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A CAPACITY EXPANSION MODEL DEALING WITH BALANCING REQUIREMENTS, SHORT-TERM OPERATIONS AND LONG-RUN DYNAMICS

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Abstract

One of the challenges of current power systems is presented by the need to adequately integrate increasing shares of variable renewable energies (VRE) such as wind and photovoltaic (PV) technologies. The study of capacity investments under this context raises refreshed interrogations about the optimal power generation mix when considering system adequacy, operability and reliability issues. This paper analyses the influence of such considerations and adopts a resource-adequacy approach to propose a stylized capacity expansion model (CEM) that endogenously optimize investments in both generation capacity and new flexibility options such as electric energy storage (EES) and demand side management (DSM) capabilities.

Three formulations are tested in order to seize the relevance of system dynamics representation over the valuation of capacity and flexibility investments. In each formulation the complexity of the representation of operating constraints increases. The resource-adequacy approach is then enlarged with a multiservice representation of the power system introducing non-contingency reserve considerations. Therefore, investments decisions are enhanced by information from system operations requirements given by the hourly economic dispatch and also by a reliability criterion given by reserve needs.

The formulations are tested on a case study in order to capture the trade-offs of adding more details on the system representation while exogenously imposing supplementary VRE penetration. The results obtained show the importance of adopting a sufficiently detailed representation of system requirements to accurately capture the value of capacity and flexibility when important VRE penetration levels are to be studied, but also to appropriately estimate resulting system cost and CO_2 emissions.

Key words
Resource-adequacy, multiservice model, renewable integration, system flexibility, electricity storage, demand side management.

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List of acronyms

ACAES:	Adiabatic compressed air energy storage
BOP:	Balance of plant
CEM:	Capacity expansion model
crf:	Capacity recovery factor
DCC:	Data and communication company
DOE:	American Department of Energy
DSM:	Demand side management
ED:	Economic dispatch
EES:	Electric energy storage
EFOR:	Equivalent Forced Outages Rates
ELCC:	Effective load Carrying Capability
EMS:	Energy management system
ENTSO-E:	European Network of Transmission System Operators
EOM:	Energy only market
FCR:	Frequency Restoration Reserves
FRR:	Frequency restoration reserve
IRRE:	Insufficient Ramping Resource Expectation
Li-Ion:	Lithium Ion batteries
LOLE:	Loss of load expectation
LOLP:	Loss of load probability
LP:	Linear programming
LTGI:	long-term generation investment
MIP:	Mixed integer programming
Nas:	Sodium-sulfur batteries
O&M:	Operation and maintenance
OPF:	Optimal power flow
PCS:	Power control system
PHS:	Pumped-hydro storage
PV:	Photovoltaic technology
RA:	Resource adequacy
RMSE:	Root mean square error
RR:	Replacement Reserves
TSO:	Transmission system operator
UC:	Unit commitment
VRE:	Variable Renewable energy
VRFB:	Vanadium redox flow batteries
WACC:	Weighted average cost of capital

1. INTRODUCTION

The power sector has undertaken a huge transformation since environmental concerns have triggered the importance of reducing CO_2 emissions of the electricity system. The fast technological development and cost reductions, together with the advantageous financial support schemes and ambitious renewable energy agendas have triggered a fast and steady deployment of RES capacity during the last decade. In particular, wind and photovoltaic technologies (VRE) have become the most prominent clean energy sources today.

VRE technologies are intrinsically variable and non-dispatchable by nature. Their very low marginal cost made them to be first scheduled in the merit order settlement process leaving the so called net or residual load to be covered by the remaining dispatchable capacity. Therefore, when the share of RES attains important levels, the net demand decreases and becomes more fluctuating and less predictable.

Existing power systems were conceived to only operate with fully dispatchable technologies. They were not planned to optimally supply high levels of flexibility to the system or to keep the network from high stochasticity on the supply side. Electricity markets were neither conceived to face this new paradigm. The main principle of current power markets is based on rewards based on energy supplied. Restraint regard has been given to ancillary services rewarding, and almost no regard has been devoted to compensating new important services such as flexibility and capacity availability.

Current power system challenges comprises new technical questions when considering the entire system needs (energy, flexibility, availability, supply reliability and stability) and not only balancing the power demand; new economic questions also arise regarding the design of a market capable of sending the right signals to coordinate participants for the efficient operation of the system in the short, mid and long-run. In this way it is mandatory to coordinate the system operations with the needs for conventional capacity investments and to consider requirement of new system services as a consequence of increasing VRE shares.

The methodology adopted in this study analyzes the power market with a resource-adequacy approach, putting some light on the links between different time horizons, considering adequate operational constraints and their associated costs to run the system. This study proposes a new formulation for optimizing long-term generation investment (LTGI) while considering system operations and reliability issues. It pretends to provide a better representation of existing Capacity expansion models (CEM) by including usually omitted need for system services that are expected to significantly impact the resulting optimal mix and CO_2 emissions. It adopts a system cost perspective and a multiservice approach where a portfolio of complementary technologies is endogenously optimized considering global system requirements. A set of conventional, VRE, electric energy storage (EES) and demand-side-management (DSM) capabilities can be jointly deployed respecting optimality conditions. Different regulatory and energy policies can also be defined for scenario analysis (RE agendas, CO_2 tax, CO_2 emission cap, fuel cost spikes, among others). The model adopts a single node approximation of the network and no interconnection exchanges are considered.

The paper is organized as follows: Section 2 presents the challenges of conceiving the power system of the future. Section 3 presents the framework of the study and identifies existing attempts to modeling the power system for capacity optimization. Section 4 offers a formal presentation of the model proposed in the study. Section 5 presents results of a case study to show some of the interrogations captured by the model. Finally, remarks and conclusions are presented in section 6 and 7.

2. THE INCREASE OF UNCERTAINTY ON RESIDUAL DEMAND: THE NEED FOR ENHANCING FLEXIBILITY

The power system has been experiencing a paradigm shift across the last decade. The entrance of important amounts of VRE capacity on the power system has raised new questions about generation adequacy, power security issues and economic optimality.

Energy security issues have experience renovated interest within the energy research community. As exposed in (Cepeda et al., 2009), reliability and adequacy are two distinct but inherently related subjects of security of supply. Adequacy is referred as the ability of the power system to meet the aggregated power and energy levels at any time given a defined capacity margin. It can be seen as the long term requirement related to capacity investments. Nevertheless, the low capacity contribution of VREs given its low achievable load factors as well as its non-dispatchable nature further harms its system value, all of which send to renovated adequacy questions associated with supplementary capacity cost when VRE shares increases.

On the other hand, reliability has being defined as the system capability to overcome any sudden contingency such as plant or lines outages. The increasing penetration of VRE has raised additional elements to this definition which concerns system balancing needs due to recurrent non-contingency situations. This issue is mainly caused by the fluctuation of residual load given the non-negligible associated forecasting errors of wind and solar generation. Not only forecasting errors impacts the system, the very low short run marginal cost and the low capacity value of VRE added with their day to day, weekly and seasonal variations made peaking units to lose profits on the energy only markets, exacerbating the "missing money problem" (Joskow, 2006). All of which arises additional adequacy and operability difficulties to the systems. Generation asset stranding is an evidence of the later. Just in 2013, 21 GW of gas plants were mothballed or closed in Europe out of which 8.8 GW were new plants with less than 10 years of operations. The is problem that those plants are not only necessary to adequate capacity levels of the system but also to easily supply the additional flexibility required to cover up the VRE fluctuations.

Same levels of resource adequacy can be obtained with very different technology mix depending on the available resources in place. Important VRE shares are expected to continue entering into the power systems thanks to profitable support schemes and important cost reductions projected, all of which introduces the necessity of conceiving new integration strategies. This is, additionally to supplying power and energy, sufficient levels of available capacity should be guaranteed on the system. Therefore, on the long-run, sufficient investments on power capacity, but also on flexibility capabilities, should be accomplished in order to allow for optimal system operability. Hence, new arbitration opportunities would appear dealing with the variability and uncertainty of net load relative to the time of delivery considered.

Current power markets execute bid-based algorithms that optimize demand and supply for every hour on a rolling horizon. Bids are assumed to contain information about the VRE variability for the hours ahead but since the main revenue stream of firms comes from the Energy only market (EOM), day-ahead and intraday, the main unit's rewards come from the energy supplied following the declared schedules. Flexible units, which commonly have more important marginal cost, are putted out of the market, leaving the system with schedules showing very poor flexibility capabilities.

On thermal or hydro dominated systems, this short-run flexibility need has not been an issue because units can be easily dispatched, but in a context where VRE becomes more prominent the demand for flexibility will be higher, and one day to one hour arbitrations would arise (Druce et al., 2016). On the longer-run, higher penetrations of VRE would open the floor for new tradeoffs between scheduling generation units and flexibility options simultaneously.

Regarding the real time scheduling, system balance is a key responsibility of TSOs. In some countries regulators have institutionalized the role of “balancing responsible parties” to cover part of the gap of VRE forecast error via a market mechanism. In this way, market participants are prompted to exercise balancing actions and are rewarded for providing short term flexibility for balancing purposes. Nevertheless, additional capacity margins and reserve needs are exacerbated by the increasing shares of VRE into the system. In (Chandler, 2011) the technical challenges and the associated cost of VRE generation over the system balancing actions are exposed. The balancing problem is separated into actions related to variability and actions related to intermittency of VRE. System case evaluations are conducted to estimate the maximum VRE capacity that a given power system can effectively integrate. Even if existing power systems are able to manage additional amounts of uncertainty, optimally integrating significant shares of VRE sources is an important issue that should be assessed when looking at the investment decisions in the long term.

Therefore, flexibility can be considered as the dynamic property of the system consisting on its ability to adjust to changing conditions on different timescales. Changing conditions can be either shocks in demand or supply, and can appear suddenly or be forecasted; consequently, the time of deployment of flexibility is also a crucial parameter that characterizes it. Similarly to capacity, flexibility has an associated cost related to the technologies supplying it, which means that on a system perspective, its cost should be also minimized.

The power system needs have being mutating from a capacity requirement problem to a “capability resources” problem, or a resource-adequacy problem, where multiple products and services are needed and should be delivered over interrelated time horizons (Gottstein et al., 2012). In this way, the technical challenges introduced by VREs under current power market architectures imply looking the system services from a broader perspective in order to conceive new market designs and new regulatory frameworks capable of optimally implementing the energy transition goals.

2.1. Effects of VRE on capacity adequacy and flexibility needs

The capacity value of a power generation technology is measured by its contribution to the generation system adequacy. The European Wind Energy Association (EWEA) suggests using the “capacity credit” to measure the firm capacity of wind power. It defines the capacity credit of wind as: “The reduction, due to the introduction of wind energy conversion systems, in the capacity of conventional plant needed to provide the same level of reliable electricity supply” (van Hulle et al., 2010). The Reliability requirements are computed using the Loss of Load Probability (LOLP), which is a metric that gives the probability of a shortfall at a given hour. The Loss of Load Expectation (LOLE) is then calculated and gives an idea of the magnitude and duration of probable outages over the period under study. The LOLE level is therefore the conventional metric for evaluating long term system adequacy. Every generator capacity contributes to enhance the LOLE. The Effective Load Carrying Capability (ELCC) of different generation technologies can be then compared using this metric (Keane et al., 2011).

As explained by (Castro et al., 2008), the capacity credit of wind depends on the characteristics of the resource on the geographic area but also on the configuration of the incumbent power system. Their work analyses the wind capacity credit using a metric to measure its effective load carrying capability, the equivalent firm capacity and the equivalent conventional capacity. The approach proceeds to compare these metrics on a system with and without PHS units. A probabilistic methodology is developed to constraint the system over equivalent reliability levels using the LOLE metric. Finally, the authors show how the capacity credit of wind is enhanced by the existence of flexible generation sources on the power mix.

Similar results have being exposed in (Sullivan et al., 2008) and (D. Swider, 2007), which examine the impact of storage for integrating VREs into power systems using tailored investment models. Even if these studies are more focused on the capacity value of storage technologies than wind capacity credits, both point out that storage, which is one of the main flexibility options, can lead to better integrate VRE into the system.

The finding of these studies suggests that flexibility options affect in a positive way the capacity value of VREs. Therefore, from an adequacy point of view, capacity and flexibility may be equivalent when significant amounts of VREs are added into the system, so there should be jointly considered.

2.2. System operability and flexibility services supply

As stated in (Palmintier and Webster, 2013), the faster dynamics of power systems with high VREs generation has exacerbated the need for very detailed representation of system operation at faster timescales within long term CEM, disregarding these issues “may misrepresent the true cost and performance of a particular generation mix and result in capacity mixes that are suboptimal or infeasible”.

