## Abstract

The increasing share of intermittent sources of energy will increase the need for frequency-control reserves. However, the supply from gas and coal-fired power plants might decrease in the following years. Being the procurement of reserves mostly market-based in Europe, the market design should send price signals to encourage participation in these markets. This paper analyses the incentives provided by the French market design for seasonal storage and pumped storage hydropower plants to participate in reserve markets. To that end, a deterministic mixed-integer linear optimization model is presented. The objective is to maximize profits in the energy and reserve markets according to 2019 market prices. By optimising the trade-offs between the day-ahead and the reserve markets, the storage hydropower plant increase its profits. The pumped storage hydropower plant sometimes chooses the Frequency Containment Reserve market or the day-ahead market only. The apparition of some hours of FCR participation with the pumped storage plant is explained by its higher number of generating hours and by the higher volatility of reserve energy prices. These two factors also explain the greater response of the pumped storage plant to the incentive measures on the FCR market.



**Keywords**. Reserve markets, hydropower, market design, incentives, storage

**JEL codes.** Q25, Q41, Q49


## Abbreviations

| | |
|---|---|
| aFRR | Automatic frequency restoration reserve |
| FCR | Frequency containment reserve |
| mFRR | Manual frequency restoration reserve |
| RR | Restoration reserve |
| RTE | Réseau de Transport d'Electricité |
| TSO | Transmission System Operator |

## 1. Introduction

The impossibility of storing large quantities of electricity requires a constant balance between production and consumption of electricity. In case of imbalances, frequency-control reserves are activated to reduce it and to ensure the stability of the grid. They are composed of Frequency Control Reserve (FCR), Frequency Restoration Reserves (FRR) and Replacement Reserve (RR). The decarbonisation of the power mix introduces new challenges for the procurement of reserves. On the one hand, the need for reserves is likely to increase because of the variability of renewable energy sources that enlarges generation imbalances (Brijs, De Jonghe, Hobbs, & Belmans; Veyrenc, et al., 2021). On the other hand, the contribution of the current sources of flexibility might decrease in the following years. The share of gas- and coal-fuel plants in the power mix is expected to decline in order to reduce greenhouse gas emissions. In addition, the profitability of these technologies is decreasing due to the merit-order effect caused by renewable energy sources. Having a zero-marginal cost, they decrease energy prices and reduce the number of hours of operation of fossil-fuel power plants (Newbery, Pollitt, Ritz, & Strielkowski, 2018). Reserve procurement is mainly realised through market-based mechanisms in West Continental Europe. In this context, price signals sent by reserve markets should incentivize the participation of flexible and low-carbon technologies. In the long run, these price signals should also incentivize new investments in such technologies (Newbery, Pollitt, Ritz, & Strielkowski, 2018).

This paper analyses this issue by looking at the specific case of hydropower technologies in France. More specifically, we look at seasonal storage and pumped storage hydropower plants. They are often cited as mature technologies able to cover a part of the increasing need for reserves (Thomas, 2014). Hydropower has a reduced carbon footprint and provides a wide range of services to the power grid as well as water services in terms of irrigation, flood control and drinking water (IRENA, 2023). The large storage capacity and fast ramping of hydropower allow it to provide flexibility on all time scales, from seconds to several months (IEA, 2021). In order to assess the incentives provided by the markets, a mixed-integer linear optimisation model maximises the profits of a hydropower plant in the energy and reserve markets. All the reserve markets existing in the studied country are represented. The model is applied to the 2019 French market environment.

Section 2 introduces the reserve markets with the European classification and the French market design. A literature review of the different modelling methods is conducted in section 3. The model is presented in section 4 with the underlying hypotheses, the objective function and the constraints. The last part of this section addresses the features which are specific to the pumped storage plant. Section 5 discusses the results obtained with both case studies. It begins with a sensitivity analysis on the representation of the water storage management. In the following, the generation profiles of both power plants are analysed in terms of market prices. The bidding strategies of each plant are identified and discussed. This analysis highlights the low participation in the Frequency Containment Reserve (FCR) market. After an explanation of this result, two incentive measures are implemented to evaluate the response of the plants. It shows that the seasonal storage plant is insensitive, suggesting that it is not the suitable target for these incentive measures. By contrast, the pumped storage plant is more responsive, indicating that less efforts would be necessary to increase its participation in the FCR market.

## 2. Reserve markets

Frequency control reserves enable to manage frequency deviations resulting from imbalances between generation and consumption. The Transmission System Operator (TSO) is responsible for reserves provision either by organising a market or by obligating the users of the transmission system to supply reserves. In Europe, we distinguish between four types of reserves which are differentiated by their activation time, their spinning or non-spinning nature and the type of activation. Their purpose and activation process are explained below in the following in the order of their activation after the imbalance. FCR intervenes within 30 seconds after an imbalance to limit the frequency deviation. Within 5 minutes, automatic Frequency Restoration Reserve (aFRR) is activated to bring system frequency back to its reference value. FCR and aFRR are spinning reserves, meaning that the suppliers must be online to supply the service. Then, manual Frequency Restoration Reserve (mFRR) is activated within 15 minutes. It can be used to complement the aFRR or to reconstitute it. Replacement Reserve (RR) is used for the reconstitution of aFRR and/or mFRR. It is activated at least 15 minutes after an imbalance (ENTSO-E, 2018). mFRR and RR are non-spinning reserves. For each reserve, we can distinguish between reserve capacity and reserve energy services. Reserve capacity corresponds to the availability of reserves. The supplier is paid to make some generation capacity available to the TSO. Reserve energy corresponds to the energy activated by the TSO. When generation is lower (higher) than consumption, upward (downward) reserve energy is activated to increase (decrease) injections and/or to decrease (increase) withdrawals.

