Journal of Zhejiang University-SCIENCE C (Computers & Electronics)
ISSN 1869-1951 (Print); ISSN 1869-196X (Online)
www.zju.edu.cn/jzus; www.springerlink.com
E-mail: jzus@zju.edu.cn

Transmission pricing and recovery of investment costs in the deregulated power system based on optimal circuit prices

Javad NIKOUKAR[†1], Mahmoud Reza HAGHIFAM[2]

([1]*Department of Technical Engineering, Science and Research Branch, Islamic Azad University, Tehran, Iran*)

([2]*Department of Electrical and Computer Engineering, Tarbiat Modares University, Tehran, Iran*)

[†]E-mail: j_nikoukar@yahoo.com

Received Mar. 30, 2011; Revision accepted Sept. 5, 2011; Crosschecked Dec. 8, 2011

Abstract: Transmission pricing has become a major issue in the discussions about the deregulated electricity markets. Consequently, open access to the transmission system is one of the basic topics to allow competition among participants in the energy market. Transmission costs have an important impact on relative competition among participants in the energy market as well as on short- and long-term economic efficiencies of the whole electricity industry, although they represent only close to 10% of the energy market price. This paper deals with the design and tests of a transmission pricing method based on the optimal circuit prices derived from the economically adapted network (EAN). Prices derived from the EAN have the advantage of being in tune with the maximum revenue allowed to the owner of transmission assets and simplifying the optimal allocation of transmission costs among participants. Beginning from the conceptual design, the proposed method is tested on a three-bus network and on the IEEE 24-bus reliability test system.

Key words: Transmission pricing, Economically adapted network (EAN), Cost allocation, Electricity market
doi:10.1631/jzus.C1100076 **Document code:** A **CLC number:** TM73

1 Introduction

A review of the main methods to transmission pricing around the world displays that they can be classified in two groups: cost based methods and value based methods. Among cost based methods we can find the contract path, MW-mile, postage stamp, investment cost related pricing (ICRP), area of influence, and tracing methods. Among value based methods we find the well known short run marginal cost (SRMC) method and the theoretical long run marginal cost (LRMC) method.

Contract path and MW-mile methods were extended at the end of the 1980s and used extensively in the US for the calculation of wheeling charges. The contract path method proposed for minimizing transmission charges does not reflect the actual flows through the transmission grid. The MW-mile method was introduced in which different participants are charged in proportion to their utilization of the grid (Pan *et al*., 2000; Zolezzi *et al*., 2001).

The simple and most widely used methods for transmission pricing in deregulated markets are the postage stamp and the SRMC methods. The ICRP method was developed by the National Grid Company (NGC) and it is currently used for the calculation of the Transmission Network Use of System (TNUoS) charges in England and Wales. The method is based on a transportation model to determine the optimal capacity of the network (Henney, 1998). The area of influence method was developed in Chile at the beginning of the 1990s and it is currently in use in Chile and Bolivia. It needs the calculation of a pro-rata to allocate the cost of the transmission assets included in the area of influence among the users who share the same common area (Reta *et al*., 2005).

From the academic point of view, tracing methods to allocate transmission system costs over generators and loads have been extensively studied but are not in practical use (Bialek, 1997; Meng and Jeyasurya, 2007).

Based on Kirchhoff's laws, a flow method called equivalent bilateral exchanges (EBE) was reported in Galiana *et al*. (2003) for transmission cost allocation to loads and generators. To build the EBE, every generator is determined proportionally as a particle of each load, and conversely, every load is determined proportionally as a particle of each generator. Conejo *et al*. (2007) presented two schemes based on the impedance matrix and the injected powers. Both schemes are based on circuit theory for transmission cost allocation to generators and loads. Usaola (2006) presented a method that integrates cooperation and coordination among the participants and their physical and economic use of the network to allocate transmission cost. Specifically, cooperative game theory appears as the most proper tool to solve the transmission cost allocation (Bhakar *et al*., 2009). The cost of transmission system usage was presented based on an economic measure of power markets in Sedaghati (2006). Sensitivity factors play a key role in many system security analyses and market applications such as the transmission cost allocation discussed in Kirschen *et al*. (1997).

Transmission SRMC is the generation cost of transporting one additional MW across the network when transmission capacity is fixed. The SRMC methods are based on location-specific generation costs; therefore, transmission investment costs are not considered. The SRMC methods are also mentioned as spot pricing or locational marginal pricing (LMP). Transmission LRMC is the operation cost and investment of transporting one additional MW across the network when transmission capacity can be varied. In this paper transmission costs are determined using a reference network or EAN. The determination of the EAN on a power system requires a complete set of data about production costs of generation and investment costs of transmission, plus long term assessments about future generation costs, location of new generations, load forecasting, and its geographical distribution. The EAN is defined as the transmission network that minimizes the total operation plus investment costs over a certain period of time (Kirschen and Strbac, 2004). From the regulatory point of view, this concept is a useful reference and can be used for transmission pricing purposes due to the special relationships that occur in the optimal network.

2 Main issues

The proposed transmission pricing method comes from the need to find an economically equitable allocation for optimal circuit investments of the EAN. In this case, nodal transmission prices can be derived from circuit prices depending on a predefined split of payments among generators and consumers. Circuit prices allocation to only the periods when flows are binding means the application of time of use pricing. Circuit prices allocation to buses means the application of location specific pricing. Thus, once circuit prices are allocated to buses, transmission prices include both the specific location and time of use. Circuit prices allocation to nodal prices and among generators and consumers can be performed by defining a reference bus and using sensitivity factors. By definition, an incremental change at injection at any bus will be compensated by an equal and opposite injection at the reference bus; hence, the nodal price at the reference bus is zero.

