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Contribution of a pumped-storage hydropower plant to reduce the scheduling costs of an isolated power system with high wind power penetration

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ABSTRACT

The paper aims at demonstrating that the consideration of constant start-up costs and ramps of the thermal generating units for assessing the contribution of pumped-hydro energy storage to reduce the scheduling costs of hydrothermal power systems with high wind penetration, may yield unrealistic results. For this purpose, an isolated power system is used as a case study. The contribution of a pumped-storage hydropower plant to reduce the system scheduling costs is assessed in the paper by using a hydrothermal weekly unit commitment model. The model considers different start-up costs and ramps of the thermal generating units as a function of the start-up type. The effects of including pumped hydro energy storage in the system on the integration of wind energy, and on the start-ups and capacity factors of the thermal generating units are also evaluated. The results of the paper demonstrate that the consideration of constant start-up costs and ramps of the thermal generating units yields unrealistic results, and that the pumped-storage hydropower plant may help reduce the system scheduling costs by 2.5–11% and integrate wind power and may allow dispensing with some inflexible thermal generating units.

1. Introduction

PHES (Pumped-hydro energy storage) is receiving special attention mainly due to the strong deployment of non-dispatchable renewable energies, which is currently taking place in a vast number of countries all over the world [1]. The role of PHES in future power systems has been highlighted in recent international reports [2]. The contribution of PHES in power systems with significant penetration of renewable energies has been evaluated in the technical literature by using different hydrothermal economic dispatch and/or UC (unit commitment) models.

Until recently, the UC problem was usually solved by using dynamic programming [3] or Lagrangian relaxation [4]. However, during last decade, some approaches based on MILP (mixed integer linear programming) have outperformed dynamic programming and Lagrangian relaxation in terms of both modeling accuracy and computational performance [5].

Recent research on the application of MILP to the UC problem is aimed at accurately modeling the start-up costs and ramps (i.e. power trajectories to be followed during the start-up process) of TGUs (thermal generating units), which depend on the time the unit remained offline since the previous shut-down [6]. As a result of this and other researches, nowadays there exist some MILP based UC models where the start-up costs and ramps of TGUs are accurately modeled.

Other optimization techniques have been applied to the UC problem with varying degrees of success. In Ref. [7], a genetic algorithm was used for the first time to solve the UC problem. In that paper, the start-up costs of the TGUs are modeled as a function of the time the unit has remained offline since the previous shut-down. The violation of the TGUs start-up ramps are properly penalized in the objective function. In Ref. [8] a robust optimization approach is used to solve the UC of a hydro-thermal generation system. In Ref. [8], the start-up ramps of the TGUs are assumed constant, and the start-up costs are neglected. In Ref. [9] a quantum inspired evolutionary algorithm, combined with a differential

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evolution algorithm, are applied to the short-term hydrothermal generation scheduling problem, neglecting the start-up costs and ramps of the TGUs. In Ref. [10], a quantum inspired binary gravitational search algorithm is used to solve the UC problem. In that paper, the start-up costs of the TGUs are modeled as a function of the time the unit has remained offline since the previous shut-down, whereas the start-up ramps are neglected. In Ref. [11], a self-learning group search optimizer is proposed to solve the UC problem. As in Ref. [10], the start-up costs of the TGUs are modeled as a function of the time the unit has remained offline since the previous shut-down and the start-up ramps are neglected.

Notwithstanding the foregoing, to the author's knowledge there is no published work where the effects of PHES on power systems with a high share of non-dispatchable renewable energy have been assessed by considering variable start-up costs and ramps of the TGUs.

In Ref. [12], authors study the optimal sizing of a wind-powered PHES system which operates in coordination with a set of TGUs. For this purpose, authors use a simulation model which assumes that the output power of the TGUs can be modified in real time as a function of the actual load demand and wind power. Start-up costs and ramps of the TGUs were not considered in the simulation. In Ref. [13], authors study the optimal sizing of a wind-powered PHES system which operates in coordination with a set of diesel units. For this purpose, authors use a simulation model similar to the one used in Ref. [12]. Ref. [14] is focused on the profitability of a new PSHP (pumped-storage hydropower plant) in the Greek electric power system. The PSHP is assumed to buy the rejected wind energy at half the instant *marginal system price*, and to sell the energy generated by the turbines at the instant marginal system price. In Ref. [15], the profitability and optimum storage capacity of PHES is evaluated in a liberalized market context. The effects of PHES in the power system are not studied in the paper.

In Ref. [16], authors analyze the value of PHES in balancing a power system with high wind power penetration by using an approach based on linear programming and a priority ranking method. In Ref. [17], authors analyze the impact of wind power and PHES in the generation mix and net load profile of the Irish power system, and assess the revenue obtained from the joint operation of wind and PHES as well as the storage capacity which best exploits the coordination between wind and PHES considering three different heuristic operation strategies. The commitment of TGUs was not considered in the paper. In Ref. [18] authors estimate the scheduling cost[1] savings and the decrease in curtailed wind energy caused by energy storage, by using heuristic algorithms and dynamic programming, and considering constant start-up costs and ramps of the TGUs [19]. In Ref. [20] authors asses the contribution of PHES to reduce the scheduling costs, wind curtailments and carbon dioxide emissions from fossil fuel fired power plants in the Irish power system, considering different levels of wind power penetration. For these purposes, authors use a commercial UC algorithm based on stochastic MILP [21], which considers constant start-up costs and ramps of the TGUs. As stated in Ref. [20], the main benefit from storage is the decrease in wind curtailment. The same algorithm is used in Ref. [22] to analyze the impact of wind power penetration on a wide number of parameters of the all-Ireland power system. A single value of installed power in PHES is considered in Ref. [22]. As in Ref. [20], start-up costs and ramps of TGUs are assumed constant. In Ref. [23], authors assess the contribution of PHES to reduce the scheduling costs, carbon dioxide emissions and the excess electricity production in the Dutch power system. For this purpose, authors use a UC model based on the one presented in Ref. [24], which considers that the start-up costs and ramps of the TGUs are constant. The UC model presented in Ref. [24] is used also in Ref. [25] to study the effects on the Dutch power system of introducing a large number of electric vehicles and increasing the wind power penetration, considering again that the start-up costs and ramps of the TGUs are constant. In Ref. [23], authors conclude that energy storage helps reduce significantly the scheduling costs of the system, the greenhouse gases emissions and the amount of curtailed wind power.

In Ref. [26], authors assess the impact of PHES on operation costs (considering the use of committed reserves by means a 5-min time step intrahour dispatch), energy prices, carbon dioxide emissions, wind curtailments and operation of TGUs in three different power systems, considering different levels of installed wind power. As in Ref. [20], authors use a commercial UC model which considers constant start-up costs and ramps of the TGUs [27]. It is worthy to note that according to the results presented in Ref. [26], the use of adjustable-speed pumped-storage units would contribute to decrease wind curtailments to a significantly greater extent than using conventional fixed-speed pumped-storage units. In Ref. [28], the author studies the impact of hydropower on the energy prices, wind curtailments, operation of TGUs and scheduling costs, considering different levels of installed wind power. For these purposes, the author proposes a smart heuristic UC algorithm, which considers different start-up costs (not ramps) of the TGUs as a function of the time passed since the previous shut-down. Even though PHES is not considered in Ref. [28], the methodology used in the thesis could be easily adapted to include PHES in the analysis. In Ref. [29], authors formulate a deterministic MILP-based transmission-constrained day-ahead UC problem, considering the intrahour coordination of PHES and wind power. The problem is solved by means of a Benders decomposition approach. The results of the paper show that the coordination of PHES and wind power may contribute to reduce the load and wind curtailments, the transmission congestion and the operation costs (considering the use of committed reserves by means of a 10-min step intrahour dispatch), as well as to firming up the wind generation dispatch. Interesting conclusions are drawn in that paper, regarding the influence of the location of the PHES units on the magnitude of the above-mentioned positive effects of wind-hydro coordination. Constant start-up costs and ramps of the TGUs are assumed in the paper. A similar model is proposed in Ref. [30], which does not consider the intrahour coordination of PHES and wind power, but considers both wind and load forecast errors and random forced generator and transmission line outages. TGUs start-ups are not considered in that paper.

