# A new technique for short-term reliability assessment of transmission and distribution networks

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***Abstract*— This paper proposes a new methodology for short-term (24 hours) reliability assessment of transmission and distribution networks, including detailed substations models. Substations are first considered as single electrical nodes to evaluate the reliability of delivery nodes. If nodes (substations) with a high LOLP (Loss of Load Probability) are identified in this preliminary analysis, the critical substations are modeled in detail to obtain the corresponding reliability indices with a higher accuracy, especially the indices corresponding to delivery points (feeders). The proposed methodology includes a topological analysis module similar to the topological processor used in State Estimation, a DC Load Flow, a DC-OPF module to compute remedial actions, and a reliability evaluation module based on state enumeration. The proposed approach is flexible and easy to implement, and special efforts have been made to reduce the computational requirements and to present the results in a way appropriate to both operators and planning engineers.**

## I. Introduction

Power system reliability has traditionally been a by-product of standard design practices and practical solutions to historical problems. Nowadays, reliability assessment is one of the most important topics in the electric power industry due to its impact on the cost of electricity and its high correlation with customer satisfaction. Reliability must be planned, designed, and optimized with regard to cost [1].

Although there is general agreement that power quality includes reliability, the boundary that separates both concepts is not well defined. Reliability primarily relates to equipment outages and customer interruptions [4], and, consequently, it is a subset of the power quality issues.

Most of current reliability assessment programs are only suited to centrally planned and operated generation, transmission and distribution systems. However, because of the increased number of players in the energy supply industry, the existing reliability assessment techniques must be adapted to the new organization [8]. In this paper, a new technique that focuses on the reliability assessment problem faced by transmission and distribution facilities is described.

The electrical topology of transmission and distribution networks is determined by bus connections, disconnectors, circuit-breakers and fuses. Together, these components determine the electrical bus configuration of distribution substations, and the resulting electrical nodes. A large number of possible substation configurations exist, being an important issue in substation reliability, operational flexibility and cost. In normal operating conditions, all the equipments are available and all the customers are energized. Unscheduled and scheduled events disrupt normal operating conditions and can lead to outages and interruptions.

In the field of switchgear and substations, a large amount of publications have been presented evaluating the reliability of many substation schemes in use. Different methods are applied and often the results are difficult to compare.

Many probabilistic techniques are now available in the form of computer software for reliability analysis, and most of them include detailed substation schemes. However, the information required to perform a reliability evaluation including detailed substation models is difficult to obtain and computation times are neither suited to on-line use nor to the short-term power system reliability evaluation.

This work describes a new methodology for the short-term prediction of transmission and distribution reliability indices, including detailed substations models when needed [10]. This new methodology includes a Topological Analysis module to obtain the electrical topology of the network whenever a change of topology is detected in short-term use or contingency evaluation. A DC Power Flow module is used to identify overloads, using a DC-OPF module to obtain remedial actions. These modules are part of the reliability assessment program based on state enumeration. The Topological Processor is used in the Statistical Evaluation of system states, in the same way as in State Estimation.

This new technique is suited to short-term power system reliability evaluation, and can be used both in planning and operation of electric power systems, providing a more complete assessment than the common N-1 Security Analysis. The reminder of the paper is organized as follows: Section 2 summarizes the approach used to evaluate system and supply point reliability indices. Section 3 describes the test system, and some preliminary results are presented. Finally, Section 4 presents some conclusions derived from this work.

## II. Reliability Assessment

Two main approaches are used for reliability assessment of transmission and distribution systems: State Enumeration and Monte Carlo Simulation [2] [4]. The main difference between the two approaches is the selection of states, and, consequently, the way adequacy indexes are evaluated.

In state enumeration approaches, states are selected in an increasing order of contingency level, stopping the process when the probability of the remaining states becomes negligible. On the contrary, in Monte Carlo approaches states are selected using random numbers so that the states having a greater probability of occurrence are more likely to be simulated. The process is usually stopped after a fixed number of simulations, and the adequacy indexes are obtained by averaging the indexes corresponding to individual simulations.

The state enumeration approach has been used in the proposed technique in order to reduce computation times, taking into account that a reduced system model is used in a first, preliminary analysis. Consequently, system states are selected in an increasing order of contingency level, stopping the process when the probability of the remaining states becomes less than a pre-specified tolerance.

### A. Component states

In order to understand the effects of substation component failures on the system performance, it is necessary to study station component outage processes.