The proposed method requires that the energy regulatory authority should supervise the determination of the EAN and the calculation of nodal transmission prices, although the calculation process can be performed by the transmission companies or the system operator. The determination of the optimal circuit capacities is a very important issue and therefore, the associated investment costs. Determination of the EAN is not a straightforward task because of the amount of data and operational simulations involved, including assumptions about the future such as load forecasting and the nodal distribution, and the development of new generation power plants and their location.

In developed countries load growth rates are generally very small (no more than 1% per year), and transmission networks are already expanded and do not require the construction of new lines or substations. In these cases the determination of an EAN on a yearly basis is fully acceptable. In developing countries, however, the load growth rates are high (5% to 8% per year), and transmission networks are still under development. In these cases, the definition of the EAN must involve a long term period of 7 to 10 years and consider the economies of scale provided by transmission assets over a long term period.

3 Formulation of the proposed method

The optimal capacity $F_l^{\max}$ of every branch l of the transmission system can be determined as a result of the solution of the long term optimization problem that minimizes generation operational costs plus transmission investment costs of the power system. Therefore, the optimal generation dispatch in each demand period, intact and contingent power flows, and transmission investment costs of each branch are known. The formulation of the long term optimization program can be expressed as

$$\min \mathrm{OIC}(g_j, F_l^{\max}) = \sum_{p=1}^{n_\mathrm{p}} h_p \sum_{j=1}^{n_\mathrm{g}} c_j g_j^p + \sum_{i=1}^{n_\mathrm{br}} a_i l_i F_i^{\max}, \quad (1)$$

$$\text{s.t.} \quad G_j^{\min} \le g_j^p \le G_j^{\max}, \quad 1 \le j \le n_\mathrm{g}, \ 1 \le p \le n_\mathrm{p}, \quad (2)$$

$$\sum_{j=1}^{n_\mathrm{g}} g_j^p = d_p, \quad 1 \le p \le n_\mathrm{p}, \quad (3)$$

$$F_i^{\max} \ge 0, \quad (4)$$

$$f_i^p = \sum_{k=1}^{n_\mathrm{bus}} \mathrm{GGDF}_{ki} g_k^p, \quad (5)$$

where n_p is the number of demand periods, n_g the number of generators, n_br the number of branches, n_bus the number of buses, h_p the duration of demand period p, d_p the nodal demand for period p, c_j the production cost of generator j, g_j^p the dispatch of generator j during demand period p, g_k^p the dispatch of the generator connected at bus k during demand period p, $G_j^{\min}$ and $G_j^{\max}$ the minimum and maximum dispatches of generator j respectively, a_i the annuity investment factor of line i (\$/(MW·km·year)), l_i the length of line i (km), f_i^p the power flow by line i during period p, and GGDF_{ki} the generalized generation distribution factor for line i and bus k.

Transmission constraints are added to the problem as part of the optimization process. These constraints are determined using the security constrained optimal power flow (SCOPF) method, and they are written as follows:

$$-F_i^{\max} \le f_i^p + \sum_{k=1}^{n_\mathrm{bus}} h_{ki}^S (g_k^p - g_k^{p0}) \le F_i^{\max}, \quad (6)$$

where S represents the system topology (intact, if the network is operating without outages, or contingent, if the network is operating with a security criterion like 'N−1' with one line out of service), and h_{ki}^S are elements of the sensitivity matrix. Superscript '0' means belonging to the unconstrained system.

$$\boldsymbol{H} = \boldsymbol{Y}_\mathrm{d} \boldsymbol{A}^\mathrm{T} \begin{bmatrix} \mathbf{0} & \mathbf{0} \\ \mathbf{0} & (\boldsymbol{Y}_\mathrm{bus}^\mathrm{r})^{-1} \end{bmatrix}, \quad (7)$$

where $\boldsymbol{Y}_\mathrm{d}$ is the diagonal matrix of branch admittances, $\boldsymbol{A}$ is the bus-branch incidence matrix for the intact system, and $\boldsymbol{Y}_\mathrm{bus}^\mathrm{r}$ is obtained from the system admittance matrix $\boldsymbol{Y}_\mathrm{bus}$ by removing the row and the column corresponding to the slack bus to make it nonsingular. To obtain the solution of the optimization problem (1), we need to calculate the generation dispatch in each demand period (g_j^p), the power flows per line in each demand period (f_i^p), and the optimal circuit capacities for every line ($F_i^{\max}$). The nodal LRMC at bus k during demand period p, λ_k^p, is calculated using the general formulation presented in Kirschen and Strbac (2004), with a specific equation when the SCOPF method is considered.

$$\lambda_k^p = \lambda^p + \sum_{i=1}^{n_\mathrm{br}} \mathrm{GGDF}_{ki} \tau_i^p, \quad (8)$$

where λ^p is the Lagrange multiplier associated with the demand constraint Eq. (3), also called system marginal costs, on every demand period p, and τ_i^p is the Lagrange multiplier associated with the transmission constraints.

In this method, the pricing concept of 'time of use' is considered via the definition of a threshold factor β, to look for binding conditions on each branch i with a flow $f_i(t)$ in a demand period t:

$$f_i'(t) = \begin{cases} f_i(t), & |f_i(t)| \ge \beta F_i^{\max}, \\ 0, & \text{otherwise}, \end{cases} \quad (9)$$

where $f_i(t)$ and $f_i'(t)$ are defined as the intact and binding flows of branch i in period t, respectively. Fig. 1 shows a duration curve of flow $f(t)$ in a branch and threshold factor β.