In Ref. [31], authors analyze the importance of accurately modeling the diverse constraints to which hydropower systems are generally subject for correctly assessing the capacity of a hydrothermal system to integrate variable renewable generation and the system scheduling costs. The results obtained in Ref. [31] show that both wind power curtailments and system scheduling costs can be reduced by accurately modeling the hydro generation assets in the generation scheduling problem. Even though PHES is not considered in Ref. [31], it is mentioned here since it demonstrates the importance of using realistic models of the generation assets for a correct assessment of the system scheduling costs. Constant start-up costs and ramps of the TGUs are considered in Ref. [31]. In Ref. [32], authors propose a heuristic short-term UC model which minimizes the fuel, start-up and emission costs of a thermal system with PHES, and which considers variable start-up costs and constant start-up ramps

[1] It is important to emphasize that in this paper, scheduling costs refer to the costs corresponding to the unit commitment and dispatch of thermal and hydro power units, considering the reserve requirements, but without considering the use in real-time of the committed reserves or other non-committed reserves, whenever necessary.

of the TGUs. The results show that PHES can help reduce significantly both the scheduling costs and the CO_2 emissions.

In Ref. [33], the impact of PHES in the generation capacity expansion plans of Northern Ireland power system is analyzed considering different levels of installed wind power capacity and costs of both fuel and emissions. For that purpose, authors use the well-known WASP-IV software, where start-up costs and ramps are not taken into account [34].

As a conclusion of the above literature review, it can be stated that, even though there exist several UC models which consider variable start-up costs and ramps of the TGUs, no previous work has evaluated the contribution of PHES in a power system with high wind power penetration considering variable start-up costs and ramps of the TGUs.

The main objective and contribution of the work presented in this paper is to demonstrate that the consideration of constant start-up costs and ramps of the thermal generating units for assessing the contribution of pumped-hydro energy storage to reduce the scheduling costs of hydrothermal power systems with high wind penetration yields unrealistic results. For this purpose, the contribution of a PSHP (pumped-storage hydropower plant) to reduce the scheduling costs in an isolated power system with high wind power penetration is assessed by using a detailed UC model which considers different start-up costs and ramps of the TGUs. As observed in Ref. [35], flexibility can be decisive for the commitment of TGUs and therefore, a correct modeling of the TGUs start-up cost and ramps is expected to be of a crucial importance to draw solid conclusions on both the scheduling costs and power schedule of a hydrothermal power system, as will be demonstrated in the paper.

Other objectives of the paper are to assess, by using the above-mentioned UC model, the cost associated to wind power integration, the effect of PHES on the start-ups (cycling) and capacity factors of TGUs, and the energy storage capacity which most contributes to reduce the scheduling costs and to integrating as much wind power as possible in the power system under study.

The topic addressed in the paper is of a high relevance in the energy sector, in view of the current plans for further deployment of non-dispatchable renewable energy, and of the role that PHES and other storage technologies are expected to play in that context. The results presented in this paper are expected to provide insight on how to assess the contribution of PHES and other storage technologies in power systems with high penetration of non-dispatchable renewable energy.

The remainder of this paper is organized as follows. The power system under study is described in Section 2. The methodology followed to pursue the mentioned objectives is summarized in Section 3. The results of the study are discussed in Section 4 and finally, the main conclusions and some proposals for further work are included in Section 5.

2. System description

The power system under study corresponds to the Great Canary island in Spain. 16 TGUs are currently in operation in the system: 5 gasoil, 4 fuel, 5 diesel and 2 CCG (combined cycle gas) units. A simple layout of the system is included in Fig. 1. The system is not interconnected with any other power system. System operation is organized in a centralized way; i.e. the transmission system operator is in charge of determining the power generation schedule of each generating unit so that the scheduling cost is minimized, considering the fuel, start-up and operation and maintenance costs regulated in Ref. [36]. At present, there is no PSHP and maximum power demand is around 550 MW. Three different levels of installed wind power have been considered (150, 200, 250 MW), according to current capacity expansion plans [37]. Current

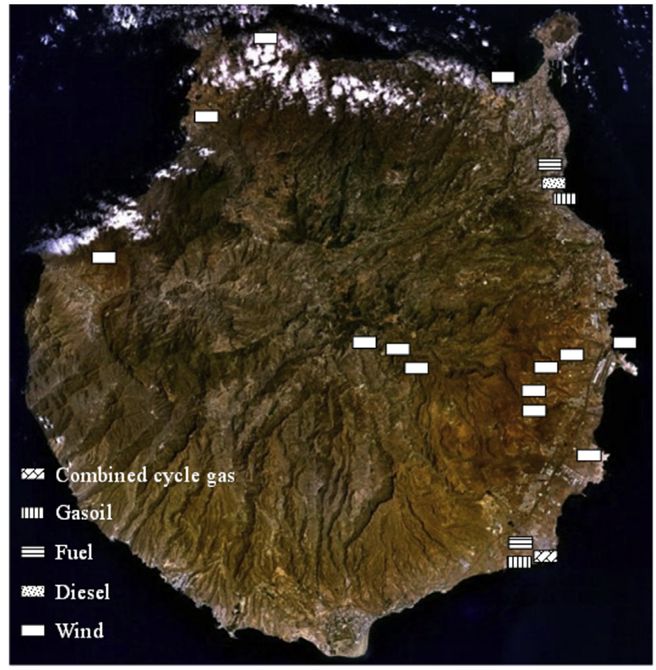

Fig. 1. Layout of the system.

installed wind power in the system amounts to 86 MW [38]. In addition, 4 different levels of installed power in the PSHP have been analyzed (25, 50, 75, 100 MW). For certain purposes, three additional levels of installed wind power have been considered (225, 275, 300 MW) (see Section 4). A single PSHP, with one fixed-speed pump-turbine unit has been considered. A rated gross head of 1000 m has been used, according to the PSHP pre-feasibility study. Minimum flow in generating mode has been assumed to be 40% of the rated flow [39]. The efficiency of the pump-turbine unit ranges from 0.82 to 0.92 in generating mode, with minimum and rated flow, respectively, and is assumed to be 0.90 in pumping mode. Given the high gross head, and that the pump-turbine operates at synchronous speed, both the flow and the efficiency in pumping mode are assumed constant. The evolution of the energy stored in the upper pond is considered in the UC model through (31). These values result in a minimum power in generating mode of 35% of maximum power. The start-up cost of the pump-turbine unit was taken from Ref. [40]. The pump-turbine unit is assumed to start-up in a much shorter time than the UC model time step (1 h). Start-up failures are not considered in the UC model. The formulas to calculate the fuel, start-up and operation and maintenance costs of the TGUs were taken from Ref. [36]. Costs of output power variations in TGUs were taken from Ref. [41]. Cold start-up ramps, minimum up- and down-times, and maximum ramp-up and -down limits when committed were taken from Ref. [42] for fuel and diesel units and [45] for gasoil (open gas cycle) and CCG units.

According to the information taken from the Spanish regulation, the TGUs of the system can be divided into three types: those with a single start-up process and an almost constant start-up cost (I_1); those with a single start-up process and a variable start-up cost which depends on the time the unit remained offline since the previous shut-down (I_2); and those with hot and cold start-up processes, each with a cost which depends on the time the unit remained offline since the previous shut-down (I_3). For the TGUs of type I_2 and I_3, a two-piece linear start-up cost function has been used. The first segment of the start-up cost function has a positive slope and the second one has a null slope. In the former (I_2), the breakpoint has been obtained by least squares; in the latter (I_3), from the intersection of the hot and cold start-up cost curves given in Ref. [36]. Examples of both start-up cost functions can be seen in Figs. 2 and 3. The x-coordinate of the breakpoint is referred to as $td(i)$ in Appendix A. It is worth noting that this approach guarantees that units of type I_3 will always start-up in the most economical way; hot start-ups which would be technically feasible after off times longer than td are not allowed in the model for economic reasons. According to [36], the fuel, start-up (cold and hot) and maintenance costs (in euro) are given by the following expressions:

- Fuel cost: $fc = (a + bP + cP^2)prc/pci$
- Cold start-up cost: $csuc = a'(1 - e^{-t/b'})prc/pci + d$
- Hot start-up cost: $hsuc = \sum_{hours\ off} cc \cdot prc$
- Maintenance cost: $mc = a'' + b'' \cdot fc$

Where P is the power supplied in MW, and t is the time passed since the last shut-down in hours. The parameters of the above equations are included in Table 1. Other parameters of the TGUs can be found in Table 2.

