A Hybrid Probabilistic Criterion for Market-based Transmission Expansion Planning

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Abstract—Market-based transmission expansion planning gives information to investors on where is the most cost efficient place to invest and brings benefits to those who invest in this grid. However, both market issue and power system adequacy problems are system planners’ concern. In this paper, a hybrid probabilistic criterion of Expected Economical Loss (EEL) is proposed as an index to evaluate the systems’ overall expected economical losses during system operation in a competitive market. It stands on both investors’ and planner’s point of view and will further improves the traditional reliability cost. By applying EEL, it is possible for system planners to obtain a clear idea regarding the transmission network’s bottleneck and the amount of losses arises from this weak point. Sequentially, it enables planners to assess the worth of providing reliable services. Also, the EEL will contain valuable information for moneymen to undertake their investment. This index could truly reflect the random behaviors of power systems and uncertainties from electricity market. The performance of the EEL index is enhanced by applying Normalized Coefficient of Probability (NCP), so it can be utilized in large real power systems. A numerical example is carried out on IEEE Reliability Test System (RTS), which will show how the EEL can predict the current system bottleneck under future operational conditions and how to use EEL as one of planning objectives to determine future optimal plans. A well-known simulation method, Monte Carlo simulation, is employed to achieve the probabilistic characteristic of electricity market and Genetic Algorithms (GAs) is used as a multi-objective optimization tool.

Index Terms—Transmission Expansion Planning (TEP), Congestion Cost, Monte Carlo Simulation, Reliability Worth/reliability cost, Transmission Expansion Flexibility (TEF), Normalized Coefficient of Probability (NCP)

I. NOMENCLATURE

\( C^m \): Construction cost of transmission line
\( \eta_{mn} \): New transmission lines from bus \( m \) to bus \( n \)
\( L_k \): Load curtailed at bus \( k \) due to contingency \( j \)
\( D_j \): Duration (hours) of load curtailment due to contingency \( j \)
\( P_j \): the probability of existence of outage \( j \)
\( f_j \): Frequency of occurrence of outage \( j \)
\( EENS \): Excepted energy not supplied

\( u(i) \): the unavailability of component \( i \)
\( a(d) \): the availability of component \( d \)
\( SS_s \): the social surplus of situation \( s \) (re-dispatch applied)
\( SS_{sc} \): the social surplus of situation \( s \) (load shedding applied)
\( GS_s \): the generation surplus of situation \( s \)
\( CS_s \): the consumer surplus of situation \( s \)

II. INTRODUCTION

The effectiveness of electricity market is strongly affected by the system planning design [1]. Market-based expansion is needed in order to incite market participants and provide a fair transaction environment. It offers planners the analysis from the following market point of view [2]:

- Encouraging and facilitating competition among electric market participants.
- Providing a non-discriminatory environment for consumers to assess all generators.
- Providing fair supply-side reserve for all generators and fair demand-side reserve for all consumers.

However, to operate and develop the network as reliable as possible is the major concern to the system planners. Because of the important role of electricity in everyday life, power system operators need to consider more on security and adequacy problems. In addition, a pure decentralized and market-based approach for system expansion may result in a dangerous and discontinuous system development [3]. Because the congestion analysis emphasized in market based planning may not imply transmission systems unreliability, it simply means that transmission line overload and high price generators are needed to allay the violation in competitive electricity market. Consequently, from transmission planner’s point of view, traditional value-based planning [4, 5] and least-cost planning [6] must be used as reference.

In a deregulated market, transmission planning is facing two major problems: (1) how to consider market factors as much as possible into planning process (2) and how to balance these market infections with power system physical limits. Further more, both issues are strongly affected by many uncertainties. Therefore, the solutions of transmission expansion planning (TEP) must satisfy the requirements of both market participants and system operators in these uncertain environments.
The uncertainties arising from the market include:

- Power and bids of independent power producers (IPPs)
- The strategic behavior of generation companies
- Bilateral/ multilateral transactions
- Load expansion/closures
- Generation costs

On the other hand, the uncertainties of a physical transmission system include:

- Contingencies resulted from unavailability of generations, transmission lines and other components out of service
- New generation expansion

In order to carry out power system plans that can truly cope with the random market events and system behaviors, probabilistic techniques have been proposed and developed for decades. It has been commonly accepted that probabilistic techniques is the most efficient means to evaluate power systems in ever-changing environments.

