BIDDING STRATEGY OF STORAGE HYDROPOWER PLANTS IN RESERVE MARKETS

Preliminary draft

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Abstract

The increasing share of intermittent sources of energy will increase the need for frequency-control reserves. However, the current supply of reserves 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. Hydropower technologies are often put forward as mature and low-carbon technologies able to contribute to cover this increasing need for reserves. The procurement of reserves being mostly market-based in Europe, the market design should send the correct signals to encourage the 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 function is to maximize revenues in the energy and reserve markets. The model considers the day-ahead energy market and all the reserve products existing in France, distinguishing between reserve capacity and reserve energy products. The plant is assumed to be a price taker and prices are known with certainty. This framework is applied with the 2019 market prices. The results show that participating in reserve markets yields higher revenues than only participating in the day-ahead market for the seasonal storage hydropower plant. It only chooses reserve energy markets whereas the pumped storage hydropower plant sometimes participates in the FCR market or only in the day-ahead market. 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 higher efficiency of a FCR price premium and of the reduction of the contract duration with the pumped storage plant. However, they are inefficient for the seasonal storage plant, suggesting that the seasonal storage plant we consider would not be the most responsive to these incentive measures.

Keywords

Reserve markets, hydropower, market design, incentives, storage

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 storage of large quantities of electricity being difficult, electricity generation and consumption must be balanced at all times. When there is an imbalance, frequency control reserves are activated to reduce it and to ensure the stability of the grid. Reserve procurement is mainly realised through market-based mechanisms in West Continental Europe. 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

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generation imbalances (Brijs, et al. 2017), (IEA/RTE 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 so as 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 cero-marginal cost, they decrease energy prices and reduce the number of hours of operation of fossil-fuel plants (Newbery, et al. 2018). 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, et al. 2018).
This paper analyses this issue by looking at the specific case of hydropower technologies. 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. Indeed, their high flexibility and storage capability allow them to supply reserves at low operational costs (Deng, Shen et Sun 2006), (Muche 2014) (Fleten et Kristoffersen 2007). In order to assess the incentives provided by the markets, a mixed-integer linear optimisation model maximises the revenues of a hydropower plant in the energy and reserve markets. All the reserve markets existing in the studied country are represented. The objective is to determine the hours during which the unit is generating and the placement in the different markets. The model is built upon two hypotheses: the plant is a price-taker and knows all the prices. It is applied to the 2019 French market environment with two cases studies. They concern a seasonal storage and a pumped storage hydropower plant.

Section 2 introduces the reserve markets with the European classification and the specific market design applied in France. 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 sensibility 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 activated at different point of time and serve different purposes. FCR intervenes within 30 seconds after an imbalance to limit the frequency deviation. Within 5 minutes after the imbalance, 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 in order 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, meaning that it is possible to supply it from an offline status. For each type of reserve, we can distinguish between two types of services, reserve capacity and reserve energy. 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 to balance generation and consumption. When generation is lower than consumption, upward reserve energy is activated to increase injections and/or to decrease withdrawals. When generation is greater than consumption, downward reserve energy is activated. In this case, a generator will generate less electricity than planned and a consumer will consume more than planned. When the procurement is market-based, there is a reserve energy market for each activation direction.

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, that is to say the supplier must be able to increase and decrease its generation level by the same amount. Since July 2020, it has a duration of four hours, namely the capacity must be reserved for four consecutive hours. Selected market participants are paid to the marginal price of the auction. The FCR energy is activated in a prorate base. Each supplier participates to the share of FCR capacity they provide over the demand. Contrary to other participating countries, RTE remunerates FCR energy to 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 (RTE 2020a). In France, 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 over the total expected generation (RTE 2020a). The aFRR energy activated in real time is shared among the suppliers at the prorata of the aFRR capacity they provide. aFRR capacity is remunerated a regulated price close to 19€/MW/h and the activated energy is paid to the day-ahead price (RTE 2020a). The mFRR and RR capacity are procured through annual and daily auctions. Several products with different durations are available (RTE 2020b). However, we will only consider a daily product in this paper. This way, the complexity of the problem is reduced by limiting links between periods. mFRR and RR capacity are remunerated to 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 (RTE 2020c). This mechanism organises auctions for energy activation the day of delivery. In this mechanism, generators are obliged to offer all their available generation capacity to the TSO. Consequently, free bids are allowed, that is a contract for reserve capacity is not mandatory in order to submit reserve energy bids. Activated bids are paid to their bidding price (RTE 2020c).

3. Literature review

3.1. Representation of several markets

Including reserve markets in the market bidding problem allows to increase the revenues a hydropower plant can derive (Aasgård 2020), (Boomsma, Juul et Fleten 2014), (MacPherson, et al. 2020), (Schillinger, et al. 2017). Because reserve prices are higher than energy prices in general, including them allows to better represent the opportunities of profits. In addition, the supply of reserves takes part of the plant operation so including them in the model allows to display more accurately its normal operation. Indeed, (Newbery, et al. 2018) state that pumped storage hydropower plants derive 75% of their revenues from flexibility services, among which reserves provision represents a significant part. This increase of revenues can vary according to the month of the year (Boomsma, Juul et Fleten 2014), the bidding strategy (Aasgård 2020), the level of information (Aasgård 2020), (MacPherson, et al. 2020), the type of power plant (Schillinger, et al. 2017) and the studied country. Therefore, the estimated revenues 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 takes place before the day-ahead market. 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 revenues from the reserve energy markets (which are cleared close to real-time) and adapt their bidding volume to this expectation.
The representation of different markets can be dealt with a sequential approach, that is with a several-stage optimisation model (Campos, et al. 2015), (Aasgård 2020), (Triki, Beraldi et Gross 2005). In the case where reserve markets clear after the day-ahead market, the day-ahead market problem is solved while considering the expected revenues in the reserve markets (Plazas, Conejo et Prieto 2005), (Aasgård 2020), (Triki, Beraldi et Gross 2005). With this approach, the available information depends on the decision stage (Aasgård 2020), (Boomsma, Juul et Fleten 2014), (Fleten et Kristoffersen 2007), (Muche 2014), (Triki, Beraldi et Gross 2005). For instance, the day-ahead and the reserve energy prices are unknown in the FCR market stage. In the reserve energy market stage, the outcomes of the FCR and day-ahead markets are known but not the reserve energy price. In deterministic models, the different markets are represented as if they all clear at the same time (Deng, Shen et Sun 2006), (Fjelldal, Nafstad et Klæboe 2014), (Paine, et al. 2014), (Schillinger, et al. 2017). In this case, the order of the markets clearing process does not impact the bidding decision. The unit perfectly knows all prices and thus, can anticipate the acceptance of its bids in all the markets. This approach has been chosen for this work as we assume that market prices are known by the unit. This approach allows to reduce the computational difficulty of the model by avoiding additional calculation linked to the acceptance of the bid in the previous 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 revenues for all possible scenarios (Triki, Beraldi et 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 et Potvin 2009), (Fleten et Kristoffersen 2007), (Plazas, Conejo et Prieto 2005). This method allows to reduce the computation time, especially with mixed-integer and/or non-linear models (Aasgård, Fleten, et al. 2019).

