A Contribution on the Regulation of Electricity Storage: the case of Hydro-Pumped Storage in Italy and Spain

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***Abstract*--This paper investigates the case for regulation of electricity storage, and identifies key areas and challenges likely to characterize such regulation. It argues that analyses to evaluate what is the most cost-efficient flexibility solution should be implemented on a case-by-case basis, electricity storage being only one out of many possible sources of flexibility. Also, improving existing facilities and regulatory frameworks should be considered as an alternative. Where hydro-pumped storage is identified as the most cost-efficient solution, a market's ability to deliver it should then be tested. Thus, a simplified theoretical approach is proposed and applied to the case study. Only where a market 'fails' to deliver such capacity, a case for regulation of electricity storage should be made. The key areas to consider when regulating hydro-pumped storage are (i) the criteria to define capacity adequacy and (ii) the procedures to select who should build and who should run such facilities. The risks and challenges posed by the regulation of hydro-pumped storage suggest that this solution should be considered with caution.**

***Index Terms*—ancillary services, electricity storage, flexibility, hydro-pumped storage, incentives, information asymmetries, regulation, unbundling**

I. Introduction

THIS paper critically explores the regulation of electricity storage. First, it investigates the case for regulation of electricity storage: it examines whether and for what reasons regulation of electricity storage, intended as an intervention to restrain the operation of market prices and signals or to set standards (e.g. for quality or system security) at variance with those that would have otherwise operated [1], may be required. Thus, it considers under what conditions the construction and operation of Hydro-Pumped Storage (HPS)[1] should be subject to specific regulation rather than to market competition. Second, it identifies the key areas and related risks likely to characterize such form of regulation.

This research is interesting because of the challenges arising from the increasing penetration of intermittent Renewable Energy Sources (RES) into the power system, namely the call for increased flexibility. Electricity storage represents one possible source of flexibility. Moreover, it is shown that within this category HPS currently constitutes the most technically and economically feasible large-scale solution. Thus, the paper focuses on hydro-pumped storage in Italy and Spain, where flexibility problems have already resulted in legislative initiatives and proposals. At the same time, it is the paper's ambition to contribute to a better understanding and to the resolution of the flexibility problem, which has a broader, European dimension, since inevitably affecting every Member State, though at a different pace.

The paper is structured as follows. First, electricity balancing and its role in security of supply, notably in the context of increasing RES, are defined. Second, alternative means for providing system flexibility are identified, and a brief techno-economic analysis of different electricity storage technologies is offered. Third, 'traditional' regulatory frameworks for electricity and gas storage are compared, and the recent legislative initiatives and proposals put forward in Italy and Spain are examined. Fourth, it is argued that analyses evaluating different flexibility instruments should be implemented on a case-by-case basis, as a natural corollary of the fact that HPS is a tool rather than an end in itself. Also, improving existing facilities or regulatory frameworks should be considered as an alternative. A simplified theoretical model is then proposed and applied empirically to the case study to evaluate a market's ability to deliver hydro-pumped storage capacity, when this is identified as the most cost-efficient flexibility solution. Fifth, the key areas for regulating hydro-pumped storage are identified, and the related risks and challenges discussed. Some concluding remarks, avenues for further research and policy implications are finally provided.

II. Electricity Balancing: Definition and Role in the Context of RES

It certainly falls outside the scope of this article to assess the importance of balancing markets to market integration and competition, to evaluate different institutional models, contractual arrangements and market designs for balancing, or to investigate the interrelations between balancing markets, intra-day trade and automatically-activated reserves. What is crucial is, rather, to recognize the need to ensure the security of a power system by achieving a continuous balance between demand and supply. This fundamental requirement is a

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[1] Pumped hydro employs off-peak electricity to pump water from a lower level reservoir up to another reservoir at a higher elevation. When electricity is needed, water is released from the high reservoir through a hydroelectric turbine into the low reservoir to generate electricity.

cornerstone of every power system, as it originates directly from the fact that currently, it is anticipated, electricity cannot be stored cost-effectively on a large scale. Hence, the vital objective for a system operator to identify the need for, and to procure, the adjustments in electricity supply or demand necessary to maintain the overall balance in its control area.

The increasing penetration of RES into the power system is, however, posing new challenges to the need of ensuring balance between electricity supply and demand in the most economically-efficient manner. This is because RES like wind and solar Photovoltaic (PV) are, notwithstanding the significant progresses made in forecasting techniques, not as reliable as ‘traditional’ sources are. For example, a wind farm might not be able to deliver the expected real-time output because of a sudden wind decrease. Moreover, even where a forecast is accurate enough to predict the actual electricity production of a RES unit, this may in fact be extremely volatile. As a result, it will be necessary to restore the system’s balance through a demand reduction by certain customers or through a generation increase by some producers, in either case creating additional costs for the system. Given that the objective of significantly increasing the share of RES production to meet ambitious environmental targets is not under discussion in the European Union (EU), it emerges the need for power systems to become more ‘flexible’ and to effectively cope with an increasing penetration of ‘intermittent’ RES and with the problems this necessarily implies.

