Comparison of the ex-ante and ex-post methods for short-term reliability management

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Abstract - In this paper we compare the performance of two recently proposed methods for managing short-term reliability.

First, we review the short-term reliability related risks associated with the possibility of transmission failures, which are measured through the probability of several scenarios and the respective consequences on some market participants. The load curtailment is used to evaluate the impact of failures on the customers.

Second, we discuss two recently proposed methods for market-based reserve allocation, an ex-ante and an ex-post considering explicitly reliability requirements specified by the demand.

Finally, we compare both methods in a test system where we show that they allocate reserve fulfilling pre-specified reliability requirements. The difference is in the amount of reserve allocated but not in the reliability level obtained. Moreover, the two methods differ with regard to stability of the electricity prices in presence of contingencies and the cost associated with different amounts of reserve.

Keywords - Ex-ante method; ex-post method; reliability-related risks; short-term reliability management markets.

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I. INTRODUCTION

It is recognized that one of the most difficult tasks after deregulation in the electric energy industry is related to the reliability assessment. Reliability problems lead to undesired interruptions and/or highly volatile prices [1], [2].

Furthermore, it is important to recognize that it is no longer realistic to expect that risks associated with reliable service would necessarily be borne by one entity, and not by the others, especially after the unbundling process that is in place in the electricity sector. In order to take into consideration this important issue, an unbundled reliability problem formulation was recently presented [3]. In this formulation, the reliability-related risk is managed in a distributed way by power suppliers, through wire (transmission and/or distribution) providers and, the customers.

Moreover, we point out that it is extremely helpful to think of reliability primarily as a risk taking and management process since one deals with the problem of ensuring uninterrupted service despite unexpected changes [4]. In an industry structure characterized by a full corporate unbundling of generation, transmission and distribution, responsibilities for risk taking have to be clearly defined through a type of contractual agreements between entities. This requires, first of all, clear notions of reliability-related products for which there are sellers and buyers, technical standards are replaced by contractual specifications.

In this setting this paper takes into consideration these changing aspects of reliability. It compares two different approaches to assessing short-term reliability considering it as a risk-management problem. The first

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approach specifies ex-ante the energy redispatch charge, and the second specified it after the fact, namely ex-post. The paper is organized as follows: in Section II some issues associated with reliability requirements are reviewed, in Section III two recently proposed market-based methods for assessing reliability -ex-ante and ex-post- are summarized [5], [6], in Section IV both methods are simulated using the same test system and the results are analyzed. Finally, in Section V the main conclusions are made.

II. NEW VIEW OF RELIABILITY

In order to be consistent with the view of reliability as a risk management problem, it is fundamental to recognize that risk management is related with the quantification of potential failure and one needs answers to the following three issues:

#1 What can go wrong within a system?

#2 How likely is the failure to happen?

#3 What consequence will the failure cause?

In this paper the occurrence of line outages is studied (Issue #1), the probability of this event is computed (Issue #2), and the deficit experienced by the demand is the state of interest (Issue #3).

Issue #1

If we consider that a line can only be in two states, either in operation or in failure, and there are N lines, then the system has 2^N states. To give an idea of this number, consider 100 lines, the number of possible states to consider is 2^{100}=1.27e30. Therefore, it can be concluded that the consideration of the entire possible system state space is not feasible.

However, not all the states have the same probability of occurrence, therefore a reasonable assumption is to consider a subset with the most likely states. To define this subset, it is necessary to calculate the probability of single line contingency scenarios and compare it with multiple line contingency scenarios.

Real examples show that it is reasonable to disregard high order line failures and consider only single line contingencies.

Issue #2

The probability of these two states (operation and failure) for line *l* can be calculated assuming a two-state Markov chain model [7].

$$\Pr(O,t)_l = \left(\frac{m_l}{m_l + l_l} + \frac{l_l \Pr(O,t_0)_l - m_l \Pr(F,t_0)_l}{m_l + l_l} e^{-(m_l + l_l)t} \right) \quad (1)$$

$$\Pr(F,t)_l = \left(\frac{l_l}{m_l + l_l} - \frac{l_l \Pr(O,t_0)_l - m_l \Pr(F,t_0)_l}{m_l + l_l} e^{-(m_l + l_l)t} \right) \quad (2)$$

It is essential to point out that the majority of formulations only consider the stationary part of the equations to model the availability of the lines, but in the short-term (hour) they can be completely different from $\Pr(O)_l$ for a specific time "*t*" and this issue needs to be properly considered for a realistic short-term reliability analysis.

