Assessment of the benefits from advanced load & wind power forecasting in autonomous power systems

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ASSESSMENT OF THE BENEFITS FROM ADVANCED LOAD & WIND POWER FORECASTING IN AUTONOMOUS POWER SYSTEMS.

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ABSTRACT : In this paper, a methodology is developed to assess the benefits from the use of advanced wind power and load forecasting techniques for the scheduling of a medium or large size autonomous power system. The power system scheduling is optimised through a genetic algorithms based unit commitment model that simulates in detail start-up/shut-down procedures of the power units, ramp constraints, generation limits etc. Different types of forecasts are considered as input to the unit commitment model and the operation costs are estimated for each case. Emphasis is given to define appropriate simple forecasting models that can be used on-line. The performance of these models is used as reference to evaluate advanced techniques. The case-study of the Greek island of Crete is examined. A simple model is developed to explain in an intuitive way how the power system structure might attenuate the effect of inaccuracy in forecasts. Finally, the impact of forecasting accuracy on the various power system management functions is discussed.
KEYWORDS : Unit Commitment, Wind power forecasting, Load forecasting, Large autonomous power systems;

1. INTRODUCTION

Although the general operation rules are the same, isolated power systems, when compared to interconnected ones, present additional constraints in their operation.

Generally, in isolated systems, the grid is weaker and spinning reserve needs to be a greater percentage of the installed power (since there is no available help from a neighbouring system) while dynamic security problems are more likely to occur. When a high penetration from renewables, namely wind power, is foreseen, these problems increase, due to the volatility of the power source. In consequence, these systems tend to be managed in a conservative way, leading to an uneconomic operation that increases the already large costs of electricity in islands.

Short-term load forecasting is of primary importance for the efficient management of any power system. In the case of systems with high wind power penetration, as can be the case of isolated systems, forecasts of the wind power production are also required. In large systems containing steam units, scheduling is performed for horizons up to 48 hours ahead. Nowadays, an average prediction error up to ~3% is considered as typical for load forecasting in interconnected systems. However, wind power forecasting models have a significantly lower performance especially for long horizons. If wind power production is considered as “negative load” then, for a system with high penetration (i.e. >20%) it can be assumed that an equivalent high percentage of load is predicted with an error much higher than the typical value of "~3%".

This paper investigates the impact of forecasting accuracy on the various power system management functions. Emphasis is given to the unit commitment (UC) one since it is related to actions like connections or disconnections of power units and hence, it has a major influence on the operation costs of the power system itself.

In order to evaluate the power system operation costs an advanced unit commitment model is used based on the genetic algorithms optimisation technique [1]. The UC model is developed for on-line short-term scheduling of autonomous systems with various types of power units (steam, diesel, combined cycle, hydro, gas turbines, PV plants, wind turbines, etc.). The units characteristics as well as different operating strategies are modelled in detail.

Advanced forecasts are generated using fuzzy logic based models for each case of wind speed and load forecasting. Fuzzy modelling was found to outperform simple as well as other advanced techniques [2]. Linear ARMA models are also considered as an alternative.

The UC model together with forecasting models have been implemented in a pilot Energy Management System (EMS) for the scheduling of the power system of Crete (project JOULE III: CARE). The island of Crete is taken here as a case-study (peak load: ~300 MW, projected wind power: ~90 MW).

The use of an advanced EMS such as the one under development in the CARE project permits an operation closer to the limits, without jeopardising security. This is achieved mainly by using wind power forecasts based on frequently updated measurements, by on-line monitoring steady-state and dynamic security and by reviewing the unit commitment in a short period cycle.

The paper presents the methodology followed to evaluate the "cost" of forecasts inaccuracy. A detailed and realistic simulation procedure is developed that differentiates this work from similar in the literature [3,4]. A simple model is developed to describe in an intuitive way the impact of forecasts accuracy on operation costs.

The UC model is run for the case-study of Crete using simple, advanced as well as “perfect” (actual time-series) forecasts and the operation costs are evaluated for each case. Perfect and simple forecasting define a zone in which the performance of advanced models is situated.

2. WIND POWER AND LOAD FORECASTING

In this Section the performance of simple and advanced forecasting methods for load and wind power forecasting is analysed for the case study of Crete.