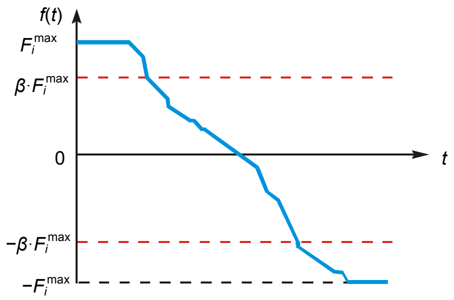

Fig. 1 Application of a threshold factor β over $f(t)$

The maximum flows per branch of the intact or any contingent network in each period that are binding according to condition (9) are stored in a matrix arrangement. A security factor $\mathrm{SF}_i(t)$ for branch i in period t can be determined for adequate circuit prices for evaluation with the intact flows of the EAN.

$$\mathrm{SF}_i(t) = F_i^{\max} \big/ f_i(t), \quad \text{for } f_i(t) \neq 0. \tag{10}$$

Then the optimal circuit prices $\mathrm{cp}_i(t)$ for branch i in period t are defined as follows:

$$\mathrm{cp}_i(t) = a_i l_i \mathrm{SF}_i(t) \Big/ \sum_{i=1}^{n_{\mathrm{br}}} h_i, \tag{11}$$

where h_i is the sum of time (in hours) in the periods when flows are binding for branch i.

The definition of location-specific prices is determined via the calculation of nodal transmission prices $\mathrm{np}_k(t)$ at bus k in period t, using sensitivity factors:

$$\mathrm{np}_k(t) = \sum_{i=1}^{n_{\mathrm{br}}} \mathrm{cp}_i(t) h_{ki}^{I}, \tag{12}$$

where h_{ki}^{I} are elements of sensitivity matrix $\boldsymbol{H}$ for intact network I.

In the calculation of the sensitivity matrix of Eq. (7), it is necessary to define a slack bus. The price at this node is zero. Therefore, we define a shift on nodal transmission prices to split the transmission costs among the generators and customers:

$$\mathrm{np}_k^{\mathrm{sh}}(t) = \mathrm{np}_k(t) - \delta(t), \tag{13}$$

where $\mathrm{np}_k^{\mathrm{sh}}(t)$, $\mathrm{np}_k(t)$, and $\delta(t)$ are the shifted nodal transmission prices, nodal transmission prices at node k in period t, and shift in nodal transmission prices in period t to obtain a desired split, respectively.

The calculation of the shift depends on the definition of a split of payments among generation and demand. The split of payments to generators $\varphi_{\mathrm{g}}(t)$ in period t is calculated as follows:

$$\varphi_{\mathrm{g}}(t) = \frac{\sum_{k=1}^{n_{\mathrm{bus}}} (\mathrm{np}_k(t) - \delta(t)) g_k(t)}{\sum_{k=1}^{n_{\mathrm{bus}}} \mathrm{np}_k(t)(g_k(t) - d_k(t))}, \tag{14}$$

where $d_k(t)$ is the demand at node k in period t. The denominator of Eq. (14) corresponds to the total transmission revenue $\mathrm{TTR}(t)$ in period t, calculated with nodal transmission prices:

$$\mathrm{TTR}(t) = \sum_{k=1}^{n_{\mathrm{bus}}} \mathrm{np}_k(t)(g_k(t) - d_k(t)). \tag{15}$$

Solving Eqs. (14) and (15), the shift in nodal transmission prices in period t is calculated as follows:

$$\delta(t) = \left(\sum_{k=1}^{n_{\mathrm{bus}}} \mathrm{np}_k(t) g_k(t) - \varphi_{\mathrm{g}}(t) \mathrm{TTR}(t) \right) \Big/ \sum_{k=1}^{n_{\mathrm{bus}}} g_k(t). \tag{16}$$

In this study the split of payments among generators and loads is considered (φ_{g}=50%).

4 Application example

To show how the proposed method is applied, the system shown in Fig. 2 is used as an example, and three demand periods are considered. The main data of the system are as follows:

Generator capacities: G1, 400 MW; G2A, 210 MW; G2B, 60 MW; G3, 100 MW.

Production costs: G1, 10 \$/(MW·h); G2A, 22 \$/(MW·h); G2B, 40 \$/(MW·h); G3, 15 \$/(MW·h).

Demand periods: 100%, 75%, and 50% of peak demand with a duration of 720, 2800, and 5240 h, respectively.

Line reactance and length: 0.2 p.u. and 300 km for every line.

Transmission annuity investment factor: 53 \$/(MW·km·year).

Consider a threshold factor of 90% of the transmission capacity as the definition of binding flows. Table 1 shows the step-by-step derivation of circuit prices and circuit revenue.