Furthermore, the use of stationary probabilities can lead to an uneconomic overestimation of reserve requirements resulting from the fact that the knowledge of the system's initial conditions $\Pr(O,t_0)_l$ and $\Pr(F,t_0)_l$ is neglected.

Issue #3

To consider the deficit experimented by the demand after the occurrence of contingencies, it is necessary to redispatch the generation considering the capacity previously reserved. There are different ways of doing it; in this paper we consider two alternatives, ex-ante and ex-post, developed in [5], [6].

The first method, defines the energy price r_i^e before the contingency and independent of the system condition, consequently this method is called ex-ante. The objective function for the redispatch is to minimize for each scenario "*j*" (contingency) the total cost of the generation changes defined in the energy market.

The second alternative calculates the energy price r_i^e after the occurrence of contingencies, because of this fact the method is referred as an ex-post method. The performance criterion for the redispatch is to minimize the generation cost of the readjustment for particular scenarios analyzed.

Relating issues #1, #2, and #3

Finally, it is necessary to relate issues #1, #2, and #3 in order to formulate a reliability requirement (which can be either system wide or user wide defined). In any case, the initial step is to agree on a reliability index in order to quantify the reliability level. Only as an illustrative example of the methodology, in this paper the reliability index used is the loss of load probability (LOLP) [7].

An alternative that is suitable for a genuine competitive electric energy industry is to define the reliability requirement P_i according to the reliability desired by the user located at bus *i*. It is here assumed that there is only one user at each bus[1].

$$\sum_j \Pr_j \; Idef_{i,j} \leq P_i \tag{3}$$

Where $\Pr_j$ represents the probability of the scenario considered, which in this model is the occurrence of the single contingency of line "*j*".

$$\Pr_j = \Pr(F)_j \prod_{l \neq j} \Pr(O)_l \tag{4}$$

The state of interest is the deficit experimented by the load. In order to relate the occurrence of this event with the scenario "*j*" in study, $Idef_{i,j}$ is defined as a function that takes the value 1 when there is deficit greater than 0 at bus "*i*" for scenario "*j*". Otherwise it takes value 0, namely:

$$Idef_{i,j} = \begin{cases} 1 & if \; Pdef_i^{\,j} > 0 \\ 0 & otherwise \end{cases} \tag{5}$$

III. ASSESSING RELIABILITY

A. *Energy market*

The energy market deals with managing of energy transactions for normal operating conditions. In the markets for energy currently operating worldwide, generators explicitly bid prices at which they are willing to supply energy. The desire of privately owned generation companies to maintain and attract shareholders implies that they will attempt to exploit any potential profit-making opportunities through their bidding behavior. The ISO allocates the resources at minimum cost in order to supply the inelastic demand while considering generation capacity limits and line capacity limits [8].

$$\underset{Pg_i}{Min} \sum_i C_i\left(Pg_i\right) \tag{5}$$

Subject to:

$$\sum_i Pg_i = \sum_i Pd_i \tag{6}$$

$$Pg_i^{\min} \leq Pg_i \leq Pg_i^{\max} \tag{7}$$

$$F_l = \sum_i H_{l,i}\left(Pg_i - Pd_i\right) \leq F_l^{\max} \tag{8}$$

Finally, the energy price for location *i* is calculated as:

$$r_i^e = l + \sum_l h_l H_{l,i} \tag{9}$$

Where *l* is the Lagrange multiplier associated with the balance constraint (6), h_l is the Lagrange multiplier associated with the transmission capacity limit constraint for line *l* (8), and $H_{l,i}$ is the change in power flow on line *l* due to a change in injection in bus *i*.

B. *Reliability-related reserve market*

In analogous way, the reserve market assesses the reliability of the electric energy industry, where participants explicitly bid prices at which they are willing to supply capacity reserve. Generators (or equivalently interruptible demand) will attempt to exploit any potential profit-making opportunities through their bidding behavior. Here we review two methods for implementing a reliability-related reserve market [5], [6].

1) An *ex-ante method*

In this formulation, the objective function is to minimize the cost of the reserve bids, and for each scenario "*j*" the total cost of the generation changes defined in the energy market. Additionally, the occurrence of deficit is modeled as a fictitious deficit generator located at each load bus.