III. Alternatives for Providing System Flexibility

Acknowledged the concerns that an increased penetration of intermittent RES creates for electricity balancing, one has to identify the possible alternatives for providing a system with enhanced flexibility (Table 1). First, the intermittency of RES can be offset by ‘peaking plants’ such as Combined Cycle Gas Turbines (CCGTs) or Open Cycle Gas Turbines (OCGT) that, because of their technical features (e.g. load gradients, power ramps, start-up times), are able to follow load-variations rapidly. Proper price signals, often unacceptable for political reasons, would attract investments in these ‘conventional’ generation units (where efficient), ensuring they provide the system with the flexible, ‘back-up’ capacity, required.

TABLE I
ALTERNATIVES FOR PROVIDING SYSTEM FLEXIBILITY

Conventional peaking units	• Provide flexible, back-up capacity • Require adequate price signals
Demand Side Management	• Shifts consumption to off-peak hours • Requires adequate price signals; low demand elasticity of households
Networks reinforcement and upgrade	• Reduces grid congestions; provides ability to cope with bidirectional flows • Need to overcome local opposition; smart grids still at small-scale pilot stage
Interconnections	• Provide additional cross-border sources of flexibility • Difficult cost allocation: requires analyses based on agreed scenarios and including externalities
Storage	• Holds energy and converts it back to electricity when most needed • HPS as most feasible large-scale technology

Second, suppliers could stimulate customers with Demand Side Management (DSM) measures to shift consumption from ‘peak’ to ‘off-peak’ hours, by incentivizing them with economic rewards. However, in most European Member States are still present end-user regulated tariffs that ‘protect’ final customers from the just mentioned price signals [2]. Moreover, the ability of customers to become more ‘active’ in shaping their consumption patterns is linked to their (demand) elasticity to prices, which is very low (at least for the household segment). The fact that Electric Vehicles (EVs) might significantly increase the potentially shiftable loads shows both that DSM is promising and that it is still in its infancy (in liberalized markets). A third alternative to enhance a system’s flexibility is represented by networks development. The expansion of transmission and distribution networks can effectively mitigate grid congestions, which are in turn exacerbated by RES tendency to concentrate in specific areas. This (costly) solution is however viable only where local opposition to the construction of large infrastructures is successfully overcome. Besides ‘traditional’ grid reinforcement, the development of ‘smart(er) grids’ would allow the system to effectively cope with bidirectional flows of electricity and larger amounts of information, facilitating decentralized generation and the phenomenon of ‘prosumers’[2]. However, smart grids are, as DSM, still at a small-scale pilot project stage. Fourth, the development of cross-border transport capacity can strengthen a system’s flexibility, simply because it allows that system to import or export additional sources of flexibility available in neighboring countries. For example, a system could benefit from peaking units available in a neighboring country when load must be increased, and export electricity to that country when wind is blowing very strongly. However, cross-border interconnections require sometimes controversial cost allocations and often difficult Cost-Benefit Analyses (CBAs), that must include externalities on the basis of agreed scenarios on future trends and location of demand and supply sources [3]. The final option to address the intermittency of RES is represented by electricity storage: converting grid-interconnected electricity to another form of energy (‘charging’), holding that other form of energy for future use (‘holding’), and then converting it back to grid-interconnected electricity at a different time (‘discharging’) [4].

A wide range of storage technologies is currently available. They can be distinguished in mechanical (e.g. hydro-pumped storage, compressed air energy storage, adiabatic compressed air storage, flywheels); electromagnetic (e.g. superconducting magnetic energy storage, supercapacitors); chemical (e.g. flow

[2] Prosumers are intended as more active consumers who, rather than just consuming electricity, also supply electricity to the grid.

batteries, cell batteries); and thermal [5][3]. Moreover, their features are several and comprise the amount of energy that can be stored and the speed at which energy can be supplied, costs of investment in terms of capacity (MW) and energy (MWh), efficiency, lifetime, and environmental impact. Also, different storage technologies can provide different system services, which range from grid frequency maintenance and voltage stabilization to load balancing. Thus, what these considerations suggest is that no storage technology should be considered best in absolute terms.

