Electricity cost optimization in a renewable energy system

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February 5, 2013

Abstract

The variable electricity output of the renewable energy sources (RES) power plants, such as wind and hydro power technologies, is seen as an important challenge for the electricity system managers.

This paper addresses the problem of an electricity system supported mainly on hydro, thermal and wind power plants, presenting a short-term model planning. A binary mixed integer non-linear optimization model for one year planning with hourly time step is described and applied to a system close to the expected Portuguese electricity scenario for the year 2020.

The main objective of this paper was to analyze the impact that different levels of installed wind power and hydropower have in the operation of thermal power units. Besides that, the analysis of results demonstrate the influence that the characteristics of the seasons of the year has on the renewable power units electricity generation and by this way on the total production cost of the system.

1 Introduction

Nowadays, the increasing use of new technologies such as wind power, characterized by production of variable output and frequently not subject to dispatch and benefiting from feed–in tariffs creates new challenges to the electricity power management. The promotion of the use of renewable energy sources (RES) for electricity generation is one of the possible greenhouse gas mitigation measures [Delarue et al., 2009] and has been supported by important incentives. On the contrary, the large thermal and hydropower groups need to compete in the market for dispatch.

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According to De Jonghe et al. [2012], large-scale wind power development affects short term operation of the electricity system, as well as the optimal generation technology mix since wind increase significantly the variability of generation. The volatility of wind power into the grid will enforce thermal generators to ramping to compensating supplying disruptions or to operate at low load conditions. According to Troy et al. [2010], increasing variability and unpredictability added to the power system due to wind curve characteristics will frequently originate that thermal units will experience an increasing number of startups, ramping and periods of operation at low load levels. In line with this Alvaro et al. [2011] support that, with the increase of wind power generation all over the world, the integration of wind power generation in electricity power systems needs to be carefully performed and requires new concepts in operation, control and management. In their study, a joint operation between a wind farm and a hydro-pump plant is addressed having into account the uncertainty of the wind power forecast.

Other concern that is usually addressed to RES technologies such as wind and hydro is the difficulty on their availability forecast. Different studies have focused on this thematic. Wang. et al. [2009] have study the impact of wind power forecasting on the unit commitment problem and economical dispatch. A set of different scenarios to deal with wind uncertainty were considered, transforming the problem into a stochastic one. Despite the complexity usually associated to the stochastic problems that usually leads to better results, the authors concluded that a deterministic method combined with an increased reserve requirement can produce results that are comparable to the stochastic case. In Vardanyan and Amelin [2011] a survey of short term hydro power planning with large amount of wind power in the system is presented. In their study some conclusions were underlying. They have concluded that research when uncertainty is considered is not fully explored and when considered can significantly increase problem size, which may require more advanced solution algorithms and techniques to bring problem size down and make it solvable.

It is well known that the principal aim of power planning, whether it is applied to long term planning horizon or to short term horizon, is to minimize the operation cost of the system allowing to fulfil a forecasted demand. Optimization models for short-term electrical power generation scheduling are therefore seen as useful and powerful tools to decision makers.

Short-term electrical power generation scheduling also known as unit commitment (UC) problem is essential for the planning and operation of power systems. The basic goal of the UC problem is to properly schedule the on/off states of all the units in the system. Further on, the optimal UC should meet the predicted load demand, plus the spinning reserve requirement at every time interval minimizing the total cost of production [Senjyu et al., 2003]. Şima Uyar et al. [2011] describe the short-term electrical power generation scheduling as an optimization problem, in which optimal startup and shutdown schedules need to be determined over a given time horizon for a group of power generators under operational constraints. The objective remains the minimization of the power generation costs meeting the hourly forecasted power demands. Following this idea, Zhang et al. [2011] focused on the variations in operating cost caused by integration of an increasing amount of wind power in thermal generation systems. According with the simulation results the authors concluded that wind power brings considerable cost increase on thermal generation. Furthermore, when wind power is integrated in the grid, more flexible generation with higher cost are dispatched in peak load regulation, units starts and stop more often and more money is spent on ramping costs, increasing the average cost of the system.

Many other studies addressing the short-term electrical power generation scheduling are well documented in literature with emphasis on the changes that occur in the operation of the thermal units due to increase of wind penetration on system and on the the market prices (see for example Traber and Kemfert [2011] and Troy et al. [2010].

The objective of this work is to analyze the impact that different levels of installed wind and hydro power have in the operation of thermal power units. For that an optimization model considering a short–term horizon planning was used.

This paper is organized as follows. Section 2 describes the proposed model formulation. In Section 3 a realistic case study close to the Portuguese system is addressed, and the results are analyzed. Finally, conclusions are stated in Section 4.

2 Model Formulation

The formulation followed in this work for the unit commitment problem in a system with high penetration of wind and hydro power is described in detail in this section. The model assumes a set of different fossil fuel units mostly comprised between coal and gas. In what concern to hydro power units, the model assumes two different types such as: the large hydro power units with reservoir and the run–of–river units. Pumping units were also also included in the model. Due to the increase complexity of the model no individual set for wind power units was considered. Instead, the model assumes all the individual wind power units as one.

2.1 Objective function

The proposed model formulation takes into account the economic cost, originating one objective functions to be considered. This objective function is set up by the sum of the variable costs of the electricity system. The variable costs, encompass the variable Operation and Management (O&M) costs, fuel and pumping cost, CO_2 emission allowance costs and shutdown and startup costs for each group. The objective function is measured in € and is defined by:

$$\sum_{t\in T}\sum_{j\in J}\left[C_{t,j}+Su_{t,j}+Sd_{t,j}\right]+\sum_{t\in T}\left[CVOM_{h_d}\times phd_t\right]+\sum_{t\in T}\left[CVOM_{h_r}\times phr_t\right]+ \\ \sum_{t\in T}\left[(Cp_p\times ppump_t)+(CVOM_p\times ppump_t)\right]+\sum_{t\in T}\left[(pwind_t\times CVOM_e)\right] \quad (1)$$

where T is a set of the time period (in hours) considered in the model, J is a set of all groups of thermal power plants included in the system, $C_{t,j}$ is the total cost of thermal power groups (€), $Su_{t,j}$ is the startup cost of thermal power groups (€), $CVOM_{h_d}$ is the O&M cost of hydropower plants with reservoir (€/MWh), phd_t is the power output of hydro power plant with reservoir in hour t (MWh), $CVOM_{h_r}$ is the O&M cost of run–of–river power plants (€/MWh), phr_t is the power output of run–of–river power plant in hour t (MWh), Cp_p is the cost of pumping (€/MWh), $ppump_t$ is the power output of pumping power plant in hour t (MWh), $CVOM_p$ is the

O&M cost of pumping power plant (€/MWh), $pwind_t$ is the power output of wind power plant in hour t (MWh) and $CVOM_e$ is the O&M cost of wind power plants(€/MWh).

The costs of thermal power groups considered in objective function above encompasses the fuel cost of each group, the O&M cost, the emissions allowance cost and the startup and shutdown costs. Those can be defined by equations (2), (3), (4) and (5).

$$C_{t,j} = \left[F_j + CVOM_j + (CO_{2_j} \times EC)\right] pt_j \tag{2}$$

$$Sd_{t,j} = CSd_j \times (v_{t-1,j} \times (1 - v_{t,j})) \tag{3}$$

$$Su_{t,j} = ColdS_j \left(v_{t,j} \times (1 - v_{t-1,j})\right) \times \prod_{n=1 \to N_j} 1 - v_{t-n,j} \tag{4}$$

$$Su_{t,j} = HotS_j \left(v_{t,j} \times (1 - v_{t-1,j})\right) \times \left(1 - \prod_{n=1 \to N_j} 1 - v_{t-n,j}\right) \tag{5}$$

where F_j is the fuel cost of group j (€/MWh), $CVOM_j$ is the O&M cost of thermal power group j (€/MWh), EC is the CO_2 emission allowance cost (€/ton), CO_{2_j} is the CO_2 emission factor of type j power group (ton/MWh), CSd_j is the shutdown cost of thermal power group j, $v_{t,j}$ is the binary variable that is 1 if thermal power group j is on in hour t or 0 if it is off, $ColdS_j$ is the cost of the cold startup of power group j (€), N_j is the time necessary for a cold startup (h) and $HotS_j$ is the cost of the hot startup of power group j (€).

2.2 Constraints

The set of adopted constraints for the unit commitment problem usually includes constraints derived from physical processes, demand requirements, capacity limitations and legal/policy impositions. These constraints are equations that impose conditions to the model formulation, defining values of the decision variables that are feasible Hobbs [1995].

2.2.1 Demand Constraint

To ensure the reliability of the system, the production of all power plants should meet the total system load at each hour of planning period. Thus, the demand must be equal to the total power output from power plants plus the special regime producers power output minus pumping consumption. The mathematical formulation of this constraint is

$$\sum_{j \in J} pt_{t,j} + phd_{t,h_d} + phr_{t,h_r} + pwind_{t,e} - ppump_{p,j} + Psrp_t = D_t \quad \forall t \in T \tag{6}$$

where D_t is the demand in hour t of planning period (MWh) and $Psrp_t$ is the generation output of all special regime producers (except large hydropower plants and wind power plants) including co-generation in each t hour of respective planning period (MWh).

2.2.2 Thermal Power Capacity Constraints with Ramp Considerations

Power capacity constraints ensures that all power groups included in the model will not produce more than respective group capacity for each hour of the planning period. Indeed, the power output will be less or equal to the power group capacity. A minimum output of 35% of capacity for coal and gas thermal power groups is considered due to its technical characteristics. Furthermore, startup and shutdown ramp constraints were also considered to ensure a more reliable system representation. Mathematical formulation of these constraints is

$$\overline{p_{t,j}} \leq \overline{P_j}\left[v_{t,j} - (v_{t,j} \times (1 - v_{t+1,j}))\right] + (v_{t,j} \times (1 - v_{t+1,j})) \times Sdr_j \tag{7}$$

$$\overline{p_{t,j}} \leq pt_{t-1,j} + Ru_j \times v_{t-1,j} + Sur_j \times (v_{t,j} \times (1 - v_{t-1,j})) \tag{8}$$

$$\overline{p_{t,j}} \geq 0 \tag{9}$$

$$\overline{p_{t,j}} \geq pt_{t,j} \tag{10}$$

$$\underline{P_j} \times v_{t,j} \leq pt_{t,j} \tag{11}$$

$$pt_{t-1,j} - pt_{t,j} \leq Rd_j \times v_{t,j} + Sdr_j \times (v_{t-1,j} \times (1 - v_{t,j})) \tag{12}$$

$$pt_{t,j} \geq 0 \tag{13}$$

where $\overline{p_{j,t}}$ is the maximum power generation of group j in time t (MWh), $\overline{P_j}$ is the maximum capacity of thermal group j (MW), Sdr_j is the shutdown ramp limit of group j (MWh), Ru_j is the ramp up limit of group j (MWh), Sur_j is startup ramp limit of group j (MWh), $\underline{P_j}$ is the minimum capacity of thermal power group j (MW) and Rd_j is the ramp down limit of group j (MWh) Arroyo and Conejo [2004].

2.2.3 Minimum up and down time of thermal power groups

Minimum Up and Down time constraints enforce the feasibility of system in terms of proper technical operation of units. Once a shutdown is verified the group must remain off for a certain period of time as well as if an startup happens, the group must remain working over a certain time period. Equation (14) and (15) ensure then operation feasibility in terms of minimum up and minimum down time constraints respectively.

$$\sum_{i \in i \leq UT_j} v_{t+i,j} \geq UT_j \times (v_{t,j} \times (1 - v_{t-1,j})) \tag{14}$$

$$\sum_{i \in i \leq DT_j} 1 - v_{t+i,j} \geq DT_j \times (1 - v_{t,j}) \times (v_{t-1,j}) \tag{15}$$

where UT_j is the minimum up time of thermal group j and DT_j is the minimum down time of thermal group j.

2.2.4 Large Hydro Constraints

For the large hydro power plants with reservoir, constraints regarding the expected storage and production capacity for each hour of planning period are considered into the model. The following equations relate the reservoir level for the hour t in terms of the previous reservoir level, inflows and consumption. Two sets of constraints appear due to the need of consider an initial reserve for the first hour of the planning period.

$$reserve_t = Inflows_t + (\eta_p \times ppump_t) - phd_t + Ir \qquad t = 0 \tag{16}$$

$$reserve_t = Inflows_t + (\eta_p \times ppump_t) - phd_t + reserve_{t-1} \qquad \forall t \in T \setminus \{0\} \tag{17}$$

where $reserve_t$ is the reservoir level on hour t of the planning period, $Inflows_t$ is the hydro inflow on hour t of the planning period, Ir is the initial reserve of reservoir on hour 0 of planning period and η_p is the efficiency of pumping units.

Additional upper and lower bounds must be used to define maximum and minimum reservoir levels as well as the maximum power output of these units that must be less or equal to groups capacity. The following set of equations represent these constraints.

$$reserve_t \leq reserve_{max} \tag{18}$$

$$reserve_t \geq reserve_{min} \tag{19}$$

$$phd_{h_d,t} \leq \overline{P_{h_d}} \tag{20}$$

where $reserve_{max}$ and $reserve_{min}$ are the maximum and minimum reservoir level allowed, respectively and $\overline{P_{h_d}}$ is the maximum power capacity of hydropower unit with reservoir.

The next set of constraints makes the production of run-of-river power plants equal to the installed power, taking into consideration the availability of these units. This type of plants are characterized by its reduced storage capacity.

$$phr_t = \phi_{h_r,t} \times \overline{P_{h_r}} \tag{21}$$

where $\phi_{h_r,t}$ is the run–of–river units availability in hour t that is strongly dependent of seasonality of each season.

2.2.5 Pumping Constraints

For the mathematical formulation of the operation of hydropower plants with pumping capacity, two reservoirs must be taken into account. The upper one storages water from inflows and from pumping itself, while the lower one storages water already used for electricity generation that later may be pumped again to the upper level. Again two set of constraints are necessary to model the initial pumping reserve for the first hour of planning period.

$$Preserve_t = phd_t - (\eta_p \times ppump_t) + PIr \qquad t = 0 \tag{22}$$

$$Preserve_t = phd_t - (\eta_p \times ppump_t) + Preserve_{t-1} \qquad \forall t \in T \setminus \{0\} \tag{23}$$

where $Preserve_t$ is the reserve of the pumping storage hydro power plant in hour t, PIr is the initial reserve of lower reservoir for instance t = 0.

The set of three next constraints representing the upper and lower bounds on the pumping reservoir and the maximum output production of pumping units, must also be included to ensure reliability of system. These are represented by the following constraints.

$$Preserve_t \leq Preserve_{max} \tag{24}$$

$$Preserve_t \geq Preserve_{min} \tag{25}$$

$$ppump_{t,p} \leq \overline{P_p} \tag{26}$$

where $Preserve_{max}$ and $Preserve_{min}$ are respectively the maximum and minimum capacity of lower reservoir and $\overline{P_p}$ is the max capacity of pumping groups.

2.2.6 Wind constraints

This constraint ensures wind power generation capacity to be equal to the total installed power taking into account the wind availability. This constraint is set as an equality assuming that wind power is not subject to dispatch, making use of the feed-in tariffs and has priority access to the grid. Wind constraint is described by

$$pwind_{t,e} = \phi_{t,e} \times \overline{P_e} \tag{27}$$

where $\overline{P_e}$ is the maximum capacity of wind power units (MW) and $\phi_{t,e}$ is the wind availability in hour t.

2.2.7 Security constraints

Power units outages although not being frequent must be considered and prevented. These outages have different reasons for happen consisting essentially on the power units breakdown and stoppages for maintenance. Furthermore suddenly increase of power consumption that may occur must be taken into considerations. Equation 28 represent this security constraint for each moment t.

$$\sum_{j \in J} \left(\overline{P_j} - pt_{t,j}\right) + \sum_{h_d \in H_d} \left(\overline{P_{h_d}} - phd_{t,h_d}\right) + \sum_{h_r \in H_r} \left(\overline{P_{h_r}} - phr_{t,h_r}\right) \geq D_t \times \alpha \tag{28}$$

where α is the parameter that will ensure the reliability of the system and usually represent 10%.

3 Model implementation and results analysis

3.1 Case study

The optimization model previously described was designed with the final aim of being used for a typical unit commitment problem for the analysis of a mixed hydro-wind-thermal power system. For this case study, a typical system encompassing all the electricity power generation technologies referred above, was taken into consideration. The particular case of the Portuguese electricity system was then selected, as representative of an example of this technology mix.

The Portuguese electricity system comprises essentially large thermal and hydro power plants in two different regimes: the ordinary regime production (ORP) encompasses thermal and large hydropower plants and the special regime production (SRP) encompasses renewable energy sources except large hydropower plants. Besides that, the investment in new technologies, essentially wind power, is increasing due to environmental and social concerns along with the need to reduce the external energy dependence. According to WWEA [2011] in 2011, Portugal occupied the tenth position on world in wind power capacity with 3960 MW installed, from which, 260 MW installed during the first half of 2011. This corresponds to 21% of total installed power of Portuguese national system and 17% of the total production [REN, 2012]. According to [REN, 2011] this increasing trajectory is expected to keep on at least until 2022 even despite of the decrease in 3% verified in the global consumption. In what concerns to ORP, in 2011, a reduction of 27% of total hydropower production was observed totaling 10808 GWh, with an hydraulic productivity index (HPI)[1] of 0.92, against 14869 GWh of 2010 with an HPI of 1.31. On the contrary, thermal power groups production experience an increase of 12%, totaling 19435 GWh against the 17299 GWH of 2010. This variability is quite informative of the changes on production that variable output units, highly dependent of climate conditions, can bring to the system.

Weather conditions and the seasonality will influence the power output in each year and consequently, will have an impact on electricity system operation and on the thermal power units

[1]Ratio between the hydropower production during a time period and the hydropower production that would be expected for the same period under average hydro conditions

performance. Figure 1 and 2 demonstrates the variability of the wind and run–of–river hydro production for January and August[2]. As may be observed the production of both wind and hydro power plants is much higher during winter (in January) than during summer (in August), due to the availability of the underlying resources. In fact in 2011, during the winter, RES production represented approximately 66% of the total electricity demand but during summer this share was only 24%. This demonstrates the need to analyze the short term scheduling of the electricity system considering a large share of RES.

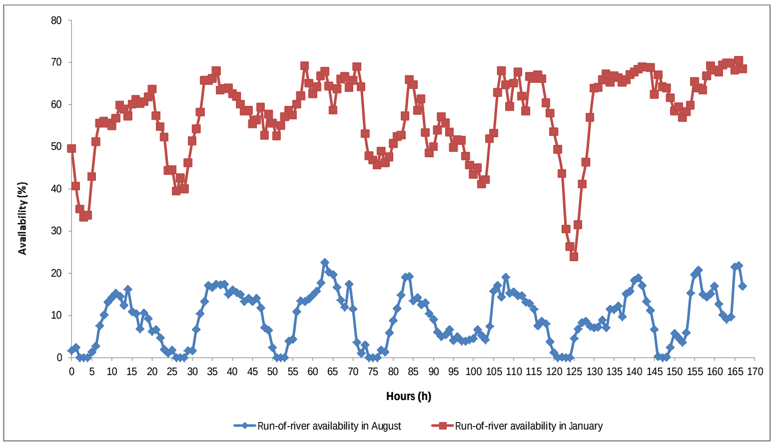

Figure 1: Hourly production of run–of–river power units in January and August 2011 weeks [Own elaboration from REN data]

In order to reduce the complexity of the analysis, a closed system was assumed and the imports and exports were not accounted in the optimization process. This way, the analysis will look for optimal electricity plans to meet the internal demand at minimum generation cost.

3.2 Simulation process

According to De Jonghe et al. [2012], although Linear Problems (LP) models have been successful because of their ability to model large problems, mixed integer programming must be used when binary variables are associated with investment projects or non-convexities, such as minimum run levels and minimum up– and downtimes.

Therefore, on the previously described model, equations (1)–(28) represent a mix integer non-linear optimization problem (MINLP) with 16633 continuing variables, 5208 integer variables, 48889 equation constraints, 579261 non-linearities and 183592 nonzeros modeled in GAMS [2011] code. The AlphaECP solver was selected to obtain the numerical results reported herein. The numerical results were obtained in a Microsoft Windows operating system using a 2.3GHz Pentium i5 computer with 4GB of memory.

[2]Availability used as a proxy of the variability of the resource measured as power output/ maximum capacity

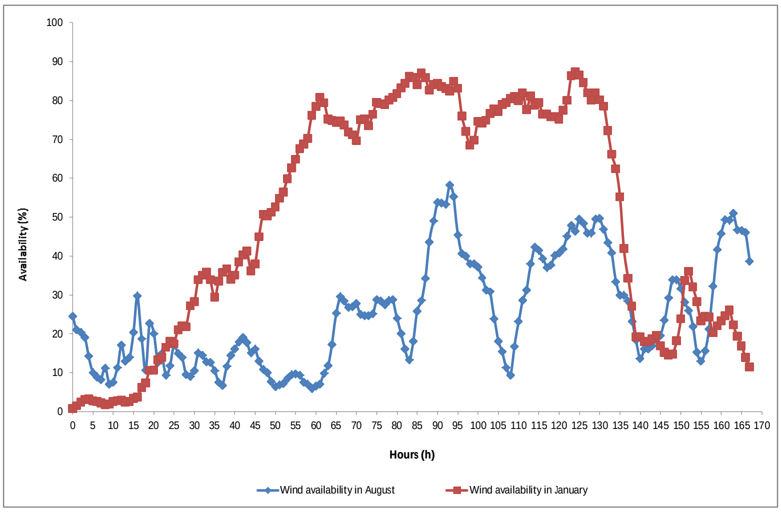

Figure 2: Hourly production of wind power units in January and August 2011 weeks [Own elaboration from REN data]

Table 1: Installed power system (Source: REN website)

	Technology	Number of power groups	Installed Power per technology (MW)
Thermal Power	Coal	8	1820
	Gas	15	4033
	Fuel	8	1145
Total	-	31	6998
Hydropower	Run-of-rivers	-	2583
	Large hydropower units	-	2649.8
Total	-	-	5232.3
Wind Power	-	-	3960
Pumping	-	-	1053.3

A single-objective problem with yearly time horizon and hourly time step was considered for a short–term electricity power generation scheduling, UC problem, in a system with different wind and hydro power penetration levels. Besides the installed wind power, the model assumes a set of different fossil fuel units mostly comprising coal and gas and two different types of hydro power technologies, the large hydropower units with reservoir and the run–of–river units. Note that hydro pumping units were also also included in the model. The simulation was conducted assuming four different scenarios in 2020. Both table 1 and table 2 describe the case study in terms of installed power and scenarios used. In the case described on table 2, scenarios were created having into account an increase in the wind power installed capacity as well as different values for the installed hydro power.

As addressed above, the behavior of a electricity system comprising high penetration of renewables will be strongly influenced by the climatic conditions and different seasons. In table 3 the average values of availability and demand that characterize each season of year since 2009 for the Portuguese power system are presented. Analyzing this table is possible to conclude that, the demand tends to be higher in the winter. Curiously, it is in this season that hydro and wind

Table 2: Case study scenarios

	Wind power (MW)	HPI)
Scenario 1	3960	2583
Scenario 2	3960	2635
Scenario 3	6000	2583
Scenario 4	6000	2635

availability is also higher. On the contrary it is in the summer that both hydro and wind power availability are lower. On the other hand, apart winter, wind power tend to be approximately equal in the remain seasons. Moreover, the electricity demand in summer is close to the demand in Autumn and even higher than the demand in the spring, which due to the lower hydro availability can create additional difficulties in the scheduling of the power system.

Table 3: Season characteristics of the Portuguese electricity system 2009–2011 (Source: Own elaboration using REN data)

	2011			2010			2009		
	Demand (MW)	Hydro availability	Wind availability	Demand (MW)	Hydro availability	Wind availability	Demand (MW)	Hydro availability	Wind availability
Winter (week 1)	6349.4	51%	31%	6515.2	61%	37%	6136.4	39%	28%
Spring (week 2)	5496.9	33%	22%	5536.1	47%	26%	5293.3	17%	21%
Summer (week 3)	5575.4	11%	23%	5830.3	18%	18%	5522.0	10%	20%
Autumn (week 4)	5684.4	24%	29%	5979.4	23%	31%	5837.6	17%	34%
Average/year	5776.5	30%	26%	5965.3	37%	28%	5697.3	21%	26%

Due to the complexity of the model, this work uses for the parameters, the data of 4 typical weeks, corresponding each one to one week of each season of the year. The objective was to obtain the total costs of the system, and to analyze the technology commitments over a year planning horizon for all scenarios presented in table 2. For simplicity reasons and to turn the model feasible it was assumed that the behavior of each week would repeat itself over the entire season being the final result the costs of the four seasons. The predicted wind and hydro power output was obtained from the hourly availability factor, which allowed to take into account the uncertainty and seasonality of wind and hydro power.

3.3 Numerical results

The results obtained for all scenarios are presented in Table 4. It is possible to conclude that for an increase of both wind and hydro power, the nominal cost of the system tend to decrease as expected. Comparing Scenario 1 and Scenario 3, it is possible to see a reduction of 19% on the estimated annual cost of the system. Consequently, the same happens when considering the week production cost for all weeks. For example, for both weeks 1 of scenarios 1 and 3 a reduction from 8.12 €/MWh to 6.40 €/MWh, which corresponds to a decrease of 21%, have occurred. This reduction can be explained by the increase of electricity generation provided by wind power, characterized by no fuel costs and lower cost of operation and maintenance when comparing with fossil fuel traditional generation units. Figure 3 and figure 4 demonstrate exactly the decrease of thermal power units production between scenario 1 and scenario 3 due to increase on wind capacity.

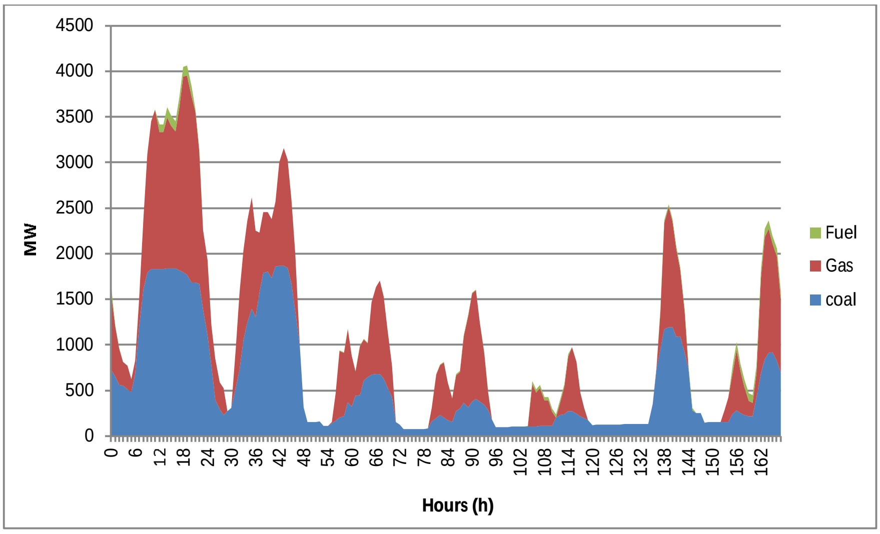

Figure 3: Hourly production of thermal power units for scenario 1 in week 1

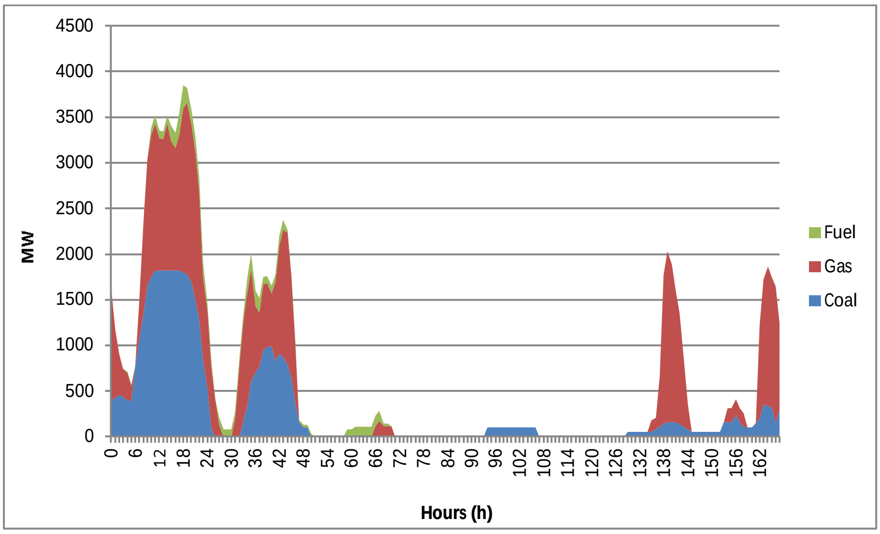

Figure 4: Hourly production of thermal power units for scenario 3 in week 1

Table 4: Optimal objective functions solutions

	Cost (€)	Marginal Cost (€/MWh)	Startups	Annual Cost (€)
		Scenario 1		
Week 1 (Winter)	10.687.227,3	8.12	126	598.142.031,0
Week 2 (Spring)	10.913.487,7	8.87	139	
Week 3 (Summer)	15.131.014,9	13.78	162	
Week 4 (Autumn)	13.113.439,3	11.94	137	
		Scenario 2		
Week 1 (Winter)	9.305.384,1	7.07	123	557.245.252,1
Week 2 (Spring)	9.685.254,7	7.87	137	
Week 3 (Summer)	14.765.659,2	13.44	148	
Week 4 (Autumn)	12.680.806,3	11.55	131	
		Scenario 3		
Week 1 (Winter)	8.469.366,1	6.40	87	484.615.702,6
Week 2 (Spring)	8.520.375,6	6.91	125	
Week 3 (Summer)	12.526.010,3	11.40	150	
Week 4 (Autumn)	10.868.889,8	9.90	108	
		Scenario 4		
Week 1 (Winter)	7.382.641,9	5.56	78	453.708.508,2
Week 2 (Spring)	7.527.755,3	6.10	90	
Week 3 (Summer)	12.220.708,2	11.13	146	
Week 4 (Autumn)	10.677.936,9	9.72	124	

Furthermore, is possible to verify that for all scenarios considered, the production costs of week 1 and week 2, are lower than those costs for week 3 and week 4, even week 1 and 2 having an higher demand, characteristic of these seasons. During spring and winter the wind and hydro availability is higher which reduces the number of expecting working hours of thermal power plants. This allows reducing the operating cost of the system, along with the number of start–ups and consequently the costs of the system become lower. This cost reduction is even more evident for higher wind and hydro power scenarios. Considering week 2 as example, comparing both scenarios 2 and 4 it is possible to verify a reduction on the cost production from 7.87 €/MWh to 6.10 €/MWh which represents a reduction of 22%.

In fact, during weeks 3 and 4 when wind and hydro availability is lower, thermal power unit need to compensate the lack of RES electricity production expected. This is specially visible in figures presented in B. In particulary, in figure 7 is possible to observe that a reduction in wind an hydro power production would result in an increase in production of thermal power units and an increase of startups and shutdown as evidenced in table 4. This behavior is followed by week 4 as shown in figure 8, although with a lower number of startups.

Interestingly, is possible to verify that the variability of RES availability influence significantly the number of startups and shutdowns of the system. A presents an example of the first 24 hours of the commitment of thermal unit in week 1 and 3, both from Scenario 1.

4 Conclusions

This paper analyzes the Short-term electricity power generation scheduling also known as unit commitment problem. For this, one optimization model was presented and adapted to the characteristics of the system under study. A deterministic programming model was proposed aiming to support the short term power generation scheduling, taking into account economic concerns. Once deterministic, the model assumes perfect knowledge of the demand and technical restrictions and costs over time. The model usefulness as a decision support tool or for the analysis of RES strategies was demonstrated for a case study. However it may be easily adapted to other cases with similar characteristics, allowing to design and analyze the interaction between the elements of the electricity system and the seasonality of the underlying renewable energy sources.

From the solution of the optimization model and assuming the described departing conditions, the results indicate that as the production levels of RES (wind and hydro power) increase the overall marginal cost of the system tend to decrease. These results can be easily explained because the costs of operation and maintenance of RES are very low when comparing to traditional fossil fuel generation units.

Another important aspect is the fact that for all the scenarios, the lower production cost are always achieved during the winter week. Although this week presents the higher electricity demand it is also the one with higher wind and hydro availability. On the contrary, during the summer weeks both the wind and hydro availability are lower leading to higher thermal power production and so, causing an increase on the marginal costs of the system. This demonstrates the impact and importance of analyzing the seasonal behavior of resources and consumption during electricity power planning.

The main results of the analysis put in evidence the importance of both wind and hydro power as strategic technologies to reduce the marginal cost of the system. Future work will address the need of a deeper analysis of the impacts that variations of wind power production has in the production of hydro power. Furthermore, it will also be of great interest to study a better way to deal with the efficiency of traditional thermal power units, which translates into the relationship between its load factor and fuel consumption.

Acknowledgements

This work was financed by: the QREN – Operational Programme for Competitiveness Factors, the European Union – European Regional Development Fund and National Funds and Portuguese Foundation for Science and Technology, under Project FCOMP-01-0124-FEDER-011377 and Project Pest-OE/EME/UI0252/2011.

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A Appendix

Table 5: Commitment of thermal power units in 2020

	Scenario 1, week 1 – hourly time step (24 h)																								
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Carriço														1	1	1	1	1	1	1	1	1	1	1	
FigueiraFoz																		1	1	1	1	1	1		
Setubal3	1																								
Setubal4													1	1	1	1	1	1	1	1	1				
Tunes1																									
Tunes2	1	1	1																						
Tunes3															1	1	1	1	1	1	1	1	1		
Tunes4																									
Ribatejo1	1																		1	1	1	1	1		
Ribatejo2											1	1	1	1	1	1	1	1	1	1					
Ribatejo3	1	1	1																	1	1	1	1	1	
Sines1								1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Sines2	1	1						1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Sines3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Sines4							1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Energin									1	1	1	1	1	1						1	1	1	1	1	
Lares1	1	1						1	1	1	1	1					1	1	1	1	1	1	1	1	
Lares2																				1	1	1	1	1	
Soporgen1										1	1	1	1	1	1	1	1	1	1	1	1	1	1		
Soporgen2									1	1	1	1	1	1	1	1	1	1	1	1					
Pego1									1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Pego2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
Pego3							1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Pego4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Tapada1	1	1	1	1	1					1	1	1	1	1	1	1					1	1	1	1	
Tapada2	1									1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Tapada3									1	1	1	1	1	1	1	1	1	1	1	1	1	1			
PegoCC1									1	1	1	1	1	1	1	1	1	1	1	1					
PegoCC2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1		

Table 6: Commitment of thermal power units in 2020

	Scenario 1, week 3 – hourly time step (24 h)																								
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Carriço									1	1	1	1	1												
FigueiraFoz		1	1	1	1	1	1					1	1	1	1	1	1	1	1	1	1	1	1	1	
Setubal1																		1	1	1	1	1	1	1	
Setubal2								1	1	1	1	1	1	1	1	1	1	1	1	1					
Setubal3											1	1	1	1	1	1	1	1	1						
Setubal4																									
Tunes1			1	1	1	1	1	1	1	1	1														
Tunes2	1	1	1	1	1																				
Tunes3				1	1	1	1	1	1	1	1	1													
Tunes4																									
Ribatejo1	1									1	1	1	1	1	1	1	1	1	1	1	1	1			
Ribatejo2	1	1	1	1												1	1	1	1	1	1				
Ribatejo3	1																	1	1	1	1	1	1	1	
Sines1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Sines2								1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Sines3	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Sines4									1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Energin										1	1	1	1	1								1	1	1	
Lares1									1	1	1	1	1	1	1										
Lares2		1	1	1	1	1					1	1	1	1	1										
Soporgen1																						1	1	1	
Soporgen2				1	1	1	1	1	1	1	1	1	1	1	1	1									
Pego1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Pego2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Pego3			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Pego4	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	
Tapada1	1						1	1	1	1	1	1													
Tapada2																					1	1	1	1	
Tapada3																		1	1	1	1	1	1	1	
PegoCC1							1	1	1	1	1	1										1	1	1	
PegoCC2																									