Table 1 Step-by-step derivation of circuit prices and circuit revenue for the three-bus power system

Line	Optimal capacity (MW)	Investment cost (T$)	Power flow per line (MW)			Binding flow per line (MW)		
			Period 1	Period 2	Period 3	Period 1	Period 2	Period 3
L12	208.3	3313	196	208	150	196	208	0
L23	91.6	1457	−92	−92	−50	92	92	0
L31	116.7	1855	−104	−117	−100	0	117	0

Line	Binding time per period (h)				Circuit price ($/(MW·h))			Circuit revenue (T$)			
	Period 1	Period 2	Period 3	Total	Period 1	Period 2	Period 3	Period 1	Period 2	Period 3	Total
L12	720	2800	0	3520	4.8	4.5	0	678	2635	0	3313
L23	720	2800	0	3520	−4.5	−4.5	0	298	1159	0	1457
L31	0	2800	0	2800	0	−5.66	0	0	1855	0	1855
Total								976	5649	0	6625

Periods 1, 2, and 3 correspond to 100%, 75%, and 50% of peak demand with a duration of 720, 2800, and 5240 h, respectively

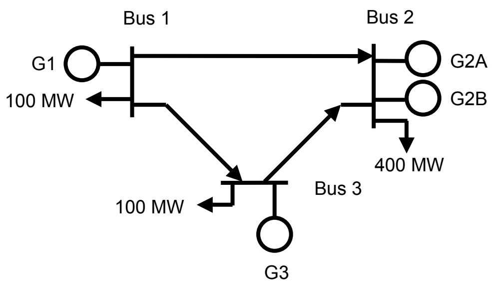

Fig. 2 Three-bus power system

Long run marginal costs are derived from the optimal solution of the long term operation plus investment problem. Thereby, the solution is the same as that found to determine the EAN. The values of the LRMC in different periods are shown in Table 2.

Table 2 Long run marginal cost for the three buses

Period	Long run marginal cost ($/(MW·h))		
	Bus 1	Bus 2	Bus 3
1	18.5	22.0	15.0
2	10.3	17.0	15.0
3	10.0	10.0	10.0

In this case circuit revenues have a perfect match with transmission investment on a line-by-line basis. Table 3 shows the nodal transmission prices derived from the EAN. Table 4 presents the nodal charges to serve as revenues to pay transmission investment costs of the EAN. This method always makes a complete match between transmission investments and revenues on a line-by-line basis.

Table 3 Nodal transmission prices derived from the EAN

Bus	Generator capacity (MW)		
	Period 1	Period 2	Period 3
1	400	400	300
2	112	0	0
3	88	50	0

Line	Power flow* (MW)		
	Period 1	Period 2	Period 3
L12	196	208	150
L23	−92	−92	−50
L31	−104	−117	−100

Bus	Nodal price** ($/(MW·h))		
	Period 1	Period 2	Period 3
1	0	0	0
2	−4.700	−6.385	0
3	−0.099	−3.775	0

* Power flow=$\boldsymbol{H}(G-D)$; ** nodal price=$\boldsymbol{H}^{\mathrm{T}}$[cp]

Table 4 Nodal revenues to pay transmission investment costs

Bus	Nodal revenue (T$)			
	Period 1	Period 2	Period 3	Total
1	0	0	0	0
2	975	5384	0	6359
3	1	265	0	266
Total	976	5649	0	6625

5 Case study

We use the IEEE 24-bus network for our case study. The topology and parameters of this network and the generation and demand data are the same as those given in Grigg *et al*. (1999). The power system has 31 generators, 38 branches, with an incremental investment factor of 30 $/(MW·km·year) and a peak demand of 2850 MW. The 'N−1' security criterion is considered in the studies.

The studies show the robustness of the proposed method using the MATPOWER program working over a large network, similar to a real one (Zimmerman *et al.*, 2011).

Table 5 shows the peak loads for this system for five demand periods. Table 6 shows the optimal capacity and power flows per period and Table 7 presents the circuit prices and circuit revenue.

Table 5 Peak loads for the IEEE 24-bus system in different periods

Period	Load (MW)	Duration (h)
1	2850	290
2	2473	1730
3	2096	2490
4	1719	2670
5	1342	1580

