The Competitiveness of Nuclear Energy: From LCOE to System Costs*

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Economists used to compare the costs of electricity based on the discounted average lifetime costs of power plants, a metric known as the levelised costs of electricity (LCOE). This transparent and comparatively simple metric worked well in a context of regulated markets. Nuclear, coal, gas and hydro thus competed based on their respective capital, labour and fuel costs at the level of the individual plant. Three forces compel a move away from LCOE. First, the social costs of CO_2 and local pollutants are becoming an important decision criterion. Second, the liberalisation of electricity markets introduces price and market risk as a dimension of investor cost. Third, the rise of variable renewable energies (VRE) such as wind and solar PV requires new costs metrics, as the system needs to back up variable resources with added capacity of dispatchable plants. A study by the OECD Nuclear Energy Agency (NEA) shows that integrating system effects increases the costs of a MWh produced by VREs up to USD 50 when they have a 75% share. While precise amounts vary with penetration and flexibility resources, policymakers need to understand that the presence of VRE requires a new notion of competitiveness that includes system effects.

For decades, economists, energy specialists and policymakers have assessed the comparative costs of electricity generation based on the discounted average costs over the lifetime and the total output of a generating plant. As a standardised form of cost-benefit accounting (CBA), these levelised costs of electricity (LCOE) indicate the required expenditures in terms of capital, fuel, and operations and management (O&M), adjusted for their incidence in time or the different technology options per unit of output (*i.e.* a MWh of electricity). This straightforward, transparent and comparatively simple metric worked well in a context of regulated markets where generators were centrally dispatched according to system requirements, tariffs were set by regulators and load factors could be predicted with confidence. In order to satisfy a given demand for electricity, the technology with the lowest LCOE was chosen to minimise the costs of providing baseload power to the electricity system. Nuclear energy thus competed with hydro, where available, and coal and gas on the basis of their respective capital, labour and fuel costs at the level of the individual plant.

Three major forces are compelling the move away from the methodological assumption that LCOEs alone can provide an adequate picture of the generating costs of electricity. First, as early as the late 1960s, concerns were growing about the environmental impacts of electricity generation. While such concerns were not confined to the electricity sector alone – with its large centralised production units, at the time still overwhelmingly run by public entities – declining air quality due to the firing of coal had coalesced into concrete efforts to identify, measure and monetise the "social", "full" or "external" costs of power generation. Such accounting of external effects would subsequently extend beyond air pollution and include the impacts of different generating technologies, both positive and negative, in areas such as resource depletion, risk management of major accidents, regional development or the security of energy supply. In recent

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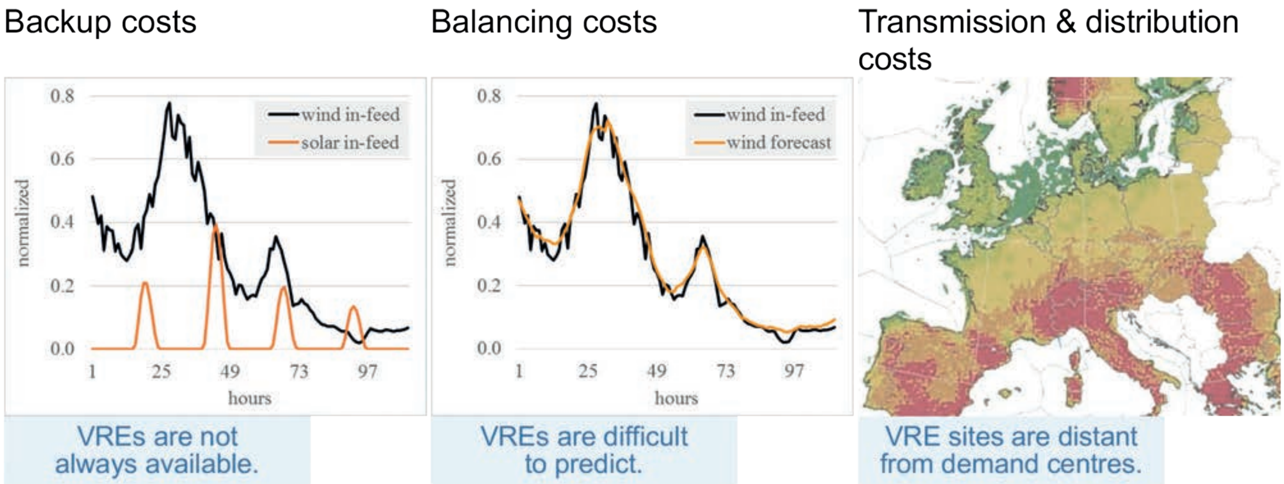

Figure 1: System costs and variable generation (source: Lion Hirth (2015)) [1].

years, CO_2 emissions resulting from the burning of fossil fuels have by far become the most important and most policy-relevant externality power generation.