The French TSO, Réseau de Transport d'Electricité (RTE), participates in the FCR Cooperation platform since 2017. This platform enables exchanges of FCR capacity between countries. The product is symmetrical, and the supplier must be able to increase or decrease its generation level by the same amount. Since July 2020, the service must be provided for four consecutive hours. Selected market participants are paid at the marginal auction price. The FCR energy is activated in a prorate basis. Each supplier participates to the share of FCR capacity they provide over the demand. Contrary to other participating countries, RTE remunerates the FCR energy at the day-ahead price. Market participants receive the day-ahead price in case of upward energy activation and pay the day-ahead price in case of downward energy activation (Réseau de Transport d'Electricité, 2020). All generators with a nominal capacity greater than 120 MW are obliged to procure aFRR capacity. The obligation is symmetrical. The volume they must reserve is determined according to the share of their expected generation in day-ahead over the total expected generation (Réseau de Transport d'Electricité, 2020). The aFRR energy activated in real time is shared among the suppliers at the prorate of the aFRR capacity they provide. aFRR capacity is remunerated at regulated price and the activated energy is paid at the day-ahead price (Réseau de Transport d'Electricité, 2020). The mFRR and RR capacity are procured through annual and daily auctions with different product durations available (Réseau de Transport d'Electricité, 2020).. mFRR and RR capacity are remunerated at the marginal price of the auction. The activation of mFRR and RR energy is realized in the adjustment mechanism according to the merit-order of energy bids (Réseau de Transport d'Electricité, 2020). In this mechanism, generators are obliged to offer all their available generation capacity to the TSO the day of delivery. Consequently, a contract for reserve capacity is not mandatory to submit reserve energy bids. Activated bids are paid at their bidding price (Réseau de Transport d'Electricité, 2020).

## 3. Literature review

### *3.1. Representation of consecutive markets*

Including reserve markets in the market bidding problem allows to increase the profits a hydropower plant can derive (Aasgård, 2020; Boomsma, Juul, & Fleten, 2014; McPherson, McBennett, Sigler, & Denholm, 2020; Schillinger, Weigt, Barry, & Schumann, 2017). Because reserve prices are generally higher than energy prices, including them allows to better represent the opportunities of profits. In addition, the supply of reserves takes part of the normal operation of hydropower plants. Indeed, (Newbery, Pollitt, Ritz, & Strielkowski, 2018) states that pumped storage hydropower plants derive 75% of their profits from flexibility services, among which reserves provision represents a significant part. Indeed, flexibility can refer to a variety of markets and services such as ramping in energy markets, congestion management, frequency voltage controls, among others (Koltsaklis, Dagoumas, & Panapakidis, 2017). This increase in profits can vary according to the month of the year (Boomsma, Juul, & Fleten, 2014), the bidding strategy (Aasgård, 2020), the level of information (Aasgård, 2020; McPherson, McBennett, Sigler, & Denholm, 2020), the type of power plant (Schillinger, Weigt, Barry, & Schumann, 2017) and the studied country. Therefore, the estimated profits are very case-specific and depend on the methodology used.

The order in which markets clear influences the decision process.. Indeed, in the case of France, the FCR market gate closure is before the day-head market gate closure. As a result, market participants must anticipate the day-ahead market outcome in order to formulate their FCR bid. In addition, the day-ahead market bid must consider the possible profits from the reserve energy markets (which are cleared close to real-time) and be adapted to this expectation.

The representation of different markets can be dealt with a sequential approach, that is with a several-stage optimisation model (Aasgård, 2020; Campos, Muñoz San Roque, Sánchez-Úbeda, & Portela González, 2015; Triki, Beraldi, & Gross, 2005). In each stage, decisions are made while considering the expected profits in the following stages (Aasgård, 2020; Plazas, Conejo, & Prieto, 2005; Triki, Beraldi, & Gross, 2005); As a result, the available information depends on the decision stage (Aasgård, 2020; Boomsma, Juul, & Fleten, 2014; Fleten & Kristoffersen, 2007; Thomas, 2014; Triki, Beraldi, & Gross, 2005). In deterministic models, the different markets are represented as if they all clear at the same time (Deng, Shen, & Sun, 2006; Fjelldal, Nafstad, & Klæboe, 2014; Paine, Homans, Pollak, Bielicki, & Wilson, 2014; Schillinger, Weigt, Barry, & Schumann, 2017). Indeed, the power plant perfectly knows all prices. Consequently, it can optimally allocate its capacity to the different markets."

### *3.2. Stochastic and deterministic approaches*

Market participants face different uncertainties at the time of market bidding: the demand level, the bidding strategies of other participants and the resulting market prices are unknown. Stochastic approaches are used to represent these uncertainties with a set of possible future prices. Scenarios trees gather these possible future prices and illustrate the dependency between market outcomes. The optimal strategy consists of choosing the allocation that maximizes profits for all possible scenarios (Triki, Beraldi, & Gross, 2005). On the other hand, the market prices considered with a deterministic approach consist of the average of all possible future prices (De Ladurantaye, Gendreau, & Potvin, 2009; Fleten & Kristoffersen, 2007; Plazas, Conejo, & Prieto, 2005).

(Thomas, 2014), (Plazas, Conejo, & Prieto, 2005), (Fleten & Kristoffersen, 2007) and (De Ladurantaye, Gendreau, & Potvin, 2009) among others, compare the results obtained with stochastic and deterministic models. Except (Plazas, Conejo, & Prieto, 2005), all these papers deal with hydropower plants. They find higher profits with the stochastic approach. This result can be explained by the use of the average price over all scenarios with the deterministic approach. Indeed, it implies a lower variability of prices and thus lower profits. In a stochastic model, some scenarios represent the highest variations of price levels. As the probability of occurrence of each scenario is different, hours with upward price spikes may have a higher weight in the objective function. The profit difference between the two approaches differs between the cited papers. (Fleten & Kristoffersen, 2007) and (De Ladurantaye, Gendreau, & Potvin, 2009) find that the stochastic approach leads to an average 8% increase in the objective function value whereas (Thomas, 2014) and (Plazas, Conejo, & Prieto, 2005) find an 1 % increase. Those differences can be explained by the different countries studied and by the method used to generate price scenarios.

In terms of bidding decisions, the choice of approach has different implications in the cited papers. (Fleten & Kristoffersen, 2007) observes identical bidding decisions between the two approaches. In both cases, the power plant only uses hourly bids. However, when start-up costs are included, the power plant only uses block bids with the stochastic approach. The authors note that this result may be the result of the formulation chosen. (Thomas, 2014) does not observe a modification of the bidding decisions between the two approaches. The power plant is planning to turbine or to pump for the same hours with both models. This result can be explained by the fact that the hours with the highest and lowest price levels are the same over all scenarios in average. As a result, the absence of price uncertainty does not introduce biased conclusions if the purpose of the model is to analyse the allocation decisions.

