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Transmission Network Expansion Planning Using Reliability and Economic Assessment

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Abstract – This paper presents a probabilistic approach of reliability evaluation and economic assessment for solving transmission network expansion planning problems. Three methods are proposed for TNEP, which are reorganizing the existing power system focused on the buses of interest, selecting candidates using modified system operating state method with healthy, marginal and at-risk states, and finally choosing the optimal alternative using cost-optimization method. TNEP candidates can be selected based on the state reliability such as sufficient and insufficient indices, as proposed in this paper. The process of economic assessment involves the costs of construction, maintenance and operation, congestion, and outage. The case studies are carried out with modified IEEE-24 bus system and Jeju island power system expansion plan in Korea, to verify the proposed methodology.

Keywords: Transmission network expansion planning (TNEP), State probability, Reliability evaluation, Economic assessment

1. Introduction

For last some years, power system needs to meet the rapid growing electric demand and future power supply while overcoming a set of economic and technical constraints. The power system planners should address the concerns such as broadening and strengthening the existing situation, which is named as the Transmission Network Expansion Planning (TNEP). However, it is very difficult to obtain the optimal alternate of TNEP regarding generating units, transformers, transmission lines and other network facilities at the same time due to complexity of power system.

Therefore, various methods have been introduced to demonstrate the reasonable application to practical TNEP and can be classified by using the mathematical optimization models and heuristic methods [1-2]. Recently, TNEP has been modeled through probabilistic method to keep security and reliability criteria as well as power market concepts [3-8]. The main focus of these methods is minimizing the total costs or investment capital, and maximizing in social welfare or investor's benefits [7-10]. Among these, system operating state method is introduced to evaluate reliability in the relatively simple way only with the expected generation capacity instead of complicated reliability indices such as LOLE and LOLP [11-12].

Within the framework stated above, TNEP problem determines the installation place and planning horizon of transmission facilities using economic assessment method whose goal is the minimization of cost or social welfare maximization.

These general TNEP problems should start all possible candidates, and screen them with the constraints of power flow and reliability assessments to obtain optimal alternative [13-14]. The constraints of power flow are for the convergence and stability of power system, and those of reliability are for ensuring the power system security. The screening processes with the constraints of both power flow and reliability assessment contain the complex calculation such as MINLP (Mixed Integer Nonlinear Programming), the various heuristic methods and Monte Carlo simulation [15-16].

This paper proposes a methodology for assessing the reliability requirement and the economic impact of TNEP which is tried as simply as possible. The concepts of inner and outer generators are introduced and two power distribution factors are proposed for outer generators and transmission lines, in addition to reorganization of power system method which is introduced to calculate the contributions of individual generators and loads to line flows in reference [17-18]. System operating state method [11-12] is modified in this paper with the corresponding state reliability indices according to the expected capacities and probabilities for the cases of normal and (N-1) contingencies, respectively, in order to make the choice of candidates among the transmission lines connected between sufficient and insufficient buses which are defined by state reliability indices. A series of these processes is provided to be substituted for existing screening method.

Thereafter, economic assessment by using cost-optimization is performed for selecting the optimal alternative among the chosen candidates

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2. Reliability Evaluation for Choosing Candidates

2.1 Power amount supplied to a bus

Usually in power system, an equivalent circuit from the viewpoint of power balance at a bus of interest can be constructed with three elements; inner and outer generators, loads and transmission lines [17-18]. Inner generators are connected to bus directly, and outer generators are connected remotely through some transmission lines connected to the bus of interest. Fig. 1 configures the equivalent circuit observed at a bus k, where G is generation capacities and the superscripts I and O denote inner and outer generators, respectively. T_l is rated transfer capacity through line l and $I_{k,l}$ is an index of connection between bus k and line l (connect: 1, disconnect: 0).

Generally, the demand of system should be met by generation of inner and outer generators under the consideration of the capacity of each generator with the assumption of lossless transmission lines.

$$\sum_{k=1}^{K} D_k = \sum_{g=1}^{N} G_{k,g}^{I} + \sum_{m=1}^{M} G_{k,m}^{I} \tag{1}$$

where, N : the number of inner generators
M : the number of outer generators
K : the number of buses