[1] This condition can be relaxed and it does not affect the main approach.

$$\underset{\substack{Pg_i^{in,j},\Delta Pg_i^{de,j}\\ \mathrm{Pdef}_i^j, R_i}}{Min}\left(\begin{array}{l}\sum_j\left[\begin{array}{l}\sum_i\left(r_i^e\left(\Delta Pg_i^{in,j}\right)-r_i^e\left(\Delta Pg_i^{de,j}\right)\right)+\\ \sum_i C_i^j\left(Pdef_i^{\,j}\right)\end{array}\right]+\\ \sum_i C_i(R_i)\end{array}\right) \quad (10)$$

This optimization problem is subject to the following set of constraints:

In this formulation a reliability requirement to be fulfilled, submitted by the demand, is explicitly formulated in contrast with the reserve requirement usually used [9], [10]. It is assumed that wholesale market participants are able to estimate the value associated with their reliability requirements.

$$\sum_j \Pr_j \; Idef_{i,j} \le P_i \quad (11)$$

The minimum and maximum generation capacity reserve is limited by both unit excess capacities and their respective maximum pick up rates. The value of ramping rates can be taken explicitly if a unit commitment method is used instead of an OPF method [11].

$$R_i^{\min} \le R_i \le R_i^{\max} \quad (12)$$

The net change in generation is defined by the increment $\Delta Pg_i^{in,j}$ and the decrement $\Delta Pg_i^{de,j}$ in generation for each scenario "*j*".

$$Pg_i^{\,j} = Pg_i + \Delta Pg_i^{in,j} - \Delta Pg_i^{de,j} \qquad \forall j \quad (13)$$

The generation redispatched plus the amount of deficit must be equal to the demand for each scenario "*j*".

$$\sum_i Pg_i^{\,j} + \sum_i Pdef_i^{\,j} = \sum_i Pd_i \qquad \forall j \quad (14)$$

The amount of deficit experimented by a load located in bus *i* cannot be greater than the respective demand Pd_i for each scenario "*j*".

$$0 \le Pdef_i^{\,j} \le Pd_i \qquad \forall j \quad (15)$$

The generators cannot increase their generation in a value greater than the amount that they have as a generation reserve R_i. This model assumes that generators can reduce their generation up to zero MW.

$$0 \le Pg_i^{\,j} \le Pg_i + R_i \qquad \forall j \quad (16)$$

The power flow on line l and for scenario "*j*" is defined by the topology, the generation, the deficit, and the demand.

$$F_l^{\,j} = \sum_i H_{l,i}^{\,j}\left(Pg_i^{\,j} + Pdef_i^{\,j} - Pd_i\right) \le F_l^{\max} \;\; \forall j \quad (17)$$

2) ***An ex-post method***

In this formulation, the objective function is to minimize the cost of the reserve bids, and for each scenario *"j"* the total cost of the generation redispatch. Moreover, the occurrence of deficit is modeled as a fictitious deficit generator located at each load bus.

$$\underset{Pg_i^j,\,\mathrm{Pdef}_i^j,\,R_i}{Min}\left(\begin{array}{l}\sum_j\left[\sum_i C_i^j\left(Pg_i^{\,j}\right)+\sum_i C_i^j\left(Pdef_i^{\,j}\right)\right]+\\ \sum_i C_i(R_i)\end{array}\right) \quad (18)$$

This optimization problem is subject to the constraints previously described (11), (12), (14), (15), (16), and (17).

The energy price for location i after the redispatch and for scenario "*j*" is calculated as:

$$r_i^{e,j} = l^{\,j} + \sum_l h_l^{\,j} H_{l,i}^{\,j} \quad (19)$$

Where $l^{\,j}$ is the Lagrange multiplier associated with the balance constraint for scenario *j* (14), h_l^j is the Lagrange multiplier associated with the transmission capacity constraint for line *l* and for scenario "*j*" (17), and $H_{l,i}^j$ is the change in power flow on line l due to a change in injection on bus *i* for scenario "*j*".

IV. NUMERICAL EXAMPLE

It is expected that both methods reviewed would fulfill the reliability benchmark pre-specified by customers. However, they can have different reserve allocated and different generation redispatched as well, which is a direct consequence of the fact that concept and mathematical formulation are different. In order to illuminate these facts, a numerical example is presented here. The test system, Fig. 1 in Appendix, has 18 buses, 30 lines, 9 generators, and 8 loads. The load is considered inelastic, the energy bids and reserve bids are constant, each generator participates in both energy and reserve markets and has maximum and minimum capacity limit, and transmission lines have capacity limits in both directions. The data are shown in Tables 5, 6, and 7.