Table 6 Optimal capacity and power flows per period

Branch	Optimal capacity (MW)	Intact flow per period (MW)						Contingency flow per period (MW)					
		1	2	3	4	5	Max	1	2	3	4	5	Max
1	88	10.5	15.5	22.0	25.4	21.8	25.4	79.2	65.3	88.0	88.0	69.7	88.0
2	113	−13.9	−18.9	−71.5	−77.1	−64.3	77.1	51.8	−57.1	−113.5	−113.5	−95.4	113.5
3	86	47.4	61.7	4.0	−13.5	−8.4	61.7	71.6	86.5	52.2	−57.3	−41.9	86.5
4	74	25.9	35.2	−14.3	−27.2	−20.6	35.2	74.0	64.2	54.4	−56.4	−44.9	74.0
5	136	39.6	48.1	7.3	−5.9	−3.3	48.1	136.0	118.0	100.0	82.0	64.1	136.0
6	144	11.7	47.7	54.3	48.2	46.3	54.3	−128.2	128.8	143.6	125.6	112.6	143.6
7	389	−205.6	−222.9	−258.2	−233.8	−195.4	258.2	−310.6	−342.1	−389.5	−347.7	−292.8	389.5
8	101	−48.1	−29.0	−68.7	−71.9	−55.5	71.9	−75.8	−64.2	−95.5	−101.0	−79.8	101.0
9	100	−23.6	0.1	−48.2	−56.3	−41.8	56.3	−71.6	−61.6	−94.4	−100.1	−75.4	100.1
10	136	−96.4	−69.9	−92.8	−88.0	−67.3	96.4	−136.0	−118.0	−119.9	−112.6	−87.9	136.0
11	142	142.3	−69.3	−91.9	−75.4	−58.9	142.3	142.3	−69.3	−91.9	−75.4	−58.9	142.3
12	218	−24.9	−119.6	−123.2	−102.7	−80.8	123.2	−52.9	−217.7	−217.7	−178.6	−139.4	217.7
13	218	−3.9	−98.1	−94.5	−94.5	−58.6	98.1	−28.7	−217.7	−217.7	−178.6	−139.4	217.7
14	232	−108.4	−122.2	−133.8	−117.7	−93.8	133.8	−186.3	−260.8	−231.6	−206.2	−167.7	231.6
15	211	−127.8	−130.4	−132.5	−114.3	−78.7	132.5	−195.6	−199.7	−211.0	−185.4	−138.1	211.0
16	302	−149.8	−164.5	−190.2	−170.6	−137.4	190.2	−249.7	−266.6	−301.8	−269.4	−209.7	301.8
17	300	−169.1	−172.7	−188.8	−167.2	−122.3	188.8	−256.5	−268.5	−299.7	−266.7	−202.4	299.7
18	283	−113.5	−70.1	−42.9	−37.7	−7.8	113.5	−282.9	−262.7	−254.9	−221.6	−165.2	282.9
19	421	−144.8	−216.6	−281.1	−250.6	−223.4	281.1	−255.8	−337.0	−420.6	−376.9	−358.4	420.6
20	206	−79.4	−55.7	−45.3	−43.8	−34.4	79.4	−206.1	−199.9	−206.1	−182.3	−131.5	206.1
21	426	−217.5	−247.5	−275.9	−237.7	−166.5	275.9	−322.8	−377.4	−425.7	−365.3	−260.3	425.7
22	449	−199.1	−245.7	−283.2	−241.4	−167.0	283.2	−322.0	−396.7	−449.4	−385.6	−290.5	449.4
23	563	−338.8	−385.0	−423.8	−367.6	−314.7	423.8	−449.8	−505.3	−563.2	−493.9	−449.8	563.2
24	526	57.3	95.8	119.6	164.1	149.8	164.1	333.0	400.1	449.2	523.5	526.2	526.2
25	389	205.6	222.9	258.2	233.8	195.4	258.2	310.6	342.1	389.5	347.7	292.8	389.5
26	518	−292.1	−322.3	−349.1	−380.7	−398.6	398.6	−382.7	−415.9	−446.4	−511.6	−518.2	518.2
27	419	65.6	101.3	126.4	116.9	186.6	186.6	299.4	367.1	418.9	370.6	403.9	418.9
28	379	−172.0	−200.9	−226.9	−257.1	−275.4	275.4	−257.2	−287.0	−313.6	−370.1	−378.6	378.6
29	250	−120.1	−121.4	−122.2	−123.6	−123.2	123.6	−250.0	−250.0	−250.0	−250.0	−250.0	250.0
30	250	−129.9	−128.6	−127.8	−126.4	−126.8	129.9	−250.0	−250.0	−250.0	−250.0	−250.0	250.0
31	447	−212.5	−219.4	−228.0	−234.2	−247.3	247.3	−358.5	−380.5	−402.5	−424.6	−446.6	446.6
32	447	−212.5	−219.4	−228.0	−234.2	−247.3	247.3	−358.5	−380.5	−402.5	−424.6	−446.6	446.6
33	156	−52.5	−45.0	−35.9	−29.0	−16.1	52.5	−95.1	94.2	114.8	135.4	156.0	156.0
34	156	−52.5	−45.0	−35.9	−29.0	−16.1	52.5	−95.1	94.2	114.8	135.4	156.0	156.0
35	159	−57.7	−27.9	−3.4	3.8	50.7	57.7	−105.6	105.0	142.9	130.7	159.3	159.3
36	159	−57.7	−27.9	−3.4	3.8	50.7	57.7	−105.6	105.0	142.9	130.7	159.3	159.3
37	230	−121.7	−83.4	−50.5	−34.8	20.5	121.7	−229.9	−157.5	−117.2	−93.2	129.2	229.9
38	230	−121.7	−83.4	−50.5	−34.8	20.5	121.7	−229.9	−157.5	−117.2	−93.2	129.2	229.9