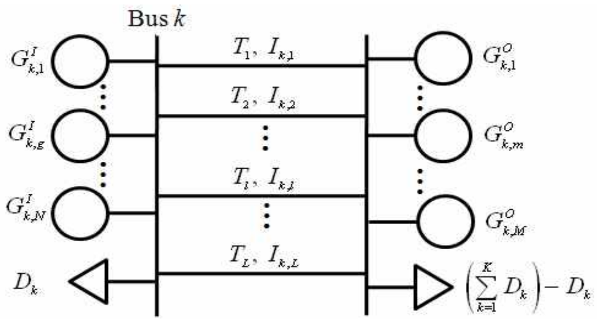

Fig. 1. Inner and outer generators of an interest bus

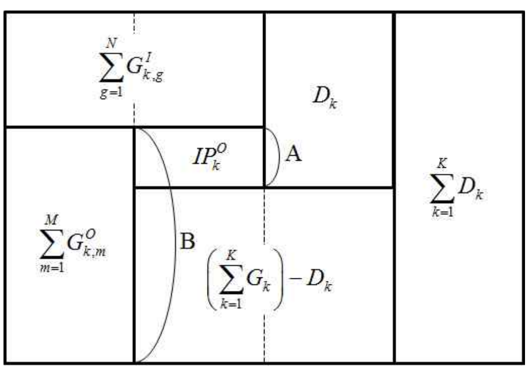

Fig. 2. Power balance diagram at interest bus k

The relationship between demand, inner and outer generations is illustrated in Fig. 2, where the summations of the variables are all the same vertically.

Out of the total amount of outer generators looking at bus k of interest, only a part of it is supplied to the demand at bus k when the amount of inner generators is not enough for its demand. In order to calculate the amount of injection power from outer generators to a specific bus k, IP_k^O, distribution factor of outer generation is defined in this paper as follows,

$$\begin{aligned} DF_k^O &= \frac{\mathrm{A}}{\mathrm{B}} \text{ in Fig. 2} \\ &= \frac{D_k - \sum_{g=1}^{N} G_{k,g}^{I}}{\sum_{k=1}^{K} D_k - \sum_{g=1}^{N} G_{k,g}^{I}} \end{aligned} \tag{2}$$

Then injection power to the bus k can be calculated as

$$IP_k^O = \sum_{m=1}^{M} G_{k,m}^{O} \cdot DF_k^O \tag{3}$$

where it should be less than total rated capacity of transmission lines connected to bus k.

$$IP_k^O \le \sum_{l=1}^{L} \left(T_l \cdot I_{k,l} \right)$$

Actually, injection power (IP_k^O) which is calculated by using distribution factor of outer generation and capacity of outer generators in bus k, can be regarded as the source through transmission lines. Therefore this power is necessary to be separated at each transmission line. The capacity ($T_{k,l}$) of each transmission line is computed by power distribution factor per line ($RA_{k,l}$),

$$T_{k,l} = IP_k^O \cdot RA_{k,l} \tag{4}$$

where,

$$RA_{k,l} = \frac{T_l}{\sum_{l=1}^{L} \left(T_l \cdot I_{k,l} \right)} \cdot I_{k,l} \tag{5}$$

2.2 Expected capacity and probability

As stated above, capacity of outer generators can be converted into the power flow of transmission lines, and the supplying resources to a bus consist of inner generators and transmission lines. Let $\boldsymbol{E}_k$ be a vector of the capacity of supplying resource at bus k, which are generators and transmission lines, then

$$\begin{aligned}\boldsymbol{E_k} &= \left[G_{k,1}^{I},\cdots,G_{k,g}^{I},\cdots,G_{k,N}^{I},T_{k,1},\cdots,T_{k,l},\cdots,T_{k,L}\right] \\ &= \left[\boldsymbol{G_k^I} \;\; \boldsymbol{T_k}\right], \qquad \text{where } \boldsymbol{T_k} \in \left\{T_l \mid I_{k,l}=1\right\}, \forall l\end{aligned} \tag{6}$$

Status i is defined in this paper as a set of condition of each supplying resource. The condition of supplying resource $E_{k,j}$ can be represented by $S_{k,j}^{i}$ for ith status and jth supplying resource at bus k. Then the status vector and matrix of bus k can be defined as

$$\begin{aligned}\boldsymbol{S_k^i} &= \left[s_{k,1}^{i},\cdots,s_{k,g}^{i},\cdots,s_{k,N}^{i},s_{k,1},\cdots,s_{k,l},\cdots,s_{k,L}\right] \\ &= \left[\boldsymbol{s_{k,g}^i} \;\; \boldsymbol{s_{k,l}}\right], \text{ where } s_{k,1} \in \left\{s_{k,1} \mid I_{k,l}=1\right\}, \forall l\end{aligned} \tag{7}$$

$$\boldsymbol{S_k} = \begin{bmatrix} \boldsymbol{S_k^1} \\ \vdots \\ \boldsymbol{S_k^i} \\ \vdots \\ \boldsymbol{S_k^{2^{J_k}}} \end{bmatrix} = \left[\left[\boldsymbol{S_k^1}\right]^T \left[\boldsymbol{S_k^2}\right]^T \cdots \left[\boldsymbol{S_k^i}\right]^T \cdots \left[\boldsymbol{S_k^{2^{J_k}}}\right]^T\right]^T \tag{8}$$