The second major force has been the progressive liberalisation of electricity markets in OECD countries – a movement that commenced in the United States in the late 1970s and gathered steam in the United Kingdom and continental Europe during the 1980s and 1990s. Liberalisation forced a change in the decision-making frameworks for investment. As regulators no longer set stable tariffs, private investors needed to price in the risks in markets with unstable prices. Issues such as bankruptcy risk in the face of sudden changes in demand, new entry or policy suddenly became relevant. Due to their high capital intensity, investments in nuclear energy and other low carbon technologies were particularly concerned. LCOE accounting can partly accommodate these changes in risk profiles by varying the cost of capital of different technologies but this remains a rather imperfect reflection of the nature of the underlying risks.

By far the most important change challenging LCOE as the relevant metric of the competitiveness of different power generation technologies was however the advent of important amounts of variable renewable energies (VRE) such as wind and solar PV. Their variability in function of the weather requires a radical rethinking of cost and benefit accounting in the electricity sector. In particular, VRE drive a wedge between notions of capacity (*i.e.* the ability to stand by and produce when called upon) and energy (*i.e.* the actual delivery of electricity). LCOEs cannot capture the difference between capacity and energy since they work with load factors that are standardised over different technologies, are stable and, in the case of baseload power technologies such as nuclear at high levels, frequently reach 85%.

A recent study by the OECD Nuclear Energy Agency (NEA) analyses the added costs of electricity systems that are due to the variability, unpredictability and comparatively small unit size of VRE [2]. System effects are composed of profile costs (due to variability), balancing costs (due to unpredictability), grid costs and connection costs (see Figure 1 above).

The NEA study goes on to estimate the relative costs of reaching an ambitious target for carbon emissions with either nuclear energy or VRE. Attaining the target with wind and solar PV will impact the generation mix, overall capacity and total costs. As VRE load factors are lower than conventional thermal power plants, higher capacities are needed to produce the same amount of electricity. Variability requires dispatchable back-up capacity such as nuclear or has that will be available at all times, but will turn at comparatively lower load factors. In a least-cost system, VRE also change the long-term structure of the remaining capacity, which shifts towards technologies with lower fixed costs such as open cycle gas turbines (OCGTs) that are better equipped to accommodate reduced load factors.

Other things equal, the total costs of realising a given emission target will increase with higher shares of VRE. Figure 2 on the next page shows how the overall costs of the system and the different system cost components increase strongly with VRE production share under a 50gCO_2/kWh carbon constraint consistent with the Paris Agreement. Taking a base case with only nuclear energy as a low carbon electricity provider, total system costs increase by 42% if wind and solar PV generate half of all electric energy. A 75% VRE target means almost doubling the costs of electricity provision.

(1) Lion HIRTH (2015), *The Optimal Share of Variable Renewables: How the Variability of Wind and Solar Power Affects their Welfare-optimal Deployment*, Presentation at the Conference on Elements of a New Target Model for European Electricity Markets, CEEM, Université Paris-Dauphine, 8 July 2015, p. 10, http://www.ceem-dauphine.org/assets/dropbox/Lion_Hirth-2015-07-08_Optimal_share_of_Variable_Renewables_Paris.pdf

(2) NEA (2019), *The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables*, OECD, Paris, https://www.oecd-nea.org/ndd/pubs/2019/7299-system-costs.pdf

Related to the amount of VREs in the different scenarios, these costs translate to increases between USD 5 and USD 50 of the costs of a MWh of electricity produced by VREs. For a meaningful comparison of the full costs and of different technologies at the system level, these unit system costs need to be added to the plant-level generation costs of VRE or LCOE. This substantially changes the notion of competitiveness, which now depends primarily on the modalities of allocating system costs. To the extent that system costs are socialised, the competitiveness of VRE improves. To the extent that system costs are allocated to the technologies creating the variability, it declines.

High shares of VRE not only drive up costs but also change how the electricity system operates. Nuclear or gas plants will not only operate at reduced load factors but will also experience frequent episodes of steep ramping up and down, which puts stress on technical structures and challenges system operations.

A striking effect of the deployment of low marginal cost VRE on the electricity market is also the appearance of hours with zero prices. At 75% VRE, 3 750 hours or 40% of the total will have an electricity price of zero or less. Economic viability will require that zero price hours are compensated by hours with high electricity prices. This implies higher volatility and, ultimately, increased investment risk and higher capital costs.

