Security assessment of the results of the day-ahead electricity market, using a Monte Carlo power system simulator

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Abstract—Many variables are involved in the power system's reliability assessment, often affected by random events, such as load levels, wind speed and accidental failures of generating units or transmission lines. Furthermore, the presence of a competitive market, which schedules the hourly working point of the electric system, has to be considered and an effective calculation of the reliability level associated to the dispatching schedule defined by the market must be operated by the System Operator (SO) before the actual energy delivery. For this kind of problems, a probabilistic approach, based on sequential Monte Carlo techniques, can be more powerful than analytical methods. In the present paper, a simulation tool for calibrating the amount of generation reserve for the following day is described and analyzed, also discussing the results of a case study based on the IEEE RTS-96 test grid.

***Keywords*—**Electricity markets, Generation reserve margin, Monte Carlo simulations.

I. Introduction

Secure power system operations are a highly challenging task, nowadays even more complex with the advent of competitive environments. Electricity deregulation is in fact resulting in highly stressed networks, due to the utilization of the transmission system in a manner very different than that for which it was planned; the frequent changes in the origin and destination of the various commercial transactions implies a growing frequency of congestion situations. This trend, combined with the fact that power systems are continually subject to various disturbances, requires the extensive use of real-time control actions [1],[2].

In addition, an effective calculation of the reliability level associated to the dispatching schedule defined by the market must be operated by the System Operator (SO) before the actual energy delivery, in order to reduce real-time lack of capacity (or grid congestions) and consequent loss of load.

In a deregulated framework, the security assessment of the working point set by the Day-Ahead Market is one of the key points of the so-called "short-term operational planning". This activity, carried out by the SO during the afternoon before the energy delivery, is aimed at validating the physical feasibility of the results issued by the electricity markets, which operate with economic rules, basically neglecting the power system configuration [3],[4].

To ensure the system security for the following day, SO must not only verify the viability of power flows corresponding to the market results, but also guarantee some system services and, primarily, the availability of an adequate amount of power for primary and secondary reserve (spinning reserve) and an adequate level of power and energy for real-time balancing operations (tertiary reserve).

Up to now, in many power systems the required operating reserve margins have been calibrated using the first contingency security criterion (N-1), improved with simple heuristic corrections [5]; such an approach takes into account, separately, only some of the worst conditions that may happen in an electric system. This deterministic method is very simple to apply, but it neglects rare and multiple fault and does not consider the different likelihood of possible contingencies. From the other hand, since making available operating reserve margins has an obvious economic impact on SO and final customers, nowadays there is an increasing pressure to set the reserve margins in a proper way.

In order to solve the above mentioned problem, the use of probabilistic techniques has been proposed by the international literature of the last 10-15 years [5],[6]. However a comprehensive approach is still missing that considers in the same tool the generating park reliability, the failure rate of power lines and the possibility of unexpected variations of load or non programmable generating sources [7]-[21]. In fact, probabilistic simulators have focused either the balance between production and load, disregarding the transmission system ("single busbar" models) [10],[12],[14],[16]-[21], or have been devoted mainly to the grid operation, helping the SO to assess the probability of critical fault scenarios [9],[11],[13],[15].

In this paper, a more complete probabilistic method is proposed, taking into account all the contingencies that may happen to generators and lines in an electric power system and, most importantly, their combinations. With this new approach, the SO will be able not only to predict the actual requirements of power reserve, but also to understand the possible interaction between grid contingencies, generation outages and

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errors in load forecasting.

A simulation method based on a sequential Monte Carlo technique is proposed and described. A case study relevant to the IEEE Reliability Test System (RTS96) is shown and discussed; the test grid is divided into three areas linked by interconnection lines, but the proposed model is independent on the number of considered areas, because it can take under control all the lines of the grid.

II. Problem formulation

This study aims at evaluating the system reliability as a function of power margins and balancing reserve amount, also investigating the impact of possible re-dispatching rules during contingency and emergency conditions. For this purpose, a simulator of the complete daily operation of a large electric system is required [22]. Using such a tool, a System Operator will be able to assess the security of the production and consumption power profiles set by the energy markets, also realizing a sensitivity analysis of the system reliability, as a function of a large set of parameters and variables: the secondary and tertiary reserve margins, the transmission system power flow limits, the management rules of pumped-storage plants, the merit order criteria for the activation of reserve units, the dispatching rules during contingency and emergency conditions, the volatility of load and non-programmable renewable energy sources, like wind and solar power stations [23],[24],[25].