where,

J_k : the number of supplying resource of $\boldsymbol{E_k}$

$s_{k,g}^{i}$, $s_{k,l}$ = 1 or 0

$n(\boldsymbol{S_k^i}) = J_k$, $n(\boldsymbol{S_k}) = 2^{J_k} \times J_k$

In normal state without any contingencies, expected capacity in any bus k for the status i can be defined as the capacity multiplied by the probability of status i and calculated as

$$\boldsymbol{EC_k^{N,i}} = P_k^i \cdot \left(E_k \cdot \left[\boldsymbol{S_k^i}\right]^T\right) \tag{9}$$

and the probability of status i can be evaluated as

$$P_k^i = \prod_{j=1}^{J_k}\left\{A_{k,j}\cdot s_{k,j}^{i} + \left(1-A_{k,j}\right)\cdot\left(1-s_{k,j}^{i}\right)\right\} \tag{10}$$

where

$$\sum_{i=1}^{2^{J_k}} P_k^i = 1$$

$A_{k,j}$ is availability of jth supplying resource at bus k.

Similarly, expected capacity when contingency occurs in addition to normal state, can be evaluated by eliminating a supplying resource which has the largest capacity in normal operating state. The expected capacity of (N-1) contingency state in bus k can be calculated as

$$EC_k^{N-1,i} = \text{min of}\left[EC_k^{N,i} - E_{k,j}\cdot P_k^i \cdot s_{k,j}^{i}\right] \tag{11}$$

where $E_{k,j}$ is j-th element of $\boldsymbol{E_k}$, and where $EC_k^{N-1,i}$ is the expected capacity of (N-1) contingency which means one of the in-serviced supplying resource j is additionally faulted from the status i of normal state.

2.3 Modified system operating state method

Modified system operating state method is introduced to evaluate reliability in the relatively simple way only with the expected generation capacity instead of complicated reliability indices such as LOLE and LOLP [11-12]. In this method, the system states are classified into three categories such as healthy, marginal and at-risk state and various candidates for TNEP can be suggested by using the probability of each state. The three states are defined as,

2.3.1 Healthy State

The healthy state is defined as the states where all supplying resources and operating constraints are within limits. At normal operating state and at (N-1) contingency state, the power supply covers its demand without any cases causing system problems.

2.3.2 Marginal State

If a system enters a condition which the loss of some supplying resources covered by the operating criterion will result in a limit violation, then the system is called in the marginal state. In this marginal state, the supply covers its demand at normal state, whereas doesn't meet its demand if (N-1) contingency occurs.

2.3.3 At-risk State

The supplying resources and operating constraints are violated and the intended function of the system is not satisfied even at normal operating state in this at-risk state.

As defined above, in any status i, since the power supply at the healthy state can cover its demand both at normal state and (N-1) contingency, the probability of the healthy state at bus k, $P^H(D_k)$ can be evaluated by summing up the probabilities for minimal expected capacity of all (N-1) contingencies should be larger than the demand..

$$P^H\left(D_k\right) = \sum_i P_k^i, \;\; i \in \left\{EC_k^{N,i} > D_k \text{ and } EC_k^{N-1,i} > D_k\right\} \tag{12}$$

In contrast, at-risk state is the probability that cannot meet its demand even when the state is normal,

$$P^R\left(D_k\right) = \sum_i P_k^i, \;\; i \in \left\{EC_k^{N,i} < D_k\right\} \tag{13}$$

Finally, marginal state is defined as the intermediate state between healthy and at-risk state as represented by (14), and the probability of marginal state can be calculated by using the probabilities of healthy and at-risk state as

(15) because these states are mutually exclusive each other.

$$P^M\left(D_k\right)=\sum_i P_k^i,\ \ i\in\left\{EC_k^{N,i}>D_k \text{ and } EC_k^{N-1,i}<D_k\right\} \quad (14)$$

$$P^H\left(D_k\right)=1-P^H\left(D_k\right)-P^R\left(D_k\right) \quad (15)$$

2.4 State reliability indices

System reliability is an important factor in the consideration of planners, designers and operators, and can be identified through modified system operating state method.

In practice, since the amount of power capacity suppliable to the system even when (N-1) contingency occurs and also the case not suppliable to the system even when normal state should be identified for TNEP, state reliability indices such as T_{50}^H and T_{50}^R are introduced in this paper, which are defined as the amounts of power whose probabilities are over 50% for the corresponding cases, respectively.