This form of price formation is particularly unfavourable to VRE themselves, as they are most likely to run when prices are low since all their generation takes place during those hours when prices are low or at zero. Because all VRE generation responds to the same meteorological conditions, they tend to auto-correlate. In combination with their zero shortrun marginal costs, this causes a decrease in the average price received by the electricity generated by VRE as their penetration level increases.

Under current costs, a mix relying primarily on nuclear energy remains the most cost-effective option to achieve a decarbonisation target of 50 gCO_2/kWh. Further declines in VRE costs however would lead to integrated systems with sizeable shares of nuclear and VRE. At low shares of generation, VRE would enter on their own merits due to their advantageous plant-level LCOE costs. However as their share rises, their increasing system costs would make adding nuclear energy the complementary least cost option at the system level (see Figure 3 on the next page comparing the two mixes). This shows how the notion of competitiveness changes. It changes not only because system costs need to be taken into account. Competitiveness also changes in function of the generation mix itself.

A future least-cost low carbon electricity mix might thus consist of shares of both VRE and nuclear at levels of around 40% each, with gas and hydroelectricity providing the flexible remainder of the balance. This assumes a "greenfield" situation, with the construction of all generating assets yet to come. In systems with long-lived low carbon assets such as nuclear or hydroelectricity, which would require only capital expenditures allowing for longterm operation (LTO) rather than full investment costs, the optimal share of these assets would of course be higher.

The task for policymakers is to cost-effectively decarbonise the electricity sector while maintaining security of supply. This means:

- Implementing carbon pricing to decarbonise the electricity supply.
- Recognising and fairly allocating the system costs to the technologies that cause them.
- Encouraging new investment in all low-carbon technologies through frameworks providing stability for investors.

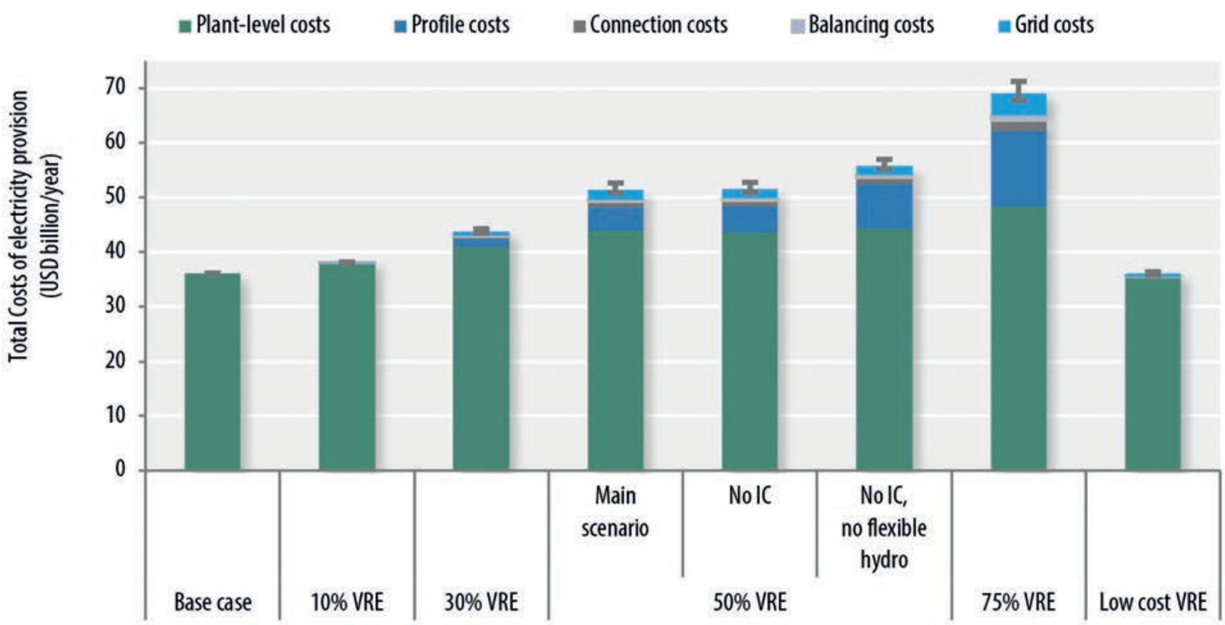

Figure 2: System costs as a function of the share of VRE (source: The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables (NEA, 2019)).