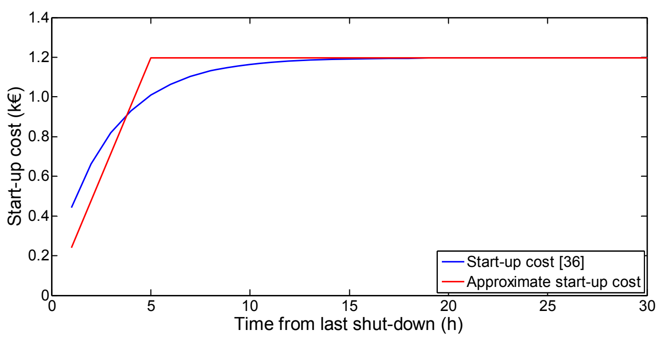

Fig. 2. Start-up cost curve of unit u7.

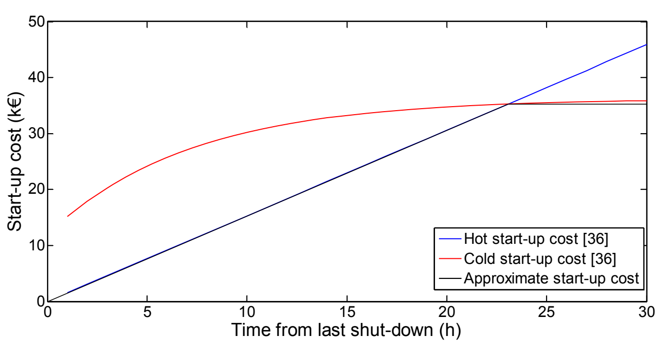

Fig. 3. Start-up cost of unit u3.

Table 2
Characteristics of the TGUs.

Unit	Fuel type	Type	*pmax*	*pmin*	*csut*	*td*	*mut*	*mdt*
u1,u2	Gasoil	I_1	37.5	15	NA	NA	1	1
u3,u4	Fuel	I_3	80	32	6	23	7	7
u5,u6	CCG	I_1	210	28	NA	NA	4	3
u7,u8,u9	Diesel	I_2	12	4.8	NA	5	1	1
u10	Gasoil	I_1	23.4	9.4	NA	NA	1	1
u11,u12	Fuel	I_3	60	24	6	20	6	5
u13,u14	Gasoil	I_1	37.5	15	NA	NA	1	1
u15,u16	Diesel	I_2	24	9.6	NA	9	1	1

3. Methodology

A weekly hydrothermal UC model based on MILP has been used to pursue the objectives of the paper. The objective function of the model consists in minimizing the scheduling costs, for given forecasts of hourly power demand and wind power. Wind curtailments are economically penalized in the objective function. Different start-up costs and ramps of the TGUs are considered in the model, as a function of the time the unit has remained offline since the previous shut-down. Maximum ramp-up and -down limits when committed, as well as minimum up- and down-time since the last start-up or shut-down and costs of output power variations are considered for the TGUs. Start-up costs of pump-turbine units are also considered. The formulation of the UC model is based on [45] and [46], with some modifications to consider the start-up costs as a piecewise linear function of the time passed since the previous shut-down, and to adapt the formulation to the start-up costs reported in Ref. [36] for the power system under study. CO_2 emissions and their cost are outside the scope of this paper.

Three 52-week scenarios of hourly wind speeds have been used in the paper. These scenarios were synthetically generated from historical data provided by the State Meteorological Agency of Spain (AEMET). AEMET provided the authors with the hourly wind speeds registered in all gauging stations of the island from 2011 to 2013, under request no. 990140627, in June 2014. At that time, there were 18 gauging stations owned by AEMET in the island. The longitude, latitude and altitude of the gauging stations are publicly available at the AEMET web page (www.aemet.es). The heights above the ground level of the gauging stations are not publicly available nor were they provided by the AEMET. A height of 10 m was assumed for all gauging stations. In order for the reader to get an idea on the daily, weekly, seasonal and interannual wind speed variability in the system, the hourly wind speeds recorded in one of the gauging stations are depicted in Figs. 4 and 5.

The exact location of the wind generators and their power-speed curves are not publicly available and therefore, the effects that aggregation and geographical distribution of wind generators have on wind power variability are not considered in the paper. The hourly wind speeds recorded at the gauging stations were scaled up to a hub height of 100 m [47] by means of the equation cited in

Table 1
Parameters for calculating the fuel, start-up and maintenance cost of the TGUs; *a*, *b*, *c*, *a′*, *b′*, *d*, *cc*, *a″* and *b″* were taken from Ref. [43], *prc* and *pci* were taken from Ref. [44].

Unit	Fuel type	Type	*a*	*b*	*c*	*prc*	*pci*	*a′*	*b′*	*d*	*cc*	*a″*	*b″*
u1,u2	Gasoil	I_1	29363.3	2225.9	1.4	746.5	10150	10150.0	0.2	3873.3	NA	249.2	0.015
u3,u4	Fuel	I_3	21254.1	2159.8	0.2	610.3	9000	357255.0	7.2	12038.1	22542	146.2	0.017
u5,u6	CCG[a]	I_1	118.2/239.7	−390.6/−440.6	11.2/5.8	427.2	11414	410809.8	0.6	33072.4	NA	2229.4	0.024
u7,u8,u9	Diesel	I_2	1286.1	2511.4	6.1	706.4	10000	15142.7	2.9	127.9	NA	63.9	0.049
u10	Gasoil	I_1	23287.9	2737.0	6.4	746.5	10150	12180.0	0.2	3873.3	NA	249.2	0.015
u11,u12	Fuel	I_3	12991.3	2677.0	0.2	610.3	9000	269052.8	17.4	11114.4	17761	124.5	0.017
u13,u14	Gasoil	I_1	29363.3	2225.9	1.4	746.5	10150	10150.0	0.2	3873.3	NA	249.2	0.015
u15,u16	Diesel	I_2	7613.8	1381.9	15.2	706.4	10000	79576.4	5.5	204.0	NA	101.0	0.049

[a] CCG units have different parameters *a*, *b* and *c*, as a function of the power generated.

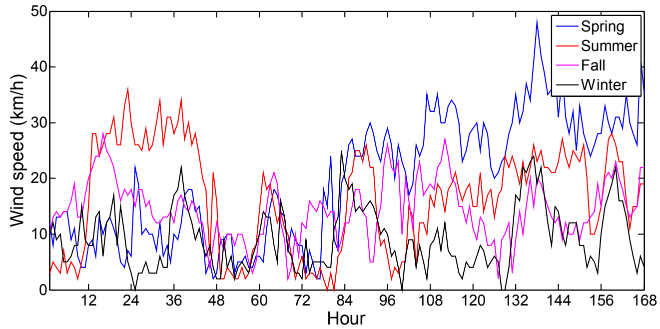

Fig. 4. Hourly wind speeds in km/h, recorded in one of the gauging stations in four different weeks, each corresponding to a different season in the period from May 2012 to May 2013.

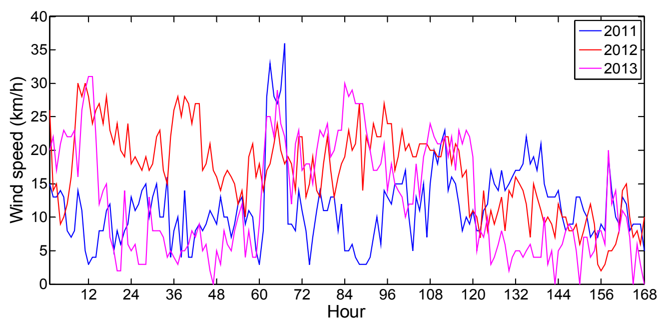

Fig. 5. Hourly wind speeds in km/h, recorded in one of the gauging stations in the same week of three different years.