The performance of simple predictors is taken as the lower acceptable performance and is used as reference. The performance of an advanced method is expected to be between that of simple predictors and "perfect" forecasting. Given that it is interesting to evaluate operation costs as a function of different levels of forecasting accuracy one can apply Monte-Carlo techniques to generate pseudo-forecasts of varying accuracy. However, it is of primary importance to use also forecasts directly generated by an advanced model since such forecasts carry characteristics difficult to simulate (e.g. correlated errors according to the time-step).

Concerning load forecasting, hourly time-series of 4 years (1994-1997) have been used. The data up to 1996 were used for the estimation of the advanced models parameters, while the data of 1997 are used for evaluation purposes. The raw load data have been pre-processed to eliminate the effect of power cuts or black-outs.

The simple models considered here to predict load consist in taking the load of the previous day (Day-1) or the load of the same day last week (Day-7) as forecast. The "Day-7" model predicts better the load of Mondays and Sundays, while the "Day-1" model predicts better the rest of the days. A combined predictor according to the type of day has a MAPE (mean abs. percent. error) of 5% for the 1997 data. This performance can be defined as the maximum acceptable error by an advanced model to be worthwhile for on-line use. The "Day-1" model on its own has a 5.7% MAPE error. Advanced models based on ARMA and fuzzy modelling were found to have a performance between 1-5% depending on the time step and the type of model.

Concerning wind speed, a hourly time-series of Crete is also considered. The performance of persistence ("wind speed in the future will be the same as now") as well that of moving averages predictors is evaluated straightforwardly from the data – see Figure 1.

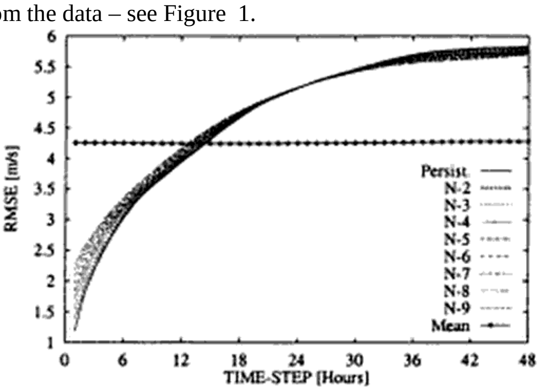

Figure 1 : *RMSE performance of persistence and moving average predictors for 48 hours ahead.*

Figure 1 shows the RMSE (root mean square error) performance of persistence and of simple predictors based on an average of *n* past values. Persistence outperforms any moving average predictor if it is used for an horizon up to 20 hours ahead. Between 21 and 48 hours ahead its use is either indifferent or not recommended since moving averages are outperforming.

An important issue is that from 15 up to 48 hours ahead neither persistence nor a moving average predictor can outperform the use of the ***mean-value*** of the time-series ($\overline{U} = 8.3$ m/s) as a predictor [RMSE($\overline{U}$)=4.29 m/s]. The improvement with respect to persistence as obtained by the *mean-val*ue predictor is between 1.6% for the 15^{th} hour ahead and 26.7 % for the 48^{th} hour ahead.

⇒ As a conclusion, for long-term horizons (15-48 hours ahead), an advanced method should outperform persistence by at least 1.5%-26.7 %, according to the time-step, to be worthwhile for on-line use.

⇒ Indeed, persistence should be used as a reference for a specific time-step k only if $RMSE_{persist.}(k)<\sigma_{data}$, where σ_{data} is the standard deviation of the time series. If not, the performance of an advanced method should be compared to the standard deviation.

In the short term (1-20 hours ahead), the advanced time-series models based on ARMA or fuzzy modelling provide an improvement between 1-13% w.r.t. persistence. For longer horizons ranging between 21-48 hours ahead the *mean-value* predictor outperforms the advanced time-series models. For such horizons, models based on meteorological information can be used if they provide an improvement w.r.t. persistence higher than 15-26.7% depending on the time step. Otherwise, it is always preferable to use the *mean-value* predictor.