(Fleten et Kristoffersen 2007), (Plazas, Conejo et Prieto 2005), (Muche 2014), (De Ladurantaye, Gendreau et Potvin 2009), among others, compare the results obtained with stochastic and deterministic optimisation models. They find higher revenues with the stochastic approach. This result can be explained by the price levels used in the deterministic models. Indeed, the use of the average price value over all scenarios implies a lower variability of prices over the optimisation period and thus lower revenues. 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 and thus in the expected revenues. The revenue difference between the two approaches differs between the cited papers. (Fleten et Kristoffersen 2007) and (De Ladurantaye, Gendreau et Potvin 2009) find that the stochastic approach leads to an average 8% increase of the objective function value compared with the deterministic model. (Plazas, Conejo et Prieto 2005) and (Muche 2014) find an 1 % increase with the stochastic approach. 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 et Kristoffersen 2007) observe identical bidding decisions between the two approaches. In both cases, the unit only uses hourly bids. However, this result changes if start-up costs are included. With start-up costs, the unit only uses block bids with the stochastic approach. The authors note that this result may be the result of the formulation chosen. (Muche 2014) does not observe a modification of the bidding decisions between the two approaches. The unit 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. As our objective is to analyse the bidding decisions, our choice of a deterministic model should not bias the results.

3.3. Water storage management

A specific issue related to hydropower plants is the management of the water reservoir in a restricted time horizon. For a given hour, the generation decision reflects an arbitrage between the revenues the plant can obtain during this hour and the revenues it could obtain in the future with the same amount of water. As the 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 et 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, et al. 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 revenues outside of the planning period by limiting the amount of water that can be used (Aasgård, Fleten, et al. 2019), (Muche 2014), (Schillinger, et al. 2017). 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 short-term model is to maximize the revenues minus this opportunity cost (Aasgård, Fleten, et al. 2019), (Flatabø, et al. 1998). . The storage level limits will be used in this paper. Our model will be solved for an extended optimisation period. The length of the extension needed to obtain relevant storage level limits will be assessed by applying several extensions.

4. Model

4.1. Hypotheses

Market prices are assumed to be known with certainty by the unit. Therefore, the uncertainty regarding market prices and the acceptance of bids is not considered. Price certainty leads to the representation of the different markets as if they all clear at the same time. All the bids can 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 the model optimizes the revenues of a single 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 (Plazas, Conejo et Prieto 2005) and (Schillinger, et al. 2017) among others. However, the volumes exchanged in the reserve energy markets can be relatively low so that one power plant can influence market prices (Schillinger, et al. 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 et Sun 2006), (Muche 2014) (Fleten et Kristoffersen 2007). However, start-up costs are often included because they may modify the unit commitment decisions by grouping the hours of generation (Fleten et Kristoffersen 2007), (Muche 2014), (De Ladurantaye, Gendreau et Potvin 2009). As a result, start-up costs are included in the model with a unitary value being the median of the values found in the literature. The opportunity cost of water is considered in the following way. The planning horizon is one year. The model is solved for an extended period. The initial and final storage levels are set exogenously to its maximal level. Then, the one-year model is solved with the initial and final storage levels obtained with the extended planning horizon.

4.2. Objective function

The model optimizes the profit 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. The duration of the reserve capacity contracts are 4 hours for the FCR and one day for the mFRR and RR. The equation of the objective function does not represent it in order to simplify the notations.

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

Table 1 Abbreviations used in the equation of 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

The hours when the unit starts up are defined in terms of two binary variables, β_h and γ_h. Their sum gives the operational status of the unit, whether it is online or off-line. If the difference between the hour h and h-1 equals to one, it means that the unit starts in hour h. The maximum operator is used to omit cases when the unit turns off and the difference equal to -1. 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 et Potvin 2009), (Muche 2014), (Nilsson et Sjelvgren 1997), (Osburn, et al. 2014).

4.3. Supply function

The formal supply function of a hydropower plant is given in equation (2), with $energy_h$ corresponding to the volume of energy generated in MWh. ρ is the water density (in kg/m^3), q 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 m^3 per second). $\eta^{turbine}$ is the total efficiency rate of the turbine, meaning that it includes 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. This assumption is sometimes used in the literature in order to decrease the complexity of the model (Aasgård, Fleten, et al. 2019), (Fleten et Kristoffersen 2007), (Muche 2014).

$$energy_h = \frac{\rho * q * H * \eta^{turbine} * Q_h}{1.10^6} * 1\ hour \quad (2)$$

4.4. Representation of storage

The water reservoir is represented with one variable corresponding to the water available for electricity generation. The reservoir is never fully empty, and its level varies between a lower and an upper level. The parameter used in the model as the maximal storage level ($\overline{storage}$) corresponds to the water volume included between these lower and upper levels. When the variable $storage_h$ hits cero, it means that the reservoir level has reached its lower limit, which is different from cero. 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)).