With these as a background, this paper proposes a probabilistic criterion called EEL. This index is carrying the probabilistic characteristics of electricity market from both the market and system reliability perspectives. It can be seen as the extension of the conventional reliability cost. In section III, the proposed EEL in a single side bidding Poolco market is presented, which is measured as the total losses of social surplus. Normal probability is replaced with NCP in computation of EEL. By applying the criterion to a network, the effectiveness of EEL is presented in case study section.

III. PROBABILISTIC EXPECTED ECONOMICAL LOSS

As a media to connect generations and distribution systems, transmission networks need to provide sufficient capacity and reserves to meet the peak demand of each day [7, 8]. However, when the desired trade is more than what can be transferred by part of the transmission network, transmission line congestion will occur. This will cause losses of social benefits, whether it is resulted from generation and transmission line contingency or simply because of the insufficient of line capacity. Traditionally, the impacts and monetary losses were evaluated by reliability worth/reliability cost in value-based planning approach, which uses subjective and objective measures of customer economics losses arising from electric energy supply curtailments [9]. In fact, not only load curtailments can lead to this customer interruption cost in a competitive electricity market. Congestion cost developed in [10] has illustrated that loss of social benefit can also result from transmission line congestion even if it can be alleviated by re-dispatch.

The proposed EEL is defined as the total losses of social benefit due to line violation, which is analyzed and modeled according to the actions which can alleviate network violation, such as, re-dispatch and load shedding.

Generally, transmission line violation includes overload and open circuit. The reasons and corresponding measurements are listed in Table I.

A. Using re-dispatch to solve line violation

In Poolco model market, there is only one single entity, the Pool Company, who purchases power from the competing generators in the open market and sell it at a single price to the retail loads. In this market structure, only generators submit their bidding prices to system operator, while consumers do not. Therefore, whatever the market clearing price is customers are charged at this price. Then we can assume the height $H$ of the step of demand curve as shown in Fig. 1(a) is high enough.

When generators can not supply the required demands due to a transmission line overload, re-dispatch is implemented by system operator to alleviate this violation. In the meantime, total consumed electricity will not be affected (as short term inelasticity of supply and demand); the desired demand after congestion $Q_a$ equals to the demand $Q_b$ before congestion occurs. The entry of higher price generators may lead to a sharper slope of supply curve than previous supply curve, as shown in Fig. 1 (a).

From the definition and the illustration we can see that the EEL can be expressed as the social surplus difference between before and after this line critical situation.

As shown in Fig.1(a) the total difference of social surplus is the area composed of B and C:

$$\Delta SS_{sr} = \Delta GS(Q)_{sr} + \Delta CS(Q)_{sr} = C + B$$ (1)
According to [9], the EEL under this condition mathematically equals to the loss of generation surplus in single side bidding model.

The supply curve can be expressed as:

\[ Q = f(P) = \sum_{n \in N} \sum_{j \in I} f_{n \rightarrow j}(\text{Min}(P_{n \rightarrow j})) \]  

(2)

where,

- \( N \): is the total number of generation.
- \( I \): is the number of blocks of each generation.
- \( Q \): is the quantity of required electricity.
- \( P \): is the bidding price of a generator.

