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Day-ahead and Reserve Prices in a Renewable-based Power System: Adapting Electricity-market Design for Energy Storage

Laureen Deman[1,2], Afzal S. Siddiqui[3,4], Cédric Clastres[1], and Quentin Boucher[2]

Abstract
Decarbonizing the power mix will require investments in storage and flexibility options to replace the current carbon-intensive supply of reserves. This paper questions whether reserve-capacity markets can serve as a capacity mechanism for flexible technologies. A fundamental model of the day-ahead and reserve markets is used to investigate the evolution of reserve prices with large shares of renewable energy and storage. The model represents the current market design in Continental Europe with a centralized supply and platforms for the exchange of reserves. By becoming the main suppliers of reserve capacity, batteries have a noticeable impact on reserve prices. Their flexibility implies zero opportunity cost most of the time, meaning that the flexibility is not rewarded by the market. These results suggest that reserve-capacity markets cannot provide additional remuneration for flexible technologies and, thus, do not solve the missing-money problem in the context of the energy transition.

JEL Classification: Q41, Q47

Keywords
renewable energy, reserve markets, storage, carbon-neutrality scenarios

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[1]Université Grenoble Alpes, CNRS, INRAE, Grenoble INP, GAEL, Grenoble, France
[2]SuperGrid Institute, Villeurbanne, Auvergne-Rhône-Alpes, France
[3]Department of Computer and Systems Sciences, Stockholm University, Kista, Sweden
[4]Department of Mathematics and Systems Analysis, Aalto University, Espoo, Finland

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Corresponding Author:
Laureen Deman, Université Grenoble Alpes, CNRS, INRAE, Grenoble INP, GAE-CS 40700, 38058 Grenoble cedex 9, France; SuperGrid Institute, Villeurbanne, Auvergne-Rhône-Alpes, France.
Email: laureen.deman@univ-grenoble-alpes.fr

1. Introduction

Reducing greenhouse gas emissions requires an increase in the share of low-carbon technologies in the power mix, with variable renewable energy (VRE) sources figuring predominantly. Besides the management of their intermittency, the stochastic nature of their generation may represent an important challenge for the power system (Hirth and Ziegenhagen 2015). In this context, forecast errors in generation and load are handled via reserve markets. Organized by the transmission system operator (TSO), they ensure the balance between generation and consumption in real time. Reserve suppliers should be able to vary their generation or consumption levels over a time horizon varying from thirty seconds to thirty minutes, depending on the reserve category.

In Continental Europe, four categories of reserves are implemented with different activation times. They can be classified into automatic and manual reserves, or, equivalently, into spinning and non-spinning reserves. Frequency Containment Reserve (FCR) and automatic Frequency Restoration Reserve (aFRR) are automatically activated in response to frequency deviations.[1] Manual Frequency Restoration Reserve (mFRR) and Restoration Reserve (RR) are manually activated by the TSO.[2] The timing of activating manual reserves varies between countries (Håberg and Doorman 2016). Therefore, the determining factors for activating these are specific to each TSO. For each category of reserve, there are two types of reserve services: reserve capacity and reserve energy (Schittekatte, Reif and Meeus 2019). Reserve capacity corresponds to the amount of generation capacity made available to the TSO in case it is needed in real time. Reserve energy corresponds to the amount of energy activated in real time to balance generation and consumption.

With less dispatchable generation, the availability of reserves may decrease in the coming years. In addition, the rising shares of renewable energy may increase the need for reserves (Hirth and Ziegenhagen 2015). Reforms of the reserve-market designs are being implemented to adapt to these changes. Among the different reforms at the national level, we can cite reductions of the delivery period to enhance participation. At the European level, platforms are being introduced to organize exchanges of reserve energy between countries (PICASSO[3] for aFRR, MARI[4] for mFRR, and TERRE[5] for RR). By organizing exchanges, flexibility resources can be shared between countries.

Besides the evolution of the reserve-market design, the availability of reserve supply needs to be addressed. Alongside hydropower, fossil-fueled power plants play an important role in supplying reserves (Papaefthymiou and Dragoon 2016). Investments in storage and flexibility options such as batteries and demand response are necessary to replace them. The volatility of wholesale energy prices should constitute a price signal incentivizing investments in such options (Mays 2021; Papavasiliou and Smeers 2017). However, several arrangements in the day-ahead market may restrain price volatility (Mays 2021). Moreover, the declining trend in day-ahead prices may not be compensated by their increasing volatility. Some analyses of chemical storage show that in the United States or in Europe, arbitrage in the day-ahead market is not profitable enough with current prices to incentivize investments (Komorowska and Olczak 2024; Lamp and Samano 2022). There is evidence of increased day-ahead price volatility with more wind generation in Germany (Ketterer 2014; Kyritsis, Andersson and Serletis

[1] They can be compared to the frequency regulation used in North America

[2] They are similar to primary reserves used in North America, with activation times ranging from fifteen to thirty minutes

[3] Platform for the International Coordination of the Automatic frequency restoration process and Stable System Operation

[4] Manually Activated Reserves Initiative

[5] Trans-European Replacement Reserves Exchange

2017). The volatility of wind generation increases the volatility of the residual load that conventional technologies have to cover. By contrast, solar generation tends to reduce the variance of day-ahead prices (Kyritsis, Andersson and Serletis 2017). As some of the highest levels of solar generation occur during peak hours, it replaces expensive generation and, thus, reduces price spikes. The combined effect of wind and solar generation on price volatility is, therefore, uncertain, as it depends on the relative share of each technology.

Capacity mechanisms have been put in place to solve this so-called missing-money problem. In energy-only markets, wholesale energy prices are not high enough to cover the fixed costs of conventional generators. With a remuneration of generation capacity, capacity mechanisms send price signals for investments. However, their design does not value flexibility so that other flexibility pricing mechanisms are needed (Mays 2021; Papaefthymiou and Dragoon 2016; Papavasiliou and Smeers 2017). Reserve-capacity markets relate to such mechanisms since they remunerate the availability of reserves, independently of their activation. Thus, reserve-capacity prices can send a price signal for investments in flexible technologies. Historically, reserve-capacity markets have been organized to ensure the availability of reserves. Yet, they could also bring an additional remuneration of flexibility. The fact that reserve-capacity markets are organized on a short-term basis allows prices to better reflect the opportunity costs of suppliers and, thus, provides a better remuneration for flexibility.

A prominent strand of the literature has analyzed the various drivers of efficiency in reserve markets (Dallinger, Auer and Lettner 2018; Farahmand and Doorman 2012; Jaehnert and Doorman 2012; Van den Bergh and Delarue 2020). In this paper, we change the perspective by focusing on the profitability of these markets in the context of the energy transition. To our knowledge, the evolution of reserve prices with large shares of renewable energy and storage has not been investigated in the literature. The determinants of reserve-capacity prices have been analyzed by Gebrekiros et al. (2015) and Müsgens, Ockenfels and Peek (2014) in the Nordic countries and Germany, respectively, with historical data. Since reserve capacity does not necessarily imply a delivery of reserve energy, it incurs in an opportunity cost. For inframarginal units in the day-ahead market, it corresponds to the loss of profit associated to the reduction of the supply in the day-ahead market. For extramarginal units, the opportunity cost is the loss of generating at minimal power in the day-ahead market (Müsgens, Ockenfels and Peek 2014). In our paper, we add the evolution of the power mix with less dispatchable generation and the associated forecasted reserve demand. This evolution implies new flexibility needs with, for instance, deployment of batteries and demand-response programs. To account for this deployment, we propose a definition of the opportunity cost of batteries. This proposal fills the gap in the literature with regard to the importance of batteries in meeting the reserve-capacity needs.

This article uses a fundamental model of the day-ahead and reserve markets to study the evolution of day-ahead and reserve prices with high penetration of renewables and storage, that is, technologies with high fixed costs. The model is designed to represent the current market design in Continental Europe with a centralized supply of energy and reserves along with common platforms for the exchange of reserves. The focus is on automatic reserves because of the higher harmonization level of their market design. The aFRR energy market is modeled with exchanges to represent the functioning of the PICASSO platform (ENTSO-E 2018). A case study of the 2022 version of the Ten-Year Network Development Plan (TYNDP) scenarios (ENTSO-E and ENTSO-G 2022) is examined with two distinct pathways to achieve carbon neutrality by 2050. They differ in the assumptions made regarding energy-efficiency levels, electrification rates of heating and transport, and technology costs.

The main finding of this paper is the leading role of batteries in the demand-supply equilibrium of reserve-capacity markets. In fact, they have a major influence on the resulting prices because, over time, they become the main supplier of reserve capacity. Since they can supply reserves alone, it is less costly for the system to dispatch battery rather than hydro or fossil-fuel power plants in reserve-capacity markets. However, prices do not evolve significantly over time, despite the increasing demand and this significant change in the supply structure. We show that this is due to the opportunity cost structure of batteries. In fact, their flexibility often implies zero opportunity costs. Batteries are either marginal in the day-ahead market or do not face a trade-off between the supply of energy and the supply of reserve capacity. With zero opportunity costs, batteries can push other reserve suppliers out of the market for upward-reserve capacity. This reduces the profitability of reserves and is reminiscent of the cannibalization effect of renewable energy in energy markets. These results suggest that reserve-capacity markets cannot provide an additional remuneration for flexible technologies and, thus, do not solve the missing-money problem in the context of the energy transition.

The article is structured as follows. Section 2 highlights the literature on reserve-market modeling and its findings in terms of market-design options. Section 3 outlines the methodology with a brief description of the model and a description of the case study. The complete formulation of the model is available in the Appendix. The results are presented and discussed in Section 4. Concluding remarks and directions for future research are offered in Section 5.

2. Literature

The market design for reserves is subject to a variety of options. Fundamental models of the day-ahead and reserve markets are used in the literature to analyze them (Dallinger, Auer and Lettner 2018; Domínguez, Oggioni and Smeers 2019; Farahmand and Doorman 2012; Jaehnert and Doorman 2012; Van den Bergh, Bruninx and Delarue 2018; Van den Bergh and Delarue 2020). Among the different market-design options are the timing of the reserve-capacity market with respect to the day-ahead market. In a joint design, energy and reserve capacity are procured at the same time. This design is the most cost-efficient solution because the interdependencies between energy and reserve-capacity supply are explicitly considered without uncertainty (Müsgens, Ockenfels and Peek 2014; Van den Bergh and Delarue 2020).

In a sequential design, the reserve capacity clears either after or before the day-ahead market. In the former, the reserve-capacity market consists of a redispatch (Jaehnert and Doorman 2012). Outcomes can be similar to the joint design if there are exchanges of reserve capacity (Domínguez, Oggioni and Smeers 2019). Otherwise, the schedule of interconnections cannot be changed in the reserve-capacity allocation process, resulting in higher procurement costs (Müsgens, Ockenfels and Peek 2014; Van den Bergh and Delarue 2020). This cost difference increases with the level of renewable energy, both in absolute and relative terms, due to the increasing use of load shedding and curtailment of renewable energy (Van den Bergh and Delarue 2020). When the reserve-capacity market clears before the day-ahead market, its cost corresponds to an opportunity cost as there is a trade-off between the supply of energy and reserve capacity. This design has been found to be the most costly by Domínguez, Oggioni and Smeers (2019) because the higher uncertainty increases the reserve-capacity demand levels. However, bringing the market-gate-closure time closer to real time reduces the procurement costs (Dallinger, Auer and Lettner 2018).

The integration of reserve-capacity markets reduces procurement costs (Dallinger, Auer and Lettner 2018; Farahmand and Doorman 2012; Jaehnert and Doorman 2012; Van den Bergh, Bruninx and Delarue 2018). In models representing Northern Europe, upward-reserve capacity is exported from the Nordic countries to the Continental ones. Thus, the cost reduction is explained by the substitution of thermal generation by hydro generation (Farahmand and Doorman 2012; Jaehnert and Doorman 2012). Despite the different assumptions regarding the timing of the reserve-capacity market, both papers obtain the same results. In fact, Farahmand and Doorman (2012) assume a joint design while Jaehnert and Doorman (2012) assume reserve-capacity markets clear after the day-ahead market. In Central Western Europe, Van den Bergh, Bruninx and Delarue (2018) find that imposing limits on reserve-capacity exchanges decreases costs by reducing lost load in real time. These limits guarantee the feasibility of reserve-energy exchanges in real time. The integration of the reserve-energy market also implies a cost reduction. It is driven by a reduction of activation through imbalance netting (Farahmand and Doorman 2012; Jaehnert and Doorman 2012). Even without imbalance netting, it reduces procurement costs through the activation of the cheapest flexible units.

