Summary

Many jurisdictions have formulated quantitative targets for energy policy, such as targets for greenhouse gas mitigation, energy efficiency, or deployment of renewable energy sources. For example, the European Union aims at reaching a renewables share in electricity consumption of 35% by 2020 and 60-80% in 2050; similar targets have been set in many regions, countries, states, and provinces around the globe. Implicitly or explicitly, such targets seem to be determined as the welfare-maximal or "optimal share" of renewables, however, it is often unclear how targets are derived. This paper discusses the socially optimal market share of wind and solar power in electricity supply, accounting explicitly for the variability of these technologies. It provides a theoretical analysis, a structured methodological literature review, and new numerical estimates for Northwestern Europe.

Wind and solar power have been labeled variable renewable energy (VRE) sources (also known as intermittent, fluctuating, or non-dispatchable), since their generation possibilities vary with the underlying primary energy source. Specifically, we refer to "variability" as three inherent properties of these technologies: variability over time, limited predictability, and the fact that they are bound to certain locations. These three aspects of variability have implication for welfare, cost-benefit, and competitiveness analyses.

The optimal amount of wind and solar capacity, as the optimal quantity of any other good, is determined by the intersection of their marginal benefit and marginal cost curves. Both curves are not trivial to characterize. The marginal costs of wind and solar power are impacted by technological learning, raw material prices, and the supply curve of the primary energy resource. The marginal benefits are affected by the nature of electricity as an economic good. Because electricity is non-storable, its price varies strongly hour-by-hour, and hence the marginal benefit of a generator depends on the time it produces. For example, the value of solar generators can be increased by the fact that they produce electricity at times of high demand. More generally, the marginal value of electricity from wind and solar power is affected by their variability. For unbiased estimates of the optimal quantity of these generating technologies, all three aspects of their variability has to be accounted for. This paper takes variability serious and estimates its impact on the welfare-optimal quantity of renewables.

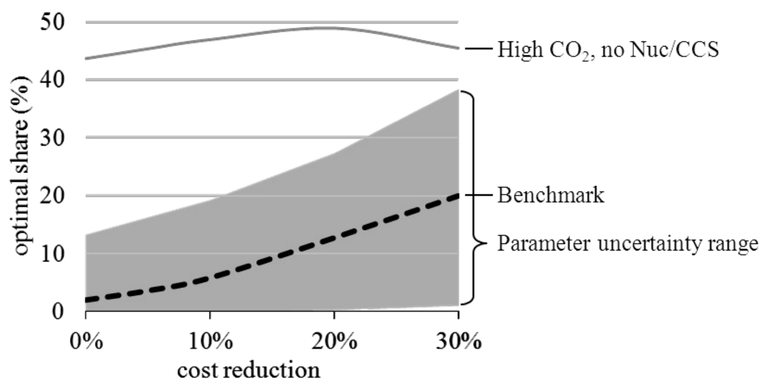
Reviewing the literature, this paper identifies three classes of calibrated models that are used for research and policy advice to estimate the optimal VRE share: integrated assessment models, energy system models, and power market models. Integrated assessment models are appropriate tools to account for technological learning and global commodity markets. Energy system models are strong when it comes to estimating electricity demand and wind and solar resource supply curves. However, both model classes have a too coarse resolution to explicitly represent variability. Power market models provide sufficient details, but are seldom used to optimize VRE capacity endogenously.

Such an "extended" power market model is applied in this paper to estimate the optimal share of wind and solar power. Assuming that onshore wind costs can be reduced to 50 €/MWh, about 30% below current levels, we find the optimal wind share in Northwestern Europe to be around 20% under best-guess benchmark assumptions. This is a three-fold increase from current levels and would imply wind power becomes a cornerstone of the generation mix. In contrast, even under further dramatic cost reductions, the optimal solar share would be zero or close to zero. We find that variability dramatically impacts the optimal wind share. Specifically, temporal variability has a huge impact on these results: if winds were constant, the optimal share would be around 65%. In contrast, forecast errors, have only a moderate impact: without balancing costs, the optimal share would increase by eight percentage points. This is surprising, given the large role forecast errors receive in the public and academic debate.

A number of system parameters and policy choices significantly affect these estimates. This paper reports the impact of dedicated "system integration options", such as electricity storage, interconnectors, more flexible thermal plants, or advanced wind turbine technology. It also reports the impact of fuel prices shocks and further renewables cost decreases. While some of these impacts are as expected, others come at a surprise. Take the example of carbon pricing: many observers suggest that CO_2 pricing has a positive and significant impact on VRE competitiveness. Many European market actors argue that during the 2020s, renewable subsidies should be phased out, and expect VRE to continue to grow, driven by carbon prices. We compare the impact of a low CO_2 price (0€/t) and a high price (100 €/t) to a moderate price (20 €/t). As expected, a low price leads to low wind power investments. Yet, a high price *also* leads to lower wind investments in the long-term. The reason for this surprising behavior is investments in competing low-carbon technologies: most low-carbon technologies, such as

nuclear power and carbon capture plants, are base load technologies with very high investment, but very low variable costs. Baseload capacity reduces the marginal value of VRE, as it can deliver electricity at low cost, once it is built. Carbon prices below 40 €/t do not trigger any nuclear or CCS investments, such that up to that point carbon pricing has a positive impact of VRE via higher costs of emitting plants. Beyond 40 €/t, the baseload investment effect dominates the emission cost effect. Hence, in some cases, a higher CO_2 prices *reduces* optimal wind deployment.

Testing a large number of such technology, price, and policy shocks, we estimate long-term optimal wind shares between 1% and 45%. However, 80% of all runs result in a much smaller range of 16-25% market share, if wind generation costs come down to 50 €/MWh (see figure below). If a high CO_2 price is combined with a ban on the low-carbon base load technologies nuclear power and carbon capture and storage, the optimal share of wind power jumps to 45% despite variability.



Long-term optimal wind shares in the benchmark run and the range of all 20 sensitivities, displayed as a function of wind power cost reductions. While there is significant parameter uncertainty, in 80% of all sensitivities the share is between 16% and 25% at low wind cost.

This leads us to the conclusions that assessing the economics of electricity generation in general, and wind and solar power specifically, requires rigorous methods that can challenge common wisdom and intuition. Models need to account for variability; otherwise they might grossly overestimate the optimal quantity of wind and solar power. The findings of this study point out the important role of onshore wind power as a competitive electricity generation technology. The long-term estimate of a market share of 20% is equivalent to three times as much wind power as today. However, the share would be higher if low-carbon mid and peak load technologies were available to supplement VRE in the transition to a low-carbon electricity sector. Biomass as well as high-efficient gas-fired plants could play a crucial role in this respect. Advanced wind turbine layouts with larger rotors relative to generator capacity could be quite beneficial, since they provide a flatter generation profile. Finally, system flexibility is key to achieve high VRE shares. Thermal power plants that provide heat or ancillary service severely limit the benefits of VRE. Relaxing these constraints through technological innovation increases optimal wind deployment.