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An integrated framework for operational flexibility assessment in multi-period power system planning with renewable energy production

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HIGHLIGHTS

- Quantitative modeling framework for operational flexibility assessment.
- Integration of short-term constraints in generation expansion planning model.
- Renewable energy penetration drives flexibility needs higher than carbon limits.

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ABSTRACT

This paper proposes an integrated framework for operational flexibility assessment in power system planning with a significant share of intermittent renewable energy sources (RES). The framework proposed includes: (i) the formulation of an integrated generation expansion planning (GEP) and unit commitment (UC) model accounting for key short-term technical constraints, (ii) the elaboration of accurate and systematic horizon reduction methods to alleviate the computational burden of the resulting large-sized optimization problems and (iii) the definition of suitable metrics for the operational flexibility assessment of the obtained plans. The framework is applied to a ten year planning horizon of a realistically sized case study representing the national power system of France, under several scenarios of RES penetration levels and carbon limits, spanning levels of up to 50%. The importance of incorporating the detailed short-term constraints within long-term planning models is shown. The results of the assessment show that, under high renewable energy penetration, neglecting the short-term constraints may lead to plans significantly short on flexibility, reaching shortage levels of up to 50% in frequency and several GWs in magnitude. Also, the load not served reaches levels of up to 3% and carbon emission is underestimated by up to 60%. Furthermore, the results highlight the importance of relying on suitable quantitative metrics for operational flexibility assessment in power systems planning rather than solely relying on generic performance measures, such as system costs and mixes of power plants, which are shown not to sufficiently reflect the flexibility levels of the obtained plans.

1. Introduction

Generation expansion planning (GEP) is a well studied techno-economic problem, which relates to determining the optimal of generation technologies mix, their siting and their investment schedules, for ensuring that the electricity demand over a certain time horizon can be satisfied. With the power sector being constantly subjected to changes, driven by economical, technical, social and environmental issues, GEP modeling techniques have continuously evolved to accommodate the newly arising requirements. Such modeling advancements have been covered in recent literature reviews and include, among others [1,2]: improvements in the details considered (e.g. reliability and maintenance), policy developments, such as the restructuring of the power sector, renewable energy sources (RES) integration and support schemes, uncertainty and stochasticity modeling, and the consideration of real-options for adaptive power systems design [3].

One of the most recent concerns in power systems planning is dealing with the high share of intermittent RES penetration required in the system, driven by strict environmental policies, such as the EU renewable energy directive [4] and its proposed revision [5], and other regional and national targets. The resulting increased variability in the net load (system demand minus RES production) requires that the

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List of symbols

Indexes

i	index of power plant cluster
j	index of sub-periods (hours)
s	index of sub-periods (load-levels)
y	index of planning year

Sets

I	set of power plant clusters
I^{new}	subset of new power plants cluster
I^{res}	subset of renewable energy units cluster
I^{th}	subset of thermal and nuclear units cluster
J	set of hourly sub-periods
S	set of load-levels sub-periods
Y	set of years in the planning horizon
Θ	set of investment decision variables
Ω	set of operation decision variables

Parameters

Y^{end}	end year of the planning horizon
Y^{res}	first year during which the RES quota target is binding
$L_{y,*}$	demand at sub-period j or s in year y (MW)
$Dur_{y,s}$	duration of load block s in year y (hours)
P_i^{max}	maximum capacity of power plant i (MW)
P_i^{min}	minimum stable power output of power plant $i \in I^{th}$ (MW/h)
C_i^{inv}	investment cost of unit i (M€)
I_i^{max}	maximum allowable units to be commissioned within the planning horizon
T_i^{life}	expected life-time of new power plant i (years)
T_i^{const}	construction time of power plant i (years)
R_i^{Umax}	maximum upwards ramping capability of power plant $i \in I^{th}$ (MW/h)
R_i^{Dmax}	maximum downwards ramping capability of power plant $i \in I^{th}$ (MW/h)
P_i^{start}	maximum output of power plant $i \in I^{th}$ when started (MW)
$CF_{i,y,*}$	capacity factor of renewable energy sources $i \in I^{res}$ during sub-period j or s, of year y (%)
E_i	amount of carbon emission per MWh of power plant i (tCO_2/MWh)
E_y^{max}	maximum total allowable emission per year y (tCO_2)
$EFOR_i$	Expected forced outage rate of power plant i (%)
M_i^u	minimum up-time for power plant $i \in I^{th}$ (hours)
M_i^d	minimum down-time of power plant $i \in I^{th}$ (hours)
DR_y	discount rate for year y (%)
$C_{i,y}^{mrgl}$	marginal cost of power plant i including the variable O&M and CO_2 costs, considering inflation (€/MWh)
C_i^s	start-up cost of power plant i (€)
C^{lns}	cost of load not served (€/MWh)
C_i^{fom}	fixed O&M costs of power plant i (€)
Pen_y^{level}	annual renewable penetration level requirement (%)
Prr	percentage of the load required to be covered by primary reserve (%)
Srr^{up}	percentage of the load required to be covered by the secondary upwards reserve (%)
Srr^{dn}	percentage of the load required to be covered by the secondary downwards reserve (%)
a^{res}	percentage of the variable generation output covered by secondary reserve (%)
r^{min}	minimum planning reserve margin (MW)

Continuous variables

$p_{i,y,*}$	energy output of power plant i at sub-period j or s, during year y (MWh)
$pr_{i,y,j}$	primary reserve of unit i at sub-period j during year y (MWh)
$sr_{i,y,j}^{up}$	secondary upwards reserve of unit i at sub-period j during year y (MWh)
$sr_{i,y,j}^{dn}$	secondary downwards reserve of unit i at sub-period j during year y (MWh)
$lns_{y,*}$	load not served at sub-period j or s, during year y (MW)
$v_{i,y,j}$	shut-down decision of unit i during sub-period j in year y

Discrete variables

$x_{i,y}$	availability (commissioning) state of power plant i in year y
$q_{i,y}$	commissioning decision of power plant i in year y
$u_{i,y,j}$	commitment status of power plant i during sub-period j in year y
$z_{i,y,j}$	start-up decision of power plant i during sub-period j in year y

Acronyms

CF	Capacity Factor
EFS	Expected Flexibility Shortfall
GEP	Generation Expansion Planning
IRRE	Insufficient Ramping Resources Expectation
LDC	Load Duration Curve
LNS	Load Not Served
MILP	Mixed Integer Linear Programming
O&M	Operation and Maintenance
RES	Renewable Energy Sources
UC	Unit Commitment

remainder of the thermal units cope with tighter operational flexibility requirements [6,7]. This is generally defined as the ability of the system to respond to the inter-temporal variability rising both from intermittent RES production and from variations in electricity demand. In this respect, operational flexibility regards the short-term operation of those generation units and their technical characteristics: ramping rates, unit commitment states, minimum up and down times, start-up times and minimum stable load, to name a few.

From an assessment point of view, accounting for operational flexibility is a critical element for overall system reliability (see for example Fulli et al. [8] for a discussion on these requirements in Europe). Reliability relates to firm-capacity[1] at each time period sufficient to satisfy the system load, using typical metrics such as loss of load expectation (LOLE) and expected energy not supplied (EENS). Operational flexibility, instead, considers how a specific operational state of the system at a given period would contribute to (or hinder) its ability to deploy its resources for accommodating subsequent load variations. For this, no time period can be assessed in isolation of the others, nor without detailed knowledge of the system state and technical characteristics at the given period.

[1] Available generation capacity excluding failed units, units in maintenance, offline units, etc.