For the energy-related applications supporting system flexibility and RES integration considered in this paper is, however, crucial that an electricity storage technology is able to discharge for several hours, with a significant capacity (e.g. hundreds of MW) and with a reduced time response (e.g. 1-5 minutes)[4]. Hydro-pumped storage not only is the technology that best satisfies these requirements (Fig. 1), but also scores comparatively well in terms of efficiency[5] (75-82%) and costs (1500-4300 $/kW, 250-430 $/kWh) [4], [6]-[7].

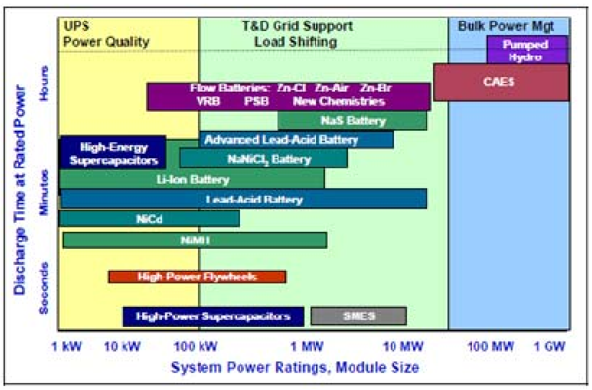

Fig. 1. Power and discharge duration of different storage technologies [6].

In conclusion, hydro-pumped storage is the most mature and cost-efficient large-scale storage technology currently available, as confirmed by the fact that over 99% of the total storage capacity installed worldwide is pumped-hydro [6].

IV. Traditional Regulation of Electricity Storage and Recent Legislative Initiatives

When evaluating the case for regulation of electricity storage, one has to begin by examining the regulatory model so far adopted. In other terms, before considering whether electricity storage should be regulated, one has to understand why so far it was not. Thus, the differences in the regulation of electricity storage and gas storage are analyzed.

In the gas sector, storage is indispensable for system operation, since consumption is strongly influenced by weather and hence seasonal, while supply is relatively inflexible. Especially in import dependent countries, as most states in Continental Europe, storage is therefore the primary flexibility tool. In particular, 'seasonal storage' allows to store gas during summer, when demand is low, and to use it during winter, when demand is higher; while 'strategic storage' is used to address shocks and risks of supply disruptions that may be due to accidents or geopolitical factors. Besides its role in seasonal balancing and security of supply, gas storage also has significant impact on market competition. For example, it represents a useful instrument for price arbitration in tighter-than-seasonal timeframes (e.g. daily, monthly) or between the electricity and the gas markets, and for shippers to balance their positions. Although gas storage is not a natural monopoly and competition between these facilities is possible in principle, insufficient storage capacity may in fact create barriers to entry [8]. Moreover, the dominance *de facto* of former incumbents on storage facilities in continental Europe leaves room for strategic behavior. As a result, the importance of gas storage for system flexibility, security of supply and market competition has been recognized in European legislation, namely in Directives 2003/55/EC and 2009/73/EC with particular reference to Third Party Access (TPA), tariff regulation, and (legal and functional) unbundling.

In the electricity sector, on the contrary, storage has not been the focus of any specific regulatory intervention. In fact, the absence of any reference to electricity storage in European directives contrasts with both the maturity of hydro-pumped storage and the role played by hydroelectric production in the EU electricity generation mix[6]. What this suggests is that hydro-pumped storage has been considered by 'traditional' regulation simply as one out of many generating technologies, notwithstanding its today very desirable capacity to increase a system's flexibility by rapidly responding to unexpected fluctuations in supply and demand.

In the country cases examined in the paper, however, a significant penetration of intermittent RES has recently prompted legislative initiatives and proposals. In Italy, where the installed wind and solar PV capacity equals 17 GW and the HPS capacity is about 8.1 GW [10], the Legislative Decree implementing Directive 2009/28/EC on the promotion of RES calls on Terna, the Transmission System Operator (TSO), to identify in its network development plan the reinforcements necessary to ensure that RES generation is fully dispatched, including storage systems [11, Art. 17.3]. The picture has not been clarified by a subsequent Legislative Decree [12], which on the one hand confirms that the prohibition for the TSO to produce or supply electricity and to (even temporarily) control generating plants is necessary to ensure that the TSO acts in an independent and non-discriminatory manner [12, Art. 36.2-36.3], in line with the unbundling principle. But on the other hand affirms that: (i) the TSO can build and manage 'diffused'

[3] EVs are not a storage technology. However, given that they are a controllable load, one could consider them as a storage *device* [5].

[4] As opposed, for example, to power-related applications such as maintaining grid frequency, suppressing fluctuations, and stabilizing voltages, which require discharging times between a few seconds and an hour and a response time of a few milliseconds [Available: http://setis.ec.europa.eu/about-setis].

