Integrating the Transmission Loss Component with the Distribution Factors Enhanced Transmission Pricing Method for Efficient Transmission Use of System Charges

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Abstract—This article proposes a transmission pricing method that integrates the transmission loss component with the distribution factors enhanced transmission pricing method for the pool electricity market. Two new schemes are proposed: (1) New Scheme 1—the losses are allocated only for the locational charges and (2) New Scheme 2—the losses are allocated for both locational and non-locational charges. Both methods use justified distribution factors to evaluate the transmission line flows more accurately. The transmission losses are allocated among the market users by integrating the generalized generation justified distribution factors and generalized load justified distribution factors with the modified pro-rata method. The proposed approach is tested on the 10-machine IEEE 39-bus (New England) system to prove its effectiveness. Results show that the proposed method is able to reconcile transmission service cost fairly.

Keywords : distribution factors enhanced transmission pricing, justified distribution factors, locational and non-locational charges, loss allocation, pro-rata method, transmission pricing

1. Introduction

An important aspect in the restructured electricity market design is the transmission pricing method [1]. It is essential for a power market policy to satisfy all its users through a fair and equitable transmission charge scheme [2]. The following should be performed in transmission access pricing: charge the user for the actual utilization of the grid; provide signals to new power plants about best locations that can relieve transmission congestion and losses; be predictable, simple, and easy to implement and ensure recovery of total transmission revenue [2, 3]. In the deregulation environment, one always disputable issue is allocating the power losses and dealing it with the transmission pricing.

In the electricity trading arrangement operating under a pool power market, transmission cost allocation is a major issue, as it is difficult to detect the contribution of each user in a line since the power output from different power plants are "pooled" together to meet the required demand. With these issues, several strategies for transmission allocation have been proposed worldwide to provide an efficient economic signal to the transmission users as well as transmission utilities [4–10].

In recent years, distribution factors have been suggested as a popular mechanism to allocate transmission payments in restructured power systems, as these factors can efficiently evaluate transmission usage [10]. In addition, this is also because of its simplicity, linearity, and physical plausibility [2, 8]. There are three approaches of distribution factors to allocate payments to different users of a transmission networks that are A factors (to net injections), D factors (only to generators), and C factors (only to loads). However, these methods have some weaknesses since they rely on some conditions. For instance, the set of distribution factors for a pair of nodes found using a particular reference bus differs from the one using another bus [11]. This can cause consume more time to generate a new set of distribution factors if the users request to use different reference node to accommodate their transactions [11, 12]. Furthermore, it would also be unsuitable to use it in transmission pricing or congestion management since the participants cannot predict the prices and avoid congestion of the network with ease if the reference is unknown [11]. To overcome this problem, a new technique has been successfully implemented independent of the references bus by making use of the properties of the distribution factors, called justified distribution factors (JDFs). JDFs are originally used to solve the congestion curtailment in the bilateral trading [11]. However, in [12], it was proved that JDFs can also be implemented in pool trading to estimate the contribution of the users in the line flows and at the same time to identify the counter-flow lines. The result generated from JDFs are used in generalized generation distribution factors (GGDFs) and generalized load distribution factors (GLDFs) to calculate the contribution of each market participant to the transmission line system in the PoolCo model.

Loss allocation is a procedure for subdividing the system transmission losses into fractions, the costs of which then become the responsibility of individual users of the power system (generation companies [GENCOs], distribution companies [DISCOs], marketers) [13]. The energy that flows into the meshed network to the loads needs to be traced, and the losses in the transmission networks need to be charged and transparently apportioned to the appropriate generator/load [14]. Unfortunately, it is not an easy task due to the non-linear characteristic of energy flow and losses in the networks. In this respect, a number of approximate models and algorithms have been introduced in the literature that try, as accurately as possible, to allocate the losses to the market users [14–24]. The developed loss allocation schemes can be categorized into incremental, circuit-based, proportional-sharing, pro-rata (PR), and miscellaneous approaches for bilateral transactions [13]. There are a number of new proposed methods that have been developed, such as the power flow based monetary flow method [3], the hybrid genetic algorithm–support vector machine technique [14], current adjustment factors (CAFs) [25], and bus impedance matrix (*Z* bus) based contribution factors [26], to improve the effectiveness of transmission loss allocation. However, they still have drawbacks while dealing with transmission pricing. First, these methods totally neglect counter-flows and always allocate positive losses. Counter-flows are very important to consider, as these can relieve the congested transmission lines. With regard to a fair transmission charging, a negative charge or credit can be given to the users that contribute counter-flows or negative losses. Second, the transmission usage and losses are calculated simultaneously. Therefore, the market operator cannot trace which market users contribute positive losses. This is very important for development of new power plant generation. New power plants should avoid being developed in areas that contribute more losses and congestions.