Table 7 Circuit prices and circuit revenues for the five periods

Branch	Circuit price per period ($/(MW·h))					Circuit revenue per period (T$)					
	1	2	3	4	5	1	2	3	4	5	Total*
1	0.0	0.0	0.07	0.061	0.0	0.0	0.0	3.8	4.1	0.0	7.9
2	0.0	0.0	−0.509	−0.472	0.0	0.0	0.0	90.5	96.8	0.0	187.3
3	0.0	0.537	0.0	0.0	0.0	0.0	57.1	0.0	0.0	0.0	57.1
4	9.838	0.0	0.0	0.0	0.0	73.3	0.0	0.0	0.0	0.0	73.3
5	17.948	0.0	0.0	0.0	0.0	204	0.0	0.0	0.0	0.0	204
6	0.0	0.0	0.989	0.0	0.0	0.0	0.0	133.5	0.0	0.0	133.5
7	0.0	0.0	−0.910	0.0	0.0	0.0	0.0	584.2	0.0	0.0	584.2
8	0.0	0.0	−0.231	−0.221	0.0	0.0	0.0	39.5	42.3	0.0	81.8
9	0.0	0.0	−0.278	−0.238	0.0	0.0	0.0	33.4	35.7	0.0	69.1
10	−2.36	0.0	0.0	0.0	0.0	65.3	0.0	0.0	0.0	0.0	65.3
11	1.672	0.0	0.0	0.0	0.0	68.3	0.0	0.0	0.0	0.0	68.3
12	0.0	−0.558	−0.542	0.0	0.0	0.0	115	165.9	0.0	0.0	280.9
13	0.0	−0.680	−0.706	0.0	0.0	0.0	115	165.9	0.0	0.0	280.9
14	0.0	0.0	−1.044	0.0	0.0	0.0	0.0	347.4	0.0	0.0	347.4
15	−0.551	−0.539	−0.531	0.0	0.0	20.2	121.4	174.9	0.0	0.0	316.5
16	0.0	0.0	−0.958	0.0	0.0	0.0	0.0	452.6	0.0	0.0	452.6
17	0.0	0.0	−0.958	0.0	0.0	0.0	0.0	449.6	0.0	0.0	449.6
18	−0.549	−0.888	−1.451	0.0	0.0	17.9	107.4	154.8	0.0	0.0	280.1
19	0.0	0.0	−0.524	0.0	0.0	0.0	0.0	365.9	0.0	0.0	365.9
20	−0.572	−0.815	−1.001	0.0	0.0	13	78.3	112.8	0.0	0.0	204.1
21	0.0	0.0	−1.247	0.0	0.0	0.0	0.0	855.6	0.0	0.0	855.6
22	0.0	0.0	−1.149	0.0	0.0	0.0	0.0	808.9	0.0	0.0	808.9
23	0.0	0.0	−0.433	0.0	0.0	0.0	0.0	456.2	0.0	0.0	456.2
24	0.0	0.0	0.0	0.272	0.298	0.0	0.0	0.0	118.9	70.5	189.4
25	0.0	0.0	0.655	0.0	0.0	0.0	0.0	420.6	0.0	0.0	420.6
26	0.0	0.0	0.0	−0.173	−0.166	0.0	0.0	0.0	175.6	104.2	279.8
27	0.0	0.0	0.392	0.0	0.265	0.0	0.0	123	0.0	78.1	201.1
28	0.0	0.0	0.0	−0.104	−0.097	0.0	0.0	0.0	71.3	42.3	113.6
29	−0.522	−0.516	−0.513	−0.507	−0.509	18	108	155.8	166.8	98.9	547.5
30	−0.311	−0.314	−0.316	−0.319	−0.318	11.6	69.5	100.3	107.4	63.7	352.5
31	0.0	0.0	−0.297	−0.289	−0.274	0.0	0.0	168.4	180.2	106.9	455.5
32	0.0	0.0	−0.297	−0.289	−0.274	0.0	0.0	168.4	180.2	106.9	455.5
33	0.0	0.0	0.0	0.0	−3.311	0.0	0.0	0.0	0.0	84.2	84.2
34	0.0	0.0	0.0	0.0	−3.311	0.0	0.0	0.0	0.0	84.2	84.2
35	0.0	0.0	0.0	0.0	1.614	0.0	0.0	0.0	0.0	129	129
36	0.0	0.0	0.0	0.0	1.614	0.0	0.0	0.0	0.0	129	129
37	−2.962	0.0	0.0	0.0	0.0	103.5	0.0	0.0	0.0	0.0	103.5
38	−2.962	0.0	0.0	0.0	0.0	103.5	0.0	0.0	0.0	0.0	103.5
Total						698.4	771.6	6531.9	1179.4	1097.9	10279.2

* For each branch the investment is equal to the total circuit revenue

With considering the ‘N−1’ criterion, the optimal capacity calculated for the system based on the EAN concept shows that the system can work without any congestion at the lines.

Table 7 shows that this method always makes a perfect match between transmission investments and revenues on a line-by-line basis. Table 8 shows the nodal transmission prices derived from the EAN and Table 9 presents the valuation of nodal transmission charges on generation and demand, showing a 50%–50% allocation.

Table 8 Nodal transmission prices for the five periods

Bus	Nodal price referred to bus 1 ($/(MW·h))					Shifted nodal price ($/(MW·h))				
	1	2	3	4	5	1	2	3	4	5
1	0.0	0.0	0.0	0.0	0.0	4.834	−0.014	−1.799	−0.360	−0.256
2	0.728	−0.023	−0.071	−0.046	−0.012	5.562	−0.037	−1.870	−0.407	−0.267
3	−4.398	−0.110	0.831	0.335	0.364	0.436	−0.124	−0.967	−0.025	0.108
4	−7.199	−0.159	−0.131	−0.024	−0.045	−2.365	−0.173	−1.929	−0.384	−0.300
5	−2.665	−0.354	−0.123	−0.033	−0.075	2.169	−0.369	−1.921	−0.393	−0.331
6	−10.064	−0.130	0.004	0.119	−0.120	−5.230	−0.144	−1.794	−0.241	−0.376
7	−3.869	−0.836	−0.584	0.193	−0.113	0.965	−0.850	−2.382	−0.167	−0.369
8	−5.542	−0.836	−0.584	0.193	−0.113	−0.708	−0.850	−2.382	−0.167	−0.369
9	−5.634	−0.270	0.052	0.215	−0.072	−0.800	−0.284	−1.747	−0.145	−0.328
10	−5.449	−0.164	0.028	0.171	−0.154	−0.615	−0.178	−1.771	−0.189	−0.410
11	−5.443	−0.184	0.929	0.184	−0.098	−0.609	−0.198	−0.869	−0.176	−0.354
12	−4.928	−0.015	0.906	0.187	−0.354	−0.094	−0.029	−0.893	−0.174	−0.610
13	−4.472	0.629	1.942	0.184	−0.367	0.362	0.615	0.144	−0.176	−0.623
14	−5.714	−0.085	1.726	0.176	0.153	−0.880	−0.099	−0.073	−0.184	−0.103
15	−5.815	0.001	2.365	0.384	1.095	−0.981	−0.013	0.567	0.024	0.839
16	−5.967	0.007	2.413	0.169	0.386	−1.133	−0.007	0.615	−0.192	0.131
17	−5.924	−0.004	2.491	0.418	−0.201	−1.090	−0.019	0.692	0.057	−0.457
18	−5.888	0.004	2.542	0.564	−0.697	−1.054	−0.010	0.744	0.204	−0.952
19	−6.358	0.081	2.167	0.173	0.384	−1.524	0.067	0.369	−0.188	0.129
20	−6.694	0.145	2.292	0.176	−1.004	−1.860	0.130	0.494	−0.184	−1.259
21	−5.856	0.012	2.589	0.602	2.081	−1.022	−0.002	0.790	0.242	1.825
22	−5.489	0.399	2.943	0.923	1.580	−0.655	0.385	1.145	0.562	1.324
23	−3.914	0.179	2.360	0.178	−0.881	0.920	0.165	0.562	−0.183	−1.136
24	−5.274	−0.041	1.722	0.366	0.815	−0.440	−0.056	−0.076	0.005	0.560
Shift						−4.834	0.014	1.799	0.360	0.256