More in details, starting from the results of the electricity markets (Day-ahead and Ancillary Service Markets) such a tool could be used by the SO:

- to allocate adequate margins of secondary and tertiary reserve in a further session of Ancillary service Market, in order to ensure a predefined level for risk indexes (Loss Of Load Probability, Expected Energy Not Served);
- to schedule load shedding procedures for the following day, if the reserve margins selected by the markets are not enough to guarantee an assigned level of reliability;
- to set the power flow limits to be allowed by SO on the transmission lines;
- to optimize the use of particular kinds of reserve units, such as pumped-storage plants;
- to optimize contingency and emergency procedures;
- to define objective criteria for their activation, in particular in case of severe contingencies, which require “normal” market rules to be temporarily suspended.

III. Probabilistic methods and Monte Carlo techniques

The problem of simulating the daily operation of a large electric system is very complex, because system adequacy, reliability and security are influenced by random events, such as the outages of generators and transmission lines, as well as errors in load forecasting. Moreover, the problem solution is strongly affected by operational policies, such as load-shedding rules or the management of pumped-storage plants.

In this case, the use of a probabilistic method is required, because the precision obtained with a deterministic tool would be too influenced by the ability of the operator to define a pre-definite set of realistic contingencies [5],[21].

In particular, the complexity of the problem suggests that a simulation method based on a sequential Monte Carlo technique [26] could be more powerful than analytical probabilistic methods. In fact analytical methods, which use a closed-form mathematical solution to calculate risk indexes, can be adopted only for very simple systems. Monte Carlo simulation methods, in the other hand, estimate the reliability indices by simulating the actual process and random behavior of the system; the method, therefore, treats the problem as a series of real experiments.

In both cases, a set of system states must be generated. The main difference between the two methods is that in the analytical method all system states must be generated and associated *a priori* to their likelihood, whereas in the Monte Carlo simulation method a random subset of all possible system states is drawn [27].

A Monte Carlo method offers many advantages; some of the most important are the following:

- it makes the analysis of complex systems possible without forcing the system model to become unrealistic;
- it constitutes a tool for allowing an easy modification of the number and characteristics of input random quantities;
- it offers the opportunity to include any random variable, as well as operation policies similar to the real ones;
- with this method, complex mathematical formulations are not required.

In a sequential Monte Carlo technique, like the one proposed in the present study, the system operation during a specified day is investigated using repeated daily simulations, each consisting of an ordered sequence of 96 quarters of an hour. During each period of 15 minutes, the behavior of the system depends on the components presently available and on the previous events. The greater the number of daily cycles, the higher the precision of calculated costs and risk indexes.

At each time step and for each component, a random number A, uniformly distributed between 0 and 1, is drawn. The state of that component at the following time step is than calculated as follows:

$$\text{If } S(t)=1\text{: if } A<\lambda,\ S(t+\Delta t)=0, \text{ else } S(t+dt)=1 \quad (1)$$

$$\text{If } S(t)=0\text{: if } A<\mu,\ S(t+\Delta t)=1, \text{ else } S(t+dt)=0 \quad (2)$$

where:

- $S(t)$ is the state of the component at time t; S=1 means available, while S=0 means unavailable;
- $S(t+\Delta t)$ is the state of the component at the subsequent time step;
- A is the number drawn by the Monte Carlo procedure;
- $\lambda = 1/MTTF$ is the Failure Rate of the component;

- μ =1/MTTR is the Repair Rate of the component;
- MTTF is the Mean Time to Failure and MTTR is the Mean Time to Repair of the component;
- MTTF and MTTR are expressed in a unit of measurement coherent with the used time step; for example, in hours if the time step is one hour.

This procedure settles the availability of each component at any time step. In an electric system, this technique can be applied to simulate contingencies, such as the failure of generators or lines, as well as unpredicted variations in load or wind speed. At each time step, the simulator verifies the state of each component and summarizes three possible system conditions:

a) each generator produces the scheduled energy and the load is fully supplied, since no fault occurred;
b) due to contingencies, the generating reserve must be activated to restore the balance between production and load or to solve grid congestions;
c) due to an under sizing of the generating reserve or to a chain of severe events in the previous time steps, actions at point b) are not enough to restore the power balance and a share of the load must be shed to avoid line cascading or a black-out.

Typically, load shedding can be due to two main reasons:

1) on account of its size or response time, the generating reserve is not able to fully supply the load ("lack of capacity");
2) the generating reserve supplied by the thermoelectric power stations is fully exploited; the pumped-storage generating units are potentially able to work for balancing service, but, due to repeated emergencies in the previous hours, their reservoir is empty; the energy required for unplanned re-pumping operations cannot be purchased until the next market session.