The cost of the basic transmission services corresponds primarily to the fixed transmission cost, also referred to as the embedded transmission facility cost [9]. The embedded cost is defined as the revenue requirements needed to pay for all existing facilities plus any new facilities added to the power system during the life of the contract for transmission service. The embedded cost methods are commonly used throughout the utility industry to allocate the cost of transmission services. The allocation of the embedded cost is done through usage calculation [27]. There are four different embedded costs of wheeling methods that could be used, namely the postage stamp method, contract path method, distance-based MW-mile method, and power flow based MW-mile method [28].

The MW-mile methodology may be regarded as the first pricing strategy proposed for the recovery of fixed transmission costs based on the actual use of transmission networks [9]. However, this method is not sufficient to cover the total transmission revenue. A new technique was introduced, namely the postage stamp coverage method, for the purpose of covering the total transmission system cost by sharing among the generators the costs associated with the unused capacity [29]. The method is simple, but its main drawback is that the charges paid by each user do not reflect the actual use that the users make of the network or the value they derive from being connected [2].

This article proposes novel transmission pricing approaches for allocating transmission service charges among pool market users. Generalized generation justified distribution factors (GGJDFs) and generalized load justified distribution factor (GLJDFs) are used to trace the contribution of each generator/load to the network system accurately. The losses are allocated among the users by integrating the modified PR (MPR) method with the GGJDF and GLJDF approaches. This method has the ability to allocate system losses among different participants taking into account the counter-flows, which are detected by the GGJDFs and GLJDFs. In addition, the user's location within the network is also considered by assigning losses according to the utilization of the grid. For transmission service charges, two schemes have been developed: (1) New Scheme 1 (NS1), which integrates the loss charge with conventional locational charges, and (2) New Scheme 2 (NS2), which integrates the loss charge with both conventional locational and non-locational charges. Both schemes are tested in a case study to identify which scheme is superior.

This article is organized as follows. Section 2 introduces a distribution factors enhanced transmission pricing (DFETP) method, and Section 3 presents the development of the MPR method to allocate losses among different uses. Section 4 describes the new transmission charge scheme formulation, and Section 5 provides a case study based on the 10-machine *IEEE* 39-bus (New England) system to show the merit of proposed scheme over the DFETP method.

2. DFETP Method

The DFETP method proposed in [30, 31] is based on DC calculations and does not consider transmission losses. There are two subsections that follow for this approach: transmission usage evaluation and transmission pricing methods.

2.1. Transmission Usage Evaluation

JDFs were introduced in [11] to overcome the drawback of the distribution factors method in which it could cause more time to generate a new set of distribution factors if the users request to use a different reference node to accommodate their transactions [3]. JDFs are used to identify the net power flow in the transmission line system, where it is formed by adding a justification factor J_{ij} to the original distribution factor, so that the distribution factors for line *i-j* at bus *i* and bus *j* have the same magnitudes but opposite signs; this is written mathematically as [11]:

$$J_{ij}^{m} = -\frac{DF_{ij}^{m}(i) + DF_{ij}^{m}(j)}{2}, \tag{1}$$

$$JDF_{ij}^{m} = DF_{ij}^{m} + J_{ij}^{m}\{1\}. \tag{2}$$

The power flow in line *i* can be traced using Eq. (3):

$$P_i = \sum_{j}^{m} JDF_i^j . P_j, \tag{3}$$

where JDF_i^j is the factor for line *i* with respect to bus *j*, P_j is the net injection power at bus *j*, and *m* is the number of buses.
To calculate the circuit flow caused by each market user, GGJDFs and GLJDFs are used [12].

The GGJDF is mathematically written as

$$JD_{i-j,g} = JDF_{i-j,g} + JD_{i-j}, \tag{4}$$

where JD_{i-j} is calculated by

$$JD_{i-j} = \frac{\left(F_{i-j} - \sum_g JDF_{i-j,g} \times G_g\right)}{\left(\sum_g G_g\right)}, \tag{5}$$

JD factors $JD_{i-j,g}$ relates generation G_g in a given bus *g* with actual power flow F_{i-j} in a line *i-j*:

$$F_{i-j} = \sum_{g} JD_{i-j,g} G_g. \tag{6}$$

The GLJDF is presented by the following equations:

$$JC_{i-j,d} = JC_{i-j} - JDF_{i-j,d}, \tag{7}$$

where

$$JC_{i-j} = \frac{\left(F_{i-j} + \sum_d JDF_{i-j,d} \times D_d\right)}{\left(\sum_d Dd\right)}. \tag{8}$$

