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THE IMPORTANCE OF INTEGRATING THE VARIABILITY OF RENEWABLES IN LONG-TERM ENERGY PLANNING MODELS

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Overview

Long-term (LT) energy planning models are widely used for policy analysis and determining pathways towards a low-carbon energy system. In decarbonizing the energy system, these models predict a large contribution of renewable energy sources (RES), especially in the electricity sector. However, these models typically have a low temporal resolution and operate at a technology level rather than at power plant level, thereby omitting technical restrictions of power plants. Both modeling limitations might render these models unsuitable to analyze scenarios with large shares of intermittent RES.

The main contribution of this work is to quantitatively assess and analyze the effects of these modeling limitations of long-term energy planning models in a setting of a rapidly increasing penetration of intermittent RES. The focus of the assessment lies on the feasibility and the economic optimality of model outcomes. The analysis exposes caveats to be considered when interpreting the results of LT planning models and allows prioritizing modeling issues to be addressed.

Methods

A LT planning model of the Belgian electricity system with a time horizon up to 2050 is developed in TIMES. The entire time horizon is divided into 10-year periods during which new investments can be made. The model simultaneously makes investment and operational decisions for all periods and all intra-period time slices. In the model, annual targets for the share of intermittent RES in yearly electricity generation are imposed, reaching a minimal level of 50% in 2050.

To analyze the impact of the temporal resolution, four model versions have been set up, differing only in the temporal resolution. The number of time slices considered is varied between 12 and 8736 per period. To validate the feasibility and to re-evaluate the dispatch decisions (and corresponding operational costs) of these models, the investment decisions of the LT-model are translated to serve as input data in a detailed market model. This market model operates at an hourly resolution and incorporates detailed technical constraints of power plants using mixed integer linear programming (MILP). Since the temporal resolution of the LT model version with 8736 time slices equals that of the market model, comparing dispatch results allows evaluating the impact of incorporating detailed technical restrictions of power plants.

Results

Results show that the operational costs (incl. fuel cost, emission taxes, variable operations and maintenance costs, start-up costs and costs related to non-served energy) are strongly underestimated in the LT-model, while the potential uptake of RES is strongly over-estimated.

Increasing the temporal resolution increases the accuracy of the results obtained with the LT model. However, the quality of the model results are not simply determined by the number of time slices used, but rather by the way the chosen time slice division is capable of approximating the residual load duration curve (RLDC) accurately. Classical approaches which select time slices based on seasonal, daily and intra-daily patterns are shown to fall short of approximating the RLDC with acceptable precision, as these time slice divisions do not grasp the fluctuations in available wind and solar energy. The result is that the LT models underestimate the amount of RES that need to be curtailed, and overestimate the potential contribution of baseload technologies. Both effects lead to an underestimation of fuel costs, forming the main driver for the underestimation of operational costs.

The operational costs are underestimated more strongly when there is a high level of RES penetration and when the temporal resolution is low. When only 12 time slices per period are considered, operational costs are shown to be underestimated by up to 60% with respect to the market model. Increasing the temporal resolution of the LT model from 12 time slices per year to an hourly resolution is shown to decrease the underestimation of the operational costs by up to 34% points. However, for systems with a high penetration level of RES, the operational cost remains underestimated by 25-30%. This can be explained by a limited flexibility of the generation fleet (mainly baseload technologies), leading to a further reduction in the use of baseload technologies and additional flexibility-related curtailment of RES. A sensitivity analysis shows that LT models approximate operational costs better when the generation fleet is more flexible, and when the difference in marginal generation costs between baseload and mid/peak load technologies would be smaller.

Conclusions

Current long-term modeling methodologies are not adapted to obtain reliable results in a setting with high shares of intermittent RES. Such LT models fall short of incorporating the short-term dynamic effects which play an important role in electricity systems with high shares of intermittent RES. Results show that LT models with a low temporal resolution overestimate the potential uptake of RES while strongly underestimating the cost attached to the provision of electricity. Furthermore, to obtain realistic results, it is not sufficient to merely increase the temporal resolution. Technical detail needs to be added to these models to guarantee feasibility and grasp the flexibility related drivers of operational costs.

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