### *3.3. Water storage management*

A specific issue related to hydropower plants is the management of the water reservoir in a limited time horizon. For a given hour, the generation decision reflects an arbitrage between the profits the plant can obtain during this hour and the profits it could obtain in the future with the same amount of water. As a result, the optimisation model needs to consider what happens after the end of the planning horizon, otherwise the water reservoir would be empty at the end of optimisation period (De Ladurantaye, Gendreau, & Potvin, 2009). Similarly, we need to consider the generation decisions made before the planning horizon. For instance, stating that the storage level is at its maximal value at the beginning of the optimisation period neglects the use of water before. A common method to deal with this issue is to solve a long-term and a short-term model (Aasgård, Fleten, Kaut, Midthun, & Perez-Valdes, 2019). The long-term model optimizes the generation scheduling with loosen constraints or with a simplified representation of the system. With the resolution of this model, we can either keep the storage level limits for the short-term model or estimating the opportunity cost of water. The storage level limits for the first and last period of the short-term planning horizon allow to consider the opportunity of profits outside of the planning period by limiting the amount of water that can be used (Aasgård, Fleten, Kaut, Midthun, & Perez-Valdes, 2019; Schillinger, Weigt, Barry, & Schumann, 2017; Thomas, 2014). A low storage level at the beginning of the year means that the opportunities of profits are more important at the end of the previous year and vice versa. Also called the water value, the opportunity cost of water represents the cost to use water now instead of keeping it for the future. The objective of the short-term model is to maximize the revenues minus this opportunity cost (Aasgård, Fleten, Kaut, Midthun, & Perez-Valdes, 2019; Flatabø, Haugstad, Mo, & Fosso, 1998). The storage level limits will be used in this paper. Our model will be solved with a longer time horizon. The length of the extension needed to obtain relevant storage level limits will be assessed by applying several extensions.

This paper is inscribed in the previously mentioned literature with a deterministic approach as in (Thomas, 2014), (Schillinger, Weigt, Barry, & Schumann, 2017), (Plazas, Conejo, & Prieto, 2005) and (Paine, Homans, Pollak, Bielicki, & Wilson, 2014). Storage level limits are used to represent the long-term management of the water reservoir as in (Thomas, 2014), (Schillinger, Weigt, Barry, & Schumann, 2017), (Aasgård, Fleten, Kaut, Midthun, & Perez-Valdes, 2019). This paper fills the gaps of the literature by looking at the trade-offs between the possible bidding strategies in energy and reserve markets in France. To our knowledge, an analysis of the different bidding strategies in the French markets has not been proposed in the literature. In addition, we put the emphasis on the different choices when the power plant is generating instead of on the choice to generate or to pump. We extend the comparison realised by (Schillinger, Weigt, Barry, & Schumann, 2017) of hydropower plants with different reservoir sizes to a pumped storage hydropower plant. In the same way than (Paine, Homans, Pollak, Bielicki, & Wilson, 2014) shows the impact of price volatility on profits, we show its impact on the choice of bidding strategy. Finally, we also evaluate the efficiency of incentive measures to increase the participation in the FCR market.

## 4. Model

### *4.1. Hypotheses*

Market prices are assumed to be known with certainty by the unit as in (Thomas, 2014), (Schillinger, Weigt, Barry, & Schumann, 2017) and (Paine, Homans, Pollak, Bielicki, & Wilson, 2014). Price certainty leads to the representation of the different markets as if they all clear at the same time. All bids must be formulated before the first market clears. In addition, those bids will not be modified between two markets because their acceptance is known in advance.

The hydropower plant is assumed to be a price-taker unit, it does not influence market prices. This hypothesis can be justified by the fact that we optimize the bidding strategy of a small unit. Its generation level is low compared with the total volumes exchanged in the markets so its ability to influence market prices is low. As a result, the decision of the plant consists of the bidding volume only. This hypothesis can be relevant for the day-ahead market and some reserve markets, as mentioned by (Schillinger, Weigt, Barry, & Schumann, 2017) and (Plazas, Conejo, & Prieto, 2005) among others. However, the volumes exchanged in the reserve energy markets can be relatively low so that one power plant can influence reserve market prices by supplying the majority of the needed volume (Schillinger, Weigt, Barry, & Schumann, 2017).

The optimization model does not specify variable operational costs for the unit. In the literature, the variable part of the operation and maintenance costs are considered too low to influence the decisions (Deng, Shen, & Sun, 2006; Fleten & Kristoffersen, 2007; Thomas, 2014). However, start-up costs are included because they group the hours of generation (De Ladurantaye, Gendreau, & Potvin, 2009; Fleten & Kristoffersen, 2007; Thomas, 2014). The opportunity cost of water is represented by storage levels to attain at the end of the period. These levels are estimated by the resolution of the same model with a longer horizon.

### *4.2. Objective function*

The model optimizes the profits of a hydropower plant over a one-year period with a one-hour time step (denoted h). The profit of the plant is calculated as the revenues obtained in each market minus the start-up costs (Equation (1)). The duration of the reserve capacity contract is 4 hours for the FCR and one day for the mFRR and RR. The annual products of mFRR and RR capacity are not considered to reduce the complexity of the problem. Indeed, delivering the same quantity throughout the year increases the complexity of the problem by increasing the number of alternative decisions to compare. The equation of the objective function and the constraints that follow do not represent it in order to simplify the notations.

$$Profit(volume_{m,h}) = \max_{\{volume_{m,h}\}_{m\in M}} \left\{ \sum_{h=1}^{8760} \left[ volume_{DA,h} * \mathrm{price_{DA,h}} + \sum_{\mathrm{rc}} volume_{rc,h} * \mathrm{price_{rc,h}} + \sum_{\mathrm{ue}} volume_{ue,h} * \mathrm{price_{ue,h}} - \sum_{\mathrm{de}} volume_{de,h} * \mathrm{price_{de,h}} - \mathrm{start\_up\_cost} * \max\{0; (\beta_h + \gamma_h) - (\beta_{h-1} + \gamma_{h-1})\} \right] \right\} \quad (1)$$