The above analysis, although restricted to a specific wind speed time series, leads to the useful conclusion that different types of models should be used according to the time-step. When planning horizons are long (24-48 h), then combined forecasting approaches should be followed. A simple combined method is to use persistence for early steps and the *mean-value* for long steps. Similarly, a combined advanced approach can be to use time-series models in short term and meteorological information based models in long term. The combined approach provides optimal accuracy for the whole horizon and this is beneficial in short term for the planning of the fast units (diesel, gas turbines), as well as in long-term for the slow units (e.g. steam units).

3. THE UNIT COMMITMENT MODEL

In interconnected systems, unit commitment is usually performed off-line, typically with an horizon of about a week or two (moving window), with hourly time-steps. This gives the basis for performing the economic dispatch every 10 or 15 minutes, most of the times including also reactive power dispatch and perhaps security constraints related to major contingencies. In small isolated systems, on the other hand, a simple unit scheduling is usually necessary, due to the simplicity of the system, even when renewable power sources are present. The latter case was conveniently addressed in the control advice system of [5].

In medium-sized or large isolated power systems, however, a different approach is necessary, namely when there are different types of thermal units (steam and gas turbines, diesel units), hydroelectric units and dispersed plants that use wind, solar and other renewable sources. The problem is more stringent if we want to allow for a high penetration of renewables, whose generated power must be forecast and has some degree of uncertainty.

Trying to cope with these needs, economic operation is divided in a unit commitment function and a dispatch function that are performed in sequence, with an optional intermediate decision step that allows the user to take into account information produced by a fast security assessment module. In this scheme, necessary because forecasts have a strong influence in the overall generation schedule, the unit commitment module can no longer be an off-line process as it generally is.

The unit commitment module itself determines what generators will be on the grid in the next intervals, trying to optimise all the costs involved (running costs related to fuel consumption, ramping costs in thermal and diesel generators, shut down and start-up costs), while taking into consideration all the technical constraints (power balance, minimum down and start-up times, technical limits of generators, ramping limits of thermal units, maximum wind penetration, spinning reserve requirements, etc.). The module also produces a pre-dispatch, that is, an approximation of the set points of each generator or wind park. The unit commitment is run in two cycles; an "external" cycle with a period of four hours that aims to generate guidelines (end-of-period constraints) for an "internal" basic cycle run each 20 minutes. The external cycle is so designed to account for the slow units like steam generators. Thus, it considers an horizon of 48 hours ahead. The internal cycle considers an horizon of 8 hours ahead. The output of the internal cycle is a pre-dispatch operation scenario for all the power units in the next 8 hours. Economic dispatch is then performed for the next 20 min. period, in order to propose set points to the generators. The input to the two UC cycles and the economic dispatch are forecasts for load and wind power. The block diagram in figure 2 shows the overall scheme.

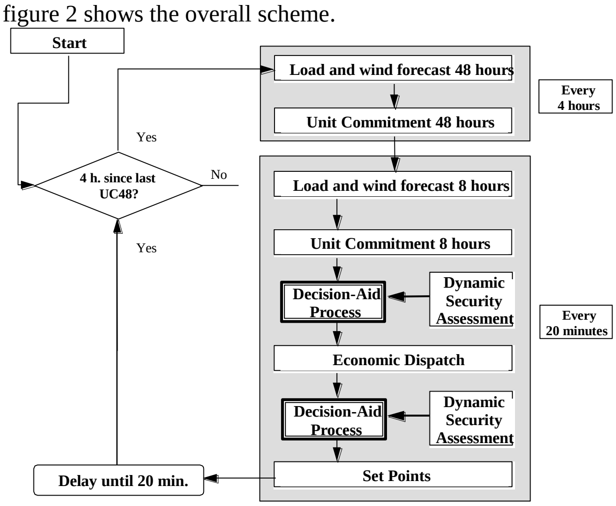

Figure 2: *General scheme of the Economic Operation Procedure*

4. ESTIMATION OF OPERATION COSTS

This Section describes the steps followed to simulate the power system operation in a realistic way in order to accurately estimate operation costs.

1.a) Definition of the power units operation schedules. The unit commitment model runs each 20 minutes using forecasted load and wind power values as input. At each time step t it produces a schedule $UC_{forec}(t)$ for the next 8 hours having an operation cost $F'_{forec}(t)$. The estimation of this cost is based on the *forecasted* load and wind power.