[5] Efficiency is intended as the difference between the amount of electricity used to pump the water up from the lower level reservoir and the electricity produced thereafter when the water is released from the higher level reservoir.

[6] Hydroelectric generation accounted in 2009 for about 11% of the electricity produced in the EU [9].

storage systems such as batteries [12, Art. 36.4]; (ii) and the construction and operation of hydro-pumped storage plants included in the network development plan should be contracted through competitive procedures (i.e. auctions), as defined by the Industry Ministry in consultation with the independent authority, in order to guarantee "*the actual realization of the plants in defined timeframes, the efficiency of costs and the exclusive use of such plants for grid security and for the optimization of [RES] electricity generation*" [12, Art. 36.5]. According to Terna's Network Development Plan, batteries for a minimum of 130 MW should be developed and would avoid procuring 410 GWh/year on the balancing market [13].

Similar proposals have been put forward in Spain, where the installed wind and solar PV capacity (23.3 GW) is putting increasing pressure on the power system, equipped with 4.8 GW of HPS capacity (of which 2.5 GW 'pure' HPS) [18]. In September 2010 the President of the TSO, Red Electrica de Espana (REE), declared before the Parliament that "*pumping storage is not generation but storage. […] one of the main weaknesses of our electricity system lies on the consideration of pumping storage as generation, when in fact it consumes more energy than it delivers. It is a storage system […] and one of the ideas I want to put on the table is whether we should modify our legislation […] it is a key system operation tool to meet the RES targets. So, the independence of pumping storage and its management as a system operation service are essential to maximize RES integration*" [14]. In Spain, legislative initiatives on electricity storage have been so far confined exclusively to the Canary islands, where generation is fully remunerated through regulated capacity and energy payments. In particular, the Council of Gran Canaria issued a call for the construction and operation of a hydro-pumped storage plant of 320 MW (Chira-Soria) that should produce 25% of the electricity consumed in the island [15]. Ten days after the original call was issued, a second Decree was released [16], extending the possibility to submit proposals to any company operating in the electricity sector, rather than reserving it (as initially) to generators; the call was eventually won by Endesa. Finally, according to the draft bill currently under discussion to implement Directive 2009/72/EC on the internal energy market, REE should not operate storage facilities, with the exception of experimental projects in the islands with a capacity equal or lower than 5 MW [17].

V. Evaluating the Case for Regulation of Hydro-Pumped Storage

A. *Comparing Flexibility Solutions*

When an additional need for flexibility is recognized, the starting point should be the implementation of analyses considering all the alternative instruments available to enhance a power system's flexibility, to ensure their optimal use. Such an approach is a logic corollary of the fact that storage, and HPS within this category, is only one out of many alternatives for providing a power system with flexibility, and may not always constitute the most cost-efficient solution. For instance, in some cases a gas peaking unit may represent a more economically convenient solution than an HPS unit (or vice versa), because of the fuel prices impacting a CCGT's variable costs. Similarly, there is no reason why one should focus on HPS only, rather than considering hydroelectric generation as well, given that the latter can provide ancillary services as effectively as the former. Computational optimization processes could help determining system configuration and temporal dispatch in order to minimize costs, while ensuring that supply meets demand at any time. For example, different generation technologies could be compared based on capital, Operation and Maintenance (O&M), fuel and CO2 costs, taking into account a grid's capacity (dependent on congestions) to achieve smoothing effects among different RES and to provide access to 'back-up' units. Moreover, interconnections, networks reinforcement and upgrade, and DSM should also be considered as possible alternative solutions. Thus, they should be included in CBAs to be implemented on a case-by-case basis, as the optimal solution will necessarily vary across locations and time, as illustrated by the example of constructing hydroelectric units, whose feasibility and convenience are highly dependent on the availability of favorable locations.

Finally, one should also recognize that, when an additional need for system flexibility is identified, the possibility to build new facilities is not the only option. Rather, the possibility of improving existing facilities and regulatory frameworks should also be considered. For instance, integrating an existing hydroelectric unit with additional turbine(s) will in most cases be a much more cost-efficient solution than building a new generating unit. Similarly, the business case for traditional peaking units would be significantly supported by allowing price spikes, as well as by establishing capacity payments or capacity markets, the latter option being already implemented in some European countries (e.g. Spain) and currently under discussion in others (e.g. United Kingdom).