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

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

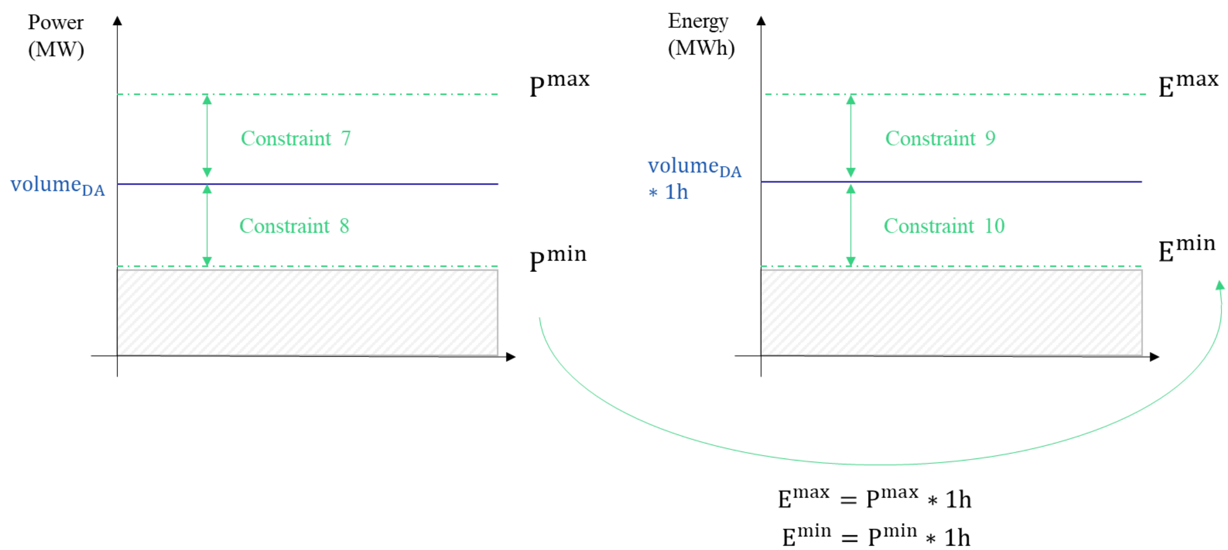
$$storage_{h=1} = storage_{initial} \tag{5}$$

$$storage_{h=H} = storage_{end} \tag{6}$$

4.5. Generation limits

The generation level of the plant is limited by a maximal (P^{max}) and a minimal power level (P^{min}). Indeed, the operational range of a hydropower plant is characterised by the inability to generate between cero and minimal capacity (Figure 1). In the figure, the dashed rectangle represents the zone which is not achievable by the unit. In order to differentiate between reserve capacity and reserve energy, we introduce two sets of constraints, following the work of (Deng, Shen et Sun 2006). One set relates to the power level limits and the other set relates to the energy level limits. The energy level corresponds to the power level multiplied by the duration of the generation period. As a result, the maximal (E^{max}) and minimal energy levels (E^{min}) are defined as the maximal and minimal power levels multiplied by 1 hour (Figure 1).

Figure 1 Operational range of the plant



4.5.1. Power level limits

Constraints (7) and (8) ensure that the committed generation capacity remains in the operational range of the unit (left part of Figure 1)[1]. These constraints follow the work of (Plazas, Conejo et Prieto 2005) (Triki, Beraldi et Gross 2005) and (Fjelldal, Nafstad et Klæboe 2014) among others. Upward reserves only appear in the maximal power constraint (equation (7)). Because the volume sold in the day-ahead market is always greater than the minimal power level, the minimal power constraint is respected in case of upward reserve activation. The FCR and aFRR capacity products are symmetrical so they also appear in the minimal power constraint. They are subtracted from the day-ahead volume to represent the downward activation. By contrast, the mFRR and RR capacity products are upward products, so they only appear in the maximal power constraint. The contract duration of the FCR, mFRR and RR products are considered. Here, this feature is not represented in the constraints to simplify the notations. The impossibility to have a power level between cero and the minimal power level requires the introduction of a binary variable (β_h) in the minimal power level constraint. This binary variable equals to one when the unit participates in the day-ahead market and cero otherwise. This way, the total committed capacity can be cero when it is not profitable to participate in any market.

[1] The letter 'c' following the name of the market means that the variable represents the volume sold in a given reserve capacity market.

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

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

4.5.2. Energy level limits

Equations (9) to (11) ensure that the energy generation level remains in the operational range of the unit[2]. The day-ahead, FCR and aFRR capacity volumes are multiplied by 1 hour in order to obtain the corresponding energy levels. 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. The binary variable γ_h is used to represent the non-spinning nature of mFRR and RR upward energy. Indeed, it is not compulsory to participate in the day-ahead market in order to supply this service. Consequently, γ_h equals to one when the unit starts up to supply mFRR or RR upward energy and cero otherwise. Equation (12) makes sure 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)).

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

$$\begin{aligned} 1h * (volume_{DA,h} - volume_{FCRc,h} - volume_{aFRRc,h}) - volume_{mFRRde,h} - volume_{RRde,h} \\ \geq E^{min} * \beta_h \end{aligned} \tag{10}$$

$$volume_{mFRRue,h} + volume_{RRue,h} \geq \gamma_h * E^{min} \tag{11}$$

$$\beta_h + \gamma_h \leq 1 \tag{12}$$

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

4.6. Links between reserve capacity and reserve energy volumes

The activation of FCR and aFRR energy is realised in a pro-rata base. It means that each reserve supplier contributes to energy activation at the pro-rata of its reserve capacity provision. In other words, the share of reserve energy supplied by one generator over the total reserve energy need corresponds to the share of reserve capacity supplied by this generator over the total reserve capacity need (equations (14) to (17)).

$$volume_{FCRue,h} = volume_{FCRc,h} * \frac{demand_{FCRue,h}}{demand_{FCRc,h}} \tag{14}$$

$$volume_{FCRde,h} = volume_{FCRc,h} * \frac{demand_{FCRde,h}}{demand_{FCRc,h}} \tag{15}$$

$$volume_{aFRRue,h} = volume_{aFRRc,h} * \frac{demand_{aFRRue,h}}{demand_{aFRRc,h}} \tag{16}$$

$$volume_{aFRRde,h} = volume_{aFRRc,h} * \frac{demand_{aFRRde,h}}{demand_{aFRRc,h}} \tag{17}$$

The volume of aFRR capacity is defined by the regulators, as no market exists in France. Generators with a nominal capacity higher than 120 MW are obliged to supply aFRR capacity. We assume that 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 always participates to the aFRR as long as it sells energy in the day-ahead market.

$$volume_{aFRRc,h} = volume_{DA,h} * \frac{demand_{aFRRc,h}}{total\ forecasted\ generation_h} \tag{18}$$

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

[2] The letter 'ue' (respectively 'de') following the name of the market means that the variable represents the upward (respectively downward) reserve energy volume.