1.b) In real operation conditions the operators apply the proposed $UC_{forec}(t)$ schedule in order to cover the real load of the system. The real operation cost $F_{forec}(t)$ is thus calculated as a function of the real and not the forecasted load and wind power.

1.c) Over a long period T of time however, the total operation cost is not the sum of the $F_{forec}(t)$'s costs. This is due to the sliding window scheme considered here, which has the following particularity: each 20 minutes the operators receive advice on the actions to be taken in the next 20 minutes up to 8 hours ahead. It is obvious that consecutive schedules propose actions for periods that overlap. The operators will execute only the actions corresponding to the next 20 minutes, while for 40, 60, etc. minutes ahead they will wait for the updated schedules. It is thus assumed that the real operation cost will be the cost of the actions proposed at the first step of each schedule. The sequence of the "first step ahead" actions is denoted as UC^T_{forec}. The corresponding cost F^T_{forec} is estimated for the real load and wind power conditions (by a simulation of the power system operation in time).

2.a) The unit commitment program is run using "perfect" forecasts as input, that is, using the real load and wind power values instead of forecasts. As in step (1.a) a series of actions $UC_{perf}(t)$ (connections/disconnections of power units) are obtained for the next 8 hours. The operation cost is estimated as $F_{perf}(t)$.

2.b) As in step (1.c) the sequence of the "first step ahead" actions is denoted as UC^T_{perf}. The power system operation is simulated under the UC^T_{perf} series of decisions to estimate the operation cost F^T_{perf} of the system over a long period T.

3.) The economic impact over T is computed as the difference :

$$\textit{\textbf{Forecasting accuracy impact}}(T) = F^T_{forec} - F^T_{perf}.$$

The step 1 can be repeated for a number of different forecasting techniques having different accuracy. When simple techniques are used for both wind speed and load forecasting, then the operation cost is denoted as F^T_{simple}. The values F^T_{simple} and F^T_{perf} define an envelop where the cost of advanced methods should be located. The size of this envelope indicates the size of investment worthwhile to do on advanced forecasting techniques.

4.1 Operation costs vs forecasting accuracy.

This paragraph presents a simple model developed to explain the effect of the forecasting accuracy on operation costs. More specifically, the cost of spinning reserve is considered. The reasoning can be easily extended to include other types of costs like start-up/shut-down costs of units, loss of load costs in case of contigencies, etc. It is assumed that forecasting "inaccuracy" k takes values between 0 for accurate forecasts and 1 for erroneous ones. Let's suppose that the forecasting model provides a load profile F for the next planning horizon (e.g. 48 hours).

Taking into account accuracy, the real load of the system is $F\cdot(1\pm k)$. If the UC program considers forecasts as they are and schedules units to cover F, then there will be situations of excessive spinning reserve (when real load is near $F\cdot(1-k)$) or situations with lack of reserve (when load is greater than F). A different strategy is that the UC program schedules units to cover the worst case of a load $L^+=F\cdot(1+k)$. Then, there is no risk of lack of reserve but costs will be greater most of times without justification since load will be less than estimated $F\cdot(1+k)$. The fraction $k\cdot F$ acts indeed as a *required spinning reserve* to the unit commitment optimisation procedure. The nominal power of the units scheduled to operate in order to cover this load will be $P_N=L^+ + \varepsilon$, where ε is the spinning reserve due to the fact that P_N is a step function with values higher or equal than L^+. The value of ε depends on the system structure, that is on the size of the power units with respect to the system load. Now, if the real load in the system is $L^+=F\cdot(1+k)$, then the observed spinning reserve is $SR=\varepsilon$. In this case the forecasts inaccuracy does not involve a cost.

If the real load in the system is $L^{-}=F\cdot(1-k)$, then the observed spinning reserve is $SR=2\cdot F\cdot k+\varepsilon$. This last expression tells indeed that :

$$SR=f(\text{accuracy})+f(\text{system structure}).$$

The term depending on the system structure is related to the fact that the unit commitment function 'fits' a step process (connection/disconnection of units) to a continuous one, which is the load profile. It is evident that inaccuracy in forecasts is partly damped by a filtering effect.

