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Innovative Applications of O.R.

The improved screening curve method regarding existing units[☆]

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ABSTRACT

In this study, a new method is developed to determine the least cost capacity expansion of a power system by using the screening curve method. The proposed methodology differs from the previous studies by its geometrical solution process to evaluate a capacity expansion problem considering both existing and candidate power plants. The algorithms are computationally more efficient and simple than the ones in previous studies for the same improvement. Further, the interpretation of the optimal capacity expansion plan is enhanced by explicitly exhibiting the results of all considered capacity expansion alternatives. The solution process can be interpreted as minimizing the long run marginal cost of supplying 1 megawatt of capacity during the whole year by finding the optimal combination of units. The developed method calculates and finds the cost polygon with the minimum area by moving along the intersection points of the screening curves to form trapezoids and then joining them to form cost polygons. The intersection points, which are needed to calculate the areas of the cost polygons, are found by using the Karush–Kuhn–Tucker conditions in a recursive manner. The last unit in the merit order of dispatching is determined by scenarios to yield an optimal capacity expansion plan. The scenarios are primarily based on a tradeoff between incurring investment costs by commissioning candidate units or taking online existing units with relatively higher variable costs compared to the candidate units.

1. Introduction

A capacity expansion model is utilized for planning the type, the size and the commissioning time of the power plants[1] to be installed in a power system. The capacity expansion models can be classified as static or dynamic models. A static capacity expansion model is utilized for the analysis of energy mix in a target year, whereas a dynamic model is utilized for a planning horizon of 2–50 years by which an expansion problem is solved simultaneously across all time periods in the planning horizon. A detailed analytical description of the mentioned models and under which conditions they can have similar results can be found in Levin, Tishler, and Zehavi (1980, pp. 2–3; 1983, pp. 892–893).

The focus of the recent capacity expansion studies has been the issues related to the increasing penetration of renewable energy sources and the optimal utilization of existing and new generation capacities. One of the important issues is the uncertainties originating from the intermittent power generation from renewable. Parpas and Webster (2014) proposed a stochastic multiscale model to take into account the uncertainties in load demand and in generation availability for capacity expansion planning. Vespucci, Bertocchi, Pisciella, and Zigrino (2016) introduced a decision support model to take into account the risk associated with the capacity expansion problem originating from the uncertainty of prices and the uncertainty of market share. Pineda and Morales (2016) presented a static mathematical model to investigate capacity expansion planning under the effects of short-term forecast errors of renewable power generation, market design and competition at the investment level.

Another important issue is the power transmission expansion planning with the comissioning of new generation capacity and the dynamic demand response management. Georgiou (2016) introduced a deterministic bottom-up mixed integer linear programming model to determine the least cost combination of electricity generation technologies considering interconnection infrastructures for the long-term energy planning of Greek power system. Sauma, Traub, and Vera, 2015 proposed a robust-optimization model for transmission expansion planning to assess the impact of postponing the connection time of some new power plants over the system cost and the optimal network expansion plan.

Finally, the economic and the environmental evaluation of national or international energy policies and the electricity market design are the other important related issues among the recent studies. Alizamir, de Véricourt, and Sun (2016) proposed op-

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[1] In this study, a unit or a generator is used as a synonym of the term "power plant".

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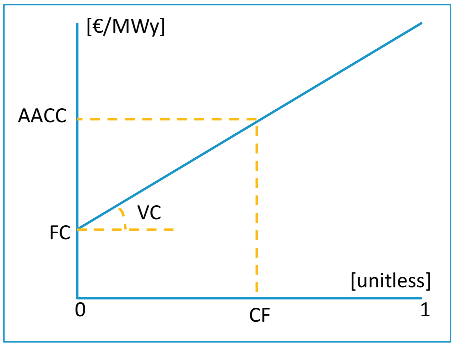

Fig. 1. The representation of a generator's cost curve for analysis with TCSCM.

timization models to analyze the dynamic control of remuneration rates (prices) of feed-in tariff policies considering the main market dynamics in the evolution of renewable technologies (i.e. learning and diffusion) and investors' strategic behaviors. Hach, Chyong, and Spinler (2016) introduced a dynamic capacity investment model to analyze the impact of different capacity market design choices for Great Britain by taking into account ramping costs and constraints, strategic bidding, and price elasticity of demand. Ritzenhofen, Birge, and Spinler (2016) presented an agent-based dynamic model to compare the impact of the different renewable energy support schemes on electricity prices, generation portfolios, security of supply and carbon emissions considering the investor behavior and the major characteristics of electricity markets (i.e. in particular for Californian electricity market).

The classical screening curve methodology (TCSCM), a practical methodology, is often utilized in capacity expansion models as considered in the recent studies by Hach et al. (2016) and Ritzenhofen et al. (2016). TCSCM provides the optimal solution to meet the increasing demand for electricity by minimizing the capital and the operational costs of generators. Although it provides initial solutions on a capacity expansion problem, the solutions are guidelines for a detailed analysis. In the next subsection, detailed information about TCSCM is provided.

