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# Market strategies for large-scale energy storage: vertical integration versus stand-alone player

Rodica Loisel<sup>1,2</sup>, Corentin Simon<sup>1</sup>

## Abstract

New projects using existing storage technologies such as Pumped Hydro Storage (PHS) face uncertainty due to the lack of clear business models. Market regimes have generally tended to embed storage and generators within the central management of operators with multiple assets such as the French EdF (*Electricité de France*). By means of back-casting, this study depicts the role of storage in the power market, within the vertical integration in the governance portfolio of EdF. A dynamic algorithm simulates hourly operation under two different storage strategies, daily and weekly, and the results are compared with actual patterns over the period 2015-2019. This reveals missing money for a stand-alone player due to price arbitrage caused by low spread, and missing market opportunities. This suggests that the economics of storage are not driven by spot prices alone, but by other services, such as the energy block provision in support of nuclear power. Differential calculus is used to estimate the value of flows integrating the duration of storage and its seasonality. These findings further support the French regulator to install new PHS despite the lack of profitability, by means of capacity-energy hybrid contracts for new competitors in place of the existing government-industry structure.

**Keywords:** pumped hydro energy storage; stand-alone market player; deterministic daily / weekly storage optimisation; myopic foresight.

## Highlights

- French PHS plants are non-correlated, some pumping, others discharging simultaneously.
- Missing market opportunities comprise up to 25% of volumes and 31 M€ of profits.
- Standalone storage captures the price spread better than actual vertically integrated PHS.
- Capacity and energy hybrid contracts could give incentives for long-term storage.
- Cost recovery capacity mechanism would be at least 49 €<sub>2017</sub>/MWh of storage.

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## 1. Introduction

The specification of the role of the energy storage in power systems is complex and depends on the storage characteristics and the balancing needs of each grid operator (CIGRE (2019)). Experience worldwide shows that price arbitrage is not typically profitable, and needs to be combined with reserves and ancillary services to stack revenue streams (Staffell and Rustomji (2016)). The definition of price arbitrage is extensive, in that it covers the supply side when buying and selling electricity, the demand side when supporting time-of-use management, and the generation side as a sort of load-following or ramping the electricity supply up or down (ESF (2019)).

This paper deals with two main topics, the first being the evaluation of the profitability of storage based on optimal operation on the power market, the second being related to the regulation and institutional regime of storage in the current design of decentralised power markets.

The literature contains many studies dedicated to **large-scale storage evaluation**, in particular Pumped Hydro Storage (PHS). The main topics include the assessment of the share that should optimally be addressed for arbitrage and balancing (Staffell and Rustomji (2016), Connolly et al. (2011), Goutte and Vassilopoulos (2019), Lu et al. (2004)), the optimal duration of storage (Strbac et al. (2012)), the value of pumped storage in comparison to other large-scale technologies (Gaudard and Madani (2019)), the system value of pumped storage (Teng et al. (2018)), the storage design in terms of its responsiveness (Yang and Yang (2019), Chazarra et al. (2017)), and services other than power provision, such as heat (Smallbone et al. (2017)), etc.

In summary, in this literature it is argued that 1) in some cases, compressed air energy storage is cost-competitive compared with PHS; 2) support policies should be oriented towards financial risk reduction rather than the provision of subsidies; 3) variable-speed pumped storage as opposed to conventional PHS would handle the variability of renewables more effectively; 4) the value of pumped storage increases with market size, e.g., European compared with national level; 5) short-duration storage has a much higher value than long-term storage. With a focus on cost metrics, it is shown that the conventional indicator of the levelised cost of energy (LCOE) seems inappropriate for evaluating storage because it considers only the electricity discharged, whereas the operation of storage also includes pumping and storage (Belderbos et al. (2017)).

A second strand of literature used in this research is focused on the **regulation of storage** and the market regime for new actors. It reflects the view that private capital, rather than utilities and state monopolies, has no incentive to invest in regular services to the grid, and is mostly considered for marginal functions (like ancillary services, Transport and Distribution [T&D] upgrade deferral, demand response). Winfield et al. (2018) compare storage regimes, monopolies, and liberalised electricity markets, and stress the role of socio-political factors in moving traditional regimes towards remunerated energy services. Interestingly, energy storage is seen as unlikely to disrupt the existing regulatory regime, and could bring only marginal adjustments to current institutional arrangements; indeed, the primary function of large-scale storage is to support base-load generators in avoiding unpredictable dispatch, thus storage supports the standard market regime.

The status of energy storage is generally ambiguous, in terms of whether it is generation, consumption, or both. Despite the potential use of storage to provide flexible and highly accurate services to different segments, power market structures themselves are partly barriers to storage operations, due to their design having initially been set for conventional systems (Winfield et al. (2018)). The power market incorporates multiple sub-markets for energy, for capacity, for reserves and balancing, for ancillary services, for demand response, and behind-the-meter services. In Europe, the design of power markets seems unfavourable for storage in terms of the

accumulation of contracts across distinct market segments, due to their complexity in terms of gate closure timelines and high transaction costs when switching between commitments.

In France, the energy authority considers that the issue is not regulation *per se*, because storage can access the market and already provides grid services, but that the market only partially accounts for the specificities of storage, such as the speed of reaction, the quality of supply, and the time of charge and discharge (CRE (2019b)). Difficulties in assessing benefits might be due to the effects of *unbundled* electricity systems on the calculus of the full value of storage (Anuta et al. (2014)). Vertical integration of storage with T&D would lend transparency in terms of the direct beneficiary of the storage services, but T&D operators are prevented from owning storage to ensure fair access to storage for all market participants (EU (2019)).<sup>3</sup> Theoretical studies have shown that the ownership of storage by TSOs could constitute a loss of welfare due to storage-network cross-subsidies, although bundling storage with generators could enhance social welfare losses too, due to speculative transactions (Sioshansi (2014)).

Waterson (2017) explains the unprofitable business case of a new, private actor by referring to the absence of markets dedicated to services of storage due to missing information on externalities. These are social benefits such as capital savings on new peaking plants, avoidance of renewable energy curtailment, deferral of grid reinforcement, and fuel saved through reduced ramp rates, etc. Without these markets, private actors would need subsidies to act in the public interest, or other market-based instruments such as capacity mechanisms. This would prevent a purely commercial strategy oriented towards short-term periods, usually diurnal, due to the difficulty of predicting future power prices. Arbitrage over longer periods, as in weeks, is less likely to be profitable, since hourly prices do not capture information on the long term such as the value of capacity assurance. Moreover, market signals suggest that it is preferable to invest in medium-sized and short-duration storage, because energy block storage is less cost-efficient. In small power systems, a bulk discharge could even have a cannibalising effect, reducing storage revenues, because large discharged flows would reduce the inframarginal rent by excluding other more expensive technologies (Sioshansi et al. (2009)).