Cost efficiency of the reserve markets is also influenced by other parameters (Dallinger, Auer and Lettner 2018). A shorter contract duration and a higher frequency of market clearing increases the available reserve capacity within balancing areas. This reduces the need for imports of reserve capacity. Asymmetric products also decrease the need for imports. These market-design options are the most appropriate for the participation of renewable energy and demand-side response in reserve-capacity markets (Dallinger, Auer and Lettner 2018).

The European platforms for the exchange of reserve energy are intended to improve the cost efficiency of reserve activation. The extant literature has focused on the efficiency gains that could be achieved with modifications of the reserve-market design. The guidelines for the design of the reserve-capacity markets in the Electricity Balancing Guideline (EBGL[6]) follow these findings. These reforms are intended to improve the efficiency of the reserve markets and to prepare for the large integration of renewable energy. We adopt a new perspective by focusing on the long-term efficiency of the reserve markets. In fact, we investigate whether they can mitigate the missing-money problem in the context of the energy transition. To our knowledge, the evolution of reserve prices with large shares of renewable energy and storage has not been investigated in the literature. This paper intends to fill this gap with a fundamental model representing the aforementioned reserve-market design. We are taking this investigation in order to assess whether reserve-capacity markets can send price signals for investments in flexible technologies.

3. Methodology

3.1. Assumptions

The model consists of three stages (Figure 1). First, the FCR and aFRR capacity markets are cleared based on expectations of the outcome in the day-ahead market. Then, the day-ahead market is cleared taking in account the outcomes of the previous markets. Finally, the aFRR energy market is cleared taking into account the aFRR capacity volumes committed in the first stage and the remaining capacity after the day-ahead market. This sequence is meant to represent the current timing of markets in the represented countries. In each market, the demand is assumed to be exogenous.

The aFRR markets are asymmetric with an upward and a downward product for both reserve capacity and reserve energy. This corresponds to the market design recommended by the EBGL. Upward reserves absorb an energy deficit in the power system by increasing generation and/or decreasing consumption. Downward reserves absorb an energy surplus by reducing generation and/or increasing consumption. This implies that a supplier of upward-reserve energy is remunerated by the TSO while a supplier of downward-reserve energy pays the TSO. By contrast, both reserve-capacity services are remunerated by the TSO.

[6]European Commission (2017b) Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing. 2017-11-28

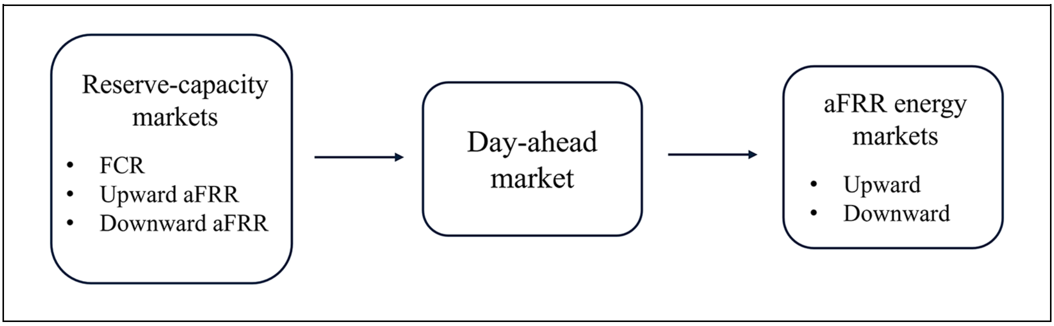

Figure 1. Stages of the model.

Uncertainty is not considered so that all the markets are cleared at the time. However, the imperfect predictability of renewable energy generation is represented by the procurement of reserve capacity. This reduces the capacity available in the day-ahead market. But, it enables flexible resources to be available in real time to handle forecast errors of wind and solar generators, among other sources of mismatch between the day-ahead and the real-time conditions. The modeling approach of Domínguez, Oggioni and Smeers (2019), Farahmand and Doorman (2012), and Van den Bergh and Delarue (2020) is adopted. In these papers, the reserve-capacity opportunity costs are not explicitly included in the model. The fact that part of the capacity has to be withdrawn from the day-ahead market is sufficient to represent them. It is similar to a framework where the reserve-capacity market clears before the day-ahead market and without uncertainty.

Since perfect competition is assumed, quantities are the decision variables of the generation units.[7] They are aggregated into technology blocks with similar characteristics (fuel, efficiency, minimum power, ramping rate) as in Farahmand and Doorman (2012).

The network is represented in a simplified manner with one node per country. Energy exchanges are represented in the day-ahead and the aFRR energy markets, and are limited by the net-transfer capacities. Exchanges of reserve capacity are allowed only for FCR for the countries participating in the FCR Cooperation Platform (Austria, Belgium, Switzerland, France, Germany, and the Netherlands). In accordance with the System Operation Guideline (SOGL[8]), exchanges of FCR capacity are limited according to the level of its demand. Moreover, we do not consider exchanges of aFRR capacity. Indeed, there is no planned cooperation project of TSOs regarding aFRR capacity.

The variable cost of reserve-energy supply is identical to the variable generation cost. As downward reserve energy implies a payment from the supplier to the TSO, this assumption leads to the need for a demand-supply equilibrium constraint in each direction contrary to

[7]The level of concentration in the reserve markets has been historically high in the majority of the countries (ACER and CEER 2015). One documented example of exercise of market power is the strategy of underbidding in the reserve-capacity market in order to increase the selection probability. This manoeuvre allows selected market participants to bid very high reserve-energy prices without reducing their selection probability. Such a strategy has been observed in Germany and Austria where it was necessary to be selected in the reserve-capacity market to be in the merit-order list for reserve energy (ACER and CEER 2015; Poplavskaya, Lago and De Vries 2020). The implementation of the EBGL makes this strategy less profitable since the European platforms for reserve energy partly disconnect the reserve-capacity and reserve-energy markets. In fact, exchanges imply new bids in the merit-order list for reserve energy.

[8]European Commission (2017a) Commission Regulation (EU) 2017/1485 of 2 August 2017 establishing a guideline on electricity transmission system operation. http://data.europa.eu/eli/reg/2017/1485/oj

Minimise	Variable costs + Start-up costs + Demand-response costs + Lost-load costs (eq. (B.1))
Subject to	Day-ahead market constraints (eq. (B.2)-(B.14)) Reserve-capacity constraints (eq. (B.15)-(B.25)) aFRR energy-market constraints (eq. (B.26)-(B.34))

Figure 2. High-level description of the model.

Domínguez, Oggioni and Smeers (2019), Farahmand and Doorman (2012), and Jaehnert and Doorman (2012). In these papers, one equilibrium constraint is sufficient either because the reserve markets are simulated separately from the day-ahead market (Jaehnert and Doorman, 2012) or because downward activations represent a cost for the system (Farahmand and Doorman 2012). In Domínguez, Oggioni and Smeers (2019), the day-ahead and the reserve markets are modeled simultaneously and downward activations reduce system cost. However, no information was found on the reserve-activation costs.

3.2. Model Description

The objective is to minimize the total costs to meet the demand in the day-ahead and reserve-energy markets (Figure 2). These include variable costs and start-up costs. Fixed costs are not accounted for since investments decisions are not modeled. Unit variable costs include fuel, carbon, and operation and maintenance (O&M) costs (ENTSO-E and ENTSO-G 2022). Demand response can be activated in the day-ahead market and the upward reserve-energy market. There are several demand-response segments with different activation prices and duration. Having various segments with different activation prices reflects diverse willingnesses-to-accept to decrease or to shift consumption, in the same way that households and industry have different willingnesses-to-pay to avoid power outages (Gorman 2022). In case of insufficient supply, lost load is accounted for in either the day-ahead or the upward aFRR energy market (equation (A1)).

A brief description of the constraints follows. The full formulation is given in Appendix A. The balance between demand and generation must be ensured in each market (equations (A2), (A15), (A26), and (A27)), subject to supply and exchange constraints (equations (A4), (A16), and (A28)). For thermal and hydro generation units, the same formulation as Farahmand and Doorman (2012) is used to represent the start-up costs and the minimum generation constraint while keeping the problem linear (equations (A5)–(A7)). Continuous variables taking values between zero and one are used as proxies for binary variables for the on-off status and the start-up status.

Within the hydro blocks, some of them have pumping capacity so that they can buy electricity in the day-ahead market to fill their reservoirs (equations (A8) and (A10)). It is assumed that no reserve can be supplied when the reservoir is being filled.

The reserve supply is limited by the ramping capacity and the operating range of each generation block (equation (A17), Müsgens, Ockenfels and Peek [2014]). The ramping limit is imposed on the proportion of on-line capacity running at minimum power to prevent start-ups for reserve supply. When supplying reserves, the block should stay between its minimum and maximum power limits (equations (A18)–(A20)).

In addition to thermal and hydro generation, batteries can contribute to meeting demand in any market. They are represented in the same way as hydro units with reservoirs. However, they are more flexible as they can operate at any point between zero and their maximum capacity (equation (A9) for the day-ahead market). They can supply reserves alone, that is, without participating in the day-ahead market (equations (A21) and (A22)).

In the aFRR energy market, exchanges between countries are represented by a change in power flows compared to the day-ahead schedule (equation (A28), Domínguez, Oggioni and Smeers 2019). Thus, the capacity of a transmission line is subject to a trade-off between the day-ahead market and the aFRR energy market. Demands between two countries can be netted if they are in opposite directions and depending on the availability of the transmission line (equation (A29), Backer, Kraft and Keles 2022).

3.3. Opportunity Cost for Reserve Capacity

In this model, dual variables represent marginal prices. In the case of reserve capacity, these prices do not reflect the opportunity cost of the suppliers because they are not included in the objective function. Indeed, the losses borne by conventional technologies are not necessarily captured by the dual variable of the reserve-capacity market. This is different from zero only if a marginal increase in the reserve-capacity demand modifies the costs in the day-ahead and/or in the aFRR energy market. For instance, a positive marginal price is observed when a marginal increase in reserve-capacity demand requires an increase in the generation of a power plant in the day-ahead market. If this is not the case, then the marginal reserve-capacity price is zero, even though the plant has forgone profits in the day-ahead market in order to increase its supply of reserve capacity.

Consequently, reserve-capacity prices are computed ex post as the marginal opportunity cost of the selected suppliers of reserve capacity. For thermal and hydro blocks, the calculation is based on Müsgens, Ockenfels and Peek (2014) for upward aFRR capacity and Dallinger, Auer and Lettner (2018) for downward aFRR capacity (Table 1). The opportunity cost for FCR is the maximum of the upward- and downward-reserve opportunity costs. For hydro blocks, the variable cost is the water value, that is, the dual variable of the water-balance constraint (equation (A12)).

If the block g is inframarginal in the day-ahead market, then its opportunity cost for upward-reserve capacity is equal to the loss of profit in the day-ahead market if one MW is moved to the upward reserve-capacity market. The loss of profit is the difference between the day-ahead market price ($p^{DA}_{n,t}$) in period t and the variable cost of the unit (C_g). For downward-reserve capacity, it is zero because there is no arbitrage between the day-ahead and the reserve market in this case. In fact, supplying downward-reserve capacity does not imply a reduction of the supply in the day-ahead market.

If the block is extramarginal in the day-ahead market, then its opportunity cost is equal to the loss in the day-ahead market, $(C_g - p^{DA}_{n,t})\underline{Q}_{g,n}$, where $\underline{Q}_{g,n}$ is the minimum power, distributed over the volume of reserve. Similarly to Müsgens, Ockenfels and Peek (2014), the maximum volume of reserve is taken, that is, the ramp limit, $Q^{RA}_{g,m,n}$. The ratio $\frac{\underline{Q}_{g,n}}{Q^{RA}_{g,m,n}}$ gives the minimum generation level required to supply 1 MW of upward reserve. The opportunity cost for downward-reserve capacity is greater than that of upward-reserve capacity because downward reserve requires a generation level above the minimum power. Therefore, losses in the day-ahead market are greater. Start-up costs are accounted for if some capacity of the block

Table 1. Opportunity Cost of Reserve Capacity for Thermal and Hydro Power Plants.[9]

Case	Upward reserve	Downward reserve
$C_g \leqslant p^{DA}_{n,t}$	$p^{DA}_{n,t} - C_g$	0
$C_g > p^{DA}_{n,t}$	$\left(C_g - p^{DA}_{n,t}\right)\frac{Q_{g,n}}{Q^{RA}_{g,m,n}} + \frac{CS_g\bar{Q}_{g,n}}{Q^{RA}_{g,m,n}} S_{g,n,t}$	$\left(C_g - p^{DA}_{n,t}\right)\left(\frac{Q_{g,n}}{Q^{RA}_{g,m,n}} + 1\right) + \frac{CS_g\bar{Q}_{g,n}}{Q^{RA}_{g,m,n}} S_{g,n,t}$

Table 2. Opportunity Cost of Reserve Capacity for Batteries.[10]

Case	Upward reserve	Downward reserve
$C^a_b \leqslant p^{DA}_{n,t}$	$p^{DA}_{n,t} - C^{up}_b$	0
$C^a_b > p^{DA}_{n,t}$	0	$C^{down}_b - p^{DA}_{n,t}$

has been started during the period t, that is, $S_{g,n,t}$ is equal to one in this case and zero otherwise. The quotient $\frac{Q_{g,n}}{Q^{RA}_{g,m,n}}$ corresponds to the minimum number of MW that needs to be operating in order to supply 1 MW of reserve.