Several daily cycles show the system's extreme and average behavior, in terms of risk indexes.

IV. The Electric System Model

The model refers to a hydro-thermoelectric system, that can be considered as constituted by more areas, linked by interconnection lines. The zoom of the analysis is anyway the single-path detail (interconnection or intra-zonal lines). In our model, only active power and energy are taken into account; network power losses are not explicitly considered, being added to the load.

The model takes into account the following main structural data:

- each generation plant (conventional steam units, Gas Turbines, hydro units, pumped-storage plants, CCGT);
- the hydro reservoirs connected to power plants;
- all the transmission branches;
- the load forecasting accuracy.

A. Thermoelectric units model

A thermoelectric unit may be a conventional steam plant, a CCGT unit or a GT unit. Each plant is characterized by minimum and maximum power output, increasing-decreasing power ramps, availability indexes (MTTF, MTTR) and start-up times.

B. Hydro plants model

Each hydro plant belonging to an assigned market zone is connected to an equivalent zonal reservoir; each generating plant is characterized by minimum and maximum power output and availability indexes (MTTF, MTTR).

C. Pumped-storage plants model

Each pumped-storage plant is characterized by a power range, consumption during pumping operations, process efficiency, availability indexes (MTTF, MTTR) and water capacity of the reservoir which the plant is connected to (each plant has its own basin).

D. Lines model

A DC load flow is operated to evaluate the loading of each line in service. Two different power flow limits are defined; the first refers to the steady-state conditions; the second, higher, is relevant to the overload that the line can support for a maximum of 15 minutes with contingency and emergency conditions.

Lines can be out of order, according to a probabilistic model described by MTTF and MTTR parameters.

E. Load model

The nodal load, detailed for each quarter of an hour, is modeled with a probability distribution, whose average value depends both on the load forecasted value and the forecasting errors experienced in the previous time steps; the standard deviation of the probability function is not constant during the 24 hours, due to the higher load uncertainty in particular moments of the day (e.g. sunrise and sunset).

V. Simulation of the System Operation

With regards to the operation of the simulated electric system, the following hypotheses have been assumed:

- the simulation is extended to a single day (24 hours) and the time step is a quarter of an hour (15 minutes);
- the forecasted dispatching of the generating park is known from the Day-Ahead Spot Market, as well as the merit order list of the units selected in the Ancillary Service Market;
- the simulation is carried out considering sequential steady state conditions; this means that all the dynamic behavior of the system from a generic time step to the subsequent is neglected;
- the model takes into account that load can be dropped during emergencies in the following different ways:
  - the use of under-frequency relays, preset to drop pumped-storage units in pumping operation;
  - the disconnection of interruptible loads, that can be manually carried out by SO control room or automatically activated by a programmable protection system;

  - the application of an automatic load shedding program, designed curtail shares of the loads at predefined under-frequency thresholds;
- the power flows across the lines are evaluated by means of a DC power flow algorithm;
- the events relevant to units outages, lines faults, unexpected load variations happen at the beginning of the considered time step;
- after a contingency and during emergency conditions, generating units can modify their scheduled production, according to their increasing/decreasing power ramp.

The operation of the system can be simulated for different values of operating reserve margins, calculating the following risk indexes:

- Expected Energy Not Served (EENS);
- Loss of Load Probability (LOLP).

This choice gives the SO a tool to check the influence of reserve margins on system reliability and to evaluate the costs deriving from the power for reserve and from the energy for real time balancing.

The system operation has been divided into three steps: normal operation, contingency or emergency operation and re-dispatching operation.

A. Normal operation

At the beginning of each time step (15 minutes), a Monte Carlo drawing, regarding the present state of the generation units and of the interconnection lines, is performed. If there are no generators or lines outages and if the drawn value of load is close to the forecasting within a predefined error, the normal operation is performed according to the dispatching of the energy market, otherwise contingency or emergency procedures are activated.

B. Contingency or emergency conditions

The operation after a contingency or during emergency conditions is performed according to the following operating rules:

- if at the present time step the unexpected failure of a generator occurs, the power not delivered is substituted by the operating reserve of the units in service and, in case, by an adequate number of units able to start up in 15 minutes (non-spinning reserve units); these units are activated by the SO according to the merit order list defined by the Ancillary Service Market;
- if some of the interconnection lines, during the 15 minutes considered, are overloaded due to generators and/or interconnection lines faults, the system is re-dispatched by the SO according to the list of the units selected in the Ancillary Service Market;
- when a severe contingency affects the generation or the transmission system and the demand cannot be fully served in secure conditions, pumped-storage units, interruptible customers or diffuse load can be shed by under-frequency relays or by specific protection systems, activated by exceeding power flows across transmission lines.