This paper is in line with the literature dedicated to storage evaluation and market regimes, in suggesting ways to improve the design of contracts based on optimal operation. In particular, it brings insights on the operation of a PHS plant on the wholesale power market and analyses the spread between the actual operation and the optimal strategy, and the missing money as the difference between profits and costs. Two storage strategies are tested over short and long timelines applied to the largest PHS plant in France. Based on the duration of storage, the aim is to understand the contractual forms that recover costs and best fit the needs of the power system. The main **contributions** are as follows. Firstly, we show that the five PHS plants in France operate in a non-correlated way, with some plants pumping and others discharging simultaneously. This suggests that the owner and operator EdF is not using storage strategically to speculate in the day-ahead market, despite large water reservoirs and the high potential power available. Secondly, a standalone market player would capture only partially the price spread in the day-ahead market in the actual vertically integrated PHS-generator structure. Thirdly, the paper complements other work on the use of cost indicators based on value rather than prices, and contains a discussion of the support needed to value long-term storage duration systematically.

The remainder of the paper is organised as follows. In Section 2 we give details of the case study, and in Section 3 we describe the model used to simulate French storage plants. We present and discuss the results in Section 4, and offer some conclusions for market policy in Section 5.

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<sup>3</sup> By derogation, TSOs are temporarily allowed to own storage facilities if there is no tender at the end of a tendering procedure for non-frequency ancillary services, thus excluding price-arbitrage operations.

## 2. Case study

The French **power mix** is dominated by nuclear power (71% of total generation in 2019), the other sources being hydropower (11%), gas (7%), wind (6.3%), and solar (2.2%). The country has started an ambitious programme of decarbonisation and phase-out of coal plants, and designed a planning framework for investment in offshore wind and solar panels. PHS plants have an installed capacity of 4.2 GW and attracted increasing interest with the development of variable renewables. In line with the French Multiannual Energy Plan, the Energy Transition Act refers to a target of 1.5 GW to be installed by 2030-2035 (PPE (2020)).

The **market regime** has a particular architecture, with a decentralised power market and a high degree of centralised electricity production, dominated by EDF, covering nuclear power, most of the hydro and thermal power and renewable energy. Transformations towards more competitive markets on the generation side and on the supply side are ongoing. The NOME Act (French New Electricity Market Organisation voted in 2010) sets the volume of nuclear power that EDF has to sell to competitors at regulated tariffs (100 TWh). In parallel, the European Commission has asked to EDF to open hydropower concessions up to competition; moreover, an infringement procedure has been launched in 2019 against France (EC (2019a)). It should be noted that most of dam hydro concessions are operated by EDF, and 150 concessions out of a total of 400 will expire soon, i.e. in 2023.<sup>4</sup>

Yet, complying with the EU competition law will take time, as hydro concessions, which are State owned, raise many cross-sector challenges such as power reliability, safety of construction works, water management, environmental protection and tourism, hence excluding for the moment their privatization. To the concession time-lasting procedure adds the EDF restructuring, which is planned to be split into three entities: nuclear and hydro (EDF Blue), trade and renewables (EDF Green) and dams (EDF Azure), according to Hercules plan.<sup>5</sup> Currently, the regulation of the market regime contains no provision concerning the future of hydro power and PHS plants, despite the willingness of operators such as Total and Engie to compete with EDF. The structure State-industry for operating PHS plants remains at the moment the rule of governance.

The **regulation of storage services reward** is evolving slowly as well, due to the low requirement for flexibility on the continental side due to the large contribution of hydro power, low levels of wind and solar, and massive demand response programs with residential hot water and load curtailment. Nevertheless, there is implicit recognition of the social value of storage beyond the low private benefit, given the awareness in the Energy Transition Act that the market is not able to cover costs, meaning that additional support is needed for new PHS projects (PPE (2020) p.185). The system operator RTE is currently testing 30 MW of batteries to better understand how value is spread throughout the system and the way the market provides remuneration for ancillary services (Project Ringo).

PHS infrastructure is designed to provide **energy management** by pumping during periods of low demand, and releasing water during peak demand (EDF (2011)), which looks very much like price arbitrage. Table 1 gives an overview of the PHS plants in France. A key element of the overall strategy is the *capacity* of the storage: a five-hour storage capacity is mostly used for

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<sup>4</sup> <https://www.latribune.fr/opinions/tribunes/concessions-hydrauliques-vers-une-ouverture-a-la-concurrence-811388.html> (accessed 24 November 2020).

<sup>5</sup> <https://www.euractiv.com/section/energy/news/france-battles-brussels-over-separation-of-edfs-nuclear-arm/> (accessed 24 November, 2020).

adjustments in response to short-term fluctuation (Super-Bissorte plant), while a forty-hour discharge capacity should generally be sufficient for seasonal storage (Montézic plant).

**Table 1.** Description of the French PHS infrastructure

French PHS plant characteristics	Montézic	Revin	G. Maison	S. Bissorte	La Coche	Le Cheylas
Year of commission	1982	1976	1985	1987	1977	1979
Turbine, MW	910	720	1 790	730	330	460
Pumping, MW	870	720	1 160	630	310	480
Number of pumps	4	4	8	4	2	2
Discharge, hours	40	5	30	5	3	6

Source EDF (2011).

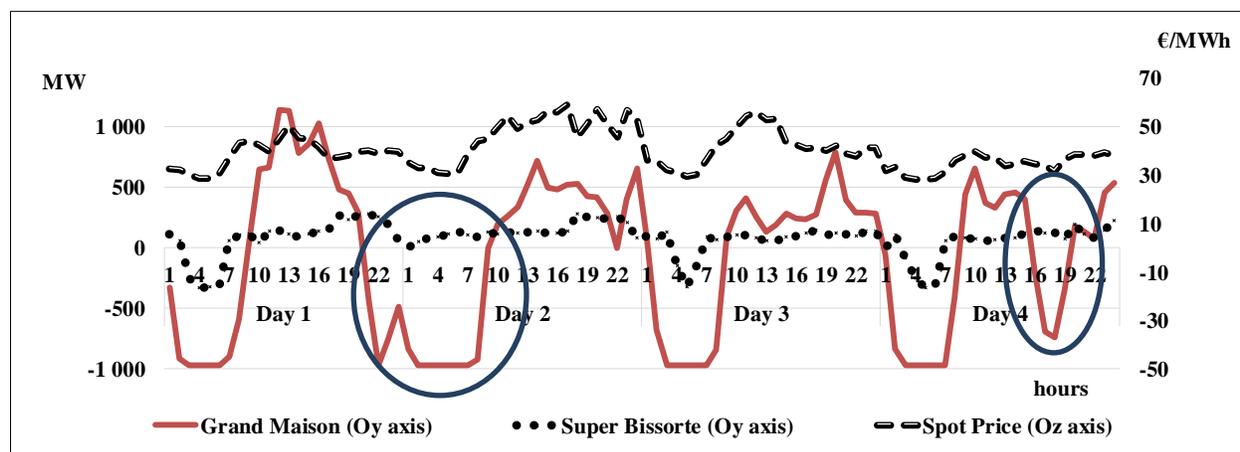
Note. The PHS plant La Coche was not operational over the period 2015-2019 due to repowering and maintenance.

Based on data obtained from the French Transmission Operator, we have analysed the actual hourly operation of the PHS fleet by plant for the year 2017.<sup>6</sup> Statistics show frequent occurrence of **uncorrelated operation** in that some plants are pumping while others are simultaneously discharging. The frequency of such events is relatively high (see Table 2).

