The impact of operating reserves in generation expansion planning with high shares of renewable energy sources

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Overview

System simulations and real-life experience show how a high share of Renewable Energy Sources for Electricity (RES-E) challenges the cost-efficient and reliable operation of the power system. The variable nature of wind and PV, results in a variable output profile and limited predictability. Consequently, this requires increased operational flexibility, i.e. capacity which can be rapidly regulated up –or downward, in order to maintain the system balance. Indeed, unpredicted output deviations caused by RES-E, add to the uncertainty of demand and equipment outages. Transmission System Operators (TSOs), contracting reserve capacity to ensure operational flexibility, expect the massive increase of variable RES-E (VRES-E) to substantially increase the operating reserve needs, and subsequently the RES-E integration costs. Current state-of-the-art considers statistical methods for the sizing and allocation of operating reserves (De Vos et al. 2013). Short-term power system models, typically unit commitment and economic dispatch models integrating reserve requirements, are used to calculate the operational costs of reserve requirements following RES-E integration.

In contrast, long-term power system models focus on the impact of RES-E on the future power system generation and transmission assets. They take into account future (de)investment costs and are used to solve the Generation Expansion Planning (GEP) problem. A GEP model attempts to identify the most optimal generation portfolio to meet demand, given a set of objectives and considering several types of uncertainty and reliability constraints (Pereira & Saraiva 2013). Typically, this considers a less detailed representation of operational constraints, such as for instance the operating reserve needs. However, determining this reserve capacity ex-post can lead to a sub-optimal generation portfolio, as this might not be designed to deal with the unexpected output variations. Therefore, disregarding reserve requirements is expected to result in an underestimation of the integration cost of RES-E. Hence, to study the influence of such requirements on the composition of the future generation portfolio, this work focuses on the integration of detailed reserve requirements in a GEP model.

Method

The impact of reserve requirements within investment models is investigated by means of a top-down partial equilibrium GEP model. A partial equilibrium model considers only part of the economy, in this case the power sector, whereas a general equilibrium model considers the whole economy and the corresponding markets. In contrast to a bottom-up model which includes specific (energy) technologies, a top-down model uses general macro-economic data to estimate e.g. evolution of demand and/or e.g. groups generation technologies per type (nuclear, coal, etc.). To adequately assess the impact of the variability of VRES-E, the GEP model simulates power system operation in time-steps of an hour taking into account operational constraints. A novel approach is proposed in which the number of online units per generation type is represented by a continuous variable. This way a number of constraints which typically require integer variables, such as minimum up and down times or the inclusion of start-up and shut-down costs, can be linearized. Thus the optimization problem remains linear, reducing calculation time while allowing more realistic technical constraints.

In order to deal with the variability of VRES-E, GEP models need to be able to deal with the uncertainty resulting from their limited predictability. Certain GEP models already try to capture uncertainty of future demand or market prices (Pereira & Saraiva 2008), or the uncertainty introduced by random generator or line outages (Yaghooti et al. 2010; Aghaei et al. 2014). De Jonghe et al. (2011) further include a deterministic balancing requirement, based on installed wind capacity. However, this simplification does not allow capturing the stochastic nature of VRES-E output deviations, nor does it distinguish between the different types of reserves. Therefore, Tigas and Mantzaris (2012) propose a residual load duration curve method. The need for reserve power is calculated based on probabilities of RES-E output deviations, unit outages, etc. However, the generation portfolio is optimized separately from reserve power capacity. Also, as they do not actually check the operational constraints of the power system, all reserve power capacity has to be met with peak units to ensure a reliable solution. By formulating appropriate operating reserve requirements, a GEP model may deal with VRES-E uncertainty in a more realistic way. In continental Europe ENTSO-E regulates the operating reserve requirements, which are subdivided in Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR).

The GEP model used in this paper is implemented for a conceptual system: four representative dispatchable technologies are selected, namely a base load, mid load, peak load and high peak load technology. Their characteristics are in accordance with the system used in the work of De Jonghe et al. (2011). Two VRES-E technologies are also included, namely wind and PV. Forecast and actual VRES-E output data as well as a load profile are gathered from ELIA, the Belgian TSO. Cost factors are sourced from the JRC's Technology Mapping initiative. The reserve power requirements for FCR, FRR and RR are integrated in the model following the methodology for the sizing of these reserves as set out by ELIA in its ancillary services study (ELIA 2013).

Results

The generation portfolio of this conceptual system is optimized for a time period of one year. Different targets for the share of RES are set starting from a 20% share and increasing. Now, two scenarios are evaluated: (1) without and (2) with reserve power requirements. Furthermore, a sensitivity analysis is conducted to investigate the impact of additional reserve capacity on the total integration cost of VRES-E. The results are expected to show that not considering these requirements leads to an underestimation of the integration cost of RES-E. Indeed, the reserve requirements impact the planned generation mix, in order to ensure the system's need for operational flexibility. Not taking into account the operational reserve requirements at the planning level results in expensive operating reserves in the short term, or even reliability reductions.

Conclusions

It is concluded that, in order to ensure a cost-efficient and reliable integration of RES-E, it is necessary to include reserve power requirements in the long-term investment optimization. Determining reserve power capacity ex post leads to a sub-optimal solution for the generation system, as this might result in a shortage of flexible resources which are needed to balance the system. The main contribution of this work is the optimization of a generation portfolio with a high share of renewables and appropriate reserve power capacity, via a new top-down partial equilibrium GEP model. Future work will look into the diversification of reserve power sources, considering also the flexibility offered by VRES-E themselves, demand response, storage and interconnection capacity.

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