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Advanced Transmission Service Charges Methodologies in Deregulated Electricity Market Environment

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Abstract

Under the deregulation scheme, the electricity business has been separated into three parts: generation, transmission and distribution. In transmission, there are number of issues arise in the context of transmission pricing. It is very important to satisfactorily allocate the transmission service charges among all involved participants, taking into account as accurately as possible the real impact of every transaction on the transmission system. Besides this, another issue is to improve the existing transmission pricing in competitive electricity market by integrating the transmission loss component with the transmission use of system (TUoS) charges. In addition, with the presence of the renewable generation integration to the existing grid, the TUoS charging methodology also need an improvement in order to be fair and equitable to the market participants. These three main transmission pricing issues are investigated in this research.

The first issue is allocating the transmission service charges fairly among the transmission users. It is essential to determine accurately the transmission usage evaluation, allocates the charge percentage among the users, and develops an efficient transmission pricing method. Accordingly, in this research, for fair transmission usage allocation purpose, various methods based on the distribution factors (DFs) are investigated because these factors are among the efficient mechanisms to evaluate the transmission line usage accurately. However, the existing DFs based methods have limitations which prevent the wider applications of these techniques in electricity market practices. Therefore, a new technique which incorporates the justified distribution factor (JDF) approach has been proposed to evaluate the transmission line flows accurately. Meanwhile, for the transmission pricing method, the MW-mile and postage-stamp coverage method are the efficient pricing techniques which are investigated in this work to cover the transmission revenues. Many improvements have been made and implemented to the existing methods in order to develop a fair and equitable transmission service charging scheme. A suitable cost allocation percentage among the market users also is considered. The Australian electricity system is used in this research as the main examples for case studies. Currently, the National Electricity Market (NEM) is using the Cost Reflective Network Pricing (CRNP) and Modified Cost Reflective Network Pricing (MCRNP) as the transmission pricing methods. According to the National Electricity Rules (NER) under Part J of Chapter 6A clause 6A.23.3(c), the TUoS charges are only paid by load (customers). Hence, in order to increase the utilisation efficiency of the network, the Australian Energy

Market Commission (AEMC) has recommended amendments to the frameworks for transmission charging to increase the extent to which charges to generators (generation companies) as well as renewable generators vary by location to reflect differences in the network costs associated with their connections and use but they are still developing new schemes.

Secondly, since most of the transmission utilities worldwide have adopted “lossless transmission pricing scheme”, therefore in this research losses were introduced in the existing transmission pricing method in order to enhance the efficiency of the transmission pricing methodology. This research proposes a transmission pricing method which integrates transmission loss component with the Distribution Factors Enhanced Transmission Pricing (DFETP) method for pool electricity market. Two new schemes are proposed: (1) New Scheme 1 (NS1) – The losses are allocated only for the locational charge (2) New Scheme 2 (NS2) – The losses are allocated for both locational and non-locational charges. Both methods use JDF 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 (GGJDFs) and Generalized Load Justified Distribution Factors (GLJDFs) with the existing Pro-Rata (PR) method.

Thirdly, the Australian government has introduced the expanded Renewable Energy Target (RET) scheme which aims to ensure that 20% of Australia's electricity supply is generated from renewable sources by 2020. Hence, this will drive large changes and have direct effects on the behaviours and investments in Australian electricity market environment especially on TUoS charging scheme. Therefore, this research is intended to explore the TUoS charging method in the Australian NEM for the development of renewable generation. There are two issues that are focused in this research: 1) the transmission configurations for connecting the remote generation cluster to the existing grid, 2) the Australian Energy Market Operator (AEMO) policy on the allocation of the cost of providing shared transmission services to different parties for new and existing terminal stations. In addition, new transmission service charging schemes for renewable energy are developed which are DFETP capacity-based method and DFETP energy-based method. These two new schemes integrate the DFETP method with the presence of the renewable generation based on capacity and energy basis. Comparisons are presented for both methods in order to identify the superior approach which reflects fair and equitable transmission service charging scheme as well as to promote and encourage the development of the green technology.