The usual method to represent a component in discrete states is the continuous Markov process. This is a specific stochastic process that is independent of all the past states except the immediately preceding one. The probability of failure or repair for a fixed interval of time is constant in a continuous Markov process. An example for a two state system is included in Figure 1.

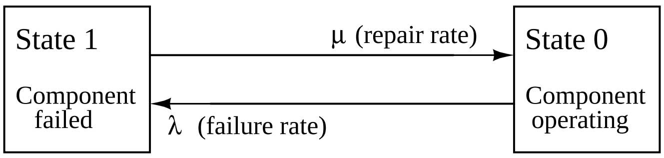


Fig. 1. Two-state space diagram of a component.

A system component may also be removed from service due to another component outage. If a component is removed from service due to failures in other external devices, then the time required to bring the component back into service is known as the switching time. The steady state probabilities of residing in the operating state, “State 0”, and in the failed state, “State 1”, are designated as P0 (availability) and P1 (unavailability) respectively. The P1 probability is also called Forced Outage Rate (FOR).

### B. Contingency probabilities

In the classical reliability theory, the time of failure $\tau$ of a given piece of equipment is modeled as an exponentially distributed random variable [6] [7]. In the proposed approach, contingencies may include the loss of several components at the same time but contingencies composed of non-simultaneous failures are not considered. The probability $p_0$ that none of the pre-selected contingencies occur during the scheduling horizon $T$ is calculated as

$$p_0 = \prod_{k=1}^{K} e^{-\lambda_k \cdot T} \tag{1}$$

where the parameter $\lambda_k$ represents the reciprocal of the mean time to the occurrence of contingency $k$, a quantity estimated from historical data.

Besides, since repair times are usually longer than the 24-hour scheduling horizon, repairs are ignored, i.e., should an equipment fail, it will be assumed to be unavailable for the remainder of the horizon.

In consequence, $p(k,\tau)$, the probability that contingency $k$ occurs during the interval $\tau$ given that all other system components are available is

$$p(k,\tau) = e^{-\lambda_k \cdot \tau} \cdot (e^{\lambda_k \tau} - 1) \cdot \prod_{z \neq k} e^{-\lambda_z \cdot T} \tag{2}$$

Note that in deriving the above probabilities, the pre-selected contingencies are assumed to be statistically independent, and, since this set is not exhaustive, the probabilities $p_0$ and $p(k,\tau)$ sum to a number less that one.

### C. Failure and Repair Time

Collection of station component outage data (failure rate and repair rate) is an important and necessary activity for the reliability evaluation [1] [2].

Equations (3) and (4) are usually used to calculate the probabilities P0 and P1:

$$\text{P0} = \frac{\text{MTTF}}{\text{MTTR+MTTF}} \tag{3}$$

$$\text{P1} = \frac{\text{MTTR}}{\text{MTTR+MTTF}} \tag{4}$$

where

$$\text{MTTF} = \text{Medium Time To Failure} = \frac{1}{\lambda} \tag{5}$$

$$\text{MTTR} = \text{Medium Time To Repair} = \frac{1}{\mu} \tag{6}$$

Tables I and II present the relevant reliability parameters [9] of the power system analyzed in this paper. Only active failures associated with station equipment have been considered because the methodology proposed in this paper assumes that the passive failures are known in advance and adequate corrective actions are programmed.

Substation failure assessment is highly dependent on the component outage data, and therefore the collection of substation component outage data is an important task. However, nowadays many utilities do not collect historical outage data in the correct form yet. In consequence, these important data must be usually obtained from technical reports or application articles [8].

TABLE I
COMPONENT FAILURE DATA: LINES AND GENERATORS

| | XL (pu) | Rating (MW) | MTTR (h) | MTTF (h) | FOR (pu) |
|---|---|---|---|---|---|
| L#01 | 0.1274 | 183.00 | 10.00 | 5837.9 | 0.00171 |
| L#02 | 0.1560 | 131.00 | 10.00 | 8761.9 | 0.00114 |
| L#03 | 0.0075 | 183.00 | 10.00 | 2178.2 | 0.00457 |
| L#04 | 0.1253 | 183.00 | 10.00 | 5837.9 | 0.00171 |
| L#05 | 0.0094 | 146.00 | 10.00 | 2178.2 | 0.00457 |
| L#06 | 0.1253 | 183.00 | 10.00 | 5837.9 | 0.00171 |
| L#07 | 0.0249 | 130.00 | 10.00 | 3926.8 | 0.00254 |
| L#08 | 0.1311 | 130.00 | 10.00 | 5837.9 | 0.00171 |
| G#01 | —— | 300.00 | 41.38 | 1423.4 | 0.02825 |
| G#02 | —— | 300.00 | 41.38 | 3631.9 | 0.01325 |