This is because the variability of VREs increases the load following actions of thermal power plants, which can have important implications over their performance, operating cost and aging. Power generation technologies have different cycling capabilities; moreover load following, restarts and shut down actions have negative impacts over outages, “wear and tear”, heat rates and polluting emissions, particularly for old fossil power plants (Perakis and DeCoster, 2001). On a special report of the DOE about the impacts of load following on power plants presented in (Myles and Herron, 2012), it is claimed that fatigue and creep are synergistic causes of damages and are poorly understood by the power industry. The report shows how the Equivalent Forced Outages Rates (EFOR) increases when utilities begins to cycle units. The authors compare baseload operation with cycling operation for different technologies and aging power plants. The life reduction of a baseload power plant without upgrading investments for cycling can be around 17 years. Even if this effect is attenuated when plants are designed for cycling or upgrades investments are done, there is still an important loss from cycling related damages when compared with baseload operation.

Furthermore (Poudineh, 2016) states that for high VRE penetrations levels, the available flexible resources may not be sufficient to manage the variations of residual load. He claims that “Traditional reliability metrics such as LOLE need to be supplemented by variable generation integration studies. Therefore the Insufficient Ramping Resource Expectation (IRRE), a LOLE like measuring net load fluctuations, could allow assessing whether planned capacity allows the system to respond to short term flexibility needs.”

In (Van Den Bergh and Delarue, 2015) a Unit Commitment model is presented to determine the optimal scheduling of thermal units in order to meet the residual load considering cycling cost as part of the objective function. Efficiency losses for part load operations of thermal units and the startup and shutdown costs are also considered. Thermal unit’s capabilities are modeled using two set of hypothesis: first a low-dynamic or conservative portfolio and then a high dynamic or more flexible one assuming values available in existing literature. A case study is presented based on the data for the German system on 2013. Comparing both portfolios the authors find that, even if the residual system was able to follow the variability of net load in both cases, a reduction of a least 40% of the cycling cost can be achieved when they are considered on the unit commitment scheduling.

2.3. Reliability requirements and flexibility services supply

Power systems should be balanced continuously, which means, demand and supply should be equal in the real time. Uncertainty is not a new concept on power systems. Outages, load forecast errors and other contingencies are regularly managed by the system’s actors. Even though, uncertainty due to the variability and intermittency nature of VRE sources can be critical at high penetration levels. State-of-the-art research (De Vos et al., 2013) and (Hirth and Ziegenhagen, 2015) estimate the additional need of reserve requirements due to VREs on their systems under study and exposes the benefits of passing from an static methodology to a dynamic one for reserve sizing when uncertainty is exacerbated by VRE penetration. These methodologies are based on the statistical study of unbalances based on data representing the operation conditions of the system. Similarly, ENTSO-E published innovative guidelines for TSOs for the dimensioning of frequency restoration reserve (FRR) capacity (ENTSO-E, 2013). It considers the uncertainty of VRE generation to efficiently settle enough amounts of FRR to cover up for VRE's forecasting errors and residual imbalances.

Moreover, detailed spectral analysis of VRE generation show the different timescale responsiveness required to cover up the full randomness of VRE generation. In (Apt, 2007) different datasets of wind farms are analyzed. The author finds that the variability of wind generation follows a large $f^{-5/3}$ Kolmogorov spectrum conveying from 30s to 2.6 days periods, which is quiet wider than that of 24h peak load and its harmonics (12h, 8h, 6h, 4h, 3h) present in demand analysis. Based on this fitted power spectrum and regarding the ramping capabilities of conventional generators the author states that "a linear ramp rate generator (e.i. a gas turbine) is not the optimum match for wind" because in order to compensate only 1% of the wind variations, the generator should be sized "twice as large as the maximum observed at low frequencies". The author concludes that the best strategy to fit the wind randomness would be to use a portfolio of flexibility options to match with the different portions of the Kolmogorov spectrum of wind, this is, considering fast devices such as flywheels, supercapacitors or even batteries, to match short period fluctuations together with slower ramp resources to match the long-period, higher amplitude fluctuations.

The dynamics of the systems in the real time would impact the type and the amount of capacity and flexibility investment that would optimize system cost. In the context of a liberalized market, identifying the optimal mix would mean detecting the most valuable investment options that the markets should foster.

3. LITERATURE REVIEW: MODELLING APPROCHES OF CAPACITY PLANNING AND OPERATING SYSTEMS WITH HIGH VRE SHARES

Either in regulated or in liberalized systems, finding the optimal capacity investments is useful in order to efficiently deploy limited resources under planning, or to accurately assess the outcomes of the current market architecture.

The goal of capacity planning is to determine the best investments portfolio of technologies to supply load demand in a reliable way and to optimally fulfill a complete set of system requirements. This task is particularly challenging since reasonable approximations used for modeling long-run decisions may produce large errors on operating costs and system reliability when applied under particular short timeframes. Furthermore, even if large and detailed bottom-up formulations can be expressed, restricted computational resources also constraints the complexity of the representation and may misrepresent the system in question. Particular care should be given when addressing capacity planning with high VRE shares because of the enhanced difficulties of representing accurately short term and real time dynamics as well as geographical considerations.

Capacity expansion models typically assumes a system cost perspective where operational and investment cost are accounted along the considered period. The time slice used on CEM is usually hours gathered from typical days, weeks or years. The time horizon depends on the particular purpose of the model but can vary from a year to decades ahead. There is a growing consensus on literature about preferred specifications to be chosen and time horizons to be considered for models focusing on the VRE integration in electricity systems.

Models aiming to estimate the impact of VRE over investment decisions should represent detailed operational considerations to assess, as much as possible, the flexibility needs of the system and its associated cost. The goal is to capture the effects of VRE fluctuations at low frequencies (seconds and minutes) over long periods, such as it is currently done for maintenance scheduling (weeks) and capacity and grid investments (years) in modelling systems without VRE.

The challenge of CEM is to bridge the existing gap between traditional short-term operation models and long-term investments models using very high resolution considerations into detailed formulations to represent system running issues but still tight enough to be solved in reasonable time (Carrión and Arroyo, 2006; Frangioni et al., 2009; Hedman et al., 2009; Morales-españa, 2013; Ostrowski et al., 2012; Rajan et al., 2005; Xian HE , Erik Delarue , William D ' haeseleer, 2006). Research on adapting Economic Dispatch (ED), Unit Commitment (UC) and Optimal Power Flow (OPF) formulations, commonly solved on a day-ahead and hour-ahead basis respectively, have being undergoing seeking to couple those models with longer term formulations like hydro scheduling, plant maintenance and capacity expansion models (Campion et al., 2013; Palmintier, 2014; Poncelet et al., 2014; Viana and Pedroso, 2013). There is also growing research on the importance of including balancing aspects and ancillary service requirements on capacity planning approaches (Hirth and Ziegenhagen, 2015; Van Stiphout et al., 2014).

Breakthrough research has been produced using tight UC formulations to calculate optimal investments. A unit clustering approach to solve the large thermal UC for an entire year have being developed in (Palmintier and Webster, 2011). Investments and operations are endogenously calculated in the model using a portfolio of conventional generation units that should match the residual load. The results clearly suggest that including "UC-derived" operations constraints on CEM allows evaluating operational flexibility more accurately. Even though investments in flexibility options are disregarded, likewise the electricity network, this approach opens a wide panorama for system expansion planning.

Similarly, a technology aggregated UC formulation together with six nodes network have being developed in (Pudjianto et al., 2013) with the purpose of simulating the optimal investments in generation, storage and transmission lines for Great Britain on 2030. The model optimizes storage capacity investments while leaving the energy dimension of storage investments as an exogenous parameter. This highly detailed bottom-up approach allows the authors assessing the system value of multiple flexibility options as well as capturing the trade-offs existing among them.

The very significant size of the UC formulation with endogenous investments and grid representation makes the development of a feasible model a very challenging task without the recourse of any heuristic. Typical simplifications are using a limited number of hours to represent a year, priority ordering, unit clustering, among others. Other alternative to simplify large problem is to relax binary variables of the UC or avoiding them at all. Those speedup techniques should be wisely used in order to control its associated error. In (Palmintier, 2014) some metrics of accuracy against computational performance are revealed for different combinations of operational constraints and formulations. A Pareto frontier is obtained showing the best possible tradeoffs for including operational issues on CEM. The reference formulation corresponds to a full MIP formulation for the UC problem including investments; the author proposes variations and compares them in terms of optimal capacity, energy RMSE and speedup gains with that of the reference formulation. It is found that the biggest source of error is not considering operating reserve followed by not considering maintenance constraints, which is in line with what previous studies claim in (Hirth and Ziegenhagen, 2015; Van Stiphout et al., 2014); The second best formulation correspond to the case of a full LP formulation followed by a full LP with no planning margins[2]. These two simpler formulations allow obtaining results under the 10% RMSE for both capacity investments and energy generation with solving times of 42 to 53.4 times faster than the full MIP.

[2] Accounting for capacity requirements.

In (Zerrahn and Schill, 2015a), a stylized greenfield dispatch and investments model using a full LP formulation is proposed to assess the value of a complete portfolio of generation, storage and flexibility options. The model minimizes the system cost and includes endogenous investments in conventional generation, renewables, power storage technologies and DSM using hourly time steps to represent an entire year. Units supply power to match an inelastic demand and the model contemplates the provision of balancing reserves. The system is modeled as a copper plate[3] and parameters are calibrated to represent the German system to reflect the 2050 perspective. Even if balancing reserve is calculated using a static method, flexibility options appear to be valuable for the system tested on medium to large VRE penetrations levels. Investments on DSM options are valuable to supply operational flexibility while investments in short-term storage capacity are mostly used to supply balancing reserves.

A similar LP dispatch and investment model is proposed in (Van Stiphout et al., 2015) to study the value of investing in storage technologies for system capacity adequacy, flexibility and supply of reliability services. Three types of operational reserves are considered and are dimensioned based on the dynamic method proposed in (ENTSO-E, 2013). This multiservice approach allows capturing the system value of storage for VRE integration. Results show how investments in storage units allow increasing the capacity credit of VRE, the need for storage increases as the target for VRE increases. Under the cost assumptions adopted, even in the absence of VRE, storage is competitive to supply high peak capacity.

Other breakthrough LP investments models consider existing capacities, network and interconnections to calculate the optimal mix of VRE under hypothetical technology shocks and evolving market and regulatory conditions (Grothe and Müsgens, 2013; Hirth, 2015; Neuhoff et al., 2008). Those types of brownfield models are useful to evaluate mid-term energy policies towards the decarbonisation of the power sector.

The model presented in the following sections adopts a bottom-up multiservice approach to propose a full LP formulation of the system cost similar to that of (Zerrahn and Schill, 2015a), while considering a dynamic dimensioning of balancing requirements such as that suggested in (ENTSO-E, 2013). The purpose of the model is to integrate the different flexibility requirements associated with high shares of VRE in a long term optimization. The particular contribution of this formulation is the detailed representation of reservoir hydroelectric and EES technologies, refining the representation of their capabilities to supply power and reserve while charging or discharging, as well as its associated cost.

4. MODEL PRESENTATION

The main motivation of the model presented below is to effectively differentiate system requirements to be able to find the most suitable mix of technologies to balance them at least cost. The model is divided in two sections: the first sub-section introduces the long-term CEM taking into account short-term flexibility requirements and operating constraints; the second sub-section adds to the first particular constraints accounting for real time FRR balancing requirements. In this way, comparing the results obtained by each of them would allow assessing the value of flexibility options for reliability issues and would shed light on the error incurred over investments when neglecting balancing issues under increasing shares of VRE.

[3] No network or interconnections were considered.

