Quantifying Integration Costs of Variable Renewable Energy Technologies in European Energy Systems

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ABSTRACT

The share of solar and wind energy technologies in European power systems is increasing, this is mainly driven by the decarbonization targets and is also associated with significant reductions in the cost of renewables. Generally, the economic impact of variable renewable energy integration is computed considering the capital investments and levelized cost of electricity (LCOE) with the assumption that the value of electricity generated remains constant irrespective of which time it is injected into the grid. In electricity markets, wind and solar PV take priority over fossil-fueled plants due to their near-zero marginal costs, as their primary energy source is free. The increasing share of variable renewable technologies in the power mix often requires additional flexibility and leads to curtailment. These additional requirements are generally not associated with VRE technologies in long-term planning and short-term operational studies. The characteristics of VRE technologies and the term "integration costs" are widely recognized, but a clear and consistent definition appears to be lacking. In this study, we evaluate the integration costs of VRE technologies using the PyPSA-EUR sector coupled EU model. For that purpose, a baseline aiming at achieving net-zero by 2050 is compared to a second fictitious case in which all renewables are assumed fully dispatchable. The time constants related to this variability (daily, weekly, seasonal) are defined as a parameter. The cost comparison between the two scenarios allows computing straightforward integration costs per MWh of VRE generation at different time scales. Our findings indicate that solar PV has the highest integration costs, reaching 30 €/MWh by 2050. In comparison, wind technologies have lower integration costs, with onshore wind at 10 €/MWh and offshore wind at 14 €/MWh in the same year. Our findings indicate that integration costs initially rise but decline by 2050 when supported by policy measures, high sector-coupling, and increased electrification.

1 INTRODUCTION

The European power sector is undergoing a significant transformation, with dispatchable electricity generation increasingly being replaced by variable renewable energy (VRE) sources such as wind and solar power. This transition is primarily driven by the European Union's ambitious climate targets, including the goal of achieving climate neutrality by 2050. Additionally, rapid advancements in technology and supportive policies have led to a substantial decline in the capital costs of wind and solar energy, making these technologies more competitive with respect to conventional generation technologies. In electricity markets, wind and solar PV take priority over fossil-fueled plants due to their near-zero marginal costs, as their primary energy source is free. The economic viability of power generation technologies is generally evaluated by comparing the levelized cost of electricity (LCOE), the discounted average generation cost per unit of energy over the lifetime of technology (€/MWh). LCOE accounts only for technology costs and projected electricity generation, assuming a constant value for electricity regardless of when, where and how it is produced and an investment is considered profitable if the LCOE is lower than the electricity market price at a given location. However, VRE sources generate electricity only when their primary resource is available, making their output highly variable and dependent on factors like wind speed, solar radiation, and overall weather and climate conditions. The variability of VRE sources requires additional measures such as enhanced transmission infrastructure, energy storage, and flexible solutions, including demand-side management, backup reserves, increased cycling and ramping of conventional plants. and strategies to manage congestion and curtailment. The additional costs resulting from the variability of VRE sources are commonly referred to as "integration costs" and are further decomposed into different cost components, like "grid costs", "balancing costs" and "adequacy costs". While these costs are a central topic of discussion, a consensus on their precise definition remains elusive.

There is an extensive literature on the integration costs and market effects of VRE technologies. The literature can be broadly categorized into two approaches: theoretical and empirical. The theoretical approach primarily focuses on the economics of variability (Joskow, 2011, Borenstein, 2012), to produce analytical expressions for the VRE market value (Bode, 2006, Brown and Reichenberg, 2021), and to quantify market value of VRE with respect to market power of dispatchable generators (Twomey and Neuhoff, 2010, Green and Vasilakos, 2010). The empirical approach is more broad, employing a variety of methods, including analyses of historical price fluctuations, as well

