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Market Based Transmission Expansion Planning For Indian Power Systems

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Abstract: *In this paper a new market Based approach for transmission expansion planning in deregulated power systems is presented. Restructuring and deregulation has exposed transmission planner to new objectives and uncertainties. Therefore, new criteria and approaches are needed for transmission planning in deregulated environments. In this paper we introduced a new method for computing the Locational Marginal Prices and new market-based criteria for transmission expansion planning in deregulated environments. The presented approach is applied to Southern Region (SR) 48-bus Indian System.*

Keywords: *Competitive electric market, Transmission expansion planning, Uncertainty, Scenario techniques, power transmission planning, price profile, risk analysis, uncertainty.*

I. INTRODUCTION

Transmission system is one of the major components of the electric power industry. If the electric loads increases, transmission expansion planning should be increased timely and proper way to facilitate and promote competition. Restructuring and deregulation of the power industry have changed the aims of transmission expansion planning and increased the uncertainties. Due to these changes, new approaches and criteria are needed for transmission expansion planning in deregulated power systems.

Transmission expansion planning approaches can be classified into:
• Non-deterministic approaches, and
• Deterministic.

In non-deterministic approaches the expansion plan is designed for all possible cases which may occur in future with considering the occurrence probability of them.

In deterministic approaches the expansion plan is designed only for the worst cases of the system without considering the probability of occurrence (degree of occurrence) of them. Hence, Non-deterministic approaches are able to take into account the past experience and future expectations.
Nondeterministic approaches can be classified in:
• Static, and
• Dynamic approaches.

2.1 Non-deterministic Transmission Expansion Planning Approaches

Uncertainties can be classified in two categories:
• Random, and
• Non-random uncertainties.
Random uncertainties are deviation of those parameters which are repeatable and have a known probability distribution. Hence, their statistics can be derived from the past observations. Uncertainty in load is in this category.

Non-random uncertainties are evolution of parameters which are not repeatable and hence their statistics cannot be derived from the past observations.

Non-deterministic approaches which have been used for transmission expansion planning are:
- probabilistic load flow,
- probabilistic based reliability criteria,
- scenario technique,
- decision analysis, and
- Fuzzy decision making.

Probabilistic load flow and probabilistic based reliability criteria approaches take into account random uncertainties. Scenario technique considers the non-random uncertainties. Decision analysis is a proper method for dynamic programming. Fuzzy decision making considers imprecision and vague data.

Review of the presented approaches and discussion of their advantages and drawbacks helps the procedure of presenting new approaches and criteria for transmission planning in deregulated environments. State of the art review on transmission expansion planning approaches is presented in this paper.
Transmission expansion planning approaches for:
• Regulated, and
• Deregulated power systems.

The main objective of power system planning in regulated power systems is to meet the demand of loads, while maintaining power system reliability. In this environment uncertainty is low. Transmission expansion planning is centralized and coordinated with generation expansion planning. Planners have access to the required information for planning. Therefore, planners can design the least cost transmission plan based on the certain reliability criteria.

In deregulated power systems participants take their decisions independently. They change their strategies frequently to acquire more information from the market to maximize their benefits. Consumers adjust their loads according to the price signals. Availability of independent power producers is uncertain. Wheeling powers are time varying and affect the nodal prices of the control areas that they pass through. Transmission expansion planning is not coordinated with generation expansion planning. Hence, there is not a specified pattern for load and dispatched power in deregulated power systems. Due to these uncertainties expansion of transmission networks have been faced with great risks in deregulated environments. Therefore, the final plan must be selected after the risk assessment of all solutions. Since risk assessment is characteristically based on probabilistic and stochastic methods, probabilistic methods should be developed for transmission planning in deregulated power systems.

2.2 Transmission Expansion Planning Approaches for Deregulated Power Systems

From the viewpoint of transmission planner, there are two major differences between transmission expansion planning in regulated and deregulated environments:

- Objectives of transmission expansion planning in deregulated power systems differ from those of the regulated ones.
- Uncertainties in deregulated power systems are much more than in regulated ones.

In this section objectives of transmission expansion planning in deregulated power systems and uncertainties in deregulated power systems are discussed.

2.3 Objectives of Transmission Expansion Planning in Deregulated Power Systems

In general, the main objective of transmission expansion planning in deregulated power systems is to provide a non-discriminatory competitive environment for all stakeholders, while maintaining power system reliability. Specifically, the objective of transmission expansion planning is providing for the desires of stakeholders. The desires of stakeholders in transmission expansion are:

- Investment cost will be decreased.
- The network charges will be decreased.
- The risk of investments against all uncertainties will be reduced.
- Encouraging and facilitating competition among electric market participants.
- Providing non-discriminatory access to cheap generation for all consumers.
- Operation cost will be reduced.
- Minimizing the costs of investment and operation.
- Increasing the reliability of the network.
- The value of the system will be increased.
- The flexibility of system operation will be increased.
- The environmental impacts will be decreased. and

2.4 Uncertainties and Vagueness in Deregulated Power Systems

Development of competitive electric markets has introduced significant uncertainties and vagueness in transmission expansion planning. Since methods of modeling random uncertainties, non-random uncertainties, and vagueness are different, power system uncertainties and vagueness must be identified and classified clearly before planning. Sources of random uncertainties in deregulated power systems are:

- power and bids of independent power producers (IPPs),
- generation costs and consequently bid of generators,
- Forced outage of generators, lines and other system facilities.
- wheeling transactions and power transactions with other areas, and
- load,
- Sources of non-random uncertainties are:
- Market rules.
- Generation expansion or closure.
- Load expansion or closure.
- Installation, closure or replacement of other transmission facilities.
- transmission expansion costs, and
- There is vagueness in the following data:
- occurrence degree of possible future scenarios,
- importance degree of stakeholders in decision making , and
- Importance degree of planning desires from the viewpoint of different stakeholders.