Element	Set	Description
t, tt	∈ T	Time slice
i	∈ I	Supply side generation technologies
con	∈ CON ⊆ I	Conventional generation technologies
vre	∈ VRE ⊆ I	Renewable energy technologies
ees	∈ EES ⊆ I	Electric energy storage technologies
dsm	∈ DSM	Demand-side technologies
lc	∈ LC ⊆ DSM	Demand side management able to supply load curtailment
ls	∈ LS ⊆ DSM	Demand side management able to supply load shifting

Table 1 – Sets

Parameter	Unit	Description
t_{slice}	[h]	Time slice considered
$C_i^{Capital}$	[€/GW]	Overnight cost of unit *con, res or ees*
crf_i	[€/GW]	Capacity recovery factor of production unit *con*
fc_{con}	[€/GWh$_{th}$]	Average fuel cost of conventional unit *con*
$\mathrm{o\&m^v}_{\mathrm{con}}$	[€/GWh]	Variable operation and maintenance cost of *con* unit
$\mathrm{o\&m^f}_{\mathrm{con}}$	[€/GW]	Annual fixed operation and maintenance cost of *con* unit
C^{CO2}	[€/ton]	CO_2 cost
$\mathrm{ef_{con}}$	[tCO_2/GWh]	Emission factor of conventional unit
$\mathrm{lf_{con}}$	[€/GW]	Load following cost of unit *con*
$\mathrm{o\&m^v}_{vre}$	[€/GWh]	Variable operation and maintenance cost of *VRE* unit
$\mathrm{o\&m^f}_{vre}$	[€/GW]	Annual fixed operation and maintenance cost of *RES* unit
rec_{vre}	[€/GW]	Cost of curtailment of *VRE* unit
$\mathrm{crf}^{S}{}_{vre}$	[€/GW]	Capacity recovery factor of power capacity of *ees* unit
$\mathrm{crf^E}{}_{vre}$	[€/GWh]	Capacity recovery factor of energy capacity of *ees* unit
$\mathrm{o\&m^v}_{ees}$	[€/GWh]	Variable operation and maintenance cost of *ees* unit
$\mathrm{o\&m^f}_{vre}$	[€/GW]	Annualized fixed operation and maintenance cost of *ees* unit
c_{lc}	[€/GW]	Cost of DSM for load curtailment
c_{ls}	[€/GW]	Cost of DSM for load shifting
δ	[%]	Load variation factor
$\mathrm{G^l}_{vre,\mathrm{t}}{}^{\mathrm{base}}$	[GW]	Base year VRE generation of technology VRE on time t
$\mathrm{P}_{vre}{}^{\mathrm{base}}$	[GW]	Base year VRE capacity installed of technology *res*
$\overline{\eta_{con}}$	[GWhth/GWh]	Full load thermal efficiency of unit con
m_{con}	[-]	Part-load efficiency slope of unit con
b_{con}	[GWh$_{th}$]	Fuel consumption intercept
$\overline{\mathrm{p_{con}}}$	[%]	Maximum power of technology *con* as a function of its installed capacity
$\underline{\mathrm{p_{con}}}$	[%]	Minimum power of technology *con* as a function of its installed capacity
$r^{+}{}_{con}$	[%/min]	Ramp-up capability of technology *con*
$r^{-}{}_{con}$	[%/min]	Ramp-down capability of technology *con*
$\overline{\phi_{ees}}$	[h]	Minimum energy-power ratio of technology *ees*
$\underline{\phi_{ees}}$	[h]	Maximum energy-power ratio of technology *ees*
sd_{ees}	[%/h]	Self-discharge of storage unit *ees*
η_{ees}	[%]	Round cycle efficiency of storage unit *ees*
$\overline{e_{ees}}$	[%]	Maximum capacity for energy storage of unit *ees*
$\underline{e_{ees}}$	[%]	Minimum capacity for energy storage of unit *ees*

$\overline{s_{ees}}^{ch}$	[%]	Maximum power demand of storage unit *ees* while charging
$\overline{s_{ees}}^{dch}$	[%]	Maximum power supply of storage unit *ees* while charging
r_{ees}^{ch+}	[%/min]	Ramp-up capability of storage technology *ees* while charging
r_{ees}^{dch+}	[%/min]	Ramp-up capability of storage technology *ees* while discharging
r_{ees}^{ch-}	[%/min]	Ramp-down capability of storage technology *ees* while charging
r_{ees}^{dch-}	[%/min]	Ramp- down capability of storage technology *ees* while discharging
t_{aFRR}	[h]	Minimum required reserve supply duration for aFRR supply
t_{mFRR}	[h]	Minimum required reserve supply duration for mFRR supply
$\overline{dsm_{lc}}$	[%]	Maximum part of load available for load curtailment lc
R	[h]	Number of recovery periods after curtailment
L_{lc}	[h]	Number of consecutive periods a *lc* can be activated
L_{ls}	[h]	Radius of the load shifting window
$\overline{dsm_{ls}}^{up}$	[%]	Maximum part of load available for load upward shifting ls
$\overline{dsm_{ls}}^{do}$	[GW]	Maximum part of load available for load downward shifting ls
$P^{Usize}{}_{con}$	[GW]	Unitary size of conventional unit con
$\varepsilon_{l}^{aFRR_{up}}; \varepsilon_{l}^{aFRR_{do}}$	[%]	Average forecasting RMSE of demand (5% tolerance)
$\varepsilon_{res}^{aFRR_{up}}; \varepsilon_{res}^{aFRR_{do}}$	[%]	Average forecasting RMSE of VRE generation (5% tolerance)
$\varepsilon_{l}^{mFRR_{up}}; \varepsilon_{l}^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
$\varepsilon_{res}^{mFRR_{up}}; \varepsilon_{res}^{mFRR_{do}}$	[%]	Average forecasting RMSE of demand (1% tolerance)
δ^{up}	[%]	Maximum regulation up capability of technology *con*
δ^{do}	[%]	Maximum regulation down capability of technology *con*
$\delta^{up^{sp}}$	[%]	Maximum spinning up capability of technology *con*
$\delta^{do^{sp}}$	[%]	Maximum spinning down capability of technology *con*
θ_{res}	[%]	Yearly share of renewable energy (RE goal)

Table 2 – List of parameters

Variable	Unit	Description
I_{con}	[M€]	Annuitized overnight cost of production unit *con*
MB_{con}	[M€]	Annuitized *con* unit mothballing cost
$F_{con,t}$	[M€]	Total fuel cost of production unit *con*
$O\&M_{con,t}$	[M€]	Operation and maintenance cost of conventional unit *con*
$CO2_{con,t}$	[M€]	CO2 emission cost of conventional unit *con*
$\Delta G_{con,t}$	[M€]	Load following cost of conventional unit *con*
LF_{con}	[M€]	Load following cost of unit *con*
P_i^{ini}	[GW]	Initial installed capacity of technology *i*
P_i^{inv}	[GW]	New capacity investments of technology *i*
P_i^{MB}	[GW]	Mothballed capacity of technology *i*
$G^l{}_{con,t}$	[GW]	Generation level of conventional unit *con*
$FC_{con,t}$	[GWh_{th}]	Linearized part-load fuel consumption of production unit con
$G^+{}_{con,t}$	[GW]	Generation increase of unit *con* in hour *t*
$G^-{}_{con,t}$	[GW]	Generation decrease of unit *con* in hour *t*
I_{vre}	[M€]	Annuitized overnight cost of VRE unit *res*
MB_{vre}	[M€]	Annuitized VRE mothballing cost
$O\&M_{vre,t}$	[M€]	Operation and maintenance cost of RE unit *res*
P_{vre}	[GW]	Total installed power of VRE units
$G^l{}_{vre,t}$	[GW]	Generation level of VRE unit *res*
$REC_{vre,t}$	[M€]	Curtailment cost of VRE unit *res*
$G_{vre,t}^{cu}$	[GW]	Power curtailed of V*RE* unit on hour *t*
I_{ees}	[M€]	Annuitized overnight cost of storage unit *ees*
MB_{ees}	[M€]	Annuitized *ees* mothballing cost
$O\&M_{ees,t}$	[M€]	Operation and maintenance cost of *ees* units
S_{ees}^{ini}	[GW]	Initial installed power capacity of storage technology *ees*
S_{ees}^{inv}	[GW]	New power capacity investments of storage technology *ees*
S_{ees}^{MB}	[GW]	Mothballed power capacity of storage technology *ees*
E_{ees}^{ini}	[GW]	Initial installed energy capacity of storage technology *ees*
E_{ees}^{inv}	[GW]	New power energy investments of storage technology *ees*
E_{ees}^{MB}	[GW]	Mothballed energy capacity of storage technology *ees*
$S_{ees,t}^{ch}$	[GW]	Power demand by storage unit *ees* on time t
$S_{ees,t}^{dch}$	[GW]	Power supply by storage unit *ees* on time t
$S_{ees,t}^{ch+}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while charging

$S_{ees,t}^{ch-}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while charging
$S_{ees,t}^{dch+}$	[GW/h]	Demand increase of storage unit *ees* in hour *t* while discharging
$S_{ees,t}^{dch-}$	[GW/h]	Supply increase of storage unit *ees* in hour *t* while discharging
${E^{l}}_{ees,t}$	[GW]	Storage level of technology ees
$DSM_{lc,t}$	[GW]	Hourly cost of DSM for load curtailment
${DSM^{l}}_{lc,t}$	[GW]	DSM curtailment of load *lc* on time t
$DSM_{ls,t}$	[GW]	Hourly cost of DSM for load Shifting
$DSM_{ls,t}^{up}$	[GW]	DSM shifting up *ls* on time t
$DSM_{ls,t,tt}^{do}$	[GW]	DSM shifting up *ls* on time *tt* from *t*
NL_{t}	[GW]	Net load on time t
LL_{t}	[GW]	Loss of load on time t
$G_{con,t}^{aFRR_{up}}$	[GW]	Contribution of *con* units to $mFRR$ up supply
$G_{con,t}^{aFRR_{do}}$	[GW]	Contribution of *con* unit to $aFRR$ down supply
$G_{con,t}^{mFRR_{up}^{sp}}$	[GW]	Contribution of spinning *con* unit to $mFRR$ up supply
$G_{con,t}^{mFRR_{do}^{sp}}$	[GW]	Contribution of spinning *con* unit to $mFRR$ down supply
$G_{con,t}^{mFRR_{up}^{nsp}}$	[GW]	Contribution of non-spinning *con* unit to $mFRR$ up supply
$S_{ees,t}^{ch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to $aFRR$ up supply while charging
$S_{ees,t}^{ch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to $mFRR$ up supply while charging
$S_{ees,t}^{ch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to $aFRR$ down supply while charging
$S_{ees,t}^{ch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to $mFRR$ down supply while charging
$S_{ees,t}^{dch,aFRR_{up}}$	[GW]	Contribution of *ees* unit to $aFRR$ up supply while discharging
$S_{ees,t}^{dch,mFRR_{up}}$	[GW]	Contribution of *ees* unit to $mFRR$ up supply while discharging
$S_{ees,t}^{dch,aFRR_{do}}$	[GW]	Contribution of *ees* unit to $aFRR$ down supply while discharging
$S_{ees,t}^{dch,mFRR_{do}}$	[GW]	Contribution of *ees* unit to $mFRR$ down supply while discharging
$Q_{t}^{aFRR_{up}}$	[GW]	Total *aFRR* up required on time *t*
$Q_{t}^{aFRR_{do}}$	[GW]	Total *aFRR* down required on time *t*
$Q_{t}^{mFRR_{up}}$	[GW]	Total *mFRR* up required on time *t*
$Q_{t}^{mFRR_{do}}$	[GW]	Total *mFRR* down required on time *t*

Table 3 – List of variables

4.1. Objective function

The model proposed adopts an LP formulation for the investment and dispatch problem. CAPEX[4] and OPEX[5] are considered together with ramping cost, efficiency penalties for partial load operation, wear and tear cost of units, CO_2 emission cost and VRE curtailment cost. The objective function presented in (1) embodies the total systems cost of the power system considering aggregated agents with perfect foresight. This hypothesis is equivalent than assuming a market with perfect competition and no information asymmetries, transaction cost and other issues.

Total system cost is therefore composed by the sum of annuitized costs of power generation and storage capacity investments and mothballing, cost of enabling DSM's capabilities and running cost incurred for using these capacities along the considered period.

In order to capture the impact of flexibility needs while capacity planning, equation (1) is minimized over a full year using hourly time slices. Investment and dispatch decisions are computed simultaneously and in an endogenous manner. Power demand is considered as price-inelastic but can be deferred or curtailed subject to the technical restrictions of DSM capabilities modeled.

$$\begin{aligned} Y = & \sum_{con}(I_{con} + MB_{con}) + \sum_{con}\sum_{t}\left(F_{con,t} + O\&M_{con,t} + CO2_{con,t} + \Delta G_{con,t}\right) \\ & + \sum_{vre}(I_{vre} + MB_{vre}) + \sum_{res}\sum_{t}\left(O\&M_{vre,t} + VREC_{vre,t}\right) \\ & + \sum_{ees}(I_{ees} + MB_{ees}) + \sum_{ees}\sum_{t} O\&M_{ees,t} \\ & + \sum_{DSM} I_{DSM} + \sum_{lc}\sum_{t} O\&M_{lc,t}^{DSM} + \sum_{ls}\sum_{t} O\&M_{ls,t}^{DSM} \end{aligned} \tag{1}$$

4.2. Cost definitions

Investment cost is accounted by using capacity recovery factors[6] (crf), also called equivalent annual cost (EAC). So, technology specific crf_i are inputs of the model. Equation (2) shows the way investment cost is calculated for conventional and RE technologies.

$$I_i = crf_i \, P_i^{inv} \qquad \forall\, i \tag{2}$$

$$crf_i = \frac{WACC_i \, C_i^{Capital}}{1-\left(\frac{1}{1+WACC_i}\right)^{a_i^{life}}} \qquad \forall\, i \tag{3}$$

Regarding EES investments, power and energy capacity are considered separately. These two dimensions of energy storage units are presented in equation (4), which comprises independent *crf* for each. Equation (5) relates these two storage dimensions using a minimum and maximum technology related storage autonomy factor. This procedure allows the model to endogenously co-optimize EES investments into power capacity and energy capacity, taking into account it's particular restrictions and cost, hence the system value of every EES technology considered in the investment portfolio to supply flexibility.