as short- and long-term dispatch and investment models for energy systems to quantify the integration costs. Some examples of using different approaches to compute the integration costs of VRE technologies are discussed here. The system LCOE approcah to compute the integration costs of VRE technologies is introduced by (Ueckerdt et al., 2013), with findings that LCOE is an incomplete indicator and overestimates the economic efficiency of VRE in particular at high shares. The quantification of integration costs of VRE technologies based on the market value is proposed by (Hirth et al., 2015), the study concludes that integration costs can be ignored at low penetration level but in high penetration assessments these costs are very high to be ignored. (IEA, WEM, 2021) also proposed value-adjusted LCOE (VALCOE) as a metric to assess the competitiveness of power generation technologies adding energy value, capacity value and flexibility value categorization for each technology. Actual cost of electricity (ACOE) index is used in (Manzolini et al., 2024) to compute the economic profitability of VRE technologies, showing that LCOE ignores the potential temporal mismatch between electricity generation and actual grid demand and understimates the actual costs of VRE technologies. (Monterrat et al., 2021) computes the integration costs of VRE technologies by including the costs of flexibility options as part of VRE costs as integration costs using a piecewise linear cost estimation model with greenfield optimization, the results show that integration cost evolves linearly depending on the load variation and the capacity factor. (Brown and Reichenberg, 2021) shows that policy measures have an strong impact on VRE integration and declining market value of VRE technologies cannot be linked with integration problems but policy choices. Levelised avoided cost of energy (LACE) and cost of valued energy (COVE) metrics are proposed in (Simpson et al., 2020) to estimate the real market value of VRE technologies. (Strbac and Aunedi, 2016) uses nuclear power as a benchmark technology with respect to wind, solar and biomass to quantify the integrations costs for these technologies in Great Britain power system. (Fürstenwerth et al., 2015) computes integration costs by comparing the system costs of a low share VRE system and a high share VRE system.
Although there is extensive literature on categorizing and calculating integration costs, most studies focus solely on electricity networks. This ignores the fact that future energy systems will be highly interconnected, with greater absorption of energy from VRE sources driven by the increased electrification of transport, heating, industry and the residential and tertiary sectors. Furthermore, many studies attribute integration costs only to VRE technologies, creating the misleading impression that only these sources incur such costs. In reality, every technology within the system has associated integration costs. A common methodological approach is ”greenfield” optimization, which estimates system costs for a specific year without considering historical capacities. Depending on the study's methodology, this can lead to overestimation or underestimation of technology capacities. Finally, one of the most critical yet often overlooked aspects is the impact of policy measures on integration costs. For example, regional carbon emission targets strongly support the greater penetration of VRE sources, this mean that if carbon pricing is factored in, the integration costs of VRE technologies can be overshadowed by those of dispatchable technologies. In this study we are using sector coupled model of PyPSA-EUR employing myopic pathway optimization to find the incremental changes across energy sectors in different optimization periods to answer the three research questions:

- What is impact of variability of VRE technologies on total system costs?
- How variability of VRE sources incurs integration costs, and how to compute them in a simple way?
- What are the integration costs of other dispatchable technologies compared to VRE technolgies?

2 METHODOLOGY

To address these questions, we employ the PyPSA-EUR sector-coupled model and myopic pathway optimization to analyze transitions over time. In the reference scenario, nuclear powerplants are subjected to capacity factors and all VRE technologies are dependent on weather data computed by Atlite (Hofmann et al., 2021) which determines maximum generation capacities while accounting for the CORINE land-use database and excluding protected natural areas identified in the Natura 2000 dataset. To quantify the integration costs, five different scenarios are developed assuming totally dispatchable fictitious VRE technologies and nuclear powerplants not following the capacity factors. The methodology is shown in the Figure 1 and follows the following incremental computations for each scenario:

- First, the reference scenario computes the total annualised system costs and the optimized VRE and nuclear powerplant capacities and generation profiles for each hour for optimized planning horizons.
- In second step, each VRE technology and nuclear powerplants maximum allowed capacities are constrained to what were computed in the reference scenario.
- In the thrid step, the capacity factor of a single VRE technology or nuclear powerplants is modified to be not dependent on the weather data in case of VRE technology and capacity factor in case of nuclear power plants and total generation of VRE technologies and nuclear powerplants are constrained to what were computed in the reference scenario. This allows the optimizer to use the technology as a dispatchable source and thus it

becomes the dedicated scenario of that technology.
- In the 4th step, the total system costs difference for each scenario compared to reference scenario allows to quantify the integration costs of technologies. For VRE technologies, these costs show the costs only incured to the system because of variability and for nuclear powerplants because of capacity factors.

In all scenarios, the existing power plants are retrieved from various open databases and a power plant matching library (Gotzens et al., 2019). All scenarios follow the default PyPSA-EUR configuration (PyPSA-Eur, 2024), incorporating anticipated efficiency improvements across technologies and sectors.