B. *Testing a Market's Ability to Deliver HPS*

When hydro-pumped storage is identified as the most cost-efficient solution, or when it is supposed to be so, because the just mentioned techno-economic analyses result unfeasible, a market's ability to deliver HPS capacity should then be tested. This is because HPS does not constitute a typical case of 'market failure' such as natural monopolies. Thus, making a case for its regulation (i.e. making its construction and use subject to specific regulation, rather than leaving them to market competition) requires first verifying that the market actually 'fails' to deliver new or to upgrade existing HPS capacity. This test is conducted through a simplified theoretical model [18][7], applied empirically to the case study.

[7] The model proposed is simplified for a number of reasons. First, it does not forecast future electricity prices but rather consider historical prices. The former could differ from the latter, as prices are influenced by factors like demand growth, competition between and strategies of producers, uncertainty that may arise because not all generators may be available at all times, and fluctuation of production costs linked to fuel prices. Second, it assumes no

First, capital and O&M costs for both HPS ‘greenfield’ and upgrade are estimated as in Figures 3 and 4. Because the costs of HPS are mainly fixed, these costs represent the margin needed (per year) to build or upgrade HPS capacity.

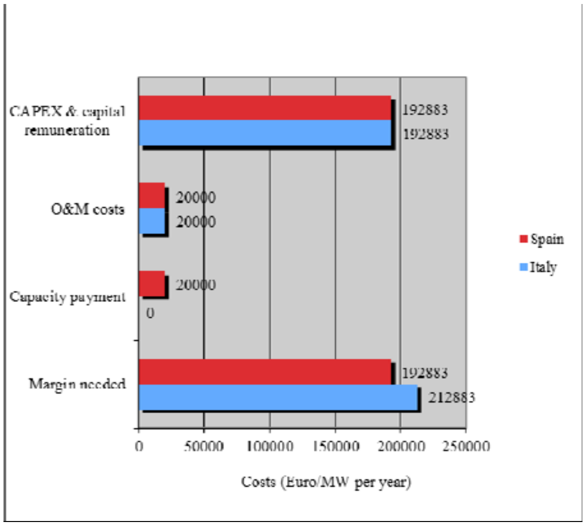

Fig. 2. Annual fixed costs for hydro-pumped storage greenfield in Italy and Spain; Investment 2000 Euro/kW, 40 years operating life, WACC 7% after taxes, O&M costs 20000 Euro/MW. Capacity payment 20000 Euro/MW as of now in Spain (for the first 10 years only) [18].

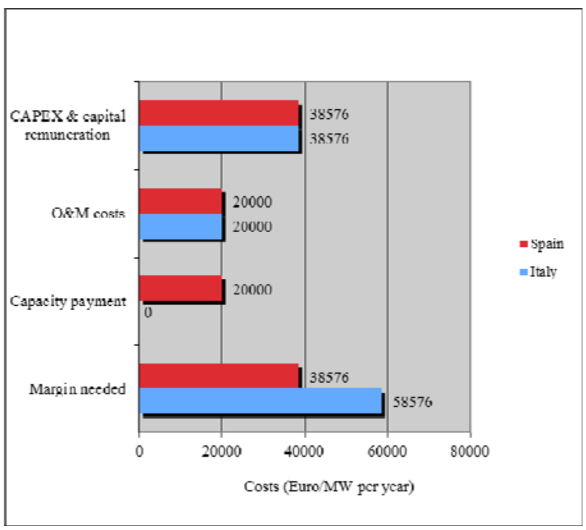

Fig. 3. Annual fixed costs for hydro-pumped storage upgrade in Italy and Spain; Investment 400 Euro/kW, 40 years operating life, WACC 7% after taxes. O&M costs 20000 Euro/MW. Capacity payment 20000 Euro/MW as of now in Spain (for the first 10 years only) [18].

Second, assuming 70% efficiency, an HPS unit will obtain enough margin to recover its costs if the price at which it sells 1 MWh of electricity is at least 1.4 times higher than the price at which it buys 1 MWh of electricity, because of the electricity losses involved in pumping. The Electricity Price Duration Curve (EPDC), intended as the distribution describing the probability or fraction of time where the market clearing price exceeds any particular level, is calculated for the year 2010 (Figures 4 and 5). One can then determine the theoretical number of hours per year at which an HPS unit could have been able to sell and buy electricity at a minimum ratio of 1.4. This and further data underlying the EPDCs for the period 2008-11 are summarized in Tables II and III.