The flexibility of batteries implies a different definition of their opportunity cost. In fact, there is a cost to supply reserve capacity only when there is a trade-off with the day-ahead market (Table 2). The provision of upward-reserve capacity implies a trade-off with the day-ahead market only if it is profitable to sell energy in the day-ahead market. The revenue in the day-ahead market ($p^{DA}_{n,t}$) is greater than or equal to the cost of having less storage in future periods ($\left|\frac{\lambda_{b,n,t}}{\eta_b}\right|$ with $\lambda_{b,n,t}$ the storage value of the battery b in period t, and η_b the efficiency rate). Thus, the opportunity cost is the difference between the lost profit in the day-ahead market and the profit earned by using the stored energy at another time. Since the provision of reserve capacity does not automatically imply the provision of reserve energy, the removal of capacity from the day-ahead market to the upward reserve-capacity market means that some of the stored energy is saved and can be used at another time. When it is not profitable to sell energy in the day-ahead market, there is no arbitrage so that the opportunity cost is zero. When the battery buys energy in the day-ahead market, there is no arbitrage either. Indeed, an increase in the purchase of energy in this market does not automatically imply a decrease in the supply of upward-reserve capacity.

For downward reserve, there is a trade-off between the reserve supply and the day-ahead market when it is profitable to charge the battery. The cost of charging the battery ($p^{DA}_{n,t}$) is less than the possible future profits with this stored energy ($|\lambda_{b,n,t}\eta_b|$). Otherwise, the supply of downward-reserve capacity is not constrained by the volume selected in the day-ahead market. As a result, the opportunity cost is zero.

From Table 2, we can observe that the variable cost for upward reserves decreases with the efficiency rate. Consequently, for the same expected future profits, the opportunity cost

[9]Start-up costs are accounted for only if some capacity of the block g has been started during the period t ($S_{g,n,t} = 1$ if $s_{g,n,t}>0$). C_g equals the water value for hydro blocks.

[10]C^a_b is the variable cost of the battery b for the reserve a. For upward reserve, $C^{up}_b = \left|\frac{\lambda_{b,n,t}}{\eta_b}\right|$ with $\lambda_{b,n,t}$ the storage value at time t and η_b the efficiency rate of the battery. For downward reserve, $C^{down}_b = |\lambda_{b,n,t}\eta_b|$.

of the less efficient battery is more likely to be zero. In fact, the day-ahead price required to have a positive opportunity cost is higher that for a more efficient battery. For downward reserves, the variable cost of a battery increases with its efficiency rate. Therefore, the opportunity cost of the less efficient battery is more likely to be zero for the same expected future profits. Thus, a less efficient battery will be further to the left of the merit-order curve of the reserve-capacity market than a more efficient battery. The result can be the displacement of more efficient batteries from reserve-capacity markets. This, in turn, means that these efficient batteries may not be available to supply reserve energy, resulting in a suboptimal allocation of balancing resources.[11]

3.4. Case Study

The model is applied to the 2022 version of the TYNDP scenarios of the ENTSO-E and ENTSO-G (2022). There are two scenarios, Distributed Energy and Global Ambition, representing two distinct pathways to achieve carbon neutrality by 2050.[12] Distributed Energy is characterized by higher energy-efficiency levels and higher electrification rates of heating and transport. In Global Ambition, hydrogen plays a bigger role (ENTSO-E and ENTSO-G 2022). Regarding technology options, solar and onshore wind are preferred in the Distributed Energy scenario, whereas offshore wind is favored in the Global Ambition scenario.

In the TYNDP scenarios, the electricity and gas sectors are represented with several nodes for each country. The differences between nodes concern the type of energy demand and supply. Hydrogen demand data is available only at the annual level. Hence, it is assumed that hydrogen is generated with surplus electricity after the electricity demand at the electricity nodes is covered.

The load in the day-ahead market corresponds to the sum of demand at the three electricity nodes minus the aFRR energy demand. The annual peak load is show in Figure 3 for a selection of countries. The annual load for each country is shown in Figure B-1 in Appendix B. Due to a lack of input data, it is not possible to model vehicle-to-grid properly. For the installed capacity of wind and solar, the capacity dedicated solely to hydrogen production is not included as there is no trade-off with the wholesale electricity market in this case. The installed capacity for gas on the one hand and coal and lignite on the other hand are given at an aggregate level. They are separated into several categories to better represent the different technologies and, thus, flexibility levels. This decomposition is based on the 2020 version of the TYNDP scenarios for which installed capacities were given with more precision between the different gas-fired and coal-fired power plants.

The aFRR energy demand levels are time-series forecasts obtained from auto-regressive moving-average models with exogenous variables (ARMAX). The method has been developed in previous work where the relationship between reserve-energy demand and the residual load level has been analyzed (Deman and Boucher 2023). The method is inspired by the literature on short-term load forecasting (Cuaresma et al. 2004; Do, Lyócsa and Molnár

[11]A sensibility analysis has been conducted to confirm this intuition by applying different efficiency rates to batteries. Over a one-week simulation, the less efficient batteries are never dispatched on the day-ahead market but are largely used in the reserve-capacity markets.

[12]There is another scenario, National Trends, but its objective in terms of reduction of greenhouse gas emissions is less ambitious. This scenario is built from a collection of national scenarios reflecting national policies stated at the end of 2020. Therefore, this scenario does not reflect a pathway to achieve carbon neutrality by 2050. As a result, the National Trends scenario is not included in the analysis for ease of comparison and transparency in the scenario-building methodology.

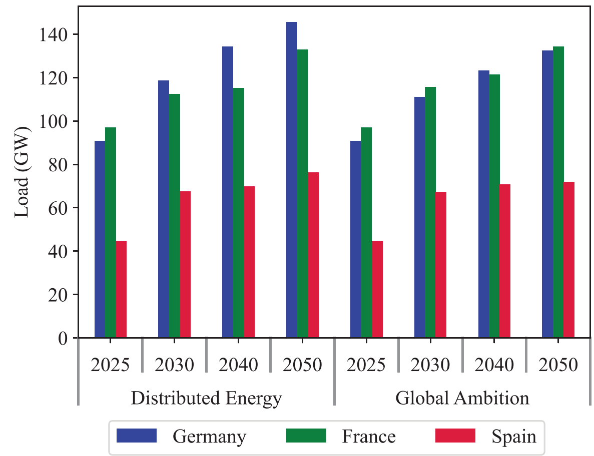

Figure 3. Peak load in the TYNDP scenarios in a selection of countries (GW).

2021) and day-ahead price analysis (Ketterer, 2014; Kyritsis, Andersson and Serletis 2017). After checking for the stationarity of the series, the number of autoregressive and moving-average terms is chosen to eliminate residual autocorrelation and to minimize the Akaike information criterion. The models are applied to the net aFRR energy demand, that is, the upward minus the downward aFRR energy demand level, with an hourly time step. The net-demand level is used to reduce the frequency of zero values. This approach makes it possible to obtain normally-distributed residuals, which is a necessary assumption for the calculation of forecasts. As a result, for a given period, the aFRR energy demand is either upward or downward. The exogenous variables are load, renewable-energy generation, and a series of dummies for the day of the week and the month of the year. The annual values are shown in Figure 4 for all countries. The detail for each country is available in Appendix B (Tables B-2 and B-3).

The aFRR capacity demand levels are percentiles of the aFRR energy demand forecasts. This method complies with the requirement of a probabilistic methodology set by the SOGL. It also enables consistency between aFRR capacity and aFRR energy-demand levels. A security level of 1 percent is taken in accordance with Article 157 of the SOGL. Only for Germany, a security level of 0.05 percent is taken because it is the level currently applied. The FCR capacity-demand levels are determined keeping the 3 GW requirement for the Continental area (IEA 2021). The annual generation and load data from the dataset of the 2022 TYNDP scenarios are taken to calculate the distribution among countries.

The studied countries are Belgium, the Netherlands, Austria, Germany, Switzerland, France, Spain, and Portugal. The evolution of the power mix in these countries is illustrated in Figure 5. The rise in renewable capacity can easily be seen. The preference for

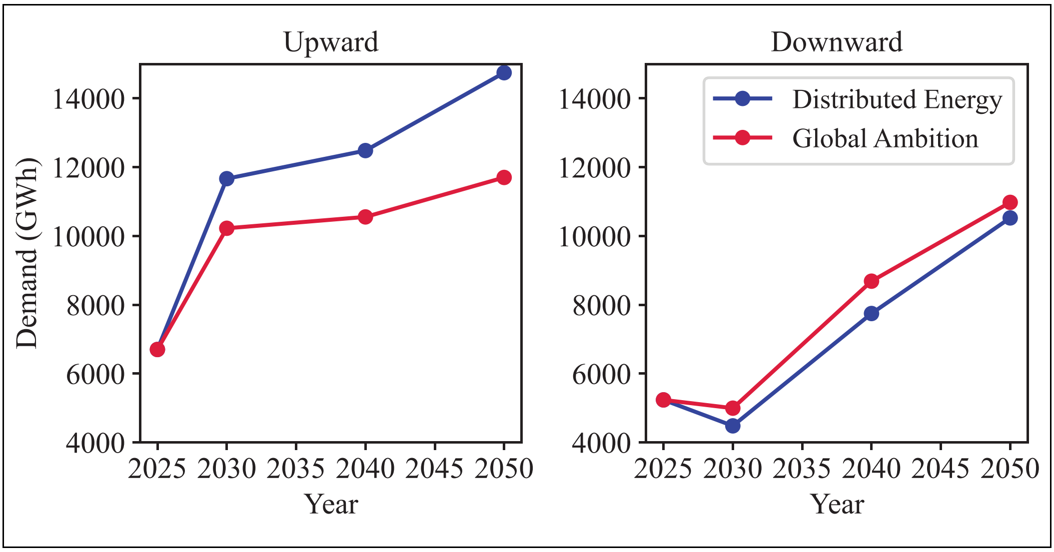

Figure 4. Annual aFRR energy demand (GWh).[13]

solar and the higher electrification rate in the Distributed Energy scenario renders a higher total installed capacity in this scenario. However, the share of renewable energy is similar in both scenarios. The capacity of fossil-fueled power plants is roughly constant but declines in relative terms. The penetration of batteries is noticeable from 2030 to accommodate the intermittency of renewable energy.[14] It should be noted that these battery capacities enable flexibility needs in the electricity market to be covered, but not necessarily in the reserve markets since they are not accounted for in the model used by ENTSO-E and ENTSO-G to build their scenarios. In fact, reserves are not represented in their model, so the only flexibility needs are those associated with the variability of VRE generation, but not its imperfect predictability.

The model is run for the years 2025, 2030, 2040, and 2050. In 2025, the same demand levels and power mixes are assumed in both scenarios because there is not enough time to see a clear difference between the two scenarios (ENTSO-E and ENTSO-G 2022).

4. Results

This section analyses the results obtained with the Distributed Energy scenario. In doing so, we evaluate how energy and reserve prices evolve with high shares of renewables and storage. This allows conclusions to be drawn about the profitability of reserve-capacity markets and their ability to mitigate the missing-money problem for flexible technologies. It should be noted that similar conclusions can be drawn from the results obtained with the Global Ambition scenario.

Spain, Germany, and France are chosen for the analysis, because these countries represent an important part of the demand of the power system represented. In addition, their power

[13]Annual levels for 2019 are given for reference, they amounted to 4,960 GWh for upward activations and 4,372 GWh for downward activations in 2019.

[14]The fixed costs of batteries are assumed to decrease by 33 percent between 2025 and 2050, reflecting innovation benefits. However, since the same cost assumptions are used in both TYNDP scenarios, the different levels of battery capacity between scenarios are the result of different flexibility needs.

