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Accounting for flexibility in power system planning with renewables

Andreas Belderbos, Erik Delarue *

University of Leuven (KU Leuven) Energy Institute, TME Branch (Applied Mechanics and Energy Conversion), Celestijnenlaan 300A, Box 2421, B-3001 Leuven, Belgium

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ABSTRACT

Due to the increasing deployment of intermittent renewables, the residual load profile, as seen by the dispatchable generation units, becomes lower and more volatile. This paper introduces a new system planning model on a power plant resolution, taking into account technical operational constraints. The objective of this model is to determine the optimal set of generation units, able to serve a given demand. Two initial solutions are obtained; one from a classical screening curve model, and another from a model using mixed integer linear programming (MILP). These initial solutions are perturbed and combined with an operational model to validate and further improve the solution. The developed model complements other models available from the literature, in its level of detail (power plant level and full year – hourly time resolution) combined with a fast computation time (<1 h). The evolution of the optimal amount of generation capacity as a function of the installed wind capacity is examined in a case study. As the share of wind power increases in the portfolio, a shift takes place from base load generation towards mid and peak load. This shift is triggered both by the lower demand and the increasing volatility. This demonstrates that operational constraints of power plants (individual basis) have an important impact on the configuration of the optimal generator set, and need being considered, especially at increasing rates of intermittent renewables.

Introduction

Worldwide, electricity generation systems are undergoing major changes. The share of renewable energy sources (RES) is growing significantly, mainly driven by growing concerns on global warming and for reasons of strategic energy security. These RES, however, often have an intermittent profile. Their output is predictable only to a limited extent, and it is variable, not or only in a limited way dispatchable (e.g., wind turbines can be curtailed, reducing their output). The impact of these RES on the system is twofold: first, they reduce the residual load (i.e., the original load with RES generation subtracted). Second, more flexibility is required to deal with the higher variability of the residual load. Hence, these effects need to be accounted for in power system optimization [1–3].

Planning and operating of modern electric power systems comprehends several complex and interlinked tasks. These tasks can be divided in three main groups, depending on the considered time horizon. A first group includes long-term resource and equipment planning which targets time ranges from one year to several decades. Examples are investment planning, transmission and distribution planning and long range fuel planning. A second group contains short-term operational scheduling and is used for time intervals from several hours to a few weeks, or even year(s). Examples are unit commitment (UC) scheduling, maintenance and production scheduling and fuel scheduling. The last group includes real time operations, which consider fractions of a second to several minutes. Examples of real time operations are automatic protection and dispatching. The focus of the present paper is on the first and second group of models.

The main research questions of this paper are (1) to what extent does the deployment of RES affect the optimal generation mix, and (2) to what extent do technical operational constraints need being accounted for in system planning models, to achieve meaningful and reliable results. Hence, in this paper, a new electricity generation system planning model is developed, focusing on the integration of RES, and the corresponding required flexibility of dispatchable generation. The objective is to integrate operational constraints from short-term generation scheduling models into a power system planning model. Specific focus is on the impact of RES on lowering the residual demand on the one hand, and on increasing the need for flexibility by a more variable residual load profile, on the other hand (both creating a shift from base to mid load and peak load). The developed model will further allow

* Corresponding author. Tel.: +32 16 322511; fax: +32 16 322985.
E-mail addresses: andreas.belderbos@kuleuven.be (A. Belderbos), erik.delarue@mech.kuleuven.be (E. Delarue).

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Nomenclature

Sets

I (index i)	set of power plants
J (index j)	set of time steps
L (index l)	set of cost segments
P (index p)	set of off line time steps
T (index t)	set of technologies

Parameters

A_i	fuel cost at minimum output [€/h]
a_i	constant coefficient of quadratic cost function [€/h]
b_i	first order coefficient of quadratic cost function [€/MW/h]
c_i	second order coefficient of quadratic cost function [€/MW^2/h]
D_j	demand [MW]
$F_{i,l}$	slope of linearized cost function [€/MW h]
fcr_t	relative fixed cost [€/MW/y]
MDT_i	minimum down time [h]
MUT_i	minimum up time [h]
OM_i	variable operation and maintenance cost [€/MW h]
$Pmax_i$	maximum power output [MW]
$Pmin_i$	minimum power output [MW]
R_j	system reserve [MW]
$SC_{i,p}$	startup cost if offline for p hours [€]
$T_{i,l}$	upper bound power limit of each segment [MW]
TP	time period length, equal to 1 [h]
vcr_t	relative variable cost [€/MW h]