The actual power flow $F_{i\text{-}j}$ in a line *i-j* can be traced by relating the *JC* factors with load D_d in a given bus *d*:

$$F_{i-j} = \sum_j C_{i-j,d} D_d. \tag{9}$$

2.2. Transmission Pricing Methods

Transmission pricing methods are distinguished to two parts: (1) locational charges and (2) non-locational charges. The most common method for locational charges that has been implemented by utilities is the MW-mile method. The issue in this method concerns counterflow users, and it is still being debated as to what basis credit should be given to the transmission user who reduces the total net flow of the transmission system. However, many transmission utilities felt uncomfortable with the idea of providing a service and, in addition, paying the users for using it. The reason is clear, because giving credit to transmission users for their contribution in the counter-flow could cause difficulties for transmission utilities to recover the revenue requirements. Hence, the MW-mile method (negative-flow sharing) was introduced [28]. In this method, the negative value of $fk(u)$ is shared between the transmission owner and users using profit sharing factor *r* [30]. This factor is determined according to the willingness of the transmission owner to share profit with the transmission users [32]. In this research, the profit-sharing factor is considered to be three, as there are three participants: the transmission owner, generator, and load. The charge levied to the user for using a set of circuit *k*s can be expressed mathematically as

$$R(u) = \sum_{allk} C_k \frac{f_k(u)}{\overline{f_k}}, \tag{10}$$

where

$$f_k(u) = +f_k(u) + \frac{1}{r}|-f_k(u)|; \tag{11}$$

$\sum_{allk} C_k$ is the total transmission revenue.

For non-locational charges, the postage stamp coverage method has been used by transmission utilities, for instance, the Electricity Supply Board National Grid (EirGrid, Republic Ireland) and Transend (Australia), to cover the total transmission revenue. This method can accurately cover the total revenue, but it seems unfair and inequitable if there is a local load case in the transmission network system. Therefore, a tracing-based postage stamp method was introduced in [31] where individual users are charged based on their actual usage of a transmission line system whether or not the network system consists of local load case.

For a generator, the power injected from G_i to the transmission line, which is connected directly to bus *i* where G_i is located, is determined. Power from the generator at bus *i*, G_i, is injected to a transmission line system [33]:

$$P_{GiT} = P_{ix} + P_{iy} + \ldots + P_{in}, \tag{12}$$

where P_{in} is the power flow in transmission line *n*, which is connected directly with bus *i* where generator G_i is located;

$$\text{Remainder of} G_i(RG_i) = P_{Gi} - P_{GiT}, P_{Gi} > P_{GiT}, \tag{13}$$

where P_{Gi} is the power output of generators of bus *i*;

$$G_i \text{ contributes to } D_i = RG_i; \tag{14}$$

hence, the actual usage of G_i in the transmission line system is P_{GiT}.

For load, the steps with the generator are similar to trace the power usage in the transmission line system. The load at bus *i*, D_i, received power from the transmission line system:

$$P_{DiT} = P_{ix} + P_{iy} + \cdots + P_{in}, \tag{15}$$

where P_{in} is the power flow in transmission line *n*, which is connected directly with bus *i* where load D_i is located;

$$\text{Remainder of } D_i(RD_i) = P_{Di} - P_{DiT}, P_{Di} > P_{DiT}, \tag{16}$$

where P_{Di} is the active power demanded by consumers of bus *i*;

$$D_i \text{ received power from } G_i = RD_i; \tag{17}$$

therefore, the actual usage of D_i in the transmission line system is P_{DiT}.

A new technique for the transmission pricing method is to charge market participants based on actual usage in the transmission line system. The actual power usage in the line system

from Eqs. (12) and (17) will be used in the postage stamp coverage method to achieve a fair and equitable transmission service charge methodology [33].
The tracing-based postage stamp method can be described by Eqs. (18)–(21).

- For the generator:

$$PS = \frac{\left(P_c \sum_{k=1}^{nlin} C_k\right) - \sum_{i=1}^{n} R_{Gi}}{\sum_{i=1}^{n} P_{GiT}}, \tag{18}$$

where P_c is the percentage cost allocation of each network user, R_{Gi} is the allocated cost to generator *I*, and C_k is the cost of circuit *k*.

- For the modified locational tariff for G_i:

$$\pi_{Gi} = \frac{R_{Gi}}{P_{GiT}}. \tag{19}$$

- For load:

$$PS = \frac{\left(P_c \sum_{k=1}^{nlin} C_k\right) - \sum_{i=1}^{n} R_{Di}}{\sum_{i=1}^{n} P_{DiT}}, \tag{20}$$

where R_{Di} is the allocated cost to demand *i*.