Uncertainties in deregulated environments have increased uncertainty in required capacity for transmission expansion and consequently increased the risk of fixed cost recovery. Therefore, incentives for investing in transmission expansion have reduced and caused a delay on transmission planning.

2.5. Scenario Technique

For the planning of any system we can use the Scenario technique and decision analysis. The algorithm of transmission expansion planning using scenario techniques is shown below.

i. To determine the set of probable future scenarios.
ii. To determine the occurrence probability or occurrence degree of future scenarios.
iii. To determine the set of possible solutions (expansion plans).
iv. To measure the goodness of expansion plans by selecting a cost function.
v. To select the final plan.

The final plan can be selected by using the following methods.

1. Expected cost method: This method selects the plan that minimizes the expected cost over different scenarios i.e.:

$$\underset{k}{Min}\ E^k = \sum_l v^l f^{k,l}$$

Where E^k = expected cost of plan k, v^l = occurrence degree of scenario l, $f^{k,l}$ = cost of plan k in scenario l.

2. Minimax regret method (risk analysis): In risk analysis the best solution is determined by minimizing the regret. Regret is a measure of risk. Regret of plan k in scenario l is defined as difference between the cost of plan k in scenario l and cost of the optimal plan of scenario l, i.e.:

$$r^{k,l} = f^{k,l} - f^{op,l}$$

Where $r^{k,l}$ = regret of plan k in scenario l, $f^{op,l}$ = cost of the optimal plan of scenario l. In risk analysis the plan that minimizes the maximum weighted regret over all future scenarios is selected as the final plan, i.e.:

$$\underset{k}{Min}\{\underset{l}{Max}(v^l r^{k,l})\}$$

3. Laplace method: According to this method the plan that minimizes the sum of costs over all scenarios is selected as the final plan.

4. Von Neumann-Morgenstern method: In this method is extremely pessimist and believes that the most unfavorable scenario is bound to occur. According to this criterion the plan that minimizes the maximum cost over all scenarios is selected as the final plan, i.e.:

$$\underset{k}{Min}\{\underset{l}{Max}(f^{k,l})\}$$

Alternatively, an extremely optimist criterion can be also used for selecting the final plan, i.e.:

$$\underset{k}{Min}\{\underset{l}{Min}(f^{k,l})\}$$

5. Hurwitz method: the plan that minimizes a convex combination of the extremely pessimist solution and the extremely optimistic solution is selected as the final plan.

6. Pareto-optimal method: A plan is Pareto-optimum if it is not dominated by any other plan. Plan X is dominated by plan Y if its cost is more than the cost of plan Y in all scenarios. This criterion is suitable for eliminating the worst solutions.

7. Robustness method: A plan is robust in a scenario, if its regret is zero in this scenario. According to this criterion, a plan is acceptable if it is robust at least in η% of the scenarios.

8. β-robustness method: According to this method a plan is acceptable if its over cost with respect to the related optimal plan does not exceed β% in each scenario.

III. LOCATIONAL MARGINAL PRICES (NODAL PRICE)

A Locational Marginal Price (LMP) is a pricing system for selling and purchasing electric energy in deregulated power systems. In the LMP pricing system, all producers sell energy at the price of their generator bus and all consumers purchase energy at the price of their load bus. By definition locational marginal price (LMP) nodal price is equal to the "cost of supplying next MW of load at a specific location, considering generation marginal cost, cost of transmission congestion, and losses". LMPs are the Lagrange multipliers or shadow prices of DC power flow constraints. The locational marginal price (LMP) is used to determine the price at each transmission bus or node. The locational marginal price (LMP) will encourages an efficient use of transmission system by assigning prices to the buyers. By using the locational marginal price (LMP), customers can sell and buy energy at the actual price of delivering energy at their buses or nodes.

In addition to the technical criteria, market based criteria is used to achieve the objectives of transmission expansion planning in deregulated power systems. In order to calculate and define the market based criteria, we need to calculate the Probability Density Functions (PDFs) of variables which shows the performance of electric market. These variables should be affected by dynamics of both power system and electric market. For assessing the performance of electric markets, we have to calculate the PDFs of LMPs. The “probabilistic optimal power flow” or “probabilistic locational marginal prices”, is used for calculating the PDFs of LMPs.

PDFs of LMPs will be affected if sellers can change their bids, sellers can change maximum or minimum of their submitted power, buyers change their bids for load curtailment, buyers can change maximum or minimum of their submitted power, transmission facilities (generator, transmission line, load,…) have forced outage, input or output power to the study area change due to new contracts with neighboring areas and wheeling transactions, or there is market power in the network. Hence, PDFs of LMPs contain more information about the power system and electric market. By analyzing the PDFs of LMPs, the performance of an electric market can be assessed.

IV. MARKET BASED CRITERIA

The main objective of transmission expansion planning in deregulated power systems is to provide a non-discriminatory competitive environment for all stakeholders, while maintaining power system reliability. To achieve this objective, it is needed to define some criteria to measure how competitive an electric market is and how much a specific expansion plan improves the competition.

In a perfect competitive market, which consists of infinity number of producers and consumers, the price is determined by interaction of all producers and consumers. In this market each customer produces or consumes only a small portion of the market production. Therefore, a producer or a consumer can not affect the price alone.

Hence, in competitive markets producers and consumers are price taker not price maker. In a competitive market there is no discrimination among producers or consumers i.e. all producers and consumers sell and buy at the same price. Moreover, in a competitive market there is no restriction for consumers to buy from any producer. To have a competitive electric market, the above conditions must be satisfied. On the other word, to have a competitive electric market all power producers and consumers must sell and buy electric energy at the same price and the power transfer restrictions must be alleviated. This means LMPs must be made equal at all buses and transmission congestion must be alleviated. Equalizing LMPs provides a nondiscriminatory market and alleviating congestion eliminates power transmission constraints.

