Electric Power Systems Research 101 (2013) 25–35

Contents lists available at SciVerse ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Min–max long run marginal cost to allocate transmission tariffs for transmission users

Érica Telles [a], Delberis A. Lima [a,*], Alexandre Street [a], Javier Contreras [b]

[a] Pontifícia Universidade Católica do Rio de Janeiro, Rio de Janeiro, Brazil
[b] Univ. Castilla, La Mancha, Ciudad Real, Spain

ARTICLE INFO

Article history:
Received 27 December 2012
Received in revised form 15 March 2013
Accepted 18 March 2013
Available online 12 April 2013

Keywords:
Long Run Marginal Costs
Nodal method
Min–max technique
Linear programming
Transmission tariff computation.

ABSTRACT

The dispersion and volatility of transmission tariffs can provide an unsafe environment for generation investors in electrical systems, which are constantly growing. Dispersion and volatility occur, for example, in Brazil, where the Long Run Marginal Costs (LRMC) method is applied to calculate transmission tariffs. To solve this problem, this paper proposes a new Transmission Tariff Computation (TTC) approach based on the LRMC method and the min–max optimization technique.

The proposed method uses the LRMC approach and the min–max optimization technique to seek less-dispersed transmission tariffs. The proposed modified LRMC method can be employed to optimize tariffs for generators and loads jointly or separately. This choice should be based on the network topology. The results are presented for a 6-bus and the IEEE 118-bus systems. The modified LRMC method is compared with the traditional LRMC method, currently in use in Brazil, and the classical Pro rata technique. Finally, some conclusions are presented.

© 2013 Elsevier B.V. All rights reserved.

1. Introduction

The transmission system is responsible for connecting the generation plants, which are generally dispersed, to the load centers. According to the Brazilian National Electric Energy Agency (ANEEL), the transmission cost that should be recovered every year in the basic network (a network with 230 kV or above) is currently greater than 13 billion Reais (R$[1]) [1]. The revenue accrued by transmission usage is applied to recover the operation, maintenance and expansion planning costs. It must be paid by generators and loads, which are the transmission users. Notwithstanding, transmission networks are huge infrastructure that aims to provide not only a path between generation and load. It also plays other roles such as ensure reliability and supply adequacy. Such features demand the installation of additional capacity to circumvent contingencies, uncertainty and to meet quality standards. As a result, the transmission system cost is generally not recoverable by transmission cost allocation methods supported on the players' usage. One of the main challenges is how to allocate these costs to generators and loads.

In recent years, several studies have been proposed to allocate transmission costs. The Pro rata method [2] allocates transmission costs to generators and loads in proportion to their respective generations and consumptions. The cost allocated to each generator and/or load is independent of the network configuration.

Other more complex methods allocate transmission costs to generators and loads based on the active power flow participation of generators and loads through transmission lines [3–7]. To identify the responsibility of the power flow through each line due to generators or loads, the proportional sharing principle is used in [3–6]. To apply the proportional sharing principle, it is necessary to define (a priori) how much of the total transmission cost should be allocated to the generators and the loads of the system. Generally, a 50/50 allocation rule is applied. In [7] the cited responsibility is defined, in the most general manner, by generation shift factors applied to predefined wheeling transactions formed by generators and loads in the system.

In addition, another representative method is the Zbus method [8]. This method considers the current injections into system buses, the impedance matrix (Zbus), and other electrical parameters to allocate the transmission cost. The main characteristic of this method is that is highly dependent on the network topology.

Long Run Marginal Cost (LRMC) methods [9–18] are employed in countries such as England, Colombia and Brazil. LRMC methods consider the marginal participation of each generator or load to increase the future investments in the transmission system through the bus-to-line active power sensitivity matrix [19]. Because the method should reflect users' responsibility for this increase, a set of hypothesis are needed to address LRMC methods:

* Corresponding author. Tel.: +55 21 35271211; fax: +55 21 35271232.
E-mail addresses: delberis@ele.puc-rio.br, delberis1@gmail.com (D.A. Lima).

[1] 1 US$ is approximately 2R$.

0378-7796/$ – see front matter © 2013 Elsevier B.V. All rights reserved.
http://dx.doi.org/10.1016/j.epsr.2013.03.009

Notation

Constants

β	power flow sensitivity matrix due to the nodal injection of active power
$\boldsymbol{P}_G$	nodal power generation vector (MW)
P_{Gi}	power generated at bus i (MW)
$\boldsymbol{P}_D$	nodal power demand vector (MW)
P_{Dj}	power demand at bus j (MW)
P_i	net power injection at bus i (MW)
C_ℓ	cost of line ℓ ($)
c_ℓ	unitary cost of line ℓ ($/MW)
F_ℓ	power flow through line ℓ (MW)
$F_\ell^{\max}$	maximum power flow of line ℓ (MW). In this paper, the maximum active power flow of line ℓ is considered equal to the transmission capacity of this line
$F_\ell^{\min}$	minimum power flow of line ℓ (MW). In this paper, active power flows lower than the minimum power flow is not considered to compute transmission tariffs
$Fpond_\ell$	weighting factor of line ℓ. This factor represents the utilization factor of line ℓ