- For the modified locational tariff for L_i:

$$\pi_{Li} = \frac{R_{Di}}{P_{DiT}}. \tag{21}$$

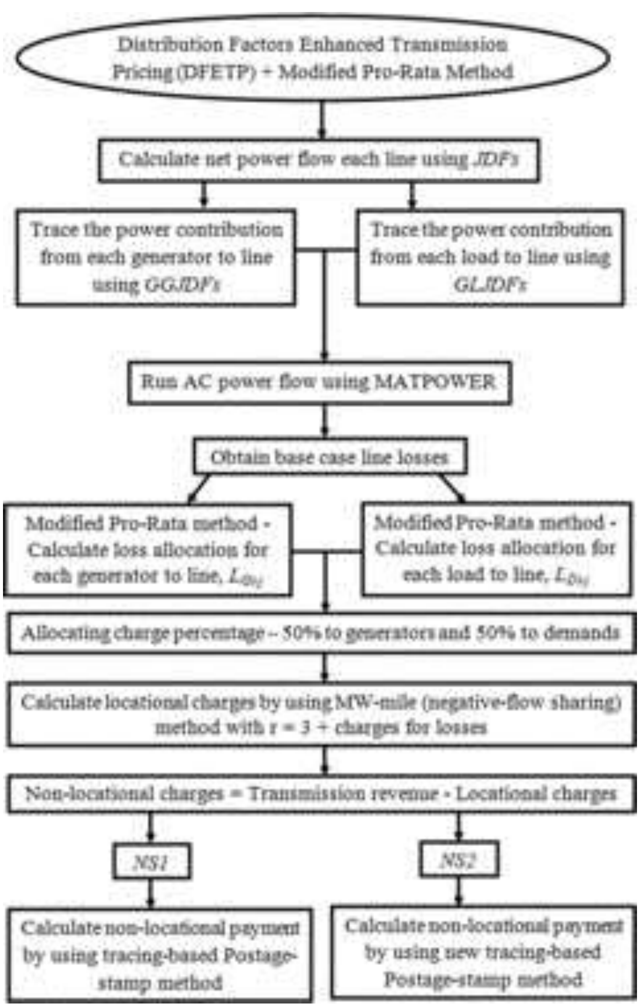

Figure 1 Proposed transmission pricing method.

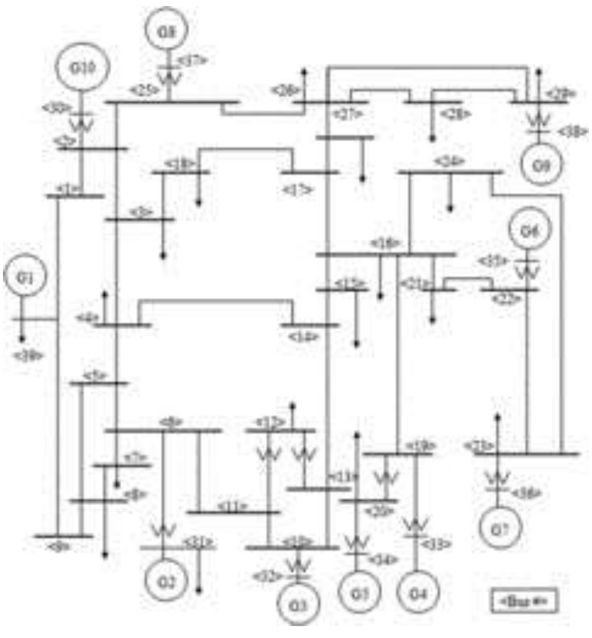

Figure 2 Ten-machine IEEE 39-bus (New England) system.

3. MPR Method

The existing PR method proportionally allocates 50% of losses to loads and 50% to generators [15]; *i.e.*,

$$L_{Gi} = \frac{L}{2}\frac{P_{Gi}}{P_G}, \qquad L_{Dj} = \frac{L}{2}\frac{P_{Dj}}{P_D}, \tag{22}$$

where
L_{Gi} is the losses allocated to generator i, L_{Dj} is losses allocated to demand j, and L denotes transmission power losses.

Generation and demand loss allocation factors are computed, respectively, as

$$L_{Gi} = \frac{L}{2}\frac{P_{Gi}}{P_G} = K_G P_{Gi}, \qquad K_G = \frac{1}{2}\frac{L}{P_G}, \tag{23}$$

$$L_{Dj} = \frac{L}{2}\frac{P_{Dj}}{P_D} = K_D P_{Dj}, \qquad K_D = \frac{1}{2}\frac{L}{P_D}. \tag{24}$$