TABLE II
COMPONENT FAILURE DATA: EQUIPMENTS

| | MTTR (h) | MTTF (h) | FOR (pu) |
|---|---|---|---|
| Circuit-breaker HV | 12.00 | 2037209.30 | $5.89{\cdot}10^{-6}$ |
| Lighting arrester HV | 6.00 | 600000.00 | $10.00{\cdot}10^{-6}$ |
| Transformer HV / HV | 120.00 | 6738462.00 | $17.81{\cdot}10^{-6}$ |

### D. Reliability Assessment at HLIII

Overall HLIII power system reliability is concerned with assessment at the actual customer level. Today, customer satisfaction is an important concern in the electric power utility environment.

The new technique for HLIII short-term reliability assessment presented in this paper includes the independent outages of generating units, transmission lines, outages due to station originated failures, subtransmission and radial distribution element failures. The method used is summarized in the next paragraphs.

The state enumeration approach has been used in the proposed technique in order to reduce computation times for short-term security evaluation. Consequently, system states are selected in an increasing order of contingency level, stopping the process when the state probability becomes less than a pre-specified tolerance.

The proposed short-term reliability assessment includes a Topological Analysis module similar to the one used in State Estimation [5]. This module activates the Topological Processor when the topology of the system changes due to either an operator control action or as a result of a contingency evaluation in the reliability assessment process, determining the energized islands and the new system bus-branch model. Substations are first considered as single electrical nodes in order to simplify the procedure.

Then, a DC load flow module determines the state of the system and, if required, a DC-OPF module is used to obtain remedial actions with minimum curtailment. The DC approach have been adopted in order to reduce computation times, taking into account that the assumed simplifications are acceptable in 132 and 66 kV levels of the Spanish distribution networks where the proposed techniques have been applied.

Finally, the statistical evaluation module updates the Loss of Load Probability (LOLP) of network nodes taking into account the probability of the particular state, along with some additional reliability indexes.

The load flow module uses line admittances and flow limits to detect any overload. The DC load flow model is given by:

$$\mathrm{M} = \mathrm{B} \cdot \theta \tag{7}$$

where “B” is the system susceptance matrix, “$\theta$” is the node voltage angle vector, and “M” is the bus injection vector.

Using the linear model given by (7), the active power flow from node i to j is given by

$$\mathrm{f}_{ij} = (\theta_i - \theta_j) \cdot \mathrm{b}_{ij} \tag{8}$$

the term “$\mathrm{b}_{ij}$” being the susceptance of the element connecting the node *i* and *j*. If the flows are within the limits, then the state in evaluation is feasible, otherwise the next step is to obtain remedial actions. The optimization procedure is based on a linear programming optimal power flow, assigning costs both to generation rescheduling and possible load shedding.

The DC optimization problem is formulated as follows:

- Objective function.

  Minimize:

$$\mathrm{C}_u \cdot \Delta\mathrm{P}^+ + \mathrm{C}_d \cdot \Delta\mathrm{P}^- + \mathrm{C}_L \cdot \Delta\mathrm{P}^L \tag{9}$$

$$\Delta\mathrm{P}^+ \geq 0 \ ; \ \Delta\mathrm{P}^- \geq 0 \ ; \ \Delta\mathrm{P}^L \geq 0 \tag{10}$$

  The coefficients “$\mathrm{C}_u$” and “$\mathrm{C}_d$” are up and down rescheduling cost of generators, “$\mathrm{C}_L$” is the load-curtailment cost, “$\Delta\mathrm{P}^+$” and “$\Delta\mathrm{P}^-$” are vectors of the amount of power that should be increased or decreased by each generator respectively, and “$\Delta\mathrm{P}^L$” is a vector of load curtailment.

- Constraints.