*Table 1 Abbreviations used in the objective function.*

| *Subscript* | *Meaning* | *Unit* |
|---|---|---|
| $M$ | All considered markets | |
| $DA$ | Day-ahead market | MW |
| $rc$ | Reserve capacity (FCR, aFRR, mFRR and RR) | MW |
| $ue$ | Upward reserve energy (FCR, aFRR, mFRR and RR) | MWh |
| $de$ | Downward reserve energy (FCR, aFRR, mFRR and RR) | MWh |

*Table 2 Nomenclature*

| *Variable* | *Meaning* |
|---|---|
| $energy_h; energy_h^{pump}$ | Volume of energy generated/consumed in hour $h$ (MWh) |
| $Q_h$ | Water discharged for energy generation in hour $h$ ($m^3$/second) |
| $Q_h^{pump}$ | Water discharged for pumping in hour $h$ ($m^3$/second) |
| $spillage_h$ | Water spilled from the downstream reservoir in hour $h$ ($m^3$) |
| $storage\_upper_h; storage\_lower_h$ | Storage level at hour $h$ ($m^3$) |
| $volume_{DA,h};\ volume_{DA,h}^{pump}$ | Volume sold/bought in the day-ahead market in hour $h$ (MW) |
| $volume_{FCRc,h}$ | Volume sold in the FCR market in hour $h$ (MW) |
| $volume_{FCRue,h}; volume_{FCRde,h}$ | Volume of FCR energy activated in real time in hour $h$ (MWh) |
| $volume_{aFRRc,h}$ | Compulsory supply of aFRR capacity in hour $h$ (MW) |
| $volume_{aFRRue,h}; volume_{aFRRde,h}$ | Volume of aFRR energy activated in real time in hour $h$ (MWh) |
| $volume_{mFRRc,h}; volume_{RRc,h}$ | Volume sold in the mFRR/RR capacity market in hour $h$ (MW) |
| $volume_{mFRRue\_on,h}; volume_{RRue\_on,h}$ | Volume of mFRR/RR upward energy sold when the unit is already online in hour $h$ (MWh) |
| $volume_{mFRRue\_off,h}; volume_{RRue\_off,h}$ | Volume of mFRR/RR upward energy sold from the offline status in hour $h$ (MWh) |
| $\beta_h$ | Energy supply in the day-ahead market in hour $h$ (binary) |
| $\gamma_h$ | Supply of mFRR/RR upward energy from the off status in hour $h$ (binary) |
| $\theta_h$ | Energy consumption in the day-ahead market in hour $h$ (binary) |

The hours when the unit starts up are defined in terms of two binary variables, $\beta_h$ and $\gamma_h$. Their sum equals to one when the unit is online and zero otherwise. If the difference between the hour h and h-1 equals to one, it means that the unit starts up in hour h. The maximum operator is used to omit cases when the difference equal to -1, that is when the unit shuts down. The parameter $start\_up\_cost$ correspond to the unitary cost of start-ups. We took the median of the different values found in the literature, brought to the unit, converted in euros and adjusted for the inflation (De Ladurantaye, Gendreau, & Potvin, 2009; Nilsson & Sjelvgren, 1997; Osburn, et al., 2014; Thomas, 2014).

### *4.3. Supply function*

The supply function of a hydropower plant is given by equation (2), where $energy_h$ is the volume of energy generated in MWh, $\rho$ is the water density (in $kg/m^3$), g is the gravity constant. H is the water head (in meters) that is the level difference between the upper and the lower reservoirs. $Q_h$ is the water discharged going through the turbine (in m3 per second). $\eta^{turbine}$ is the total efficiency rate of the turbine, including the hydraulic efficiency as well as the transmission, alternator and transformer losses. The expression is multiplied by the time step of one hour in order to convert it into MWh. The water head and the hydraulic efficiency vary over time according to the discharge level. However, we consider that the water head and the efficiency rate are constant in order to decrease the complexity of the model (Aasgård, Fleten, Kaut, Midthun, & Perez-Valdes, 2019; Fleten & Kristoffersen, 2007; Thomas, 2014).

$$energy_h = \frac{\rho * \mathrm{g} * \mathrm{H} * \eta^{\mathrm{turbine}} * Q_h}{1 * 10^6} * 1 \text{ hour} \tag{2}$$

### *4.4. Representation of storage*

The water reservoir is represented with one variable corresponding to the water available for electricity generation ($storage_h$). The maximal storage level ($\overline{\text{storage}}$) considers the minimal amount of water that has be left in the reservoir. The water balance equation (4) actualises the storage level at each period according to the hourly discharges ($Q_h * 3600\ seconds$) and hourly inflows ($inflows$). Inflows correspond to natural inflows linked to rainfalls and the river flow. We consider that they are constant throughout the year. The initial and final storage levels are exogenously set to values found by solving the model for an extended period of time (equations (5) and (6)).

$$storage_h \leq \overline{\text{storage}} \tag{3}$$

$$storage_h = storage_{h-1} - (Q_h * 3600 \text{ seconds}) + \text{inflows} \tag{4}$$

$$storage_{h=1} = \text{storage}_{\text{initial}} \tag{5}$$

$$storage_{h=8760} = \text{storage}_{\text{end}} \tag{6}$$

### *4.5. Generation limits*

In order to differentiate between reserve capacity and reserve energy, we introduce two sets of constraints, following the work of (Deng, Shen, & Sun, 2006). One set relates to the power level limits and the other set relates to the energy level limits. The energy levels correspond to the power levels multiplied by the time step of one hour. Constraints (7) and (8) concern the power level limits[1], following the work of (Triki, Beraldi, & Gross, 2005), (Plazas, Conejo, & Prieto, 2005) and (Fjelldal, Nafstad, & Klæboe, 2014) among others. Upward reserves only appear in the maximal power constraint to avoid simultaneous activation of upward and downward reserves. The FCR and aFRR capacity products are symmetrical so they also appear in the minimal power constraint. By contrast, the mFRR and RR capacity products are upward products, so they only appear in the maximal power constraint. The impossibility to have a power level between zero and the minimal power level requires the introduction of a binary variable ($\beta_h$). It equals to one when the unit participates in the day-ahead market and zero otherwise.