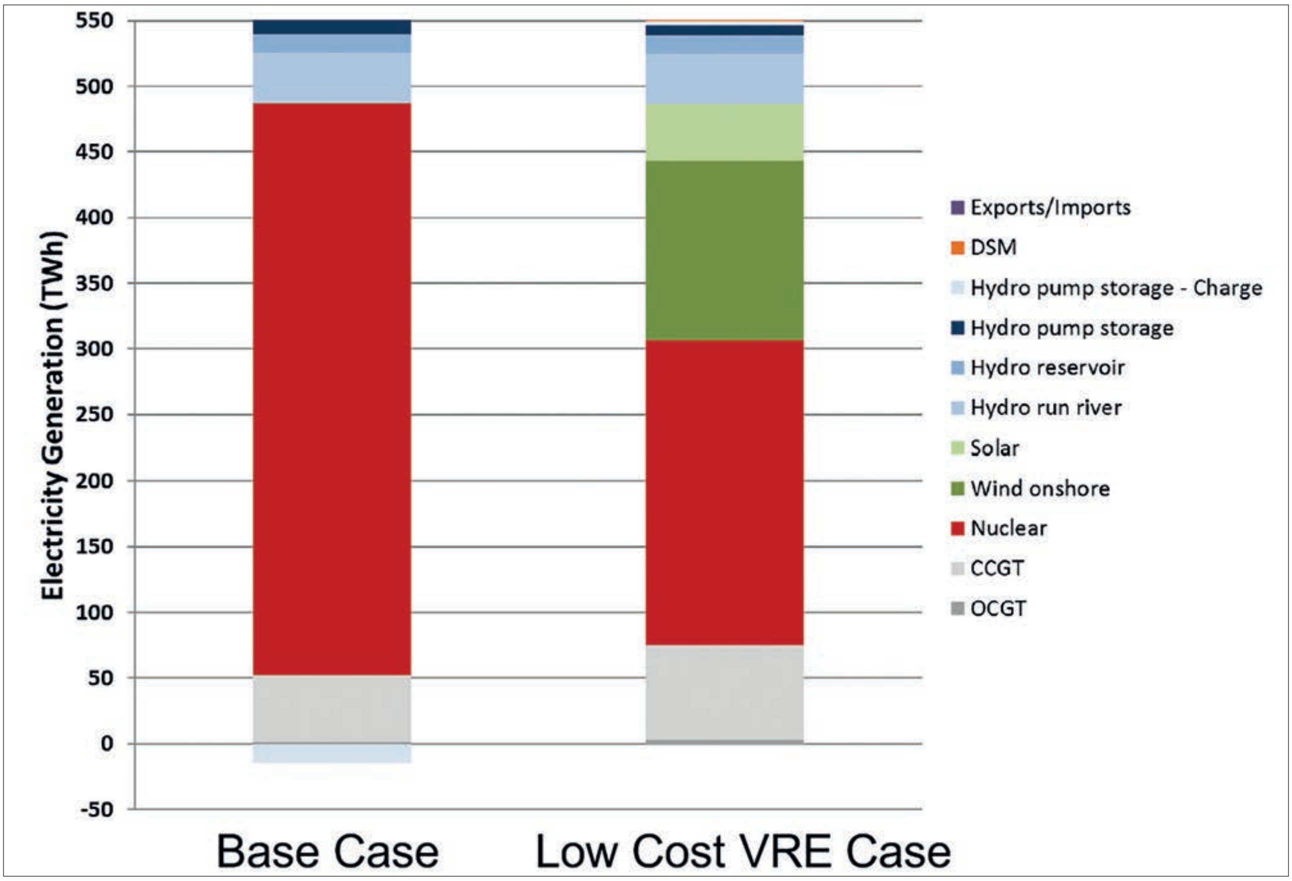

Figure 3: An equilibrium of nuclear and low cost variable renewables (source : Adapted from The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables (NEA, 2019)).

- Using competitive short-term markets for the cost-efficient dispatch of resources.
- Ensuring adequate levels of capacity and flexibility, as well as transmission and distribution infrastructure.

These five measures form the basic framework for a low-carbon electricity system with an optimal mix between VREs and clean, dispatchable sources, such as hydroelectricity and nuclear energy. All low carbon-generating source will be needed. However realising the most cost-efficient low carbon energy mix requires a full understanding of the system effects associated with each individual generation technology.

Policymakers also require a new understanding of the meaning of competitiveness in the presence of variable generation technologies such as wind and solar PV. First, they need to understand that decarbonising with VRE only can increase the total costs of reaching a given target significantly even if their competitiveness in pure LCOE terms looks favourably. Second, they need to adopt metrics of competitiveness that included these added costs. This is no trivial matter as these metrics depend on system configuration, available flexibility resources and technical specification of different technologies, for instance their flexibility.

This is why the OECD Nuclear Energy Agency (NEA) is now developing a programme to assist individual Member counties to assess the total costs of different configurations of low carbon electricity systems and the competitiveness of different generators in the presence of ambitious carbon constraints and sizeable shares of variable technologies.