C. Re-dispatching operation

During this procedure, that can require several time steps to be performed, the secondary reserve regulating band is restored. The system is re-dispatched by means of balancing operations, which increase the production of the cheaper units and decrease the production of the most expensive ones, possibly turning off the non-spinning reserve units put in service during step B. All units are re-dispatched according to the merit order of the Ancillary Service Market. This dispatching is valid till the end of the day. This re-dispatching operation is performed also to modify the hourly production produced by the errors between the hourly forecasted load and the correspondent drawn load. All the operations are performed avoiding any possible overload on the transmission grid.

Since the simulation is carried out considering sequential steady state conditions, in the considered quarter of hour only the overall effects of the secondary reserve are taken into account, while the primary regulation can be neglected because it is substituted by the secondary reserve as soon as possible, within the current time step (15’). The power produced by the units under secondary regulation is proportional to the band they have been awarded on Ancillary Service Market and it is independent on their zonal location.

About the tertiary reserve, two different types of dispatching procedures are possible:

- dispatching in contingency or emergency conditions, operated in the same time step of the contingency and typically obtained by non-spinning hydro and pumped-storage units; this procedure is carried out in order to eliminate overloads across lines;
- standard reconstitution of secondary reserve margins, operated in the following time steps and generally obtained by non-spinning thermal units (typically gas turbines) or spinning conventional steam plants operating below their rated power.

All the above mentioned operations are carried out at minimum cost by means of an OPF, according to the merit order list defined by the Ancillary Service Market and taking into account the technical constraints corresponding to the transmission and generation system (maximum power flows across lines, start-up times and power ramps of production plants).

VI. The Simulator

The model previously described has been implemented in an application program, that simulates the normal, contingency and emergency conditions of the electric system.

In Fig.1 the main flow chart of the simulation software is reported. Such a picture shows the existence of a first external loop, aimed at simulating several times the day under investigation (100 times in the example), as required by the Monte Carlo approach. The internal loop corresponds to the 96 quarters of an hour composing the day.

