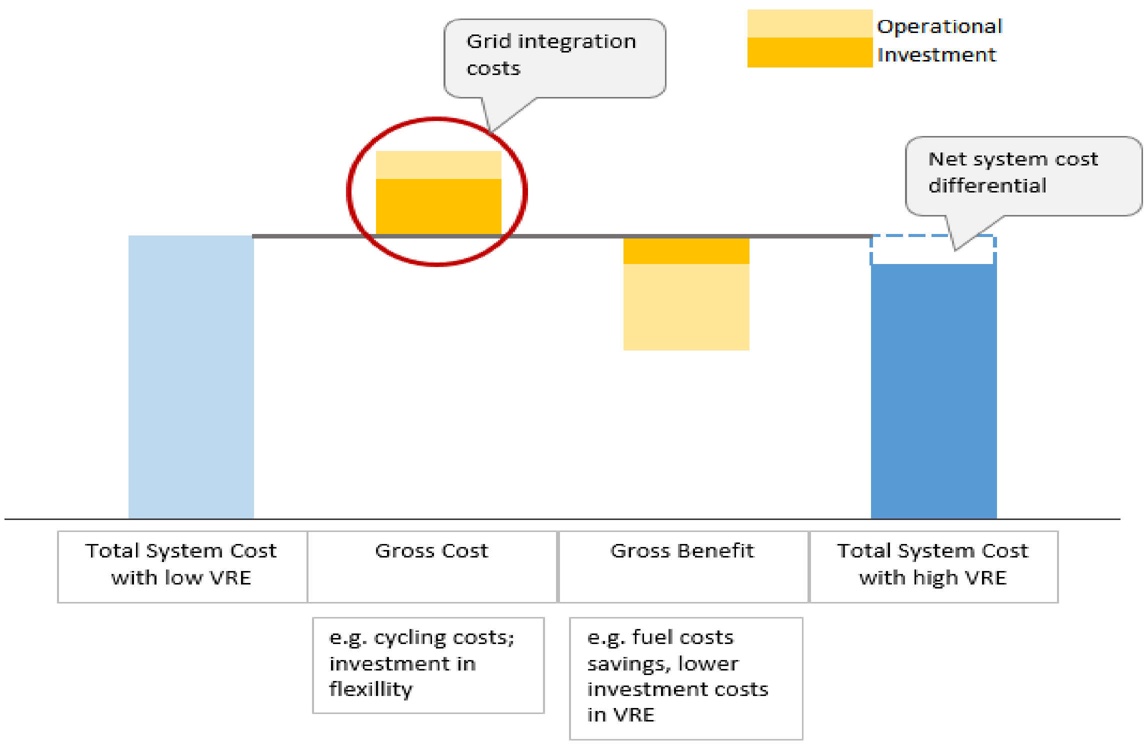
In order to avoid the challenge of isolating and calculating system integration costs and benefits against an *ad-hoc* benchmark technology, we could address a different question: *"How much cheaper or more expensive will it be for the power system to rely on a certain amount of* variable renewables *generation compared to an alternative scenario?"*

This question allows us to take a more holistic approach by comparing the total system costs and benefits of different scenarios.

More and more studies are looking at overall system cost and benefits for a specific energy mix and they no longer try to single out the cost of a specific technology. When they do, they tend to represent the system costs and benefits as compared to a reference scenario with a different energy mix. Some of High- variable renewables scenarios tend to bring a substantial net reduction in operational costs (mostly fuel savings, lower carbon emissions, reduced air pollution) compared to scenarios with higher shares of fossil fuels. Reasons for higher costs in high- variable renewables scenarios can be a) cost of variable renewables itself, but due to continued cost reductions this is less and less the case, b) cost of flexible resources, notably a need to maintain a relatively large non- variable renewables generation fleet with low utilisation or larger grid requirements.

The following figure shows an indicative representation of how cost can be explained.