In these section two probabilistic criteria, average congestion cost and standard deviation of mean of LMP, are proposed to measure how much a specific plan facilitates competition among customers. Average congestion cost shows how intensive transmission constraints are and consequently shows how competitive electric market is. Standard deviation of mean of LMP shows how mean of LMP spreads throughout the network. Therefore, it shows how discriminative and consequently how competitive electric market.

4.1. Average Congestion Cost

Congestion cost of a line is defined as the opportunity cost of transmitting power through it. Consider figure 4.1, line *i* of a network is depicted in this figure. The end buses of this line numerated with *i*1 and *i*2. $P_{l_{i_{1},i_{2}}}$ MW electric power transmits from bus *i*1 to bus *i*2 through this line. LMPs of buses *i*1 and *i*2 are *lmpi*1 and *lmpi*2 in $/MWhr. Buying 1 MW electric power from bus *i*1 costs *lmpi*1 $/hr and buying 1 MW power from bus *i*2 costs *lmpi*2 $/hr. Therefore, the opportunity cost of transmitting 1 MW electric power from bus *i*1 to bus *i*2 is equal to (*lmpi*2- -*lmpi*1) $/hr. Thus, congestion cost of line *i* or the opportunity cost of transmitting $P_{l_{i_{1},i_{2}}}$MW electric power from bus *i*1 to bus *i*2 through line *i* is equal to:

$$CCi = (lmpi2 - lmpi1)\, P_{l_{i_{1},i_{2}}} \quad i=1,2,\ldots\ldots,N_l$$

Where CCi is congestion cost of line *i* in $/hr

N_l is Number of network lines.

Total congestion cost of the network or the opportunity cost of transmitting power though the network is equal to:

$$tcc = \sum_{i=1}^{n_b} (lmpi2 - lmpi1)\, P_{l_{i_{1},i_{2}}}$$

where *tcc is* total congestion cost of the network in $/hr.

It can be proved that the total congestion cost of the network is equal to the sum of payments by loads minus sum of receives by generators, i.e.:

$$tcc = \sum_{i=1}^{n_b} P_{d_i} lmpi - \sum_{i=1}^{n_b} P_{g_i} lmpi$$

Where P_{d_i} load at bus *i* in MW, P_{g_i} generation power at bus *i* in MW, N_b *number* of network buses.

If there is no congestion in the network, the next MW of each load is supplied by the cheapest undispatched generation (marginal generator) and then LMPs of all buses are equal.

Average of the total network congestion cost after addition of plan *k* is equal to:

$$\mu_{tcc}^{k} = \frac{1}{N_r} \sum_{i=1}^{n_l} cc_{i,j}^{k}$$

with μ_{tcc}^{k} average of total congestion cost of the network in the presence of plan *k* in $/hr.

In the rest of this paper "average congestion cost" is used instead of "average of total congestion cost of the network".

4.2. Standard Deviation of Mean of Locational Marginal Price

Standard deviation of mean of LMP in the presence of plan *k*, where mean is taken over *Nr* samples and standard deviation is taken over *Nb* buses, is given by:

$$\sigma_{lmpi}^{k} = \sqrt{\frac{1}{N_b - 1} \sum_{i=1}^{N_b} (\mu_{lmpi}^{k} - \mu_{lmp}^{k})^2}$$

Where σ_{lmpi}^{k} is standard deviation of mean of LMP in the presence of plan *k* in $/MWhr, μ_{lmpi}^{k} mean of LMP of bus *i* over *Nr* samples in the presence of plan *k* in $/MWhr, μ_{lmp}^{k} mean of μ_{lmpi}^{k} over *Nb* buses in $/MWhr (average LMP of the network), μ_{lmp}^{k} is equal to:

$$\mu_{lmp}^{k} = \frac{1}{N_b} \sum_{i=1}^{N_b} \mu_{lmpi}^{k}$$

Standard deviation of mean of LMP in the presence of plan *k* ($\sigma_{\mu_{lmp}}^{k}$) indicates how spread out the mean of LMP of different buses (μ_{lmpi}^{k} for *i*=1, 2,…, *Nb*) are from the average LMP of the network (μ_{lmp}^{k}). As the standard deviation of mean of LMP decreases, differences among the mean of LMP of different buses decrease and the price profile become flatter. Flatter price profile indicates less price discrimination. As flatness of price profile increases, congestion cost decreases. Therefore, as the standard deviation of mean of LMP decreases, both transmission constraints and price discrimination decrease and hence competition is encouraged. In the same way as the standard deviation of mean of LMP increases, competition is discouraged. Therefore, standard deviation of mean of LMP is a proper criterion for measuring the competitiveness degree of electric markets.

V. MARKET BASED TRANSMISSION EXPANSION PLANNING

In this approach at first possible strategic scenarios, which may occur in planning horizon, are identified. PDFs of LMPs are computed for each scenario using probabilistic optimal load flow. Then some expansion plans (candidates) are suggested for transmission expansion by the analysis of electric market. Each of the candidates is introduced to the network and the market based criteria are computed for each scenario. The final plan is selected by risk analysis of the solutions. The presented approach can be precised in the following steps:

1. Identifying the set of possible strategic scenarios.
2. Compute the PDFs of LMPs for the existing network in each future scenario.
3. Suggesting candidates for transmission expansion by analyzing electric market.
4. Computing the market based criteria for each plan in each scenario.
5. Selecting the final plan by risk assessment of all expansion plans.
6. Computing the capacity of selected expansion plan.