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[4] Capital expenditures

[5] Operational expenditures

[6] Estimated using overnight cost, lifespan and weighted average cost of capital (WACC).

$$I_{ees} = crf^{S}{}_{ees}\, S_{ees}^{inv} + crf^{E}{}_{ees} E_{ees}^{inv} \qquad \forall\ ees \tag{4}$$

$$S_{ees}\underline{\phi_{ees}} \leq E_{ees} \leq S_{ees}\overline{\phi_{ees}} \qquad \forall\ ees \tag{5}$$

Similarly, enabling DSM capabilities involve investing on adequate infrastructure according to (Bradley et al., 2013) (Strbac, 2008), namely on the energy management system (EMS) or smart metering system as outlined in (Department for Energy and Climate Change and Ofgem, 2014). The elements considered on the overnight cost for enabling DSM capabilities are supposed to be the same for both load curtailment and load shifting services; so, once they are accounted they enable both tasks. The EMS cost is mainly user specific (e.i. the meter, displays, communication system and installation), but there are also important shared cost having place (i.e. the centralized Data and Communications Company (DCC) and other IT's systems costs). For the sake of simplicity, investment costs are represented in the model as aggregated cost for having a resource available but which availability is intrinsically constrained by operational limits at the consumer level and also by the grid. This is represented on equation (6), where DSM is the maximum power the EMS can handle.

$$I_{DSM} = crf_{DSM}\ DSM \qquad \forall\ ees \tag{6}$$

Running costs of conventional units are divided into fuel cost, O&M cost, CO_2 cost and load following cost. The cost of mothballing existing capacity was introduced in a simplified way assuming it as 5% of the overnight cost for every technology under consideration.

Equation (8) accounts for the fuel cost of conventional units where $Fuel_{con,t}$ is the instantaneous fuel consumed corrected by the part-load efficiency, fc_{con} is the average cost of fuel consumed by unit "*con*". Equation (9) accounts for fixed and variable operational and maintenance cost. CO_2 cost deals with fuel specific emission factors and part-load efficiencies as expressed in equation (10). Load following costs are defined in equation (11) as proportional to the absolute value of the difference of the synchronized power of two consecutives periods.

Variable and fixed O&M cost of EES units are represented in equation (13). Storage units can be charging or discharging at the same time if needed. Equation (13) accounts for the associated cost of both uses independently. VRE curtailment is also included as a source of flexibility, and even if there is no technical cost associated with curtailing renewables, equation (14) accounts for a possible VRE curtailment cost if any.

$$MB_i = 0.05\, crf_i P_i^{MB} \qquad \forall\ i \tag{7}$$

$$F_{con,t} = Fuel_{con,t}\, fc_{con} \qquad \forall\ con \tag{8}$$

$$O\&M_{i,t} = \mathrm{o\&m^{v}}_i\ G^{l}{}_{con,t} + \mathrm{o\&m^{f}}_i\, P_i \qquad \forall\ i \tag{9}$$

$$CO2_{con,t} = \mathrm{C}^{CO2}\ \mathrm{ef}_{con}\, Fuel_{con,t} \qquad \forall\ con \tag{10}$$

$$\Delta G_{con,t} = \left| G^{l}{}_{con,t} - G^{l}{}_{con,t-1} \right| \mathrm{lf_{con}} \qquad \forall\ con \tag{11}$$

$$MB_{ees} = 0.05\left(crf^{E}{}_{ees}\ S_{ees}^{MB} + crf^{E}{}_{ees} E_{ees}^{MB}\right) \qquad \forall\, ees \tag{12}$$

$$O\&M_{ees,t} = \mathrm{o\&m^{v}}_{ees}\left(S_{ees,t}^{ch} + S_{ees,t}^{dch}\right) + o\&m^{f}{}_{ees}\, S_{ees} \qquad \forall\, ees, t \tag{13}$$

$$REC_{vre,t} = G_{vre,t}^{cu}\ \mathrm{rec}_{vre} \qquad \forall\ vre \tag{14}$$

The fuel consumption due to part-load generation is linearly approximated as presented on equation (15). Equations (16) and (17) are computed from technical data of generation units and uses exogenous parameters of the model. Replacing and Rearranging terms into equation (15) results on equation (18) which articulates the hourly fuel consumption as a function of synchronized power and installed capacity.

$$Fuel_{con,t} = G^{l}{}_{con,t}\, m_{con} + b_{con} \qquad \forall\ con \tag{15}$$

$$m_{con} = \frac{\Delta FC_{con}^{max}}{\Delta P_{con}^{max}} = \frac{\frac{P_{con}\,\overline{p_{con}}}{\overline{\eta_{con}}} - \frac{P_{con}\,\underline{p_{con}}}{\underline{\eta_{con}}}}{P_{con}\,\overline{p_{con}} - P_{con}\,\underline{p_{con}}} = \frac{\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - \frac{\underline{p_{con}}}{\underline{\eta_{con}}}}{\left(\overline{p_{con}} - \underline{p_{con}}\right)} \tag{16}$$

$$b_{con} = \left(\frac{\overline{p_{con}}}{\overline{\eta_{con}}} - m_{con}\,\overline{p_{con}}\right) P_{con} \tag{17}$$

$$Fuel_{con,t} = \left(G^{l}{}_{con,t} - \overline{p_{con}}\,P_{con}\right) m_{con} + P_{con}\frac{\overline{p_{con}}}{\overline{\eta_{con}}} \qquad \forall\ con \tag{18}$$

Demand side management services, namely load curtailment (*lc*) and load shifting (*ls*) have particular O&M cost dealing with activation cost, EMS maintenance, DCC operational expenditures among others. Maximum capacity, activation cost and recovery time are inputs of the model. Equations (19) and (20) account for the operational cost of activating each of these services.

$$O\&M_{lc,t}^{DSM} = DSM^{l}{}_{lc,t}\ o\&m_{lc} \qquad \forall\ t, lc \tag{19}$$

$$O\&M_{ls,t}^{DSM} = DSM_{ls,t}^{up}\ \mathrm{o\&m}_{ls} \qquad \forall\ t, ls \tag{20}$$

4.3. Defining RE generation, net load and energy market balance

Investments in VRE capacity are endogenously computed on the model. As presented on equation (21), the hourly production $G^{l}{}_{res,t}$ is obtained by resizing the unitary base year hourly generation by the net capacity added. Therefore, it is convenient that the base year adopted to represent VRE generation comes from a statistically representative year obtained from historical data.

$$G^{l}{}_{vre,t} = \frac{\mathrm{G^{l}}{}_{vre,\mathrm{t}}{}^{\mathrm{base}}}{\mathrm{P}_{vre}{}^{\mathrm{base}}}\ \left(P_{vre}^{ini} + P_{vre}^{inv} - P_{vre}^{MB}\right) \qquad \forall\ vre, t \tag{21}$$

Consequently, the net load (NL_t) is defined as the result of applying a variation coefficient (δ<0 demand contraction, δ>0 demand expansion) to the hourly base year load and withdrawing from it the net RE generation, assumed as fatal supply.

$$NL_t = \mathrm{L_t^{base}}\,(1+\delta) - \sum_{vre}\left(G_{vre,t}^{l} - G_{vre,t}^{cu}\right) \qquad \forall\ t \tag{22}$$

Therefore, the balancing equation of the energy market is formulated as:

$$\begin{aligned} NL_t = &\sum_{con} G^{l}{}_{con,t} + \sum_{ees}\left(S_{ees,t}^{dch} - S_{ees,t}^{ch}\right) \\ &+ \sum_{lc} DSM^{l}{}_{lc,t} + \sum_{ls}\sum_{tt=t-L_{ls}}^{tt=t+L_{ls}} DSM_{ls,tt,t}^{do} - \sum_{ls} DSM_{ls,t}^{up} \end{aligned} \qquad \forall\ t \tag{23}$$

4.4. Operational constraints of conventional units

Power capacity can be given either by initial conditions on the case of a brownfield scenario or by investing in additional capacity. In the case that there is excess power capacity, there is also possible to mothball part of this capacity if this is proven economically optimal. Equation (24) computes investments and mothballing to define the net capacity of every technology on the system.

$$P_{con} = P_{con}^{ini} + P_{con}^{inv} - P_{con}^{MB} \qquad \forall\ con \tag{24}$$

Equation (25) defines the power supply limits of conventional units as a function of total available capacity.

$$\underline{p_{\text{con}}}P_{con} \leq \ G^{l}{}_{con,t} \leq \ \overline{p_{\text{con}}}P_{con} \qquad \forall\, t, con \tag{25}$$

The intertemporal variation of power dispatch for conventional units is defined in equation (26). Ramping up ($G^{+}{}_{con,t}$) and down ($G^{-}{}_{con,t}$) restrictions of conventional units are given by equations (27) and (28) where parameters $r^{+}{}_{con}$ and $r^{-}{}_{con}$ are the maximum ramp-up and down per minute of conventional units respectively.

$$-G^{-}{}_{con,t} \ \leq G^{l}{}_{con,t} - \ G^{l}{}_{con,t-1} \leq \ G^{+}_{con,t} \qquad \forall\, t, con \quad \textit{(w/o reserve requirements)} \tag{26}$$

$$G^{+}{}_{con,t} \leq r^{+}{}_{con}\ P_{con}\ 60\ t_{slice} \qquad \forall\, t, con \tag{27}$$

$$G^{-}{}_{con,t} \leq r^{-}{}_{con}\ P_{con}\ 60\ t_{slice} \qquad \forall\, t, con \tag{28}$$

The constraints controlling the power generation level of reservoir hydro plants depend on the seasonal inflows and water availability. The existing historic meteorological data available for water inflows is given using a weekly time slice, then, the control for reservoir hydro is formulated using this time step and assuming that all the inflows, corresponding to the entire inflow of the week, occurs at the first hour of the week under consideration. The energy conservation equations for the first and succeeding weeks are exposed on equations (29) and (30) respectively. The average water level on the first week ($\mathrm{H2O}_{\mathrm{w}}^{\mathrm{avg}}$) is normalized by the installed capacity ($\overline{\mathrm{P}_{\mathrm{hydro}}}$), which allows to represent water levels as a function of investments on hydro capacity. Inflows and water consumption used for electricity generation are similarly normalized. Equation (31) controls the minimum and maximum water levels.

$$H2O_{w}^{l} = \frac{H2O_{w}^{avg}}{\overline{P_{hydro}}}\, P_{hydro} + \frac{H2O_{w}^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t\,\in\,w} Fuel_{hydro,t} \qquad if \quad w = 1 \tag{29}$$

$$H2O_{w}^{l} - H2O_{w-1}^{l} = \frac{H2O_{w}^{inflow}}{\overline{P_{hydro}}} P_{hydro} - \sum_{t\,\in\,w} Fuel_{hydro,t} \qquad if \quad w > 1 \tag{30}$$

$$\underline{H2O} < H2O_{w}^{l} \leq \overline{H2O} \qquad \forall \quad w \tag{31}$$

4.5. Operational constraints of storage units

EES units are one of the main flexibility sources considered. Charging and discharging modes are modeled independently for every technology. This would allow simulating different storage capabilities, for example: deploying fast response from Li-Ion batteries for balancing purposes while charging a bulk energy storage unit.