$$volume_{DA,h} + volume_{FCRc,h} + volume_{aFRRc,h} + volume_{mFRRc,h} + volume_{RRc,h} \leq \mathrm{P}^{\max} * \beta_h \tag{7}$$

$$volume_{DA,h} - volume_{FCRc,h} - volume_{aFRRc,h} \geq \mathrm{P}^{\min} * \beta_h \tag{8}$$

Equations (9) to (11) concern the energy generation limits of the unit. We keep the FCR and aFRR capacity volumes to ensure that this committed capacity is not used in other markets. Similarly to the power constraints, the upward (respectively downward) volumes only appear in the maximal (respectively minimal) energy constraint. We allow for participation in the mFRR and RR upward energy market from off-line status (equation (12)). The binary variable $\gamma_h$ equals to one when the unit starts up to supply mFRR or RR upward energy and zero otherwise. Equation (12) ensures that only one of the binary variables equals to one for a given hour. Finally, the volume of energy generated for a given hour equals to the sum of the day-ahead volume, the upward reserve energy volumes minus the downward reserve energy volumes (equation (13)).

$$\begin{aligned} 1h * (volume_{DA,h} + volume_{FCRc,h} + volume_{aFRRc,h}) + volume_{mFRRue,h} + volume_{RRue,h} \\ \leq \mathrm{E}^{\max} * (\beta_h + \gamma_h) \end{aligned} \tag{9}$$

[1] The letter ‘c’ following the name of the market means that the variable represents the volume sold in this reserve capacity market.

$$1h * (volume_{DA,h} - volume_{FCRc,h} - volume_{aFRRc,h}) - volume_{mFRRde,h} - volume_{RRde,h} \geq \mathrm{E}^{\min} * \beta_h \quad (10)$$

$$\gamma_h * \mathrm{E}^{\min} \leq volume_{mFRRue,h} + volume_{RRue,h} \leq \gamma_h * \mathrm{E}^{\max} \quad (11)$$

$$\beta_h + \gamma_h \leq 1 \quad (12)$$

$$energy_h = volume_{DA,h} + \sum_m volume_{ue,h} - \sum_m volume_{de,h} \quad (13)$$

### 4.6. Links between reserve capacity and reserve energy

The activation of FCR and aFRR energy is realised at the pro-rata of reserve capacity provision. In other words, the share of reserve energy supplied by the unit over the total need corresponds to the share of reserve capacity supplied by the unit over the total reserve capacity need (equations (14) to (17)).

$$\mathrm{volume_{FCRue,h}} = volume_{FCRc,h} * \frac{\mathrm{demand_{FCRue,h}}}{\mathrm{demand_{FCRc,h}}} \quad (14)$$

$$\mathrm{volume_{FCRde,h}} = volume_{FCRc,h} * \frac{\mathrm{demand_{FCRde,h}}}{\mathrm{demand_{FCRc,h}}} \quad (15)$$

$$\mathrm{volume_{aFRRue,h}} = \mathrm{volume_{aFRRc,h}} * \frac{\mathrm{demand_{aFRRue,h}}}{\mathrm{demand_{aFRRc,h}}} \quad (16)$$

$$\mathrm{volume_{aFRRde,h}} = \mathrm{volume_{aFRRc,h}} * \frac{\mathrm{demand_{aFRRde,h}}}{\mathrm{demand_{aFRRc,h}}} \quad (17)$$

The aFRR capacity demand is divided between generators according to the share of their day-ahead generation over the total forecasted generation in day-ahead. As a result, the unit supplies aFRR capacity as long as it sells energy in the day-ahead market.

$$\mathrm{volume_{aFRRc,h}} = volume_{DA,h} * \frac{\mathrm{demand_{aFRRc,h}}}{\text{total forecasted generation}_\mathrm{h}} \quad (18)$$

For the mFRR and RR markets, a generator with a reserve capacity contract is obliged to submit a bid in the corresponding upward reserve energy market. The bidding volume must corresponds to the contracted reserve capacity (Réseau de Transport d'Electricité, 2020) (equations (19) and (20)). The reserve capacity volume is multiplied by one hour because we assume that reserve energy is activated for the whole hour.

$$volume_{mFRRue,h} \geq 1\mathrm{h} * volume_{mFRRc,h} \quad (19)$$

$$volume_{RRue,h} \geq 1\mathrm{h} * volume_{RRc,h} \quad (20)$$

### 4.7. Constraints specific to the pump-turbine case

The power consumption of the pump in MWh is given by equation (21), with $\eta^{\mathrm{pump}}$ corresponding to the total efficiency rate of the pump and $Q_h^{pump}$ the water pumped toward the upstream reservoir (in $m^3$ per second). We consider that the water head and the efficiency rate are constant.

$$energy_h^{pump} = \frac{\rho * \mathrm{g} * \mathrm{H} * Q_h^{pump}}{\eta^{\mathrm{pump}} * 1.10^6} * 1 \text{ hour} \quad (21)$$

Because we have inflows, we have chosen to explicitly represent the downstream water reservoir, contrary to (Thomas, 2014), (McPherson, McBennett, Sigler, & Denholm, 2020), (Paine, Homans, Pollak, Bielicki, & Wilson, 2014) and (Chazarra, Pérez-Díaz, & García-González, 2014). This way, we ensure that the storage capacity of the lower reservoir is never exceeded. As a result, we have two water balance equations (equations (22) and (23)). The upper reservoir collects inflows and the water pumped from the lower reservoir ($Q_h^{pump} * 3600$ seconds) and looses the water released toward the turbine ($Q_h * 3600\ seconds$). There are no natural inflows to the lower reservoir because we assume that there is no river flowing to it. Because the lower reservoir may be smaller than the upper reservoir, we allow for releases to the river ($spillage_h$) to avoid a situation where both reservoirs are full. Spillages are constrained to be smaller than the maximal hourly discharge level in order to distribute spillages over time (equation (24)). Otherwise, spillages may rarely occur but with large amount of water. This type of situation is to avoid because it may cause downstream flooding and may not be allowed by regulations.