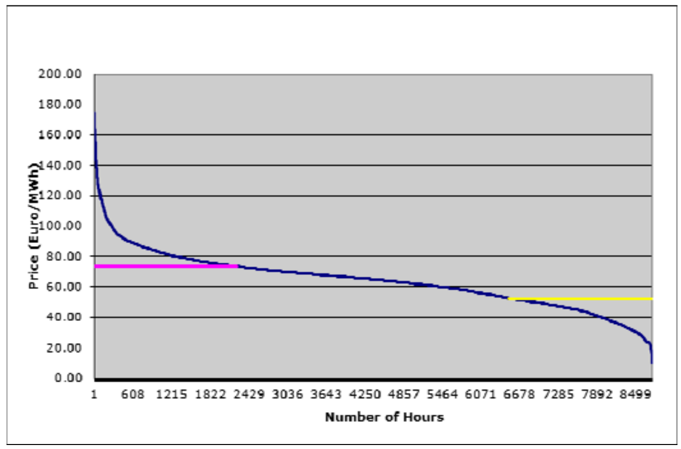

Fig. 4. Electricity price duration curve in Italy in 2010.

TABLE II
DATA UNDERLYING PRICE DURATION CURVES FOR ITALY IN 2008-11; ELABORATION ON [19] AND DECEMBER 2011 ESTIMATED

	2008	2009	2010	2011
Theoretical number of hours with enough price spread for HPS	2914	2922	2245	1770
Maximum price (Euro/MWh)	211.99	172.25	174.62	160.62
Minimum price (Euro/MWh)	21.54	9.07	10	10
Number of hours with price equal to zero	0	0	0	0
Theoretical selling average price for HPS (Euro/MWh)	123.92	93.24	86.17	93.40
Theoretical purchasing average price for HPS (Euro/MWh)	52.02	36.21	41.94	49.42
Selling / purchasing average price ratio	2.38	2.57	2.05	1.89

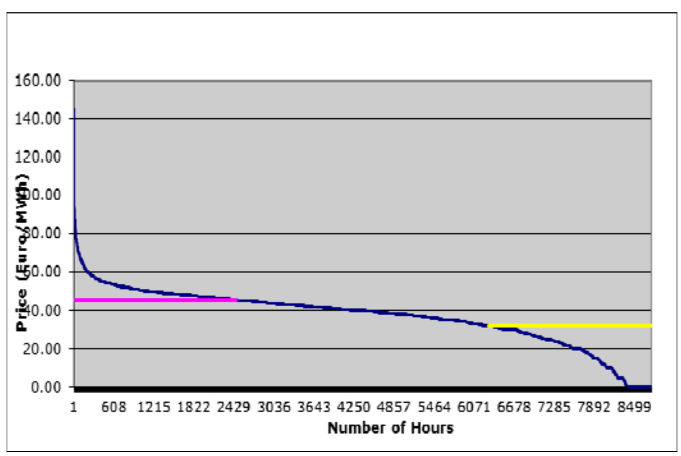

Fig. 5. Electricity price duration curve in Spain in 2010.

possibility to store significant quantities of water from a year to the next one, so that all the water pumped in one year is dispatched in the same one-year period. Third, it assumes enough capacity in the higher-level reservoir to produce electricity when prices are more attractive, regardless of the volume of water that has already been stored. Finally, the analysis is static as it is implemented once the price duration curve (i.e. the proportion of time for which the price exceeded a certain value) has been elaborated. Thus, it does not consider the effect of dispatching the electricity produced by the HPS unit on the price duration curve.

TABLE III
DATA UNDERLYING PRICE DURATION CURVES FOR SPAIN IN 2008-11; ELABORATION ON [20] AND DECEMBER 2011 ESTIMATED

	2008	2009	2010	2011
Theoretical number of hours with enough price spread for HPS	1712	1400	2469	1460
Maximum price (Euro/MWh)	103.15	100	145	91.01
Minimum price (Euro/MWh)	10	0	0	0
Number of hours with price equal to zero	0	16	331	47
Theoretical selling average price for HPS (Euro/MWh)	83.67	51.61	51.81	62.65
Theoretical purchasing average price for HPS (Euro/MWh)	47.21	23.51	18.34	27.31
Selling / purchasing average price ratio	1.77	2.19	2.82	2.29

Finally, a theoretical yearly average margin is calculated as the difference between the theoretical selling average price and the theoretical purchasing average price. The relation between the fixed costs initially estimated and the theoretical average margin results in the minimum number of hours which an HPS unit should run yearly to recover its fixed costs, thus providing a useful indication of a market's ability to deliver HPS capacity. In Italy, an average margin of about 54 Euro/MWh for the period 2008-11 signals that an HPS greenfield would require to run approximately 4000 hours/year to recover its fixed costs, while an HPS upgrade would need approximately 1000 hours/year to recover its fixed costs. In Spain, with an average margin of about 33 Euro/MWh, an HPS greenfield would need to run approximately 5800 hours/year to recover its fixed costs, while an HPS upgrade would need at least 1200 hours/year to recover its fixed costs.