Ref. [48]. Different statistical models were fitted to the average hourly wind speeds across the gauging stations with less missing data, and were later used to generate the above-mentioned scenarios. It should be noted that the use of the average values across the gauging stations with less missing data somehow introduces a sort of aggregation effect. The synthetically generated hourly wind speeds were transformed into power values by means of a typical wind turbine generation curve [49], similar to those of Vestas V90, V100 and V110 [47]. The parameters of the said curve were fitted in such a way that the average annual capacity factor of the wind power generation is 33%, consistently with the average capacity factor of wind farms currently operating in the system [38]. The estimated hourly wind powers in several weeks of one of the scenarios are depicted in Fig. 6. One historical 52-week scenario of hourly loads is used in the paper; i.e. a total of 3 × 1 52-week scenarios, hereinafter referred to scenarios 1, 2 and 3. The scenario of hourly loads was taken from the web page of the transmission system operator (www.ree.es) and corresponds to the year 2012. In addition, different levels of installed power both in wind (*iwp*) and in the PSHP (*ps*) are considered. The 52 weeks of each scenario are processed sequentially (week by week) by the UC model. The values of certain variables at the end (during the last *ta* hours) of each week are considered in the UC model for the following week. The power schedule of all generating units as well as the scheduling costs, including the start-up costs, are calculated in all scenarios, considering different values of installed wind and pumped hydropower. Within each weekly UC problem, a single perfect forecast of the hourly power demand and wind power is assumed [50]. Spinning reserve requirements are estimated from the recommendations given in Ref. [51]. For the sake of clarity, a block diagram of the methodology followed for a given scenario, and given values of *iwp* and *ps* is included in Fig. 7.

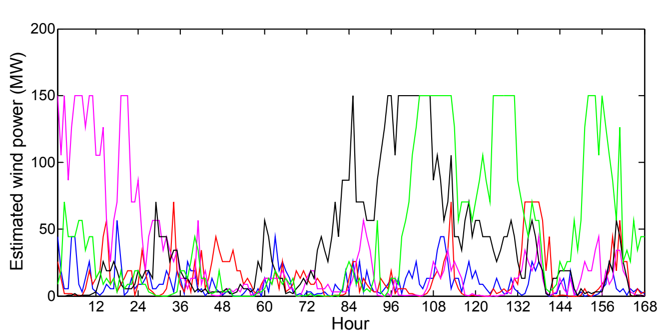

Fig. 6. Estimated wind powers in several weeks of scenario 1.

The contribution of the PSHP to reducing the scheduling costs has been calculated by comparing the costs with and without PHES. Energy storage capacity limits are not considered. The storage capacity which most contributes to reduce the scheduling of the system is obtained for each scenario as a result of the model, in a similar way to [17].

The choice of a weekly horizon for the UC problems has been motivated by the results presented in Ref. [45], where it is observed that certain units with large start-up cost may not be committed when using shorter time horizons.

The cost associated to wind integration has been assessed by comparing the scheduling costs with and without the above-mentioned penalty term for wind curtailments in the objective function, in a similar way to [35].

Details of the UC model formulation can be found in Appendix A.

4. Results

Main results obtained in this study are described in Sections 4.1–4.7. In Section 4.1, it is demonstrated that the consideration of constant start-up ramps and costs of the TGUs yields unrealistic results. Once this has been demonstrated, in Sections 4.2–4.5 the effects of the PSHP on the system scheduling costs, thermal power

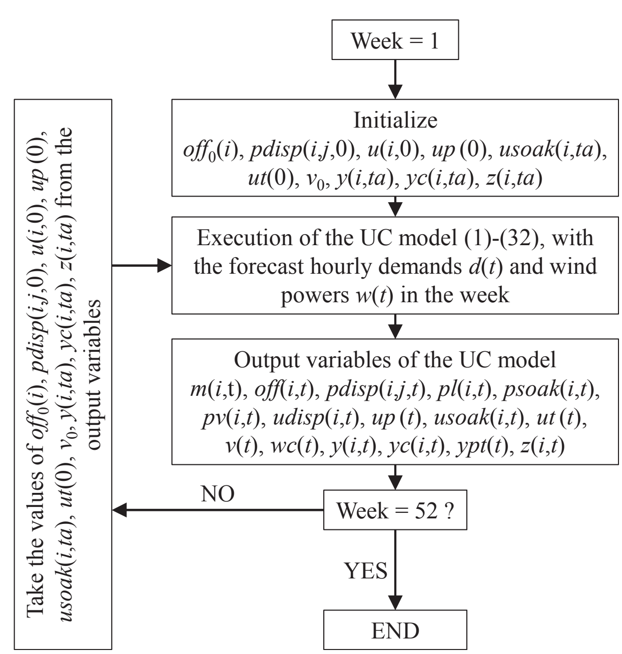

Fig. 7. Methodology followed for a given scenario, and given values of *iwp* and *ps*.

duration curve, capacity factors and number of start-ups, are calculated. In Section 4.6, the storage capacity which contributes the most to reduce the scheduling costs as well as to integrating as much wind power as possible is calculated. In Section 4.7, the impact of wind integration on the system scheduling cost is preliminarily estimated. It is important to note that the numerical results in Sections 4.1–4.7 might experience certain changes if the exact location and the real power-speed curves of the wind generators were considered. However, the results provide a good picture of the above-mentioned effects of the PSHP on the power system, as well as of the optimal storage capacity and impact of wind integration on the system scheduling costs. In addition, the results in Section 4.1 leave no room for doubt that the consideration of constant start-ups and ramps of the TGUs yield very unrealistic results. Further work on the effects that aggregation and geographical distribution of wind generators have on the wind power variability and the role of PHES in the power system under study is proposed in Section 5.

4.1. Importance of considering variable start-up ramps and costs

In order to highlight the importance of considering variable start-up costs and ramps, one of the three above-mentioned scenarios has been sequentially processed by the UC model, without considering the PSHP, and with both variable and constant start-up costs and ramps (VSUC&R, CSUR&C) of the TGUs. In this latter case, all units have been assumed to be able to start-up within one hour and each start-up has been valued at the hourly cost of a hot start-up. Fig. 8 shows the scheduling cost obtained with both the model with CSUC&R and the one with VSUC&R. As can be seen in the figure, the scheduling cost obtained with the model with CSUC&R is considerably lower than the one obtained with the model with VSUC&R. However, as can be deduced from Figs. 9 and 10, the scheduling cost obtained with the former is far from being realistic, since the TGUs start-up cost has been significantly underestimated. The underestimation of the TGUs start-up cost by the model with CSUC&R ranges from 9% to 24% of the scheduling cost, what makes the power generation schedule obtained with the model with CSUC&R be from 7% to 21% more expensive than the one obtained with the model with VSUC&R. The impact of considering CSUC&R increases with the wind power penetration. Fig. 9 shows the TGUs start-up cost estimated by the model with CSUC&R, the one calculated from the said model results, by considering the dependence of the start-up cost of the TGUs of type I_2 and I_3 on the time passed since the previous shut-down, and the one calculated by the model with VSUC&R. Fig. 10 shows the number of start-ups of the TGUs of type I_3, estimated by the model with CSUC&R, the number of start-ups of the said set of TGUs which would be more economical to carry out in a cold way, and the number of both total and cold start-ups calculated by the model with VSUC&R for the said set of TGUs. As can be seen from these figures, the consideration of constant start-up costs and ramps of the TGUs, which is to the authors' knowledge the usual practice in the scientific literature, yields very unrealistic results, both from an economic and technical point of view.

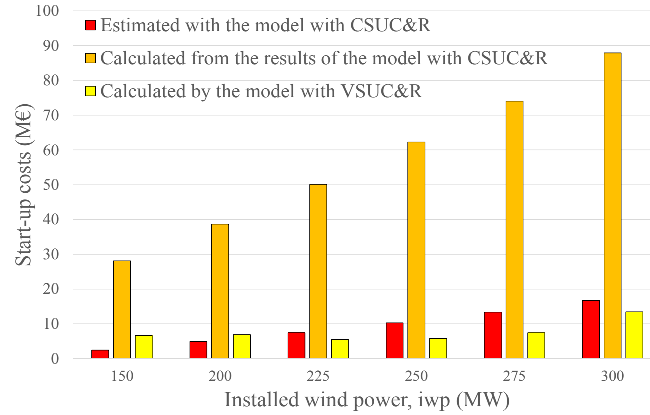

Fig. 9. Start-up cost of TGUs estimated by the model with CSUC&R, calculated from the results of the model with CSUC&R, and calculated by the model with VSUC&R (scenario 1).

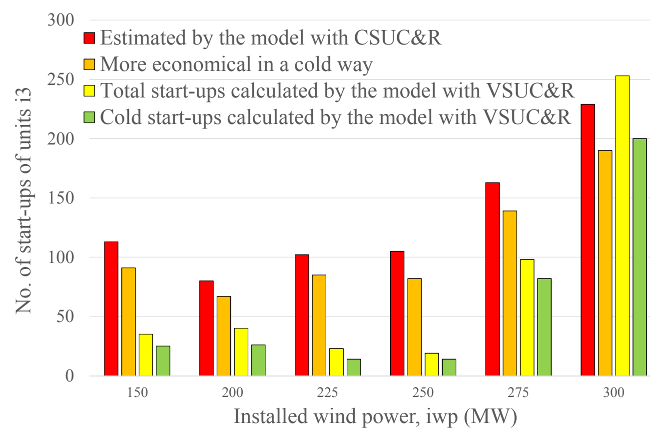

Fig. 10. Number of start-ups of the TGUs of type I_3 estimated by the model with CSUC&R; of these, number of start-ups which would be more economical to carry out in a cold way; and number of total and cold start-ups of the said set of TGUs calculated by the model with VSUC&R (scenario 1).