Equations (32) and (33) are the EES equivalent to equation (24). It gives the net capacity of energy and power of EES units available in the system. Equation (34) represents the energy conservation equation for EES technologies. It shows the dynamics of EES units considering a technology based self-discharge term (sd_{ees}) and accounts for energy losses using round-cycle efficiency. Equation (35) restricts the level of energy stored as a function of available capacity. Equation (36) - (37) are equivalent to equation (25) applied to storage units when assuming charging and discharging modes independently, furthermore it restricts the net flexibility supply from storage to fully charge and discharge the same unit at the same time.

$$E_{ees} = \ E_{ees}^{ini} + E_{ees}^{ini} - \ E_{ees}^{MB} \tag{32}$$

$$S_{ees} = S_{ees}^{ini} + S_{ees}^{ini} - S_{ees}^{MB} \quad (33)$$

$$E^{l}{}_{ees,t} = E^{l}{}_{ees,t-1}\,(1 - sd_{ees}) + \left(\sqrt{\eta_{ees}}\ S_{ees,t-1}^{ch,} - \frac{S_{ees,t-1}^{dch}}{\sqrt{\eta_{ees}}}\right) t_{slice} \qquad \forall\, t, ees \quad (34)$$

$$\underline{e_{ees}}\, E_{ees} \leq\ E^{l}{}_{ees,t} \leq \overline{e_{ees}}\, E_{ees} \qquad \forall\, t, ees \quad (35)$$

$$S_{ees,t}^{ch} \leq\ S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\, t, ees \quad (36)$$

$$S_{ees,t}^{dch} \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\, t, ees \quad (37)$$

Ramping capabilities of storage units are also represented. Equations (38) and (39) present the ramping limits of power supply and demand of EES units while charging and discharging following the same reasoning presented in equation (26) for conventional units. Equations (40) - (43) restricts the ramping up/down for charging and discharging modes respectively.

$$-S_{ees,t}^{ch-} \leq\ S_{ees,t}^{ch} - S_{ees,t-1}^{ch} \leq\ S_{ees,t}^{ch+} \qquad \forall\, t, ees \quad (38)$$

$$-S_{ees,t}^{dch-} \leq\ S_{ees,t}^{dch} - S_{ees,t-1}^{dch} \leq S_{ees,t}^{dch+} \qquad \forall\, t, ees \quad (39)$$

$$S_{ees,t}^{ch+} =\ r_{ees}^{ch+}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \quad (40)$$

$$S_{ees,t}^{dch+} =\ r_{ees}^{dch+}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \quad (41)$$

$$S_{ees,t}^{ch-} =\ r_{ees}^{ch-}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \quad (42)$$

$$S_{ees,t}^{dch-} =\ r_{ees}^{dch-}\, S_{ees}\, 60\, t_{slice} \qquad \forall\, t, ees \quad (43)$$

Unlike conventional generation technologies, for EES units to supply power they should have enough energy level stored in order to be eligible for commitment on discharging mode. Inversely, enough capacity for storing energy should exist at any time for an EES unit to be able to take power from the grid (charging mode). Equations (44) and (45) render the later.

$$\left(S_{ees,t}^{ch}\, t_{slice}\right)\sqrt{\eta_{ees}} \leq\ E_{ees} - E^{l}{}_{ees,t-1} \qquad \forall\, t, ees \quad (44)$$

$$\frac{S_{ees,t}^{dch}\, t_{slice}}{\sqrt{\eta_{ees}}} \leq\ E^{l}{}_{ees,t-1} \qquad \forall\, t, ees \quad (45)$$

4.6. Operational constraints of DSM units

Load curtailment and load shifting are the two types of DSM services considered in the model. The load curtailment service is modeled as a scheduled prompt decrease in demand with financial compensations. No rebound effect is included. The curtailed capacity at any hour can't be higher than the fraction of load considered for supplying this service ($\overline{dsm}_{lc}$). The state equation presented in equation (47) links the recovery time (*R*) restrictions with the maximum consecutive periods (L_{lc}) load can be curtailed.

$$0 \leq DSM^{l}{}_{lc,t} \leq\ \overline{dsm}_{lc}\ \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\,(1+\delta) \qquad \forall\, t, lc \quad (46)$$

$$\sum_{tt=0}^{R-1} DSM^{l}{}_{lc,t+tt} \leq \overline{dsm}_{lc}\ \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\,(1+\delta)\, L_{lc} \qquad \forall\, t, lc \quad (47)$$

At the same time, load can also be shifted within a certain time window. This implies that a shifted load on one direction at time t should be compensated by a similar size shift on the opposite direction over the shifting period ($t - L_{ls}$, $t + L_{ls}$). Similarly, every shift is constrained according the maximum fraction of load assumed to supply this service ($\overline{dsm_{ls}}^{up}$; $\overline{dsm_{ls}}^{do}$). Equations (49) and (50) introduce these restrictions adopting the formulation presented in (Zerrahn and Schill, 2015b), in this way shifts can be done only in one direction at time t.

$$DSM_{ls,t}^{up} = \sum_{tt=t-L_{ls}}^{t\,+\,L_{ls}} DSM_{ls,t,tt}^{do} \qquad \forall\, t, ls \tag{48}$$

$$DSM_{ls,t}^{up} \leq \overline{dsm_{ls}}^{up}\, \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\, (1+\delta) \qquad \forall\, t, ls \tag{49}$$

$$DSM_{ls,t}^{up} + \sum_{tt=t-L_{ls}}^{tt=t\,+\,L_{ls}} DSM_{ls,t,tt}^{do} \leq max\left(\overline{dsm_{ls}}^{up} ; \overline{dsm_{ls}}^{do}\right) \mathrm{L}_{\mathrm{t}}^{\mathrm{base}}\, (1+\delta) \qquad \forall\, t, ls \tag{50}$$

$$DSM^{l}{}_{lc,t} + DSM_{ls,t}^{up} + \sum_{tt=t-L_{ls}}^{tt=t\,+\,L_{ls}} DSM_{ls,t,tt}^{do} \leq DSM \qquad \forall\, t, lc, ls \tag{51}$$

4.7. Renewable energy goal

The RE penetration level is presented in equation (52). The model defines the RE share (θ_{res}) goal as the total energy produced by renewables over the total energy produced on the system. Hydroelectric generation is considered as a renewable resource and then accounted consequently. In this way, energy policies based on renewable energy agendas can be easily studied. It simulates a goal related to the volume of VRE produced over the considered period. Even if this simulate a requirement for VRE penetration, endogenous investment on VRE technologies are computed to at least satisfy this condition. Note that setting θ_{res} to zero has the same effect completely relaxing this constraint[7].

Additional goals assuming exogenous RE installed capacity can be also studied on the model.

$$\sum_{t}\sum_{con\neq hydro} G_{con,t}^{l} \leq \left(\frac{1-\theta_{res}}{\theta_{res}}\right)\left[\sum_{t}\sum_{vre}\left(G^{l}{}_{vre,t} - G_{vre,t}^{cu}\right) + \sum_{t}\sum_{hydro} G^{l}{}_{hydro,t}\right] \tag{52}$$

4.8. Balancing reserve requirements

4.8.1. Reserve sizing

The ENTSO-E defines three types of operating reserves (ENTSO-E, 2013): Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserves (RR). The FCR are the first containment reserve after an incident. They are automatically activated within seconds. The FRR are considered a secondary containment and can be automatically (*aFRR*) or manually activated (*mFRR*). They are activated based on system state information, either by an imbalance in the schedule or to recover FCR capacity. Finally, the RR are the third form of containment reserve and their function is to replace already FCR capacity deployed in order to restore system reliability for facing a new incident.

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[7] This is the case where no energy policy distortion is considered into the system.

As far as the objective of the model is to quantify the impact of flexibility needs while capacity planning and no smaller than hourly time slice are implemented, only frequency restoration reserve (FRR) is considered. ENTSO-E code requires a probabilistic sizing of FRR reserves. The conventional methodology implemented by TSOs is to apply a recursive convolution method based on imbalance sources using predefined system reliability level.

Reserve requirements considered on the model concern only not-event situations. The formulation to account for it is based on the probability of system imbalances due to forecast errors of VRE generation as detailed in (De Vos et al., 2013; Van Stiphout et al., 2014), and demand variability. No unit outages are considered. Equations (53) - (56) present the reserve sizing formulas implemented in the model. The model uses a probabilistic approach for FRR sizing regarding load deviations and VRE forecast errors.

Regarding the VRE generation, system imbalances can be decomposed on prediction error due to forecast inaccuracies and fluctuations inside the time interval considered due to resource variability. For the purpose of capacity planning, the parameter $\varepsilon_l^{aFRR_{up/do}}$ represents the uncertainties of load and $\varepsilon_{res}^{aFRR_{up/do}}$ accounts for forecast errors driven by VRE generation. Parameters are set using historical data controlling for reliability levels of 95% and 99% for *aFRR* and *mFRR* respectively.

$$Q_t^{aFRR_{up}} = \varepsilon_l^{aFRR_{up}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{up}} \, P_{vre} \qquad \forall\, t \tag{53}$$

$$Q_t^{aFRR_{do}} = \varepsilon_l^{aFRR_{do}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{aFRR_{do}} \, P_{vre} \qquad \forall\, t \tag{54}$$

$$Q_t^{mFRR_{up}} = \varepsilon_l^{mFRR_{up}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{up}} \, P_{vre} \qquad \forall\, t \tag{55}$$

$$Q_t^{mFRR_{do}} = \varepsilon_l^{mFRR_{do}} \, L_t^{base} \, (1+\delta) + \sum_{vre} \varepsilon_{vre}^{mFRR_{do}} \, P_{vre} \qquad \forall\, t \tag{56}$$

4.8.2. Accounting for reserve scheduling

Reserve requirements should be supplied by available units capable of copping with particular technical specifications. The present formulation only considers conventional generation and storage units8 to supply reserve. The balancing equations for every type of reserve are presented on equations (57) - (60).

$$\sum_{con} G_{con,t}^{aFRR_{up}} + \sum_{ees} \left(S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{dch,aFRR_{up}} \right) = Q_t^{aFRR_{up}} \qquad \forall\, t \tag{57}$$

$$\sum_{con} G_{con,t}^{aFRR_{do}} + \sum_{ees} \left(S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{dch,aFRR_{do}} \right) = Q_t^{aFRR_{do}} \qquad \forall\, t \tag{58}$$

$$\sum_{con} \left(G_{con,t}^{mFRR_{up}^{sp}} + G_{con,t}^{mFRR_{up}^{nsp}} \right) + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \right) = Q_t^{mFRR_{up}} \qquad \forall\, t \tag{59}$$

$$\sum_{con} G_{con,t}^{mFRR_{do}^{sp}} + \sum_{ees} \left(S_{ees,t}^{ch,mFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \right) = Q_t^{mFRR_{do}} \qquad \forall\, t \tag{60}$$

[8] Even if EES technologies can supply operating reserve, some power markets do not allow EES to supply balancing reserve due to regulatory issues.

In this manner, synchronized power capacity of every unit is split into power generation to satisfy net load, but also reserved capacity to contribute to balancing the system against expected real time fluctuations related to the VRE generation at time t.

Regarding conventional units, five types of power reserve supply comes up when including the two directions of automatic and manual reserves ($G_{con,t}^{aFRR_{up}}$, $G_{con,t}^{aFRR_{do}}$, $G_{con,t}^{mFRR_{up}^{sp}}$, $G_{con,t}^{mFRR_{do}^{sp}}$, $G_{con,t}^{mFRR_{up}^{nsp}}$). Upward reserve supply is assumed to be on hold capacity enabling the system to accommodate a sudden increase of net load, thus it deducts from the power capacity committed to the energy market. Downward reserve capacity is the opposite, it enables the system to defy for an unattended decrease of net load, thus, downward reserve adds to the online capacity. Spinning (sp) units can supply automatic and manual reserve, non-spinning (*nsp*) ones can only supply upward manual reserve. The formulation implemented in the model allows units to bid upward and downward reserves simultaneously but in a restrictive way.