(RTE 2020b) (equations (19) and (20)). The upward reserve energy volume corresponds to the reserve capacity volume multiplied by one hour because we assume that reserve energy is activated for the whole hour.

$$volume_{mFRRue,h} \geq 1h * volume_{mFRRc,h} \tag{19}$$

$$volume_{RRue,h} \geq 1h * volume_{RRc,h} \tag{20}$$

4.7. Adding a pump to the unit

The power consumption of the pump in MWh is given by equation (21), with η^{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). In the same way than for the seasonal storage plant, we consider that the water head and the efficiency rate are constant.

$$energy_h^{pump} = \frac{\rho * q * H * Q_h^{pump}}{\eta^{pump} * 1.10^6} * 1\ hour \tag{21}$$

Because we have inflows, we have chosen to explicitly represent the downstream water reservoir, contrary to the literature (Chazarra, Pérez-Díaz et García-González 2014), (MacPherson, et al. 2020), (Muche 2014), (Paine, et al. 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 ($Q_h * 3600\ seconds$). The lower reservoir collects the water discharged from the upper reservoir ($Q_h * 3600\ seconds$) and looses the water pumped towards the upper reservoir ($Q_h^{pump} * 3600\ seconds$). There are no natural inflows to the lower reservoir because we assume that there is no river flowing to it. We also allow for releases from the lower reservoir to the river with the variable $spillage_h$. Because the lower reservoir may be smaller than the upper reservoir, evacuating water is necessary 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 permitted by regulations.

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

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

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

The volume of energy consumed to pump water is defined by the variable $volume_{DA,h}^{pump}$. This variable is constrained to equal to the maximal pumping capacity (P_{pump}^{max}). Indeed, we assume that the only operational point of the pump is its maximal power (equation (25)). The binary variable θ_h equals to one when the unit is pumping and cero 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)).

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

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

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

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 (Chazarra, Pérez-Días et Garcia-Gonzalez 2017) and (Muche 2014), we assume that changing the operational mode of the unit, between the turbine and the pump modes, implies start-up costs. However, we consider that start-up costs are identical in the turbine and in the pump modes. To our knowledge, there is few data available regarding the specific start-up costs of pumped storage hydropower plants.

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

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[3]. Only the reserve capacity prices and demand levels are from the RTE data platform[4]. Table 2 shows the values of the parameters chosen for the case study. The first two columns gather the parameters of the model for seasonal storage plant. 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 4% 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 2 Parameter values of the case studies.

Parameter	Value	Parameter	Value
P^{max}	1 MW	P^{max}_{pump}	1 MW
P^{min}	0.5 MW		
$\eta^{turbine}$	92%	η^{pump}	87%
H	100 m		
$\overline{storage\_upper}$	200,000 m^3	$\overline{storage\_lower}$	50,000 m^3
$inflows$	260 m^3/h		
$start\_up\_cost$	4 €/MW/start-up		

5.1. Improving the representation of the water management

Before analysing the results, the impact of the values assigned to the initial and final storage levels are analysed. Indeed, we have set their values to the maximal storage level. For the pumped storage plant the values for the downstream reservoir are 25,000 m^3, that is half of its maximal capacity. The results obtained with those values may be inaccurate. Indeed, the objective of this value is to consider the operation of the power plant before and after the optimisation period. The initial and final storage level must reflect the generation decisions made outside of the optimisation period. A low upstream storage level at the beginning of 2019 means that the opportunities of profits are more important at the end of 2018 than they could be at the beginning of 2019. In the same idea, a high upstream storage level at the end of 2019 means that it is more profitable to save water for the beginning of 2020 than to use it at the end of 2019. In order to estimate the value of the initial and final storage considering this feature, the same optimisation problems have been solved with an extended time horizon. Several extensions have been tested with the addition of 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. With this number of tests, we can expect a convergence of the results that will justify the choices of initial and final storage levels. These problems were solved with the CPLEX solver with the same relative gaps presented above. The initial and final storage levels are the same than with the original optimisation period. 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 Table 5 and Table 6 in the appendices.

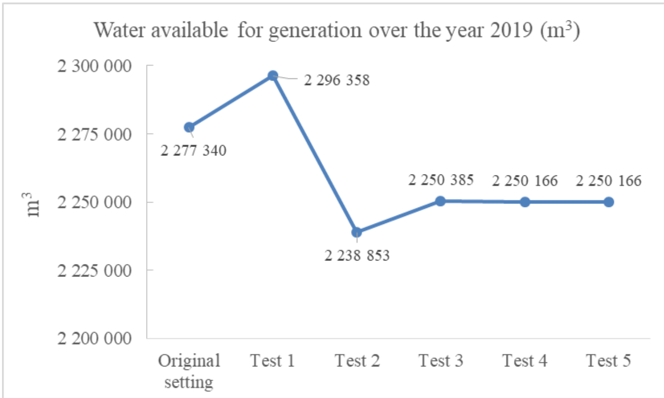
Figure 2 illustrates the volume of water available for generation in 2019 with the seasonal storage plant with the original setting (optimisation over one year) and the five tests. It corresponds to the sum of water inflows and the difference between the storage levels at the beginning and the end of the year. In the original setting, only the inflows

[3] https://transparency.entsoe.eu/

[4] https://www.services-rte.com/en/home.html

are used for generation because the initial and final storage levels must be identical. The water available with the first test is higher than for all other cases. It is the only test where the storage level at the beginning of the year is greater than at the end. This is due to the profitability of the last weeks of November 2018 which lead to an important use of water for the other tests. Because these weeks are not in the planning horizon of the first test, it overestimates the storage level at the beginning of the year. The water available with the second test is lower than with the following tests. This is due to the closeness of the end of 2019 with the end of the planning horizon of the second test. Because the storage level must reach its maximal value by the end of the optimisation period, the unit uses less water than it would otherwise in order to fulfil this constraint. Test 3 shows a small difference with the tests 4 and 5. This difference is negligible as it represents only 219 m^3 of water or 0.05 MWh.