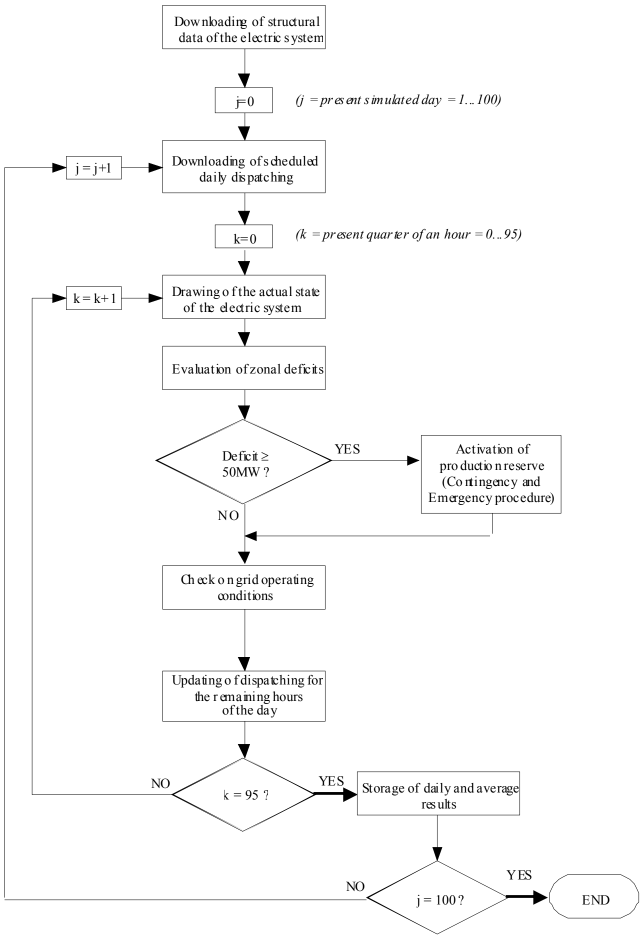

Fig.1 – Main flow chart of the power system simulator

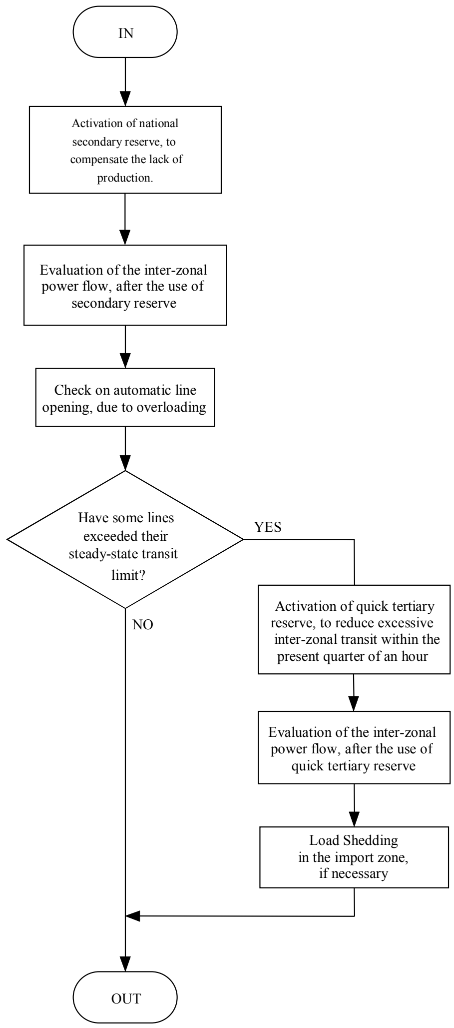

Fig.2 – Activation of generation reserve (Contingency and Emergency procedure)

The structural data, updated only once at the start of the program, refer to the technical specifications of the grid and the generation system.

The scheduled daily dispatching derives from the clearing of the Day-Ahead Energy Market and Ancillary Service Market. For each quarter of an hour of the simulated day, the following data are assumed as an input by the simulator:

- generation schedules, secondary and tertiary reserve margins of each generating unit;
- forecasted load for each load bus;
- scheduled state of each transmission branch;
- merit order lists and prices for up and down regulation defined by the Ancillary Service Market.

According to the Monte Carlo method, for each time step the actual state of the electric system is drawn: actual load, plant outages and line faults. If the lack (or excess) of power consequent to units outages and/or errors in load forecasting exceeds a predefined threshold, the production reserve is activated, following the Contingency and Emergency Procedure reported in Fig.2. The aim of this procedure is to make the state of the electric system secure in the current quarter of an hour; further procedures will be focused on system security for the following time steps.

As shown in Fig.2, assuming the system primary regulation to have already restored the energy balance between generation and loads, the secondary reserve is automatically activated; the power increase/decrease issued by the units under secondary regulation is proportional to the band they have been awarded on Ancillary Service Market and it is independent of their zonal location. The consequent power flows on inter-zonal and import links are updated; line tripping is possible due to overload. If any remaining line exceeds its steady-state transit limit, the quick tertiary reserve (hydro, pumped-storage and gas turbines plants) of both interested zones is activated for an equal amount but opposite directions, in order to reduce the transit; the activation order depends on economical merit order lists defined by the Ancillary Service Market, taking into account geographical, rapidity and capability constraints. If such an action is not able to restore a secure working condition in the present quarter of an hour, in order to avoid line cascading a manual load shedding procedure in the import zone is activated and an equal amount of decreasing quick tertiary reserve in export zone is required.

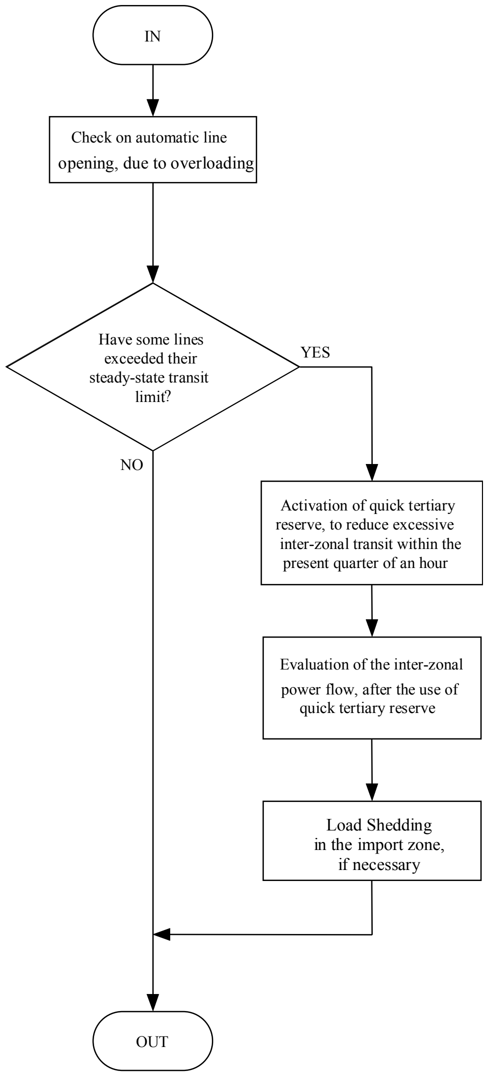

Fig.3 – Check of grid operating conditions

As pointed in Fig.1, even in the absence of a significant difference between production and load (that means no generating unit outages and a small error in load forecasting) the software verifies the grid operating conditions, in order to manage possible grid faults and avoid cascading failures (Fig.3).