In this article, the MPR method is introduced by integrating the existing PR method with the GGJDF and GLJDF approaches to allocate the losses among different market users. The merit of this method is that it considers the counter-flows, which contribute negative losses. Based on Eq. (22), let P_{Gi-j} and P_{Di-j} denote the power contributed by generator G and load D to line i-j, which is determined by GGJDFs, and GLJDFs are used to replace P_{Gi} and P_{Di}. P_{Gi-j} and P_{Di-j} can be (+) or (–) depending on the *JD* and *JC* factors. Thus, the equation implies that the line losses are distributed among participants based on the actual utilization of the line. In addition, for P_{i-j}, the net power flow in line i-j is used instead of P_G and P_D, as the analysis is based on the utilization of the transmission line system. Therefore, the contribution of losses of each market participant to the line system can be determined as

$$L_{Gi-j} = \frac{L_{i-j}}{2}\frac{P_{Gi-j}}{P_{i-j}}, \qquad L_{Di-j} = \frac{L_{i-j}}{2}\frac{P_{Di-j}}{P_{i-j}}, \tag{25}$$

$$L_{Gi-j} = \frac{L_{i-j}}{2}\frac{P_{Gi-j}}{P_{i-j}} = K_{i-j} P_{Gi-j}, \qquad K_{i-j} = \frac{1}{2}\frac{L_{i-j}}{P_{i-j}}, \tag{26}$$

$$L_{Di-j} = \frac{L_{i-j}}{2}\frac{P_{Di-j}}{P_{i-j}} = K_{i-j} P_{Di-j}, \qquad K_{i-j} = \frac{1}{2}\frac{L_{i-j}}{P_{i-j}}, \tag{27}$$

where L_{i-j} is the loss base case, which is determined from the AC power flow.

From Eqs. (25) and (26), it can be summarized that the loss contributed by each generator G to line i-j is

$$L_{Gi-j} = K_{i-j} P_{Gi-j}, \tag{28}$$

Table 1 DC flow and loss base case

Bus i	Bus j	DC flow base case, P_{ij} (MW)	Loss base case, L_{ij} (MW)
1	2	−129.1	0.468
1	39	129.1	0.369
2	3	377.1	1.514
2	25	−256.2	3.804
3	4	109.7	0.307
3	18	−54.5	0.039
4	5	−116.7	0.145
4	14	−273.6	0.556
5	6	−432.1	0.385
5	8	315.4	0.78
6	7	415.3	1.023
6	11	−379.5	0.867
7	8	181.5	0.131
8	9	−25.1	0.133
9	39	−25.1	0.089
10	11	378	0.499
10	13	272	0.301
13	14	263	0.657
14	15	−10.7	0.014
15	16	−330.7	0.935
16	17	232.2	0.419
16	19	−512	3.645
16	21	−334.8	0.804
16	24	−45.1	0.021
17	18	212.5	0.278
17	27	19.7	0.089
21	22	−608.8	2.612
22	23	41.2	0.019
23	24	353.7	2.451
25	26	59.8	0.296
26	27	261.3	0.932
26	28	−145.4	0.763
26	29	−195.1	1.903
28	29	−351.4	1.612
12	11	1.5	0.025
12	13	−9	0.036
6	31	−467.9	0
10	32	−650	0
19	33	−632	2.816
20	34	−508	2.406

Bus *i*	Bus *j*	DC flow base case, P_{ij} (MW)	Loss base case, L_{ij} (MW)
22	35	−650	0
23	36	−560	1.391
25	37	−540	1.726
2	3	−250	0
29	38	−830	5.426
19	20	120	0.278
Total loss			42.964

and the loss contributed by each load *D* to line *i*-*j* is

$$L_{Di-j} = K_{i-j} P_{Di-j}, \tag{29}$$

where $K_{i\text{-}j}$ is the loss allocation factor for line *i*-*j*.

4. New Transmission Charge Scheme

Two schemes introduced in this article are NS1 and NS2. For NS1, the loss charge integrates with conventional locational charges, while for NS2, the loss charge is considered for both conventional locational and non-locational charges. In case study, both schemes are tested to identify which scheme is superior and reflects a fair and equitable transmission pricing method.

4.1. NS1

By integrating the loss charge component with a DFETP locational signal, a new generation/demand locational charge equation can be obtained as follows.

- New locational charges for generator:

$$R_{Gi} = P_c \sum_{allk} C_k \frac{f_{kGi} + L_{kGi}}{\overline{f_k}}, \tag{30}$$

  where f_{kGi} is the *k*-circuit flow caused by generator *i*, $\overline{f_k}$ is the *k*-circuit capacity, and L_{kGi} denotes the *k*-circuit losses caused by generator *i*.

- Locational tariff for generator:

$$\pi_{Gi} = \frac{R_{Gi}}{P_{GiT}} \tag{31}$$

- For demand:

$$R_{Di} = P_c \sum_{allk} C_k \frac{f_{kDi} + L_{kDi}}{\overline{f_k}} \tag{32}$$

where f_{kDi} is the k-circuit flow caused by demand i, and L_{kDi} is the k-circuit losses caused by demand i.