**Table 2.** Number of hours of uncorrelated operations for five PHS plants in 2017

		Discharging				
PHS plant		Grand maison	Le Cheylas	Super Bissorte	Montezic	Revin
Charging	Grand maison	-	730	607	700	780
	Le Cheylas	552	-	410	130	96
	Super Bissorte	627	623	-	768	780
	Montezic	1 310	711	1 199	-	468
	Revin	1 162	420	979	285	-

Fig. 1 shows the operation of two plants over the course of four days, revealing an overall correlation with the hourly spot price: for low prices, the storage plant is pumping (negative flows, below Ox axis); at high prices, water is released and the plant is discharging (positive flows). Yet, the two plants are uncorrelated for more than 25 hours over four selected days (from 20<sup>th</sup> to 23<sup>rd</sup> June 2017), with the large Grand'maison plant charging while the smaller Super-Bissorte is discharging (highlighted by the two ellipsoids).

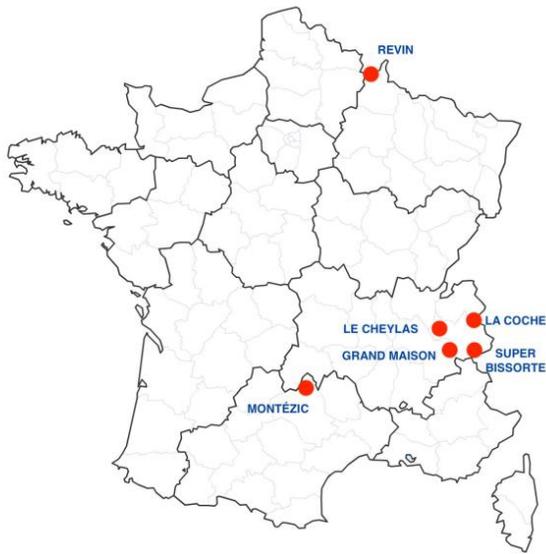


**Fig 1.** The operation of two PHS plants over four days in 2017

<sup>6</sup> RTE, 2017, [http://clients.rte-france.com/lang/fr/visiteurs/vie/prod/production\\_groupe.jsp](http://clients.rte-france.com/lang/fr/visiteurs/vie/prod/production_groupe.jsp), accessed at 03/11/2019.

The characteristics of the two PHS plants are quite different, in that Grand'maison (1,790 MW discharging/ 1,160 MW pumping/ 30h storage) is much larger than Super-Bissorte (730 MW discharging/ 630 MW pumping/ 5h storage). The uncorrelated flows therefore reflect the ratio of the nominal power of the two schemes; for example Grand'maison discharges an equivalent of 191 GWh over the year, while S-Bissorte is simultaneously pumping 110 GWh, and Grand'maison pumps 316 GWh while S.-Bissort is discharging 66 GWh. In statistical terms, the number of uncorrelated events represents respectively 13% and 17% of the time when Grand'maison is operating in discharging and pumping modes. The longest uncorrelated event lasted for 16 hours (on 28<sup>th</sup> January, from 7 am to 10 pm).

The network is analysed in order to understand the nature of these different system services supplied simultaneously, at a national level and at regional/European level, accounting for local congestion and balancing needs of neighbours. **Locally**, grid reliability and congestion fixing are part of the decision-making process of the state-owned Transmission System Operator, RTE.<sup>7</sup> Congestion is fixed by geographical area, by means of flow redispatching and countertrading to modify generation or transmission plans. Four of the PHS plants belong to the same geographical area (Auvergne-Rhône-Alpes, see Fig. 2) and in case of local congestion they should operate in a similar way, meaning that plants are not likely to supply services to the grid of opposite sign.



**Fig. 2.** Locations of the six storage plants in France

*Source: Google Maps*

The geographical location of different plants can partly explain the non-correlations between two plants in different areas, for example Revin (in the North) and Grand'maison (South-East), because they can supply services to the system with specific regional constraints. For plants located in the same area, the nature of the system services should be the same over a given one-hour period, meaning that uncorrelated events cannot be assimilated to services in the same grid area. Considering services other than those within the national grid, we note the high level of **connectedness of France** with its neighbours (Saez et al. (2019)). Hence the spot power price is correlated with that of neighbouring countries, or the trends at least are similar over the year due to market coupling through EpeXspot (Belgium, Germany, Great Britain, Luxembourg, the Netherlands and Switzerland). Spreads are nevertheless important over periods with low export-import flows and no convergence, e.g., price spreads between France and Germany are higher

<sup>7</sup> [https://clients.rte-france.com/lang/an/visiteurs/vie/redispatch\\_countertrade\\_and\\_costs.jsp](https://clients.rte-france.com/lang/an/visiteurs/vie/redispatch_countertrade_and_costs.jsp)

than between France and Belgium (CRE (2018)). During uncorrelated events, therefore, plants in the same area cannot provide opposite services to the grid.

Given that these two PHS plants are located in the same regulation area and are 70 km apart, the flows might be expected to have different durations, amplitudes, and delivery times, but to be correlated at any point in time. In practice, however, the direction of flow can be opposite at the same time, as mentioned above. A further complexity derives from the fact that each plant follows a contractual strategy that is adapted to the capacity of its reservoir (EdF (2011)), e.g., weekly energy storage for Grand'maison and daily storage for S-Bissort. In the next section, the operation of a PHS plant is modelled to gain a deeper understanding of the economic rationale behind the trading seen on the power market.

### 3. Methodology

Two main modelling classes have been identified in the literature: 1) models testing the duration of storage, short-term (around 4h) and long-term (~700 h), at different capacity rates and energy-to-power ratios (Jülch, 2016); and 2) models dedicated to price arbitrage testing perfect and imperfect foresights of future power prices (Staffell and Rustomji (2016)). A combination of these approaches is built to test two time-line strategies, adopting myopic foresight in assuming that future prices, in days and weeks, cannot affect current storage operation. This is due to the high liquidity of the French wholesale and balancing markets, with no prior reason to store power over weeks.

The model optimises the operation of the PHS plant Grand'maison, at two time horizons: daily storage provision and weekly storage for longer discharge. In the first case, the PHS operator supplies the spot market with the aim of maximising revenues over one day under diurnal perfect information on prices. In the second case, the operator has longer-sight information that allows optimisation of storage and deliveries over one week. The longer the horizon, the less accurate the information on prices, which reduces the incentive to store bulk energy; apart from this, the French power system is strongly inter-meshed and connected to neighbouring countries, which further reduces the opportunity value of storage.

The model maximises the operational revenue from discharging as triggered by the hourly spot market price, under the market constraint of cost paid for power charged. Technological constraints also apply, such as the round-trip efficiency, the minimum load of the reservoirs, the availability of the plant, and the nominal capacities of pumps, reservoir, and turbines. The model is built using Python software and the solver *scipy.optimize*, and is based on 8,760 time slices organised within 52 recursive dynamic blocks for weekly storage optimisation, and 365 blocks for daily storage. Within each block, the information on hourly power price is perfect, starting with the first period of each week or day, and ending at the last hour of the block. Over the year, information on prices for the next block is myopic, and the dynamics among blocks are sequential.

The model returns volumes of charging and discharging, which are further extrapolated to the technical lifetime of the plant so as to reproduce the investor business model considering the base year as representative. The economics are assessed using the Net Present Value (NPV) of benefits and the Levelised Cost of Energy (LCOE).