The state of the electric system being secure for the current quarter of an hour, a specific procedure operates the re-dispatching of production units for the following time steps. Such a procedure aims at restoring the secondary reserve regulating band and substituting the quick tertiary reserve (hydro, pumped-storage plants, GTs) with slower but cheaper plants, like spinning conventional steam units.

The system is re-dispatched by means of balancing operations, which increase the production of the cheaper units and decrease the production of the most expensive ones, possibly turning off the non-spinning reserve units put in service during contingency and emergency procedure. All units are re-dispatched according to the economic merit order set by the Ancillary Service Market.

As shown in Fig.1, before the following daily simulation, the main results are stored, focusing on EENS and most significant occurred contingencies, like outages of big power plants, cascading failures and system separation. At the end of the simulation, the output file shows both the average and the possible extreme behaviors of the electric system during the day under investigation.

VII. The Case Study

The proposed method has been applied to the IEEE 96-Bus Reliability Test System (RTS-96). The detailed system data can be found in [28]. Such a system is composed by 96 generating units (18 hydro plants and 78 thermoelectric plants), 51 bus-bars and five interconnection lines. The system peak load is about 7200 MW and the total installed generation is 9400 MW. The topology for RTS-96 is shown in Fig. 4.

The system is assumed to have a load profile corresponding to the 90% of the yearly peak. The generation dispatching (resulting from the day-ahead energy markets) has been calibrated by the authors respecting the first contingency security criterion (N-1). Considering the load, Area C imports energy from Area A and B. In order to stress the transmission system, the original RTS-96 network has been slightly modified; in particular, the MTTF of Line CB-1 has been decreased.

For the simulations, a time step of a quarter of an hour has been adopted. The analyzed day has been simulated 1000 times according to the Monte Carlo procedure (the computational time is about 6 minutes on a 3-GHz Pentium PC), obtaining the following average results: the balancing energy provided by the III reserve is about 1930 MWh (1.3% of the served load) and the EENS is around 20 parts per million.