Variables

$\delta(i,j,l)$	generated electric power in each segment [MW]
$cap(t)$	installed capacity [MW]
fc	fixed cost [€]
$fu(i,j)$	fuel cost [€/h]
$g(t,j)$	hourly generation [MW]
$om(i,j)$	variable operation and maintenance cost [€/h]
$sc(i,j)$	startup cost [€]
tc	total cost [€]
$u(i)$	investment status [–]
vc	variable cost [€]
$z(i,j)$	commitment status [–]

evaluating classic system planning approaches, which are also often used as such in this context.

Several power system planning models have been developed over time [4]. While some focus on the expansion of the transmission and/or distribution system [5,6], the scope of this work is on expansion of the electricity generation system. The textbook example of generation system planning optimization is the so-called "load duration based" or "screening curve" approach (see, e.g., Stoft [7]). Several specific features have been added to such planning models. Santos and Legey incorporate environmental costs in an expansion planning model [8]. Delgado et al. use a planning model in a stochastic setting to focus on the impact of nuclear (they for instance consider different scenarios for fuel and allowance prices) [9]. Unsihuay-Vila et al. consider both generation and transmission expansion planning, in a load duration based model setting with multiple objectives (i.e., cost, life-cycle emissions and diversification) [10].

RES integration (e.g., wind) is often studied from an operational viewpoint (see, e.g., [11,12]). However, also from a planning perspective, the flexibility requirement in modeling is being acknowledged [13]. Recent developed models for system planning made efforts to take explicitly into account the flexibility limitations of thermal generators, focusing on wind power integration, preserving the chronological order of time segments (hourly or aggregated) [14,15]. Delarue et al. also added uncertainty on cost parameters as risk in such framework [16]. Also in existing bottom-up modeling frameworks, such as ReEDS [17] and TIMES [18,19], the impact of RES are being studied. These models are typically set-up as linear models, working on technology rather than individual power plant basis, and considering a limited set of so-called time-slices, to represent the variations in demand and RES generation. Within such frameworks, efforts have recently been made to expand the temporal resolution, to cover the full 8760 h [20]. Such improved representation can have significant impact on the actual amount of RES generation achieved in a system or on CO_2 emissions [21,22]. Several approaches also have used planning models as TIMES, soft-linked to an operational model to validate results in technical terms [23,24].

Other models start from an operational model and include the investment decision as a variable, taking into account a limited number of time periods [25]. A recent formulation/analysis, combining full year representation and power plant resolution has been presented by Palmintier [26,27]. A clustered UC formulation is proposed, embedded in a planning model formulation.

Compared to the existing literature, this paper presents a novel approach for system planning optimization. It takes a full year horizon (with hourly time steps) into account and works on a power plant resolution (rather than on a technology basis), taking into account technical operational constraints (with binary variables). The developed modeling methodology can be solved in relatively limited calculation time (<1 h). It can therefore easily be used for broader system studies and sensitivity analyses. This model is then used to quantify the impact of taking into account technical constraints of power plants, and as such, addresses the impact of intermittent RES on electricity generation planning. This way, the present research adds to the available literature, by the development of the model and the quantitative insights stressing the relevance of operational characteristics.

The structure of this paper is as follows. The next section presents the problem formulation, first for the power system planning model (on technology basis), second for an operational optimization (UC) and third for an integrated approach. Section 'Integrated system planning model with operational constraints' presents the newly developed methodology. In Section 'Model simulations' the simulation results of the case study are presented and discussed. Section 'Conclusion' concludes this paper.

Problem formulation

Many models exist to optimize the electricity system. The models relevant in the context of this paper can be traditionally divided in several groups (see discussion in previous section), i.e., the system planning models, the operational scheduling models or a combined approach. A problem formulation of each model type will be elaborated below.