Figure 4. Total system cost concept. Source: IRENA



The total system costs and benefits approach does not provide a direct quantification of different VRE related effects but it is essential to determine the optimal mix of technologies in substantially transformed systems. This approach brings a number of benefits:

- avoids the pitfalls of introducing a *non-variable* VRE benchmark technology;
- it is conceptually straightforward, with a comparison between new CAPEX and operational costs including fuel savings;
- Considers both variability and uncertainty at time scales relevant to power system operations; and
- allows to compare the all-in system costs and benefits of different scenarios; as many as the policy maker/researcher would like to consider.

It is therefore possible to compare the interplay of positive (e.g. lower carbon emissions, high market value, reduced fuel costs, lower pollution, etc.) and negative effects (e.g. additional grid infrastructure costs, re-dispatch costs, curtailment, etc.) of different energy mix scenarios to the society as a whole. Doing an overall system value calculation could expose the numerous benefits renewables can provide to the energy system.

WindEurope recommends using the **total system costs and benefits (or system value approach)**, instead of trying to single out costs and benefits of individual technologies However, it is clear that the results still depend strongly on what is chosen as reference scenarios for the comparison (for instance, a system with or without nuclear, a system without coal or a system with coal +CCS, extended use of hydrogen versus reliance on gas peaking units).

3. THE VALUE OF FLEXIBILITY

Countries on the road to decarbonise their energy system will need to rely heavily on renewables. It is therefore essential to increase the flexibility of their energy systems as a whole (going beyond the power system). A lack of flexibility, be it in hardware (e.g. grid capacity) or in software (coordinated operational practices of TSO) would lead to unsustainable costs.

The system needs for flexibility (including long-term adequacy under this definition), can be simply divided in three categories:

i) Stability (real-time);
ii) Balancing (minutes, hours, daily); and
iii) Adequacy (monthly, seasonal, inter-seasonal).

For each system need category, there is a palette of technological solutions that are already developed and can be deployed, albeit in various stages of maturity. There are hundreds of publicly funded projects and private initiatives focusing on further developing these technologies and assessing their contributions to the system needs. It is not the aim of this paper to describe them comprehensively. The next points highlight some of the key aspects WindEurope believes should be prioritised:

- **Cooperation among TSO and** cross-border collaboration (exchange of balancing energy and capacity, sharing of reserves) to reduce the overall needs and better use the existing resource is essential (both for adequacy and balancing).
- **The market design** needs to keep evolving to further integrate new technologies, adapted to their characteristics. Trading should be allowed as close as possible to real time. Enabling effective intraday markets is the first goal. Balancing reserves should be procured daily to allow variable resources to participate. Products should be short to reflect real-time variability. Aggregation of different technologies should be a standard, rather than the exemption.
- **Cooperation between TSOs and DSOs** to unblock the flexibility of distributed assets connected to the distribution grid (most of the wind and solar units installed today). Better defining roles and responsibilities while capitalising on the benefits from digitalisation (Data management) will be essential on this front.
- **Demand side response,** both implicit and explicit, is key. For instance, electric charging infrastructure for road transports should be developed with smart software to not only benefit from lower energy cost but to offer vehicle to grid services. Industrial demand response and interruption schemes could be incentivise through smarter and more dynamic tariff design. Today, still some countries favour large consumes who demand a fix base load demand.
- **Flexibilisation of conventional power plants** (active steering, minimum load, ramping speed) is important in the short run for RES integration.
- **Storage.** Battery storage can help addressing system need in the daily timeframe and they are already helping the integration of renewables. Other solution such as heat storage could revolutionise the energy sector. In the long term, renewable electricity storage into gas/liquid fuel (hydrogen, ammonia) could be a suitable alternative to ensure adequacy and power the shipping/aviation sectors. In summary, different storage technologies can address the various flexibility-needs at all timeframes.