Figure 2 Water available for generation over the year 2019 according to the length of the planning horizon with the seasonal storage plant.



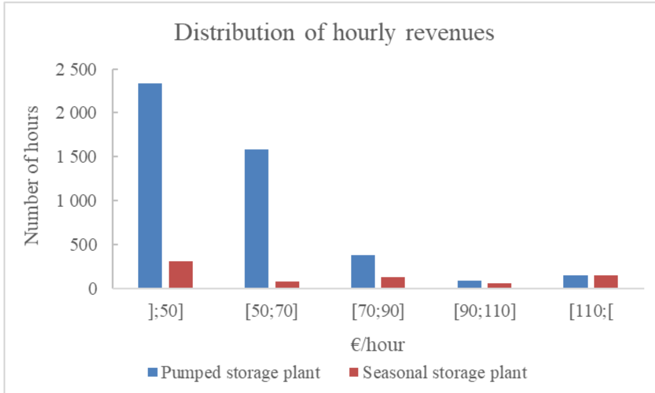
These tests show that setting the initial and final storage levels to its maximal capacity is not optimal. Modifying these values allows us to get a more accurate representation of the management of the reservoir. The first test does not fully capture the management of water outside of the planning horizon. The second test slightly overestimates the final storage level. From the third test, we see a convergence of the results suggesting that choosing one test instead of another one will not significantly influence our results. The results obtained with the third tests will be used in the following. The same choice has been made for the pumped storage plant.

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, that is 8.5% of the time. 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 minimal generation level, 1,125 hours are necessary to use all the available water. If the unit always generates at its maximal generation level, 562 hours are necessary. Therefore, the unit must generate between 6.4% and 12.8% of the year. 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 et Fleten 2014), (MacPherson, et al. 2020), (Schillinger, et al. 2017).

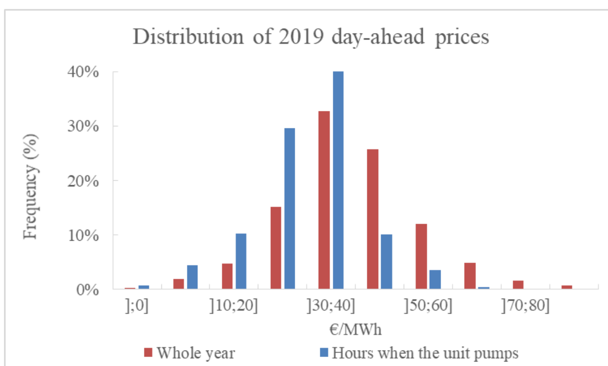
The profit obtained by the pumped storage plant rises to 124,069 €. This amount considers the start-up costs as well as the cost to buy electricity to pump water. With the same volume of upstream reservoir and inflows, the pumped storage plant increases the profit by 98% compared to the seasonal storage plant. This profit increase is possible thanks to several returns of the water between the upstream and downstream reservoirs. Indeed, the volume of water discharged through the turbine is more than 6 times greater with the pumped storage plant. However, the average generation revenue per MWh is 68.5 €/MWh, compared to 113€/MWh with the seasonal storage plant. Figure 3 compares the distribution of hourly revenues in the seasonal storage and in the pumped storage cases. The occurrences of revenues greater than 90€/hour are similar for both cases. This is due to the fact that the hours with the highest prices are chosen in priority for both cases. 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 of 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. The majority of the water surplus is used during hours with this price level, explaining the difference in average unit generation revenue.

Figure 3 Distribution of hourly revenues with the seasonal storage and pumped storage plants.



The pumped storage plant pumps water for 3,368 hours, for a total cost of 111,340€. The choice of the hours to pump are made according to the day-ahead price level. Other market prices are not considered because the unit cannot supply reserves when it pumps. As the unit buys electricity to pump water, the most profitable strategy is to choose the hours with the lowest day-ahead prices. This strategy is illustrated in Figure 4 with the frequency of day-ahead prices when the unit pumps compared to the frequency over the whole year. In 80% of cases, the unit pumps when the day-ahead price is lower than its median of 38.6 €/MWh. However, there are cases when the unit pumps despite relatively high day-ahead prices, above 40€/MWh. It mainly occurs in January, when day-ahead prices are higher than the rest of the year in average. However, the generation revenues that the unit can obtain are also higher in January. Therefore, it is profitable to pump during those hours of relatively high day-ahead prices because the generation revenues are even higher.

Figure 4 Frequency of 2019 Day-ahead prices for the whole year and when the unit pumps (%).



5.3. The predominance of pure strategies

Over the year, the seasonal storage plant allocates its available water in two different ways (Figure 5). The first allocation decision is to participate in the day-ahead market and in a downward reserve energy market (first bar in the graph)[5]. The maximal power is sold in the day-ahead market and 0.5 MWh is sold in the downward reserve energy market. This combination maximises the revenues as the minimal energy level prevents from offering a higher volume of downward reserve energy. This decision results in 0.5 MWh of energy generated (sky-blue line in the graph). This allocation is chosen 46% of the time the seasonal storage plant is generating and provides 23% of generation revenues. The second allocation decision is to participate in an upward reserve energy market only (second bar in the graph). The plant offers its maximal power in this market, which results in 1 MWh of energy generated. This allocation is chosen 54% of the time the seasonal storage plant is producing and provides 77% of the generation revenues. This difference between the share of each bidding strategy in terms of frequency and revenues is explained by a volume and a price effect. Because the hourly volume of net energy is larger with the second strategy, the aggregated volume of net energy would be larger with this strategy even with a similar participation frequency for both strategies. Indeed, the first strategy results in 0.5 MWh of energy generation per hour and 1 MWh for the second strategy. The price

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

effect represents the fact that unit revenues are significantly higher for the second strategy. The average revenues equal to 83€/MWh with the first strategy and 126€/MWh with the second. Consequently, upward reserve energy revenues would represent a higher share of total revenues even with a similar aggregated volume for both strategies.

