Integrating variable electricity supply from wind and solar PV into power systems

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Abstract

In contrast to energy supply from fossil and nuclear power plants, wind power and solar PV are *variable.* Their output is beyond human control, dependent on weather, and cannot always be supplied on demand. Variability causes “integration costs” that occur at a system level in addition to generation costs of variable renewable energy (VRE).

This thesis aims to improve the economic evaluation of VRE in particular with respect to their variability and corresponding integration costs. Its three main ambitions are contributing to the understanding of i) the economics of variability, ii) the modeling of variability and iii) the short-term costs and distributional effects induced by VRE. It thereby tries to bridge the gaps between three research strands that evaluate VRE: the integration costs literature, the marginal economic value literature and the integrated assessment model (IAM) literature.

First and most fundamentally, I present a framework for the economics of variability. It is based on a new definition of integration costs that, in contrast to previous definitions, relates to economic theory more clearly and captures all costs of variability. The framework reveals an important new component of integration costs, termed “profile costs”. They account for the low capacity credit of VRE, reduced utilization of dispatchable plants and over-produced VRE generation. Previous integration costs studies neglected some or all of these aspects, and could therefore not link to the marginal value literature. The link developed in this thesis shows two equivalent perspectives on integration costs: From a *cost* perspective the costs of integration are added to those of generation resulting in *system levelized costs of electricity* (System LCOE), while from a *value* perspective integration costs reduce the marginal economic value of VRE. The new concept of System LCOE broadens the cost perspective of integration costs studies such that it is equivalent to the economic literature on marginal value.

Both perspectives can be embedded in a welfare-economic setting: equivalent first-order conditions determine the optimal deployment of VRE. If the System LCOE of VRE drop below the average System LCOE of a purely conventional power system, more VRE deployment increases welfare. Production-based LCOE, the widely used conventional metric (and other indicators like grid parity), are misleading because they neglect variability. A situation where the LCOE of VRE are below those of conventional plants does not imply that VRE deployment is efficient or competitive. By contrast, the metric of System LCOE allows evaluating and comparing technologies, and could replace incomplete indicators. It retains the intuitive and familiar format of LCOE and, in addition, accounts for the complex interaction of VRE with the power system.

Based on this framework the thesis quantifies integration costs for wind. From a literature review and own modeling it is shown that (marginal) integration costs increase with penetration and reach about

25–45[1] €/MWh at wind shares of about 30%. This is substantial compared to the average whole-sale electricity price or generation costs of wind of about 60 €/MWh. Integration costs for solar are of similar magnitude at high shares, mainly driven by profile costs, as indicated by comparing the integration challenges of wind and solar. Integration costs reduce the optimal and competitive share of VRE and can discourage high shares of VRE. However, the economic viability of VRE would increase if the full cost of conventional generation technologies were accounted for, foremost the climate change externality of fossil energy and the health risks of nuclear power. In addition, integration options might significantly reduce integration costs. This thesis helps identifying suitable integration options by revealing the most important integration challenges. A shift from capital-intensive base load plants to peak load gas plants substantially reduces profile costs. More fundamental changes in the energy system like a substantial change of demand patterns, long-distance transmission grid expansion or seasonal storage technologies could further reduce integration costs.

The second contribution of this thesis is the development of two approaches to improve the modeling of variability in IAMs based on the above insights into the economics of variability. The first approach suggests implementing System LCOE in IAMs to represent the full costs of VRE. Some IAMs already represent variability with simple cost penalties for VRE, yet System LCOE can improve this by providing cost penalties with a rigorous economic basis. System LCOE are system-dependent and thus need to be estimated with high-resolution models for a broad range of energy system configurations. To keep this parameterization manageable, variability aspects should be modeled explicitly in IAMs without using exogenous cost penalties, where possible. An option to achieve this is the second approach. which explicitly accounts for the most important integration costs component profile costs, by implementing residual load duration curves (RLDC) into REMIND-D, a multi-sector long-term model of the German economy. Hereby not only major integration challenges but also the optimal energy system's response can be modeled endogenously such as changes in the conventional capacity mix or the deployment of hydrogen and methane storage facilities (power-to-gas storage). If implemented into IAMs, both approaches could increase the credibility of mitigation scenarios results in particular the economic potential of VRE.

In its third contribution this thesis shows that in the short term, when VRE are driven by support policies, particularly high integration costs can be induced. These costs are not only imposed by VRE's variability but by an adverse combination of three aspects: variability, an unfavorable legacy power system, and a low capital turnover rate. This might create a barrier to reaching the long-term optimal deployment of VRE. Redistribution effects intensify this potential lock-in effect. VRE support induces redistribution flows from conventional producers to electricity consumers, which can be larger than the net system cost increase due to VRE. This gives conventional generators the incentive to oppose VRE support. If large redistribution flows are not desired by society or single actors, they can present implementation barriers to specific policy instruments. Combining two policies, renewables support and carbon pricing, might allow policy makers to reduce redistribution effects. This would reduce implementation barriers even if the policy mix might not be the first-best policy to internalize externalities such as the climate change externality.

[1] The higher values do neglect a number of integration options like the long-distance transmission, energy storage and changes in the temporal demand profiles.