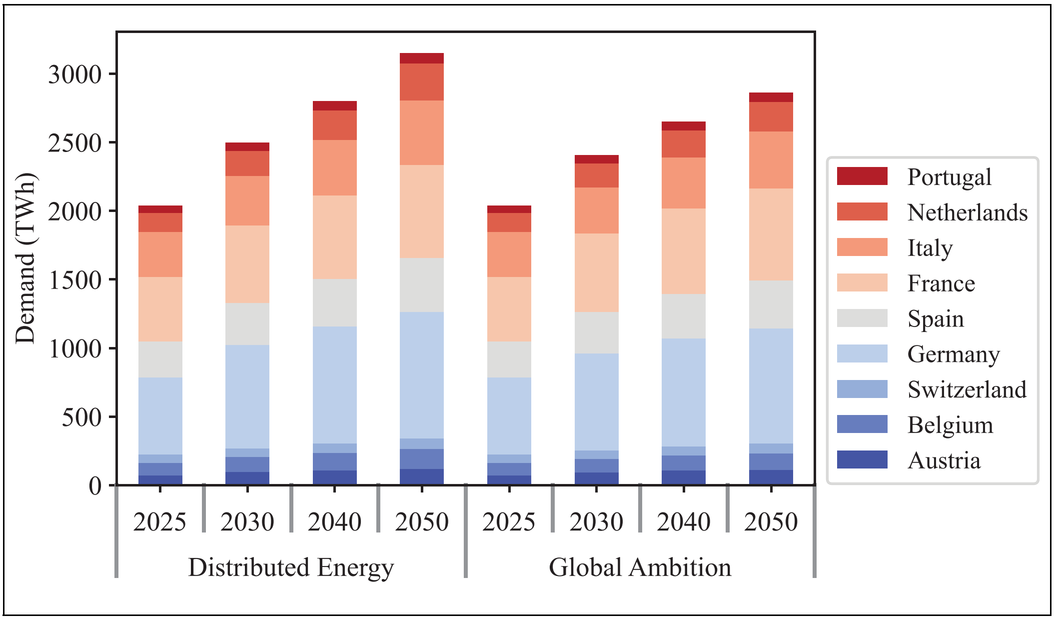

Figure 5. Installed capacity in the TYNDP scenarios (GW).

Table 3. Weighted-average Day-ahead Price (€/MWh).

	Scenario							
	Distributed energy				Global ambition			
Country	2025	2030	2040	2050	2025	2030	2040	2050
Germany	54	159	48	57	54	215	279	235
Spain	47	33	16	20	47	19	20	13
France	26	37	30	50	26	28	19	37

systems exhibit contrasting patterns. For example, Spain is relatively isolated from the other countries, and its power mix has a significant potential for solar energy. Meanwhile, France is more interconnected and has a historical nuclear fleet. Finally, Germany is also well interconnected and has an substantial potential for wind energy.

4.1. Relationship of Forecasted Day-Ahead Prices With Reserve Markets

The evolution of the weighted-average day-ahead prices is shown in Table 3 for both scenarios. Spain balances its energy system with its renewable capacities, some gas-fired plants, and its imports. Consequently, its prices remain low. In France, we observe an increasing trend in prices, but this increase is moderated by nuclear plants. In Germany, prices soar because of imbalances between renewable capacities and demand. In both cases with higher prices (France and Germany), the lost load explains these trends. Even with a low frequency of occurrence, it has a significant impact on the average day-ahead price due to its high unit cost (€2,001/MWh). For instance, there are twenty-one hours with lost load in France in

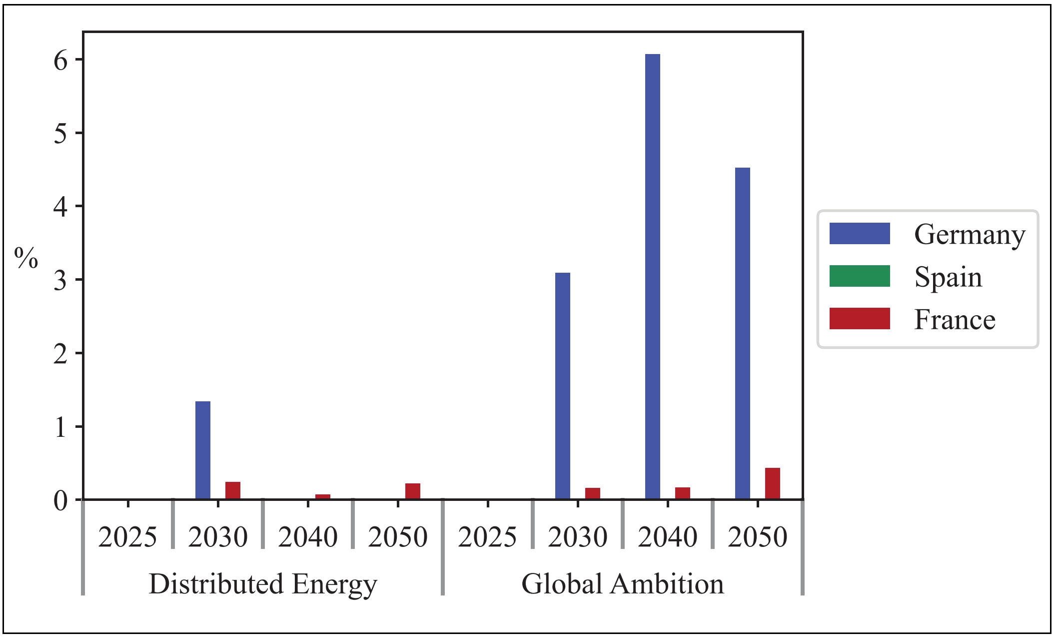

Figure 6. Frequency of lost load in the day-ahead market.[15]

2030 in the Distributed Energy scenario, accounting for 53 percent of the annual day-ahead market costs (Figure 6).

The impact of lost load in Germany is particularly striking for day-ahead prices with the Global Ambition scenario from 2030 (Figure 6). Renewable-energy capacities are insufficient to cover the electricity demand. The German power mix does not cover the flexibility and dispatchable generation needs. Indeed, gas capacity is almost constant in this scenario whereas it more than doubles in the Distributed Energy scenario. Therefore, Germany needs to import energy to balance its system. We should note that not all of its interconnections are included in the model. In particular, the Danish interconnector allows Germany to benefit from the flexibility of the Nordic power system with its large shares of hydropower. Thus, not representing these countries withholds an important source of imports for Germany.

To better analyze the evolution of day-ahead prices, their distribution in the Distributed Energy scenario is shown in Figure 7. In the three countries, the frequency of zero prices increases over time until reaching 35 percent in Germany, 60 percent in Spain, and 45 percent in France in 2050. These frequencies are driven by the increasing share of renewable energy. As their variable costs are negligible, the day-ahead price is zero if they are marginal. However, zero prices do not mean that renewable energy covers all the demand. Conventional technologies are dispatched not only to supply reserves but also to back up renewable energy. Moreover, it is more cost effective to stay online for them during hours of low residual load due to start-up costs. Therefore, conventional technologies must do a

[15]Germany faces a significant frequency of lost load in the Global Ambition scenario. This is probably due to the lower level of flexible supply in this scenario, with 69 GW of gas, hydro and batteries capacity (compared to 114 GW in the Distributed Energy scenario).

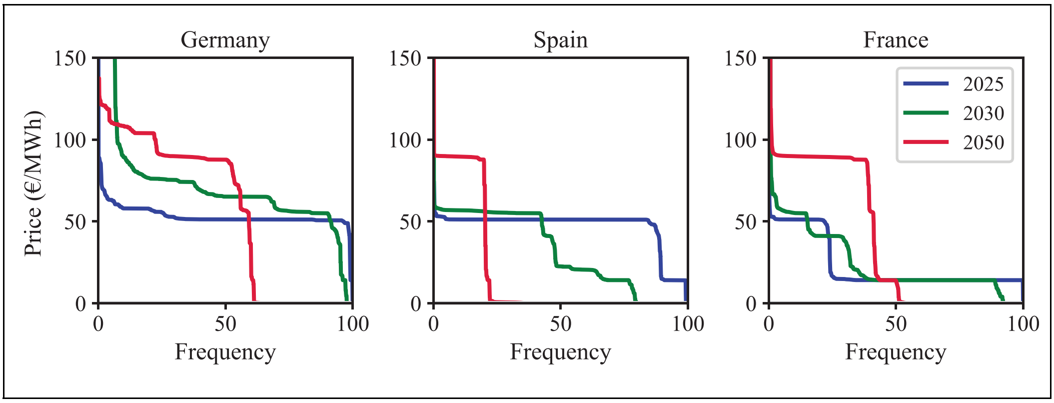

Figure 7. Distribution of day-ahead prices in the Distributed Energy scenario.

trade-off between either supplying reserves or back-up, on the one hand, or being switched off, on the other hand.

4.2. Role of Batteries in the Reserve-Capacity Supply

Over time, batteries become the main supplier of reserve capacity (Figure 8). The pace of transition varies from country to country, depending on the speed of battery installation. For instance, batteries are the only supplier of upward aFRR capacity 74 percent of the time in Germany in 2030, and this share rises to 87 percent in 2050. By contrast, batteries are never the only supplier in France in 2030 because an important part of the demand is covered by nuclear power plants. It is less costly to supply reserve capacity by batteries rather than by gas-fired plants. In the day-ahead market, gas-fired plants are dispatched less often. Consequently, they supply reserve capacity less often as well. It is too costly to call them in the day-ahead market only to supply reserves. In this case, the flexibility of batteries is largely used. In Spain and France, which have high hydro-storage capacity, there is a shift for hydro units between upward aFRR capacity supply and downward aFRR capacity supply. This effect is less visible for Spain in Figure 8 due to the increased downward aFRR capacity demand. Such an increase in the downward aFRR capacity supplied by hydro units is associated with an increase in the volumes dispatched in the day-ahead market. In turn, this increases the potential supply of downward-reserve capacity, which is at zero cost if the unit is also dispatched in the day-ahead market (Table 1). During periods of high VRE generation, the supply of downward-reserve capacity by hydro units avoids the dispatch of gas-power plants, which are more costly, more carbon intensive, and less flexible.

4.3. Low Opportunity Costs of Batteries

This change in the supply structure does not have a significant impact on the reserve-capacity prices (Figure 9). The most extreme case is Germany where changes in the price distribution are really limited. In 2025, batteries are already marginal the majority of the time, and they become increasingly so over time. The opportunity cost of batteries can equal to zero for two reasons (Table 2). On the one hand, their opportunity cost is zero when there is no arbitrage

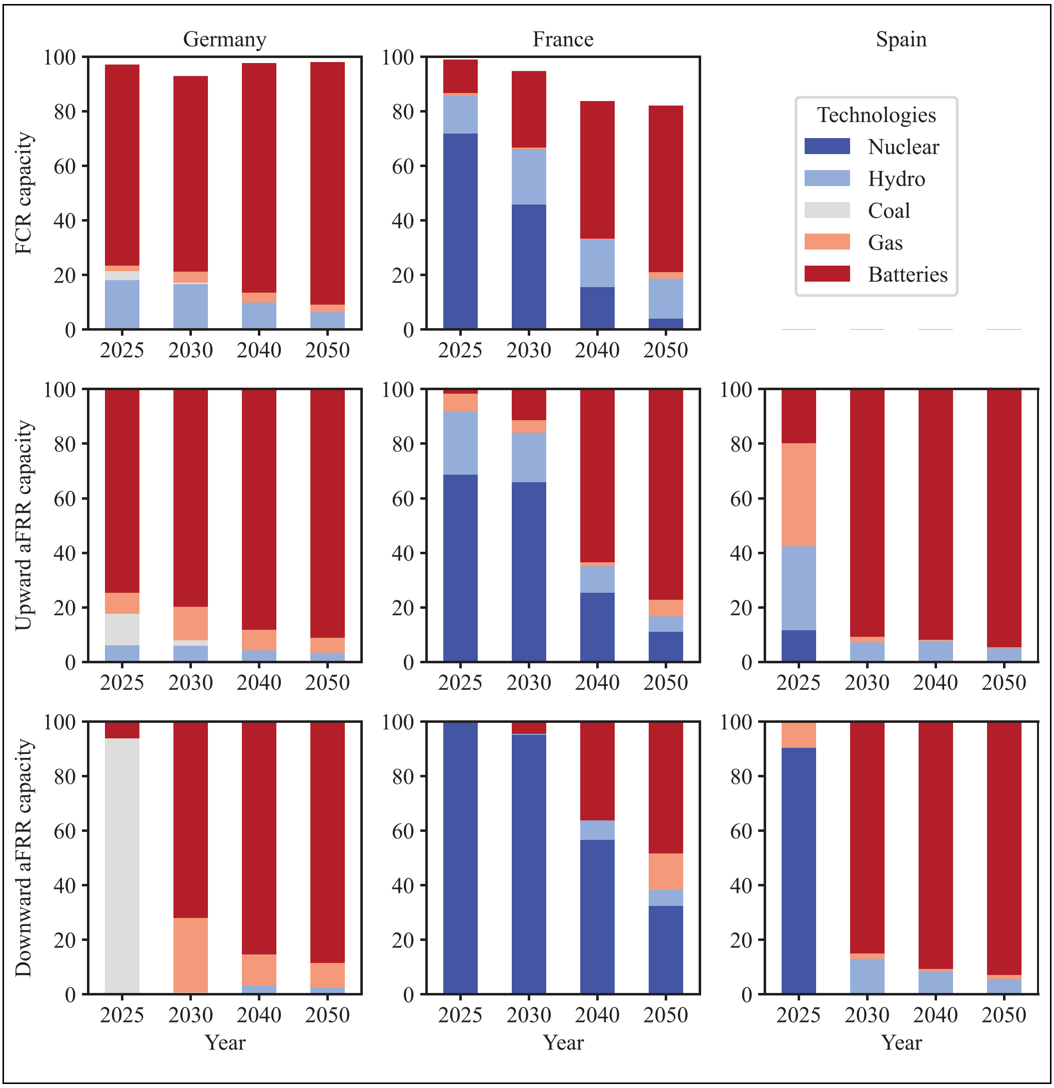

Figure 8. Distribution of reserve capacity supply in Germany, Spain, and France (Distributed Energy scenario).[16]

with the day-ahead market, that is, when batteries only supply reserves. On the other hand, the opportunity cost of batteries is zero when they are marginal in the day-ahead market.