  Power flow equations:

$$\mathrm{M} + \Delta\mathrm{P}^+ - \Delta\mathrm{P}^- + \Delta\mathrm{P}^L = \mathrm{B} \cdot \theta \tag{11}$$

  Generation limits:

$$\mathrm{P}^{min} \leq (\mathrm{P}_G + \Delta\mathrm{P}^+ - \Delta\mathrm{P}^-) \leq \mathrm{P}^{max} \tag{12}$$

Power flow limits:

$$(-\mathrm{P}_f)^{max} \leq (\mathrm{P}_f = \mathrm{X}^{-1} \cdot \mathrm{A}^T \cdot \theta) \leq (+\mathrm{P}_f)^{max} \quad (13)$$

where “$\mathrm{P}^{min}$” and “$\mathrm{P}^{max}$” are the vectors of generators’ limits, “$\mathrm{P}_f$” is the vector of branch flows, “$\mathrm{A}^T$” is the incidence matrix, and “X” is the reactance matrix of lines and transformers.

Finally, the statistical evaluation module updates the Loss of Load Probability (LOLP) of network nodes taking into account the probability of the particular state, along with some additional supply-point reliability indexes [3].

Once node reliability indices are obtained, electrical nodes (substations) with a high LOLP are identified, and if LOLP is over a pre-specified alert threshold, the critical substations are modeled in detail to obtain the reliability indices with a higher accuracy, specially the indices corresponding to delivery points of radial distribution feeders.

Consequently, reliability indexes of the affected primary distribution feeders are computed with more accuracy, revealing critical feeders in terms of reliability. With the proposed approach, computation times are suited to the short-term reliability evaluation of composite transmission and distribution networks.

This methodology uses a 24 hour load forecast and provides a prediction about the reliability of the system and detailed information appropriate to system operators in order to program adequate corrective actions.

## III. Test System and Results

The proposed approach has been applied to a 132 and 66 kV subtransmission system of a regional Spanish network. This system is composed of 6 substations and 8 lines (Fig. 2), and the detailed models of the 132/66 kV substations have been included in the analysis. As example, the detailed model of SUB#3 is showed in Fig. 3.

All the substations have local loads, and the system is fed by a single interconnection line of the bulk transmission system. The system receives the power injections of the generating units G#01 and G#02 located at SUB#01 and the generating unit G#03 located at SUB#4 is a fictitious unit modeling a transmission line.

The power system presents two characteristic topologies during the day of the study. In the period from 9:00 to 23:00 the SUB#4 is a PV-node because, simultaneously, there are demand and generation in this substation. But during the rest of the day the SUB#4 is a PQ-node because there is not generation in this time.

### A. Results of the simulation: First Analysis.

This new technique uses the 24 hour-load-forecast of each node of the system. As example, the Fig.4 shows this information of the SUB#3 because this substation corresponds to the node with the most relevant reliability indices of the system.

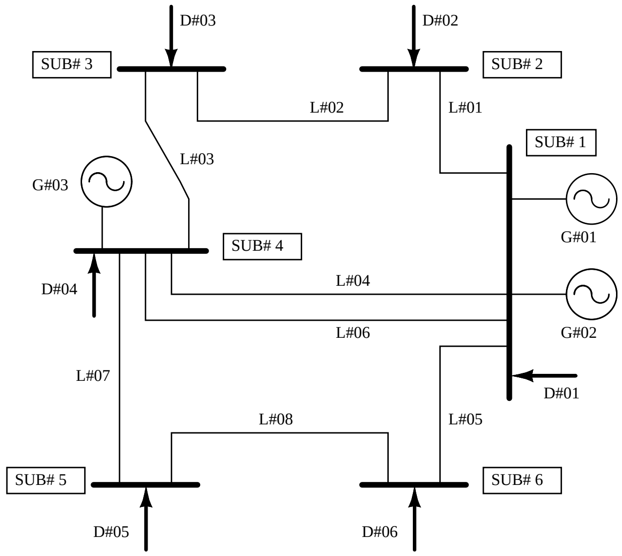


Fig. 2. Simplified model of the 132 kV system.

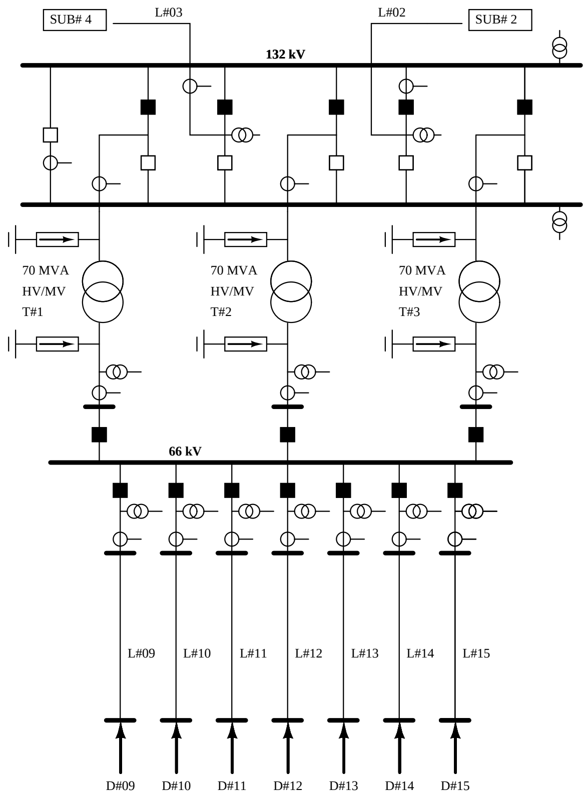


Fig. 3. Complete substation model of SUB#3.

It can be seen (Fig.2 and Fig. 3) that the number of system components becomes very large if all substations are modeled in detail with all its major components.

The number of the system components to consider in the reliability assessment procedure can be drastically reduced if substations are considered as single electrical nodes. The new technique presented in this paper applies this concept in a first simplified reliability assessment over the branch-node scheme

(Fig.2).

When the nodes (substations) with a high LOLP (Loss of Load Probability) are identified in the preliminary analysis, the critical substations are modeled in detail, and the analysis is repeated with a detailed model of the critical substations. It is the case of SUB#3 which is a double bus substation, and all its feeders are presented in detail (Fig. 3) in order to obtain the corresponding reliability indices with a higher accuracy, especially the indices corresponding to delivery points (feeders). Obviously, this information is extended to the 24 hour load-forecast (Fig.4, Fig.5, Fig.6 and Fig.7).

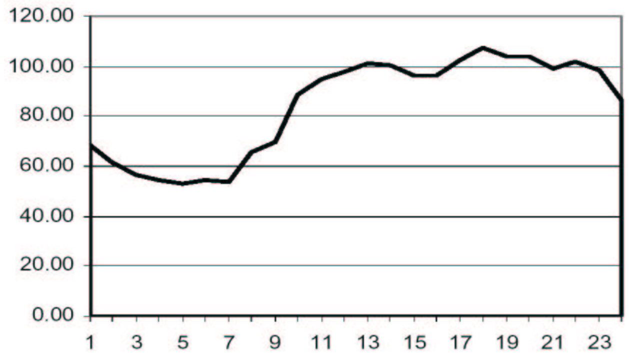


Fig. 4. Load forecast 24 hours ( MW ) - SUB#03.

The reliability indices EPNS (Expected Power Not Served, and LOLP (Loss Of Load Probability) of SUB#3 are shown in figures 5 and 6. Note that EPNS has been expressed in KW and LOLP in percentage (%).

The figure 7 shows the EPNS in SUB#6, which is a problematic node, but with better reliability indices than SUB#3.

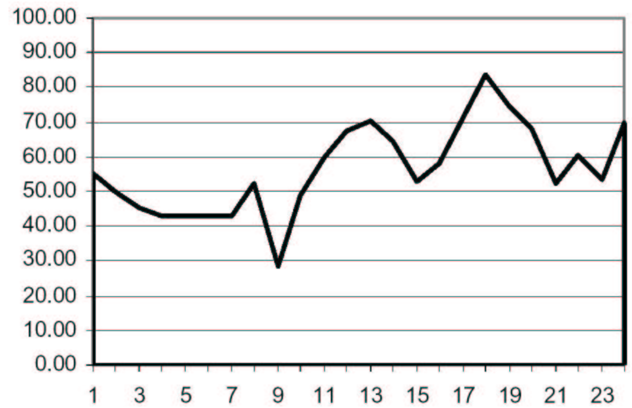


Fig. 5. EPNS 24 hours ( kW ) - SUB#03.

The results presented in figures 5, 6 and 7 correspond to a first analysis performed under the assumption that the system operators (OPF-module) are able to change the scheduled generation to obtain remedial actions with minimum curtailment when there is an incident or contingency in the system.