Then \( P = f^{-1}(Q) = F(Q) \). Thus social surplus difference can be expressed as:

\[ \Delta SS_{sr} = \int_{Q \in [0, Q_{s}]} (F_{b}(Q) - F_{a}(Q)) \cdot dQ \]  

(3)

where \( F_{b}(Q) \) and \( F_{a}(Q) \) are the supply curve before and after congestion. It is a function of required demand \( Q \). By adding the probability attribute to this function, the social surplus becomes:

\[ \Delta SS_{sr} = \int_{Q \in [0, Q_{s}]} (F_{b}(Q) - F_{a}(Q)) \cdot dQ \cdot P_{xy} \]  

(4)

where \( P_{xy} \) is the probability of load of line \( x \) exceeding the maximum capacity that can be supplied on that line during congestion \( y \), and the congestion is solvable by re-dispatch of \( y \in C \), which includes all congestions.

\[ B. \ Use load-shedding to solve line violation \]

In some situations, it is impossible to eliminate all congestion or system contingency by rescheduling generator outputs, as it may create more economical losses than the situation we discussed in part A, because some loads must be curtailed. This behavior can be seen from Fig. 1 (b). Both customer surplus and generation surplus have been abated. This social surplus change is because of the load shedding. From the system reliability point of view, this can be calculated by reliability worth/reliability cost.

The concept of reliability worth/reliability cost methodology has been presented in many research studies. It can be seen as a useful adjunct to test system performance against planning criteria by verifying that planning decisions provide reasonable value to customers, [4]. There are three broad categories of approaches in assessing unreliability costs: 1) analytical methods; 2) blackout case studies; and 3) customer survey [9]. Customer survey is the most commonly used method. Hence it will be used for the proposed EEL.

The customer damage functions obtained from customer survey can be aggregated at any bus and produce a composite customer damage function (CCDF). And besides, the CCDF can be converted into an extended index interrupted energy assessment rate (IEAR) that links system reliability with customer interruption cost.

In power system hierarchical lever II, IEAR for a service area is the ratio of the total cost and total expected energy not supplied.

\[ IEAR = \frac{\sum_{j \in LC} L_{ij} \cdot C_{ij} \cdot f}{\sum_{j \in LC} L_{ij} \cdot P_{j} \times 8760} \]  

(5)

Therefore, the total loss of social surplus in this situation can be calculated by using Eqn. (6).

\[ \Delta SS_{sc} = IEAR \cdot \sum_{j \in LC} L_{ij} \cdot P_{i} \times 8760 \]  

(6)

\[ C. \ Normalized \ Coefficient \ of \ Probability \]

Theoretically, the probability of a system state can be expressed as a function of components availability and unavailability. If the outage of each component is independent, then the probability of the situation \( (c_{1}, c_{2}, \ldots, c_{n}, d_{1}, d_{2}, \ldots, d_{m}) \) can be expressed as:

\[ p = \prod_{j=1}^{m} u(c_{j}) \cdot \prod_{j=1}^{m} a(d_{j}) \]  

(7)

where components \( (c_{1}, c_{2}, \ldots, c_{n}) \) are out of service and facilities \( (d_{1}, d_{2}, \ldots, d_{m}) \) are in service.

In this paper, the probability \( p \) will be replaced with NCP, which is defined as the current situation probability \( p \) divided by a common factor [11, 12].

\[ NCP = \frac{\prod_{c_{j} \in OUT} u(c_{j}) \cdot \prod_{d_{j} \in IN} a(d_{j})}{\prod_{c_{j} \in \Omega} a(c_{j})} \]  

(8)

where \( \Omega \) represents the set of all connected facilities of the system. So that, \( \Omega = IN \cup OUT \). Mathematically, the common factor becomes:

\[ \prod_{c_{j} \in \Omega} a(c_{j}) = \prod_{c_{j} \in OUT} a(c_{j}) \cdot \prod_{d_{j} \in IN} a(d_{j}) \]  

(9)

Then, the definition of NCP can be expressed according to the following equation:

\[ NCP = \prod_{c_{j} \in OUT} \frac{u(c_{j})}{a(c_{j})} \]  

(10)

In fact, the NCP is not a probability, but the ratio of unavailability and availability of fault components.