$$storage\_upper_h = storage\_upper_{h-1} - (Q_h - Q_h^{pump}) * 3600 \text{ seconds} + \text{inflows} \tag{22}$$

$$storage\_lower_h = storage\_lower_{h-1} + \left(Q_h - Q_h^{pump}\right) * 3600 \text{ seconds} - spillage_h \tag{23}$$

$$spillage_h \leq \overline{\mathrm{Q}} * 3600 \text{ seconds} \tag{24}$$

The volume of energy consumed to pump water is defined by $volume_{DA,h}^{pump}$. Its only possible value is the maximal pumping capacity (equation (25)). The binary variable $\theta_h$ equals to one when the unit is pumping and zero otherwise. Equation (26) ensures the link between the volume of energy bought in the market and the volume of water it represents. We also assume that the unit cannot turbine and pump at the same time (equation (27)).

$$volume_{DA,h}^{pump} = \mathrm{P}_{\mathrm{pump}}^{\max} * \theta_h \tag{25}$$

$$volume_{DA,h}^{pump} = energy_h^{pump} \tag{26}$$

$$\beta_h + \gamma_h + \theta_h \leq 1 \tag{27}$$

The cost to buy electricity in the day-ahead market is introduced in the objective function (equation (28)). In addition, the definition of start-ups now considers the pumping mode. Following the work of (Thomas, 2014) and (Chazarra, Pérez-Díaz, & García-González, 2017), we assume that going from the turbine to the pump mode and inversely implies start-up costs. However, we consider that start-up costs are identical in both operational modes. To our knowledge, there is few data available regarding the specific start-up costs of pumped storage hydropower plants.

$$\begin{aligned}\mathrm{Profit}\left(volume_{m,h}\right) = \max_{\{volume_{m,h}\}_{m\in M}} \Bigg\{ \sum_{h=1}^{8760} \Bigg[ & \left(volume_{DA,h} - volume_{DA,h}^{pump}\right) * \mathrm{price_{DA,h}} \\ & + \sum_{\mathrm{rc}} volume_{rc,h} * \mathrm{price_{rc,h}} + \sum_{\mathrm{ue}} volume_{ue,h} * \mathrm{price_{ue,h}} \\ & - \sum_{\mathrm{de}} volume_{de,h} * \mathrm{price_{de,h}} - \mathrm{start\_up\_cost} \\ & * \max\{0; (\beta_h + \gamma_h) - (\beta_{h-1} + \gamma_{h-1}); \theta_h - \theta_{h-1}\} \Bigg] \Bigg\}\end{aligned} \tag{28}$$

## 5. Results

The models for the seasonal storage and the pumped storage plants are applied to the 2019 prices in the French markets. Almost all the prices and demand levels used are from the ENTSO-E Transparency Platform ([dataset] ENTSO-E, s.d.). Only the reserve capacity prices and demand levels are from the RTE data platform ([dataset] Réseau de Transport d'Electricité, s.d.). Table 3 shows the values of the parameters chosen for the case study. The first two columns concern the parameters gathered by both models. The two other columns concern the parameters specific to the pumped storage plant. The capacity of the upper reservoir, the volume of inflows and the water head value have been chosen to represent a seasonal storage plant. The volume of inflows refills the reservoir in a month. The models have been solved with the CPLEX solver. A relative gap of 0.01% and 0.04% has been applied for the seasonal storage and the pumped storage cases respectively. The higher gap applied to the pumped storage plant is explained by the greater complexity of this model, which slows down the resolution.

*Table 3 Parameter values of the case studies.*

| *Parameter* | *Value* | *Parameter* | *Value* |
|---|---|---|---|
| $\mathrm{P}^{\max}$ | 1 MW | $\mathrm{P}_{\mathrm{pump}}^{\max}$ | 1 MW |

| | | | |
|---|---|---|---|
| $p^{min}$ | 0.5 MW | | |
| $\eta^{turbine}$ | 92% | $\eta^{pump}$ | 87% |
| H | 100 m | | |
| $\overline{storage\_upper}$ | 200,000 m$^3$ | $\overline{storage\_lower}$ | 50,000 m$^3$ |
| inflows | 260 m$^3$/hour | | |
| start_up_cost | 4 €/MW/start-up | | |

### *5.1. Implementation of long-term water management*

Before analysing the results, the impact of the values assigned to the initial and final storage levels is analysed. Because they are set exogenously, their value may not accurately represent opportunities of profit outside of our optimisation period. In order to estimate relevant storage levels, the same optimisation problems have been solved with several time horizons by adding several months before and after our initial optimisation period. Five extensions have been tested, with the addition of one up to five months. For instance, the first test consists of solving the problem from December 2018 to January 2020. These problems were solved with the CPLEX solver with the same relative gaps previously mentioned. Only the explanation for the seasonal storage plant is presented but the reasoning is the same for the pumped storage plant. The results for both cases are available in Appendix A.

The historical volume of water available for generation in 2019 is used to assess the relevance of each test (figure 1). It corresponds to the sum of water inflows and the difference between the storage levels at the beginning and the end of the year. In the original setting with an optimisation over 2019, only the inflows are used for generation because the initial and final storage levels are identical. The tests 3 to 5 have similar values. Their difference only represents 219 m$^3$ of water or 0.05 MWh. With these tests, the extension of the planning horizon is sufficient to represent the opportunities of profit of the last weeks of November 2018 (contrary to the first test where the optimisation starts in December 2018). In addition, the constraint to reach the maximal storage level at the end of their respective planning horizon does not significantly influence the use of water at the end of 2019 (contrary to the second test). This convergence of results suggests that choosing one test instead of another one will not significantly influence our results. The results obtained with the third test will be used in the following. The same choice has been made for the pumped storage plant.

[Figure-1]

### *5.2. Intertemporal trade-offs for the use of water*

The profit of the seasonal storage plant reaches 62,459€ over the year for 740 hours of generation (8.5% of the year). This low percentage of participation is explained by the relationship between the volume of available water and the generation capacity. If the unit always generates at its maximal (minimal) generation level, 562 hours (1,125 hours) are necessary to use all the available water. Therefore, the unit must generate between 6.4% and 12.8% of thetime. Because the unit does not always generate at the same level, we obtain a percentage situated between these two values. The profit per MWh generated amounts to 111€/MWh, which is almost three times the average day-ahead price in 2019 (38.65 €/MWh). This difference is the illustration to the fact that the unit chooses the hours with the highest prices to generate. It also represents the participation in reserve markets, which yields higher revenues than the day-ahead market in average. This feature is consistent with the results of the literature (Aasgård, 2020; Boomsma, Juul, & Fleten, 2014; McPherson, McBennett, Sigler, & Denholm, 2020; Schillinger, Weigt, Barry, & Schumann, 2017).