- **Adequacy** is rather a long term challenge that will fundamentally be affected by the speed at which electrification of heating and transport is to happen. Providing long-term signals and ensuring enough investment in generation capacity is very important. Integrating the power grid and the gas grid could deliver benefits as well. Technology and regulation should go hand in hand to allow innovation to emerge. Demonstration and pilot projects can help identifying the most interesting business models but regulation needs to quickly adapt to make it happened. Cross-border contributions should be taken into account when assessing national adequacy situations and should be allowed under capacity mechanisms, when these are in place. Ultimately, it is a matter of how much Europe dares to take the energy transition as a European rather than a city or country challenge. Interconnections are crucial for supporting adequacy in large systems.

CONTACT

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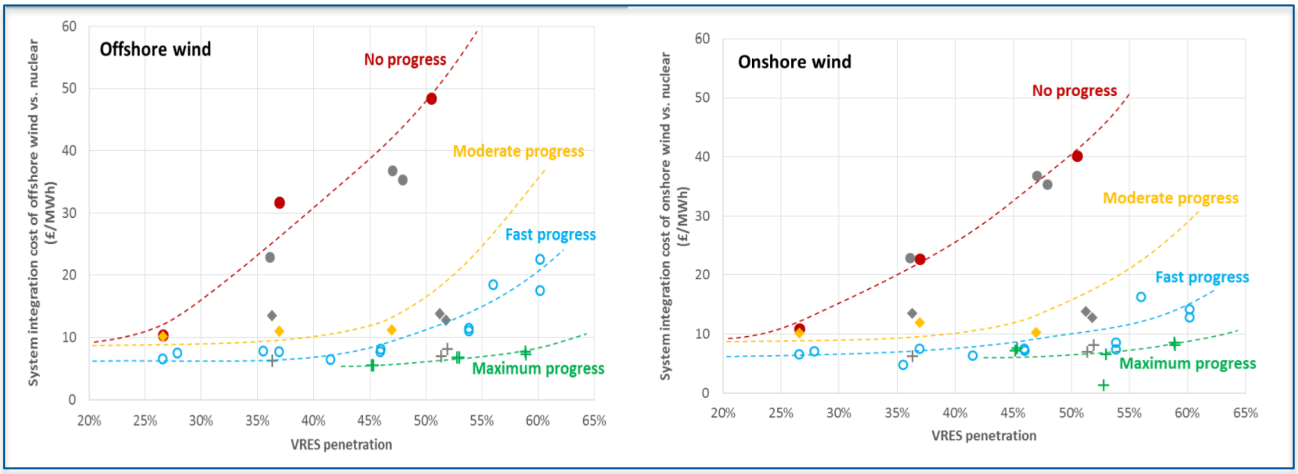
ANNEX 1– EXAMPLE OF CURRENT STUDIES AND THEIR METHODOLOGY

In many cases, the approached taken has been to calculate grid integration cost and add them to the known generation cost (LCOE). The ultimate goal being to compare different technology costs including all their attributes.

This line of thought is well reflected in the literature review done by the UK's Energy research Centre, with their 2017 review report on the Cost and impact of intermittency[8]. The report finds that the additional costs of adding variable renewable generation to an electricity system can vary quite dramatically, but they are usually modest, with higher costs normally the result of inflexible or sub-optimal systems. Most of the studies analysed present variable renewable integration costs, but their methodologies differ substantially leading to results that are often not suitable for comparison.

The London Imperial Colleague has worked extensively on this topic as well[9]. Their studies for the UK system have delivered concrete results for both on and offshore. The integration costs are presented as marginal cost (€/MWh), compared to a reference technology (in this case nuclear), depending on the share of wind, as well as on the power system characteristic (level of demand response, storage, energy mix, etc.).The spread of integration cost is thus huge (from 5 up to to 50£/MWh), mostly driven by assumptions on the flexibility of the system and the reference technology used in the model.

Figure 5. Marginal system integration cost for additional wind power as compared to a system relying on Nuclear power. Source: see footnote 9



[8] The cost and impacts of intermittency, UK Energy Research Council, 2016 http://www.ukerc.ac.uk/publications/the-costs-and-impacts-of-intermittency-2016-update.html

[9] Roadmap for flexibility services to 2030, London Imperial College and Poyry, May 2017 https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf