Short-term scheduling model for a wind-hydro-thermal electricity system

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Abstract:

This study addresses the problem of the self-scheduling of an electricity system mainly based on hydro, fossil fuel thermal and wind power plants. A binary mixed integer non-linear optimization model is described and applied to short-term electricity planning of a system close to the expected Portuguese one on the year 2020. The model is written in a GAMS code and a global optimization solver is used to obtain the numerical results. The objective function encompasses the minimization of total system production costs through a centralized unit commitment. Different constraints, essentially related to operating parameters that characterize the power plants available for dispatch, are included in the model. The obtained results show the importance of the renewable energy sources seasonality on the thermal power plants operating conditions and on the total cost of the system.

Keywords:

Electricity planning, Electricity system analysis, Unit Commitment problem.

1. Introduction

The emergence of new technologies such as wind power, characterized by production of variable output, not subject to dispatch and benefiting from feed–in tariffs, creates new challenges to the electricity power management. On the contrary, the large thermal and hydropower groups need to compete in the market for dispatch. Also, adding more variability and unpredictability to a power system, due to wind power curve characteristics, will frequently originate that thermal units will experience increased number of startups and shutdowns, and periods of operation at low load levels (see [1]).

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 operational costs of the system while that a certain forecasted demand is fulfilled. In order to accomplish this aim, optimization models for both short-term electrical power generation scheduling and strategic power planning are seen as useful and powerful tools to be used by decision makers.

Short-term electricity 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. Furthermore, the UC problem should consider the predicted load demand and spinning reserve requirement, minimizing the total cost of production [2].

Uyar, A. et al. in [3] described the short-term electrical power generation scheduling as an optimization problem, in which optimal startup and shutdown schedules, for a group of power generators, need to be determined over a given time horizon and considering operational constraints. The model objective remains as the minimization of the power generation costs meeting the hourly forecasted power demands. The short-term electricity power generation scheduling is well documented in the literature, with special concerns about the wind power penetration on the traditional thermal units systems, and on the market prices (see, for example, [4] and [1]).

Despite the economic interests considered in these models, environmental concerns are also increasingly relevant. The Catalão, J. et al. study [5] focused on a multi-objective formulation, where two objective functions were considered, namely the total fuel cost and total CO2 emissions.

Chao–Lung and Chiang [6] also presented a multi-objective formulation for the economic emission dispatch of a hydrothermal power systems. Again, two objective functions were considered, one for the total cost and the other for the total emissions. The results included the optimal total cost and the optimal gas emission solutions. Compromise solutions were presented in a form of a Pareto-optimal front, representing the trade-off between the total cost and environmental objectives.

The major goal of the present work is to propose an optimization model for the short-term electricity power generation scheduling problem. The objective function encompasses the minimization of total system production and maintenance costs through a centralized unit commitment problem. The model considers different constraints essentially related to operating parameters that characterize the power plants available for dispatch. A mixed hydro-thermal-wind power system, with characteristics close to the Portuguese case, that presents by itself a set of typical technical and geographical characteristics, is addressed.

This paper is organized as follows. Section 2. describes the proposed optimization model. In Section 3. and Section 4. a realistic case study, close to the Portuguese system, is modeled and the results are analyzed. Conclusions are stated in Section 5..

2. Model formulation

2.1. Objective function

The proposed model considers only one objective function, which aggregates all the assumed costs of the electricity system. These costs includes the variable operation and management (O&M) costs, fuel and pumping costs, $CO2$ emissions costs, and startup and shutdown 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 (€), $CVOM_{hd}$ 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), $CVOM_{hr}$ 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). Additionally, the costs of thermal power groups, i.e., the fuel cost of each group, the O&M cost, the emissions allowance cost, and the startup and shutdown costs, are defined as follows.

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

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

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

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

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 $CO2$ emission allowance cost (€/ton), $CO2_j$ is the $CO2$ emission factor of type j power group (ton/MWh), CSd_j is the shutdown cost of thermal power group j, $v_{t,j}$ is a binary variable w.r.t. the thermal power group j on hour t, $ColdS_j$ is the cold startup cost of power group j (€), N_j is the shutdown time necessary for a cold startup (in hours) and $HotS_j$ is the hot startup cost of power group j (€).

2.2. Constraints

The set of adopted constraints for the unit commitment problem includes constraints derived from physical processes, demand requirements, capacity limitations and legal/policy impositions. These constraints, presented as mathematical equations, define values of the decision variables that are feasible [7].

2.2.1. Demand constraint

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

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

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

2.2.2. Thermal power capacity and ramp constraints

Power capacity constraints ensures that all power groups included in the model will not produce more than the respective group capacity, for each hour of the planning period. A minimum power output of 35% of both coal and gas thermal power groups is considered, due to technical characteristics. Furthermore, startup and shutdown ramp constraints are also included, to ensure a more reliable system representation. The constraints of the mathematical formulations are presented in the following equations.

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

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

$$\overline{p_{t,j}} \geq 0 \qquad (9)$$

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

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

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

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

where $\overline{p_{j,t}}$ is the group j maximum power generation in time t (MWh), P_j is the thermal group j maximum capacity (MW), Sdr_j is the group j shutdown ramp limit (MWh), Ru_j is the group j ramp upper limit (MWh), $Surj$ is the group j startup ramp limit (MWh), P_j is the thermal power group j minimum capacity (MW) and Rd_j is the group j ramp lower limit (MWh) [8].

2.2.3. Thermal power groups minimum up and down time

Minimum up and down time constraints enforce the feasibility of the 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 (minimum down time). The same occurs when a startup happens, the group must remain working for a certain time period (minimum up time). Equations (14) and (15) ensure the minimum up and down time constraints for thermal power plants, 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 thermal group j minimum up time and DT_j is the thermal group j minimum down time.

2.2.4. Large hydropower constraints

For the large hydropower plants with reservoir, constraints regarding the expected storage and production capacity are considered in the model. The following equations allow to relate the reservoir level on hour t to the previous (hour t - 1) reservoir level, inflows and hydropower output. Two sets of constraints are considered, since an initial reserve is considered.

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

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

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 and η_p is the efficiency of the pumping units.

Additional upper and lower bounds must be used to define maximum and minimum allowed reservoir levels, respectively. An upper bound on the power output of the group is also considered. These bounds are described in the following equations.

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

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

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

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 units with reservoir.

Run–of–river power plants are characterized by a reduced water storage capacity. As such, the next set of constraints make the run–of–river power plants production equal to the installed power, taking into consideration the availability of these units.

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

where $\Phi h_{r,t}$ is the run–of–river units availability in hour t, which is strongly dependent on the seasonality.

2.2.5. Pumping constraints

Two reservoirs must be taken into account for a proper mathematical formulation of hydropower plants with pumping capacity. The upper level reservoir storages water from inflows and from the pumping itself, while the lower level reservoir storages water already used for electricity generation. Water may be pumped from the lower level storage to the upper level storage, in order to take advantage of the over electricity production of the system. Again, two set of constraints are described in order to consider the initial pumping reserve.

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

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

where $Preserve_t$ is the pumping storage hydropower plant reserve in hour t and PIr is the lower level reservoir initial reserve.

Upper and lower bound constraints are considered on the pumping reservoirs and on the power production of the pumping units. These bounds are represented in 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 the maximum and minimum capacity of lower level reservoir, respectively, and $\overline{P_p}$ is the pumping groups maximum capacity.

2.2.6. Wind power constraints

It is assumed that wind power is not subject to dispatch and has priority access to the grid. As such, the proposed constraint ensures that the wind power generation capacity is equal to the total installed power, taking into account the wind availability. Wind constraint is described by

$$pwind_{t,e} = \phi_{t,e} \times \overline{P_e} \qquad (27)$$

where $\overline{Pe}$ is the wind power units maximum capacity (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. While there are several reasons for power units outage, the power units breakdown and stoppages for maintenance are the main ones. Furthermore, the system should take into consideration a possible suddenly increase on power consumption. Equation (28) represent this security constraint.

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

where α is the parameter that will ensure the reliability of the system, usually taken as 10%.

3. Case Study

The previous section presents a typical unit commitment problem, designed with the final aim of being used in the analysis of a mixed hydro-wind-thermal power system, with characteristics close to the Portuguese one.

The Portuguese electricity system comprises essentially large thermal and hydro power plants. Recently, the investment in new technologies, mainly wind power, is increasing due to environmental and social concerns along with the need to reduce the external energy dependence. According to [9] in 2011, Portugal occupied the tenth world position in wind power capacity with 3960 MW installed, from which, 260 MW were installed during the first half of 2011. In the end of 2010, and according to [10], wind power represented 21% of the Portuguese national system installed power.

The Portuguese system comprise two different regimes. The ordinary regime production (ORP) encompasses thermal and large hydropower plants and the special regime production (SRP) encompasses renewable energy sources and cogeneration (except large hydropower plants). Wind power still represents the major renewable energy source of the SRP with a share of 50%. In what concerns the ORP, in 2011, a reduction of 27% of the total hydropower production was observed totaling 10808 GWh, with an hydraulic productivity index (HPI)[1] of 0.92, in compare with a production of 14869 GWh in 2010 with an HPI of 1.31. On the contrary, thermal power groups production experience an increase of 12%, totaling in 2011 19435 GWh against the 17299 GWH in 2010. This variability is quite informative of the changes on production that variable output units 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 the electricity system operation, mainly on the thermal power units. Figure 1 and 2 show the variability of the hydro and wind production for January and August[2]. As may be observed, the production for both hydro and wind power plants is

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[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.
[2] Availability used as an approximation of the variability of the resource measured as power output divided by the maximum capacity.

much higher during the winter week (in January) than during the summer week (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 the share was only 24%. This demonstrates the need to analyze the short term scheduling of electricity systems with a large share of variable output RES.
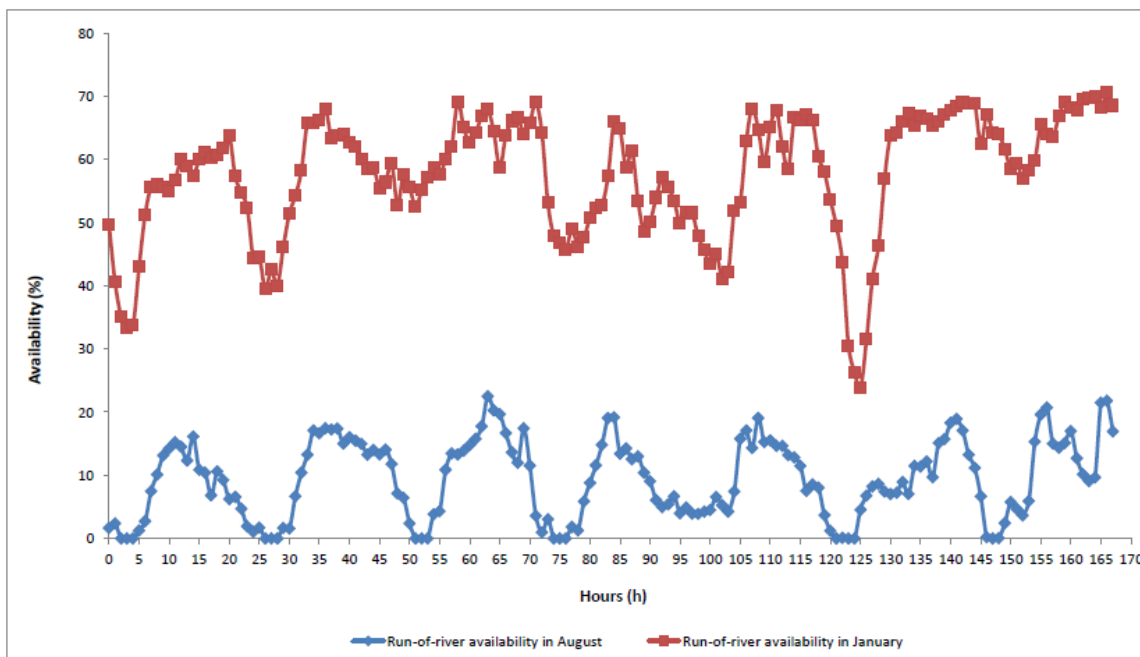

Figure 1: Weekly production of run–of–river power units in January and August 2011. [Own elaboration from REN data]
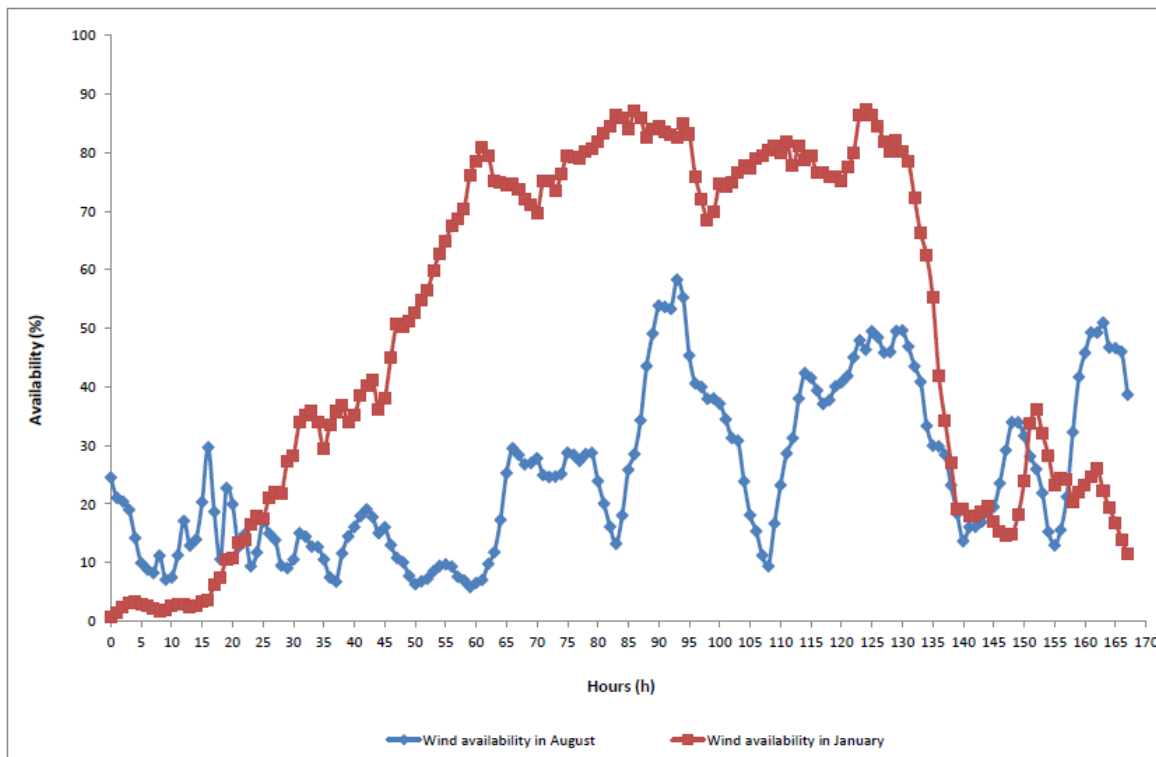

Figure 2: Weekly production of wind power units in January and August 2011. [Own elaboration from REN data]

In the next section, numerical results corresponding to a week horizon planning are presented. A short term electricity power generation scheduling is considered for the year 2020 forecasted Portuguese system (see reference [11]).

4. Numerical results

The forecasted Portuguese system over a week horizon planning for 2020 is considered in order to validate the proposed model. Considering a set of 168 hourly load blocks allow to obtain a more accurate analysis of results. In agreement with the year 2020 forecasted Portuguese system, a mix of 32 thermal power groups comprising gas, coal and fueloil technologies were considered in the model.

The previously described model, represented in equations (1) to (28), originates a single objective mix integer nonlinear optimization problem (MINLP) with 11089 continuing variables, 5208 binary variables and 26016 nonlinear inequality constraints, written in the GAMS [12] modeling language. The AlphaECP [13] solver was selected to obtain the numerical results reported herein, since it proved to be the most efficient solver available. The numerical results were obtained in a Microsoft Windows operating system using a Intel core i5 processor with 4GB of memory.

For simplicity, it was considered January as representative of the winter season and the August as representative of the summer season. Table 1 shows the optimal objective function values for January and August.

Table 1: Optimal objective function values

	Cost (M€)	
	January	August
Optimal cost	13.5	27.8

Results presented in Table 1 show that for January, the minimum cost of total power generation is lower than for August. This can easily be explained by comparing both figures A.1 and A.2 presented in Appendix A.. During the winter season, the variability of thermal power groups production is higher and the average thermal power production was 1273 MW. Also during winter, a reduction of the system variable cost is achieved, strongly dependent of the fossil fuel consumption. Nevertheless, an increase in the number of shutdowns and startups of the thermal power plants (with a direct impact on the ramping) is observed. In opposition, during summer, thermal power production remains rather steady with an average production of 3021 MW. Furthermore, no startups or shutdowns occurred, due to the low wind and hydropower production. The increase on the optimal cost is in part justified by the increase in the thermal power production during August, when compared with January. The higher summer cost is also explained by the need to fulfill the minimum up and downtime constraint of thermal power groups, in order to meet the load demand and compensate the lower wind and hydropower production. Despite the higher number of startups and shutdowns of thermal power plants in the winter season, this solution becomes less expensive due to the high availability of wind and hydropower. Thermal units are only used to compensate the lack of the RES reserves and for higher demand hours. This explains a higher wind and hydropower production with no fuel costs associated and consequently leading to a lower production cost of the entire power system.

5. Conclusions

This paper analysis the short-term electricity power generation scheduling in a mixed hydro-thermal wind power system based on data close to the ones characterizing the Portuguese electricity system.

A MINLP was proposed aiming to support the short term strategic decision, taking into account the

cost objective.

The results indicate that the seasonality associated with the renewable power sources affects the behaviour of the system, and consequently its total cost. Although the electricity demand during winter increases, the higher availability of wind and hydropower production ensure that thermal power groups will remain working at a lower rate than during summer. This leads to a reduction of the variable cost of the system, strongly driven by the fuel costs. The higher number of startups and shutdowns occurred in the winter season do not necessarily reflect an increase in the system costs. The startups and shutdowns costs are in fact less relevant then the fuel cost of thermal power groups, representing 54% of the total cost of the system during winter and 0% during summer.

The importance of designing short range planning models is crucial to study problems like the self-scheduling of a thermal electricity producer in day-ahead electricity markets. Future work will address the need to combine long term energy expansion strategies with short-term electrical power generation scheduling, for an hourly time step during one year horizon planning, evaluating the impact that the hydro-wind power combination strategies may have on the efficiency of thermal power plants. The model is expected to be expanded in order to increase the analysis period and to include the possibility of cross-border trading.

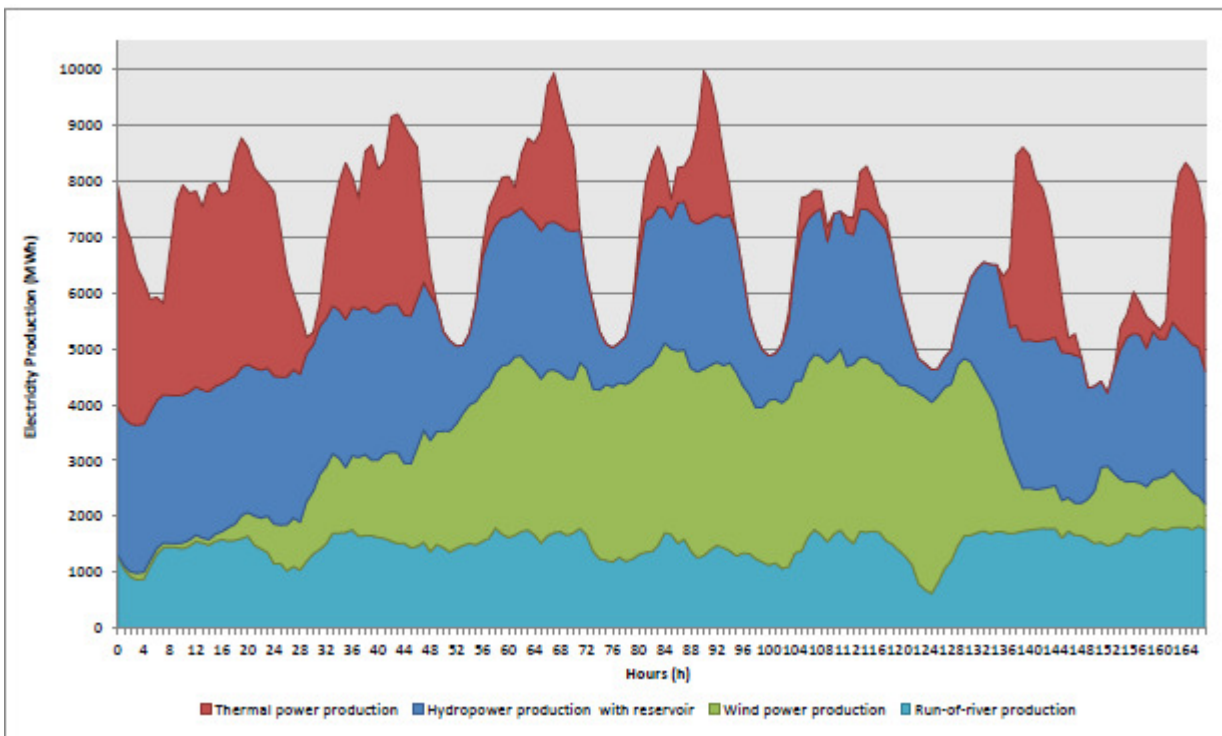## Acknowledgments

Appendix A

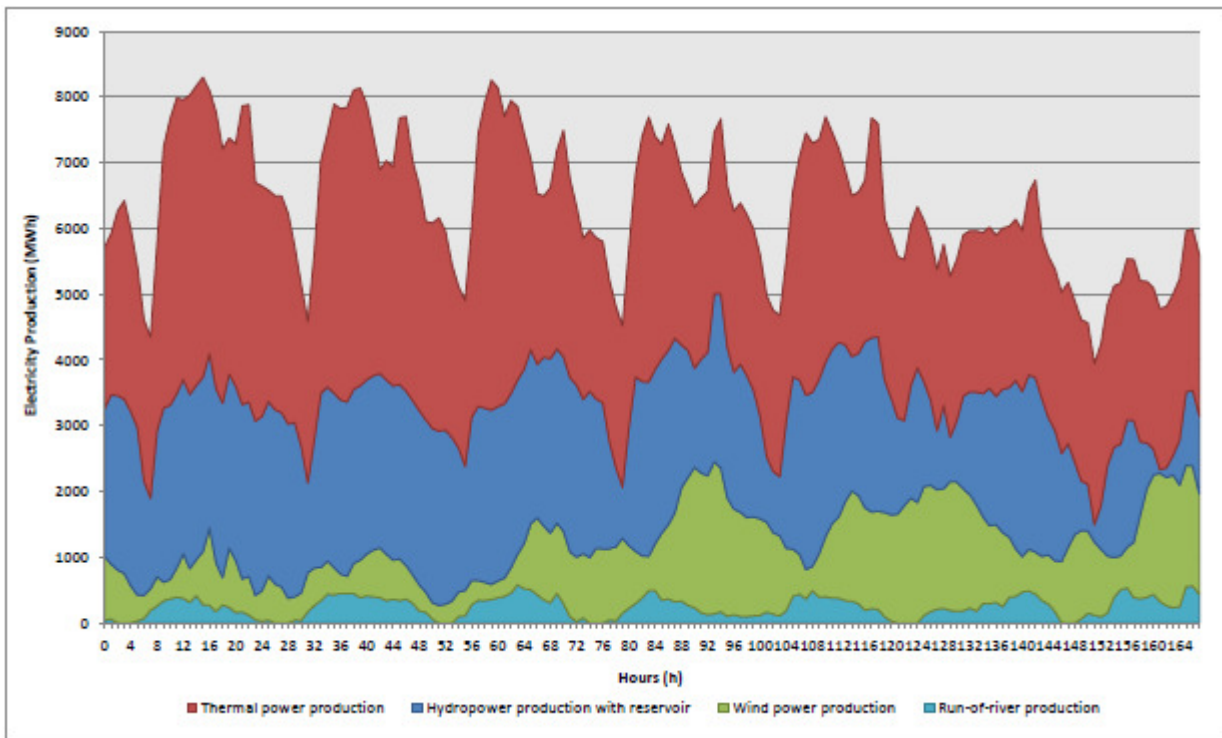*Figure A.1: Power units production for January (week planning).*

Figure A.2: Power units production for August (week planning).

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