Based on the formulation proposed by (Van Stiphout et al., 2014), equations (61) and (62) restricts the automatic reserve supply of conventional units as a function of their generation level on time t given its automatic regulation capabilities *(δ^{up} , δ^{do}).*

Equations (63)-(64) accounts for manual reserve constraints preventing for contracting capacity margins already used for automatic reserve supply. Reserve supply coming from non-spinning units ($G_{con,t}^{mFRR_{up}^{nsp}}$) is only possible for spare capacity of technologies with fast start capabilities. Equation (67) describes the capacity margins of these non-synchronized units. Therefore, when accounting for reserve requirements, equation (25) should correct for the fraction of reserved capacity, as presented in equations (68) and (69). The ramping constraint is also modified to limit ramping capabilities regarding the capacity reserved on equations (70) and (71).

$$G_{con,t}^{aFRR_{up}} \le \delta^{up}\, G^{l}{}_{con,t} \qquad \forall\, con, t \qquad (61)$$

$$G_{con,t}^{aFRR_{do}} \le \delta^{do}\, G^{l}{}_{con,t} \qquad \forall\, con, t \qquad (62)$$

$$G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \le \delta^{up^{sp}}\, G^{l}{}_{con,t} \qquad \forall\, con, t \qquad (63)$$

$$G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \le \delta^{up^{sp}}\, G^{l}{}_{con,t} \qquad \forall\, con, t \qquad (64)$$

$$G_{con,t}^{aFRR_{up,do}} \le \overline{\mathrm{p}_{\mathrm{con}}} P_{con} \qquad \forall\, con, t \qquad (65)$$

$$G_{con,t}^{mFRR_{up,\ do}^{sp}} \le \overline{\mathrm{p}_{\mathrm{con}}} P_{con} \qquad \forall\, con, t \qquad (66)$$

$$P_{con}\ \underline{\mathrm{p}}_{\mathrm{con}} \le G_{con,t}^{mFRR_{up}^{nsp}} \le \left(P_{con} - G_{con,t}^{l}\right) \qquad \forall\, con, t \qquad (67)$$

$$G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \le \overline{\mathrm{p}_{\mathrm{con}}} P_{con} \qquad \forall\, con, t \qquad (68)$$

$$\underline{\mathrm{p}_{\mathrm{con}}} P_{con} \le G^{l}{}_{con,t} - G_{con,t}^{aFRR_{up}} - G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\, con, t \qquad (69)$$

$$\Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{do}} + G_{con,t}^{mFRR_{do}^{sp}} \le G_{con,t}^{+} \qquad \forall\, con, t \qquad (70)$$

$$-G^{-}{}_{con,t} \le \Delta G^{l}{}_{con,t} + G_{con,t}^{aFRR_{up}} + G_{con,t}^{mFRR_{up}^{sp}} \qquad \forall\, con, t \qquad (71)$$

Similarly than for conventional units, equations (72) - (75) complete equations (36) and (37) to include reserve supply restriction. Contrary to generation units, EES units on charging instants are represented as loads, thus, upward reserve supply while charging means to charge slightly above the optimal level to be able to decrease system load when needed for balancing the system, which limits are expressed in (72). Downward reserve supply while charging is the opposite, charging below the optimal level to be able to increase load when needed, expressed in (73). Equations (74) and (75) represent similar constraints for EES units while discharging.

$$S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\ \overline{s_{ees}}^{ch} - S_{ees,t}^{ch} \qquad \forall\ t, ees \qquad (72)$$

$$S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \leq S_{ees,t}^{ch} \qquad \forall\ t, ees \qquad (73)$$

$$S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{dch,mFRR_{up}} \leq S_{ees,t}^{dch} \qquad \forall\ t, ees \qquad (74)$$

$$S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees}\ \overline{s_{ees}}^{dch} - S_{ees,t}^{dch} \qquad \forall\ t, ees \qquad (75)$$

Equations (76) and (77) correct minimum charging and discharging level as previously exposed in (36) and (37) to account for reserve supply of EES units. Similarly than for conventional units, ramping constraints of EES units are also furtherly constrained by reserved capacity. Therefore, equations (78)-(81) replace equations (38)-(39).

$$S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees}\ \overline{s_{ees}}^{dch} \qquad \forall\ t, ees \qquad (76)$$

$$S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees}\ \overline{s_{ees}}^{ch} \qquad \forall\ t, ees \qquad (77)$$

$$\Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \leq S_{ees,t}^{ch+} \qquad \forall\ t, ees \qquad (78)$$

$$-S_{ees,t}^{ch-} \leq \Delta S_{ees,t}^{ch} + S_{ees,t}^{ch,aFRR_{do}} + S_{ees,t}^{ch,mFRR_{do}} \qquad \forall\ t, ees \qquad (79)$$

$$\Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{do}} + S_{ees,t}^{dch,mFRR_{do}} \leq S_{ees,t}^{dch+} \qquad \forall\ t, ees \qquad (80)$$

$$-S_{ees,t}^{dch-} \leq \Delta S_{ees,t}^{dch} + S_{ees,t}^{dch,aFRR_{up}} + S_{ees,t}^{ch,mFRR_{up}} \qquad \forall\ t, ees \qquad (81)$$

Finally, adequate levels of energy should be guaranteed to supply energy and reserve simultaneously. Equations (82) and (83) control sufficient available level on storage reservoirs for units to participate on both energy and reserve markets. t_{aFRR} and t_{mFRR} are the required time durations for reserve supply stablished by the TSO.

$$\left[S_{ees,t}^{ch}\ t_{slice} + S_{ees,t}^{ch,aFRR_{do}}\ t_{aFRR} + S_{ees,t}^{ch,mFRR_{do}}\ t_{mFRR}\right]\sqrt{\eta_{ees}} \leq E_{ees} - E^{l}{}_{ees,t} \qquad \forall\ t, ees \qquad (82)$$

$$\left[S_{ees,t}^{dch}\ t_{slice} + S_{ees,t}^{dch,aFRR_{up}}\ t_{aFRR} + S_{ees,t}^{dch,mFRR_{up}}\ t_{mFRR}\right]\frac{1}{\sqrt{\eta_{ees}}} \leq E^{l}{}_{ees,t} \qquad \forall\ t, ees \qquad (83)$$

5. CASE STUDY

5.1. Data

A case study for long-term capacity planning is presented below. The system has been loosely calibrated to the French power system. Time dependent parameters such as demand, water inflows of reservoirs, VRE generation profiles and day-ahead forecast errors have been obtained from the public database of the French TSO for 2014[9]. Cost performance parameters are based on publicly available literature. Capital cost and running cost of generation technologies were taken from (IEA/NEA, 2010) - (Schröder et al., 2013), technical parameters were taken from (Schröder et al., 2013) - (Kumar et al., 2012). A fixed interest rate of 7% was presumed across all the technologies on the investment portfolio. A baseline cost of CO2 of 20€/ton was also supposed based on discussions with experts.

Technology	*Overnight cost*	Lifespam	crf_i	$\mathrm{o\&m^f}$	$\mathrm{o\&m^v}$	Fuel cost	CO_2 content	Load following cost
	[€/KW]	*[yr]*	*[€/KW yr]*	*[€/KW yr]*	*[€/MWh]*	*[€/MWh]*	*[t CO_2/MWh]*	*[€/MW]*
Nuclear	3217	40	241	82,1	12,3	7,8	-	55
Lignite	1601	30	129	30	6, 2	15,0	0,374	30
Hard coal	1390	30	112	30	6, 2	23,5	0,340	30
CCGT	854	30	68,8	20	2,8	54,2	0,241	20
CT	459	30	37	15	6,1	81,3	0,328	10
OCGT	757	30	61	15	6,0	54,2	0,241	15
Reservoir hydro	2953	50	214	0	1,4	0	-	8
Wind	2390	25	205	26,7	22,1	-	-	-
PV	3561	25	306	27,2	22.5	-	-	-

Table 4. Cost assumptions of generation technologies. Sources: (IEA/NEA, 2010) - (Schröder et al., 2013)

Technology	Efficiency	Pmin	Pmax	Ramp up	Ramp down	δ^{up}	δ^{down}	δ^{sp}	m_{con}
	[%]	*[%P/min]*	*[%P/min]*	*[%P/min]*	*[%P/min]*	*[%P/min]*	*[%P/min]*	*[%P/min]*	-
Nuclear	*32%*	*45%*	*100%*	*5%*	*5%*	*2,5%*	*2,5%*	*75%*	*2,30*
Lignite	*47%*	*40%*	*100%*	*4%*	*4%*	*2,0%*	*2,0%*	*60%*	*0,27*
Hard coal	*47%*	*38%*	*100%*	*4%*	*6%*	*2,0%*	*3,0%*	*60%*	*1,95*
CCGT	*62%*	*33%*	*100%*	*8%*	*8%*	*4,0%*	*4,0%*	*120%*	*1,51*
CT	*34%*	*0%*	*100%*	*25%*	*25%*	*12,5%*	*12,5%*	*375%*	*2,47*
OCGT	*39%*	*20%*	*100%*	*10%*	*10%*	*5,0%*	*5,0%*	*150%*	*1,97*
Reservoir hydro	90%	0%	100%	20%	20%	10,0%	10,0%	300%	1,11

Table 5. Technical parameters of generation units. Sources: (Schröder et al., 2013) - (Kumar et al., 2012)

A portfolio of five bulk EES technologies was selected assuming the state of maturity expected by 2020[10] (Kintner-Meyer et al., 2012). Among the technologies considered there are: Li-ion batteries (Li-ion), Sodium-sulfur (NaS) batteries, Vanadium redox flow batteries (VRFB), pumped-hydro storage (PHS) and adiabatic compressed air energy storage (adiabatic - CAES). Assumed cost are based on (Kintner-Meyer et al., 2012) taking the 2020 projections. Technical parameters were taken from (Zerrahn and Schill, 2015a) and (Schröder et al., 2013).

[9] Public data from the website of the french power system operator: www.rte-france.com/en/eco2mix/eco2mix

[10] Only expected commercial technologies were considered.

Technology	CAPEX -2020								OPEX -2020	
	Battery	System	PCS	BOP	Life-spam	WACC	crf^E	crf^S	$\mathrm{o\&m^v}$	$\mathrm{o\&m^f}$
	[$/KWh]	*[$/KW]*	*[€/KWh]*	*[€/KWh]*	*[yr]*	*[%]*	*[€/KWh yr]*	*[€/kW yr]*	*[€/KWh]*	*[€/KW]*
Li-ion	510	-	150	50	10	3%	59,8	23,4	0,7	5
NaS	290	-	150	50	10	3%	34,0	23,4	0,7	5
VRFB	131	775	150	50	25	3%	7,5	56,0	1	2
PHS	10	1890	-	-	50	3%	0,4	73,5	0	7
ACAES	3	850	-	-	30	3%	0,2	43,4	0	7

Table 6. Cost assumptions of EES technologies. Source: "National Assessment of Energy Storage for Grid Balancing and Arbitrage" (Kintner-Meyer et al., 2012).

Technology	EES_Emin *[%]*	Chg_ramp *[% S/min]*	Dchg_ramp *[% S/min]*	Auth_min *[h]*	Auth_max *[h]*	Self_dch *[% E/h]*
Li-ion	20%	1500	1500	1	12	0,0014%
NaS	10%	1500	1500	5	10	0,0417%
VRFB	10%	3	3	2	24	0,0052%
PHS	10%	0.67	0.67	5	36	0,0521%
ACAES	15%	0.15	0.15	2	24	0,0313%

Table 7. Technical parameters of EES units. Sources: (Zerrahn and Schill, 2015a) , (Schröder et al., 2013)

5.2. Results

Three variations of the capacity expansion model (CEM) presented in the previous sections are implemented in order to shed some light on the impact of introducing detailed operational constraints while capacity planning. Capacity investments and economic dispatch are co-optimized using the formulations presented in the previous section. Residual load is calculated based on the load data for France subtracted by the net power exchange, the non-variable renewable energy generation (assumed exogenous) and the VRE production (endogenous) according the penetration level under study. All market players are supposed to bid at marginal price in the energy and FRR markets, including DSM capabilities.

The first formulation tested, hereafter denoted F1, is the formulation comprising FRR balancing needs as presented in sections 4.1 - 4.8, including ramping limits, part-load efficiency losses and CO_2 emissions. The second formulation, denoted F2, includes all the equations of sections 4.1 - 4.7, but drops the module accounting for FRR requirements (section 4.8). The third formulation studied, F3, grasps additional simplification from F2, relaxing the ramping constraints of generation and storage technologies (equations (26)-(28) and (38)-(43)) but still considers load following cost. Technology specific parameters and cost remains the same on the three formulations.

Formulation	Description	FRR requirements	Omitted constraints
F1 – Full	LP formulation considering operational constraints and reserve requirements	Probabilistic	-
F2 – Typical	LP formulation disregarding reserve requirements	Not included	-
F3 – Simplified	Screening curve like formulation	Not included	Ramping limits: (26)-(28) & (38)-(43)

Table 8. Formulations.

The three formulations differ on the level of detail of operating constraints describing system requirements. Hence, flexibility can be deployed for different purposes and can be required on different timeframes. Therefore, both power generation technologies and EES can contribute for supplying FRR. EES and DSM can supply short-term flexibility for peak shaving and valley filling arbitrations from a daily to weekly basis. Only EES capacity allows accommodating for seasonal variations and doldrums of VRE generation, as well as for guaranteeing capacity adequacy on the long-term, completing generation technologies.