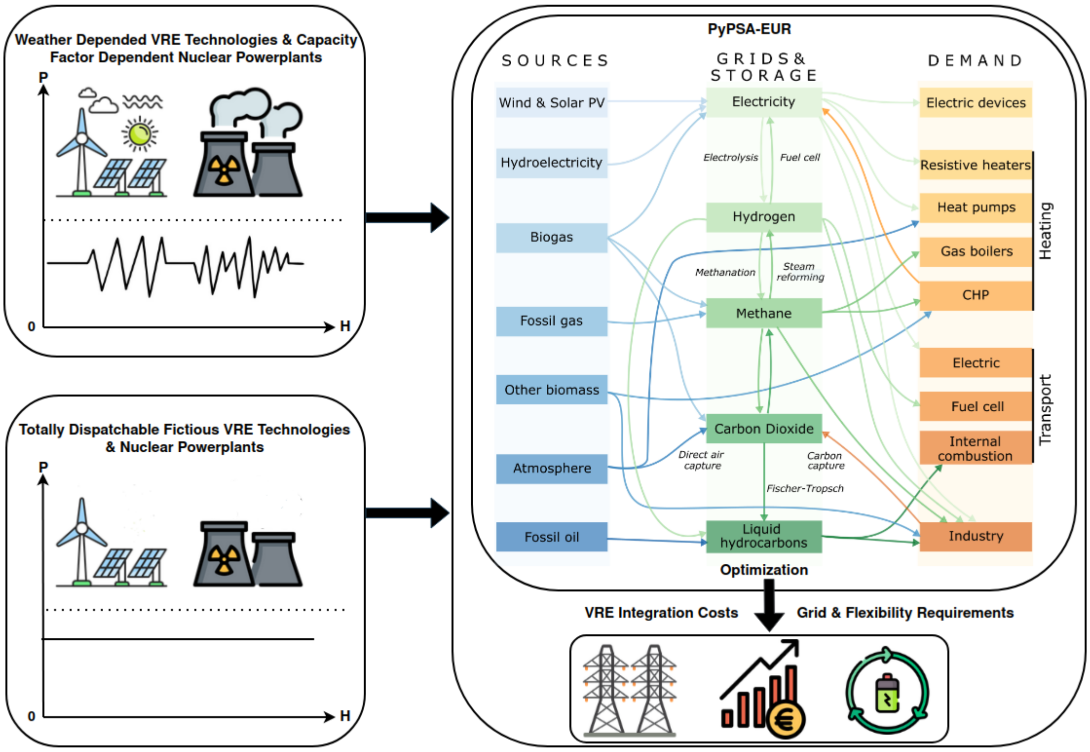

Figure 1: Schematic view of the modeling framework adapted from (PyPSA-Eur, 2024).

2.1 Scenarios

The study considers a reference scenario and 5 different scenarios for VRE technologies and nuclear powerplants, the scenarios are defined as follows:

- **Reference scenario:** All VRE technologies are variable and depend on weather conditions, nuclear powerplants depend on capacity factors.
- **Dispatchable solar scenario:** Solar PV technology is dispatchable while all other VRE technologies are variable.
- **Dispatchable onwind scenario:** Onshore wind technology is dispatchable while all other VRE technologies are variable.
- **Dispatchable offshore scenario:** Offshore wind technology is dispatchable while all other VRE technologies are variable.
- **Dispatchable VRE scenario:** All VRE technologies including solar and wind are dispatchable while nuclear powerplants depend on capacity factors.
- **Dispatchable nuclear scenario:** Nuclear powerplants are totally dispatchable while all VRE technologies are variable.

The time-series of generation profiles for reference scenario is totally dependent on weather conditions while in all other scenarios represented by balck lines, the optimizer generates the generation profiles of all technologies considering them totally dispatchable as shown in the Figure 2. The total generation shown by variable and fictitious dispatchable VRE technologies is equal as will be discussed in coming sections, Figure 2 shows how these technologies can behave if not dependent on weather conditions, or it can also mean their behavior in a highly coupled and flexible energy system. A comparison of generation profiles during a summer and winter week indicates that wind technologies variation is highly accommodated by increased flexibility, while solar PV shows significant seasonal variation.

The study covers five countries Belgium, France, Germany, Great Britain, and the Netherlands, represented as single nodes in the model. However, Great Britain is assigned two nodes to account for the additional synchronous area of Northern Ireland. The temporal scale spans one year with a 1-hour resolution. In this study, with a single node per country, the focus is restricted to optimizing interconnection capacities between countries, without accounting for additional capacity requirements at the distribution level. The maximum expansion of transmission lines in all scenarios is capped at 50% of the previously installed capacity for each planning horizon. This constraint reflects the time limitations associated with planning and deploying additional transmission capacities, particularly for interconnections. A global carbon reduction target is set at -55% by 2030, -80% by 2040, and -100% by 2050 for all scenarios, relative to emissions in the 1990, aligning with both short and long-term EU objectives. The optimizer is free to utilize all generation, flexibility, conversion, and carbon capture and sequestration technologies to solve the linear optimization problem. More details on scenario configurations are presented in Table 1, with further information available in (PyPSA-Eur Supply and Demand, 2024).