- Locational tariff for demand:

$$\pi_{Di} = \frac{R_{Gi}}{P_{DiT}} \tag{33}$$

Table 2 Usage allocation, loss allocation, and locational charges for *G*2 and *G*4

		Usage allocation (MW)		Loss allocation (MW)	
Bus *i*	**Bus *j***	***G*2**	***G*4**	***G*2**	***G*4**
1	2	3.0057	−64.5008	−0.0054	0.1169
1	39	−3.0057	64.5008	−0.0043	0.0922
2	3	−48.039	−66.1122	−0.0964	−0.1327
2	25	51.0448	1.6113	−0.3789	−0.012
3	4	−141.477	32.2131	−0.1981	0.0451
3	18	68.2459	−131.703	−0.0244	0.0471
4	5	−197.485	60.7272	0.1227	−0.0377
4	14	16.8908	−80.3429	−0.0172	0.0816
5	6	−250.087	−5.095	0.1114	0.0023
5	8	52.6016	65.8222	0.065	0.0814
6	7	95.906	62.4592	0.1181	0.0769
6	11	130.2955	−68.4975	−0.1488	0.0782
7	8	77.6146	38.2241	0.028	0.0138
8	9	89.3774	49.9371	−0.237	−0.1324
9	39	89.3774	49.9371	−0.1586	−0.0886
10	11	−118.307	62.6894	−0.0781	0.0414
10	13	118.3073	−62.6894	0.0655	−0.0347
13	14	129.7087	−62.275	0.162	−0.0865
14	15	146.5995	−149.618	−0.0961	0.0981
15	16	121.5642	−182.788	−0.1719	0.2584
16	17	−18.2499	263.9653	−0.0165	0.2381
16	19	49.1317	−566.903	−0.1749	2.0179
16	21	29.7058	39.3586	−0.0357	−0.0473
16	24	35.2372	46.6875	0.0082	−0.0109
17	18	−55.8847	148.0808	−0.0366	0.0969
17	27	37.6348	115.8845	0.0849	0.2615
21	22	8.2694	10.9565	−0.0177	−0.0235
22	23	8.2694	10.9565	0.0019	0.0025

		Usage allocation (MW)		Loss allocation (MW)	
Bus *i*	**Bus *j***	***G*2**	***G*4**	***G*2**	***G*4**
23	24	−11.0939	−14.6988	−0.0384	−0.0509
25	26	33.5201	−21.608	−0.083	−0.0535
26	27	−15.6507	−86.7567	−0.0279	−0.1547
26	28	21.0949	27.9497	−0.0554	−0.0734
26	29	17.2012	22.7907	−0.0839	−0.0151
28	29	4.9785	6.5962	−0.0114	0.0486
12	11	−11.9881	5.8082	−0.1003	0.0132
12	13	11.4014	−6.5856	−0.0228	0
6	31	−476.288	0.9433	0	0
10	32	0	0	0	1.408
19	33	0	−632	0	0
20	34	0	0	0	0
22	35	0	0	0	0
23	36	0	0	0	0
25	37	0	0	0	0
2	3	0	0	0	0
29	38	0	0	0	0
19	20	49.1317	65.0969	0.0569	0.0754
Total allocated loss	−1.347	+4.131			
DFETP ($)	323,019.75	330,327.63	—	—	
Loss charges ($)	—	—	−223.47	+686.05	
NS1 ($)	—	—	322,796.28	331,013.68	
NS2 ($)	—	—	322,796.28	331,013.68	

Table 3 Locational charges for demands

	Locational charges ($)			
Demand				
at bus *i*	**DFETP**	**Loss charges**	**NS1**	**NS2**
*D*3	138,862.07	290.47	137,567.49	137,567.49
*D*4	212,117.53	576.07	212,693.6	212,693.6
*D*7	155,255.68	299.2	155,554.88	155,554.88
*D*8	350,408.56	704.91	351,113.47	351,113.47
*D*12	4338.07	1.96	4340.03	4340.03
*D*15	148,498.78	234.09	148,728.87	148,728.87
*D*16	146,145.96	151.64	146,297.6	146,297.6
*D*18	84,090.95	117.78	84,208.73	84,208.73
*D*20	449,992.74	38.98	450,031.72	450,031.72
*D*21	158,122.09	67.06	158,189.15	158,189.15
*D*23	178,341.74	−25.38	178,316.36	178,316.36
*D*24	183,358.83	132.56	183,491.39	183,491.39

	Locational charges ($)			
Demand				
at bus *i*	DFETP	Loss charges	NS1	NS2
*D*25	109,700.52	−105.43	109,595.09	109,595.09
*D*26	72,432.37	41.67	72,474.04	72,474.04
*D*27	159,890.61	213.38	160,103.99	160,103.99
*D*28	139,671.96	−27.52	139,644.44	139,644.44
*D*29	205,543.62	−145.63	205,397.99	205,397.99
*D*31	6652.21	9.58	6661.79	6661.79
*D*39	720,481.18	992.57	721,473.75	721,473.75
Total	3,623,901.47	3567.96	3,627,469.42	3,627,469.42

The non-locational charges for both users are recovered by using the tracing-based postage stamp method as shown in Eqs. (18)–(21).