Figure 5 Two market allocations chosen by the seasonal storage plant.

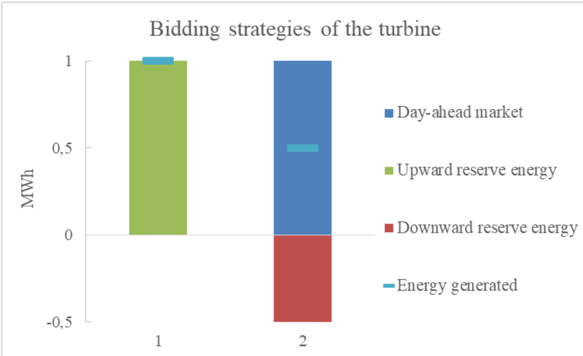
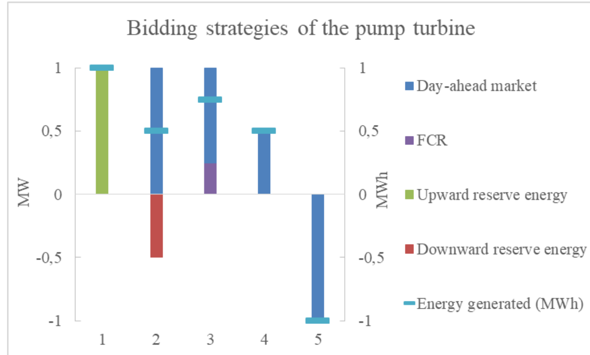


Figure 6 Market allocations chosen by the pumped storage plant.



The two bidding strategies chosen by the seasonal storage plant are also used by the pumped storage plant (Figure 6). They consist of participating in the upward or in the downward reserve energy market (strategies 1 and 2 respectively in the graph). Those two strategies are chosen 41% and 57% of the time the pumped storage plant is generating respectively. Similarly to the seasonal storage plant, the majority of the generation revenues comes from the upward reserve energy markets. They represent 73% of the generation revenues of the pumped storage plant. We also have the same difference between the share of each bidding strategy in terms of frequency and revenues. With the pumped storage plant these two strategies represent 25.5% and 73% of the generation revenues respectively. 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 explaining this phenomenon with the seasonal storage plant persists with the pumped storage plant. However, the price effect is reduced with the pumped storage plant. Indeed, the first strategy yields 65€/MWh and the second yields 70€/MWh. The pump has reduced the average unit revenue in both markets, but the upward reserve energy market remains more profitable in average. Two other strategies are chosen when the pumped storage plant generates energy, even if they remain marginal. The first new strategy is to participate in the FCR market. In this case, the pumped storage plant sells 0.25 MW of FCR capacity, which is the maximum it can offer, and 0.75 MWh of energy in the day-ahead market. This strategy is rarely used, only 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. This strategy is chosen 1.7% of the time the pumped storage plant is generating. 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. Finally, the fifth strategy is adopted when the unit pumps. Because we assume that the unit cannot supply reserves when it is pumping, it only participates in the day-ahead market. In addition, it can only buy its maximal energy level to pump, that is 1 MWh.

In both cases, the unit only participates in one reserve market at the same time, corresponding to a pure strategy. Therefore, the hypothesis of one hour of reserve energy activation is respected in the results. However, this hypothesis is not stated explicitly in the model. Participation in two reserve markets for the same hour could have been observed in the results, while respecting all the constraints. We do not observe it because it yields lower unit revenues than a pure strategy. If we only consider the upward and downward reserve energy markets, participating in both markets at the same time would require two conditions to be met. The unit revenues of this mixed strategy should be higher than the revenues per MWh obtained in the upward reserve energy market only and to the revenues per MWh obtained in the downward reserve energy market only. Satisfying those two conditions at the same time is less likely than satisfying one of them. To illustrate this feature, several mixed strategies have been tested. They have been defined with the following reasoning. Firstly, the day-ahead volume is defined with a value strictly lower than the maximal energy level and strictly greater than the minimal level. The upward reserve energy volume corresponds to the difference between the maximal energy and the day-ahead volume. The downward reserve energy volume equals to the difference between the day-ahead volume and the minimal energy level. This way, the mixed strategy respects the constraints related to the operational range of the unit. It is compared with the pure strategies illustrated in Figure 5. Five mixed strategies have been chosen to compare their revenues with the pure strategies (Table 3).

Table 3 Mixed strategies compared with pure strategies.

Mixed strategies	Day-ahead volume (MWh)	Upward reserve energy volume (MWh)	Downward reserve energy volume (MWh)
1	0.51	0.49	0.01
2	0.6	0.4	0.1
3	0.75	0.25	0.25
4	0.8	0.2	0.3
5	0.99	0.01	0.49

For each hour of the year, the revenues per MWh of these mixed strategies are compared with the revenues per MWh of the upward and downward pure strategies. The revenues are calculated for each pair of upward and downward reserve energy markets (mFRR upward energy and mFRR downward energy, mFRR upward energy and RR downward energy …). The comparison shows that the revenue per MWh of the mixed strategy is always lower than the revenue of at least one pure strategy. As a result, the mixed strategy is always dominated and is never chosen by the seasonal storage or the pumped storage plant.

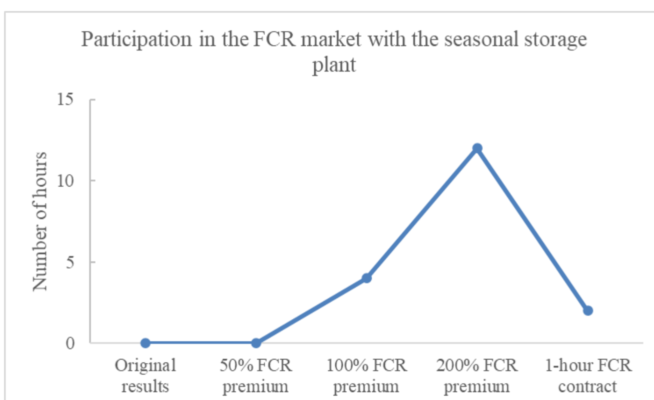
5.6. Market design modifications to incentivize the participation in the FCR market.