Fig. 3 shows an example of distribution of these three state probabilities varying with demand, where T_{50}^H is the capacity which should supply demand in case that healthy state probability is 50%. In other words, when system supplies demand with T_{50}^H, system can supply power for demand with probability of 50% even at (N-1) contingency. Similarly, T_{50}^R is the capacity in case that at-risk state probability is 50%. Once the curves in Fig.3 are obtained, T_{50}^H and T_{50}^R can be also obtained as the points of the state probability 0.5 and healthy and at-risk curves.

At this point of T_{50}^H, this figure shows that probability of marginal state is 0.3. It means, as described in the definition of marginal state, the capability should supply perfectly the demand in normal condition and cannot at (N-1) contingency with the probability of 0.3. Similarly, the probability of at risk state is 0.2 at this point and it cannot supply the demand with the probability of 0.2 even at normal condition.

As can be seen in Fig. 3, the system states can be easily distinguishable from demand and power supply using the state reliability indices such as T_{50}^H and T_{50}^R. Oppositely remarking, the maximum capacity which can be reliably provided and minimum capacity not suppliable to the system can be estimated depending on the value of state probability chosen in advance.

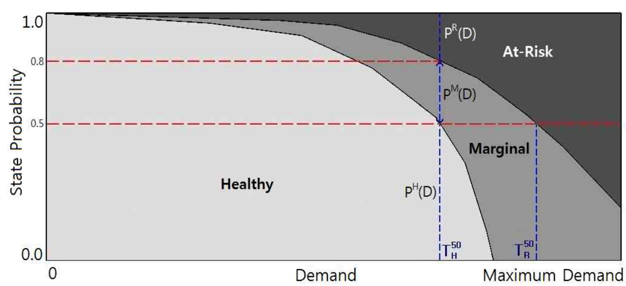

Fig. 3. Distribution diagram of three state probability

2.5 TNEP candidates and their expandable capacities

Sufficient index is defined in this paper as a degree of sufficiency in which the available capacity of healthy state is how much larger than the demand compared with the total demand, and is represented for bus k of interest as

$$SI_k=\frac{T_{50,k}^H-D_k}{\sum_{k=1}^{K}D_k}\cdot 100(\%) \quad (16)$$

Similarly, insufficient index is defined as the lack of degree of power supply and can be calculated as

$$ISI_k=\frac{D_k-T_{50,k}^R}{\sum_{k=1}^{K}D_k}\cdot 100(\%) \quad (17)$$

Thereafter, sufficient and insufficient buses are classified in this paper by sufficient and insufficient indices, respectively. Finally, TNEP candidates will be chosen among the transmission lines connected between sufficient and insufficient buses.

3. Cost-optimization

Cost-optimization is to select the optimal alternate which is the least cost or maximum net benefit among candidates [19-21]. In this paper, candidates chosen by sufficient and insufficient indices as stated above are compared each other with cost-optimization, and the least cost candidate is selected finally as an optimal alternate of TNEP within the constraints of the conventional power flow equation, and the minimum and maximum capacity of generation and transmission line.

$$\begin{aligned} min\left[C\right]&=Cost-Benefit\\ Cost&=C_{cons}+C_{M\&O}\\ Benefit&=B_{cong}+B_{out}\end{aligned} \quad (18)$$

where, C : total cost [$]
C_{cons} : construction cost [$]
$C_{M\&O}$: annual equivalent M&O cost [$]
B_{cong} : benefit of alleviated congestion [$]
B_{out} : outage cost saved by TNEP [$]

If new equipment is installed for TNEP, construction and maintenance costs will be increased but congestion and outage costs will be decreased instead. The economic benefit should be maximized if the summation of congestion and outage costs is higher than construction and maintenance costs. All the costs in (18) can be as simplified as possible because the purpose of the TNEP in this paper is only for planning stage.

3.1 Construction cost

Construction cost will be changed widely according to installation place and method. Actually, exact construction cost can be judged only when the construction is completed. Construction cost needs to be estimated as simply as possible for TNEP, and is performed by multiplying planned capacity of generator and line length by cost of generator and transmission line which are from the historical data. Then the estimated construction cost in the planning stage can be formulated as (19).

$$C_{cons} = c_G \cdot x_G + c_T \cdot x_T \tag{19}$$

where, c_G : cost of generator construction [$/MW]
x_G : additional generator capacity by TNEP [MW]
c_T : cost of transmission line construction [$/km]
x_T : planned transmission line length [km]

3.2 Maintenance and operating cost

The M&O cost includes the costs of regular maintenance, repairs, stocking spare parts, insurance, land lease fee, administration, etc. However, since this cost is so complex to calculate exactly and is immeasurable due to its wide variety of consideration and uncertainty for the future, it is assumed to be constant in the planning stage. It also occurs every year during the economic life and the total annual equivalent M&O cost is represented by net present value (NPV) as

$$C_{M\&O} = \sum_{t=1}^{T} \frac{c_m}{(1+I)^T} \tag{20}$$

where c_m is the annual equivalent M&O cost, I discount rate and T economic life of transmission line which is 20 years in this paper

3.3 Congestion cost

Configuration of transmission network and generator location can cause congestion problems [22]. After economic dispatch is performed, congestion can be identified based on the constraints of line capacity. To overcome the congestion, more expensive generators may be in-service (x_{con} in Fig. 4) additionally in the adjacent area of demand, and the inexpensive generators scheduled by economic dispatch are changed into out-of-service (x_{coff} in Fig. 4) instead [23-24].