The advantages of NCP [11, 12] are summarized as:

- Simplify the computation and eliminate burdensome and common piece of information.
- Its direct correspondence with the situation probability and the fault components, regardless of the number of components.
- NCP avoids the handling of utterly small numbers and the cumulating of numerical errors.
Thus, Eqn. (6) can be rewritten as:

$$\Delta SS_{se} = IEAR \cdot \sum_{j \in L} L_{ij} \cdot P_{i} \times 8760$$

$$= IEAR \cdot \prod_{c, s} a(c_{i}) \cdot \sum_{j \in L} L_{ij} \cdot NCP \times 8760 \quad (11)$$

According to the sensitivity analysis [9], the IEAR is reasonably stable and does not vary significantly with peak load or other operating conditions. Therefore, a single IEAR will be used to simplify the calculations.

$$\Delta SS_{se} = \beta \cdot \sum_{j \in L} L_{ij} \cdot NCP \quad (12)$$

In a particular system, $\beta$ is constant, because the common factor $\prod_{c, s} a(c_{i})$ lies on the availability of all components in a power system.

$$\beta = IEAR \times \prod_{c, s} a(c_{i}) \times 8760 \quad (13)$$

D. Mathematical Expression of EEL

As we discussed before, the EEL is the total losses of social benefit due to line violations. It can be represented as the summation of social surplus losses in two line critical situations, as shown in (14).

$$EEL = \Delta SS_{sc} + \Delta SS_{sr}$$

$$= \beta \cdot \sum_{j \in L} L_{ij} \cdot NCP + \sum_{s, \text{line} \in L} \left( \int_{0}^{P_{i}} \left[ F_{s}(Q) - F_{j}(Q) \right] \cdot dQ \cdot P_{xy} \right) \quad (14)$$

IV. COMPUTATION PROCEDURE

Based on the above theories, the procedure of calculating EEL is summarized as follows,

1) Collect the availabilities and capacities of all generations and lines.
2) Simulate the bidding prices of all generators in the planning horizon years.
3) Generate the load duration curve according to the peak load and a set of levels represented in hourly, daily and weekly peak values. Meanwhile, simulate the load which will increase on particular increase rate.
4) Dispatch generation according to bidding prices and load duration curve.
5) Monte Carlo simulation generate contingency in terms of unavailabilities of generation and transmission line.
6) Run optimal power flow to get the flow solution.
7) If any congestion occurs, run re-dispatch process. Then calculate the $\Delta SS_{sr}$ of each appearance and record the probability of occurrence and line ID. If re-dispatch can solve this congestion, go to step 9, run next iteration.
8) Justify if there is contingency that lead to load shedding, then calculate $\Delta SS_{sc}$ results from load curtailments and record the corresponding line ID.
9) Repeat step 6, 7 and 8 a great number of times.
10) Figure out the EEL by using equation (14). The overall procedure involving all these steps is shown in Fig. 2.

V. CASE STUDY

The case study is carried out on IEEE Reliability Test System (RTS) [13]. This system is shown in Fig. 3, which consists of 32 generators and 17 loads. In the future horizon years (5 years), it is assumed that new generation is not needed. For all existing producers, they are dispatched according to their bidding prices. For simplicity and without losing generosity, bilateral/multilateral contracts are not considered in this case study.

In this case, there are several assumptions:

1) The bidding price of each generator will keep fixed in each single year. However, the bidding prices will change annually, because it will be strongly affected by their fuel cost. Therefore, generator bidding prices...
are increased according to the different increase rate corresponding to their fuel types.

<table>
<thead>
<tr>
<th>Type</th>
<th>Year 1</th>
<th>Year 2</th>
<th>Year 3</th>
<th>Year 4</th>
<th>Year 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>-</td>
<td>-</td>
<td>1%</td>
<td>1%</td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>1%</td>
<td>1%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>Oil</td>
<td>2%</td>
<td>3%</td>
<td>5%</td>
<td>3%</td>
<td>2%</td>
</tr>
<tr>
<td>Coal</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
</tr>
</tbody>
</table>

2) Load increase unevenly. The increase rate of some bus will be much higher than others.