VI. CASE STUDY: SOTHEREN REGION (SR) 48-BUS INDIAN SYSTEM

In this section the proposed approach is applied to the SR 48-bus system. Figure 1. shows the single line diagram of SR 48-bus system. Characteristics of generators and loads for the peak load of planning horizon are given in Tables I and II. It is assumed that the unavailability of each transmission line is equal to 0.001.

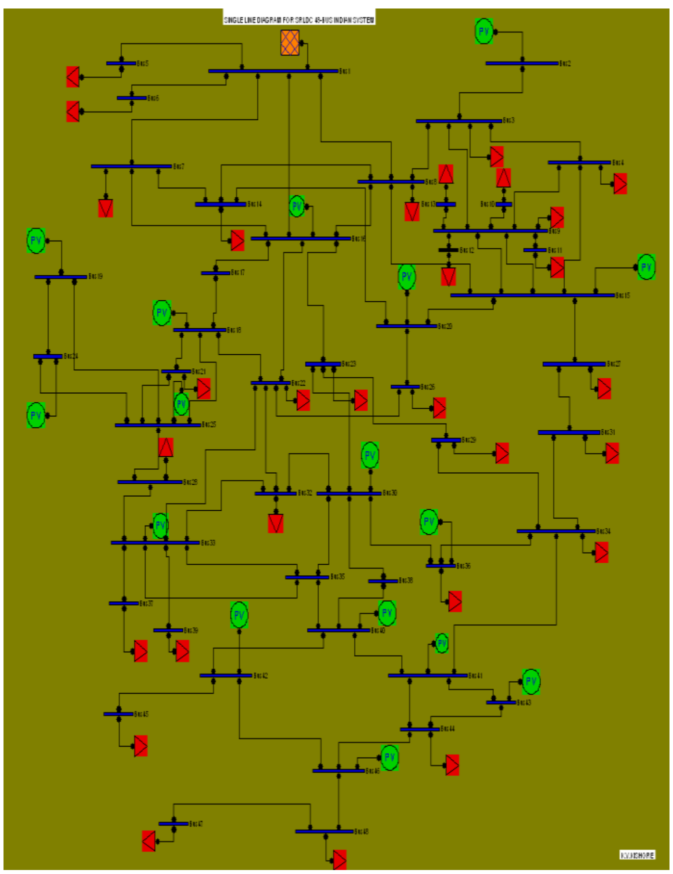

Fig.1.-Single line diagram of SR 48-bus system.

Table I. Characteristics generators

S.NO	BUS NO	GENERATOR DATA	LMP($/MWHR)
1.	1	1300	16.96
2.	2	1550	9.90
3.	15	1600	10.50
4.	16	1100	17.41
5.	18	1800	17.33
6.	19	1500	17.21
7.	20	1650	17.24
8.	24	1200	17.33
9.	25	1600	17.21
10.	30	1550	17.43
11.	33	1750	17.49
12.	36	1550	17.44
13.	37	1750	18.30
14.	40	1500	18.32
15.	41	1450	17.85
16.	42	1250	18.29
17.	43	1600	17.82
18.	46	1550	18.20

S.NO	BUS	LOAD	LMP($/MWHR)
1.	3	350	18.59
2.	4	450	16.66
3.	5	300	17.76
4.	6	250	17.78
5.	7	350	17.38
6.	8	500	16.84
7.	9	250	21.61
8.	10	350	21.73
9.	11	250	21.44
10.	12	300	21.14
11.	13	250	21.70
12.	14	350	17.35
13.	17	450	17.43
14.	21	750	17.51
15.	22	650	17.42
16.	23	350	17.65
17.	26	700	17.41
18.	27	300	18.81
19.	28	650	17.59
20.	31	250	18.74
21.	32	450	17.44
22.	34	950	18.54
23.	35	850	17.85
24.	38	950	18.69
25.	39	822	20.02
26.	44	1150	18.03
27.	45	860	18.62
28.	47	410	18.69
29.	48	400	18.51

Table II. Characteristics generators

6.1. THERE IS NOT ANY NON-RANDOM UNCERTAINTY

In this case there is only one scenario. Therefore, the minimax regret plan and the optimal plan are the same. Transmission planning is performed under the following market based criteria:

a. $\sigma_{\mu_{lmp}}$: Standard deviation of mean of LMP (SML).

b. $\sigma_{\mu_{lmp}, w=P_g}$: Standard deviation of mean of LMP weighted with mean of generation power (WG).

c. $\sigma_{\mu_{lmp}, w=P_d}$: Standard deviation of mean of LMP weighted with mean of load (WD).

d. $\sigma_{\mu_{lmp}, w=P_g+P_d}$: Standard deviation of mean of LMP weighted with mean of sum of generation power and load (WGD).

e. μ_{tcc} : Average congestion cost (ACC).

f. μ_{tlp} : Average load payment (ALP).

The Values of SML, WG, WD, WGD, ACC, and ALP in different stage of planning for SR 48-bus system are shown in table III(A-F). If a new line is added to the network, standard deviation of mean of LMP reduces from \$4.039958/MWhr for the line (5-10) to \$2.07781/MWhr for the line (7-24) and Average Congetion Cost reduces from \$1608.4091/hr to \$1037.48/hr are shown in table III.(A). If a new line is added to the network, standard deviation of mean of LMP reduces from \$5.3723/MWhr for the line (32-42) to \$2.6901/MWhr for the line (2-4) are shown in table III.(B).If a new line is added to the network, standard deviation of mean of LMP reduces from \$843.51/MWhr for the line (31-43) to \$1.2140/MWhr for the line (11-15) are shown in table III.(C).If a new line is added to the network, standard deviation of mean of LMP reduces from \$9.4147/MWhr for the line (36-38) to \$2.0625/MWhr for the line (40-44) are shown in table III.(D).If a new line is added to the network, standard deviation of mean of LMP reduces from \$20.410/MWhr for the line (34-42) to \$1.2360/MWhr for the line (11-20) are shown in table III.(E).If a new line is added to the network, standard deviation of mean of LMP reduces from \$2.1315/MWhr for the line (28-36) to \$2.0638/MWhr for the line (38-42) are shown in table III.(F).