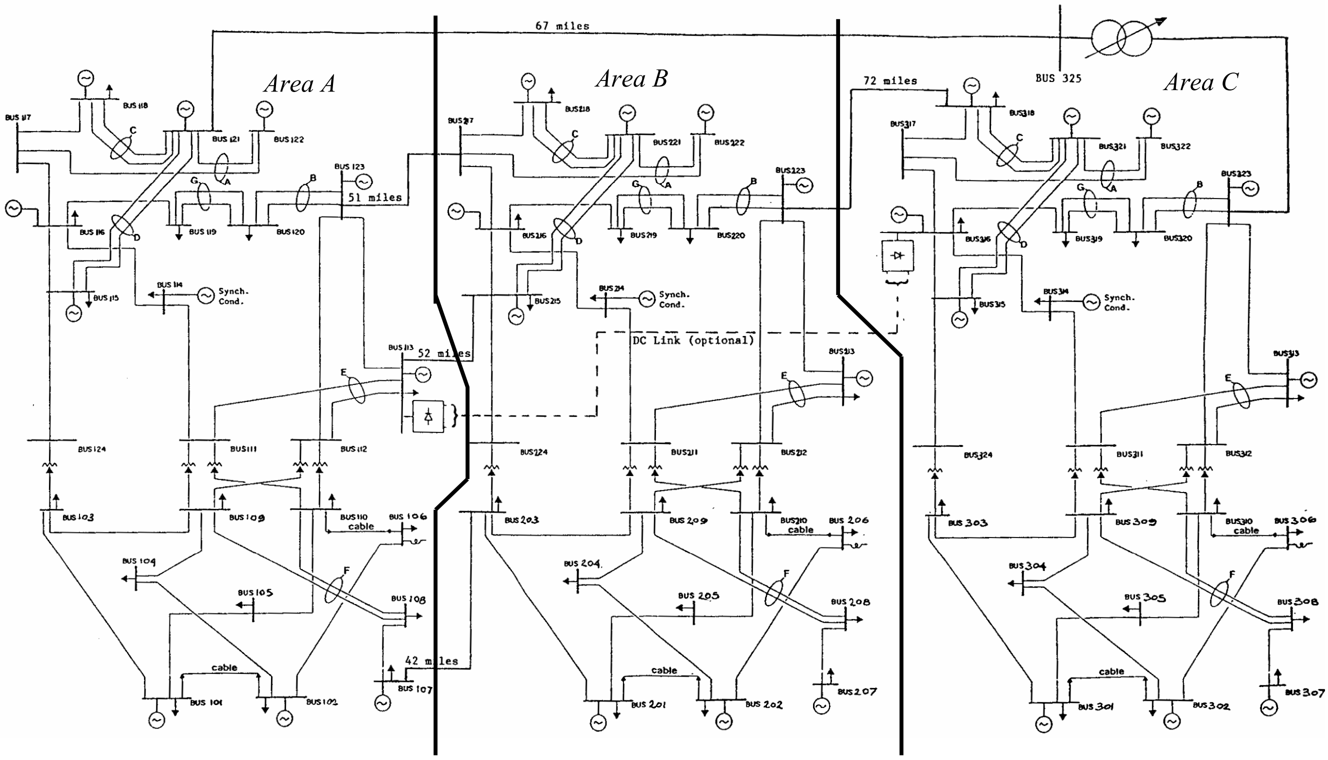

Fig.4 - IEEE RTS-96 power system

The following considerations refer to the less reliable simulated day, when the following events happen:

- 04.30 A.M.: unit outage (Area C; loss of 80 MW)
- 01.30 P.M.: unit outage (Area A; loss of 65 MW)
- 03.00 P.M.: line outage CB-1 and inter-zonal congestion (line CA-1)
- 09.45 P.M.: unit outage (Area A; loss of 10 MW)
- 10.15 P.M.: large unit outage (Area C; loss of 300 MW) and interzonal congestion (line CA-1)
- 11.45 P.M.: unit outage (Area C; loss of 60 MW)
- 11.45 P.M.: interzonal congestion (line CA-1).

The secondary reserve actually activated by SO (vertical bands), compared to the available amount, is shown in Fig. 5; its trend depends on production units outages and differences between forecasted and actual load.

Fig. 6 shows the use of tertiary reserve. It is interesting to remark that, watching at the sign of the reserve activated in the three areas, it is possible to discriminate inter-zonal congestions from outages of production units. As a matter of fact, after a unit outage or an unexpected load variation, the secondary reserve is activated in the present quarter of an hour; balancing units provide the tertiary reserve in the following time step, up to complete reconstitution of secondary reserve margins; in case of an inter-zonal congestion (line overloading), tertiary reserve is activated, aimed at eliminating the line overloading within 15 minutes.

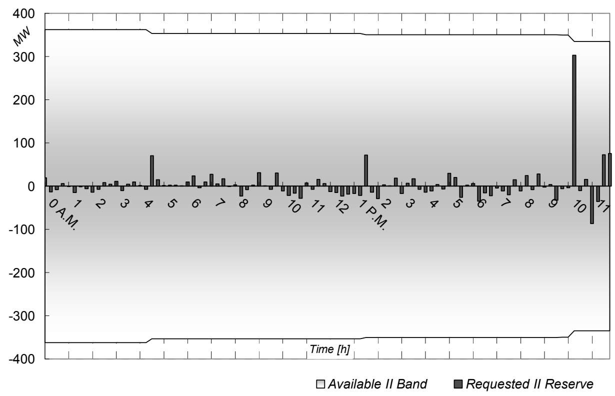

Fig. 5 - Use of II Reserve in the less reliable simulated day

Before 4.30 A.M., no unit outage occurs and the error in load forecasting is small. The event at 4.30 causes a lack of production in Area C and a corresponding use of secondary reserve.

Tertiary reserve in Area C is generally more expensive than both Area A and B; therefore, if no specific network constraint is activated, Area C reserve is commonly activated to reduce local generation and Area A/B reserve is activated to increase the production. The secondary reserve is uncharged within 2 quarters of an hour. Similarly, a lack of production at 1.30 P.M. requires secondary reserve; tertiary reserve is activated mainly in Areas A/B.