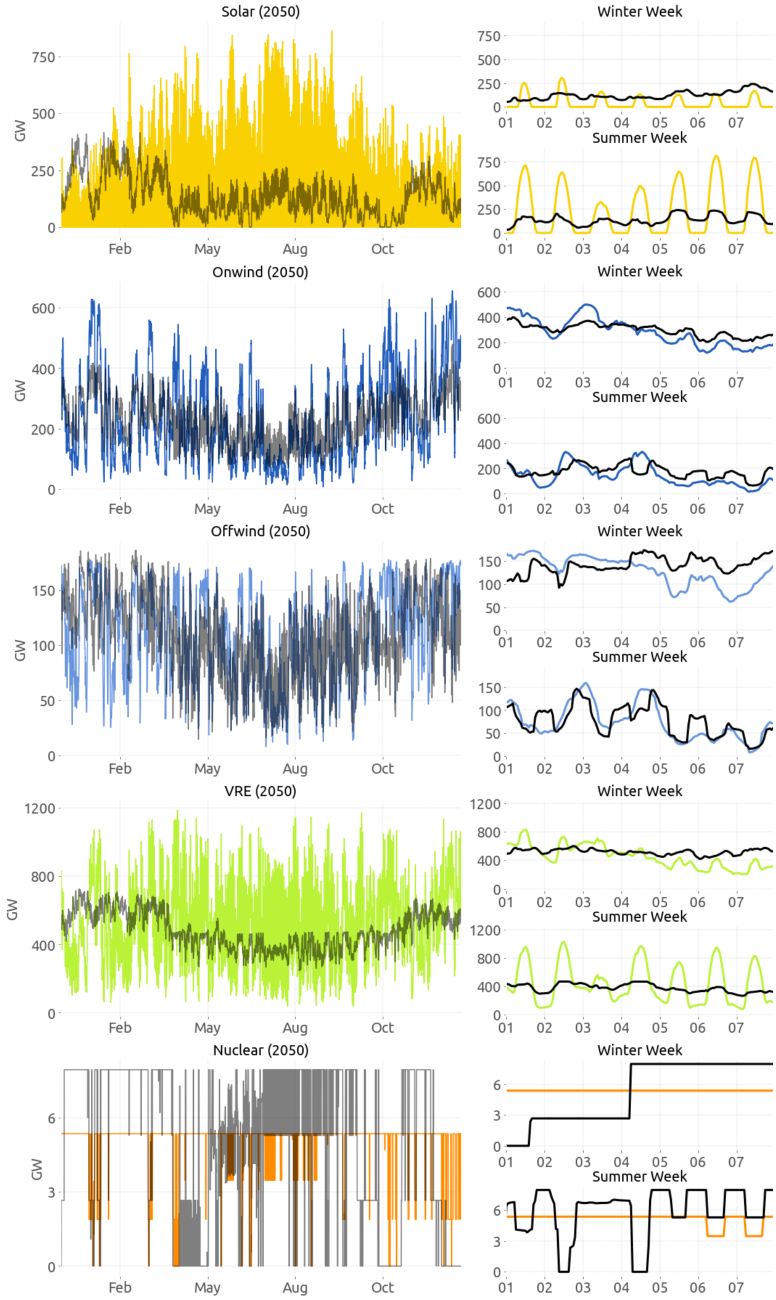

Figure 2: Hourly time-series generation profiles computed for all scenarios.

Table 1: Configuration details of scenarios

Scenario	All Scenario		
Year	2030	2040	2050
Technologies	All	All	All
Transmission Expansion (%)	50	50	50
EV Share (%)	25	60	85
Fuel Cell Vehicles Share (%)	5	10	15
Maritime Hydrogen Share (%)	0	30	50
Maritime Methanol Share (%)	30	40	50
District Heating Share (max 25%)	30	60	100

2.2 Optimization model

The optimization aims to minimize the total annual system costs, subject to the model's constraints. The objective function for this linear programming (LP) problem is given in Equation. 1.

$$\min_{G,E,P,F,g} \Bigg[\sum_{i,r} c_{i,r} \cdot G_{i,r} + \sum_{i,s} c_{i,s} \cdot E_{i,s} + \sum_{\ell} c_{\ell} \cdot P_{\ell} + \sum_{k} c_k \cdot F_k + \sum_{t} w_t \cdot \left(\sum_{i,r} o_{i,r} \cdot g_{i,r,t} + \sum_{k} o_k \cdot f_{k,t} \right) \Bigg] \tag{1}$$

Where, i, r, s, ℓ, k, and t denote the indices for bus, generator technology, storage technology, transmission line, link, and time step, respectively. In this model, a line component corresponds to an AC transmission line, while a link corresponds to a component with controllable power flow, such as bidirectional HVDC links, unidirectional lossy HVDC links, AC/DC network converters, heat pumps, CHPs, and more. The annualized capital costs for generator and storage technologies at bus i are represented by $c_{i,r}$ and $c_{i,s}$, respectively. Similarly, c_ℓ and c_k denote the annualized capital costs for transmission lines and links. The variables $G_{i,r}$ and $E_{i,s}$ indicate the generator and storage technology types and capacities at bus i, while P_ℓ and F_k represent the capacities of transmission lines and links. The time-step weightings, w_t, are set to 1 for a one-hour resolution in the simulation. The variable operating costs for generator dispatch $g_{i,r,t}$ and link dispatch $f_{k,t}$ are denoted by $o_{i,r}$ and o_k respectively.
The computed capital costs are annualized over the economic lifetime n using the annuity factor a, which accounts for the discount rate r, as shown in Equation 2.