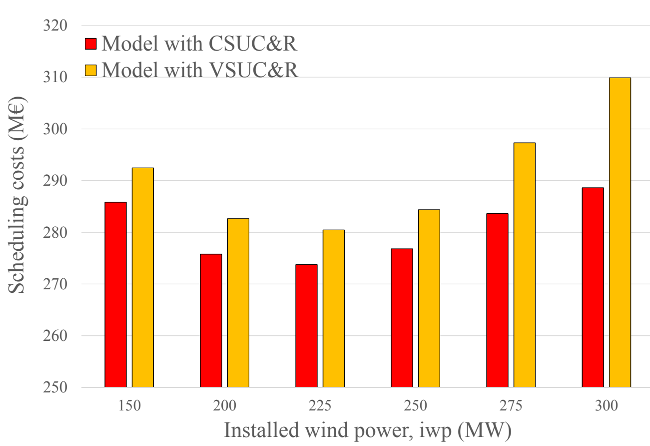

Fig. 8. Scheduling costs estimated by the model with CSUC&R and VSUC&R (scenario 1).

4.2. Scheduling costs

As can be seen in Fig. 11, the scheduling costs decrease as the installed power capacity of the PSHP (*ps*) increases for a given level of installed wind power (*iwp*). In order to give an idea about the magnitude of the cost savings due to the PSHP, avoided costs (AC) are included in Table 3, expressed in relative terms with respect to both the total scheduling costs and the investment cost, which has been estimated from the data included in Ref. [52]. As can be deduced from Fig. 11, for a given level of installed wind power, the marginal cost savings due to the PSHP (i.e. AC per each additional MW of installed power capacity in the PSHP) decrease as *ps* increases, what can be expected to a certain extent, since the most

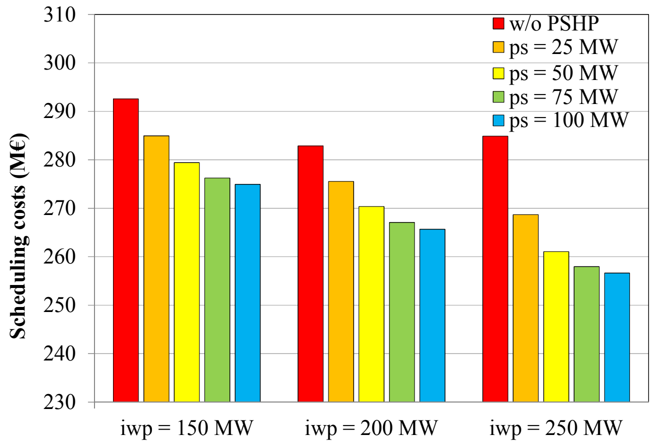

Fig. 11. Average scheduling costs across the three scenarios (M€).

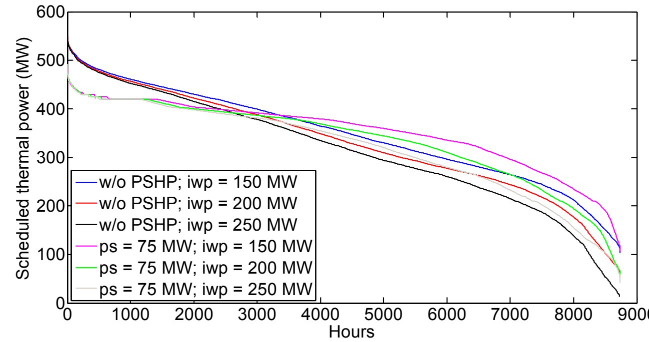

Fig. 12. Scheduled thermal power duration curve (Scenario 1).

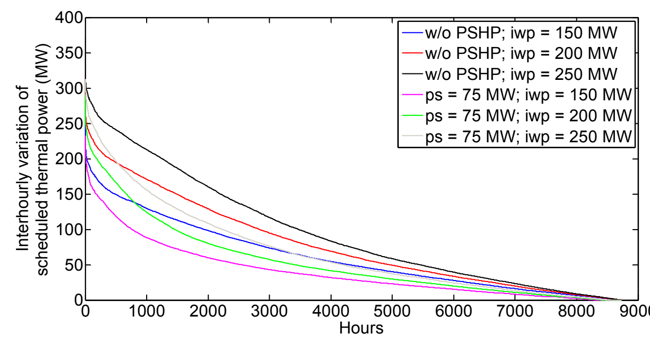

Fig. 13. Duration curve of hourly variation of scheduled thermal power (Scenario 1).

Table 3
Average avoided costs due to the PSHP across the three scenarios.

	AC (% of scheduling costs)			AC (% of investment cost)		
ps | *iwp*	150 MW	200 MW	250 MW	150 MW	200 MW	250 MW
25 MW	2.61	2.59	5.69	7.30	7.03	15.53
50 MW	4.61	4.54	8.87	6.52	6.21	11.81
75 MW	5.85	5.84	10.31	5.60	5.41	9.22
100 MW	6.38	6.44	10.96	4.70	4.59	7.54

expensive TGUs are replaced first by the PSHP. As can be seen in Table 3, even though for a given *iwp* the contribution of the PSHP to reduce the scheduling costs increases as *ps* increases, and that according to [52] the marginal investment in the PSHP decreases as *ps* increases, the cost savings due to the PSHP decrease with respect to the investment cost as *ps* increases. Nevertheless, by contrast to [53], where start-up costs and ramps of the TGUs were not considered, the cost savings due to the PSHP are significant with respect to the investment costs. Therefore, with a proper design of the PSHP remuneration mechanisms, the investment might be justified, especially with higher levels of *iwp* and lower levels of *ps*. It is important to bear in mind that, as stated in Ref. [12], freshwater availability may be a major problem in the island of Gran Canaria. To the authors' knowledge, there exist two technically feasible solutions to cope with the problem of freshwater availability: to use a seawater pump-turbine [54] or to build a desalination plant, that might be partially or totally funded by the PSHP owner. Either option would cause an increase in the investment cost, which should be considered to evaluate the viability of the PSHP.

4.3. Scheduled thermal power duration curve

In order to understand the effects of the inclusion of wind power and the PSHP in the system, the duration curve of both the scheduled thermal power and the hourly variation of the scheduled thermal power, are shown in Figs. 12 and 13, for the scenario 1 without the PSHP and with $ps = 75$ MW. As can be seen in Fig. 12, wind power contributes to slightly reduce the thermal power during peak periods and, to a much greater extent, during off-peak periods, thus decreasing the capacity factor of base-load and rigid units, such as the CCG and fuel units. In turn, the PSHP contributes, respectively, to reduce and increase significantly the scheduled thermal power during peak and off-peak periods, thus increasing the capacity factor of base-load units, such as the CCG units, and reducing that of peaking units such as diesel and gasoil ones.

From Fig. 13, it can be concluded that the system requires more flexibility as the installed wind power increases. In turn, from Figs. 12 and 13, it is possible to figure out to what extent PHES contributes to reduce both peak scheduled thermal power as well as hourly variation of scheduled thermal power, and therefore to increasing the capacity factor of base-load units and to decreasing that of peaking units.

4.4. Power generation mix

Some of the conclusions drawn from Figs. 12 and 13, can be confirmed in Table 4, where the average capacity factors of each thermal generation technology, as well as those of the pump-turbine in generating and pumping mode, across the three scenarios are shown. The capacity factor of each technology has been calculated as the ratio between the total energy scheduled for each technology and the maximum energy each technology would supply assuming full-load operation during 8736 h (52 weeks times 168 h per week). As can be seen in the Table, for a given *iwp*, the power scheduled for peaking units (diesel and gasoil) decreases considerably as *ps* increases, whereas that of CCG units increases, consistently with Figs. 12 and 13.