A.

PLANS	ACTUAL	22-29	5--10	11--20	8--12	16-18	1--6	7--21	7--24
SML($/MWhr)	3.439327	3.0327	4.0399	2.9102	2.7547	2.5272	3.4126	3.6585	2.0778
WG($/MWhr)	9.932229	8.7553	11.666	8.3989	7.9529	7.2977	9.8527	10.565	5.9990
WD($/MWhr)	6.053525	5.3378	7.1106	5.1223	4.8486	4.4481	6.0066	6.4393	3.6572
WGD($/MWhr)	11.63161	10.254	13.662	9.8376	9.3144	8.5464	11.539	12.373	7.0259
ACC($/hr)	2152.176	6581.4	608.40	6432.8	2247.4	5644.2	4201.4	223.56	10371.
ALP($/MWhr)	141993.4	130690	146751	139927	138554	132151	141522	143490	127880

B

PLANS	ACTUAL	1--25	2--4	15-31	17-19	32-42	12--20	9--18	2--5
SML($/MWh	3.439327	2.6901	2.0369	4.5530	3.0903	5.3723	2.9206	32.561	3.2026
WG($/MWh	9.932229	7.7690	5.8801	13.146	8.9240	15.515	8.4291	93.993	9.2465
WD($/MWh	6.053525	4.7349	3.5851	8.0137	5.4392	9.4557	5.1406	57.311	5.6368
WGD($/MW	11.63161	9.0982	6.8869	15.396	10.451	18.169	9.873	110.08	10.829
ACC($/hr)	2152.176	2128.9	5679.3	1072.3	4437.1	9475.6	6013.0	59106.	2580.9
ALP($/MWh	141993.4	134233	129341	142498	138119	147009	139795	285011	141229

C

PLANS	ACTUAL	7--19	8--20	11--15	15-26	17-24	31-43	20-23	17-25
SML($/MWh	3.439327	2.0609	2.0928	1.2140	9.9763	2.0788	843.51	2.0715	2.0718
WG($/MWh	9.932229	5.9486	6.0415	3.5038	28.820	6.0018	2437.6	5.9799	5.9812
WD($/MWh	6.053525	3.6274	3.6836	2.1368	17.559	3.6589	1484.6	3.6460	3.6466
WGD($/MW	11.63161	6.9673	7.0760	4.1040	33.748	7.0292	2854.1	7.0038	7.0051
ACC($/hr)	2152.176	8943.5	4192.4	2491.2	27659	1600.7	175202	3098.5	3607.1
ALP($/MWh	141993.4	127499	128238	125648	174276	127892	163870	127580	127681

D

PLANS	ACTUAL	1--19	34-43	26-30	39-42	36-38	40-44	29-36	32-40
SML($/MWh	3.439327	2.0754	2.1630	2.0809	2.1797	9.4147	2.0625	2.0862	2.1220
WG($/MWh	9.932229	5.9914	6.2445	6.0078	6.2924	27.179	5.9556	6.0214	6.1268
WD($/MWh	6.053525	3.6529	3.8070	3.6625	3.8365	16.570	3.6301	3.6720	3.7349
WGD($/MW	11.63161	7.0172	7.3135	7.0362	7.3697	31.832	6.9747	7.0527	7.1755
ACC($/hr)	2152.176	2241.9	1783.9	2767.8	489.82	48170.	3459.5	6514.5	2886.4
ALP($/MWh	141993.4	127905	128576	128128	128357	153175	128070	127590	128708

E

PLANS	ACTUAL	11--20	27--36	41-31	34-42	20-27	29-30	22-30	9--20
SML($/MWh	3.439327	1.2360	2.1323	6.2583	20.410	2.0861	2.1162	2.0751	9.2893
WG($/MWh	9.932229	3.5666	6.1541	18.066	58.945	6.0209	6.1087	5.9914	26.810
WD($/MWh	6.053525	2.1755	3.7532	11.015	35.923	3.6717	3.7248	3.6524	16.350
WGD($/MW	11.63161	4.1777	7.2083	21.159	69.029	7.0522	7.1548	7.0169	31.402
ACC($/hr)	2152.176	4361.4	5984.3	16204.	9671.8	5422.2	6379.2	3882.7	19795.
ALP($/MWh	141993.4	125680	128004	137873	158640	127024	127957	127860	165716

F

PLANS	ACTUAL	7--16	1--20	44-42	30-34	38-42	45-40	21-20	28-36
SML($/MWh	3.439327	2.0777	2.0793	2.0802	2.0749	2.0638	2.0790	2.0824	2.1315
WG($/MWh	9.932229	5.9986	6.0032	6.0063	5.9874	5.9579	6.0023	6.0119	6.1542
WD($/MWh	6.053525	3.6569	3.6597	3.6613	3.6520	3.6325	3.6593	3.6653	3.7517
WGD($/MW	11.63161	7.0254	7.0309	7.0343	7.0133	6.9780	7.0298	7.0412	7.2076
ACC($/hr)	2152.176	1092.2	1014.5	1567.9	7114.0	3184.0	4747.1	3406.8	4303.8
ALP($/MWh	141993.4	127898	127928	127992	127431	127711	127922	127978	129106

Table III.(A-F). Values of SML, WG, WD, WGD, ACC, and ALP in different stages of planning.

6.2. THERE IS NON-RANDOM UNCERTAINTY

In this case it is assumed that the following non-random uncertainties have been identified by planners:

- A generator may be added at bus 9 of the network.
- An IPP may be added at bus 16 of the network.
- Load of bus 41 may be change.