In the presentation of the model (Eq1-Eq8), bold characters are used for endogenous variables and normal font is used for fixed values.

**Eq1.** Operational profit maximisation (the objective function):

$$\pi_s = \sum_1^{B_s} \text{Max}_{d,h} \sum_{\substack{h=24 \\ d=1}}^{d=t_s} p_{d,h} \cdot (PD_{d,h} - PC_{d,h})$$

**Eq2.** Dynamics of the storage reservoir:

$$R_{d,h} = R_{d,h-1} + PC_{d,h} \cdot \text{eff} - PD_{d,h}$$

**Eq3.** Minimum load condition (storage reservoir does not empty) and maximum level of charging:

$$\text{MinLoad} \cdot K_R \leq R_{d,h} \leq K_R$$

**Eq4.** The power discharged is lower than the power charged over the year:

$$\sum_1^{B_s} \sum_{\substack{h=24 \\ d=1}}^{d=t_s} PD_{d,h} \leq \sum_1^{B_s} \sum_{\substack{h=24 \\ d=1}}^{d=t_s} PC_{d,h} \cdot \text{eff}$$

**Eq5.** The power discharged does not exceed the capacity of the turbines:

$$PD_{d,h} \leq K_T$$

**Eq6.** The power charged does not exceed the capacity of the pumps:

$$PC_{d,h} \leq K_P$$

**Eq7.** PHS Net present value:

$$NPV_s = \sum_{y=1}^{60} [(\pi_s - c_{OM_y}) / (1+r)^y] - INV_0$$

**Eq8.** PHS Levelised Cost of Energy, including the cost of the electricity charged:

$$LCOE_s = \frac{INV_0 + \sum_{y=1}^{60} \frac{c_{OM_y} + c_{PC_y}}{(1+r)^y}}{\sum_{y=1}^{60} \frac{\sum_{h=1, d=1}^{h=24, d=t_s} PD_{d,h}}{(1+r)^y}}$$

## The Index

y – years over the technical lifetime (1,60)

d – day (1, 365)

h – hour (1, 24)

s – optimisation strategy: daily or weekly optimisation,  $s = \{“day”, “week”\}$

$t_s$  – time interval of optimisation strategy: daily ( $t_{“day”} = 1$ ) or weekly optimisation ( $t_{“week”} = 7$ ).

$B_s$  – the number of recursive blocks over the year, by strategy: daily optimisation ( $B_{“day”} = 365$ ); weekly optimisation ( $B_{“week”} = 52$ ).

## Parameters

*eff* – round-trip efficiency of pumping and discharging (*eff* = 80%)

*MinLoad* – minimum load of reservoir to be continuously filled-in (10%)

## Exogenous Variables (Inputs)

$p_{d,h}$  – spot market power price at hour *h*, day *d* (in €/MWh)

$K_R$  – capacity of reservoir (in MWh)

$K_T$  – capacity of turbines (in MW)

$K_P$  – capacity of pumps (in MW)

$r$  – discount rate (8%)

INV0 – PHS investment cost (in €)

$c_{OM}$  – annual Operation & Maintenance cost (in €)

### Endogenous Variables (Outputs)

$\pi_s$  – yearly operational profit by strategy ( $\pi_{day}, \pi_{week}$ ) (in €)

$PD_{d,h}$  – power discharged at hour  $h$ , day  $d$  (in MW)

$PC_{d,h}$  – power charged at hour  $h$ , day  $d$  (in MW)

$R_{d,h}$  – energy stored in the reservoir at hour  $h$ , day  $d$  (MWh)

NPVs – Net present value by optimisation strategy (in €)

LCOEs – Levelised cost of electricity by optimisation strategy (in €)

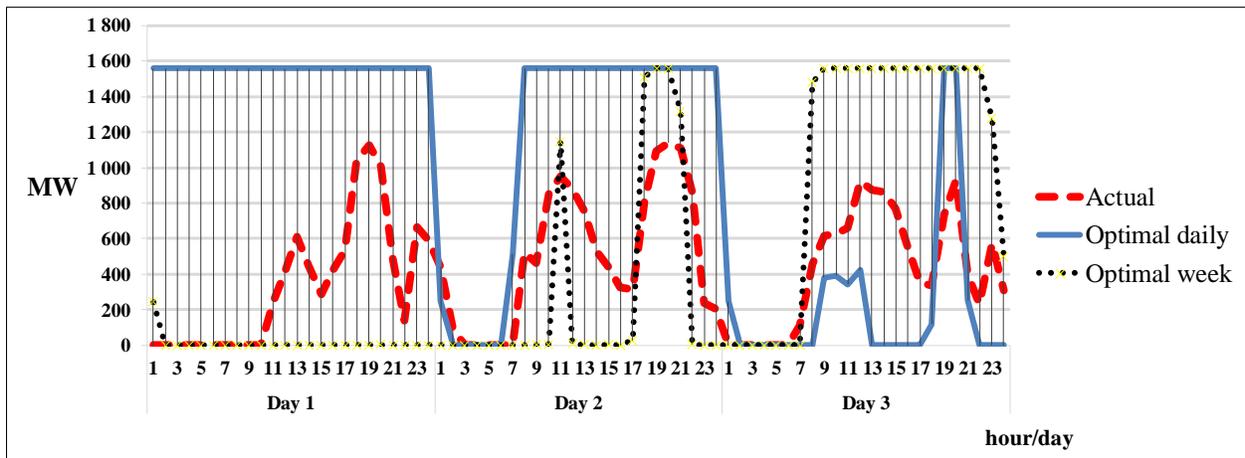
$c_{PC}$  – annual cost of power charged (in €)

## 4. Results

The results of the optimisation are analysed for the two storage strategies, *Daily* and *Weekly*. They are further compared to the *Actual* operation in 2017, by means of back-casting, revealing the way in which the real behaviour is constrained by the technology itself and by the power market.

### 4.1. A volume perspective

Optimisation results show that of the two storage strategies, the one that best fits the *Actual* behaviour is the *Daily* storage. There is some variation over the year, however, in that both the historical behaviour in 2017 and the plant optimisation seem to **alternate** between *Weekly* and *Daily* storage. Fig. 3 shows the operation of Grand'maison over a three-day period and reveals that the discharge under the *Daily* strategy follows the dynamics of prices and locally reaches the same amplitude as *Weekly*. Over the year, the trend is similar but with irregular switching from one strategy to another.