Generally, congestion makes the prices different between two areas which are called as local marginal prices (LMPs), and congestion cost occurs due to the difference of LMPs.

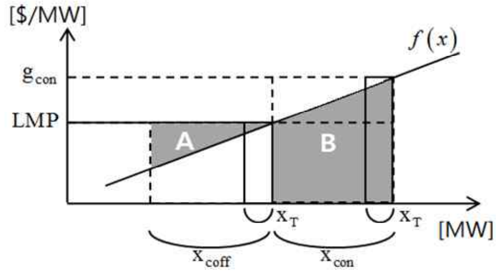

Fig. 4. Concept of congestion cost

In Fig.4, the generators out-of-serviced (x_{coff}) due to the congestion should be compensated by uplift as depicted in area A, and also the cost (area B) is added due to newly in-serviced generators (x_{con}). Congestion cost before TNEP is defined as the summation of two areas A and B, and is represented as

$$C_C^B = \int_{x_{coff}} \left(LMP - f(x)\right)dx + \int_{x_{con}} f(x)\,dx \tag{21}$$

where $f(x)$ is generation cost function. In Fig. 4, if it is assumed that $x_{coff} \approx x_{con}$ and

$$\int_{x_{coff}} \left(LMP - f(x)\right)dx \approx \int_{x_{con}} \left(g_{con} - f(x)\right)dx \tag{22}$$

where g_{con} is marginal cost of additional generator.

Then (22) can be simplified as

$$C_C^B = x_{con} \cdot g_{con} \tag{23}$$

After TNEP, congestion cost will be decreased if the congestion is alleviated due to the increased capacity (x_T) of transmission line by expansion, then the generation capacity out-of-serviced and in-serviced (x_{coff} and x_{con}) would be decreased by x_T. Congestion cost after TNEP can be calculated as

$$\begin{aligned} C_C^A &= \int_{x_{coff}-x_T} \left(LMP - f(x)\right)dx + \int_{x_{con}-x_T} f(x)\,dx \\ &\approx \left(x_{con} - x_T\right) \cdot g_{con} \end{aligned} \tag{24}$$

In this paper, the benefit of congestion alleviation can be estimated by the difference of congestion cost before and after transmission construction, and is simply represented as

$$\begin{aligned} b_{cong} &= C_C^B - C_C^A = g_{con} \cdot x_T \\ B_{cong} &= \sum_{t=1}^{T} \frac{b_{cong}}{(1+I)^t} \end{aligned} \tag{25}$$

3.4 Outage cost

Outage cost is evaluated in two ways, macro and micro methods. The former is conceived on the point that economic loss occurs after power interruption as economic activities are halted, while the latter is based on the survey of individual customers. From the viewpoint of micro method, the outage cost would be increased drastically according to its duration, while the outage duration is not considered as much in macro method. Generally, power system planners do not consider outage duration because it is much shorter than transmission planning period.

In this paper, for simplification, the benefit of outage cost saved by the increased capacity (x_T) is calculated by macro method using the value of electricity which contributes to GNP, and is represented as follows

$$b_{out} = c_o \cdot x_T \cdot \left(1 - p_T\right) \cdot r_p$$
$$B_{out} = \sum_{t=1}^{T} \frac{b_{out}}{\left(1+I\right)^t} \tag{26}$$

where, c_o : GNP per total annual system demand [\$/MWh]
p_T : FOR of installed transmission line
r_p : average repair times [hr]

In practice, FOR (Forced Outage Rate) of the equipment to be installed doesn't exist and is determined in this paper by using FOR of similar equipment already installed.

4. Case Studies

4.1 Modified RTS 24 bus system (MRTS)

The first case study is performed to apply the proposed method and check the availability by using 24-bus IEEE RTS (Reliability Test System) which is modified to increase the capacities of all generators by 10% because total expected generation capacity in the original RTS is less than the load at (N-1) contingency.

LOLE of whole MRTS system is 2.4623[hr/yr] while the system reliability criterion for LOLE is required to the value of 2.4[hr/yr]. This system does not meet the system reliability criterion, but expected generation capability for normal state considering failure rate of inner generators at each generation bus (see Table 1) is enough to supply demand (2,850[MW]).