Figure 3 depicts the above concepts. For simplicity, only the power of the peak units to be connected within the examined period is shown. From the figure it is evident that forecasting accuracy is critical in some regions of the load curve : at 06:00 and at 24:00 when the curve slope is steep. At that points the required reserve constraint may trigger the connection of additional units. The figure shows also that the spinning reserve term ε is high at certain periods and overweighs on the spinning reserve term that depends on the forecasts uncertainty. Certainly the situation can be different if one considers higher wind power penetration levels and higher uncertainty for wind power especially for longer time steps. However, the continuous update of forecasts and UC schedule (sliding window scheme) tend to correct decisions. For example, according to the figure, the UC advises the operators at 24:00 that they should connect five units at 06:00. As time will approach 06:00 these decisions will be updated using forecasts with higher accuracy due to the smaller lead time. This however would not be the situation if the examined power system had more slow (steam) than fast units (gas, diesel).

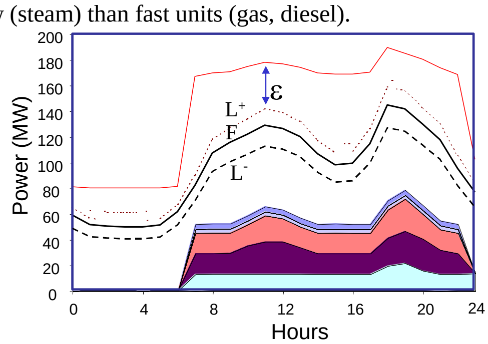

Figure 3 : *Unit commitment scheme for 24 hours ahead.*

5. CONCLUSIONS

This paper presented a methodology for the evaluation of the benefits from the use of sophisticated forecasting techniques in the case of autonomous systems. An advanced unit commitment model is used to generate realistic schedules for the power system operation and estimate properly related costs. For this purpose, it receives load and wind power forecasts in the form of intervals of uncertainty, instead of crisp numbers. Moreover, it adopts fuzzy constraints to accommodate uncertainty and risk. Specifically, fuzzy constraints for wind penetration permit to reach a compromise between potential risk and the reduced costs of increasing wind generation.

This methodology has been applied for the case study of Crete. The difference in operation costs for the cases of perfect and simple forecasting was found to be less than 1.5% for a projected wind penetration of 20%. The small value of this difference can be explained if one takes into account the arguments developed in the previous sections, especially on the system structure. Future stages of this work include a more detailed assessment by focusing on special load situations (extreme weather conditions, special days, etc.) and on important wind power variations (e.g. due to wind fronts). The benefits from the use of advanced forecasting and scheduling techniques will be also evaluated on-line following the installation of the CARE EMS system in Crete during 1999. This evaluation will focus also on management functions like economic dispatch and fast security assessment.

The economic dispatch function is performed for the first time step of the planning horizon. It produces set points for the generators based on the forecasted load and wind power values. In case of inaccurate forecasts the Automatic Generation Control device will try to establish optimal dispatch having as target bad forecasts.

The role of the dynamic security assessment function is to evaluate the degree of security of the proposed by the UC schedules. Security is checked against a number of pre-selected disturbances like a major wind power variation. Schedules that might result to large frequency excursions are rejected. When the UC output is evaluated as unsafe, the values of control parameters like the level of spinning reserve, can be properly adjusted and the unit commitment can be re-run to produce a new schedule. Inaccurate forecasts might lead to situations where excessive spinning reserve is allocated because the operation schedule is erroneously characterised as unsafe and inversely.

The impact of accurate forecasting has been examined here from an Energy Management System point of view. When an EMS is used as a decision support tool for the operators, forecasts are displayed through the man machine interface. The operator, using his experience, can assess visually if forecasts are in acceptable levels or not. If he is confident that they are acceptable he will be ready to follow the EMS recommendations. This would not be the case for “visually inaccurate” forecasts (especially for the peaks). Then, even if the implemented management functions are able to handle or "filter" inaccuracy and still produce economic solutions, the system operators would tend to reject them. Forecasts accuracy influences thus the acceptability itself of an EMS.

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