$$a = \frac{1 - (1 + r)^{-n}}{r} \tag{2}$$

We define the integration costs of a technology by the difference between the total annualized system costs when the technology is variable compared to when the technology is dispatchable. Then the difference in the system costs divided by the total generation of that technology through out the year gives us the integration costs of that technology as shown in Equation 3.

$$\begin{gathered} C_{\text{total}} = C_{\text{total}}^{\text{Reference}} - C_{\text{total}}^{\text{Scenario}} \\ C_{\text{r}}^{\text{inti}} = \frac{C_{\text{total}}}{\sum\limits_{i,r}^{\text{Scenario}} g_{i,r,t}} \end{gathered} \tag{3}$$

Where, C_{total} is the total costs difference between reference and dispatchable VRE scenario and C_r^{inti} computes the integration costs of the technology in €/MWh. $g_{i,r,t}$ is the generation profile at the bus i, of technology r and at hour t. Nuclear power plants are modeled as links in the model, here in case of nuclear $g_{i,r,t}$ being replaced by $f_{i,k,t}$.

The optimization process integrates various constraints to ensure both accuracy and feasibility. These include general technology-specific constraints for generators, storage units, transmission lines, and energy flow balances. Additionally, study-specific constraints are applied, such as limits on transmission line expansion, carbon emissions and sequestration, and technology capacity expansion. Detailed information on the mathematical formulation and implementation of these constraints can be found in (PyPSA-System optimization, 2024, Neumann et al., 2023).

The following additional constraints are also added to compute the integration costs for each scenario. Equation

4 constraints the maximum generation of VRE technologies with respect to the total generation in the reference scenario.

$$\sum_{i,r}^{\text{Scenario}} g_{i,r,t} \leq \sum_{i,r}^{\text{Reference}} g_{i,r,t} \tag{4}$$

Also, to ensure that optimized capacities of VRE technologies are equal in all scenarios, maximum allowed capacities (G or F) are constrained with respect to capacities optimized in the reference scenario by Equation 5 for both VRE technologies and nuclear power plants.

$$\begin{aligned} G_{\text{VRE}}^{\text{Reference}} &= G_{\text{VRE}}^{\text{Scenario}} \\ F_{\text{Nuc}}^{\text{Reference}} &= F_{\text{Nuc}}^{\text{Scenario}} \end{aligned} \tag{5}$$

Finally, the integration costs of a technology are added in the LCOE of that technology to get the modified LCOE which considers the integration costs, we call it adjusted LCOE as shown in Equation 6.

$$LCOE_{\text{r}}^{\text{Adjusted}} = LCOE_{\text{r}} + C_{\text{r}}^{\text{inti}} \tag{6}$$

3 RESULTS AND DISCUSSION

Figure 3 shows the computed integration costs for each technology. Our findings indicate that solar PV has the highest integration costs of 20 €/MWh in 2030, increasing to 30 €/MWh by 2050. The integration costs of onshore wind are the lowest among VRE technologies, showing 16 €/MWh in 2030, dropping significantly to 11 €/MWh by 2050. Offshore wind integration costs show 18 €/MWh in 2030 and decrease to 14 €/MWh in 2050.

When all VRE technologies are considered in the system, the integration costs decrease to 8.5 €/MWh in 2030 and 11 €/MWh in 2050, showing that these technologies complement each other.

For nuclear power plants, integration costs are around 10.5 €/MWh in 2030, when a number of nuclear plants are still operational. However, by 2050, the costs increase as most nuclear power plants are decommissioned and their penetration level significantly decreases.