The expected capacities of normal operating state and (N-1) contingency state can be calculated for whole system, and they are 3,494.8[MW] and 2,812.5[MW], which are corresponding to the values of T_{50}^{H} and T_{50}^{R}, respectively. The probabilities of healthy, marginal and at-risk state can be estimated as explained in (12)-(15) and then Fig. 5 can be obtained by comparing expected capacity of each state and demand. The state probabilities of each state are also depicted in Fig. 5, where at the point of T_{50}^{H} , the values of probabilities of healthy, marginal and at-risk state are 0.518, 0.404 and 0.078, respectively

This figure shows that T_{50}^{H} (2,812.5[MW]) is a little bit less than demand (2,850[MW]), while T_{50}^{H} is much greater than demand. Therefore, only transmission reinforcement, not generation addition, is required in this system.

In order to calculate the amount of power supplied to each bus, all transmission lines connected to the corresponding bus should be converted to power supplying sources as described in the section II-A. For example, supplying resources of buses #15 and #23 represented by E_{15} and E_{23} as explained in (6) are shown in Table 2.

Expected capacity and probability for normal and (N-1) contingency state at each bus can be calculated by using (9) - (11), and the graphs of expected capacity vs. probability are shown in Fig. 6 for the buses 15 and 23. Fig. 7 shows the complement of cumulative probabilities of Fig. 6 and they can be regarded as the state probabilities of healthy, marginal and at-risk state for the buses 15 and 23 as expressed in (12) and (15), compared with Fig. 5 for the whole system.

As similar as the process of the whole system evaluation in Fig. 5, the values of T_{50}^{H} and T_{50}^{R} of each bus are obtained and compared with the load of the corresponding

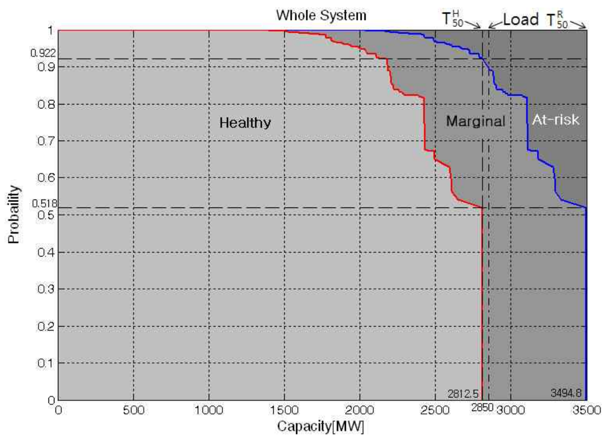

Fig. 5. Distribution diagram of probability for MRTS

Table 2. Supplying resources of buses of interest

Bus #15	15~21 #1	15~21 #2	15~24	15~16	Gen #15
Capacity[MW]	17.2	17.2	17.2	19.6	236.5
Availability	0.59	0.59	0.59	0.67	0.92
Bus #23	12~23	13~23	20~23 #1	20~23 #2	Gen #23
Capacity[MW]	184.2	195.7	253.3	253.3	726.0
Availability	0.48	0.51	0.66	0.66	0.94

Table 1. Generation Data of 24-bus IEEE MRTS

Bus	#16	#1	#2	#15	#7	#22	#18	#21	#13	#23	Total
Capacity [MW]	170.5	211.2	211.2	236.5	330.0	360.0	440.0	440.0	650.0	726.0	3775.5
Availability	0.96	0.96	0.96	0.92	0.96	0.96	0.88	0.88	0.95	0.94	