Notice that, as shown in figures 5 and 7, this new technique provides a short-term (24 hours) prediction about the reliability of the system, along with detailed information appropriate

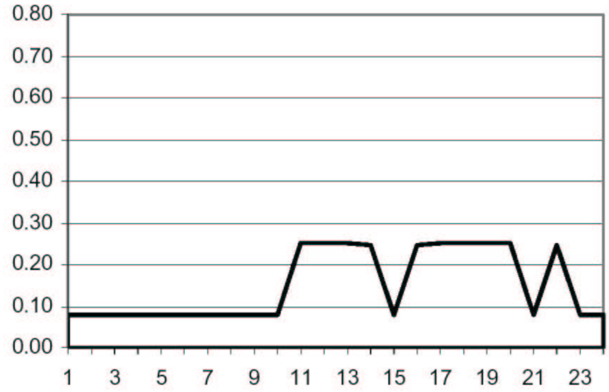


Fig. 6. LOLP 24 hours ( % ) - SUB#03.

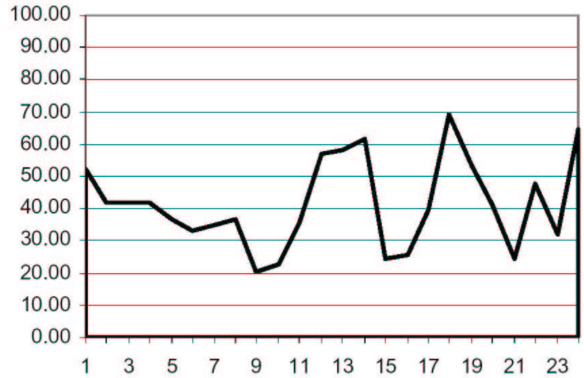


Fig. 7. EPNS 24 hours ( kW ) - SUB#06.

to system operators in order to program adequate corrective actions. Obviously, this is a more complete information than the one provided by a simple N-1 security analysis.

Furthermore, if the conditions used in the 24 hours prediction (generation, topology, weather, outages, demand, etc) change, system operators would have the possibility to anticipate the reliability indices of the system in the new conditions.

*B. Results of the simulation: Second Analysis.*

The proposed technique is quite flexible and permits to include sensitivity analysis such as the influence of available generation on reliability indices. However, the results presented were obtained assuming that generators are able to change the scheduled power in order to minimize the load curtailment. Results obtained under this assumption, presented in figures 5, 6 and 7, are referred to as "Case-1$^{st}$" (optimization problem).

If generators are not allowed to freely change scheduled values, results are rather different and very conclusive. This is the case of fictitious generators (external equivalent) or generators subject to market schedules. In this situation, generators are just able to adjust the generation to the demand, and are not available for rescheduling in order to achieve minimum load-curtailment in subtransmission systems. The results presented in the remaining of the paper were obtained under this assumption, which is named as "Case-2$^{nd}$".

Regarding the “Case-$2^{nd}$” some interesting results can be seen in figures 8 and 9, which correspond, respectively, to the reliability indices EPNS and LOLP of SUB#3. Note that in these figures the numeric scales of both EPNS and LOLP are different from the scales used in previous figures 5, 6 and 7, thusq revealing a significant increase in both reliability indices with respect to the “Case-$1^{st}$”.

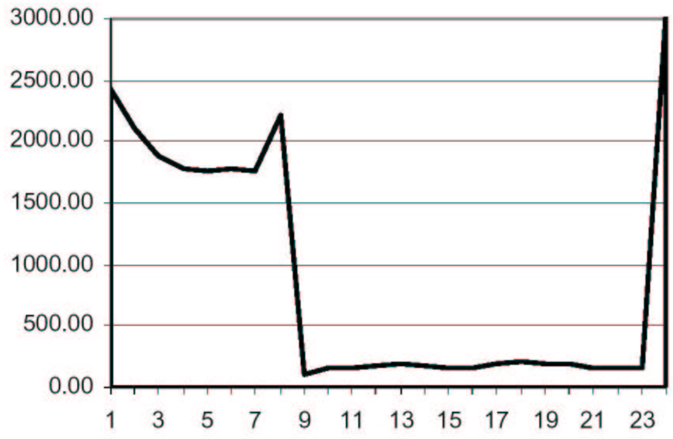


Fig. 8. EPNS 24 hours ( kW ) - SUB#03 - Case $2^{nd}$.