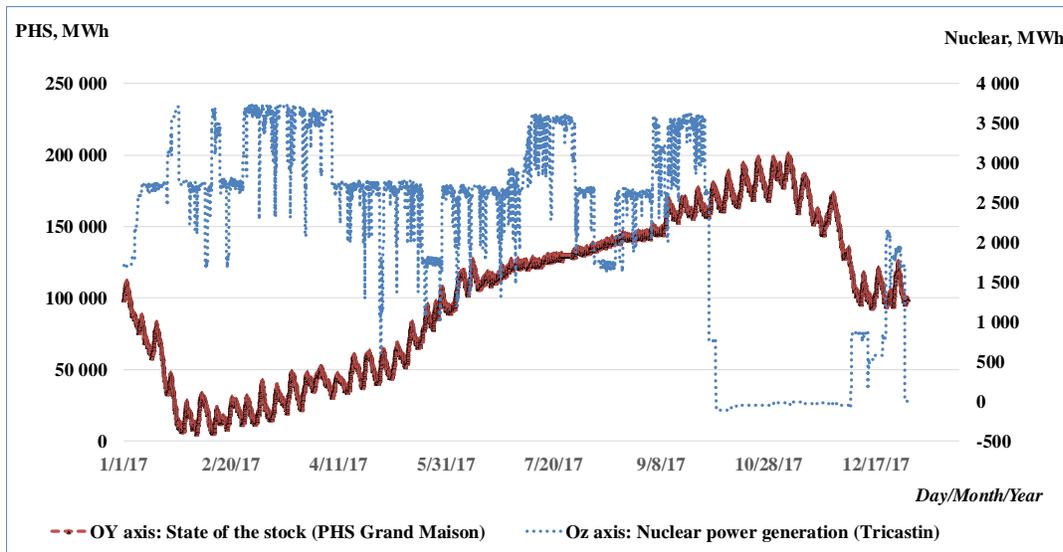


**Fig. 3.** Discharge operation of Grand'maison PHS plant over three days: Actual (real data) versus Optimal (model results)

On first inspection, it seems that the difference between *Actual* and the optimisations reveals that the PHS plant provides a service nearer to **ramping energy blocks** than to a highly variable supply on the spot market, and this seems to be specific to systems exposed to high ramping needs (Cigre (2019)). It should be noted that four large nuclear power plants are located in the vicinity of the Grand'maison PHS plant, and despite their commitment to meet a forecast load, anticipation of the rate of change is always subject to technological constraints. All French nuclear power plants are capable of load-following, and all provide flexibility and ancillary

services to the grid. However, where there is a need for faster response and longer-lasting reserves, and negative reserves in particular, operations could be limited by the design of the reactor in terms of ramping and minimum load safety requirements.

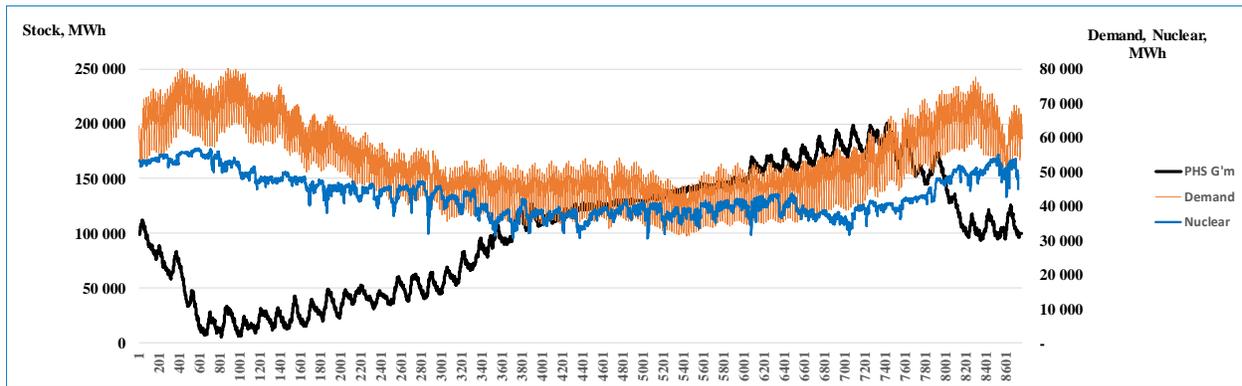
Among the four **nuclear power plants**, one in particular at Tricastin shows complementary behaviour with storage discharge, with four reactors of 900 MW each. Figure 4 shows that over the year, the nuclear power plant operates in load-following mode, and the PHS stock (i.e., stored energy) seems to support these dynamics: the stock decreases at the beginning of the year when the nuclear power plant is operating at half its nominal power, and starts filling up when the four reactors are operating at full power (the generation level is at 3,600 MWh from February to March).



**Fig. 4.** The actual operation of the PHS plant (Oy) and of the nuclear power plant (Oz).  
Source of data: RTE website (<https://www.services-rte.com/fr/home.html> last accessed March 2019)

The general filling of the storage from April to September sustains the nuclear load-following operating mode when the level of demand is decreasing, and it shows a sudden discharge over two months (i.e., from October to December), when EdF decided to shut down the four reactors to allow maintenance on a nearby canal dyke. The PHS stock starts to fill again in mid-December, while at the same time the nuclear power starts ramping up again. Beyond these **monthly cycles**, we also note weekly and daily cycles triggered by fluctuations in the market, showing how the PHS operator alternates the strategies over the short- and long-term, but with a major six-month trend underlying the overall operation. The PHS plant appears to be integrated with nuclear facilities in general within a virtual provider, which seems rational given that they both belong to the same operator, EdF.

Irrespective of the responsive support of Grand'maison for one nuclear plant in particular, the dynamics of the PHS plant follow the trend of nuclear plants in terms of load-following. Figure 5 shows that over 2017, nuclear has high levels of supply at the beginning of the year and starts declining but less than the demand from March to October. The stock of PHS decreases when the demand is high, at the beginning and the end of the year, and fills up in between.



**Fig. 5.** Hourly Demand, Nuclear power generation and PHS Grand'maison stock in 2017, based on RTE data.

By inspection of Fig.5, it seems that the PHS plant is probably driven by *flows* in the form of energy blocks, because the operator EdF uses storage to manage optimally its diversified portfolio of nuclear-renewable-thermal units in a centralised manner. PHS plants optimise the dispatching of the EDF energy mix, with storage mainly used during peak periods in discharging mode, and additionally for balancing markets with negative and positive adjustments.

#### 4.2. Cost and value calculation

The storage operator acting in standalone mode would record **losses** with price-arbitrage only. In simulations for the year 2017, the NPV before taxes is  $-32 \text{ M€}_{2017}$  per year under the *Daily* strategy, and much lower in the *Weekly* case ( $-52 \text{ M€}_{2017}$  per year). More generally, a lack of profits is found for any large storage plant in other markets, because the price spread is not large enough to cover investment costs. In the *Daily* case, the average selling price is  $56 \text{ €}_{2017}/\text{MWh}$  and the buying price is  $33.5 \text{ €}_{2017}/\text{MWh}$ , with an average spread of  $22.5 \text{ €}_{2017}/\text{MWh}$ . The status of standalone on the wholesale market means that the power charged is paid at the market price, with no arrangement in place allowing generators to buy electricity at a discount. Assuming that the electricity would be charged for free, the model would change, turning losses into profits (NPV is positive even in the less interesting *Weekly* case:  $130 \text{ M€}_{2017}$  per year or  $30 \text{ €}_{2017}/\text{MWh}$ ). This indicator is generally used in the academic literature to facilitate the interpretation of results, ignoring the charging cost of electricity; but even then, this cost indicator mostly has features of price-driven cost estimation because it depends on the price profile (Belderbos et al. (2017)).