Using the formulation given in Section III, the energy market is cleared supplying the entire load as depicted in Table 1, for this dispatch line L_{14-15} results congested. Moreover, we assume that all generators participate in both energy and reserve markets, so to define the maximum reserve capacity limit for the units we state $R_i^{max} = P_{gi}^{max} - P_{gi}$. The minimum reserve capacity for each generator is assumed 0 MW.

	Energy dispatch (MW)	R_i^{max} (MW)
Pg_1	250.88	0
Pg_2	92.88	7.12
Pg_3	0	140
Pg_4	0	100
Pg_5	150	0
Pg_6	0	100
Pg_7	40.93	169.07
Pg_8	0	100
Pg_9	10	0

Table 1: Energy dispatch.

We calculate next the reserve allocation for the ex-ante and ex-post method on the basis of the formulations given in Section III, and assuming $LOLP_i$=0.2. The results are shown in Table 2.

Reserve allocation		
	Ex-ante (MW)	Ex-post (MW)
R_1	0	0
R_2	7.12	7.12
R_3	140	0
R_4	100	0
R_5	0	0
R_6	100	43.82
R_7	56.82	72.99
R_8	100	100
R_9	0	0

Table 2: Reserve allocation.

As we could see from these results, each method has different reserve allocation. Then we simulate the operation of the system for the entire set of single contingencies and compare the reliability level (LOLP) obtained.

Outage L_{ij}	Bus	Ex-ante Deficit (MW)	Ex-post Deficit (MW)
L_{1-16}	12	26.21	25.54
L_{1-17}	12	39.93	39.23
L_{8-9}	10	5	5
L_{8-9}	12	73.85	74.37
L_{8-9}	13	18	18
L_{8-9}	14	10.5	10.5
L_{13-15}	13	18	18
L_{13-15}	14	10.5	10.5

Table 3: Simulation for ex-ante and ex-post methods.

For this system with 30 lines, line outage probabilities of 0.01, it is shown considering only single contingencies that both methods -ex-ante and ex-post- allocate reserve satisfying the same reliability level given by LOLP= $8*(1-0.01)^{29}*0.01=0.0598$.

We calculate next the cost for both methods of reserve allocation and the energy prices after contingency for some scenarios. To calculate the reserve costs, the reserve bid values given in Table 5 are used.

We find that the reserve allocation cost for the ex-ante method is \$583.58, and for the ex-post method is \$465.53.

The higher cost for the ex-ante method must be weighted against the stability in prices observed by participants (r_i^e) independent of system conditions. To illustrate this we display in Table 4 the energy prices for the ex-ante method and the ex-post method. We see that when the ex-ante method is used, prices are stable and known when the energy prices are created, therefore these are the same. On the other hand, the energy prices for the ex-post method increase at some buses and decrease at others.

Normal operation		Outage L_{12-17}	
		Ex-post	Ex-ante
	Price	Price	Price
Bus	($/MWh)	($/MWh)	($/MWh)
1	2.39	3.7	2.39
2	2.24	3.44	2.24
3	1.76	2.67	1.76
4	2.32	3.33	2.32
5	3.09	4.24	3.09
6	3.46	4.69	3.46
7	4.38	5.78	4.38
8	5.01	6.54	5.01
9	5.92	7.63	5.92
10	5.92	11.33	5.92
11	6.68	6.67	6.68
12	5.92	14.11	5.92
13	7.34	5.84	7.34
14	12.51	10.65	12.51
15	0.66	1.23	0.66
16	4.92	11.16	4.92
17	3.72	3.7	3.72
18	2.71	3.77	2.71

Table 4: Energy prices for normal operating condition (Line L_{14-15} congested at 80MW) and for scenario outage L_{12-17} (Line L_{14-15} congested at 80MW, and line L_{12-13} at 200MW).

V. CONCLUSIONS

In this paper we discuss the short-term reliability management as a risk management problem. The uncertainty associated with transmission outages and the consequences experimented by loads were studied. The Performances of two methods in assessing short-term reliability were compared on a test system.

First, we formulate the short-term reliability related risks associated with the possibility of transmission failures, which were measured through the probability of several scenarios in consideration and the respective consequences seen by some market participants, in this paper the load curtailment. The lines are modeled using two-state Markov models using time dependent probabilities. The state of the lines at the time of calculation is assumed known. Moreover, in this paper we only consider single contingency scenarios.