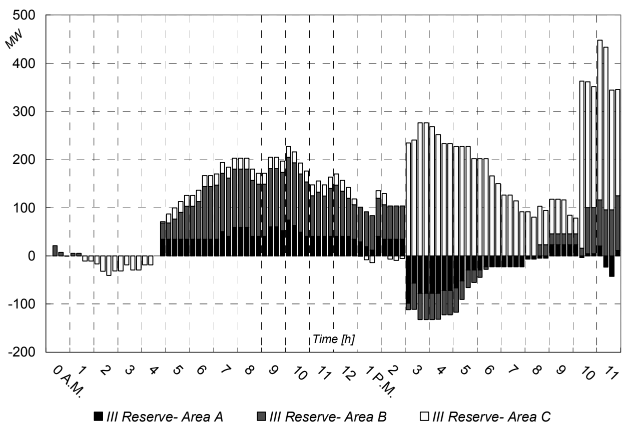

Fig. 6 - Use of III Reserve in the less reliable simulated day

It is interesting to observe in Fig. 7 that after 6.30 A.M. the difference between actual and forecasted load is always positive till 10.45 A.M.. Thus, the requested tertiary reserve increases its value, due to the superposition of error in load forecasting and lack of generation at 4.30 A.M.

At 3.00 P.M., path CB-1 connecting Area C with Area B, goes out of service, causing a congestion (line CA-1). Fig. 8 shows CB-1/CA-1 power flows. The re-dispatching requires the intervention of tertiary reserve in the present quarter of an hour and all areas are involved in the power shifting (see Fig. 3). In order to avoid line cascading, even thought cost is high, Area C tertiary reserve is activated up to ≈+230 MW and Areas B/C reserve is decreased to ≈-120 MW.

Due to both merit order list of Ancillary Service Market and the reduced margins in Area C, each production outage ends up by increasing the power flow on lines CA-1/CB-1, up to congestions (Fig. 8). In fact, at 10.15 P.M. a lack of production of 300 MW occurs in Area C; it causes a line overloading (CA-1) and consequently a load shedding of 20 MW in Area C, due to the lack of quick tertiary reserve in the present quart of an hour.

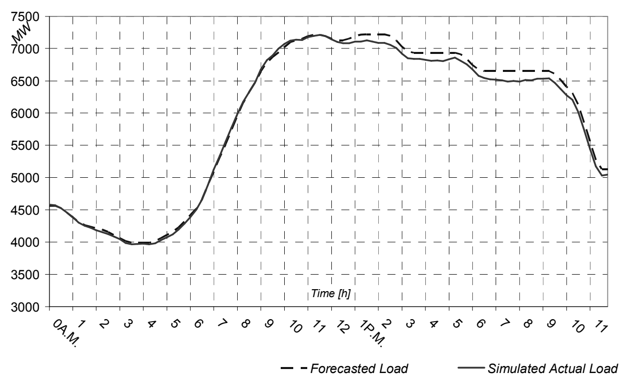

Fig. 7 - Load profile in the less reliable simulated day

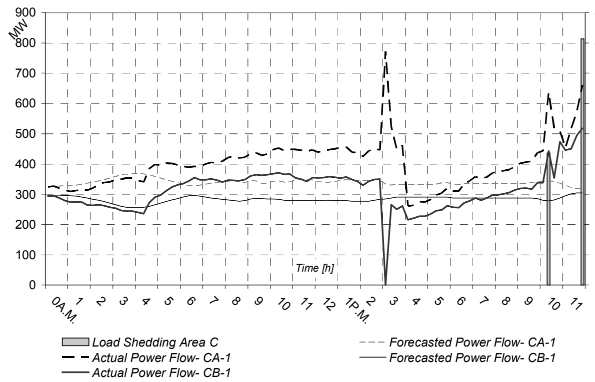

Fig. 8 - Power flows in the less reliable simulated day

Both in the event at 10.15 P.M. and at 11.45 P.M., it can be remarked that load shedding and inter-zonal lines power flows are strictly related. As matter of fact, the event at 11.45 P.M. causes an additional lack of production in Area C, with a consequent load shedding in Area C (about 40MW).

VIII. CONCLUSIONS

Monte Carlo procedures, largely used in the past to assess the reliability of vertically integrated systems, are still very useful also in deregulated frameworks. The tool here proposed results to be able to help the System Operator to evaluate, at the end of the day-ahead markets, how the setting of generation reserve margins can affect the amount of Energy Not Served expected for the following day. This method can be used to calibrate the reserve margins corresponding to a preset adequate security level, as well as to optimize the operating procedures used by the System Operator for real time balancing.

The discussed case study, based on the IEEE test grid (RTS-96), shows a strong correlation between the load shedding procedures and the grid congestions, since the load curtailment is often due to transmission constraints, rather than to the generation reliability.

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