Consequently, this research focuses on the development of an efficient transmission pricing scheme where these main issues can be addressed properly for the Australian NEM.

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CHAPTER 1 INTRODUCTION

1.1 Research Background

The electricity supply industry has been undergoing a rapid change over the past two decades. Historically, electric utilities have been vertically integrated, meaning that it was responsible for providing its customers with the full range of electric services including all aspects of generating, transmitting and distributing of electricity. However, under the deregulation scheme, the electricity business has been unbundled into three components: generation, transmission and distribution. One of the key issues in restructured power system is the transmission access pricing. The main task in the development of the transmission service charges are that it must be non-discriminatory, transparent, economically efficient, and allow full recovery of costs [1]. Most importantly, the pricing strategies should be implementable, fair and practical. The costs incurred by transmission business are recovered through both connections and use of transmission system charges. The categories of transmission services can usually be split into three main components [2-4]:

- Transmission Connection Charges
- Transmission Use of System (TUoS) Charges
- Operational Transmission Charges (ancillary services)

This research focuses more on TUoS charges as this charge represents the largest portion of transmission charges. It attempts to recover past investments, finance future ones and remunerates Transmission System Operator for transmission system operation and maintenance (O & M) expenses. In addition, the operational transmission charge which is the loss component also is considered in order to increase the efficiency of the transmission service charges methodologies.

In the electricity trading arrangement under restructured structure, for instance the 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 in order to provide efficient economic signal to the transmission users as well as transmission utilities. The distribution factors approach which was traditionally used in power systems for security and contingency analysis can also be used to overcome this price allocation problem. There are three approaches of distribution factors to allocate payments to different users of a transmission network that are: A factors – to net injections, D factors – only to generators and C factors – only to loads. However, this method has some shortcomings. For instance, if the users request to use different reference node to accommodate their transactions, this could cause more computational time because the set of distribution factors for a pair of nodes found using a particular reference bus differ from the one using another bus [5].

Furthermore, this would also be unsuitable to use it in the transmission pricing or congestion management since the participants cannot predict the prices and avoid congestion of network with ease; if they do not know the reference bus [5]. Therefore, this problem can be overcome by using the JDF method. The JDF was originally used to solve the congestion curtailment in the bilateral trading [5]. However, in this research it is proved that the JDF can also be implemented in the 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 results generated from the JDF are used in Generalized Generation Distribution Factors (GGDFs) and Generalized Load Distribution Factors (GLDFs) in order to calculate the contribution of each market user to the transmission line system.

The cost of the basic transmission services corresponds primarily to the fixed transmission cost that is referred as the embedded transmission facility cost [6]. The embedded cost methods are commonly used throughout the utility industry to allocate the cost of transmission services. 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 services. The allocation of the embedded cost is done through the usage calculation [7]. There are four different types of embedded costs of wheeling methods which can be used, i.e. postage-stamp method, contract path method, distance based MW-mile method and power flow based MW-mile method [8]. Electric utilities traditionally allocate the fixed transmission costs among the users of firm transmission service based on postage-stamp and contract path methods [4, 6]. In the postage-stamp method, the charges associated with the use of transmission system are independent of the transmission distance, supply, and delivery points or the loading on different transmission facilities caused by the transaction under study [4]. In addition, a new technique was introduced namely postage-stamp coverage method to cover the total transmission system cost by sharing the costs associated with the unused capacity among the transmission users [6]. Contract path method, on the other hand, assumes that the transacted power would be confined to flow along an artificially specified path through the involved transmission systems. A MW-mile methodology can be regarded as the first pricing strategy proposed for the recovery of fixed transmission costs based on the actual use of transmission networks [6]. This method calculates the charges associated with each wheeling transaction based on the transmission capacity use as a function of the magnitude of transacted power, the path followed by transacted power, and the distance travelled by transacted power [4]. Therefore, in this research, a combination of MW-Mile (negative flow-sharing approach) and tracing-based postage-stamp method is introduced in order to achieve a fair and equitable transmission pricing strategies.