In order to better understand the results shown in Table 3, it is important to add some information to that included in Tables 1 and 2. In terms of flexibility, diesel and gasoil units are equivalent: they can start-up fast and have a similar operating range. CCG units can start-up as fast as diesel and gasoil units, but they have a much wider operating range, a higher start-up cost, and a lower marginal production cost, and therefore operate as base load units. Fuel units are by far the least flexible units in the system; they can start-up as fast as the other units at the expense of a high fuel consumption (hot start-up). The marginal production cost of fuel units is of the same order of magnitude as that of diesel and gasoil units, whereas

Table 4
Capacity factors (p.u.).

iwp | *ps*	w/o PSHP	25 MW	50 MW	75 MW	100 MW	w/o PSHP	25 MW	50 MW	75 MW	100 MW
Gasoil						**CCGT**				
150 MW	0.598	0.311	0.130	0.069	0.027	79.45	81.34	82.69	83.55	84.08
200 MW	0.609	0.309	0.142	0.070	0.046	75.74	77.47	78.65	79.48	79.97
250 MW	0.922	0.317	0.151	0.073	0.067	71.14	73.47	74.71	75.40	75.89
Fuel						**Turbine**				
150 MW	0.866	0.128	0.028	0.017	0.010	NA	21.91	19.51	17.60	16.31
200 MW	0.670	0.079	0.021	0.021	0.025	NA	19.86	17.67	16.04	15.30
250 MW	0.562	0.047	0.019	0.003	0.013	NA	20.22	16.42	14.99	15.04
Diesel						**Pump**				
150 MW	12.44	8.17	3.97	1.54	0.68	NA	29.05	26.16	23.93	22.47
200 MW	11.59	7.50	3.77	1.36	0.64	NA	26.36	23.70	21.82	21.06
250 MW	14.29	7.55	3.20	1.42	0.84	NA	26.79	22.00	20.39	20.66

the hourly production cost is slightly higher. According to [36], the marginal production costs of diesel and gasoil units are of the same order of magnitude. However, both the hourly production cost and the start-up cost of the former are considerably lower than those of the latter; hence the bigger capacity factors of the former. As can be seen in Table 4, the PSHP tends to replace both the peaking (diesel and gasoil) and rigid (fuel) TGUs and contributes along with CCG units to integrate in the system as much wind power as possible, as well as to minimizing the scheduling costs.

It is interesting to note that the capacity factor of the PSHP, both in generating and pumping mode, decreases as *ps* increases. In pumping mode, this result is a direct consequence of a decrease in the number of hours in operation as *ps* increases. However, in generating mode, this result is not due to a decrease in the number of hours in operation of the PSHP, but to a decrease in the average power generated during said hours, which can be checked in Table 5, where the average power scheduled in generating mode is expressed as a percentage of *ps*. This result indicate that the “room” for the PSHP to contribute to reduce the scheduling cost decreases as *ps* increases, in agreement with the above-discussed results shown in Fig. 8 and Table 3.

4.5. Start-ups of TGUs

As expected, the incorporation of the PSHP in the system has also certain effects on the number of scheduled start-ups of TGUs (see Table 6). For a given *iwp*, the incorporation of the PSHP allows a considerable reduction in the number of start-ups of gasoil, diesel and fuel units, as well as in the number of cold start-ups of the last ones (see Table 7). As discussed above, even though the operating ranges of diesel and gasoil units are of the same order of magnitude, the start-up costs of the former are lower than those of the latter; hence the significantly higher number of start-ups of the former. Additionally, it is important to take into account that the start-up cost of the PSHP unit is lower than those of both diesel and gasoil units, whereas its operating range is of the same order of magnitude.

From Tables 4, 6 and 7, it is possible to state that a small PSHP would allow dispensing with the fuel and gasoil units, and that a middle-size PSHP would prevent the need for using diesel units, with the corresponding positive environmental effects. The assessment of the average annual scheduling cost without considering these units is proposed as a future line of work in Section 5.

4.6. Storage capacity

The storage capacity which contributes the most to reduce the scheduling costs as well as to integrating as much wind power as possible has been obtained for each scenario from the results of the UC model, by comparing the maximum and minimum hourly stored energy throughout the year. As can be seen in Table 8, for

Table 5
Average power scheduled in generating mode.

iwp | *ps*	25 MW	50 MW	75 MW	100 MW
150 MW	66.40	59.88	52.60	47.43
200 MW	65.52	59.26	53.06	47.39
250 MW	69.67	60.75	52.34	49.27

Table 7
Average number of cold start-ups of fuel units across the three scenarios.

iwp | *ps*	w/o PSHP	25 MW	50 MW	75 MW	100 MW
150 MW	29	7	2	1	1
200 MW	25	4	2	2	2
250 MW	26	3	2	0	1

Table 6
Average number of start-ups across the three scenarios.

iwp | *ps*	w/o PSHP	25 MW	50 MW	75 MW	100 MW	w/o PSHP	25 MW	50 MW	75 MW	100 MW
Gasoil						**CCG**				
150 MW	232	157	80	48	20	0	1	5	8	13
200 MW	252	162	81	43	28	2	6	10	13	19
250 MW	388	165	92	42	39	250	87	13	18	29
Fuel						**Turbine**				
150 MW	43	7	2	1	1	NA	1104	1130	1110	1117
200 MW	35	4	2	2	2	NA	1159	1181	1167	1197
250 MW	34	3	2	0	1	NA	1295	1187	1198	1252
Diesel						**Pump**				
150 MW	2448	1947	1291	683	332	NA	1048	867	706	712
200 MW	2393	1885	1228	660	302	NA	1129	976	889	976
250 MW	2862	2030	1205	632	351	NA	1253	1112	1044	1164

Table 8
Average storage capacity across the three scenarios expressed in terms of the number of hours necessary to empty the upper pond at full load.

iwp | *ps*	25 MW	50 MW	75 MW	100 MW
150 MW	30.15	30.76	27.18	36.56
200 MW	28.69	29.50	27.99	36.95
250 MW	26.87	27.65	27.97	36.66

$ps = 25, 50$ MW the storage capacity decreases as *iwp* increases, whereas for $ps = 75, 100$ MW, it remains approximately constant. In order to understand this result, it is important to take into account that as demonstrated in Ref. [53], a given wind power profile may or not contribute to increase the number of hours, within a given time horizon, in which the generating–pumping cycle can be profitable, as a function of its covariance with the load demand profile. The decrease in the capacity factor of the PSHP as installed wind power increases (see Table 4), indicates that, as an average, the covariance between the weekly wind power and load demand profiles is relatively high. Analogously, for a given weekly wind power profile the hours during which the PSHP is pumping and generating may be more or less spread throughout the week as a function of *iwp*. In order to determine the most economically feasible storage capacity, it would be convenient to include a hard constraint on the storage capacity limit and run the UC model with different limit values, which is outside the scope of this paper. Nevertheless, just to get an idea on the range of the optimal storage capacity, the average storage capacity which has been exceeded only 5 weeks is shown in Table 9, using the same units as in Table 8. The values in Tables 8 and 9 support the choice of the UC model time horizon.

4.7. Wind integration costs

In order to evaluate the impact of wind integration on the system scheduling costs, the UC model has been run with $wcpen = 0$, in the cases without PSHP. Since wind curtailments were scheduled only with $iwp = 250$ MW (both with $wcpen = 10^6$ and $wcpen = 0$), 6 more cases have been analyzed: $iwp = 225, 275, 300$ MW with $wcpen = 0$ and $wcpen = 10^6$.

As can be seen in Fig. 14, up to 250 MW of installed power, the UC model is able to avoid wind curtailments, by properly penalizing the objective function. When wind curtailments are not properly penalized in the objective function, curtailed wind energy increases sharply for *iwp* greater than 225 MW. For *iwp* greater than 250 MW, the capability of the system to avoid wind curtailments is certainly limited.

The impact of wind integration on the scheduling costs has been evaluated by comparing the scheduling costs with $wcpen = 0$ and 10^6, and is included in Table 10. From Fig. 14 and Table 10, it can be concluded that, with the current generation assets and power demand level, it may be difficult to avoid wind curtailments for installed wind power capacities greater than 250 MW, and that in order to minimize wind curtailments, the scheduling costs may increase significantly for installed wind power capacities in the said range.