Second, we formulate two market-based methods to allocate reserve, ex-ante and ex-post, considering explicitly reliability requirements submitted by the demand.

To conclude, we implemented both methods in a test system where we verified that both methods allocate reserve sufficient to meet the same reliability level specified as a LOLP measure. The difference in reserve allocation resulted in cost differences but not in reliability levels. Furthermore, the tradeoff analysis is done between the economic signal given by the stability of the energy prices in presence of contingencies and the cost of having different amount of reserve.

VI. APPENDIX

Bus	Pgimax (MW)	Pgimin (MW)	Energy bid ($/MWh)
10	5	0	15.001
11	0	0	15.002
12	377	0	15.003
13	18	0	15.004
14	10.5	0	15.005
15	22	0	15.006
16	43	0	15.007
17	42	0	15.008
18	27.2	0	15.009

Table 5: Generation data.

Bus	Energy bid ($/MWh)	Reserve bid ($/MW)	Pgimax (MW)	Pgimin (MW)
1	0.5	2.2	250.88	0
2	0.6	1	100	0
3	2.8	0.4	140	0
4	3.3	0.6	100	0
5	1.4	1.4	150	0
6	2	0.9	100	0
7	2.74	3	210	0
8	3.7	2	100	0
9	3	0.1	10	0

Table 6: Deficit generation data.

Initial-bus	Final-bus	X p.u.	Line limit (MW)	(1-v)
1	2	0.028	400	0.01
1	15	0.091	400	0.01
1	16	0.206	400	0.01
1	17	0.108	400	0.01
2	3	0.085	400	0.01
3	4	0.036	400	0.01
3	15	0.053	400	0.01
4	15	0.132	400	0.01
4	6	0.148	400	0.01
4	18	0.555	400	0.01
4	18	0.43	400	0.01
5	6	0.064	400	0.01
6	7	0.102	400	0.01
6	8	0.173	400	0.01
6	18	0.173	400	0.01

Initial-bus	Final-bus	X p.u.	Line limit (MW)	(1-v)
7	8	0.071	400	0.01
8	9	0.05	200	0.01
9	10	0.167	400	0.01
9	11	0.084	400	0.01
9	12	0.295	400	0.01
9	13	0.158	400	0.01
10	12	0.126	400	0.01
11	13	0.073	400	0.01
12	13	0.058	200	0.01
12	16	0.081	400	0.01
12	17	0.179	400	0.01
13	14	0.043	400	0.01
13	15	0.086	400	0.01
14	15	0.054	80	0.01

Table 7: Line data.

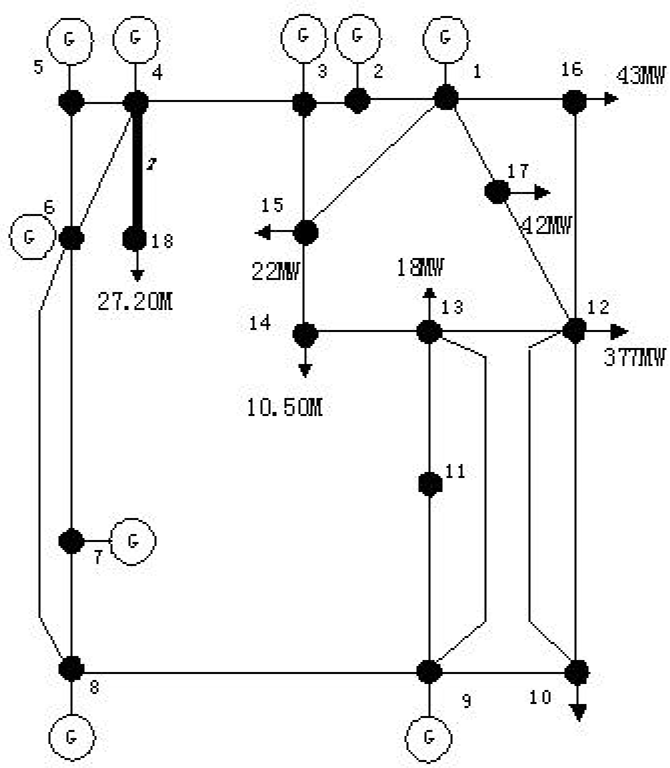

Fig. 1 Test system.

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