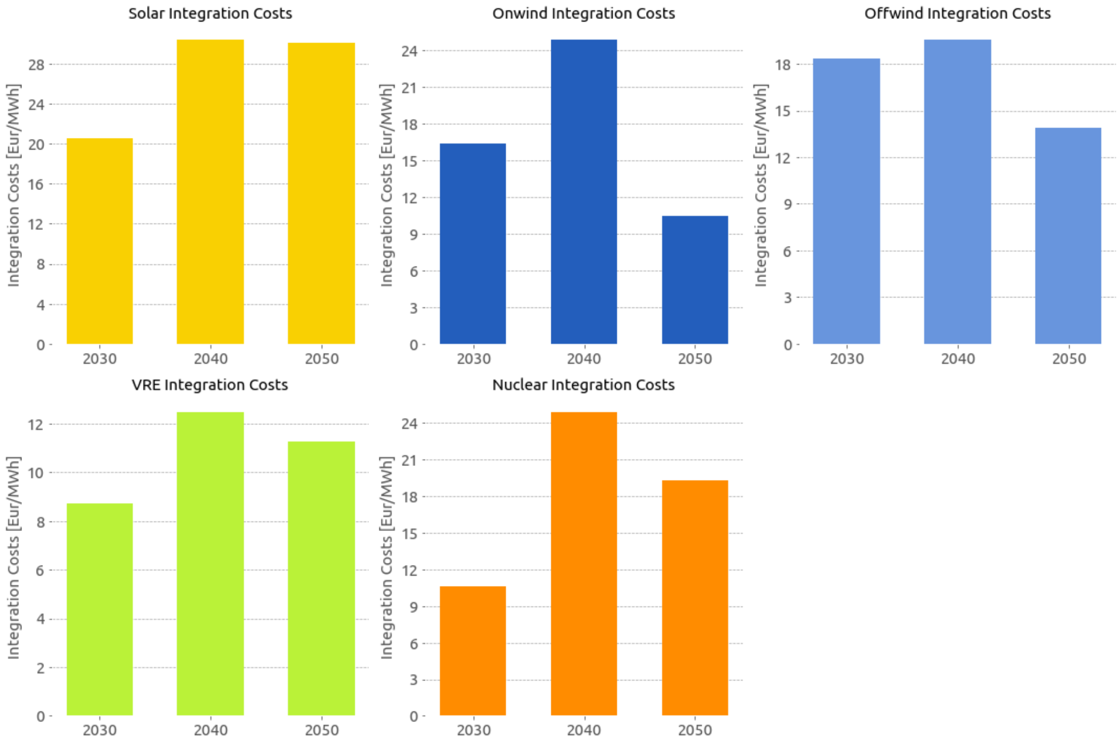

Figure 3: Integration costs computed for solar, wind and nuclear technologies.

VRE integration costs in the literature shows different results for different studies and methodologies, for example (Ueckerdt et al., 2013) shows integration costs of wind to be 60 €/MWh at 40% penetration while (Hirth et al., 2015) estimate these costs tobe 25-35 €/MWh at 30-40% penetration level. (Strbac and Aunedi, 2016) estimates these costs tobe in range 5-9 €/MWh for onshore and offshore wind, 10-15 €/MWh for solar in year 2030 while (Fürstenwerth et al., 2015) quantifies the integration costs of VRE tobe 40 €/MWh. (Monterrat et al., 2021) shows that at low penetration of VRE technologies the integration costs are less than 10 €/MWh which can increase over 60 €/MWh for some countries.

Our results show that the integration costs of VRE technologies initially increase and decline with the increased penetration of these technologies in the system. This certainly shows that if carbon emission targets are considered, the system allows for more absorption of the generation from these technologies, strongly supported by interconnections and flexibility technologies. Another important aspect is the increased electrification of transport, industry and heating sectors which again allow increased utilisation of these technologies but still, the variability of these technologies produces some costs, which are reduced to a large extent in future years by increased electrification and sector coupling.

Figure 4 shows the integration costs of VRE technologies and nuclear power plants with respect to their penetration in the electricity network for each planning horizon. In 2030, solar has relatively high integration costs, even at low penetration (< 20%). This indicates that early-stage solar integration requires additional grid investments or backup capacity. Solar integration costs increase to 30 €/MWh by 2050, still, these costs are relatively high compared to other technologies. Offshore wind shows slightly higher integration costs compared to onshore wind. At penetration levels above 80%, VRE (solar and wind) incurs very low integration costs. This indicates improvements in system flexibility, such as demand response, storage, or better transmission infrastructure. The fact that VRE can reach near 100% penetration suggests that renewables become more dominant and manageable in the system in future years. The penetration level of nuclear powerplants decreases significantly by 2050 compared to 16% in 2030. The results indicate that compared to solar, wind (both onshore and offshore) has lower integration costs, making it a more attractive option for increasing renewable penetration in the system. The low integration costs for high-penetration VRE suggest that with proper grid investments (e.g., storage, interconnections, demand flexibility), high-penetration renewable systems with low integration costs are feasible.

Most of the studies in literature show increased integration costs with increased penetration of VRE technologies in power-mix (Monterrat et al., 2021, Ueckerdt et al., 2013, Hirth et al., 2015). Our results show that contrary to the results found in literature, the integration costs of VRE technologies decrease with increased electrification and sector-coupling. This is certainly possible with additional absorption of generation from VRE technologies by transport, industrial, and heating sectors, and also, the carbon emission targets allow investments in flexibility technologies and grid infrastructure to allow high penetration of VRE technologies.