In conclusion, this simplified approach suggests that while both in Italy and Spain an HPS greenfield is unlikely to recover its costs, upgrades of existing HPS plants might be able to do so. However, these results should be interpreted with caution, not only because the model applied builds on a number of assumptions. But also because assessing the business case for an HPS unit on the basis of the relation between peak and off-peak prices, though correct in the long-term, could be misleading in the short-term, as the value of HPS (or any other storage) derives mainly from its capacity and response rather than its energy. For an HPS unit, in other terms, the ancillary services market is likely to be much more valuable than the energy market. Thus, it would be interesting to examine the results that one could obtain by relaxing the constraints here applied and by conducting more sophisticated analyses. For example, Black and Strbac find that value is gained by using standing reserve to provide the greater part of additional balancing required, that the value of storage-based standing reserve is driven by the amount of wind capacity installed and the flexibility of the generation system, and that much of storage's value comes from handling the high frequency of smaller imbalances [21]. Moreover, some authors have investigated optimal unconstrained and constrained (because of reservoir capacity limits) bidding strategies for an HPS unit, eventually developing a fixed-schedule bidding strategy for a season by optimizing several weeks in the season [22]. While others have proposed approaches to optimize both the operation of a combined wind-hydro pumping storage power plant and the hydraulic design of such a plant [23].

VI. KEY CHALLENGES IN THE REGULATION OF HYDRO-PUMPED STORAGE

A case for the regulation of hydro-pumped storage should be made only where HPS is identified as the most cost-efficient flexibility solution available, which a market is nevertheless unable to deliver. When considering who might and who should provide what ancillary services to whom, and under what regulatory supervision, one has to analyze the economic consequences of different options, in order to identify what regulatory framework would be necessary to ensure outcomes in the public interest. The paper argues that, when regulating HPS, the key areas to consider are:

1. the criteria to define capacity adequacy;
2. the procedures to apply when capacity is not considered adequate, namely:
    a. who should build the additional capacity;
    b. who should run that capacity.

A. Defining Capacity Adequacy

It is evident that the definition of capacity adequacy should prevent emergencies that might disrupt a system's security, and that would create irresistible pressures for late political interventions. At the same time, the determination of targets on capacity should not be made in a discretionary manner, evading any techno-economic analysis, as in the case of the objective set by the European Council in 2002 to have in every Member State interconnections equivalent to at least 10% of the installed generation capacity [24]. In this regard, the work of the European Network of Transmission System Operators for Electricity (ENTSO-E) might represent both a source of (some) good practices and an example of the challenges involved in this complex exercise. Coherent assumptions, reliable data, and sound calculation methodologies are crucial to elaborate scenarios on generation and demand, and to identify the relation between growing RES capacity and generated RES electricity. This in turn represents the basis for understanding the impact of intermittent RES on system adequacy and for providing reasonable indications on the need for investments in HPS. A TSO, given the aggregate information it holds, might be the best-positioned player to make efficient decisions on the location and quantity of storage resources needed. At the same time, there might also be perverse incentives leading to investment distortions. For example, if the costs of such facilities were funded through tariffs, then shareholders could have an incentive to overbuild. Similarly, integrating in a TSO's network development plan decisions on both grid expansion and installation of storage facilities might facilitate efficient investment planning. However, leaving these decisions in the hands of the same, regulated, entity might also lead to investment distortions, because a TSO could favour investments that are profit-maximizing (due to a better remuneration), but suboptimal from a social welfare perspective. What these considerations suggest is not only that, while TSOs should be the primary actors in determining the criteria to define capacity adequacy, this role should be integrated by consultation procedures able to mitigate the risk of investment distortions. But also and most importantly that it is essential to align the interests of TSOs to social optimum, so that the benefits of TSOs reflect systems' benefits, and their investment decisions result in infrastructure selections optimal for society as a whole. In conclusion, while unbundling shall promote non-discrimination, it does not guarantee optimality in choice and timing of infrastructure development [3]. That is a matter which calls for adequate regulatory incentives. How to get these incentives right is, however, far from clear[8].

B. Building and Operating HPS Capacity

When a need for additional HPS capacity (that a market is unable to deliver) is recognized, the following step would be to identify who could and who should build that additional capacity. If the procedures applied to define capacity adequacy had effectively addressed risks of investment distortions (e.g. overbuilding), then it would not appear controversial to select who should be responsible exclusively for the construction of HPS units through a cost-efficient, market-based approach, namely by using auctions in public procurement.