*Daily* strategy is more profitable than *Weekly*, and again this finding is not specific to the French market, since it has already been argued in the literature that markets promote daily rather than seasonal storage (Gaudard and Madani (2019), Strbac et al. (2012)). Moreover, due to the duration of charge-discharge cycles of 6 hours on average, a daily strategy is more profitable than intra-day trading (Connolly et al. (2011)). Per unit of energy, the operational profits, i.e., covering only variable costs, are around  $15 \text{ €/MWh}$  for both the *Weekly* and *Daily* cases, in line with other studies. Gaudard and Madani (2019) show that the use of 96 h storage on European markets from 2011 to 2016 provides operational profits between 2 and  $20 \text{ €/MWh}$ , while 24 h of storage brings higher profits, between 5 and  $77 \text{ €/MWh}$ . In our study, operational profits are at the lower end of this range due to lower market prices in France than in the 17 markets evaluated by Gaudard and Madani (2019).

In terms of volume, the energy supplied is 19% less important in *Actual* than in *Daily* optimisation ( $-500 \text{ GWh}$  discharged), with a wide spread varying from 0 to 100% of the nominal capacity of the turbines. Consideration of a longer period from 2015 to 2019 confirms this trend,

with generally **missing market opportunities**, because storage fails to capture between 19% and 25% of market volumes and between 2 M and 31 M€<sub>2017</sub> of profits. Table 3 includes an assessment of profits evaluated at spot price each year and shows that the PHS plant records losses, with the highest loss rate in 2018 when prices are on average at their highest. The high prices in France in 2017 and 2018 are explained by reduced nuclear availability and low hydro levels, affected seasonally by low temperatures during winter and high demand for electricity for domestic heating, as well as by high temperatures during summer with an increased demand for cooling (CRE (2018)).

**Table 3.** PHS operation in Actual and Optimal cases, with price statistics, by year

		2015	2016	2017	2018	2019
<b>Spot price, €/MWh</b>	Average	38.5	36.6	45.0	50.0	39.3
	Maximum	123	874	206	260	121
	Minimum	0.0	-10.7	-2.2	-31.8	-24.9
<b>PHS Grand'maison</b>						
<b>Actual</b>	Discharge, GWh	2 014	2 003	2 071	2 185	2 001
	NPV, M€	-56.4	-43.3	-35.2	-62.6	-57.9
	NPV, €/MWh	-45.7	-35.4	-27.8	-46.8	-47.3
<b>Optimal Daily</b>	Discharge, GWh	2 549	2 678	2 565	2 537	2 563
	NPV, M€	-36.6	-28.7	-32.6	-31.6	-38.2
	NPV, €/MWh	-23.5	-35.4	-20.8	-20.4	-24.4
<b>Optimal Weekly</b>	Discharge, GWh	3 102	3 497	3 105	2 935	2 555
	NPV, M€	-47.3	-35.2	-52.5	-54.4	-52.0
	NPV, €/MWh	-24.9	-16.4	-27.6	-30.3	-33.3

Source: Data on prices are obtained from [www.epexspot.com](http://www.epexspot.com) (last accessed 10/09/2020).

It should be noted that *Daily* and *Weekly* optimisation strategies use perfect **foresight of prices** over one day and one week, respectively. This allows perfect anticipation of periods of charging and discharging. In contrast, the *Actual* case builds on *estimated* information on price variations, thus part of the difference between these strategies lies in the degree of price anticipation. In practice the difference should be low, thanks to the recent price prediction tools, which have improved the accuracy of price and volume forecasts. With the development of variable renewables and increased spot-price fluctuations, significant efforts have been made to develop day-ahead price forecasting models, based on time-series and computational intelligence (Haluzan et al. (2020), Monteiro et al. (2018)).

The robustness of forecasting models can even result in cash flows similar to actual ones, as shown by a PHS case study in Germany where actual unit commitment is shown to correspond to the planned one (Muche (2014)). In terms of accuracy, Connolly et al. (2011) show that with good price forecasting, optimisation of PHS plants 24h ahead could yield 97% of the optimal

profits with perfect foresight. Even without price forecasting, the accuracy of anticipated profits could be as high as 88%, as estimated by Stafell and Rustomji (2016) who argue that more than price values, it is the profile shape of prices for arbitrage which is of key importance. Most of the time, for example, discharging occurs between 5-7 pm due to the high probability of high prices at this time of day.

For French PHS plants, optimisation is undertaken by the group EdF Trading, which builds and runs models for price and risk evaluation, based on data obtained from the publicly available ENTSO-E platform combined with transmission system data from the operator, RTE. The main mission of the group is related to EdF's gross margin maximisation, and the forecast error is low as a result of combined optimisation on the wholesale market at the portfolio level and for each asset individually.

The margin errors are as high as 50% in 2018, with an average of 32% over the period 2015-2019, thus they are difficult to compare with price forecasting errors. This seems to show that there are other constraints that add to the standalone model tested here. These constraints could be internal, related to the technology itself, but also external due to centralised dispatching of all power generators in the system, including exports and imports, which complement or substitute for PHS charging/discharging at the appropriate time. This suggests that the PHS business model is not driven by spot prices alone, even if most of the time there is some correlation between them. Other strategic options might exist, triggered by the needs of system operators in other markets, or subject to contractual arrangements in support of other power plants, or through some hybrid mechanism.

Apart from profits, the decision of the French regulator to build more PHS plants in the future leads us to assume an implicit social or **system value of storage** from benefits such as the reliability of the grid while charging, and security of supply while discharging. At European level, the value of this is estimated at 200 €/kW for 2020, and much higher in the future, at 700 €/kW in 2050, in order to reduce costs associated with power generation and transmission (Teng et al. (2018)). Locally, within the activity of EdF, the value comes from charging during periods of low demand when nuclear power plants are being asked to reduce their generation substantially. The value of power charged is then zero on the market, or negative, and storage acts more as a negative reserve. In 2017, market profitability would be achieved for any cost of power charged at 25.8 €<sub>2017</sub>/MWh or less in the *Weekly* case. Alternatively, if the power is charged at the given market price in 2017, the required price spread would be at least 43 €<sub>2017</sub>/MWh. These indicators are the metrics needed to complement the NPV in order to characterise the power system in which the PHS operates (Belderbos et al. (2017)).

Interestingly, *Weekly* storage supplies larger volumes on the wholesale market than *Daily*, but sells at lower prices on average over the year (54.5 €/MWh *Weekly* against 56 €/MWh *Daily*). The **difference in prices** could seem marginal, but when added to a less interesting average cost while charging (39.3 €<sub>2017</sub>/MWh in *Weekly* case > 33.5 €<sub>2017</sub>/MWh in *Daily*), the operational profit becomes significant, and much higher in *Daily* than in *Weekly* (+ 20 M€<sub>2017</sub>).

The load factor is more important in *Weekly* than in *Daily* for all PHS plant components, suggesting that for the long term the question of storage duration is important but so is discharging frequency (see Table 4). The **stock is used differently** among the three cases: a more dynamic use of storage for short duration (*Daily*), thus less filling-in of stock over time (21% against 42% in *Weekly*). More volume is discharged in the *Weekly* strategy than in *Daily*, and flows are stored for longer. Lower discharge in *Actual* (the lowest usage rate of turbines, 13%) suggests a likely seasonal support with energy blocks to large-power plants. This behaviour confirms that the operation is triggered firstly by pumping and storage commitments and secondly by discharging during peak times: the stock is used for longer than in standalone

optimisation, while pumping and discharging occur less over the year (by seven percentage points).