The first situation becomes less frequent over time as batteries are more needed in the day-ahead market to cover the intermittency of renewables. In case of dispatch in the day-ahead market, batteries set the price the majority of the time (Figure 10). Thus, batteries are more often the marginal unit, and the intuition on price levels is the following. Their variable cost is a function of the efficiency rate and the storage value, which is equivalent to the water value for hydropower. It reflects the increase in profits obtained by saving energy for future periods (Wolfgang et al. 2009). Since it is optimal to use this energy to replace the most expensive generation units, the storage value is equal to the marginal cost of generation in periods with the

[16]FCR capacity supply is less than 100 percent because of imports.

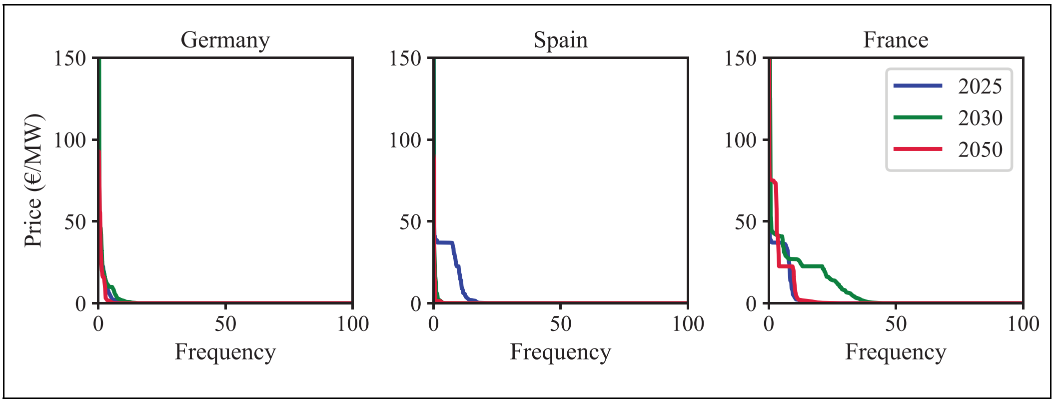

Figure 9. Distribution of upward aFRR capacity prices (Distributed Energy scenario).

highest day-ahead prices. Their flexibility means that there are few constraints preventing them from being dispatched during these hours. Consequently, batteries are either the most expensive unit dispatched or have the same marginal cost as the marginal unit in the day-ahead market. This relationship implies that when a battery is facing an arbitrage between the day-ahead and the reserve-capacity market, it is indifferent between the two markets, thereby resulting in a zero opportunity cost.

The same phenomenon is observed for downward-reserve capacity. The opportunity cost is positive when there is an arbitrage with the charging of the battery (Table 2). However, the battery also sets the day-ahead price when it is buying energy in this market. In this case, the price is equal to $|\lambda_{b,n,t}\eta_b|$. This can be explained by the fact that the energy consumption of batteries can easily be reduced to cover a marginal increase in demand and keep the system balanced. Consequently, the opportunity cost for downward-reserve capacity is zero. On the other hand, the batteries are charged a small fraction of the year, for example, between 20 percent and 30 percent of the time in 2050. When it is not the case, there is no arbitrage between the day-ahead and the downward-reserve capacity market, thereby implying a zero opportunity cost.

The intraday market, which can be an important source of revenue for flexible units, is not considered in the calculation of opportunity costs. However, it does not affect the opportunity costs associated with batteries. Indeed, if the storage value of a battery cannot be below the day-ahead market price when it is dispatched in this market, then it should also be the case when considering an additional dispatch option, for example, the intraday market. In this case, the storage value takes into account the expected profits in the intraday market in addition to those in the day-ahead market. Thus, the opportunity cost of reserve capacity is calculated using the maximum of the day-ahead and the intraday market prices (instead of the day-ahead market price). Therefore, the opportunity cost would have the same property as the one obtained by considering only the day-ahead market.

Similarly, the introduction of uncertainty does not increase the opportunity costs of batteries. In this case, the expected wholesale energy price is compared to the expected variable cost for reserve. Both expectations are obtained by weighting each element by its associated probability. In the case of upward-reserve capacity, if the wholesale energy price for a given scenario cannot be greater than the variable cost for reserve, then the same applies to their expectations over a whole set of scenarios. This is confirmed by comparing the expected opportunity costs of batteries to their deterministic opportunity costs, following the methodology presented in Appendix C.

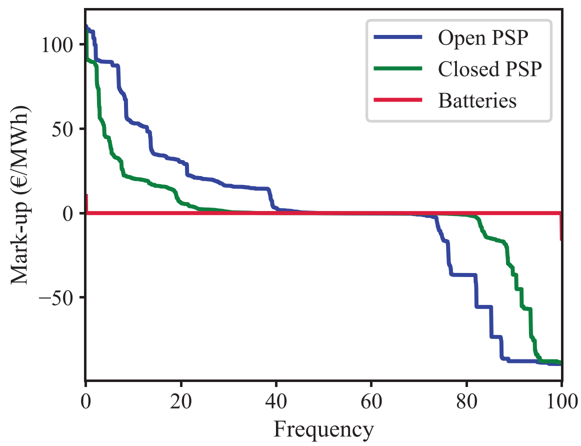

Figure 10. Mark-up of flexible technologies on the day-ahead market in Germany (Distributed Energy scenario in 2050).[17]

4.4. Comparison With Other Storage Technologies

In our model, we consider three hydropower technologies: run-of-river, reservoirs, and pumped storage. In the following, we only analyze pumped storage technologies as they produce and they consume energy as batteries. Run-of-river does not have storage, and reservoirs do not consume energy. Thus, they differ from batteries.

In contrast to batteries, hydro units are not always marginal in the day-ahead market (Figure 10). We observe the same tendencies in France and Spain. Their start-up costs mean that it is not always profitable for them to replace the most expensive units in the day-ahead market. As a result, their water value is less volatile and is often lower than the day-ahead price. This results in positive opportunity costs for upward-reserve capacity when they are dispatched in the day-ahead market. Their opportunity cost is also positive when the day-ahead market is not profitable (Table 1). In this case, the minimum power and ramping constraints introduce losses in the day-ahead market that need to be covered by the reserve-capacity price. These two factors imply that the opportunity cost is more often positive for hydro units than for batteries. This pushes hydro units out of the market for upward-reserve capacity for a significant proportion of the time. In fact, the frequency of dispatch of hydro units in the upward aFRR capacity market decreases by 30 percent in Germany, by 87 percent in Spain, and by 55 percent in France between 2025 and 2050, while the frequency of dispatch in the day-ahead market remains similar. On the other hand, the frequency of dispatch of batteries in the reserve-capacity market increases by 23 percent in Germany, by three times in Spain, and by seven times in France over the same period, following a significant increase in their installed capacity.

In the downward aFRR capacity market, the opportunity cost of hydro units is zero if they are dispatched in the day-ahead market. As such, the cost difference with batteries does not explain their frequency of dispatch as it does for upward aFRR capacity. However, hydro units rarely supply downward aFRR capacity, despite the fact that they generate in the day-ahead market most of the time. For instance, pumped-storage units supply

[17]Mark-ups are negative when the reservoir is being filled. Start-up costs are not accounted for hydropower.

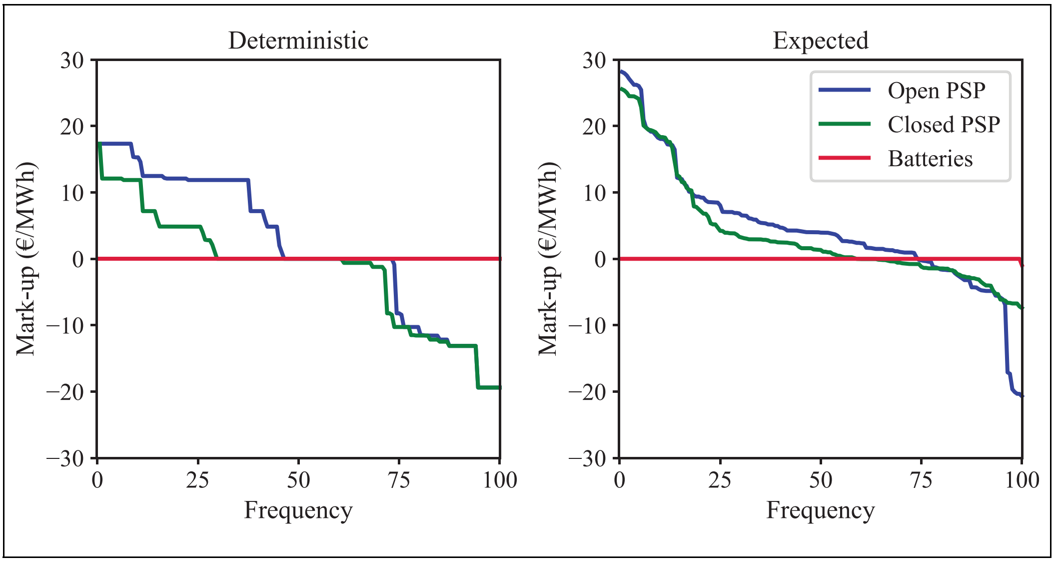

Figure 11. Mark-up of flexible technologies on the day-ahead market in Germany (Distributed Energy scenario for the first week of 2040).

downward aFRR capacity less than 10 percent of the time in 2050 in Germany, Spain, and France. This can be explained by the fact that supplying downward reserve requires a generation level above the minimum power level for hydro units in the day-ahead market. To keep the system balanced, this energy has to be compensated by either spillage, exports, pumping, or charging of batteries. Consequently, during periods of energy surplus, it is more efficient to have batteries supplying downward-reserve capacity, as they do not have this constraint. In fact, the minimum-power constraint could increase the energy surplus of the system and may not always be compensated.

The introduction of uncertainty at the reserve-capacity market stage exacerbates these patterns (Figure 11). The expected mark-up of hydro units in the day-ahead market is more often different from zero than the deterministic one. In fact, over the whole set of weather scenarios, we can expect that the hydro unit is not marginal in the day-ahead market in at least one case. By contrast, there is no difference between the deterministic and the expected mark-up for batteries for the reason explained in Section 4.3. Consequently, it is possible that batteries may displace hydro units in the market for upward-reserve capacity, even when considering uncertainty.

5. Discussion and Conclusions

Decarbonizing the power mix also requires the decarbonization of the flexibility supply. With fewer fossil-fueled power plants, investments in storage and flexibility options are needed to cover the increasing demand for reserves. An important body of the literature has analyzed the different drivers of efficiency in reserve markets (Dallinger, Auer and Lettner 2018; Farahmand and Doorman 2012; Jaehnert and Doorman 2012; Van den Bergh and Delarue 2020). In this paper, we change the perspective by focusing on the profitability of these markets in the context of the energy transition. As the day-ahead market prices may not be sufficient to remunerate such investments (Mays 2021; Papavasiliou and Smeers

2017), this paper investigates whether reserve-capacity markets can play the same role as a capacity mechanism for flexible technologies. By remunerating the availability of reserves, independently from their activation, they may send a price signal for investments in flexible technologies. A fundamental model of the day-ahead and reserve markets is used to examine the evolution of reserve prices in scenarios with large shares of renewable energy. Reserve-capacity prices are computed as the marginal opportunity cost with respect to the day-ahead market. To fill a gap in the literature, a definition is proposed for batteries. This definition depends on the profitability to bid on the day-ahead market and on the storage value.