Characteristics new generator, IPP, and load are given in table IV. To take into account these non-random uncertainties in transmission expansion planning, the following scenarios are defined:

- Scenario 1: base case (scenario which is shown in tables I and II)
- Scenario 2: base case plus the new generator
- Scenario 3: base case plus the load change
- Scenario 4: base case plus the IPP
- Scenario 5: base case plus the new generator and load change
- Scenario 6: base case plus the new generator and IPP
- Scenario 7: base case plus the load change and IPP
- Scenario 8: base case plus the new generator, load change, and IPP

It is assumed that all above scenarios have the same occurrence degree. SML, WG,WD, WGD, ACC, and ALP are used as planning criterion. In other word, SML, WG,WD, WGD, ACC, and ALP are used as cost function of risk analysis.

Table IV. Characteristics new GENERATOR, IPP, and LOAD.

TYPE	BUS NO	CHANGE IN MW
GENERATOR	9	500
LOAD	16	1600
IPP	41	500

It is assumed that all above scenarios have the same occurrence degree. SML, WG, WD, WGD, ACC, and ALP are used as planning criterion. In other word, SML, WG, WD, WGD, ACC, and ALP are used as cost function of risk analysis. Table V (a-f) shows the values of SML, WG, WD, WGD, ACC, and ALP in different scenarios and different stages of planning. (a) Values of SML when different criteria are used for planning. (b) Values of WG when different criteria are used for planning. (c) Values of WD when different criteria are used for planning. (d) Values of WGD when different criteria are used for planning. (e) Values of ACC when different criteria are used for planning. (f) Values of ALP when different criteria are used for planning.

a). SML

	EXIST.NET	STAGE-1	STAGE-2	STAGE-3	STAGE-4	STAGE-5	STAGE-6	STAGE-7	STAGE-8
PLAN	ACTUAL	7--18	1--20	44-42	30-34	38-42	44-40	21-20	28-24
SC1	3.439327	2.077712	2.079325	2.080234	2.07491	2.063855	2.079072	2.082477	2.131579
SC2	0.379874	0.378176	0.38068	0.385903	0.340236	0.374865	0.400305	0.384043	0.380804
SC3	2.911137	2.900426	2.91595	2.915491	2.282255	2.911521	2.705201	2.977165	2.908878
SC4	2.075711	2.069777	2.077115	2.077967	2.07155	2.061608	2.072854	2.08071	2.081175
SC5	1.632132	2.580389	1.646446	1.419588	1.168545	1.719564	1.392344	1.465178	1.445641
SC6	1.124504	1.124255	1.123859	1.12515	1.129791	1.124177	1.125628	1.125453	1.125359
SC7	2.891005	2.926367	2.885296	2.653102	2.279542	2.890466	2.636858	2.986106	2.899116
SC8	1.549003	2.575962	1.577001	1.513754	1.164728	1.647471	1.314106	1.406236	1.341017

b). WG

	EXIST.NET	STAGE-1	STAGE-2	STAGE-3	STAGE-4	STAGE-5	STAGE-6	STAGE-7	STAGE-8
PLAN	ACTUAL	7--18	1--20	44-42	30-34	38-42	44-40	21-20	28-24
SC1	9.932229	5.998658	6.003285	6.006352	5.987412	5.957992	6.002332	6.011972	6.154223
SC2	1.508193	1.061636	1.068734	1.083393	0.954741	1.052347	1.123818	1.078161	1.069048
SC3	12.08545	8.513487	8.559884	8.558598	6.695956	8.546248	7.941369	8.738986	8.539295
SC4	8.474957	5.975026	5.996749	5.999642	5.977621	5.951353	5.985253	6.006778	6.008384
SC5	6.588761	7.365249	4.699962	4.052462	3.334541	4.908196	3.974529	4.182331	4.126632
SC6	4.465503	3.156754	3.155781	3.159429	3.170941	3.156528	3.160699	3.160212	3.159917
SC7	12.00256	8.589256	8.470298	7.788931	6.687945	8.484807	7.74109	8.765357	8.511146
SC8	6.253363	7.352748	4.501849	4.321276	3.323592	4.702522	3.751521	4.014163	3.828267

c). WD

	EXIST.NET	STAGE-1	STAGE-2	STAGE-3	STAGE-4	STAGE-5	STAGE-6	STAGE-7	STAGE-8
PLAN	ACTUAL	7--18	1--20	44-42	30-34	38-42	44-40	21-20	28-24
SC1	6.053525	3.656959	3.659799	3.661399	3.652028	3.632571	3.659354	3.665346	3.751771
SC2	0.945561	0.665624	0.670031	0.679225	0.598847	0.659796	0.704573	0.67595	0.670249
SC3	7.367057	5.190129	5.217907	5.217087	4.08395	5.209982	4.840786	5.327449	5.205253
SC4	5.166742	3.642994	3.65591	3.657408	3.646115	3.628616	3.64841	3.662236	3.663056
SC5	4.130348	4.617442	2.94621	2.540262	2.091038	3.07705	2.491512	2.621844	2.586883
SC6	2.799053	1.97879	1.978093	1.980366	1.988534	1.978653	1.981206	1.980899	1.980733
SC7	7.31611	5.236548	5.163054	4.747557	4.079096	5.172305	4.718491	5.343447	5.187784
SC8	3.919976	4.609521	2.821943	2.708767	2.084207	2.948045	2.351509	2.516371	2.399666

