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Analysis on the interaction between short-term operating reserves and adequacy

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ABSTRACT

An electricity generation system adequacy assessment aims to generate statistically significant adequacy indicators given projected developments in, i.a., renewable and conventional generation, demand, demand response and energy storage availability. Deterministic unit commitment (DUC) models with exogenous reserve requirements, as often used in today's adequacy studies to represent day-to-day power system operations, do not account for the contribution of operating reserves to the adequacy of the system. Hence, the adequacy metrics obtained from such an analysis represent a worst-case estimate and should be interpreted with care. In this paper, we propose to use a DUC model with a set of state-of-the-art probabilistic reserve constraints (DUC-PR). The performance of the DUC-PR model in the context of adequacy assessments is studied in a numerical case study. The Expected Energy Not Served (EENS) volume obtained with the DUC model is shown to be a poor estimate of the true EENS volume. In contrast, the DUC-PR methodology yields an accurate estimate of the EENS volume without significantly increasing the computational burden. Policy makers should encourage adopting novel operational power system models, such as the DUC-PR model, to accurately estimate the contribution of operating reserves to system adequacy.

1. Introduction

The electricity generation system should meet the demand for electricity of all users within acceptable standards. When these conditions are met over a certain period of time, the system is said to be reliable (UCTE, 2010). Reliability can be decomposed in adequacy and (operational) security. First, adequacy involves the ability of the system to meet the demand in the long term, taking into account all reasonable demand profiles, generation profiles of renewable energy sources (RES), hydrological conditions and outages of system components (Billinton and Allan, 1984; UCTE, 2010). Adequacy can be further split in three levels: system adequacy, market adequacy and access to fuels adequacy (Eurelectric, 2004). System adequacy includes generation adequacy and network adequacy. Second, security relates to the short run, and is the ability of the power system to deal with sudden disturbances such as unforeseen network or generator outages and load or RES-based generation forecast errors. The immediate action required to maintain the balance between supply and demand when these unforeseen events occur can be provided by deploying operating reserve capacity. Since sufficient operating reserves must be available at all times, security is closely linked to generation adequacy. An adequate system should also maintain sufficient operating reserves to ensure a predefined level of security. The focus of this paper is on this link between generation adequacy and operational security, and in particular on the role of operating reserves in generation adequacy assessments. High levels of electricity generation from intermittent renewable energy sources may increase the operating reserve requirements, intensifying the interaction between operating reserves and system adequacy. Furthermore, obtaining statistically significant adequacy metrics for high RES power systems is increasingly challenging due to the variability of RES-based generation.

The goal of a generation adequacy assessment is to expose potential risks to the security of supply, based on projected developments of the power system. The degree to which a generation system is adequate is usually expressed with probabilistic indicators (Felder, 2001). In this regard, generation adequacy assessments commonly simulate the day-to-day operation of the power system at hand using an operational or market-based model under a significantly large number of scenarios to obtain statistically significant estimates of adequacy indicators. Examples of these indicators include the Expected Energy Not Served

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Nomenclature

I	Set of power plants, indexed by i.
J	Set of time intervals, indexed by j.
L	Set of reserve levels, indexed by l.

Decision variables

χ_j	Curtailment of RES-based generation at time interval j, MW
$\chi_{j,l}^{L+}$	Curtailment of RES-based generation as upward reserve provider at time interval j in reserve level l, MW.
$\chi_{j,l}^{L-}$	Curtailment of RES-based generation as downward reserve provider at time interval j in reserve level l, MW.
Φ_j	Load shedding at time interval j, MW.
$\Phi_{j,l}^{L+}$	Load shedding as upward reserve provider in time interval j in reserve level l, MW.
$ac_{i,j,l}^{NSR+}$	Activation cost of non-spinning reserves provided by fast-starting power plant i at time interval j in reserve level l, €.
$ac_{i,j,l}^{R+}$	Activation cost of upward spinning reserves provided by power plant i at time interval j in reserve level l, €.
$ac_{i,j,l}^{R-}$	Activation cost of downward spinning reserves provided by power plant i at time interval j in reserve level l, €.
$c_{i,j}^{CO2}$	CO2-emission cost of conventional power plant i at time interval j, €.
$c_{i,j}^{F}$	Fuel cost of conventional power plant i at time interval j, €.
$c_{i,j}^{R}$	Ramping cost of conventional power plant i at time interval j, €.
$c_{i,j}^{SU}$	Start-up cost of conventional power plant i at time interval j, €.
$g_{i,j}$	Output of conventional power plant i at time interval j, MW.
$nsr_{i,j}^{+}$	Non-spinning reserves delivered by power plant i at time interval j, MW.
$nsr_{i,j,l}^{L+}$	Non-spinning reserves delivered by power plant i at time interval j in reserve level l, MW.
$r_{i,j}^{+}$	Upward spinning reserve provided by power plant i at time interval j, MW.
$r_{i,j}^{-}$	Downward reserve provided by power plant i at time interval j, MW.
$r_{i,j,l}^{L+}$	Upward spinning reserve provided by power plant i at time interval j in reserve level l, MW.
$r_{i,j,l}^{L-}$	Downward spinning reserve provided by power plant i at time interval j in reserve level l, MW.