When considering who should control that additional capacity and under what regulatory supervision, one should evaluate whom, among the potential service providers, might be best positioned to efficiently operate such resources and whom might have, on the contrary, perverse incentives that could lead to wasteful operation. Given the aggregate information hold by a TSO, there might be economies of scope in placing under its common control decisions on HPS operation, in order to maximize intermittent RES intake. However, there might also be conflicting interests that could distort a TSO's storage-related decisions. For example, a TSO could use storage facilities to protect its business interests rather than exclusively for keeping the system in balance, hence delivering suboptimal results for society as a whole. Moreover, provision of ancillary services by a TSO might create a conflict of interest that could distort its non-storage-related decisions, since the incentives for such neutral entity to facilitate market transactions in a non-discriminatory manner at the lowest costs to meet customer needs could be threatened, if a TSO were to profit when peak prices make stored electricity more valuable [4]. A TSO's strong information advantages, the related risks of strategic behaviour, and the difficulty to detect and punish such behaviour or to create effective firewalls to maintain a system operator's neutrality, suggest that a cautious approach should be favoured, reserving the control of large-scale storage facilities to market players.

C. Establishing an Adequate Regulatory Framework

Supposing the right to operate HPS facilities is periodically auctioned or contracted to market participants, that in turn sell ancillary services to a TSO at regulated tariffs, one has finally to define the regulatory framework for storage systems operation. A cost-of-service model of regulation would not only be affected by its (familiarly debated) scarce capacity to promote efficiency. But would also raise new problems, notably related to functionalization, i.e. whether storage should be functionally categorized as "generation", "transmission" or "distribution". As a general ratemaking principle, the customer classes that cause or benefit from a given facility should bear its costs. With storage, however, it will often be difficult to ascertain which of these functional categories is predominant, and therefore difficult to determine which customer classes cause or benefit from a storage facility's costs [4]. Furthermore, models of incentive regulation such as the 'price-cap' would ensure that operators are incentivized toward efficiency, because they bear responsibility for their profits. However, a price-cap regulation would pose significant information requirements to ensure that regulators effectively set targets that are both achievable and that push regulated companies toward efficiency. Because of the complexity of the topic and the information asymmetries discussed, these information challenges appear currently hard to overcome. Finally, other forms of incentive regulation could be adopted. This might be the case, for example, of output-based models of regulation, where the remuneration received by the operator is linked to 'exogenous' parameters, such as RES capacity growth. However, this mode of remuneration would necessarily imply calculating the costs avoided through electricity storage that a system would have otherwise incurred to achieve the same output. Although necessary to avoid discretionary premium setting, measuring costs and benefits of alternative flexibility solutions would be in many cases problematic. What the inadequacy of every 'standard' model of regulation seems to suggest is the need for innovative forms of regulation. A possible source of inspiration to address this new problem could paradoxically come from old regulatory solutions, namely contracts. Thus, a possibility that could be further investigated would see generators and TSOs negotiating an 'adequate' remuneration for the ancillary services provided by the former to the latter, while reserving to the regulatory agency the role of approving, monitoring the implementation and assisting the revision of these contracts.

VII. Concluding Remarks

This paper offered a contribution on electricity storage, investigating the case for its regulation and identifying key areas and challenges likely to characterize such regulation.

When an additional need for system's flexibility is recognized, analyses considering all flexibility instruments

[8] With regard to interconnections, for instance, among the main problems are how to measure their full benefits, how to internalise externalities, and how to allocate costs to reflect benefits distribution [3].

should be implemented. These analyses should be conducted on a case-by-case basis, possibly through simulation techniques and cost-benefit analyses. In addition, the alternative of improving existing infrastructures and regulatory frameworks should also be considered.

When HPS is identified as the most cost-efficient flexibility solution, a market's ability to deliver additional HPS capacity should be evaluated, for instance by developing sophisticated optimization models.

Only when HPS is identified as the most cost-efficient flexibility solution, which the market is nevertheless unable to deliver, should a case for HPS regulation be made.

The aggregate information hold by a TSO suggests it should be the main responsible in defining a system's adequacy, but such a role should be integrated through consultation processes and, most importantly, by regulatory incentives able to align the interests of a TSO to the social optimum, so that its investment decisions result in an infrastructure selection optimal for society as a whole. How to get the regulatory incentives right to ensure efficient and timely infrastructure development remains, however, extremely challenging.

Auctioning the construction of additional HPS capacity appears as a relatively straightforward, cost-efficient, approach. While the need to preserve a system operator's neutrality suggests adopting a cautious approach, where the operation of storage systems is reserved to market players.

Finally, what emerges from the analysis of 'standard' regulatory frameworks is that all of them present weaknesses. This suggests the need to develop innovative forms of regulation, where an option to be further investigated would see generators and TSOs negotiating an adequate remuneration for the provision of ancillary services in contracts that would have to be approved, supervised and reviewed by regulatory agencies.

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