Table 9 Generation and demand payments for the five periods

Bus	Generation payments (T$)						Load payments (T$)					
	1	2	3	4	5	Total	1	2	3	4	5	Total
1	210.9	−3.7	−151.7	0.0	0.0	55.5	149.8	−2.3	−355.2	−62.5	−20.5	−290.6
2	242.6	−9.7	−196.7	0.0	0.0	36.3	154.8	−5.4	−331.6	−63.3	−19.3	−264.7
3	0.0	0.0	0.0	0.0	0.0	0.0	22.5	−33.5	−318.3	−7.2	14.4	−322.1
4	0.0	0.0	0.0	0.0	0.0	0.0	−50.2	−19.1	−261	−45.7	−16.5	−392.6
5	0.0	0.0	0.0	0.0	0.0	0.0	44.2	−39.2	−249.4	−44.8	−17.5	−306.6
6	0.0	0.0	0.0	0.0	0.0	0.0	−204.1	−29.4	−446.2	−52.6	−38	−770.4
7	74	−57.4	0.0	0.0	0.0	16.6	34.6	−159	−544.5	−33.5	−34.3	−736.7
8	0.0	0.0	0.0	0.0	0.0	0.0	−34.7	−217.5	−744.9	−45.9	−46.9	−1089.8
9	0.0	0.0	0.0	0.0	0.0	0.0	−40.2	−74.4	−558.9	−40.8	−42.6	−756.9
10	0.0	0.0	0.0	0.0	0.0	0.0	−34.4	−52	−631.3	−59.2	−59.4	−836.4
11	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	26.9	116.5	0.0	0.0	0.0	143.4	27.6	243.6	69.6	−75	−122.7	143.1
14	0.0	0.0	0.0	0.0	0.0	0.0	−49	−28.7	−25.8	−57.3	−14.8	−175.7
15	−43.7	−3.5	218.4	7.7	0.0	179	−89.3	−6.2	328.5	12.2	197.7	443
16	−50.4	−1.8	236.9	0.0	0.0	184.7	−32.5	−1.0	112.4	−30.8	9.7	57.8
17	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
18	−121	−6.7	739.8	217	−610.2	227.9	−100.7	−4.8	453	109	−235.8	220.6
19	0.0	0.0	0.0	0.0	0.0	0.0	−79.2	18.2	122.1	−54.6	17.3	23.8
20	0.0	0.0	0.0	0.0	0.0	0.0	−68.3	25	115.6	−37.9	−119.8	−85.5
21	−117.3	−1.2	785.9	257.4	1152.2	2077	0.0	0.0	0.0	0.0	0.0	0.0
22	−47	165.8	711.6	374.1	522.4	1726.9	0.0	0.0	0.0	0.0	0.0	0.0
23	174.2	187.5	921.8	−266.6	−524.5	492.4	0.0	0.0	0.0	0.0	0.0	0.0
24	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	349.2	386	3266	589.6	548.9	5139.6	−349.2	−385.7	−3265.9	−589.8	−549	−5139.6

The total transmission revenue is 10 279.2

Table 10 presents a sensitivity analysis to probe the impact of the threshold factor, to define flows that are binding on time of use allocation of transmission revenues. Threshold values between 50% and 100% were chosen and the temporal distribution of circuit revenues was determined. For a threshold of 100% (only the flows that are equal to the optimal capacity are binding), the temporal distribution of the transmission revenues is similar to the distribution of LRMC transmission revenues for the EAN. In contrast, for a threshold of 50% (flows over 50% of the optimal capacity are binding), the temporal distribution of the revenues is similar to the time distribution per period, indicating that the transmission prices lose the time of use signal for a threshold less than 50%.

For the EAN, transmission revenue covers exactly the investment cost of the network (Table 11). For over invested networks, a recovery in excess of the EAN revenue is permitted because there are benefits derived from lower generation operational costs. For example, for a 50% over capacity in the network, only 1.5% additional revenue is obtained.

6 Conclusions

From theoretical and practical experiences in transmission pricing, it appears that there is no global method for pricing the use of the electricity transmission network. SRMC is a well known optimal price method in the energy market; however, it is not able to compensate the investment costs of the transmission network. Different prices between buses as a result of the SRMC application are not the correct way to pay for the use of the transmission network. SRMC does not have any relation to transmission investments and also, in real networks with over capacity, the SRMC surplus can be very small or even equal to zero. A better approach to determining the transmission prices is the use of LRMC based on an economically adapted network (EAN). However, in meshed networks LRMC revenues follow Kirchhoff's voltage law (KVL) but transmission investments do not. Then there is no match between LRMC revenues and investment costs for the optimal network on a line-by-line basis. Transmission pricing based on the concept of EAN has proven an efficient transmission access pricing method that allows the recovery of transmission investment costs. This method always achieves a perfect match between transmission investments and revenues on a line-by-line basis. Prices derived from the EAN have the advantage of being in tune with the maximum revenue allowed to the owner of transmission assets, and being independent of the selection of the slack bus and also the optimal allocation of transmission costs among the users of the network. In summary, a cost based method like nodal transmission prices derived from the EAN is preferred to a value based method for transmission pricing.