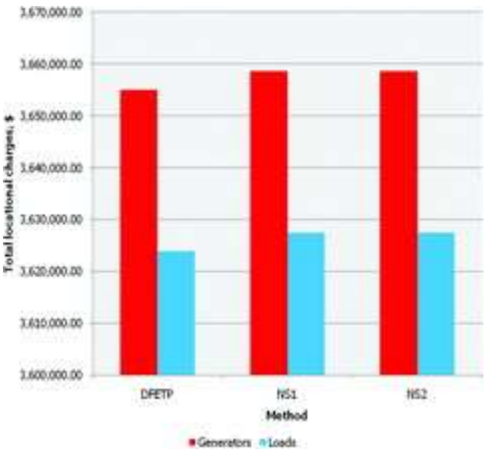

Figure 3 Total locational charges for generators and loads.

Table 4 Non-locational charges for G2 and G4

	Node 31			Node 33		
A. Generation (MW)	476.29			632		
B. Losses (MW)		−1.347			+4.131	
A + B (MW)			474.943			636.131
DFETP ($)	197,842.68			262,521.93		
NS1 ($)	197,555.39			262,140.72		
NS2 ($)	196,840.60	−556.85	196,283.75	261,192.25	+1707.09	262,899.34

4.2. NS2

By integrating the loss charge component with DFETP locational and non-locational signal, a new generation/demand locational charge equation can be obtained as follows:

- New locational charges for generator:

$$R_{Gi} = P_c \sum_{allk} C_k \frac{f_{kGi} + L_{kGi}}{\overline{f_k}}. \tag{34}$$

- Locational tariff for generator:

$$\pi_{Gi} = \frac{R_{Gi}}{P_{GiT} + TL_{Gi}} \tag{35}$$

  where TL_{Gi} denotes total losses contributed from *Gi*.

- For demand:

$$R_{Di} = P_c \sum_{allk} C_k \frac{f_{kDi} + L_{kDi}}{\overline{f_k}} \tag{36}$$

- Locational tariff for demand:

$$\pi_{Di} = \frac{R_{Di}}{P_{DiT} + TL_{Di}},$$

  (37)

  where TL_{Di} denotes total losses contributed from *Di*.

Finally, the transmission cost not remunerated is recovered by using the new tracing-based postage stamp method.

- Non-locational tariff for generator:

$$\pi PS_{Gi} = \frac{\left(P_c \sum_{k=1}^{nlin} C_k\right) - \sum_{i=1}^{n} R_{Gi}}{\sum_{i=1}^{n} P_{GiT} + TL_{Gi}}. \tag{38}$$

- Non-locational charges for each generator:

$$PS_{Gi} = \pi PS_{Gi} \times (P_{GiT} + TL_{Gi}). \tag{39}$$

- Non-locational tariff for demand:

$$\pi PS_{Di} = \frac{\left(P_c \sum_{k=1}^{nlin} C_k\right) - \sum_{i=1}^{n} R_{Di}}{\sum_{i=1}^{n} P_{DiT} + TL_{Di}}. \tag{40}$$

- Non-locational charges for each demand:

$$PS_{Gi} = \pi PS_{Gi} \times (P_{DiT} + TL_{Di}). \tag{41}$$

The proposed approach can be summarized by the flowchart shown in Figure 1.

5. Case Study

The IEEE 39-bus test system shown in Figure 2 is selected using the proposed method. The parameters for the system were reported in [34, 35]. The capacity of all circuits is assumed to be 800 MW. The system consists of 10 generators producing a total power of 6139.964 MW and 19 loads that need a total of 6097 MW. There is local load at buses 31 and 39. Let the total transmission revenue be $12,224,200.

Table 5 Non-locational charges for D29 and D39

	Node 29			**Node 39**		
A. Generation (MW)	283.5			922.93		
B. Losses (MW)		−0.877			+5.973	
A+B (MW)			282.623			928.903
DFETP ($)	119,252.42			388,224.46		
NS1 ($)	119,081.42			387,667.76		
NS2 ($)	118,650.56	−367.00	118,283.56	386,265.11	+2499.99	388,765.10

Table 1 shows the DC flow base case using the JDFs method and the loss base case obtained from MATPOWER analysis.

Table 2 shows the usage allocation, loss allocation, and locational charges for $G2$ at node 31 and $G4$ at node 33. The usage allocation is obtained by using the GGJDF method, while for loss allocation, MPR methods are adopted. As can be seen, the total loss allocated for $G2$ and $G4$ are –1.347 and +4.131, respectively. Hence, by applying the proposed method, $G2$ will pay less as it contributes negative losses. On the other hand, high charges for $G4$ contributes positively to system losses, and this makes the payment higher after integrating the loss component. The locational charges for NS1 and NS2 are similar as both methods considered losses in transmission charging.