On F3, the FRR requirements follows the probabilistic methodology proposed on (ENTSO-E, 2013) based on day-ahead forecasting error allowing to calculate the RMSE of VREs. Statistical system imbalances are set using confidence levels of 99% and 90% to the unitary probability distribution for mFRR and aFRR dimensioning respectively (Van Stiphout et al., 2014). Therefore, when additional shares of VRE are imposed, the RMSE factors are linearly extrapolated as a function of VRE installed capacity. Minimum duration required for reserve supply of EES units was set to 0.5 h.

Imbalance source	Hour-ahead RMSE			
	aFRR+ $[*/P_{res}]$	aFRR- $[*/P_{res}]$	mFRR+ $[*/P_{res}]$	mFRR- $[*/P_{res}]$
Wind	1,07%	1,28%	7,84%	2,94%
PV	0,07%	0,38%	0,37%	1,05%
Load	0,24%**	0,56%**	0,46%**	0,84%**

** Percentage of daily peak load

Table 9. Imbalance sources for reserve dimensioning.

All imbalances are supposed to be dealt by the TSO, who establishes a market for hourly FRR reserve. All players but DSM are supposed to be bid for FRR supply at marginal price. Power and reserve supply participation is restricted by the total installed capacity of technologies and their ramping, regulation and fast-start capabilities. Therefore, power dispatch and reserve requirements are co-optimized with capacity investments.

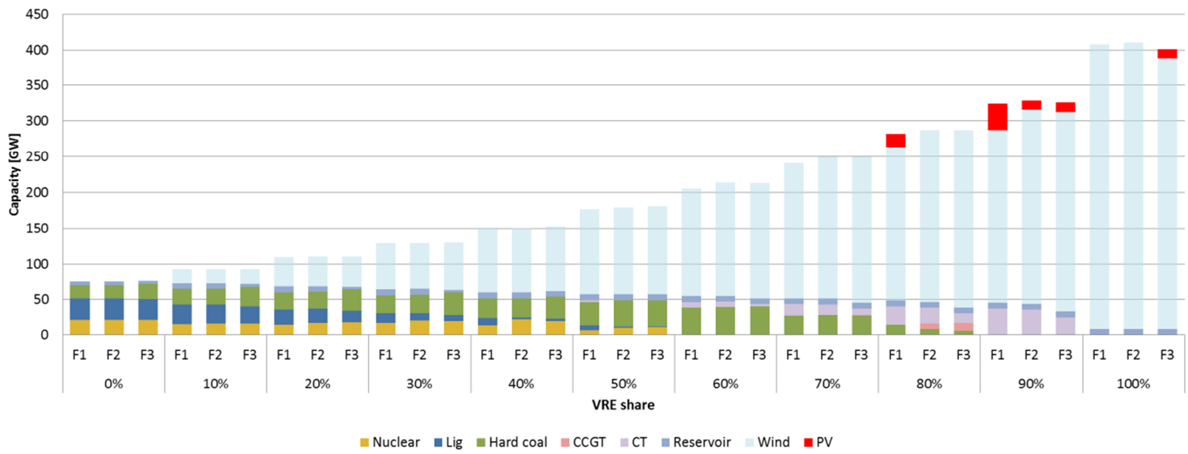

Figure 1. Optimal capacity investments on the greenfield scenario.

Under the assumptions adopted, VRE capacity is only installed when a share of RE is imposed into the system. In the case when investments on VRE are endogenously optimized without market distortions ($\theta_{res} \geq 0$), no wind or PV capacity are into the optimal portfolio. This evidences that from a system perspective investing in VRE capacity is suboptimal and causes induces additional costs.

Across all the formulations the required VRE capacity increases exponentially evidencing its very low capacity value. VRE investments are mainly composed by wind. Given that no restrictions are made to additional wind investments, PV becomes optimal and enters on the optimal investment portfolio only after wind value is sufficiently diluted. Nevertheless, at 100%VRE shares, the added capacity of EES on F1 and F2 makes place for additional wind rather than PV.

Furthermore, even if investments in reservoir hydro capacity are competitive regardless the VRE penetration level, it can be seen a fuel transition from low to high marginal cost technologies when increasing the VRE imposed. This means that from a system perspective, VRE under purchasing obligations directly competes with baseload technologies. It can be seen that under the CO_2 emission cost assumed, wind capacity is in competition with baseload technologies. It first shifts lignite, then nuclear and finally hard-coal capacity as can be seen in Figure 1. It can be expected that using a higher CO_2 cost, the main outcome showing that VRE competes with baseload would remain but the shifting order would change. Then, for sufficiently higher CO_2 cost, nuclear would be the last technology to be pushed out of the optimal mix. Assuming different cost of CO_2 cost would have a significant impact on the marginal cost of polluting technologies which changes their relative competitiveness. The marginal cost sensitivity to CO_2 cost is given by the CO_2 emission factor related to every technology. Therefore, changing the assumption of CO_2 cost would change the relative competitiveness between polluting and not polluting baseloads technologies, with higher CO_2 cost making the case favorable for nuclear against coal technologies. As presented on Figure 1, for an optimal setting, VRE penetration erodes the market for poorly flexible baseload technologies. VRE penetration imposes a reduction on the market volume for conventional technologies, a volume effect, shrinking progressively investments on low capital inflexible assets to more costly flexibility options. The way VRE capacity substitute other technologies can be interpreted as a fuel transition effect. It would depend on the relative competitiveness of conventional units, which is affected by the capabilities and cost of available investment options for supporting the system as a hole.

On the three cases, investing in solar capacity is only optimal for very high VRE penetration levels (80% - 100%). This is due to the lower relative competitiveness of solar against wind capacity for the system under study[11]. The late entry of solar capacity is given by the cannibalization effect taking place over wind capacity. This is, at constant levels of flexibility on the system the capacity value of wind power strongly depreciates when increasing the VRE shares. Investing into solar capacity becomes optimal only when the cost of wind integration is higher than the cost of solar capacity.

It can be seen that the optimal level of capacity investments obtained are consistent between the three formulations for any VRE penetration. Nevertheless, Figure 1 shows that the type of investments sensitively diverges for VRE shares above 20%. On F1, lignite and nuclear capacity shrink simultaneously when increasing VRE levels, while on F2 and F3 the fall is more successive. Moreover, no gas or fuel technologies are competitive when considering low to mid-shares of VRE. For mid CRE penetrations, peak plants become optimal earlier in F1 than on F2 and F3. Figure 1 shows that investing into peak and high peak technologies, which display higher marginal cost but achieve operations with higher flexibility, become economically optimal for VRE shares above 50% on F1 and above 60% on F2 and F3. This result particularly confirms the intuition that a better representation of system operations allows to better valuate flexible capabilities of generation technologies. This result can be furtherly proved when looking the optimal investments on flexibility options presented on Figure 2, where the total amount of flexibility investments is higher in F1, than in F2 and F3 for any VRE penetration.

[11] Load, wind and solar data loosely calibrated to the case of France.

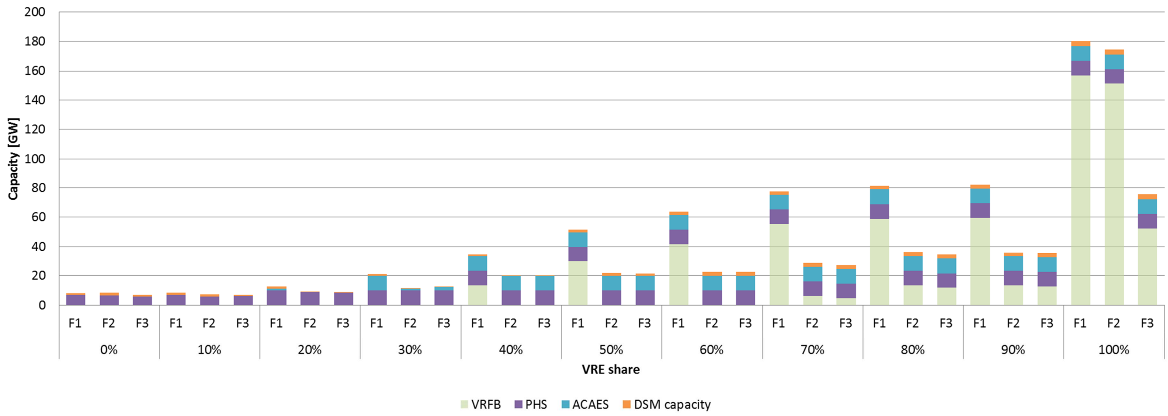

Figure 2. Optimal flexibility investments on the greenfield scenario.[12]

The three formulations show similar trends when looking at investments on flexibility options: The very low cost necessary for enabling DSM capabilities makes it competitive regardless the VRE penetration across all the formulations, but still leaving room for investments in EES technologies. The three cases opt for equivalent levels and type of investments at low VRE penetration, where just PHS is competitive. When considering low to mid VRE penetrations levels (20-60%), flexibility for VRE integration starts to be a main driver for investments in EES. For high VRE shares, significant investments on EES capacity are required to attain minimum system cost.

The three cases opt for equivalent levels and type of investments of flexibility options from 0-10% of VRE penetration. At this level, PHS capacity allows for supplying flexibility for weekly arbitrations and for avoiding cycling conventional units and to keep them from part load efficiency losses. This is maintained until VRE shares of 20%, where enough flexibility is supplied by low marginal cost generation technologies, mainly hydro and coal, while short-term flexibility is provided by increasing investments into PHS and DSM.

Figure 2 shows that from 20% VRE levels the amount of optimal flexibility investments increases faster on F1 rather than on F2 and F3. Additional investments on EES technologies become optimal when VRE furtherly increases. As previously exposed, F3 only valuates flexibility for price arbitrations because no ramping constraints and no other system service are imposed on the optimization. At the same time, F2 enhances the value of flexibility by including the dynamic limits of generation units. The similar levels of investments on flexibility options at 20% until 60% VRE shares across F2 and F3 evidences that from a system perspective, benefits coming from price arbitration and ramping cost savings are not sufficient to justify additional investments into EES. This is explained because of the technology transition occurring on the supply side from primarily baseload technologies to more peaking technologies. The investments on essentially flexible power generation technologies, evinced when imposing mid VRE shares causes a substantial reduction on the market for flexibility when only balancing arbitrations and capacity adequacy are considered (F2). Gains from price arbitrations alone only prompt further investments on EES capacity for VRE shares above 70%.

More complete representation of system operations allow to better capturing the value of supply multiple services, so stacking multiple value sources. Regarding flexibility options, F1 adds the value coming from system reliability by taking into account FRR requirements, which improves the case for investments on flexibility options. On F1, for VRE levels above 50%, an investment on EES units rapidly grows. Figure 2 shows the important impact that including FRR has over the optimal level of

[12] Li-ion batteries (Li-ion), Sodium-sulfur (NaS) batteries, Vanadium redox flow batteries (VRFB), pumped-hydro storage (PHS) and adiabatic compressed air energy storage (adiabatic - CAES).

EES capacity. It shows that EES investments trigger from 10% of VRE penetration on F1 against 20% for F2 and F3. Not only the optimal level of EES capacity is higher on F1, the portfolio of optimal EES investments also diversifies faster. The difference becomes significant from 20% onwards.

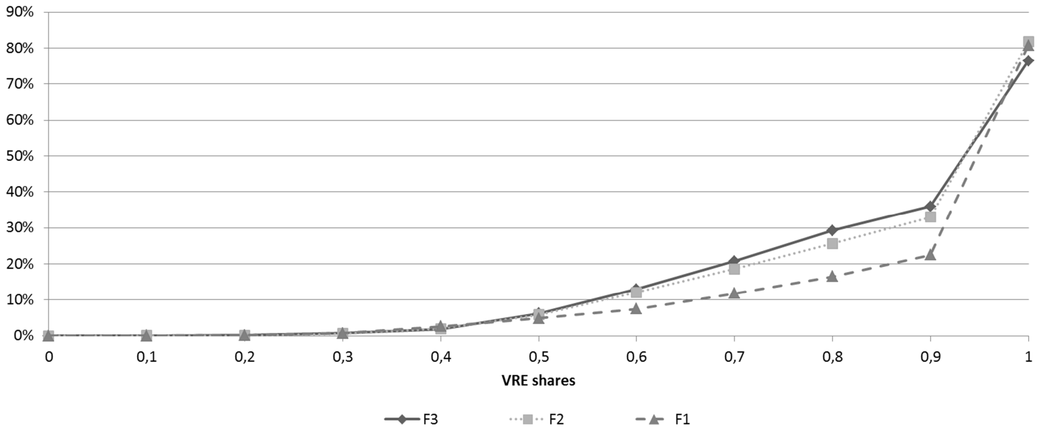

Figure 3. VRE curtailment as a percentage referred to total demand (512 TWh).