In a power system with high shares of renewable energy, batteries account for a large share of the flexibility of the power system. Over time, they become the main supplier of reserve capacity. Since they can supply reserves alone, it is less costly for the system to dispatch batteries rather than hydro or fossil-fueled power plants in reserve-capacity markets. In these markets, prices do not evolve significantly over time, despite the increasing demand. This is due to the zero opportunity cost of batteries, which can be the result of two distinct situations. On the one hand, their opportunity cost is zero when there is no arbitrage with the day-ahead market, that is, when batteries only supply reserves. On the other hand, the opportunity cost of batteries is zero when they are marginal in the day-ahead market. The first situation becomes less frequent over time as batteries are more needed in the day-ahead market to cover the intermittency of renewables. In case of dispatch in the day-ahead market, batteries set the price the majority of the time because of the relationship between their marginal generation cost and the day-ahead price. As a result, their opportunity cost is often zero. This pushes other technologies out of the market for reserve capacity for a significant proportion of the time.

These results suggest that the additional flexibility of batteries is not rewarded by the market. Indeed, their ability to supply reserves alone eliminates the trade-off with the day-ahead market and, thus, reduces their opportunity cost to zero. Their flexibility also means that they often set the day-ahead price when they are dispatched, reducing their opportunity costs to zero. In contrast, the relatively lower level of flexibility of hydro units implies positive opportunity costs when they are not dispatched in the day-ahead market. With zero opportunity costs, batteries can push other reserve suppliers out of the market for upward-reserve capacity. In this case, they set the reserve-capacity price and receive no remuneration for the availability of their flexibility. This phenomenon can be compared to the cannibalization effect of renewable energy. With higher penetration rates, they reduce their own remuneration with the merit-order effect they induce (Prol, Steininger and Zilberman 2020). These results also suggest that reserve-capacity markets cannot provide an additional remuneration for flexible technologies and thus, do not solve the missing-money problem in the context of the energy transition.

The case study used in this paper includes an exogenous power mix, which is the result of a model where investment decisions are based on the dispatch in the electricity market only. Consequently, it could be suboptimal to meet the flexibility needs in both the electricity and the reserve markets. The suboptimality of the exogenous capacity mix can be illustrated by the high incidence of lost load in some countries, such as Germany for instance. However, due to the structure of opportunity costs for storage, this outcome does not lead to scarcity prices in the reserve-capacity markets. Indeed, the potential lack of flexible supply does not lead to high reserve-capacity prices. We, therefore, believe that our results are robust to the underlying power mix. Introducing endogenous capacity investments in the model could mitigate the missing-money problem. However, the lags in capacity expansion mean that the power system is rarely in perfect equilibrium, which implies that the generation mix is typically not optimal from a system-operations perspective.

6. Appendix

A Model Description

A.1. Nomenclature

Indices and sets			
$t \in \mathcal{T}$	Time periods	$d \in \mathcal{D}$	Days
$n \in \mathcal{N}$	Nodes	$\ell \in \mathcal{L}$	Transmission lines
$g \in \mathcal{G}$	Conventional-generation blocks (hydro and thermal generation blocks)		
$h \in \mathcal{H}$	Hydro blocks	$b \in \mathcal{B}$	Battery blocks
$st \in \mathcal{ST}$	Storage blocks ($\mathcal{H} \cup \mathcal{B}$)	$r \in \mathcal{R}$	Renewable-energy blocks
$i \in \mathcal{I}$	Generation blocks ($\mathcal{G} \cup \mathcal{B} \cup \mathcal{R}$)	$m \in \mathcal{M}$	Markets
$m^{RC} \in \mathcal{M}^{RC}$	Reserve-capacity markets	$a \in \mathcal{A}$	Direction of reserve activation

Parameters	
$D^m_{n,t}$	Demand in market m at node n in period t (MW for reserve-capacity markets, MWh for others)
K_ℓ	Net transfer capacity of transmission line ℓ (MW)
$A_{\ell,n}$	Incidence matrix, $\in \{-1, 0, 1\}$
C^{LL}	Value of lost load (€/MWh)
C^{DR}	Activation cost for demand response (€/MWh)
$\overline{DR}_n$	Maximum number of activations per day for demand response at node n
$\overline{Q}_{dr,n}$	Limit of demand response at node n (MW)
$\overline{Q}_{i,n}, \underline{Q}_{i,n}$	Maximum and minimum power of block i at node n (MW)
CS_g	Start-up cost of block g (€/MW/start-up)
C_g	Variable cost of block g (€/MWh)
$Q^{RA}_{g,m,n}$	Ramping limit of block g at node n for reserve m^{RC} (MW)
η_{st}	Efficiency rate of storage block st (%)
$F_{r,n,t}$	Load factor of block r at node n in period t, $\in [0, 1]$
$I_{h,n,t}$	Natural inflows to hydropower block h at node n in period t (MWh)
$\bar{V}_{st,n}$	Maximum reservoir capacity of storage block st at node n (MWh)
$\bar{X}_{m,n}, \bar{M}_{m,n}$	Maximum export and import values of reserve capacity m^{RC} at node n (MW)
Variables	
$q^m_{i,n,t}$	Volume sold in market m by block i at node n in period t (MW for reserve-capacity markets, MWh for others)
$u^{DA}_{st,n,t}$	Volume of energy bought in day-ahead market by storage block st at node n in period t (MWh)
$x^1_{g,n,t}$	Per unit generation between 0 and minimum power of block g at node n in period t, $\in [0, 1]$
$x^2_{g,n,t}$	Per unit generation between minimum and maximum power of block g at node n in period t, $\in [0, 1]$
$x^3_{g,n,t}$	Per unit capacity allocated to reserve capacity of block g at node n in period t, $\in [0, 1]$
$x^{1P}_{st,n,t}$	Per unit share of maximum power used to fill the reservoir of unit st at node n in period t, $\in [0, 1]$
$s_{g,n,t}$	Capacity share of block g started at node n in period t, $\in [0, 1]$
$v_{st,n,t}$	Reservoir level of storage block st at node n in period t (MWh)
$w_{h,n,t}$	Spilled energy from hydropower block h at node n in period t (MWh)
$f^m_{\ell,t}$	Energy flow from market m in transmission line ℓ in period t (MWh)
$z^{m^{RC}}_{\ell,t}$	Exchanges of reserve capacity m^{RC} on transmission line ℓ in period t (MW)
$f^{IN}_{\ell,t}$	Change in energy flow due to imbalance netting in transmission line ℓ in period t (MWh)
$d^{DA}_{n,t}$	Lost load in the day-ahead market at node n in period t (MWh)

(continued)

$d^{RT}_{n,t}$	Lost load in real-time at node n in period t (MWh)
$dr^{DA}_{n,t}$	Demand response activated in the day-ahead market at node n in period t (MWh)
$dr^{aFRRe}_{n,t}$	Demand response activated in the aFRR energy market at node n in period t (MWh)
Dual variables	
$p^{m}_{n,t}$	Marginal price in market m at node n in period t (€/MW)
$\lambda_{st,n,t}$	Water (or storage) value of storage block st at node n in period t (€/MWh)

A.2. Objective Function. The objective is to minimize the total costs over all generators, $i \in \mathcal{I}$, to meet the demand in the day-ahead and reserve-energy markets at all the represented nodes, $n \in \mathcal{N}$, and over the entire time horizon, $t \in \mathcal{T}$ (equation (A1)). These include variable costs ($C_i(q^{DA}_{i,n,t} + q^{aFRRe,up}_{i,n,t} - q^{aFRRe,down}_{i,n,t})$) and start-up costs ($s_{i,n,t}\bar{Q}_{i,n}CS_i$). Unit variable costs ($C_i$) include fuel, carbon, and operation and maintenance (O&M) costs (ENTSO-E and ENTSO-G 2022). They are multiplied by the sum of the volumes of energy sold in the day-ahead market ($q^{DA}_{i,n,t}$) and the upward aFRR energy market ($q^{aFRRe,up}_{i,n,t}$). Downward aFRR energy ($q^{aFRRe,down}_{i,n,t}$) reduces the total costs because it implies a payment from the generator to the TSO. Unit variable costs are zero for solar, wind, and hydro units and batteries. Unit start-up costs (CS_i) are multiplied by the share $s_{i,n,t}$ of capacity ($\bar{Q}_{i,n}$) started in period t. Demand response can be activated in the day-ahead market and the upward reserve-energy market ($dr^{DA}_{n,t}$ and $dr^{aFRRe}_{n,t}$ respectively) with a unit cost of C^{DR}. In case of insufficient supply, lost load is accounted in the day-ahead or the upward aFRR energy market ($d^{DA}_{n,t}$ and $d^{RT}_{n,t}$, respectively) with a cost of C^{LL}.

$$\min\left\{\sum_{t\in\mathcal{T}}\sum_{n\in\mathcal{N}}\left\{\sum_{i\in\mathcal{I}}\left\{C_i\left(q^{DA}_{i,n,t} + q^{aFRRe,up}_{i,n,t} - q^{aFRRe,down}_{i,n,t}\right) + s_{i,n,t}\bar{Q}_{i,n}CS_i\right\}.\right.\right.$$
$$\left.\left. + C^{DR}\left(dr^{DA}_{n,t} + dr^{aFRRe}_{n,t}\right) + C^{LL}\left(d^{DA}_{n,t} + d^{RT}_{n,t}\right)\right\}\right\} \quad \text{(A1)}$$

A.3. Constraints

Day-ahead market. The demand-supply equilibrium constraint in the day-ahead market is ensured by equation (A2). The value of the dual variable of this constraint gives the day-ahead marginal price ($p^{DA}_{n,t}$).

$$D^{DA}_{n,t} = \sum_{i\in\mathcal{I}} q^{DA}_{i,n,t} - \sum_{st\in\mathcal{ST}} u^{DA}_{st,n,t} - \sum_{\ell\in\mathcal{L}}\left(A_{\ell,n}f^{DA}_{\ell,t}\right) + dr^{DA}_{n,t} + d^{DA}_{n,t} \ \forall n,t \quad \text{(A2)}$$

The volume committed in the day-ahead market by renewable energy blocks can be smaller than the generation level to allow for spillage (equation (A3)).

$$0 \leqslant q^{DA}_{r,n,t} \leqslant F_{r,n,t}\bar{Q}_{r,n} \ \forall r,n,t \quad \text{(A3)}$$

Energy exchanges between nodes are represented by $f^{DA}_{\ell,t}$. They are multiplied by the value $A_{\ell,n}$ of the incidence matrix A to account for the direction of the flow. For a transmission line ℓ and a node n, $A_{\ell,n}$ equals to 1 if the node n is the starting point of the line ℓ, -1 if it is the ending point, and 0 otherwise. Energy exchanges between nodes are constrained by the net transfer capacity of the transmission line (equation (A4)).

$$-K_\ell \leqslant f^{DA}_{\ell,t} \leqslant K_\ell \ \forall \ell,t \quad \text{(A4)}$$

Equations (A5) to (A7) represent the generation constraints of thermal and hydropower generation units. The volume sold in the day-ahead market ($q^{DA}_{g,n,t}$) is split into two parts as in Farahmand and Doorman (2012) to keep the problem linear. The first part represents the share of online capacity running at minimum power ($x^1_{g,n,t}$). The second part represents the share of capacity operating between minimum and maximum power ($x^2_{g,n,t}$). Equation (A6) ensures that the block is online when it bids into the day-ahead market. It also ensures that the committed capacity is less than or equal to the maximal capacity. Start-up costs are accounted through equation (equation (A7)) with the variable $s_{g,n,t}$. Its value is greater than zero when the value of $x^1_{g,n,t}$ increases between two consecutive periods, that is when a share of installed capacity is started up.

$$q^{DA}_{g,n,t} = x^1_{g,n,t}\underline{Q}_{g,n} + x^2_{g,n,t}\left(\bar{Q}_{g,n} - \underline{Q}_{g,n}\right) \; \forall g, n, t \tag{A5}$$

$$0 \leqslant x^2_{g,n,t} \leqslant x^1_{g,n,t} \leqslant 1 \; \forall g, n, t \tag{A6}$$

$$x^1_{g,n,t} - x^1_{g,n,t-1} \leqslant s_{g,n,t} \leqslant 1 \; \forall g, n, t \tag{A7}$$

For hydro blocks with storage, $q^{DA}_{st,n,t}$ represents the volume sold in the day-ahead market. $u^{DA}_{st,n,t}$ is the volume of energy bought to pump water (equation (A8)). It is expressed as the share of pump capacity ($\bar{Q}^P_{st,n,t}$) used with the variable $x^{1,P}_{st,n,t}$.