B Appendix

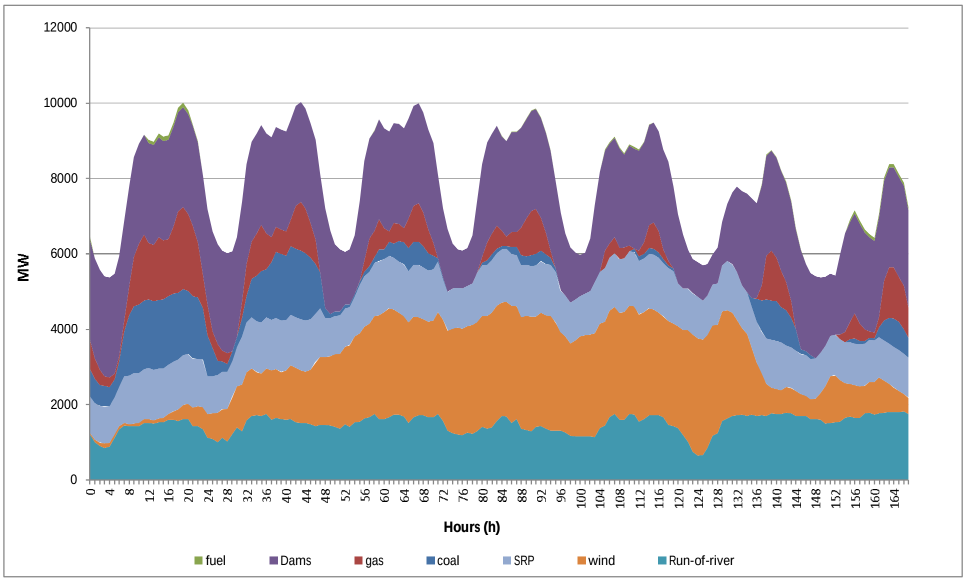

Figure 5: Power production for Scenario 1 in a Winter week

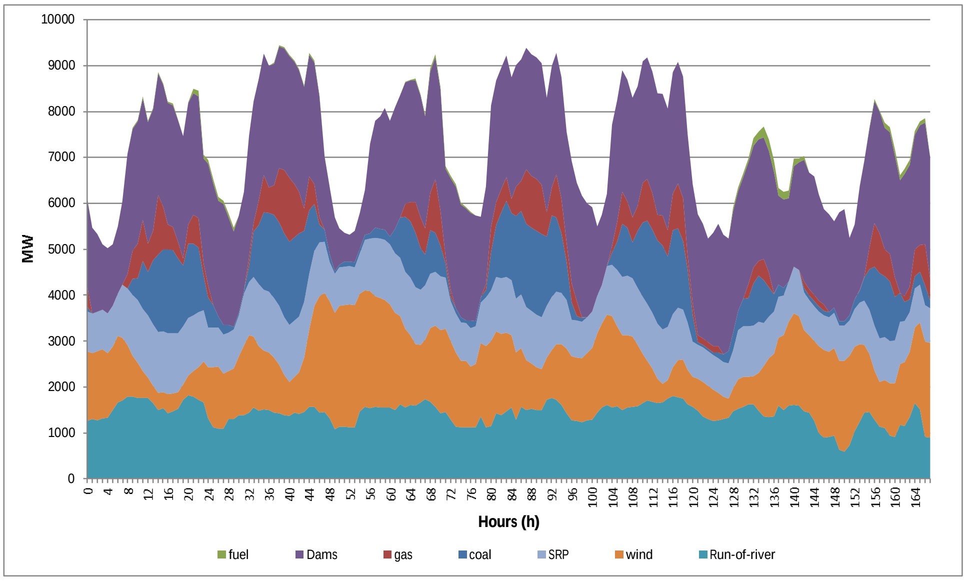

Figure 6: Power production for Scenario 1 in a Spring week

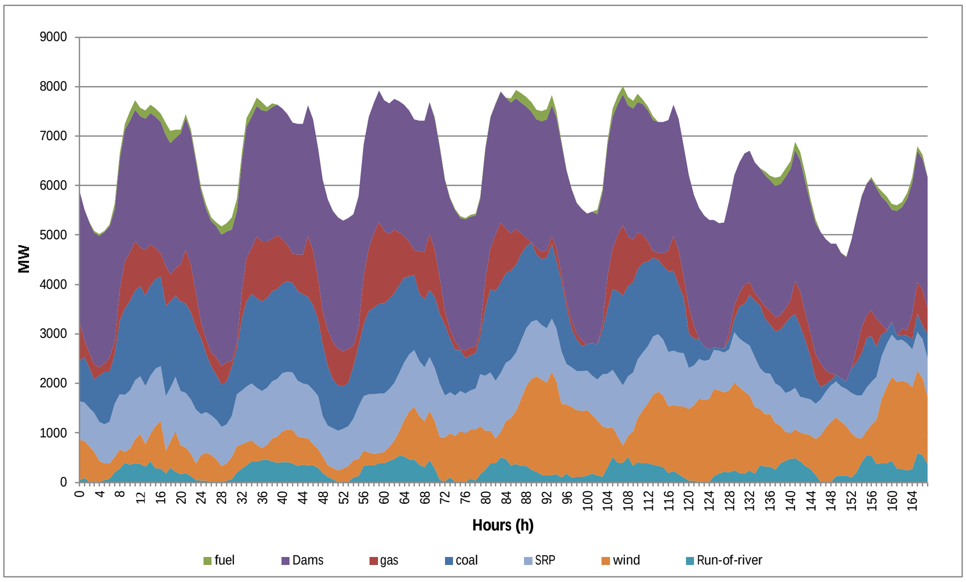

Figure 7: Power production for Scenario 1 in a Summer week

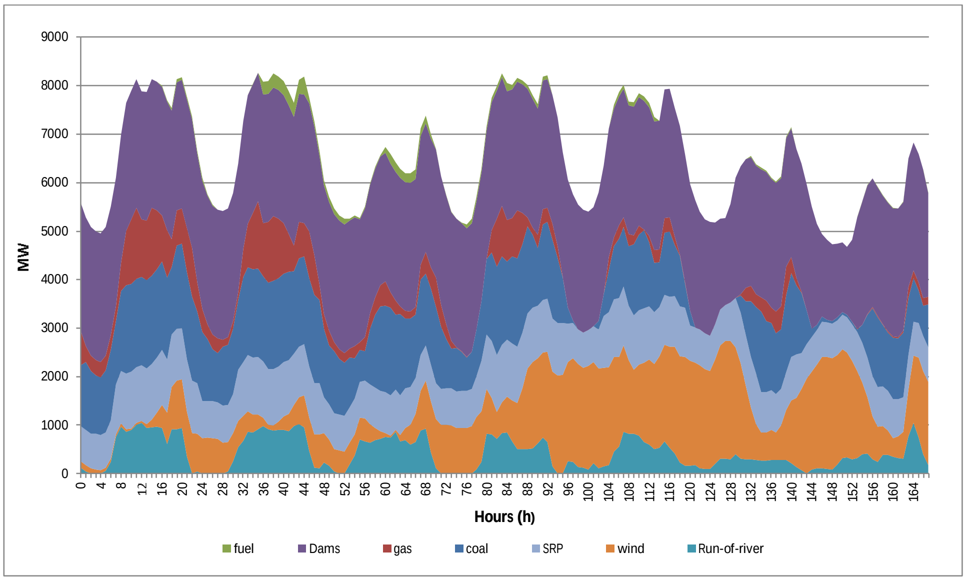

Figure 8: Power production for Scenario 1 in a Autumn week