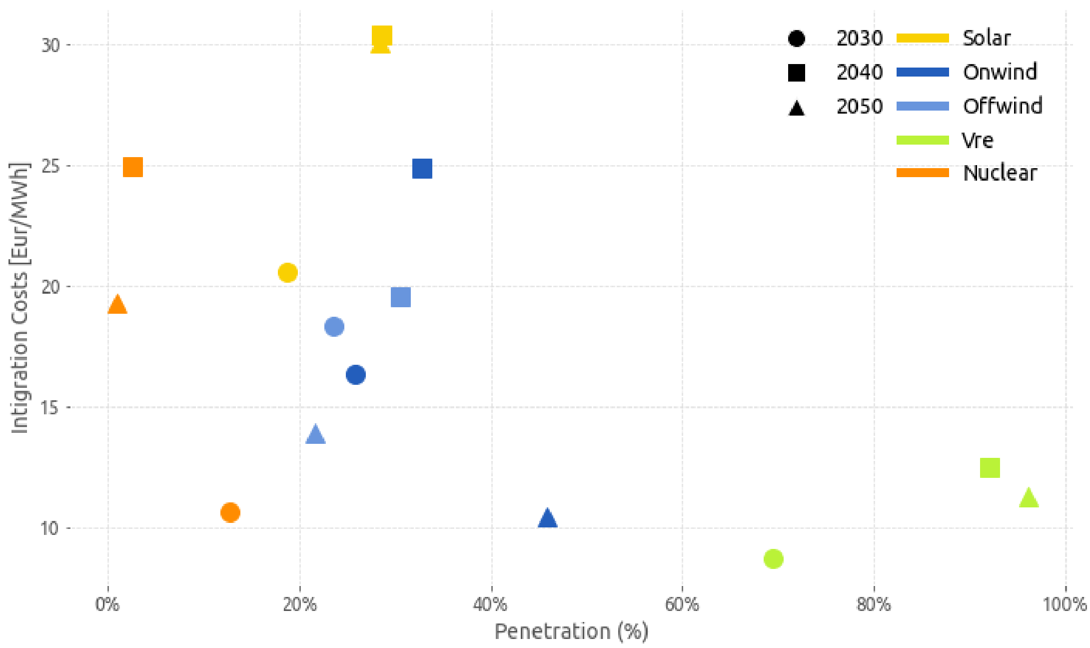

Figure 4: Integration costs with respect to penetration level of technologies in the power sector

Figure 5 presents a comparison of various cost metrics for VRE technologies and nuclear power plants. LCOE and VALCOE are computed from the reference scenario in which VRE technologies depend on weather data and nuclear power plants on capacity factors, while the computed LCOE with integration costs represented by "Adjusted LCOE" is computed for the scenarios in which these technologies are totally dispatchable. The VALCOE is adapted from (IEA, WEM, 2021) and is shown in Equation 7.

$$\mathrm{VALCOE}_x = \mathrm{LCOE}_x + [E - E_x] + [C - C_x] + [F - F_x] \tag{7}$$

Where, E is energy value of average system unit compared to energy value of a technology E_x, the capacity value of the system C is compared with capacity value of a technology C_x and F is the flexibility value of the system compared with flexibility value of a technology F_x.

The energy value of a technology is computed using the Equation 8, where P_t^{elec} is the marginal cost of electricity at each hour and $g_{i,r,t}$ is the generation of each technology at each timestep. The energy value extracts the market value of the generation injected to the grid considering the electricity prices.

$$\mathrm{E}_x = \frac{\sum_t^{8760} [P_t^{elec} \cdot g_{i,r,t}]}{\sum_t^{8760} g_{i,r,t}} \tag{8}$$

Equation 9 is used to compute the capacity value of a technology. The capacity credit measures a technology's reliability in meeting peak demand, indicating its contribution to grid adequacy. In our study, we took an average of the top 30 peak demand hours and the contribution of technology in these hours to quantify the capacity credit of a generation technology. The base capacity value is considered 75 €/kW.

$$\mathrm{C}_x = \frac{\text{Capacity credit}_x \cdot \text{Base Capacity Value}}{\text{Capacity factor}_x \cdot 8760/1000} \tag{9}$$

The flexibility value of a technology is computed using the Equation 10. The flexibility value multiplier of each technology is computed by considering its share in total generation for each hour. For base flexibility value, specific figures are not publicly disclosed in the available sources, therefore, we assumed it to be equal to base capacity value.

$$\mathrm{F}_x = \frac{\text{Flexibility Value Multiplier}_x \cdot \text{Base Flexibility Value}}{\text{Capacity factor}_x \cdot 8760/1000} \tag{10}$$

The results show that for dispatchable technologies like nuclear power plants, the differences in costs are very minor with a high share in the grid, and LCOE can be represented as an acceptable metric, but for VRE technologies, their variability must be considered. The VALCOE of solar is almost double the computed LCOE; the main reason for this is that the capacity value part of the IEA VALCOE equation for solar is always near to zero as during the peak demands, the generation from solar is very low. For wind technologies, the VALCOE is lower than the LCOE in 2050, showing high energy, capacity, and flexibility values. Our results also indicate low integration costs for wind technologies. This certainly shows that sector coupling and increased flexibility of the system can accommodate a high penetration of wind technologies at a very low cost. Another important aspect is that all results are shown combined for all countries, certainly some countries are importing some part of wind energy via interconnections and it would be very interesting to analyze the results at the country level and see how the variability of VRE technologies is accommodated in future years with high sector coupling and electrification of diverse sectors.