$$u^{DA}_{st,n,t} = \overline{Q^P}_{st,n} x^{1,P}_{st,n,t} \; \forall st, n, t \tag{A8}$$

The same logic is applied to batteries. There is no minimal power for batteries, so $q^{DA}_{b,n,t}$ is expressed as a function of $x^1_{b,n,t}$ only (equation (A9)).

$$q^{DA}_{b,n,t} = x^1_{b,n,t}\bar{Q}_{b,n} \; \forall b, n, t \tag{A9}$$

Within each storage block, each unit cannot supply and consume energy at the same time (equation (A10)).

$$0 \leqslant x^1_{st,n,t} + x^{1,P}_{st,n,t} \leqslant 1 \; \forall st, n, t \tag{A10}$$

For hydro blocks with pumps, start-up costs are also accounted when a unit of the block switches from generation to pump mode or the other way around (equation (A11)).

$$x^{1,P}_{h,n,t} + x^1_{h,n,t} - x^{1,P}_{h,n,t-1} - x^1_{h,n,t-1} \leqslant s_{h,n,t} \; \forall h, n, t \tag{A11}$$

The energy-balance constraint of storage blocks is given in equation (A12), where $v_{st,n,t}$ is the amount of energy stored in the reservoir at the end of the period t. It corresponds to the amount of stored energy from the previous period in addition to natural inflows ($I_{st,n,t}$) minus the energy bought in the day-ahead market ($u^{DA}_{st,n,t}$) and spillage ($w_{st,n,t}$). Inflows and spillage equal to zero for batteries. The volume of pumped energy, ($u^{DA}_{st,n,t}$) is added if the block has pumping capacity. The efficiency rate (η_{st}) allows to represent energy losses. The dual variable of the energy balance constraint is the water value for hydro blocks and the storage value for batteries ($\lambda_{st,n,t}$).

$$v_{st,n,t} = v_{st,n,t-1} + I_{st,n,t} - \frac{q^{DA}_{st,n,t} + q^{aFRRe,up}_{st,n,t}}{\eta_{st}} + q^{aFRRe,down}_{st,n,t}\eta_{st} + u^{DA}_{st,n,t}.\eta_{st} - w_{st,n,t}\ \forall st, n, t \tag{A12}$$

The reservoir level should always be lower than the capacity of the reservoir (equation (A13)).

$$0 \leqslant v_{st,n,t} \leqslant \bar{V}_{st,n}\ \forall st, n, t \tag{A13}$$

Activation of demand response in the day-ahead market should be lower than its maximum capacity (equation (A14)).

$$0 \leqslant dr^{DA}_{n,t} \leqslant \bar{Q}_{dr,n}\ \forall n, t \tag{A14}$$

Reserve-capacity markets. The demand-supply equilibrium for each reserve-capacity market is given by equation (A15). If exchanges are not allowed, supply will only come from units at that node.

$$D^{m}_{n,t} = \sum_{i\in\mathcal{I}} q^{m}_{i,n,t} - \sum_{\ell\in\mathcal{L}}\left(A_{\ell,n}.z^{m}_{\ell,t}\right)\ \forall m \in \mathcal{M}^{RC}, n, t \tag{A15}$$

Exchanges are allowed for FCR capacity only, which are constrained by maximum imports and exports values ($\bar{M}_{m,n}$ and $\bar{X}_{m,n}$ (equation (A16)). These values are defined exogenously according to the SOGL (annex VI). Exchanges cannot exceed 30 percent of the FCR capacity demand. In case the FCR capacity demand is lower than 100 MW, exports are limited to 100 MW.

$$-\bar{M}_{m,n} \leqslant \sum_{l\in\mathcal{L}} A_{l,n} z^{m}_{\ell,t} \leqslant \bar{X}_{m,n}\ \forall n, t \tag{A16}$$

The maximum supply of reserve capacity is defined by equation (A17). Following Müsgens, Ockenfels and Peek (2014), we set its values as the minimum between the difference of the maximal and minimal power and the ramping capability of the unit. The former requires that a unit must be online in order to supply reserves, corresponding to the fact that we only consider spinning reserves. Batteries can supply reserve capacity alone so their minimal power is set to zero. The second term is a function of the full activation time of the reserve, that is, thirty seconds for FCR and five minutes for aFRR.

$$0 \leqslant q^{m}_{i,n,t} \leqslant \min\left\{\bar{Q}_{i,n} - \underline{Q}_{i,n}\,;\, Q^{RA}_{i,m,n}\right\} x^{1}_{i,n,t}\ \forall i, m \in M^{RC}, n, t. \tag{A17}$$

In addition to the ramping limit, the supply of reserve capacity is constrained by the operational range of the block. When supplying upward reserve, the maximum capacity should not be exceeded (equations (A18) and (A19)). When supplying downward-reserve capacity, the block should stay above its minimum power (equation (A20)). We follow the approach of Dallinger, Auer and Lettner (2018) to constrain the supply of reserve capacity according to the values of $x^{2}_{g,n,t}$ and $x^{3}_{g,n,t}$ (equations (A18)–(A20)). These constraints ensure that each technology block cannot offer more reserve capacity than available, considering the committed volume in the day-ahead market. It is assumed that hydro pumped-storage blocks cannot supply reserves when they are pumping water.

$$q_{j,n,t}^{FCRc} + q_{j,n,t}^{aFRRc,up} = x_{j,n,t}^{3}\left(\bar{Q}_{j,n} - \underline{Q}_{j,n}\right) \; \forall j \in \mathcal{G} \cup \mathcal{B}, n, t \tag{A18}$$

$$0 \leqslant x_{g,n,t}^{2} + x_{g,n,t}^{3} \leqslant x_{g,n,t}^{1} \leqslant 1 \; \forall g, n, t \tag{A19}$$

$$q_{j,n,t}^{FCRc} + q_{j,n,t}^{aFRRc,down} \leqslant x_{j,n,t}^{2}\left(\bar{Q}_{j,n} - \underline{Q}_{j,n}\right) \; \forall j \in \mathcal{G} \cup \mathcal{B}, n, t \tag{A20}$$

For batteries, reserve capacity can be supplied when charging (equation (A21)) or discharging (equation (A22)). It can also be supplied alone.

$$0 \leqslant x_{b,n,t}^{1} + x_{b,n,t}^{3} \leqslant 1 \; \forall b, n, t \tag{A21}$$

$$0 \leqslant x_{b,n,t}^{1P} + x_{b,n,t}^{2} \leqslant 1 \; \forall b, n, t \tag{A22}$$

For storage blocks, the supply of aFRR capacity is also constrained by the filling level of the reservoir. There should be enough energy in the reservoir for a full activation of upward aFRR (equation (A23)) along with a sufficient margin to fill the reservoir for a full activation of downward aFRR (equation (A24)). For FCR, these constraints are only imposed for batteries to prevent them from supplying FCR when they have no energy stored (equation (A25)). For hydro, since the water reservoir is not fully emptied, the minimum filling rate corresponds to $v_{st,n,t}$ with a value of zero. In addition, the sum of activation over an hour equal to zero in average. Thus, the use of water over an hour is limited. Consequently, it is assumed that hydro blocks can supply FCR without having to consider the filling rate of the reservoirs.

$$q_{st,n,t}^{aFRRc,up} \leqslant v_{st,n,t-1} \; \forall st, n, t \tag{A23}$$

$$q_{st,n,t}^{aFRRc,down} \leqslant \bar{V}_{st,n} - v_{st,n,t-1} \; \forall st, n, t \tag{A24}$$

$$(1/4) * q_{b,n,t}^{FCRc} \leqslant \min\{v_{b,n,t-1}; \bar{V}_{b,n} - v_{b,n,t-1}\} \; \forall b, n, t \tag{A25}$$

Reserve-energy market. The equilibrium between the demand and supply of aFRR energy is ensured by equations (A26) and (A27). Contrary to Backer, Kraft and Keles (2022), Domínguez, Oggioni and Smeers (2019), Farahmand and Doorman (2012), and Jaehnert and Doorman (2012), there is a market-equilibrium constraint for each direction of activation. This choice is motivated by the negative sign assigned to downward activation in the objective function, since they reduce total costs. Indeed, the negative sign allows the most expensive units to be dispatched first for downward activation. With this sign convention and the same costs for generation and reserve energy, a single market-equilibrium constraint leads to unrealistic results with unjustified large activations in both directions that compensate for each other. Expensive units are dispatched in the day-ahead and then replaced by cheaper units in the aFRR energy market.

Overactivation is not an issue in Farahmand and Doorman (2012) and Jaehnert and Doorman (2012) because the day-ahead and reserve-energy costs are minimized separately. As a result, it is not possible to replace large amount of expansive generation with cheaper generation. In Backer, Kraft and Keles (2022), the merit order in the aFRR energy market consists of historical aFRR energy bids. No information has been found on the sign of the downward aFRR energy bids. However, we can infer that having the bidding volume as upper bound represents a stronger constraint.

Both equilibrium constraints are binding even if there is an aFRR energy demand only in one direction for a given period. In the following, the example of upward aFRR energy demand is taken for the explanation. In case of market splitting, downward activation should equal to zero (equation (A27)). In case of exchanges, exports of downward aFRR energy to other countries are possible and should equal to downward activation.

$$D_{n,t}^{aFRRe,up} = \sum_{j \in \mathcal{G} \cup \mathcal{B}} q_{j,n,t}^{aFRRe,up} - \sum_{\ell \in \mathcal{L}} \left(A_{\ell,n} \left(f_{\ell,t}^{aFRRe,up} + f_{\ell,t}^{IN} \right) \right) + d_{n,t}^{RT} + dr_{n,t}^{aFRRe} \ \forall n, t \tag{A26}$$

$$D_{n,t}^{aFRRe,down} = \sum_{j \in \mathcal{G} \cup \mathcal{B}} q_{j,n,t}^{aFRRe,down} + \sum_{\ell \in \mathcal{L}} \left(A_{\ell,n} \left(f_{\ell,t}^{aFRRe,down} + f_{\ell,t}^{IN} \right) \right) \ \forall n, t \tag{A27}$$

Exchanges of aFRR energy are represented with two variables $f_{\ell,t}^{aFRRe,up}$ and $f_{\ell,t}^{aFRRe,down}$. They represent the change in power flows on a transmission line compared to the day-ahead schedule (Domínguez, Oggioni and Smeers 2019). Two distinct variables are necessary to differentiate power flows. If it is not the case, then export of upward aFRR energy in equation (A26) would lead to exports of downward aFRR energy through equation (A27).

For both variables, a positive value indicates an increase in energy export and/or a decrease in imports compared to the day-ahead schedule for the node n. Thus, a positive value of $f_{\ell,t}^{aFRRe,up}$ represents an export of upward aFRR energy while a positive value of $f_{\ell,t}^{aFRRe,down}$ represents an import of downward aFRR energy. The opposite holds for a negative value (Dallinger, Auer and Lettner 2018). The real-time power flow corresponds to the sum of the day-ahead schedule, plus upward and downward aFRR energy and imbalance netting flows (Backer, Kraft and Keles 2022; Dallinger, Auer and Lettner 2018). It should be lower than the net transfer capacity of the transmission line (equation (A28)).

$$-K_\ell \leqslant f_{\ell,t}^{DA} + f_{\ell,t}^{aFRRe,up} + f_{\ell,t}^{aFRRe,down} + f_{\ell,t}^{IN} \leqslant K_\ell \ \forall \ell, t \tag{A28}$$

Imbalance netting is represented by the variable $f_{\ell,t}^{IN}$. It follows the same sign convention as the aFRR energy flows. Its value is positive if there is a downward aFRR energy demand at the node n and an upward aFRR energy demand at the node n'. Its value is negative in the opposite situation. If both countries have an aFRR energy in the same direction then there is no possibility for imbalance netting (Backer, Kraft and Keles 2022). Its maximal value depends on the relative aFRR energy demand levels in the two countries, which are exogenous. For example, if there is an upward aFRR energy demand of 100 MW at node n and a downward aFRR energy demand of 50 MW at node n', $f_{l,t}^{IN}$ should be between −50 MW and 0. However, if the demand at node n equals to 40 MW, then $f_{\ell,t}^{IN}$ should be between 0 and 40 MW (equation (A29)).