The profit obtained by the pumped storage plant rises to 124,069 €, that is a 98% increase compared to the seasonal storage plant. This is explained by the possibility to use several times the same amount of water. However, the average generation revenue per MWh is lower with 68.5 €/MWh. The distribution of revenues for both power plants explains this difference (figure 2). The occurrences of revenues greater than 90€/hour are similar for both cases because the hours with the highest prices are chosen in priority. If an hour with such a price level is not chosen, it is because there is not enough water in the upstream reservoir or because the unit saves water for future periods with higher prices. Some of those unexploited hours are used by the pumped storage plant, as it can be seen with the increase in occurrences of revenues between 70 and 110€/hour. Automatically, the surplus of water obtained with the pump is mainly used during hours with lower price levels. It can be seen in the number of occurrences of revenues lower than 70€/hour.

[Figure-2]

*5.3. Preference for reserve energy markets*

Two allocation decisions are made by the seasonal storage plant (figure 3). The first allocation decision is to participate in an upward reserve energy market[2]. This allocation is chosen 54% of the time the plant is producing and provides 77% of the generation revenues. The second allocation decision is to participate in a downward reserve energy market. This allocation is chosen 46% of the time and provides 23% of the generation revenues. This difference between the frequency and the share of revenues is explained by a volume and a price effect. Because the hourly net energy volume is greater with the first strategy, the annual net energy volume would be greater with this strategy even with a similar frequency for both strategies. Indeed, the first strategy results in 1 MWh of energy generation per hour and 0.5 MWh for the second strategy. The price effect represents the fact that unit revenues are significantly greater with the first strategy. The average revenues equal to 126€/MWh with the first strategy and 83€/MWh with the second. Consequently, upward reserve energy revenues would represent a larger share of total revenues even with a similar annual volume for both strategies.

[Figure-3]

[Figure-4]

The two bidding strategies chosen by the seasonal storage plant are also used by the pumped storage plant (figure 4). Those two strategies are chosen 57% and 41% of the time the pumped storage plant is generating respectively. We have the same difference in terms of frequency and revenues. The two strategies represent 73% and 25.5% respectively of the generation revenues of the pumped storage plant. This similarity is explained by the fact that the pump does not modify the results of the trade-offs between the different markets for a given hour. The volumes that can be sold in each market remain the same. As a result, the volume effect explained previously persists with the pumped storage plant. However, the price effect is reduced as in this case, the first strategy yields 70€/MWh and the second yields 65€/MWh in average. Two other strategies are chosen by the pumped storage plant, even if they remain marginal. The first one is to participate in the FCR market. This strategy is only chosen 0.4% of the time. The introduction of this strategy will be explained in the following part. The last generation strategy is to participate in the day-ahead market only and is chosen 1.7% of the time. The associated volume varies from 0.5 MWh to 1 MWh. In most cases, this strategy is chosen either when reserve energy is not activated or when the other strategies are less profitable.

*5.4. Incentive measures in the FCR market.*

The participation in the FCR market is significantly low for our two power plants. On the one hand, it could be explained by the lower revenues compared to the other markets. On the other hand, the 4-hour contract duration could reduce the participation in this market. In order to evaluate the relevance of these factors, the impact of a FCR price premium and of the reduction of the contract duration are analysed. Three premium levels, increasing the FCR capacity price by 50%, 100% and 200% are applied. The FCR contract duration is reduced to one hour in order to eliminate intertemporal trade-offs in the bidding decision. These two modifications are implemented separately.

The insignificant impact of the incentive measures is shown in figure 5 (black bars). A price premium that increases the FCR remuneration by 50% does not have any impact in the FCR participation. With an increase in the FCR remuneration of 100% and 200%, the unit participates in the FCR market 4 and 12 hours respectively. The reduction of the contract duration increases the participation by only 2 hours. The hypothesis regarding the duration of mFRR and RR energy activation may influence these results. Determining the volume sold in reserve energy markets, this hypothesis modifies the revenue per MWh obtained. The FCR volume remaining the same, changing this hypothesis may modify the result of the trade-off between the different markets.

The grey bars in figure 5 shows the impact of the incentive measures with 30 minutes of reserve energy activation. In the original setting, the FCR participation remains negligible with only 12 hours of participation. With the 50% and 100% price premia, the FCR market remains marginal compared with the other markets. Indeed, the plant participates in the FCR market 24 and 36 hours respectively. The 200% price premium has a significant impact with 112 hours of FCR participation, representing 10.5% of the time the plant is generating. The reduction of the contract duration has the same impact than the 50% price premium, with 24 hours of participation. Therefore, the efficiency of each incentive measure is larger with this duration of reserve energy action. However, it remains moderate suggesting that the hypothesis we made does not influence our conclusion. The efficiency of the 200% price premium is significant, but its implementation is very unlikely due to its high costs.

[2] In the following, the mFRR and RR upward (downward) energy markets will be referred to as upward (downward) reserve energy markets.

[Figure-5]

The water surplus obtained with the pumped storage plant is usedat times when prices are lower than at times when the seasonal power plant is also producing . It explains why the pumped storage plant sometimes participates in the FCR market. It also indicates that the incentive measures might have a larger effect than with the seasonal storage plant. In the reserve energy markets, prices are significantly more volatile than in the FCR market (Table 4). Consequently, we can expect that the revenue difference between reserve energy and FCR is smaller when reserve energy prices are lower. Figure 6 represents this phenomenon with the distribution of unit revenue differences between the FCR and reserve energy markets. If the difference is positive, the FCR market is either the most profitable one or the only available market for this hour. Indeed, when neither upward nor downward reserve energy are activated, the FCR market is not in competition with these markets. If we only consider the generation hours of the seasonal storage plant, it is the case in only 0.1 % of cases (1 hour). If we consider the remaining hours, this share rises to 9.4% (751 hours). Therefore, the probability that the pumped storage plant participates in the FCR market is higher. However, the pumped storage plant only participates in the FCR market for 20 hours. The difference with the 751 hours mentioned above is explained by the pump. In fact, among the 751 hours mentioned, the unit chooses to pump for half of them. We must also consider the 4-hour duration of the FCR contract which introduces an additional constraint to choose this market.