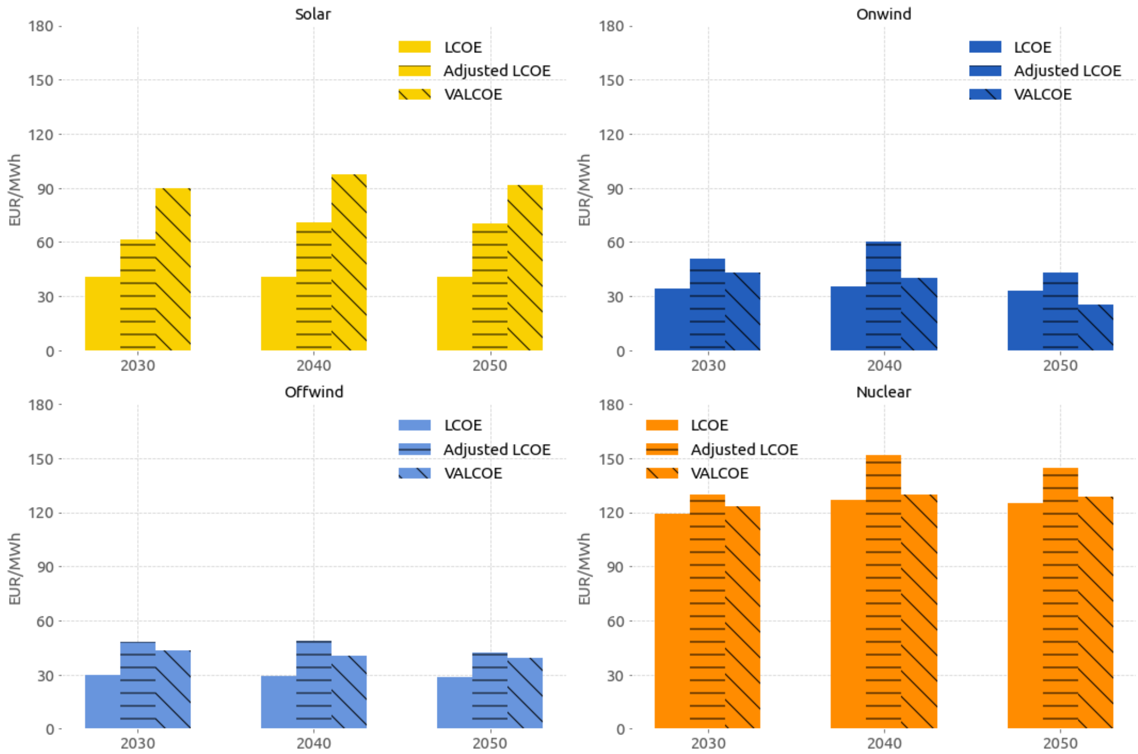

Figure 5: Comparison of computed LCOE, VALCOE and adjusted LCOE with integration costs

4 CONCLUSIONS

Our study show that the variability of VRE technologies and the associated integration costs linked with this variability can be computed in a simple way using the available modeling tools. The preliminary results show that solar PV incurs the highest integration costs, starting at 21 €/MWh in 2030 and increasing to 30 €/MWh by 2050. For wind technologies which include onshore and offshore wind, integration costs are high in 2030 and 2040 but decrease significantly by 2050.

The comparison of results with existing literature shows that integration costs of VRE technologies vary significantly depending on methodologies and assumptions. Most of the studies estimate much higher integration costs at higher penetration levels. Our results contradict this by showing that integration costs decline as VRE penetration increases. This is mainly attributed to optimistic carbon emission targets or policies and increased system flexibility and high level of sector coupling, particularly in transport, industry, and heating sectors.

Overall, our findings reinforce that increasing VRE penetration, supported by strategic policy measures and investments in grid and storage solutions, can lead to a cost effective and flexible energy system to accommodate VRE variability. Future research will focus on country-level analyses to better understand regional differences in integration costs and the impact of sensitivities in this regard, especially the level of integrations costs with different transmission line capacities and also some limitations on sector coupling. The current study do not consider the operational costs associated with the cycling of dispatchable technologies, which include ramping, start-up and shutdown costs. The variability of VRE technologies have a large impact on these costs therefore it is an important aspect to consider in future improvements to have a more realistic view on the integration costs.

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