$$\begin{cases} f_{\ell,t}^{IN} = 0, & \text{if } sgn\left(D_{n,t}^{aFRRe}\right) = sgn\left(D_{n',t}^{aFRRe}\right) \\ -\min\{D_{n,t}^{aFRRe,up}; D_{n',t}^{aFRRe,down}\} \leqslant f_{\ell,t}^{IN} \leqslant 0, & \text{if } D_{n,t}^{aFRRe,up} > 0 \\ 0 \leqslant f_{\ell,t}^{IN} \leqslant \min\{D_{n,t}^{aFRRe,down}; D_{n',t}^{aFRRe,up}\}, & \text{if } D_{n,t}^{aFRRe,down} > 0 \end{cases} \tag{A29}$$

The maximum supply of upward and downward aFRR energy, $q_{j,n,t}^{aFRRe,up}$ and $q_{j,n,t}^{aFRRe,down}$ respectively, is constrained in the same way as reserve capacity (equation (A30)). It is also constrained by equations (A31) and (A32) to ensure that the units of the block stay between their minimal and maximal power. The supply of FCR is considered in these constraints because the capacity committed in this market should always be available. The same limits apply for batteries except that $x^1_{b,n,t}$ does not appear on the right-hand side of the constraints to allow for the supply of aFRR energy without participating in the day-ahead market. In addition, $\underline{Q}_{b,n}$ equals to $-\bar{Q}_{b,n}$ for batteries.

$$0 \leqslant q^{aFRRe,a}_{j,n,t} \leqslant \min\left\{\overline{Q}_{j,n} - \underline{Q}_{j,n}\,;\, Q^{RA}_{j,aFRR,n}\right\} \forall j \in \mathcal{G} \cup \mathcal{B}, n, t \tag{A30}$$

$$q^{DA}_{j,n,t} + q^{FCRc}_{j,n,t} + q^{aFRRe,up}_{j,n,t} \leqslant x^1_{j,n,t}\overline{Q}_{j,n} \;\forall j \in \mathcal{G} \cup \mathcal{B}, n, t \tag{A31}$$

$$q^{DA}_{j,n,t} - q^{FCRc}_{j,n,t} - q^{aFRRe,down}_{j,n,t} \geqslant x^1_{j,n,t}\underline{Q}_{j,n} \;\forall j \in \mathcal{G} \cup \mathcal{B}, n, t \tag{A32}$$

Demand response can be activated to cover the upward aFRR energy demand. The sum of activations in the day-ahead and aFRR energy market should be lower than the maximum capacity of demand response (equation (A33)). It is also subject to a maximum number of activations per day (equation (A34)).

$$0 \leqslant dr^{DA}_{n,t} + dr^{aFRRe,up}_{n,t} \leqslant \bar{Q}_{dr,n} \;\forall n, t \tag{A33}$$

$$\sum_{t=24.d+1}^{24.(d+1)} \{dr^{DA}_{n,t} + dr^{aFRRe,up}_{n,t}\} \leqslant \bar{Q}_{dr,n}.\overline{DR}_n \;\forall n, d \tag{A34}$$

B. Data for Case Study

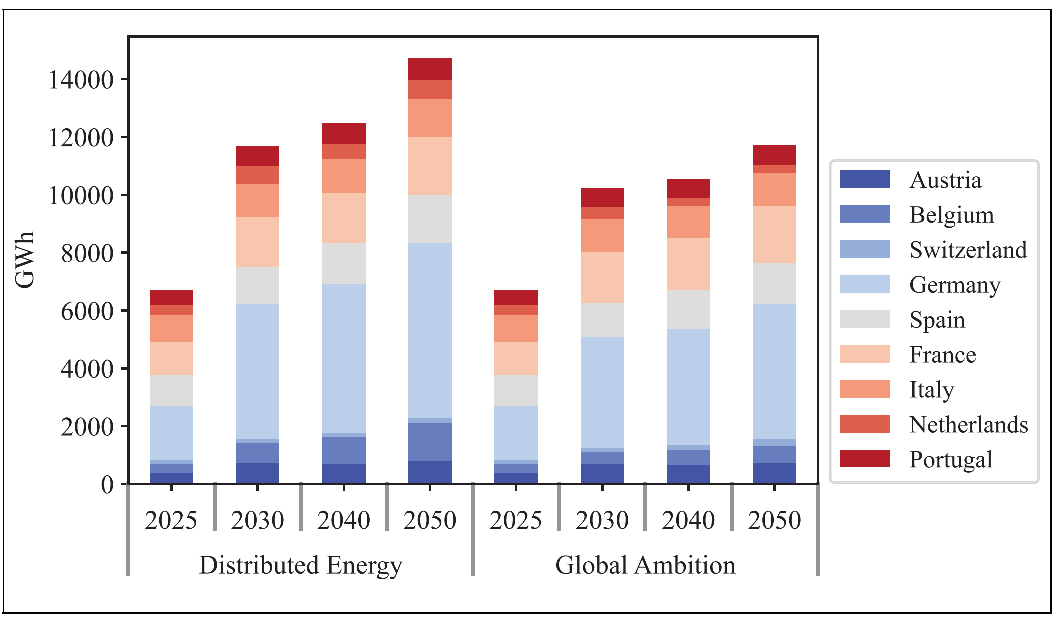

Figure B-1. Annual load in the TYNDP scenarios (TWh).

Table B-1. Installed Capacity in the TYNDP Scenarios (GW).

	Scenario							
	Distributed energy				Global ambition			
Technology	2025	2030	2040	2050	2025	2030	2040	2050
Solar	271	604	1188	1519	271	437	853	1034
Onshore Wind	232	340	536	653	232	309	421	511
Offshore Wind	32	97	190	233	32	124	247	309
Hydro	139	151	156	156	139	151	156	156
Nuclear	71	59	36	15	71	72	63	51
Fossils	232	201	281	323	232	182	164	184
Batteries	9	90	176	261	9	65	119	155

Table B-2. Annual Upward aFRR Energy Demand (GWh).

	Scenario							
	Distributed energy				Global ambition			
Country	2025	2030	2040	2050	2025	2030	2040	2050
Austria	382	718	694	814	382	685	678	719
Belgium	306	707	932	1305	306	420	505	611
Switzerland	141	141	144	175	141	151	177	221
Germany	1,879	4,658	5,131	6,039	1,879	3,828	4,003	4,665
Spain	1,052	1,281	1,449	1,679	1,052	1,192	1,361	1,440
France	1,140	1,725	1,722	1,980	1,140	1,757	1,795	1,971
Italy	959	1,146	1,177	1,313	959	1,124	1,087	1,125
Netherlands	329	633	525	668	329	438	298	291
Portugal	514	658	708	773	514	630	650	657

Table B-3. Annual Downward aFRR Energy Demand (GWh).

	Scenario							
	Distributed energy				Global ambition			
Country	2025	2030	2040	2050	2025	2030	2040	2050
Austria	199	151	328	379	199	150	284	349
Belgium	366	179	203	211	366	329	349	355
Switzerland	180	183	210	199	180	167	157	137
Germany	1,013	276	342	473	1013	395	456	565
Spain	1,395	1,417	1,788	2,201	1,395	1,422	1,569	1,760
France	1,262	1,124	1,910	2,394	1,262	1,118	1,966	2,120
Italy	301	423	717	1,029	301	333	508	673
Netherlands	475	685	2,184	3,554	475	1,038	3,339	4,950
Portugal	44	44	63	84	44	44	59	67

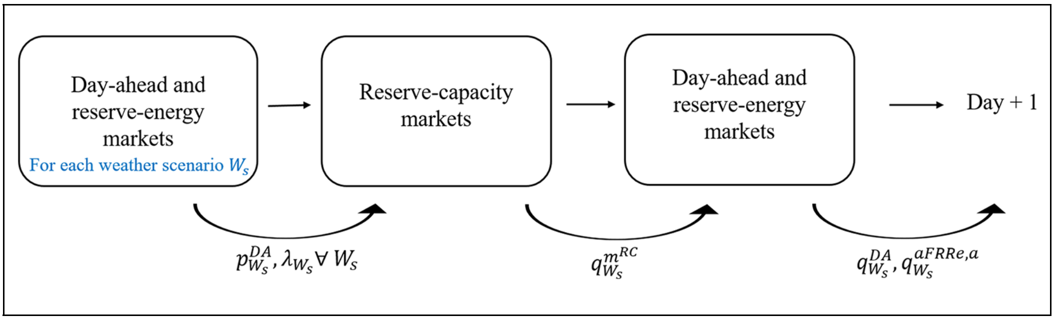

Figure C-1. Description of the model with uncertainty.[18]

C. Extension With Uncertainty

To better assess the impact of uncertainty on reserve-capacity opportunity costs, an extension to the model is presented in this Appendix. To that end, uncertainty is introduced between the reserve-capacity markets stage and the other stages (Figure C-1). This is done by splitting the resolution of the model into three stages. In the first stage, only the day-ahead and the reserve-energy markets are represented. This stage is solved for a set of weather scenarios (denoted W_s). From these simulations, the day-ahead prices, the water values and the storage values associated with each weather scenario are taken. These are used for the second stage, that is, the reserve-capacity markets, where the objective is to minimize the total procurement costs. The bidding prices consist of the expected opportunity costs, calculated from the set of day-ahead prices, water values, and storage values taken from the first step. The calculation of opportunity costs is based on the same methodology as in Section 3.3. The resulting dispatch is used as input to obtain the actual dispatch in the day-ahead and reserve-energy markets (third stage). This process is applied to a single day at a time to reflect the clearing process of the reserve-capacity and day-ahead markets.

The resolution of this model for a full year is computationally challenging due to the size of the problem. With the TYNDP scenarios, we have access to three sets of weather conditions for the load and VRE generation series. With three weather scenarios, the model would result in a scenario tree with $3^{365} = 1.4 \times 10^{174}$ branches. Since our objective is to assess the impact of uncertainty on opportunity costs, we can limit our analysis to the comparison of expected and deterministic opportunity costs at the end of the second stage. This comparison allows to see whether the conclusions obtained with the deterministic model still hold when uncertainty is introduced in the reserve-capacity markets. To that end, the first two stages are run with a horizon of one day. The first stage is run separately for each weather scenario. We consider twenty-seven weather scenarios for each day, which are the combination of three sets of weather conditions for three parameters: load, VRE generation, and reserve-energy demand. The deterministic model is also run for one day and one weather scenario. The resulting opportunity costs are calculated and referred to as the deterministic opportunity costs. The same restrictions are applied to the reservoirs of hydro units and batteries to obtain comparable results. Some results are shown in Figure C-2 for the Distributed Energy scenario in 2040.[19] The blue and red curves show the reserve-capacity prices under

[18]Subscripts for the units, nodes, and time periods have been omitted to ease the reading.

[19]The same probability is applied to each weather condition when calculating the expected opportunity costs. When it is not the case, reserve-capacity prices are slight different but they show the same pattern.

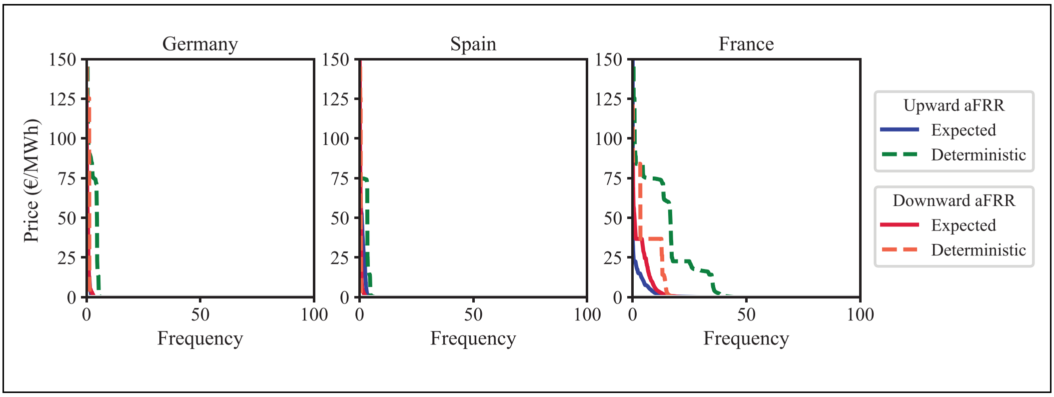

Figure C-2. Upward and downward aFRR capacity prices with and without uncertainty.[20]

uncertainty. They are below the green and orange curves, representing the reserve-capacity prices without uncertainty. Thus, the representation of uncertainty at the reserve-capacity market stage does not modify the main results presented in Figure 9.

Authors' Note

The views and opinions expressed in this paper are those of the authors and do not necessarily reflect those of the partners of the XFLEX HYDRO project partners.

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ORCID iDs

Laureen Deman https://orcid.org/0000-0002-9829-2501
Afzal S. Siddiqui https://orcid.org/0000-0003-1841-1310

[20]The results correspond to the Distributed Energy scenario in 2040, with each day of the year solved independently.

Supplemental Material

Supplemental material for this article is available online.

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