Table 6 Non-locational tariff for market users

	Non-locational tariff ($/kW)		
Users	**DFETP**	**NS1**	**NS2**
Generators	0.4154	0.4148	0.4133
Loads	0.4206	0.4200	0.4185

Table 3 shows the locational charges by using DFETP and the proposed methods, which are NS1 and NS2 for demands. It clearly shows that positive losses increase the locational charges, while incentives are given to the demand, which contributes negative losses. As the total loss charge is $3567.96, the total locational charge is increased from $3,623,901.47 to $3,627,469.42. As shown in Figure 3, with the presence of losses charges, total locational charges for generators and demands are increased.

Table 4 shows the non-locational charges for the generator at nodes 31 and 33. The generation for $G2$ is actually 477 MW, but due to the local load, $G2$ only uses 476.290 MW in the transmission line system. The actual power usage of the generator in transmission line system P_{GiT} can be determined by using the tracing-based postage stamp method. The non-locational charges for NS1 and NS2 are lower than the DFETP method because the locational charges for both proposed methods are high compared to the DFETP method. The loss charges are taken into account in the NS2 method. Hence, it can be seen in Table 4 that $G2$ paid less non-locational charges, as a negative charge is allocated to it. A similar result is also shown for demand in Table 5, where for $D29$, $367 is credited from the total non-locational charge, which decreases from $118,650.56 to $118,283.56 as $D29$ contributes negative losses.

Figure 4 compares the total non-locational charges for the DFETP, NS1, and NS2 methods. The total non-locational charges are less for the proposed scheme, and this is significant as for the locational charges; the proposed scheme takes into consideration both the user's utilization in the network and the loss contributed by that user within the line.

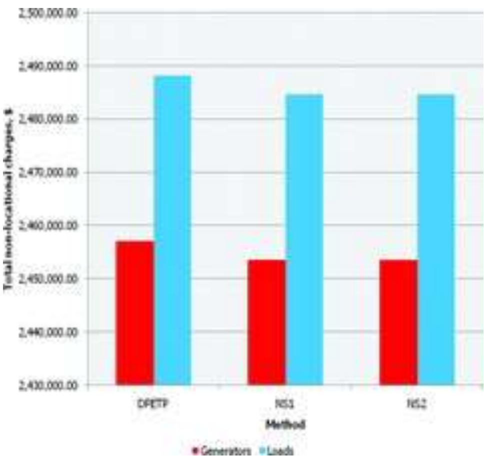

Figure 4 Total non-locational charges for generators and loads.

As can be observed from Table 6 and Figure 5, the proposed NS1 and NS2 allocate less non-locational tariff because the locational charges for both methods consider the losses. The losses are taken into consideration in non-locational charges by NS2. Hence, the non-locational tariff for NS2 is less than that for NS1. Incentives are given to the user for loss reduction. On the other hand, they will be charged more if they contributes more losses to the network system.

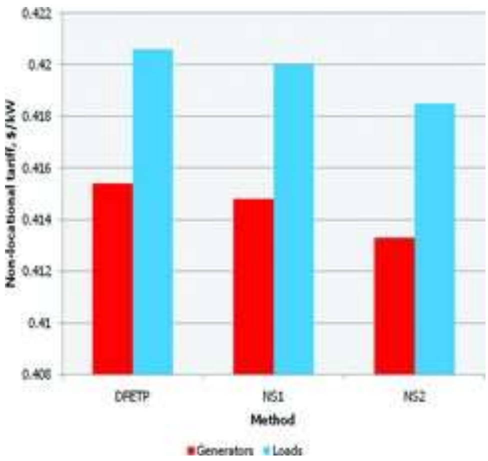

Figure 5 Non locational tariff for market users using existing and proposed schemes.

6. Conclusion

This article has proposed two new schemes—NS1 and NS2—for transmission service charges in pool power markets. For both methods, JDFs, GGJDFs and GLJDFs are used for transmission usage allocation among different transmission users. Losses are considered in the locational charges for both schemes. The losses are allocated for different market users by using the MPR method, which integrates GGJDFs and GLJDFs with the existing PR method. This method has the ability to allocate system losses among different network users in each line, taking into account the counter-flow detected by GGJDFs and GLJDFs. Thus, the merit of the proposed methods lies on rewarding the user for relieving the transmission losses, and this yields less locational charges paid by that user. For non-locational charges, only NS2 considered losses in transmission charging. The market users are charged based on their actual usage and loss contribution in each transmission line system. Incentives are given to the users that relieve the transmission system losses. In addition, the advantage of this proposed scheme is to encourage new power plants to be built in appropriate locations for relieving the transmission load. In conclusion, NS2 is superior to other methods, as it reflects fair and equitable transmission service charges. In this scheme, both locational and non-locational charges are assigned to the market users based on their usage and loss contributed in the transmission line.

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