*Table 4 Standard deviation of market prices*

| *Markets* | *Standard deviation of prices* |
|---|---|
| Day-ahead | 14 |
| FCR | 3 |
| mFRR upward energy | 28 |
| RR upward energy | 30 |
| mFRR downward energy | 13 |
| RR downward energy | 14 |

[Figure-6]

We applied the same incentive measures than the one applied to the seasonal storage plant. Both measures have a significant impact on the FCR participation (Figure 7). Indeed, the implementation of the 1-hour contract increases the FCR participation to 141 hours. The FCR premia induce a FCR participation of 80, 168 and 476 hours, respectively. The distribution of the revenue differences between the FCR and reserve energy markets explains why these measures are effective (Figure 6). During the hours when the seasonal storage plant is shut down, the difference between the FCR and reserve energy revenues is lower. For 37% of these hours, the FCR market increases the revenues by between 0 and 10€/MWh compared to reserve energy. As a result, the FCR price premium is more likely to modify the sign of the revenue difference with the pumped storage plant.

[Figure-7]

## 6. Conclusion

The objective of this paper was to analyse the incentives of a hydropower plant to participate in reserve markets. A seasonal storage and a pumped storage hydropower plants with the same hydrological conditions were studied with 2019 French prices. A sensitivity analysis on the values assigned to the initial and final reservoir levels has shown that the exogeneous values we first set were not optimal. A convergence of the results has been observed from the addition of three months before and after our initial planning horizon. We have used the results obtained with this method as they better represent the management of the water reservoirs. The generation profile of the seasonal storage plant is to generate a low percentage of the time, when revenues are the highest. The addition of the pump increases the number of generation hours. As a result, the pump enlarges the price levels for which it generates. It also allows to take advantage of a greater number of hours with the highest prices. The analysis of the bidding strategies showed that it is almost always more profitable to participate in reserve markets. Over the year, upward reserve energy markets are the most important source of revenues, followed by downward reserve energy markets. By contrast, the FCR market is never chosen by the seasonal storage plant and only 0.4% of the time by the pumped storage plant. The apparition of some hours of FCR participation with the pumped storage plant is explained by the higher number of generating hours and by the higher volatility of reserve energy prices. These two factors also explain the greater efficiency of a FCR price premium and of the reduction of the contract duration with the pumped storage plant. However, these incentive measures are inefficient for the seasonal storage plant, suggesting that the seasonal storage plant we consider is not the suitable target for these measures.

Comparing the different incentive measures tested, the reduction of the FCR contract duration seems to be the most efficient. Indeed, we can assume that its implementation costs are very low, as it can be applied without increasing the frequency of auctions. Thus, despite its low effectiveness, it is a non-regret option. By contrast, the low effectiveness of the price premium decreases its attractiveness, without considering the distortions it could introduce. Most of the time, the studied power plants do not participate on the FCR market, even when the FCR remuneration is doubled by a price premium.

In a power system with high shares of renewable energy, the dispatch of power plants only to supply reserves introduce inefficiencies. During hours of low residual load, and hence low day-ahead prices, conventional technologies would supply reserve at high cost. A most efficient way to procure the necessary amount of FCR would be to allow the participation of renewable energy sources. During hours of low day-ahead prices, they are abundant and have low opportunity costs (Hirth & Ziegenhagen, 2015). Some regulatory and market design changes are needed to allow and incentivise this participation (Hirth & Ziegenhagen, 2015).

## 7. Funding

This work was supported by the Hydropower Extending Power System Flexibility (XFLEX HYDRO) project which has received funding from the European Union’s Horizon 2020 research and innovation programme under grant agreement No. 857832 The model presented in this paper has been built for the work package 11 of the XFLEX HYDRO project to evaluate the economic impact of flexible hydropower technologies. The funding source had no involvements in the study design, the collection, analysis and interpretation of data, the writing of the article or in the decision to submit it for publication.

## Appendix A

*Table A.1 Storage levels and water available for generation with the seasonal storage plant ($m^3$).*
*Note: The tests consist in extending the time horizon of the optimisation. The original setting corresponds to a time horizon of one year (2019). In test 1, one month is added before and after the core optimisation period (2019), so that the problem is solved from December 2018 to January 2020. In test 2, the optimisation period is extended by two months before and after the core optimisation period, so that the problem is solved from November 2018 to February 2020, etc. These tests are meant to analyse the impact of the starting and ending conditions on the results for 2019.*

| | *Original setting* | *Test 1* | *Test 2* | *Test 3* | *Test 4* | *Test 5* |
|---|---|---|---|---|---|---|
| Level of upstream reservoir at the beginning of 2019 | 200,000 | 164,170 | 79,974 | 80,194 | 79,974 | 79,974 |
| Level of upstream reservoir at the end of 2019 | 200,000 | 145,152 | 118,461 | 107,148 | 107,148 | 107,148 |
| Water available for generation in 2019 | 2,277,600 | 2,296,358 | 2,238,853 | 2,250,385 | 2,250,166 | 2,250,166 |

*Table A.2 Storage levels and water available for generation with the pumped storage plant ($m^3$).*
*Note: The tests consist in extending the time horizon of the optimisation. The original setting corresponds to a time horizon of one year (2019). In test 1, one month is added before and after the core optimisation period (2019), so that the problem is solved from December 2018 to January 2020. In test 2, the optimisation period is extended by two months before and after the core optimisation period, so that the problem is solved from November 2018 to February 2020, etc. These tests are meant to analyse the impact of the starting and ending conditions on the results for 2019.*

| | *Original setting* | *Test 1* | *Test 2* | *Test 3* | *Test 4* | *Test 5* |
|---|---|---|---|---|---|---|
| Level of upstream reservoir at | 200,000 | 132,970 | 103,655 | 105,007 | 103,031 | 105,613 |

| | | | | | | |
|---|---|---|---|---|---|---|
| the beginning of 2019 | | | | | | |
| Level of upstream reservoir at the end of 2019 | 200,00 | 88,488 | 88,488 | 89,517 | 88,488 | 88,488 |
| Water available for generation in 2019 | | 2,321,822 | 2,292,507 | 2,292,831 | 2,291,884 | 2,294,465 |

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