Table 9
Average storage capacity exceeded only 5 weeks (h) across the three scenarios.

iwp | *ps*	25 MW	50 MW	75 MW	100 MW
150 MW	17.94	16.67	17.52	16.07
200 MW	14.76	15.00	14.70	15.56
250 MW	13.23	12.79	13.39	14.72

Finally, it is important to note that no wind curtailments were scheduled in the cases with PSHP; just to gain insight on how the system would use the available wind power, the percentage of wind power used for pumping is shown in Table 11. As can be seen in the Table, for a given *iwp* the higher the installed power of the PSHP, the higher its contribution to integrating wind energy in the system.

5. Conclusions

This paper demonstrates that the consideration of constant start-up costs and ramps of the TGUs for assessing the contribution of a PSHP to reduce the scheduling costs of an isolated power system with high wind power penetration may yield very unrealistic results both from an economic and technical point of view. The contribution of a PSHP to reduce the scheduling costs of an isolated power system with high wind power penetration has been assessed by using a UC model which considers different start-up costs and ramps of the TGUs as a function of the time passed since the previous shut-down. To authors' knowledge no other paper has been published where variable start-up costs and ramps of the TGUs are considered to estimate the contribution of a PSHP to reduce the scheduling costs of a power system. All papers revised by the authors, dealing with the role of PHES in the reduction of the power system costs in systems with high wind power penetration disregard that both the start-up costs and ramps of some TGUs may vary significantly as a function of the time passed since the previous shut-down.

The results obtained in the paper show that in the power system under study, the power generation schedule obtained considering constant start-up costs and ramps of the TGUs can be from 7% to 21% more expensive than the one obtained considering variable start-up costs and ramps, as a function of the wind power penetration.

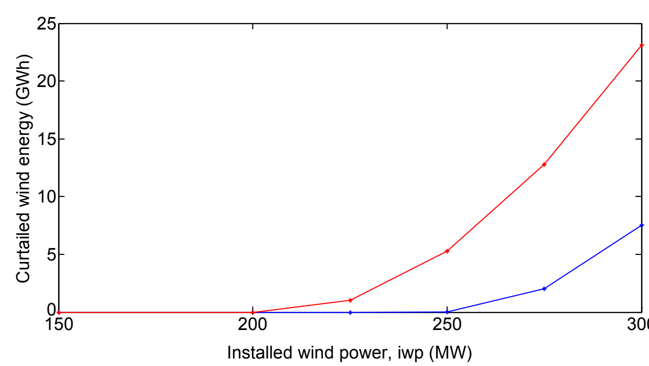

Fig. 14. Average curtailed wind energy with $wcpen = 0$ and $wcpen = 10^6$, across the three scenarios.

Table 10
Average impact of wind integration on the scheduling costs across all scenarios (€/MWh).

iwi \ iwp	225 MW	250 MW	275 MW	300 MW
€/MWh	2990.14	2149.62	2735.99	2848.71

Table 11
Average percentage of available wind power used for pumping (%).

iwp | *ps*	25 MW	50 MW	75 MW	100 MW
150 MW	12	20	25	30
200 MW	9	15	20	26
250 MW	7	12	16	23

In addition, the results indicate that PHES may provide significant savings in the scheduling costs of the system used as case study, so much so that with a suitably designed remuneration mechanism, the investment might be feasible.

The effects of incorporating a PSHP to the system on the start-ups and capacity factors of the TGUs, as well as the impact of wind integration on the scheduling costs, have been evaluated by using the same UC model. From the results, it can be stated that in the power system under study: the inclusion of a PSHP provokes a decrease in the start-ups and capacity factor of peaking units and an increase in the capacity factor, and therefore in the start-ups, of flexible base-load units; the PSHP help significantly reduce the contribution of rigid base-load units to the power supply and to increase the integration of wind energy; for installed wind power capacities greater than 250 MW (around 45% of the maximum power demand), it will be difficult to avoid wind curtailments and the scheduling costs might increase considerably if the transmission system operator decides to give priority access to wind power.

It is important to note that the numerical results of the paper may experience certain changes if the exact location and power-speed curves of each wind power generator were considered. However, the results provide a good picture of the effects of the PSHP on the system used as case study, and leave no room for doubt that disregarding the dependence of the start-up costs and ramps of some TGUs on the time passed since the previous shut-down yields very unrealistic results. Further work, some of which is already in progress, is therefore necessary to obtain more sound conclusions on the contribution of a PSHP in the system under study, namely: to consider the exact location of each wind power generator, and the effects that the aggregation and geographical distribution have on the wind power variability; to study the case of a multi-unit PSHP as well as the possibility of variable speed operation; to perform the analysis without considering the contribution of fuel, gasoil and diesel, which according to the results here presented, could be replaced by the PSHP; to consider the uncertainty in the forecast wind power and power demand; and to analyze the contribution of the PSHP to reduce the costs of load-frequency control, by simulating the system operation in real time.

Furthermore, it would be interesting to perform the presented analysis in larger power systems. However, the UC model used in the paper would not be useful for this purpose due to its large computational burden. A set of weekly runs were done in a system with 30 TGUs, each run taking from 6 to 12 h on a computer with an Intel Xeon processor E5-2687W @ 3.10 GHz, and 64 GB RAM, what makes the use of the UC model of little practical interest for the analysis of larger power systems. This is in the authors' opinion the most important reason why all commercial unit commitment models used in the literature to analyze the contribution of energy storage in the power system, consider that the start-up costs and ramps of all thermal generating units are constant. The authors are currently modifying the UC model formulation corresponding to the constraints of the thermal generating units according to [6], with the aim of increasing its computational efficiency and being able to analyze larger power systems.

Acknowledgment

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Appendices

A. Notation and formulation of the UC model

Notation

Indices and sets

i, I	thermal units
i, I_1	thermal units with a single start-up type and an almost constant start-up cost ($csut(i) = 1$)
i, I_2	thermal units with a single start-up type and a variable start-up cost as a function of the time the unit remained offline ($csut(i) = 1, td(i) > 1$)
i, I_3	thermal units with hot and cold start-ups ($csut(i) > 1, td(i) > 1$)
j, J	segments of the hourly fuel cost curve of thermal units
t, T	hourly periods of the time horizon (one week)

Parameters

$a(i)$	parameter for calculating the operation and maintenance costs of unit i (€/hour)
$b(i)$	parameter for calculating the operation and maintenance costs of unit i (€ per fuel cost)
$c\min(i)$	minimum fuel cost of unit i, corresponding to $p\min(i)$ (€/h)
$csut(i)$	time necessary for a cold start-up of unit i (h)
$d(t)$	net load demand in period t (MW)
$hsuc(i)$	hot start-up cost of unit i (€/h)
iwp	installed wind power (MW)
$mdt(i)$	minimum down-time after a shut-down of unit i (h)
$mrd(i)$	maximum hourly ramp down of unit i after the soak phase (MW/h)
$mru(i)$	maximum hourly ramp up of unit i after the soak phase (MW/h)
$mut(i)$	minimum up-time after a start-up of unit i (after the soak phase) (h)
$off_0(i)$	hours since last shut-down of unit i at the beginning of the time horizon up to Td (h)
$p(i,j)$	length of segment j of production cost curve of unit i (MW)
$p\min(i)$	minimum power of unit i (after the soak phase) (MW)
$p\max(i)$	maximum power of unit i (MW)
ps	maximum power of the PSHP both in generating and pumping modes (MW)
pvc	power variation cost (1.5 €/MW/h)
$q\min t$	minimum flow of the PSHP in generating mode (m^3/s)
qp	flow of the PSHP in pumping mode (m^3/s)
$r(i)$	slope of cold start-up ramp of unit i (MW/h)
rt	slope of the flow-discharge curve of the PSHP in generating mode ($m^3/s/MW$)
$s(i,j)$	slope of segment j of fuel cost curve of unit i (€/h/MW)
$SR(t)$	spinning reserve requirement in period t (MW)
$sucpt$	start-up cost of the PSHP (€)
$td(i)$	number of hours above which a cold start-up of unit i $\in I_3$ is more economical than a hot one, or where the breakpoint of the start-up cost curve is located for units i $\in I_2$ (h)
v_0	stored volume of water at the beginning of each week (m^3)

$w(t)$ available wind power in period t (MW)
$wcpen$ penalty for wind curtailments (€/MW)

Positive variables
$pdisp(i,j,t)$ generated power by unit i in segment j in period t (MW)
$pl(t)$ generated power by the PSHP above *pmint* in period t (MW)
$psoak(i,t)$ generated power by unit i in period t during start-up process (MW)
$pv(i,t)$ interhourly variation in generated power by unit i (MW)
$v(t)$ stored volume of water in the upper pond at the end of period t (m^3)
$wc(t)$ curtailed wind power in period t (MW)