The seasonal storage plant never participates in the FCR market. The pumped storage plant participates in this market only 0.4% of the time. Two complementary reasons could explain this result. The first reason concerns the revenues obtained in this market, which could be lower than in the other reserve markets. The second reason concerns the 4-hour contract duration which could reduce the participation in this market. Indeed, this contract duration requires that the FCR revenues must be higher than the revenue in others markets for four consecutive hours. This may be less likely than with a shorter period, one or two hours for example. In order to evaluate the relevance of these two explanatory factors, the impact of a FCR price premium and of the reduction of the contract duration are analysed for both case studies. Three premium levels are applied to the FCR capacity price. They increase the FCR capacity remuneration by 50%, 100% and 200% respectively. The FCR contract duration is reduced to one hour in order to eliminate intertemporal trade-offs in the decision to participate in the FCR market. These two market design modifications are implemented separately.

5.6.1. Seasonal storage hydropower plant

Figure 7 shows that the impact of the market design modifications is insignificant. A price premium that corresponds to 50% of the FCR price does not have any impact in the FCR participation. With a price premium that doubles (100%) and triples the FCR capacity price (200%), the unit only participates in the FCR market 4 and 12 hours respectively. Thus, the impact of the price premium is very limited. The reduction of the contract duration increases the participation by only 2 hours.

Figure 7 Impact of a FCR price premium and a reduction of the contract duration in the FCR participation for the seasonal storage plant.



The hypothesis regarding the duration of mFRR and RR energy activation may influence the results obtained. Because this hypothesis determines the volumes that can be sold in reserve energy markets, it modifies the revenue per MWh obtained. For instance, the volumes of reserve energy sold with 30 minutes of activation are divided by half compared with 1 hour of activation. However, the volume sold in the FCR market are always the same. Therefore, modifying this hypothesis may modify the result of the trade-off between the FCR and the reserve energy markets.

Figure 8 Participation in the FCR market with 30 minutes of reserve energy activation for the seasonal storage plant.

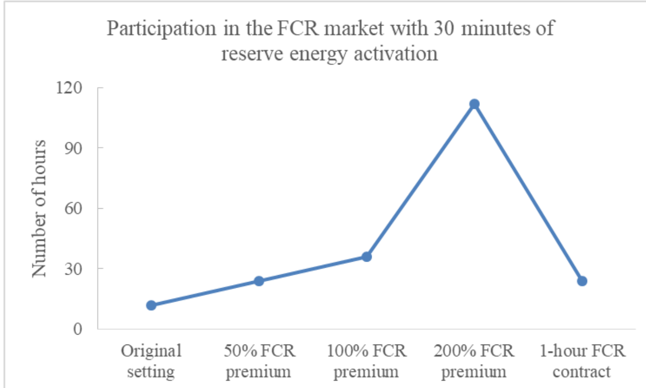


Figure 8 shows the impact of the price premia and the one-hour contract with 30 minutes of reserve energy activation. In the original setting, the FCR participation remains negligible with only 12 hours of participation. The 50% and 100% price premia multiply the FCR participation by 2 and 3 respectively. However, it remains marginal compared with the other markets. Indeed, the seasonal storage plant participates in the FCR market 2.2% and 3.3% of the time it is generating respectively. The 200% price premium has a significant impact with 112 hours of FCR participation, representing 10.5% of the time the seasonal storage plant is generating. The reduction of the contract duration has the same impact than the 50% price premium, with 24 hours of participation. Therefore, this duration of reserve energy activation increases the efficiency of each market design modification. The efficiency of the 200% price premium is significantly greater, but its implementation is very unlikely due to its high costs. Concerning the other modifications, their impact is moderate underlying the fact that the hypothesis we made does not influence our conclusion.

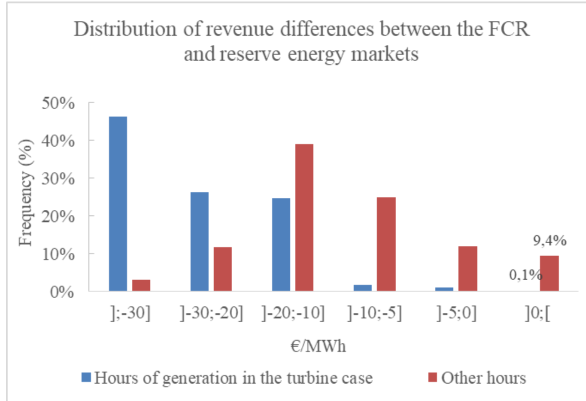
5.6.2. Pumped storage hydropower plant

The water surplus obtained with the pumped storage plant is used during hours with comparatively lower price levels. It explains why the pumped storage plant sometimes participates in the FCR market. It also indicates that a FCR premium or the reduction of contract duration might have a larger effect than with the seasonal storage plant. The main bidding strategies chosen by the pumped storage plant are to participate in the upward or downward reserve energy markets. In those markets, prices are significantly more volatile than in the FCR market (Table 4). Consequently, we can expect that the difference between the reserve energy and FCR revenues is smaller when reserve energy prices are lower. Figure 9 represents this phenomenon with the distribution of differences between the FCR and reserve energy markets unit revenues. 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 hours of generation of the seasonal storage plant, it is the case in only 0.1 % of cases, corresponding to one hour. If we consider the remaining hours, this share rises to 9.4%, corresponding to 751 hours. Therefore, the probability that the pumped storage plant participates in the FCR market is higher, because it can generate more often than the seasonal storage plant. However, the pumped storage plant does not participate in the FCR market for 751 hours. Indeed, Figure 9 looks at the profitability of the FCR market for each hour individually. It does not consider the four-hour contract that introduces tighter constraint for the FCR participation. In addition, it does not consider the trade-offs between generation and pumping. The hours when the FCR market is the most profitable can also be the hours when it is the more interesting to pump. In fact, among the 751 hours when the FCR market is the most profitable or the only market available, the unit chooses to pump for half of them. Consequently, the FCR market is chosen if reserve energy prices are relatively low but also if the day-ahead price is not too low. This additional condition explains why the unit participates in the FCR market only 20 hours over the 751 hours mentioned above.