1.1. The classical screening curve methodology

TCSCM is preferred to be utilized during the preliminary investigation of the capacity expansion planning studies to narrow down the technology alternatives for detailed analysis. The method enables the graphical means of constructing and examining the cost curves of all candidate[2] thermal units considered for capacity expansion. An example cost curve of a generator is illustrated in Fig. 1 and mathematically expressed in Eq. (1.1.1). A cost curve[3] (or a screening curve) depicts the annual average cost of capacity usage (AACC) or annual revenue requirement of a generator,[4] which is composed of fixed (FC) and variable costs (VC), and is a function of the capacity factor[5] (CF). The intercept of the curve is the FC of the unit, whereas the slope of the curve is the VC,

$$\begin{aligned} \mathrm{AACC}[\text{€ per megawatt-year}] &= \mathrm{FC}[\text{€ per megawatt-year}] \\ &\quad + \mathrm{VC}[\text{€ per megawatt-year}] \times \mathrm{CF}[\text{unitless}]. \end{aligned} \tag{1.1.1}$$

The costs can also be represented in € per megawatt-hour, if the unit € per megawatt-year is divided by 8760 hours per year. Although energy is measured in megawatt hour, while power and capacity are measured in megawatt, the price of power, capacity and energy are all priced in € per megawatt-hour,[6] so are fixed and variable costs (Stoft, 2002, pp. 32–33). For more information about TCSCM refer to Shaalan (2001, pp. 167–204) and Stoft (2002, pp. 30–45).

The annual revenue requirement is the amount of income needed by the generators to cover their annual fixed and variable costs. The annual fixed costs are composed of capital expenditure (CAPEX) and the fixed operating and maintenance costs (FOM). The CAPEX, expressed as specific investment cost in € per megawatt$_{el}$, encompasses the costs of erecting the power plant and bringing it to commercial operation and as well as the costs related to interest charges accrued during the construction period. During the calculations, the CAPEX is assumed to be recovered annually (or annuitized as fixed investment charges in € per megawatt-year) over the economic life time (t) of the generator by using a capital recovery factor (r). The formula is represented below:

$$The\,Capital\,Cost\,of\,Capaciy\;\;per\;\;year = CAPEX \cdot \frac{r\cdot(1+r)^t}{(1+r)^t-1} \tag{1.1.2}$$

The FOM costs constitute taxes and insurance, personnel administration costs, etc. The annual fixed costs are independent of the amount of electricity generated, whereas dependent on the size of the generator and whether running or not must be paid.

The variable costs are, dependent on the amount of electricity generated, composed of the variable operating and maintenance costs (VOM) and the fuel costs. The VOM costs include the cost of waste disposal, the cost of unscheduled repairs, etc. The fuel costs are mainly dependent on the type of fuels used by the power plants and their efficiencies.

The first stage of the screening methodology is to construct cost curves for each type of generator according to their fixed and variable costs (see Fig. 2). The candidate units are then compared on the basis of their AACC, and the most competitive ones are selected to be operative during the planning horizon. In the graph three types of generators are depicted, namely open cycle gas turbine (GT), combined cycle gas turbine (CC) and coal fired power plant (COAL). In relative terms, the GT generates power at the lowest cost among the other two in CF_3 times 8760 hours per year or less. By the same token, the COAL (the base load plant power plant) is the most economically attractive generator starting from CF_2 times 8760 hours per year or more. Finally, the CC (the medium load power plant) can be cost effectively operated, if it is run at least CF_3 times 8760 hours per year and at most CF_2 times 8760 hours per year.

At the second stage of the process, the cost-effective operation intervals, which are found at the first stage, are projected onto the annual load duration curve[7] to find the optimal capacities for the mentioned power plants (indicated as Cap in Fig. 2). The merit order of loading provides the increasing order of variables cost in

[2] The candidate units are the new units which are going to be commissioned, if they are found out to be economical during the evaluation process.

[3] Throughout this study, the cost accounting terms in International Atomic Energy Agency (1984, pp. 151–163) are adapted for the sake of compatibility of terminology with most of the studies on capacity expansion in the literature.

[4] A screening curve shows the average cost of using a plant's capacity. It should not be confused with the annual average cost of energy (AACE) supplied, i.e. AACE (in € per megawatt-year) = FC (in € per megawatt-year)/CF + VC (in € per megawatt-year) (Stoft, 2002, pp. 36–39).

[5] The fraction of time the capacity of a unit is used.

[6] "Power" is the flow of energy (in megawatt) and "capacity" is the potential to deliver power (in megawatt). In contrast, energy is a static amount (in megawatt hour). Consequently the price (per unit cost) of power is measured in $ per hour per megawatt of power flow ($ per hour per megawatt = $ per megawatt-hour), while the price of energy is measured likewise in $ per megawatt-hour. Stoft (2002, pp. 30–31) states that generation cost data are usually presented in $ per kilowatt. This indicates the cost of the flow of capacity produced by a generator over its lifetime, so the true (but unstated) units are in $ per kilowatt-lifetime.

[7] It is formed by ordering demand in each hour in a year according to its magnitude. Each point on the abscissa denotes the fraction of time (expressed as τ_1, τ_2), during which the corresponding demand on the ordinate is equaled or exceeded. The ordinate is assumed to be normalized to 1.