d). WGD

	EXIST.NET	STAGE-1	STAGE-2	STAGE-3	STAGE-4	STAGE-5	STAGE-6	STAGE-7	STAGE-8
PLAN	ACTUAL	7--18	1--20	44-42	30-34	38-42	44-40	21-20	28-24
SC1	11.63161	7.025472	7.0309	7.034352	7.013303	6.978054	7.029855	7.041205	7.207652
SC2	1.258716	1.253047	1.261401	1.278705	1.127009	1.242081	1.32642	1.272533	1.261783
SC3	10.00829	9.970802	10.02488	10.02335	7.843117	10.00911	9.300459	10.23482	10.00071
SC4	7.018551	6.998025	7.023295	7.026546	7.001864	6.970326	7.009576	7.035152	7.03695
SC5	5.498707	8.692966	5.547053	4.782822	3.935937	5.792981	4.690897	4.936188	4.870426
SC6	3.726621	3.725682	3.724487	3.728785	3.742878	3.725418	3.730308	3.729731	3.729394
SC7	9.939488	10.05966	9.919832	9.121773	7.833749	9.937036	9.065794	10.26567	9.967583
SC8	5.218753	8.678168	5.313192	5.100083	3.923032	5.550197	4.427584	4.737682	4.518188

e).ACC

	EXIST.NET	STAGE-1	STAGE-2	STAGE-3	STAGE-4	STAGE-5	STAGE-6	STAGE-7	STAGE-8
PLAN	ACTUAL	7--18	1--20	44-42	30-34	38-42	44-40	21-20	28-24
SC1	2152.176	1092.232	1014.524	1567.937	7114.094	3184.022	4747.177	3406.892	4303.871
SC2	190.0198	484.6475	16.03968	267.9297	1071.847	378.8614	519.4112	421.6358	435.1009
SC3	2044.689	2939.535	1644.136	2964.35	9008.695	3918.336	6589.747	4246.47	1995.534
SC4	1574.961	5037.089	1012.569	1573.512	7084.954	3191.102	2652.564	3253.694	2420.702
SC5	1325.782	5191.53	606.1	2250.612	5978.913	3272.189	3060.745	2316.382	2328.13
SC6	904.3108	2483.059	458.387	1154.499	5252.984	1788.756	2101.518	1912.53	1934.731
SC7	2034.176	7190.698	1951.516	2721.881	8977.44	3838.51	3745.199	4247.951	2118.782
SC8	1278.082	5482.327	596.2328	2220.307	5972.164	3162.77	2831.007	2813.299	2045.664

f). ALP

	EXIST.NET	STAGE-1	STAGE-2	STAGE-3	STAGE-4	STAGE-5	STAGE-6	STAGE-7	STAGE-8
PLAN	ACTUAL	7--18	1--20	44-42	30-34	38-42	44-40	21-20	28-24
SC1	141993.4	127898.6	127928.9	127992.1	127431.8	127711.3	127922.7	127978.5	129106.8
SC2	123280.7	123305.6	123290.7	123315.6	123156.4	123289.8	123399.7	123401.7	123347.9
SC3	143617.4	143718.9	143570.7	143837	136513.4	143580.4	141573.3	143248.9	143585.1
SC4	127822.2	127774.5	127870.1	127931.2	127362.9	127655.3	127952	127913.4	127899.4
SC5	133693.2	140088.9	133749.5	132529.1	129478.6	134108.5	132230.5	133047.4	132778.3
SC6	123208.3	122293	123197.4	123248	123748.7	123160.8	123359.1	123202.5	123196.8
SC7	143941.3	143444.2	144010.9	141321.1	136468.5	143906.6	141132.6	143712.3	143759.4
SC8	133304.8	140109.8	133429	133143.9	129333.5	133792.1	131983	132715	132183.4

Table V (a-f). Values of SML, WG, WD, WGD, ACC, and ALP in different scenarios and different stages of planning.

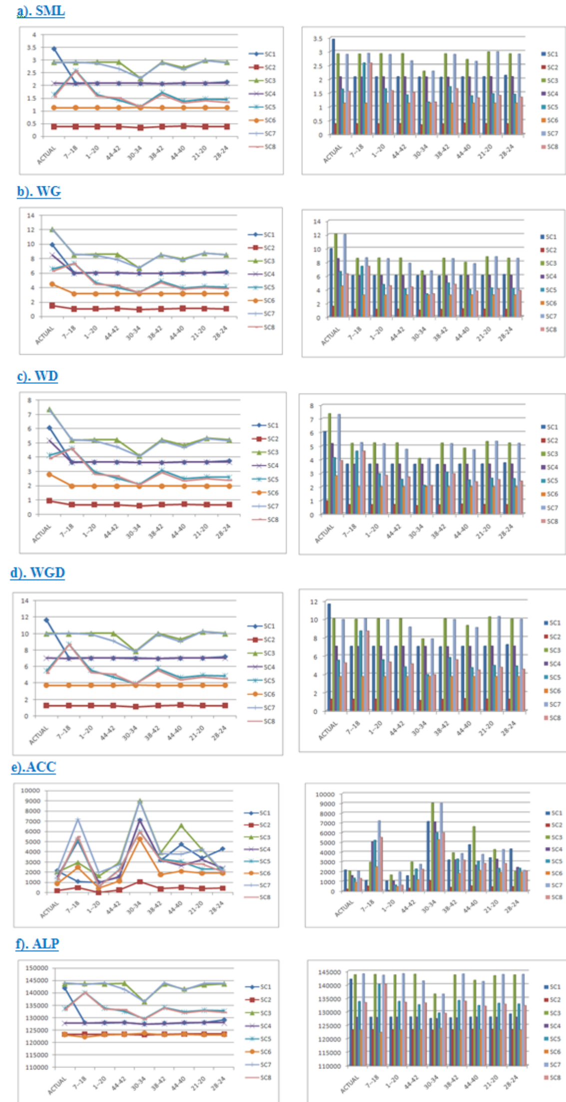

Fig. 1.(a-f). Values of SML, WG,WD, WGD, ACC, and ALP in different scenarios and different stages of planning. There are eight signs over each bar which show the values of criteria in different scenarios. In each stage, there are eight bars. (a) Values of SML when different criteria are used for planning. (b) Values of WG when different criteria are used for planning. (c) Values of WD when different criteria are used for planning. (d) Values of WGD when different criteria are used for planning. (e) Values of ACC when different criteria are used for planning. (f) Values of ALP when different criteria are used for planning.