**Table 4.** Load factor by storage component, by strategy (actual versus optimisation)

Rate of use	Actual, 2017	Optimisation Strategy	
		Daily	Weekly
Stock	20%	21%	42%
Pumps	23%	29%	35%
Turbines	13%	16%	19%

Based on rates of usage, the cost calculation provides an indicator often used in the literature, namely the levelised cost of *storage* (LCOS, Jülch (2016), Lazard (2018)), which is simply the application of **LCOE to storage** technologies. The same formula applies to the energy produced by storage as to a generator, by inclusion of the cost of electricity charged. In general terms, the costs of PHS plants are in the range 42-265 €<sub>2010</sub>/MWh (Krajacic et al. (2013)). By applying this formula, we obtain the lowest cost in the *Daily* storage, due to low charging costs: 140 €<sub>2017</sub>/MWh in *Daily*, 128 €<sub>2017</sub>/MWh in *Weekly* and 166 €<sub>2017</sub>/MWh in *Actual*. When power is charged for free, costs decrease: 107 €<sub>2017</sub>/MWh, 88 €<sub>2017</sub>/MWh and 132 €<sub>2017</sub>/MWh respectively.<sup>8</sup> The latter indicator, the LCOS with power charged for free, can be applied to any price profile, or to estimate the value of the capacity adjusted with the usage rate and adapted to the proper metrics, i.e., the value per MW. Better cost figures for an investor would be obtained using the power charged as negative reserve (IRENA (2015)), thus the cost for the electricity charged would become a benefit, decreasing the average cost.

The annual operational benefits by strategy, valued at spot prices, are the lowest in the *Weekly* case (16 M€<sub>2017</sub>), and highest in *Daily* (36 €<sub>2017</sub>), with intermediate figures in *Actual* (33 €<sub>2017</sub>). Despite the large actual use of the reservoir in *Weekly* (42%) and the resulting low unit cost, profits are the lowest due to low selling prices and the high cost of charging. Without any commitment for **long-term storage**, the economic rationality to hold energy over long periods seems less economically viable. This model appears irrational in storing a *common* commodity other than electricity, since any warehouse business model would account not only for the dynamics of flows *in* and *out*, but also for the duration for which the volume is stored. The value of the time for which flows are stored seems implicit here, given that the market does not reflect this value in its selling prices. The *Actual* case reflects the system needs in terms of flexibility in the year 2017, as well as large seasonal requirements for pumping, discharging and bulk long-lasting stored energy flows.

**By stakeholder**, the value is at least the average cost, which is also the break-even point: it is 132 €<sub>2017</sub>/MWh for a *large private operator* like EDF using storage as seasonal support (*months*) to its various generators, probably charging the power for free; it is 88 €<sub>2017</sub>/MWh for a *system operator* making *weekly* optimisation to ensure capacity and storing the surplus free of charge, and is 140 €<sub>2017</sub>/MWh for a *standalone* operator with *daily* price-arbitrage, who should pay for the power charged at the market price.

The differences among the strategies in terms of electricity “charged”, “stored” and “discharged” stem from the fact that the three services are not one and the same commodity from a market point of view, i.e., the time when the electricity is used by the PHS plant corresponds to different buying-cost and selling-price from one strategy to another. Hence, the cost calculation based

<sup>8</sup> The PHS total cost is estimated at 1600 €/kW, split as Storage 50%, Turbines 30%, Pumps 20%. Estimations are 748 M€ for turbines, 499 M€ for pumps, 1248 M€ for the reservoir. The lifetime is 20 years for pumps and turbines, and 100 years for the reservoir. Costs are approximate, subject to uncertainty related to site features and commercial confidentiality.

only on the levelised cost of energy discharged seems restrictive to flows **out**, because the indicator ignores the dynamics of the stock and the value of the flows stored. On average, 1 MWh is stored for 9.8 hours over the year in the *Daily* strategy, 48 hours in *Weekly* and 10 hours in *Actual*.

The difference between long-term and short-term storage makes it necessary to devise new metrics based on the **duration of storage** and the filling rate of the reservoir, similar to the scarcity of an asset: the higher the filling rate, the higher the value of storage, as less and less space becomes available. The cost of the power to be charged should approach zero when the reservoir filling rate is close to 100%, meaning that the marginal MWh of the power in excess is wasted when the storage is full, and will be off-market and thus worthless. Studies on the optimised time of storage show that there is little value in having more than six hours of storage in the Australian market, for example (McConnell et al., 2015), and that after four hours of storage there are only limited incremental arbitrage opportunities in the PJM energy market (Sioshansi et al. (2009)).

We now consider the **opportunity cost** of the *Weekly* storage of providing *daily* storage, making the two strategies equivalent, to compensate for the missing market and to incentivise long-term storage, based on market mechanisms only, without compensations, being thus still unprofitable. Applying differential calculus, the operator could be rewarded into two ways:

- A complement set on the capacity of storage, as the difference in revenues among *Daily* and *Weekly* strategies divided by the capacity of storage, resulting in 32 €<sub>2017</sub>/MWh of capacity of storage. The remaining missing money for *Weekly* provision would be according to the formula  $(NPV_{\text{annual/MWh}} - \text{Market\_profit\_Weekly} - \text{Capacity Payment}) > 0$ , thus 17 €<sub>2017</sub>/MWh of discharge. A full cost recovery capacity mechanism would need values of at least 49 €<sub>2017</sub>/MWh of capacity of storage to support *Weekly* storage.
- A premium by season, influenced by its length, computed as the same difference in revenues among the two strategies, divided by the number of seasons leads to 0.37 M€<sub>2017</sub> per week. This seasonal capacity mechanism might be easy to implement because the length of the season is regular, but with some transaction costs. In contrast, the *Actual* case shows irregular seasons, combining very long-term storage, e.g., months, with very short-term discharges triggered by market volatility.

### 4.3. Analysis of the regulation framework for storage

Implementation of a capacity payment, by reservoir size or by season, would build on the strengths of the existing **capacity market**, which has been operational in France since 2016 to guarantee the availability of generators during peaks. The value in 2020 is 20 k€/MW, and it should be noted that the unit of measure is Euros per MW and not per MWh. The capacity value applies to generators only, thus application to the capacity of the storage, expressed in MWh, gives an yearly value of 24 k€/MWh, obtained as follows: 20 k€/MW x Capacity of turbines (=1,820 MW) x 400 h (peak load over one year) / Capacity of storage (600,000 MWh).

A capacity payment would require redefinition of technologies eligible to the market, such as inclusion of storage based on reservoir capacity instead of turbines. Extension of market opportunities could improve PHS revenues and usage rates by connecting capacity markets between neighbouring countries, albeit with prior coordination among TSOs to ensure adequate cross-border harmonisation (Mastropietro et al. (2015)). A spot market could enable transactions particularly over unpredictable periods of scarcity and avoid the inefficiencies of traditional bilateral contracts.

The question of how to best design the payment of storage and to account for the three services (charging, storing and discharging) remains complex due to many unknowns: the beneficiary of the service, the service itself, the market segment, and the cost of charging. The system needs vary in time and will vary even more with the further development of renewables. In the future, **hybrid regimes** could best correspond to storage under a two-segment architecture: a capacity mechanism with variable time scales reflecting the value of storage and the reservoir capacity, and use of the spot market to value pumping and discharging. These two revenue streams could result from two types of market competition: competition *in* the market for energy-only delivery, and competition *for* the market via the capacity market (Roques and Finon (2017)).