Table 10 Distribution of payments by period with the threshold varying from 50% to 100%

Period	LRMC revenue (T$)	Duration (h)	Percentage					
			100%	90%	80%	70%	60%	50%
1	972.7 (9%)	290 (3%)	9%	7%	5%	5%	6%	3%
2	312.8 (3%)	1730 (20%)	5%	8%	22%	20%	21%	20%
3	5995 (58%)	2490 (29%)	61%	63%	32%	31%	31%	29%
4	178.2 (2%)	2670 (30%)	5%	11%	34%	29%	32%	30%
5	2820.4 (27%)	1580 (18%)	20%	11%	7%	15%	10%	18%
Total	10279.2 (100%)	8760 (100%)	100%	100%	100%	100%	100%	100%

Table 11 Transmission revenue for the EAN and an over invested network

Transmission capacity/optimal capacity	Total operation and investment cost (T$)	Operation cost (T$)	Transmission investment cost (T$)	Transmission revenue (T$)	Transmission revenue/optimal revenue
1.0	134748.9	124478.5	10270.4	10270.4	1.000
1.1	135490.1	124192.8	11297.3	10381.4	1.011
1.2	136505.2	124180.9	12324.3	10404.1	1.013
1.5	139580.9	124175.5	15405.4	10419.3	1.015

Acknowledgements

The first author gratefully acknowledges the support from Science and Research Branch, Islamic Azad University, Tehran, Iran.

References

Bhakar, R., Sriram, V.S., Padhy, N.P., Gupta, H.O., 2009. Transmission embedded cost allocation in restructured environment: a game theoretic approach. *Electr. Power Compon. Syst.*, **37**(9):970-981. [doi:10.1080/15325000902918842]

Bialek, J., 1997. Topological generation and load distribution factors for supplement charge allocation in transmission open access. *IEEE Trans. Power Syst.*, **12**(3):1185-1193. [doi:10.1109/59.630460]

Conejo, A.J., Contreras, J., Lima, D.A., Padilha-Feltrin, A., 2007. Z_{bus} transmission network cost allocation. *IEEE Trans. Power Syst.*, **22**(1):342-349. [doi:10.1109/TPWRS.2006.889138]

Galiana, F., Conejo, A.J., Gil, H., 2003. Transmission network cost allocation based on equivalent bilateral exchanges. *IEEE Trans. Power Syst.*, **18**(4):1425-1431. [doi:10.1109/TPWRS.2003.818689]

Grigg, C., Wong, P., Albrecht, P., Allan, R., Bhavaraju, M., Billinton, R., Chen, Q., Fong, C., Haddad, S., Kuruganty, S., *et al.*, 1999. The IEEE Reliability Test System-1996. A report prepared by the Reliability Test System Task Force of the Application of Probability Methods Subcommittee. *IEEE Trans. Power Syst.*, **14**(3):1010-1020. [doi:10.1109/59.780914]

Henney, A., 1998. Contrasts in restructuring wholesale electric markets: England/Wales, California, and the PJM. *The Electr. J.*, **11**(7):24-42. [doi:10.1016/S1040-6190(98)00074-8]

Kirschen, D., Strbac, G., 2004. Fundamentals of Power System Economics. John Wiley & Sons, New York. [doi:10.1002/0470020598]

Kirschen, D., Allan, R., Strbac, G., 1997. Contributions of individual generators to loads and flows. *IEEE Trans. Power Syst.*, **12**(1):52-60. [doi:10.1109/59.574923]

Meng, Y., Jeyasurya, B., 2007. Investigation of Transmission Cost Allocation Using a Power Flow Tracing Method. IEEE Power Engineering Society General Meeting, p.1-7. [doi:10.1109/PES.2007.385565]

Pan, J., Teklu, Y., Rahman, S., Jun, K., 2000. Review of usage-based transmission cost allocation methods under open access. *IEEE Trans. Power Syst.*, **15**(4):1218-1224. [doi:10.1109/59.898093]

Reta, R., Vargas, A., Verstege, J., 2005. Allocation of expansion transmission costs areas of influence method versus economic benefit method. *IEEE Trans. Power Syst.*, **20**(3):1647-1652. [doi:10.1109/TPWRS.2005.852104]

Sedaghati, A., 2006. Cost of transmission system usage based on an economic measure. *IEEE Trans. Power Syst.*, **21**(2):466-473. [doi:10.1109/TPWRS.2006.873133]

Usaola, J., 2006. A transaction-based method for allocation of transmission grid cost and losses. *Electr. Power Syst. Res.*, **76**(6-7):395-403. [doi:10.1016/j.epsr.2005.09.003]

Zimmerman, R.D., Murillo-Sánchez, C.E., Gan, D., 2011. MATPOWER User's Manual, Version 4.1. Power Systems Engineering Research Center.

Zolezzi, J., Rudnick, H., Danitz, F., Bialek, J.W., Pan, J.P., Teklu, Y., Rahman, S., Jun, K., 2001. Review of usage-based transmission cost allocation methods under open access. *IEEE Trans. Power Syst.*, **16**(4):933-934. [doi:10.1109/59.962455]