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage (KV)</th>
<th>Year</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>11-24</td>
<td>230</td>
<td></td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
</tr>
<tr>
<td>1-5,7</td>
<td>138</td>
<td></td>
<td>2%</td>
<td>2%</td>
<td>2%</td>
<td>3%</td>
<td>3%</td>
</tr>
<tr>
<td>6,8</td>
<td>138</td>
<td></td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
<td>5%</td>
</tr>
</tbody>
</table>

3) The generating unit and transmission line state duration are assumed to be exponential and only two states are considered (Up/Down). Common mode failures are not considered in this case.

The presented theory is applied to two planning states: A) predicting the current system bottleneck in future operational condition, and B) as a criterion to generate optimal plans.

A. Using EEL to Predict the System Bottleneck

From transmission planning point of view, no matter the EEL is results from generation outage or transmission line violation, the economical losses are leaded by the direct causes: 1) transmission line congestion which is solvable by re-dispatch, and 2) transmission line congestion which is unsolvable by re-dispatch, so load-shedding is needed 3) transmission line outage. Therefore, the EEL of each line can be recorded according to their direct causes.

By running Monte Carlo Simulation, the EEL of each line that resulted from the congestion, which is solvable by re-dispatch, are calculated and plotted in Fig. 4.

And EEL of each line that caused by load curtailments are shown in Fig. 5.

Then, the total EEL of each line can be calculated by using Eqn. (14). The results obtained are shown in Fig. 6. It can be seen that line 11 has the most economical losses in the whole system in the planning horizon years, followed by line 13 and then line 12. That is, in future operational conditions, the transmission line between bus 7 and bus 8 may cause system bottleneck. This means that it will result in more social benefits losses and has more probability of congestion occurrence.

According to the results, planners and mangers can specify their desired level of security and risk for a particular line.
Then they are able to determine the adequacy of the current situation and make judgments regarding future reinforcement. In this case, planners may consider expanding the current system to alleviate potential economical losses.

B. Search Optimal Plans

Transmission planning is commonly considered as a multi-objective task. In this case, a method presented in [14] and [15] is applied and modified via taking EEL into account. Therefore, the objectives are

- To serve the customer reliably and economically.
- Minimize the present value of capital cost, operational and maintenance cost.
- Emphasis the transmission expansion flexibility to adapt to the continual changes from the market.
- Minimize the social surplus losses result from transmission line congestion and customer economic losses owning to contingency.

As a result, if expected energy not supplied (EENS) is used to present the reliability of a system, then the objective functions of transmission planning can be updated to the following optimization problem.

Min \( \text{COST} = C^T \eta_{\text{min}} + \sum_{g} V_g \cdot G_g \) \( (14) \)

Min \( \text{EENS} = \sum_{j=1}^{nC} L_{g_j} \cdot D_j \cdot f_j \) \( (15) \)

Min \( \text{EEL} = \beta \cdot \sum_{j=1}^{nC} L_{g_j} \cdot NCP \) \( + \sum_{x \in \text{line,} y \in \text{C}} (\int_{\text{Qd(0,Q)}} (F_p(Q) - F_p(Q)) \cdot dQ) \cdot P_{sy} \) \( (16) \)

Min \( \text{TEF} = \int_{\text{medium load}} \sum_{k} \sum_{j} L_{g_k} P_{j} dt \) \( (17) \)

Subject to

\( P_l - \sum_{j=l}^{n} V_j (G_g \cos \delta_g + B_g \sin \delta_g) = 0 \) \( (18) \)

\( Q_l - \sum_{j=l}^{n} V_j (G_g \cos \delta_g - B_g \sin \delta_g) = 0 \) \( (19) \)

\( P_{\text{min}} \leq P \leq P_{\text{max}} \) \( (20) \)

\( Q_{\text{min}} \leq Q \leq Q_{\text{max}} \) \( (21) \)

\( V_{\text{min}} \leq V \leq V_{\text{max}} \) \( (22) \)

This planning approach is a complex optimization problem, which may cause difficulties in conventional optimization techniques. In this paper, binary genetic algorithms multi-objective optimization tool are utilized to solve the problem. GA is good at finding “acceptably good” solutions with “acceptably quick” time.