Table 4 Standard deviation of prices in the different markets.

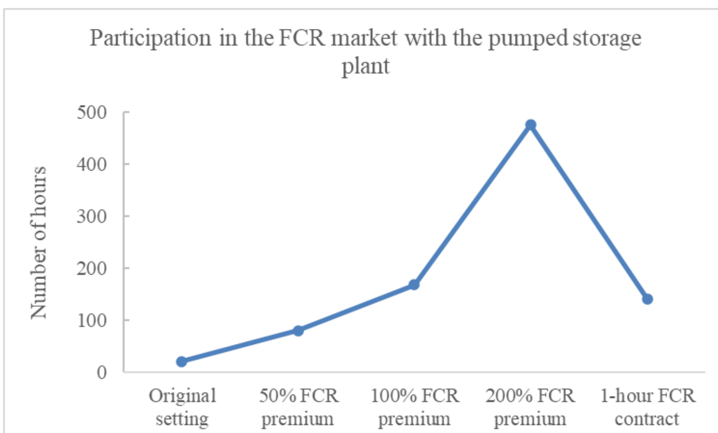
Markets	Standard deviation of prices
Day-ahead	14
FCR	3
mFRR upward energy	28
RR upward energy	30
mFRR downward energy	13
RR downward energy	14

Figure 9 Distribution of unit revenue differences between the FCR and reserve energy markets.



In the same way than for the seasonal storage plant, a FCR price premium and a reduction of the FCR contract duration have been implemented. Both measures have a significant impact in the FCR participation (Figure 10). Indeed, the implementation of a 1-hour contract multiplies the FCR participation by seven. The FCR premia multiply it by 4, 8 and 23 respectively. The distribution of the revenue differences between the FCR and reserve energy markets explains why these measures are effective for the pumped storage plant (Figure 9). During the generation hours of the seasonal storage plant, the difference between the FCR and reserve energy revenues is more important. For the remaining hours, the difference is lower with 37% of hours for which the difference ranges between 0 and -10€/MWh. As a result, the FCR price premium is more likely to modify the sign of the revenue difference with the pumped storage plant. It explains the larger impact of the market design modifications for the pumped storage plant.

Figure 10 Participation in the FCR market in the original setting with a price premium and with a 1-hour contract for the pumped storage plant.



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. We analysed the results obtained with 2019 French prices. A sensibility analysis has been performed on the values assigned to the reservoir levels for the beginning and the end of the optimisation period. 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 for the analysis 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. However, the limited amount of available water and the capacity of the reservoir prevent from benefiting from all the hours with the highest revenues. The addition of a 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. Concerning the pumping strategy, the lowest prices are mainly chosen. For the month of January, we observed pumping hours with relatively high day-ahead prices. These choices remain profitable because the generation revenues remain higher than the pumping cost.

The analysis of the bidding strategies shows 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 0.1% of the time by the pumped storage plant. These results do not consider price uncertainty and the order in which markets clear. Because upward reserve energy prices are more volatile than the others, considering uncertainty may modify the preference for this market. In addition, reserve energy markets are the last ones to clear. The risk not to be selected in these markets is another element that may modify our results.
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 higher 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.

7. Appendices

Table 5 Storage levels and water available for generation according to the length of the planning horizon with the seasonal storage plant (m^3).

	Test 1	**Test 2**	**Test 3**	**Test 4**	**Test 5**
Last hour of 2018	164,170	79,974	80,194	79,974	79,974
Last hour of 2019	145,152	118,461	107,148	107,148	107,148
Water available for generation in 2019	2,296,358	2,238,853	2,250,385	2,250,166	2,250,166

Table 6 Storage levels and water available for generation according to the length of the planning horizon with the pumped storage plant (m^3).

		Test 1	**Test 2**	**Test 3**	**Test 4**	**Test 5**
Last hour of 2018	Upstream reservoir	132,970	103,655	105,007	103,031	105,613
	Downstream reservoir	37,190	40,393	40,393	42,974	40,393
Last hour of 2019	Upstream reservoir	88,488	88,488	89,517	88,488	88,488
	Downstream reservoir	43,559	43,559	43,559	43,559	43,559
Water available for generation in 2019		2,321,822	2,292,507	2,292,831	2,291,884	2,294,465

Table 7 List of variables

Name of the variable	**Meaning**	**Unit**
$energy_h$	Volume of energy generated during hour h	MWh
$energy_h^{pump}$	Volume of energy consumed to pump water	MWh
Q_h	Water discharged for energy generation	$\mathrm{m}^3/\mathrm{second}$
Q_h^{pump}	Water discharged for pumping	$\mathrm{m}^3/\mathrm{second}$
$spillage_h$	Water spilled from the downstream reservoir	m^3
$storage\_upper_h; storage\_lower_h$	Storage level	m^3
$volume_{DA,h}$	Volume sold in the day-ahead market	MW
$volume_{DA,h}^{pump}$	Volume bought in the day-ahead market for pumping	MW
$volume_{FCRc,h}$	Volume sold in the FCR market	MW
$volume_{FCRue,h}; volume_{FCRde,h}$	Volume of energy injected in real time in relation to the FCR capacity contract	MWh
$volume_{aFRRc,h}$	Volume corresponding to the compulsory supply of aFRR capacity	MW
$volume_{aFRRue,h}; volume_{aFRRde,h}$	Volume of energy injected in real time in relation to the aFRR obligation	MWh
$volume_{mFRRc,h}; volume_{RRc,h}$	Volume sold in the mFRR/RR capacity market	MW
$volume_{mFRRue,h}; volume_{RRue,h}$	Volume of mFRR/RR upward energy sold and supplied when the unit is already online	MWh
β_h	=1 if the unit participates in the day-ahead market	Binary
γ_h	=1 if the unit supplies mFRR/RR upward energy from the off-status	Binary

θ_h	=1 if the unit is pumping	Binary

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