Parameters

λ^{Φ}	Value of lost load, €/MWh.
τ	Duration of the time interval, h.
$P_{j,l}^{+}$	Activation probability of reserves scheduled in upward reserve level l at time interval j.
$P_{j,l}^{-}$	Activation probability of reserves scheduled in downward reserve level l at time interval j.
D_j	Electricity demand at time interval j, MW.
$D_{j,l}^{+}$	Upward reserve requirement at time interval j in reserve level l, MW.
$D_{j,l}^{-}$	Downward reserve requirement at time interval j in reserve level l, MW.
G_j^F	Forecasted wind power output at time interval j, MW.

(EENS) and the Loss Of Load Expectation (LOLE) (Billinton and Allan, 1984; Schneider et al., 1989). The scenarios, sometimes referred to as Monte Carlo (MC) years, typically consist of combinations of yearlong time series of the load, intermittent generation from renewable energy sources (RES), hydrological conditions and outages of conventional generation assets (ENTSO-E, 2016).

The Pentalateral Generation Adequacy Assessment by the Pentalateral Energy Forum (PLEF, 2015) served as a pioneering regional study (Austria, Belgium, Switzerland, Germany, France, Luxemburg and the Netherlands) in terms of a probabilistic, Monte Carlo-like, approach. Another example of a transnational, probabilistic adequacy assessment is the Pan-European Mid-term Adequacy Forecast (MAF) by ENTSO-E (2016). Four different market simulation tools are used to simulate the day-to-day operation of the power system as a unit commitment and economic dispatch (UC/ED) problem. In such a UC/ED problem, the modeler aims to minimize the system-wide operating cost to meet a certain demand for electricity, while respecting all technical constraints of all assets in the system (e.g., maximum ramp rate, minimum up/down time, line capacity limits, etc.) and possibly some security margins (e.g., operating reserve requirements). The MAF performs day-ahead market analyses of the considered MC years, but excludes explicit modeling of intraday trading or the balancing market. With respect to operating reserves, both the MAF and the PLEF study consider a so-called base case and a sensitivity case. In the base case, operating reserves are assumed not to contribute to generation adequacy (i.e., the required reserves are subtracted from the net generation capacity and the remainder must ensure the day-ahead market balance). In a sensitivity analysis, the contribution of operating reserves to adequacy during scarcity situations has been considered by assuming all operating reserves are available to mitigate load shedding (i.e., the reserves are not subtracted from the net generation capacity). The assumed contribution of the operating reserves improves the adequacy situation close to 'real-time', but may now result in a too optimistic estimate of the adequacy of the system. In 2014, CEER published an overview of the methodologies for national adequacy assessments used in 20 European Member States, revealing that no common approach was employed regarding the treatment of operating reserves (CEER, 2014). In at least 7 countries, the operating reserve requirement was subtracted from the net generation capacity, while at least 4 countries included the operating reserves. None of the generation adequacy assessments considers flexibility and balancing mechanisms to ensure operational reliability.

If operating reserves are explicitly represented in today's adequacy assessments, researchers typically resort to deterministic unit commitment (DUC) models with explicit, exogenous reserve requirements. Load shedding as reserve provider (upward flexibility) and additional real-time curtailment of RES-based generation (downward flexibility) are often not considered. Since these DUC formulations do not consider the expected reserve activation costs, insufficient information is available to cost-optimally size and schedule operating reserves. ENTSO-E (2016), however, highlights the importance of improving the representation of operating reserves in future adequacy studies. The methodology and analysis presented in this paper can be seen as a contribution towards this goal.

The objective of this paper is to demonstrate that the way operating reserves are represented in the operational models used in adequacy studies significantly impacts the resulting adequacy indicators. Deterministic approaches may lead to overly conservative estimates of the adequacy indicators. As more accurate, stochastic alternatives typically result in excessive computational costs in a Monte Carlo simulation-based adequacy analysis, we pursue methodological advancements to adequately capture the interaction between operating reserves and adequacy indicators. In addition, we formulate policy guidelines to more accurately estimate the contribution of operating reserves to generation adequacy. Towards this aim, we propose to use a DUC model with a set of state-of-the-art probabilistic reserve constraints (DUC-PR) that (1) allows accounting for the probability and cost of activating reserves during the allocation process, and (2) allows load shedding and