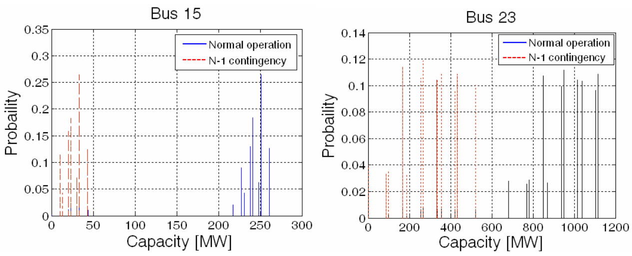

Fig. 6. State probability for buses #15 and #23

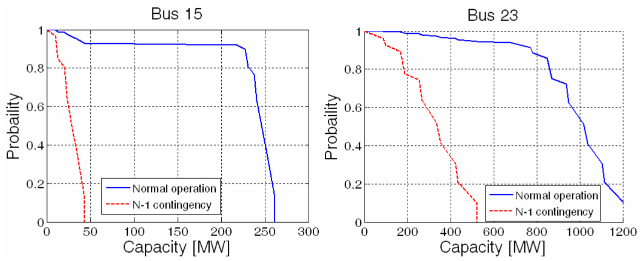

Fig. 7. Distribution diagram of probability for #15 and #23

Table 3. Sufficient and Insufficient Indices

Bus	Demand [MW]	[MW]	T_{50}^{R} [MW]	SI (%)	ISI (%)	Surplus capacity [MW]	Decision
1	108	48.2	250.9	-2.10	-5.01	-	-
2	97	56.7	257.6	-1.41	-5.64	-	-
3	180	24.4	163.6	-5.46	0.58	-	insufficient
4	74	0	24.4	-2.60	1.74	-	insufficient
5	71	0	28.3	-2.49	1.50	-	insufficient
6	136	0	60.6	-4.77	2.65	-	insufficient
7	125	161.5	326.7	1.28	-7.08	36.5	sufficient
8	171	34.8	89.1	-4.78	2.87	-	insufficient
9	175	95.7	334.0	-2.78	-5.58	-	-
10	195	106.9	186.2	-3.09	0.31	-	insufficient
11	0	0	0	0	0	-	-
12	0	0	0	0	0	-	-
13	265	157.3	774.9	-3.78	-17.89	-	-
14	194	0	71.6	-6.81	4.29	-	insufficient
15	317	23.3	240.8	-10.31	2.67	-	insufficient
16	100	36.3	199.9	-2.24	-3.51	-	-
17	0	0	0	0	0	-	-
18	333	29.3	416.5	-10.66	-2.93	-	-
19	181	43.2	92.2	-4.84	3.12	-	insufficient
20	128	45.4	71.1	-2.90	2.00	-	insufficient
21	0	127.8	556.0	4.48	-19.51	127.8	sufficient
22	0	124.8	470.3	4.38	-16.50	124.8	sufficient
23	0	1016.7	334.3	35.67	-11.73	1016.7	sufficient
24	0	0	0	0	0	-	-

bus, and the buses can be split into sufficient and insufficient ones which are determined by sufficient and insufficient indices as described in the section 2-5.

In Table 3, it can be seen that the most sufficient buses are 23, 21, 22 and 7, and the most insufficient buses 14, 19, 8 and 15. Candidates should be selected between sufficient and insufficient buses among these transmission lines because the purpose of TNEP is that the surplus power from sufficient bus should be supplied to the insufficient bus. The selected candidates and their system data are given in Table 4.

Table 4. Candidates of TNEP for MRTS

Bus #15	15~21 #1	15~21 #2	15~24	15~16	Gen #15
Capacity[MW]	17.2	17.2	17.2	19.6	236.5
Availability	0.59	0.59	0.59	0.67	0.92
Bus #23	12~23	13~23	20~23 #1	20~23 #2	Gen #23
Capacity[MW]	184.2	195.7	253.3	253.3	726.0
Availability	0.48	0.51	0.66	0.66	0.94

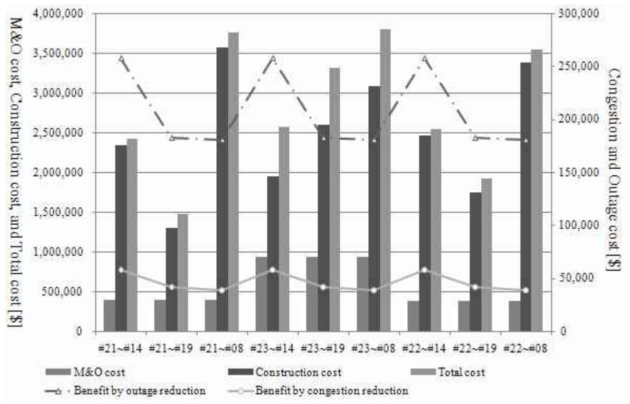

Fig. 8. Total costs of candidates

The costs of generation, M&O, outage and transmission line construction are assumed in this paper based on the real data from Power Trading Support System in Korea as 75.78[$/MW], 500.0[$/MW], 212.3[$/MW] and 65,000 [$/mile], respectively, and discount rate is 15%, because these data are not given in RTS.

The savings of congestion cost is calculated by using (25) with the value of generation cost, and marked by "o" in Fig. 8.

Outage cost can be computed by reduced interruption capacity and cost of outage when contingency occurs. For example, outage cost of new transmission line 21-14, can be calculated by contingency capacity (122.4[MW]) and cost of outage using (26), when FOR and repair time are assumed to be 0.33 and 3[hr], respectively.

Fig. 8 also shows the results calculated by economic assessment of each candidate. The congestion cost and outage cost are represented by solid and dotted lines, and the construction cost and total cost are expressed as histograms. In this figure, it can be concluded that the most efficient candidates are to install transmission line between bus 21 and 19 (candidate 2). After TNEP, reliability index (LOLE) is changed from 2.4623 to 2.3452 [hr/yr], and it can be seen that new index now meets the system reliability requirement 2.4 [hr/yr].