By running GA, three options are obtained. They are to build different new lines between different buses.

Option 1: build a new transmission line between bus 7 and bus 8.

Option 2: add a new line between bus 8 and bus 9.

Option 3: add a new line between bus 8 and bus 10.

Table IV shows the system data after expansion. Option 1 spends the minimum cost however achieves the highest reliability with the least EEL. Simultaneously, option 1 is the most flexible plan which has the minimum value of TEF. Therefore, option 1 will be chosen as the most optimal plan.

VI. CONCLUSION

In this research work, a new probabilistic criterion is proposed for transmission planning in a single side bidding Poolco model electricity market. The proposed EEL has the ability to balance the tension between investors who desire market freedom, and the system operators who require commitment in order to ensure power systems adequacy and security. The new index EEL extents conventional reliability worth/reliability cost to a Market–based criterion. It tries to spirit up the competition between generations and provides open access to all market participants. Meanwhile, reliability cost caused by market and power system uncertainties has been taken into account.

The case study was illustrated using the IEEE RTS. By applying EEL, more accurate objectives of TEP in a deregulated electricity market were presented. The results imply that EEL will be a valuable index for power system planners in predicting current transmission network bottleneck in future operational condition. Moreover, it offers a more accurate criterion for assessing grid economics losses under restructured market conditions.

The significances of EEL are that 1) it improves the traditional reliability cost. It not only measures the economical losses of load curtailment but also the social benefit losses of unoptimizable operation. 2) NCP used in the computation can simplify the calculation and enable EEL to apply on large realistic power system. 3) It can be used to predict current transmission network bottleneck in future. Consequently, it enables planners to assess the worth of providing reliable service. 4) It is a criterion for managers to determine optimal expansion plans.

VII. APPENDIX

TABLE V COMPOSITE CUSTOMER DAMAGE FUNCTION FOR EACH BUS

<table>
<thead>
<tr>
<th>Duration (h)</th>
<th>0.017</th>
<th>0.3333</th>
<th>1</th>
<th>4</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bus 1</td>
<td>0.658</td>
<td>1.911</td>
<td>5.519</td>
<td>17</td>
<td>43.213</td>
</tr>
<tr>
<td>Bus 2</td>
<td>0.072</td>
<td>0.613</td>
<td>2.011</td>
<td>9</td>
<td>29.131</td>
</tr>
<tr>
<td>Bus 3</td>
<td>0.574</td>
<td>1.591</td>
<td>4.769</td>
<td>15</td>
<td>37.241</td>
</tr>
<tr>
<td>Bus 4</td>
<td>0.094</td>
<td>0.774</td>
<td>2.485</td>
<td>11</td>
<td>33.295</td>
</tr>
<tr>
<td>Bus 5</td>
<td>0.532</td>
<td>1.728</td>
<td>5.056</td>
<td>17</td>
<td>42.202</td>
</tr>
<tr>
<td>Bus 6</td>
<td>0.623</td>
<td>1.729</td>
<td>5.026</td>
<td>16</td>
<td>39.144</td>
</tr>
</tbody>
</table>
More details of bidding price can be found in [10].

VIII. REFERENCES


IX. BIOGRAPHIES

Miao Lu obtained her Master of Information Technology degree from Griffith University, Australia in 2003 and B.E. in Electrical Engineering from North China Electrical Power University (Beijing) in 1998. She is now pursuing her PhD in Electrical Engineering degree at The School of Information Technology and Electrical Engineering, The University of Queensland, Australia. Her research interests include power system analysis, power system planning, reliability assessment and risk management, and power system computations.

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