Integer variables
$m(i,t)$ 1 if unit is offline in periods (t-1) and t; 0 otherwise
$off(i,t)$ Hours since last shut-down of unit i in period t up to Td (h)
$udisp(i,t)$ 1 if unit i is online in period t; 0 otherwise (periods during which the unit is starting up are excluded)
$up(t)$ 1 if the PSHP is pumping in period t; 0 otherwise
$usoak(i,t)$ 1 if unit i is starting up in period t; 0 otherwise
$ut(t)$ 1 if the PSHP is generating in period t; 0 otherwise.
$y(i,t)$ 1 if unit i is started up in period t; 0 otherwise
$yc(i,t)$ 1 if unit i begins a cold start-up in period t; 0 otherwise
$ypt(t)$ 1 if the PSHP is started up in period t in generating or pumping mode; 0 otherwise
$z(i,t)$ 1 if unit i is shut down in period t; 0 otherwise

Formulation of the UC model
Objective function.

$$\min \sum_{t\in T}\left[\sum_{i\in I}\left(\begin{array}{l} udisp(i,t)\cdot \mathrm{cmin}(i)+\sum\limits_{j\in J} pdisp(i,j,t)\cdot s(i,j)\\ +pvc\cdot pv(i,t)+a(i)\cdot udisp(i,t)+\\ b(i)\cdot\left(\begin{array}{l} udisp(i,t)\cdot \mathrm{cmin}(i)+\\ \sum\limits_{j\in J} pdisp(i,j,t)\cdot s(i,j)\end{array}\right)\end{array}\right)+\sum_{i\in I_1} hsuc(i)\cdot y(i,t)+\sum_{i\in I_2\ or\ I_3} hsuc(i)\cdot m(i,t)+ \atop \sum\limits_{i\in I_3} a(i)\cdot usoak(i,t)+sucpt\cdot ypt(t)+wcpen\cdot wc(t)\right]$$
$$+\sum_{i\in I_2\ or\ I_3} hsuc(i)(off_0(i)-off(i,168)) \quad (1)$$

Constraints. Values of all variables in periods previous to the beginning of the time horizon have been properly initialized.

- Demand supply:

$$d(t)+wc(t)=\sum_{i\in I}\left(udisp(i,t)\cdot \mathrm{pmin}(i)+\sum_{j\in J} pdisp(i,j,t)\right)+\sum_{i\in I_3} psoak(i,t)+ut(t)\cdot \mathrm{pmint}+pl(t)-up(t)\cdot ps \quad \forall t\in T \quad (2)$$

- Maximum power above $pmin(i)$:

$$pdisp(i,j,t)\le p(i,j)\cdot udisp(i,t) \quad \forall i\in I, j\in J, t\in T \quad (3)$$

- Interhourly power variations:

$$pv(i,t)\ge \sum_{j\in J}(pdisp(i,j,t)-pdisp(i,j,t-1) \quad \forall i\in I, t\in T \quad (4)$$

$$pv(i,t)\ge \sum_{j\in J}(pdisp(i,j,t-1)-pdisp(i,j) \quad \forall i\in I, t\in T \quad (5)$$

- Maximum ramp-up and −down above *pmin*:

$$\sum_{j\in J}(pdisp(i,j,t)-pdisp(i,j,t-1))\le mru(i) \quad \forall i\in I, t\in T \quad (6)$$

$$\sum_{j\in J}(pdisp(i,j,t-1)-pdisp(i,j,t))\le mrd(i) \quad \forall i\in I, t\in T \quad (7)$$

- Maximum up- and down-time since last start-up and shut-down:

$$y(i,t)+\sum_{n=t}^{t+mut(i)-1} z(i,n)\le 1 \quad \forall i\in I, t\in T \quad (8)$$

$$yc(i,t)+\sum_{n=t}^{t+mut(i)+csut(i)-1} z(i,n)\le 1 \quad \forall i\in I_3, t\in T \quad (9)$$

$$z(i,t)+\sum_{n=t}^{t+mdt(i)-1} y(i,n)\le 1 \quad \forall i\in I, t\in T \quad (10)$$

- Power trajectory during a cold start-up; i.e. start-up ramp:

$$psoak(i,t)\le r(i)\sum_{n=t-csut(i)+1}^{t} usoak(i,n) \quad \forall i\in I_3,\ t\in T \quad (11)$$

$$psoak(i,t)\le usoak(i,t)\cdot \mathrm{pmin}(i) \quad \forall i\in I_3,\ t\in T \quad (12)$$

- Constraints that guarantee consistency among integer variables used to model TGUs start-up costs and ramps:

$$y(i,t)-yc(i,t)\le \sum_{n=t-td(i)}^{t-1} z(i,n) \quad \forall i\in I_3,\ t\in T \quad (13)$$

$$yc(i,t) \le 1 - \sum_{n=t-td(i)}^{t-1} z(i,n) \quad \forall i \in I_3,\ t \in T \tag{14}$$

$$y(i,t) - z(i,t) = udisp(i,t) - udisp(i,t-1) \quad \forall i \in I_1 \text{ or } I_2, t \in T \tag{15}$$

$$y(i,t) - z(i,t) = udisp(i,t) + usoak(i,t) - (udisp(i,t-1) + usoak(i,t-1)) \quad \forall i \in I_3, t \in T \tag{16}$$

$$yc(i,t) \le y(i,t) \quad \forall i \in I_3,\ t \in T \tag{17}$$

$$y(i,t) - yc(i,t) \le \sum_{n=t-td(i)}^{t-1} z(i,n) \quad \forall i \in I_3, t \in T \tag{18}$$

$$yc(i,t) \le 1 - \sum_{n=t-td(i)}^{t-1} z(i,n) \quad \forall i \in I_3, t \in T \tag{19}$$

$$usoak(i,t) = \sum_{n=t-csut(i)+1}^{t} yc(i,n) \quad \forall i \in I_3, t \in T \tag{20}$$

$$off(i,t) \le off(i,t-1) + 1 \quad \forall i \in I_2 \text{ or } I_3, t \in T \tag{21}$$

$$off(i,t) + udisp(i,t)\cdot(1 + td(i)) \ge off(i,t-1) + \sum_{n=t-td(i)+1}^{t} z(i,n) \quad \forall i \in I_2, t \in T \tag{22}$$

$$off(i,t) + (udisp(i,t) + usoak(i,t))\cdot(1 + td(i)) \ge off(i,t-1) + \sum_{n=t-td(i)+1}^{t} z(i,n) \quad \forall i \in I_3, t \in T \tag{23}$$

$$off(i,t) \le td(i)\cdot(1 - udisp(i,t)) \quad \forall i \in I_2, t \in T \tag{24}$$

$$off(i,t) \le td(i)\cdot(1 - (udisp(i,t) + usoak(i,t))) \quad \forall i \in I_3, t \in T \tag{25}$$

$$m(i,t) \ge off(i,t) - off(i,t-1) \quad \forall i \in I_2 \text{ or } I_3, t \in T \tag{26}$$

- Spinning reserve requirement

$$\sum_{i \in I} (udisp(i,t)\mathrm{pmax}(i) - (udisp(i,t)\mathrm{pmin}(i) + pdisp(i,t))) + ut(t)ps - (ut(t)\mathrm{pmint} + pl(t)) \ge SR(t) \quad \forall t \in T \tag{27}$$

- Constraints corresponding to the PSHP

$$pl(t) \le ut(t)(ps - \mathrm{pmint}) \quad \forall t \in T \tag{28}$$

$$ut(t) + up(t) \le 1 \quad \forall t \in T \tag{29}$$

$$ypt(t) \ge (ut(t) - up(t)) - (ut(t-1) - up(t-1)) \quad \forall t \in T \tag{30}$$

$$v(t) = v(t-1) + 3600\cdot(up(t)\cdot qp - ut(t)\cdot \mathrm{qmint} - rt\cdot pl(t)) \quad \forall t \in T \tag{31}$$

$$v(t = 168) = v_0 \tag{32}$$

B. Acronyms used throughout the paper

AC	avoided costs
CCG	combined cycle gas
CSUC&R	constant start-up costs and ramps
MILP	mixed integer linear programming
PHES	pumped-hydro energy storage
PSHP	pumped-storage hydropower plant
TGU	thermal generating unit
UC	unit commitment
VSUC&R	variable start-up costs and ramps

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