4.2 Jeju transmission expansion plan

In Korea, mainland and a separated Jeju island are interconnected by HVDC. KEPCO (Korea Electric Power

Table 5. Candidates of Jeju case study

Candidates	
Plan 1	Addition of new Generators (100 [MW], 2 Units)
Plan 2	Reinforcement of existing HVDC (100 [MW], 2 lines)
Plan 3	Installation of new HVDC (100 [MW], 2 lines)

Table 6. Threshold values of healthy and at risk states

	Healthy Region (T_{50}^{H})	At Risk Region (T_{50}^{R})
Plan 1	942 [MW]	1,136 [MW]
Plan 2	944 [MW]	1,175 [MW]
Plan 3	950 [MW]	1,180 [MW]

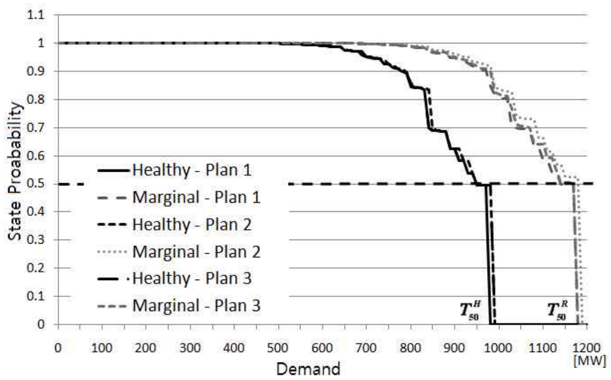

Fig. 9. Three state probabilities for Jeju

Corporation) as power system planner faces challenge to maintain the reliability because peak demand of Jeju is expected to increases significantly by 10 % every year in the following two decades and encounters the limit of capacity only with the existing HVDC. Under this situation, three candidates have been considered by KEPCO as shown in Table 5. These three candidates are examined thoroughly by using the proposed method.

Fig. 9 shows the regions of healthy, marginal and at risk states for each candidate of Plans 1, 2, and 3, and the values of T_{50}^{H} and T_{50}^{R} for healthy and at risk regions can be obtained as shown in Table 6.

The peak demand at Jeju is 613 [MW], and all the three plans are enough to the requirement of system reliability, and therefore, economic evaluation is followed to select the best candidate.

The real data of construction, generation and outage costs are given as follows;

- Construction Cost
  HVDC Expansion/Installation: 430.0[million $]
  New Generator Construction: 337.9[million $]
- Generation cost
  Main land (Year 2010): 75.14[$/MWh]
  Island (Year 2010): 164.27[$/MWh]
- Outage cost
  Main land (Year 2010): 3,590.6[$/MWh]
  Island (Year 2010): 4,917.6[$/MWh]
- Maintenance and operations cost

Table 7. Economic assessment for Jeju plans

	Construction	Maintenance	Congestion	Outage	NPV
	[million $]	[million $/Yr]			[million $]
Plan 1	337.9	5.3	14.4	9.0	-160.2
Plan 2	430.0	3.4	28.8	8.2	-100.1
Plan 3	430.0	3.4	28.8	9.0	-92.3

  HVDC (Year 2006): 3.4 [million $/Yr]
  Generator (Year 2006): 5.26[million $/Yr]
- Average repair time per year: 11 [hr]

For the case study, this research has been conducted for 20 years because life time of power equipment is usually estimated to be 20 years, and discount rate is assumed to be 8%. Construction cost is imposed once in the first year, while benefit of reduction of congestion and outage cost is brought every year during the life time.

In Table 7, the values of NPV are negative because only four kinds of elements are considered in this case study, although there should be many considerations in economic assessment which are the environment cost, financial expense, etc. If these costs are considered altogether, the value of NPV would be positive, but is difficult to estimate in real power system, especially in planning stage.

Nevertheless, it can be concluded that installation of new HVDC (Plan 3) is the best choice by comparing the NPV in Table 7. In reality, KEPCO have determined Plan 3 as the viable proposition

5. Conclusion

Power system planners face challenges to maintain the reliability of the system and to balances between reliability and economic efficiency for TNEP. This paper proposed simplified method to obtain TNEP in terms of reliability and economic assessment. Power system can be easily reorganized to obtain the expected capability with normal and N-1 contingencies, using the concept of inner and outer generator models. The TNEP candidates are selected by the modified system operating state methodology considering the corresponding state reliability indices according to the expected capacities and probabilities, and finally the optimal TNEP alternate is determined by minimizing the cost subject to the reliability constraints. The effectiveness of proposed approaches was demonstrated successfully on IEEE-RTS 24 bus system and ongoing expansion project including HVDC system in Korea.

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