VII. SELECTING OF FINAL PLAN

By using the minimax regret criterion we have to select the final plan are shown in Table.VI. at different stages of planning for each criterion.

SELECTING FINAL PLAN

a).

PLAN	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
SML	(38-42) 2.063855	(30-34) 0.340236	(30-34) 2.282255	(38-42) 2.061608	(30-34) 1.168545	(1-20) 1.123859	(30-34) 2.279542	(30-34) 1.164728
WG	(38-42) 5.957992	(30-34) 0.954741	(30-34) 6.695956	(38-42) 5.951353	(30-34) 3.334541	(1-20) 3.155781	(30-34) 6.687945	(30-34) 3.323592
WD	(38-42) 3.632571	(30-34) 0.598847	(30-34) 4.08395	(38-42) 3.628616	(30-34) 2.091038	(1-20) 1.978093	(30-34) 4.079096	(30-34) 2.084207
WGD	(38-42) 6.978054	(30-34) 1.127009	(30-34) 7.843117	(38-42) 6.970326	(30-34) 3.935937	(1-20) 3.724487	(30-34) 7.833749	(30-34) 3.923032
ACC	(1-20) 1014.524	(1-20) 16.03968	(1-20) 1644.136	(1-20) 1012.569	(1-20) 606.1	(1-20) 458.387	(1-20) 1951.516	(1-20) 596.2328
ALP	(30-34) 127431.8	(30-34) 123156.4	(30-34) 136513.4	(30-34) 127362.9	(30-34) 129478.6	(7-18) 122293	(30-34) 136468.5	(30-34) 129333.5

b).

PLAN	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8
SML	(38-42) 1.723619	(30-34) 0	(30-34) 1.158396	(38-42) 0.937749	(30-34) 0.044686	(1-20) 1.123859	(30-34) 2.279542	(30-34) 1.164728
WG	(38-42) 5.003251	(30-34) 0	(30-34) 3.540175	(38-42) 2.795572	(30-34) 0.17876	(1-20) 3.155781	(30-34) 6.687945	(30-34) 3.323592
WD	(38-42) 3.033724	(30-34) 0	(30-34) 2.105857	(38-42) 1.650523	(30-34) 0.112945	(1-20) 1.978093	(30-34) 4.079096	(30-34) 2.084207
WGD	(38-42) 5.851045	(30-34) 0	(30-34) 4.11863	(38-42) 3.245839	(30-34) 0.21145	(1-20) 3.724487	(30-34) 7.833749	(30-34) 3.923032
ACC	(1-20) 998.4843	(1-20) 0	(1-20) 1185.749	(1-20) 554.182	(1-20) 147.713	(1-20) 458.387	(1-20) 1951.516	(1-20) 596.2328
ALP	(30-34) 5138.8	(30-34) 863.4	(30-34) 14220.4	(30-34) 5069.9	(30-34) 124339.8	(7-18) 121429.6	(30-34) 135605.1	(30-34) 128470.1

c).

PLAN	SC1	SC2	SC3	SC4	SC5	SC6	SC7	SC8	Final plan
SML	(38-42) 0.86181	(30-34) 0	(30-34) 0.579198	(38-42) 0.468875	(30-34) 0.022343	(1-20) 0.56193	(30-34) 1.139771	(30-34) 0.582364	**(30-34) 1.139771**
WG	(38-42) 2.501626	(30-34) 0	(30-34) 1.770088	(38-42) 1.397786	(30-34) 0.08938	(1-20) 1.577891	(30-34) 3.343973	(30-34) 1.661796	**(30-34) 3.343973**
WD	(38-42) 1.516862	(30-34) 0	(30-34) 1.052929	(38-42) 0.825262	(30-34) 0.056473	(1-20) 0.989047	(30-34) 2.039548	(30-34) 1.042104	**(30-34) 2.039548**
WGD	(38-42) 2.925523	(30-34) 0	(30-34) 2.059315	(38-42) 1.62292	(30-34) 0.105725	(1-20) 1.862244	(30-34) 3.916875	(30-34) 1.961516	**(30-34) 3.916875**
ACC	(1-20) 499.2422	(1-20) 0	(1-20) 592.8745	(1-20) 277.091	(1-20) 73.8565	(1-20) 229.1935	(1-20) 975.758	(1-20) 298.1164	**(1-20) 975.758**
ALP	(30-34) 2569.4	(30-34) 431.7	(30-34) 7110.2	(30-34) 2534.95	(30-34) 62169.9	(7-18) 60714.8	(30-34) 67802.55	(30-34) 64235.05	**(30-34) 67802.55**

Table VI.(a-c) shows the selecting the final plan by using the minimax regret criterion at different stages of planning.

By comparing the different plans the final plan is (30-34).

VIII. CONCLUSION

In this paper, a new probabilistic tool for computing the probability density functions of nodal prices was introduced. New market-based criteria were defined for transmission planning in deregulated environments. A new approach for transmission expansion planning in deregulated environments using the above tool and criteria was presented. All random and nonrandom power system uncertainties are considered by this approach and the final plan is selected after risk assessment (minimax regret criterion) of all solutions. This approach tries to facilitate competition and provides nondiscriminatory access to cheap generation by providing a flat price profile throughout the network. It is value based and considers investment cost, operation cost, congestion cost, load curtailment cost, and cost caused by system unreliability. The presented approach was applied to Southern Region (SR) 48-Bus Indian System and the effectiveness of presented market-based criteria was demonstrated for the single and multiple scenario cases.

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