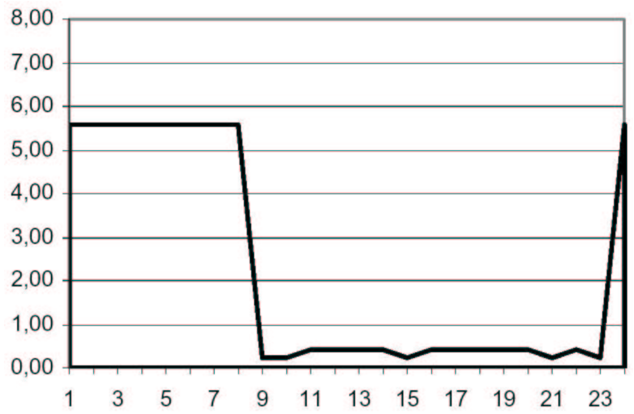


Fig. 9. LOLP 24 hours ( % ) - SUB#03 - Case $2^{nd}$.

Tables III and IV present a comparison of the results corresponding to hours 18:00 and 24:00. The first is the hour of maximum demand, and the second belong to the period time in which there is no generation in SUB#4.

As an example, at the hour of maximum demand (18:00 hour) in the subtransmission system, the Total-EPNS-Case-$2^{nd}$ value is 16 times higher than the Total-EPNS-Case-$1^{st}$ value (TABLE III). And at 24:00 in the subtransmission system, the Total-EPNS-Case-$2^{nd}$ value is 21 times higher than the Total-EPNS-Case-$1^{st}$ value (TABLE IV).

This relevant deterioration is obviously motivated by the fact that in the “Case-$2^{nd}$” the generators are not available to minimize load curtailment in the subtransmission system. Besides, note that subtransmission contingencies do not have a significant effect on the transmission level of the power system.

TABLE III

COMPARATIVE - EPNS AND LOLP - 18: HOUR

| | EPNS (kW) | | LOLP (%) | |
|---|---|---|---|---|
| | Case $1^{st}$ | Case $2^{nd}$ | Case $1^{st}$ | Case $2^{nd}$ |
| SUB#2 | 83.56 | 169.98 | 0.2510 | 0.4050 |
| SUB#3 | 83.49 | 208.79 | 0.2510 | 0.4096 |
| SUB#4 | 34.66 | 1562.14 | 0.0870 | 5.5785 |
| SUB#5 | 4.21 | 4.21 | 0.0087 | 0.0087 |
| SUB#6 | 69.13 | 2361.81 | 0.2403 | 8.2315 |
| Total | 275.05 | 4306.93 | —— | —— |

TABLE IV

COMPARATIVE - EPNS AND LOLP - 24: HOUR

| | EPNS (kW) | | LOLP (%) | |
|---|---|---|---|---|
| | Case $1^{st}$ | Case $2^{nd}$ | Case $1^{st}$ | Case $2^{nd}$ |
| SUB#2 | 57.62 | 1793.79 | 0.0805 | 5.5732 |
| SUB#3 | 69.64 | 3057.21 | 0.0809 | 5.5736 |
| SUB#4 | 196.28 | 3321.14 | 0.4242 | 5.8981 |
| SUB#5 | 84.62 | 81.97 | 0.4036 | 0.3858 |
| SUB#6 | 64.63 | 1600.26 | 0.4165 | 5.8907 |
| Total | 472.79 | 9854.37 | —— | —— |

Another important issue affecting the reliability of the system is the existence of two relevant intervals in figures 8 and 9. These intervals correspond to 9:00 and to 23:00. At 9:00, the generator G#03 begins to inject energy in SUB#4, as imposed by the daily market. Besides, at 23:00 the generator is shut down.

This scheduling also has a significant effect on the reliability of the subtransmission network under supervision, and this additional information is important as intervals of higher vulnerability of the system are revealed, and system operators should program preventive actions in the short-term.

## IV. CONCLUSIONS

In this article, a new technique for short-term reliability assessment of transmission and distribution networks is presented.

Substations are first considered as single electrical nodes to compute system and supply points reliability indices. If this preliminary analysis identifies supply nodes with a high loss of load probability, the critical substations are modeled in detail to obtain the reliability indices with a higher accuracy.

The proposed methodology, based on the state enumeration approach in order to reduce computation times for short-term use, includes a Topological Analysis module to obtain the electrical topology of the network, a DC Power Flow module to compute power flows, and a DC-OPF module to obtain remedial actions.

Preliminary results of the application of the proposed approach have revealed computation times appropriate for short-term use or contingency evaluation.

## ACKNOWLEDGMENT

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