Because storage provides several services in different market segments, multiple contracts are necessary but the complexity of the market segments makes the operation difficult and sometimes causes conflicts. When the storage capacity is reserved for one service, it becomes unavailable for bidding in another market. The literature seems to recommend a simple **two-part contract**, shared between ancillary services and the spot market, yet with largest revenues from frequency regulation (based on price arbitrage) and capacity payment, more than from ancillary services (5% in Yu and Foggo (2017)). This split is dependent on the power system, although in general revenues from system support are low due to narrow markets and low volumes.

Adjusting the capacity between the wholesale market and the balancing market comes with transactions costs due to computational issues. In France, the current time step of imbalances is 30 minutes, but by 2025 it must align with European regulations; this provides the obligation for all control areas to introduce an imbalance settlement period of 15 minutes, to bring generators' bids closer to real time (EC (2017)).

**Other cost-efficient contracts** could solve the missing money issue. De Maere d'Aertrycke et al. (2017) show that in incomplete markets due to risks of low prices and volumes, contracts for differences might be an effective solution and easy to regulate; long-term contracts and capacity markets are effective only if the system is appropriately calibrated to ensure market liquidity. A hybrid regime with energy-only and capacity market is needed as long as markets do not integrate scarcity pricing, as a political goal to prevent high social costs. An energy-only market with price caps can neither internalise the security-of-supply nor provide adequate levels of capacity (Kepler (2017)), and this market failure justifies payments on top in response to the capacity issue (Petitet et al. (2017)).

For on-top payments or other forms of subsidies, a first approach has been made in the French case for storage connected with renewables, with however unclear distinction between standalone and vertically integrated systems (CRE, 2019b). Another evolving aspect of the regulation lies in the recognition of specificities of storage by service type, by addressing short-duration fast-responding technologies such as batteries, and long-lasting storage such as PHS. More generally, the status of storage will be based on ad-hoc provisions, such as to adapt to particularities of each technology and to account for the heterogeneous value of storage (Abrell et al. (2019)). For instance, the regulator has extended the framework applied to PHS to other large-scale storage schemes, with respect to tax credits for PHS<sup>9</sup>, and any other technology can benefit from similar tax credits if they have similar features, e.g., high energy consumption and charging during off-peak hours (CRE (2019b)).

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<sup>9</sup> PHS plants benefit from fiscal exemptions, up to 50% on charges for using public networks (the tax is known as TURPE in French). Further improvements are possible by exemption from tax on networks during congestion or peak load; and for part of the contribution to the public service of electricity (CSPE in French), which could be paid on final consumption only, i.e., on PHS plant losses (20%), and not for both charging and discharging flows.

This study can be **applied to other storage technologies**, in terms of modelling and recommendations, provided they have similar features in terms of the scale of pumping, storing and discharging, such as compressed-air energy storage and hydrogen storage. The general findings should incentivise integration of the characteristics of flows by seasonality, to align the value of the volume discharged to the duration of the storage. To that, significant regulatory and market design changes are necessary, and actions are ongoing (Castagneto Gisse et al. (2018)). Within the Green Deal roadmap for decarbonisation, the European Union will further support the storage industry, and batteries in particular (EC (2019b)). In North American markets, grid codes and regulation are reviewed so that storage can be used to build viable business models; pilot programmes are being run in Canada to gather information on the value of the reliability of services of storage in administrated markets (IESO (2018)). Independent system operators and regional transmission organisations in the USA are revising their tariffs to establish a participation model for storage, and some allow participation of storage in their energy markets, capacity markets, and for reserves and ancillary services (Sakti et al. (2018)).

## 5. Conclusions and Policy Implications

This paper has evaluated the historical operation of pumped-hydro storage in France and showed that storage behaves non-strategically on the market, as suggested by the low usage rate of the large water stock and the remaining potential for price-arbitrage. As an EDF asset, PHS follows rather a private operator strategy in managing a large portfolio, as seems to indicate uncorrelated discharge events we found among PHS plants. Using calculus, it is confirmed the literature's findings that the **business model is not viable** for a standalone PHS player based on price-arbitrage only. The study recommends a design based on a seasonal time-scale capacity market combined with wholesale price signals for charging-discharging electricity. This hybrid scheme best accounts for complementarities within the power mix, as is the case for the French system with its heterogeneous renewable profiles and time-varying loads.

Storage has historically been implemented within State-industry collaborations and has played an institutional role rather than a commercial one. The **PHS operation** being less a matter of power price triggering charging and discharging, its value is not clearly revealed by the power market. Because PHS plants are managed centrally, it is difficult to identify the value of a single plant in order to design contracts on a case-by-case basis. The operation mode joins findings of other studies which have shown that the highest welfare is recorded when a *social planner* is using the storage, as opposed to cases when the storage is owned by a generator or is standalone (Sioshansi (2014)). This suggests that the model of PHS which is centrally managed could be optimal, as long as the whole power system is supported by the operation of PHS, instead of a single operator, i.e. EDF.

In the absence of a clear role for storage, either standalone or as part of a bundled service provider, the **decision to invest** in new storage facilities continues to be integrated within a central planning strategy. In light of the plans put forward under the French Energy Act to install more PHS plants, it is noted that storage investment decisions are system-level determined, rather than being driven at actor level. The need for storage in this case finds few arguments in the price spread, and is related much more to political targets: fewer dispatchable generators in the future power mix (partial phase-out of nuclear, closure of coal-fired units), and more renewables (+55 GW wind and solar by 2030), increasing the need for security of supply and grid reliability. For new actors to entry the market, the current regime needs to move towards a competitive frame, to identify the interests and requirements of new actors.

The way this study could apply to other power systems is restricted to **competitive markets** where new entrants can operate and freely bid on the market in reaction to load and price

fluctuations. France is currently ongoing deep transformations triggered by national energy transition targets and by European requirements in terms of dam hydropower concession. Two frames are constraining the current business model of storage. On the one hand, the European Union admits that storage facilities are subject to unequal conditions of competition across member states and aims at addressing those legal and business barriers preventing the integration of pumped hydro storage into electricity markets (EP, 2020). On the other hand, the absence of any legal frame on hydro concessions in France is blocking the entry of new actors, along with freezing new works of EDF to comply with the Energy Transition Act targets on new PHS projects. The upcoming years will be pivotal for positioning the storage business model, after EDF restructuring and after designing common European grid codes, both long-standing.

Our recommendations for capacity plus energy payments based on a decentralised management of storage facilities, might not easily apply to the existing infrastructure. An alternative option is to identify the beneficiary of the service support to legitimate some forms of **vertical integration**, with the TSO on a temporary basis or with renewables and nuclear generators. Private capital investment could find some attraction in gaining entry to these contractual arrangements in order to offer bundled services, not least to avoid fees in each market (Winfield et al. (2018)).

In the future, the French power system will need longer and faster system services, together with the need for the regulator to rethink the role of energy storage in providing ancillary services (CRE (2019a)). Ultimately, changes to the design of such systems alone could change the institutional framework to allow investors to support high costs, and to help the public understand the strategic value of PHS, leading to broader support for new projects of this type.

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