Variables

α_{ij}	percentage of power injected at bus i to feed a unitary load at bus j
$\pi_{G_i}^L$	locational tariff of generator i ($/MW)
$\pi_{D_j}^L$	locational tariff of load j ($/MW)
Δ_G	postage stamp for generators ($/MW)
Δ_D	postage stamp for loads ($/MW)
π_{G_i}	transmission usage tariff for generator i ($/MW)
π_{D_j}	transmission usage tariff for load j ($/MW)

Sets

Ω_G	set of generators
Ω_D	set of loads
Ω_L	set of transmission lines
G_k	set of generators that are not optimized by the modified LRMC method up to iteration k
D_k	set of loads that are not optimized by the modified LRMC method up to iteration k
M_{Gk}	set of generators that have been optimized by the modified LRMC method up to iteration k
M_{Dk}	set of loads that have been optimized by the modified LRMC method up to iteration k

- There is an "ideal minimum cost network" required to supply the demand for existing routes, and this network has the same topology and impedances of the existing network (with expansions under determinative expansion planning);
- The ideal network is defined assuming peak demand conditions of each load;
- To supply the demand, the generators are dispatched proportionally by considering their capacity registered (pro-rata).The last both assumptions are applied to try to achieve the maximum transmission system stress, which according to [16] is not always guaranteed;
- Is assumed that the transmission capacity of each line and transformer coincides with the ideal power flow verified in the element for the demand condition considered;
- It will be considered that the expansion of the transmission system should be built by the existing routes. It means that marginal increments on the power flow in transmission lines would result in additional charges over the tariff, simulating the future real investments in transmission system, which occurs discontinuously with the entrance of new ventures.

In [9], the LRMC technique is applied with the Equivalent Bilateral Exchanges (EBE) method. In this method, an EBE has pre-defined nodal exchange factors (NEFs) that represent the percentage of the generation in bus i that feeds load bus j. The transmission cost is allocated based on the amount of power flow that each EBE produces and is transported through transmission lines. In [10] a Modified Equivalent Bilateral Exchange (MEBE) is proposed by considering the features of EBE method and the losses in the network.

Similar to the EBE method, the LRMC method applied in Brazil [12,13,15], which is also called Nodal LRMC, computes transmission tariffs by considering the impact of a variation in the power injection at bus i and an equivalent compensation of this variation at the slack bus. Because the solution is dependent on the choice of the slack bus, a slight modification is proposed to create a slack-bus-independent method. The details about the method are described in Section 2.2.

For practical purposes, a tariff-based approach is used to allocate transmission costs. The transmission tariff should be multiplied by the maximum generation or demand in a time period (usually a month) to charge the transmission users. The approach based on tariffs is well accepted because, in general, transmission systems have a relatively well-defined power consumption and generation dispatch compared with distribution systems, for example. Thus, the power flow (base case) established can be considered representative. Moreover, the tariffs must change only if the system changes (new lines or new generators are installed). Thus, the tariffs computed are more stable and predictable over time.

There is no consensus yet on the best method to allocate transmission costs. In [20], an analysis of different methods is performed to highlight the advantages and disadvantages of each one. According to [9], the positive characteristics that should be considered are independence from the choice of slack bus, the satisfaction of both laws of Kirchhoff, location-dependent tariffs, a low temporal volatility of transmission tariffs and the allocation of nonzero tariffs to all network users.

In developing countries, such as Brazil, fast generation and transmission expansion triggered by a sharp demand growth can cause volatility in transmission tariffs. These undesirable effects generate an unsafe environment for new generation investments, mostly for the ones that utilizes renewable resources. In addition, different from conventional sources (gas, oil, etc.), most renewable sources cannot freely select the connection bus in transmission system. In this case, renewable resources availability and quality are the most important variables. There are several examples where renewable sources are far from load centers. For instance, Brazilian hydro basins in Amazon and wind in the middle of US are some representative examples. In some cases, transmission tariff obtained by traditional methods can make new investments in renewables unattractive. To tackle this problem, a new paradigm based on the robust min–max optimization technique is proposed to set transmission tariffs [21–23]. The idea behind the min–max technique is that, for a given steady state operation point, the agents with the worst tariffs should have priority in the tariff optimization process to minimize tariffs. The main motivation for this approach relies on the fact that volatile tariffs bring uncertainty to the investors' future cash flows, which ultimately can be seen as an entrance barrier for new investments.

Download English Version:

https://daneshyari.com/en/article/705202

Download Persian Version:

https://daneshyari.com/article/705202

Daneshyari.com