Figure 3 presents the evolution of VRE curtailment which is assumed as a free option to balance demand and supply. The results are clear: Even with important investments in flexibility options, it is economically optimal to significantly curtail VRE for penetrations levels above 50%. For example, at 60% VRE shares, curtailment levels are placed around 10% of total demand. This means that in fact current VRE generation corresponds to around 70% of total load from which 10% are spilled.

Nevertheless, an important distinction between formulations should be made, curtailment levels can be sorted in decreasing order starting for F3 then F2 and finally F1. This is a consequence of the broadened representation of flexibility needs and the adoption of a multiservice approach on F1. The systems obtained using F1 are consequently more flexible than those using F2 and F3, which allows a better integration of VRE and therefore less VRE energy spillage.

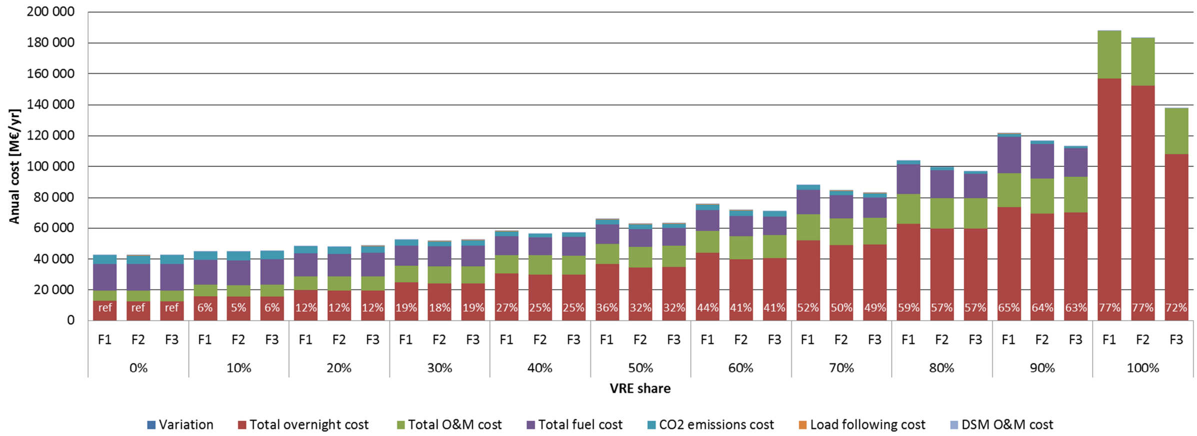

Figure 4. Total system cost.

Looking at system cost, the three cases indicate similar trends. Total system cost rapidly rises when increasing VRE shares. This cost growth is driven mainly by the overnight cost incurred by forcing non-economical VRE capacity to respect the RE goal simulated. This in turns requires adding capital intensive EES capacity for VRE integration to better accommodate the forced VRE capacity. Nevertheless, since the three formulations calculates the optimal mix for the imposed levels of VRE penetration, lower levels of EES on the mix would imply less overnight cost but even higher total cost corresponding to a suboptimal strategy. Passing from 0% to 30% of VRE penetration implies a cost increase of about 19% across all the formulations, while passing from 30% to 60% of VRE penetration more than doubles this increase with 44% for F1 and 41% for F2 and F3 respectively. Nevertheless, formulations F2 and F3 neglect integration cost dealing with reliability, better assessed on F1.

It can also be seen on Figure 4 a non-negligible increase of O&M cost across the formulations. Even if the fuel transition effect moves the optimal mix to less costly O&M cost when increasing VRE shares, there is a bigger amount of installed capacity due to the lower capacity factor of VREs and there is more energy produced on the system that is spilled by VRE curtailment. In relation to the fuel cost, the volume effect creates a reduction on primary energy consumption but the fuel transition effect move towards the usage of more expensive fuels; both effects balance each other resulting on relatively steady fuel cost, except for the case of 100% VRE where there is only RE generation and pure flexibility options on the system.

Similarly, CO_2 cost diminishes progressively while increasing VRE shares due to the global reduction of CO_2 emissions. Aside the volume effect of compelling more clean energy on the mix when increasing VRE shares, there is a fuel transition effect explained by the increase of the relative competitiveness of flexible gas fueled technologies compared to baseload conventional plants (nuclear and coal). More flexible generation capacity better contribute to VRE integration. Given that the CO_2 content of gas is lower than that of lignite or coal, the net effect of a fuel transition from coal to gas is a reduction of system's emissions. Nonetheless, at constant energy generation levels, replacing nuclear for hydrocarbon based technologies makes the system to increase the CO_2 emissions. This interpretation is recognized on Figure 5.

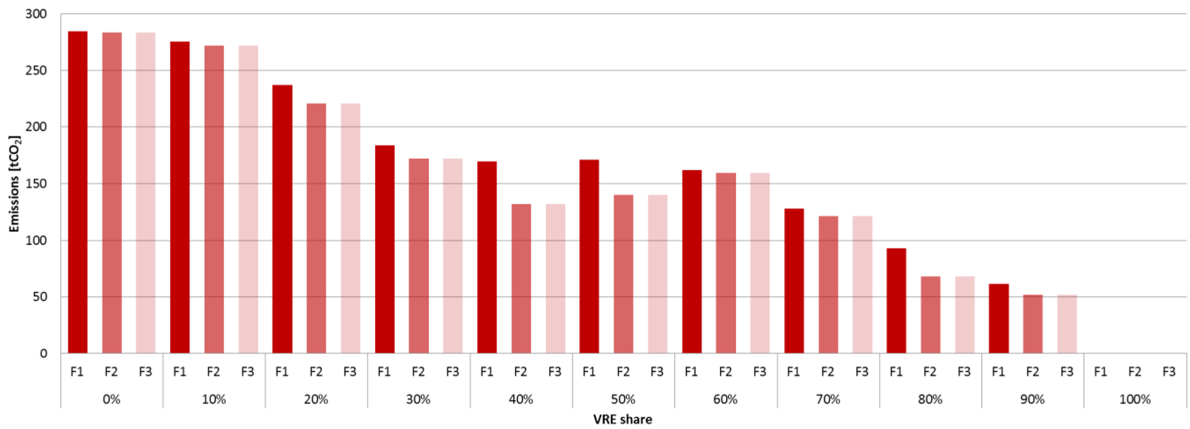

Figure 5. CO2 emissions on the greenfield scenario.

In order to understand the trend of CO_2 emissions, the competition between VRE capacity and baseloads technologies should be depicted. On the three formulations, it is confirmed that at low VRE shares lignite capacity is the first baseload technology to be replaced by VRE capacity. The result is an important reduction on the CO_2 emissions. At mid VRE shares, the lignite capacity is continues to be pushed out of the optimal mix and the replacement of nuclear capacity follows. There is an initial reduction on the total CO_2 emissions from 20% to 40% VRE shares followed by a rebound from 40% to 60%, resulting on a "U" shape on the CO_2 emissions. This trend is explained by the volume and fuel transition effects acting in the same direction at low to mid VRE penetration and then in the opposite direction from 40% to 60%. This shape is slightly mitigated on F1 because of a better estimation of system flexibility for VRE integration. From 60% of VRE penetration, VRE generation becomes the main baseload technology triggering investments on flexible capacity and flexibility options in order to facilitate its integration, all that prompts the start of the replacement of the remaining hard coal capacity, occasioning a net decline on the CO_2 emissions. It can also be seen that formulations F2 and F3 tends to under estimate CO_2 emissions when compared to F1.

6. DISCUSSION

The model presented in this paper is a capacity expansion model in which energy supply and reserve requirements can be co-optimized considering a large set of operational constraints of the system. This framework is well suited to evaluate investments in capacity and flexibility resources simultaneously; hence, it is in line with a resource-adequacy (RA) method in which the balance between demand and supply is also studied during challenging ramping conditions and where there is little conventional capacity scheduled due to ambitious renewable energy penetration levels progressively forced into the system. The current formulation assumes a system under perfect competition and perfect foresight. Real markets are far from being deterministic and predicable, market players can also interact at some degree. Special attention should be payed when analyzing the value of flexibility resources under deterministic frameworks. Bidding strategies of pure flexibility options are based on tradeoffs between real time market situations and the expectations of price evolutions, which is predominantly a stochastic problem. Thus, the results obtained using these ideal assumptions set an upper bound on the value of flexibility.

Furthermore, the formulation here presented leaves aside the power network. No interconnections or grid constraint is considered. This simplification can overestimate the flexibility needs of the system for the services considered. Nevertheless, the inclusion of further details on the dynamics of the power system, such as supplementary ancillary services, locational signals for congestions management, network investment deferral, among others, would open additional sources of valuating flexibility on the system and would compensate the inaccuracies introduced by the idealistic assumptions considered.

7. CONCLUSIONS

The lack of representation of system needs, including operational and reliability information, may result on suboptimal capacity investments when variability enters into the system. This makes necessary to reformulate the long-term generation investment (LTGI) problem as a resource-adequacy problem in which a broader representation of system requirements is necessary to capture the value of different system services. Additionally, an accurate representation of technology capabilities is also required to cope with the power demand and manage the wider system services required on the system.

Nevertheless, there are trade-offs to assess when introducing detailed operational constraints into capacity expansion models. The dimensionality of the solving problem grows dramatically and computation time becomes constraining when refining the complexity of power system dynamics. The stylized formulations presented in this paper shed light on the impact of representing operating constraints while endogenously optimizing capacity and flexibility investments. Hence, the contribution of this paper is twofold: first, endogenous investments in flexibility options are incorporated into a linear dispatch-investment model. Thus, EES and DSM capabilities are jointly optimized with conventional and VRE capacity investments to balance system's needs. Second, the integration of reliability criterions on power system planning is supposed to claim increasing importance at significant VRE penetration levels because of the increasing forecasting errors impacting the residual load. Therefore, the conventional representation of the power system is enlarged by the introduction of FRR requirements for the capacity optimization.

The impact of operating constraints over the optimal investments is tested comparing three formulations (F1, F2 and F3), which use the same system cost definition but assume different detail on the representation of system constraints and system's needs. Results show that VRE shares between 0-20%, there is almost any difference between the optimal capacities across the three formulations: investment level and technology type are equal; the same is valid for system cost and resulting CO_2 emissions. Only flexibility for power adequacy and for optimal operation of conventional units is valuated. Thus, little amounts of PHS and DSM investments are required because power generation units sufficiently supply power and system flexibility.

Nevertheless, after 30% of VRE penetration, higher flexibility for optimal VRE integration becomes imperative. Therefore, it is confirmed that an inaccurate representation of operational constraints conducts to highly suboptimal investments, or even, to infeasible power mix. Investments on flexibility options rise earlier and faster when a more complete representation of system dynamics is adopted. When a broader representation of power system requirements is adopted, flexibility options prove to add significant value to the system. These results confirm the belief that, assuming the cost levels expected by 2020, flexibility technologies have a major role to play when considering significant shares of VRE.

It can be seen on the most complete formulation (F1) that investments in flexibility options increases exponentially between 30% and 60% VRE penetration levels, in this range its value is high because of the complementarities originated when less flexible generation technologies compose the system. From 70% to 90% of VRE shares, peak and extreme peak investments enter into the optimal mix making flexibility options to compete with capabilities from flexible generation technologies. This competition results on a stagnation on the optimal investments on EES and DSM. At 100% of VRE penetration, investments on flexibility options retakes its exponential grow pattern because of the tight technical restriction imposed by no allowing generation from conventional technologies, even for extreme conditions.

It is also confirmed that a misrepresentation of operational constraints neglects system cost associated with VRE integration. This cost deviation corresponds to both, underestimation of additional investments in flexibility options and intensification of operating cost to accommodate for a more fluctuating residual demand. Associated CO_2 emissions are also underrated due to the mistreated contribution of conventional units for VRE integration given the important cost of investing in flexibility options. Energy spillage in form of VRE curtailment is lower on formulations with higher detail on the system dynamics because they better capture the system value of flexibility, then, the resulting mix is more flexible and enhanced for VRE integration.

These results not only show the importance of enlarging the problem formulation in order to include additional system services for capacity optimization on scenarios of important VRE shares, but also highlight the necessity to jointly include generation and flexibility options into the investment portfolio. That is, adopting a system perspective multiservice approach.

In summary, the notion of flexibility has been analyzed and interpreted as a service with multiple delivery timeframes, for different purposes and being supplied by complementary technologies. Alternative model formulations are compared for increasing shares of VRE and results confirm quantitatively the postulates evocated in the literature. The modularity of the model proposed also allows to study power investments on brownfield scenarios and to conduct sensibility analysis over relevant energy policy issues. The model can furtherly be improved to include cross-border exchange as an additional source of flexibility. All those subjects constitute the topic of further research.

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