1.2 Research Objectives

The research aim is mainly to investigate issues of transmission pricing in a deregulated market environment focusing on the transmission service charges. It involves the following main tasks:

- Investigate suitable transmission usage allocation methods for evaluating the contributions of individual transmission user to the line flows.

- Establish the transmission allocation charge percentage among the users.

- Develop an accurate transmission pricing methodology which can generate an appropriate amount of transmission revenue and provide an efficient economic signal to the users.

- Integrate transmission loss component with the proposed transmission use of system charges methodology to enhance the efficiency.

- Develop transmission pricing strategies for renewable generators in order to promote the green technology in a market environment.

- Form an overall framework of transmission pricing in a market environment which facilitates fairness in network usage and promotes the penetration of renewable energy sources.

1.3 Contribution of the Thesis

The main original contributions of this thesis are identified as follows:

1) Introduce the use of JDF, GGJDFs and GLJDFs approach as the transmission usage evaluation in estimating the contribution of each user in the line power flows as well as identifying the counter flow lines. These methods are capable in dealing with multi-reference bus users.

2) MW-mile (negative-flow sharing) approach is used for the locational charges in order to solve the counter flow pricing problem. The benefit of negative flow or counter flow is distributed to the transmission owner and users based on the profit sharing concept, r.

3) A novel method which is tracing-based postage-stamp method is introduced for the non-locational charges. This approach can be used to a network system with or without local load case and reflects a fair charging approach as the market users are charged based on the actual usage of the network system.

4) Based on the combination of above 1), 2) and 3) points, a novel and efficient transmission use of system charges methodology called DFETP method is formed to provide a better and fair charging for both parties in the trading.

5) An efficient transmission charges is developed by integrating the loss component with the DFETP method. In this proposed scheme, the losses are included in the transmission pricing which can improve the Australian NEM transmission use of system pricing scheme. The user that contributes more losses will have to pay more charges because this proposed scheme allocates losses based on the actual utilization of the grid.

6) A comprehensive study is undertaken on the transmission configurations for integrating the renewable generation to the existing network system based on the Australian NEM policy.

7) New transmission service charges methods for renewable generation are proposed in order to promote and encourage the development of green technology in deregulated environment.

8) The thesis contains a review, supplemented by work examples, of the transmission use of system charges in the Australia.

1.4 Thesis Overview

This thesis consists of seven chapters. Brief descriptions of each chapter are as follows:

Chapter 1 discusses the research background, research objectives, contribution of the thesis and thesis overview.

Chapter 2 describes three types of related charges for the transmission system services which are the connection charges, TUoS charges and energy charges. In this research, the TUoS charges are focused as these charges contribute the large portion in transmission service charges. It deals with the issues of TUoS charges under deregulated environment. Basic structure of transmission services that cover the transmission usage evaluation, transmission allocation percentage among transmission users and transmission pricing methods that used to recover the costs of transmission are described. Last section of this chapter discusses the background of the Australian NEM transmission pricing methodology. It focuses on the Australian's electricity transmission network system, economic regulation of electricity transmission services and NEM TUoS charges methodologies, which cover the conceptual, the components associated with the charges and the charge allocation.

Chapter 3 describes the methodology and the mathematical model of the first proposed approach for the DFETP method. It focuses on the concept and formulation of the JDF, GGJDFs and GLJDFs as the transmission usage evaluation in order to trace the contribution of each user to the transmission line. The MW-mile (negative-flow sharing) and tracing-based postage-stamp method are used for the locational and non-locational charges to cover the transmission revenue. A flow chart is shown to summarize the complete DFETP scheme. The 10-machine IEEE 39-bus (New England) system and the 59-bus system of the South East Australian power system are used as case studies for simulation testing using Matlab simulation program to prove its effectiveness.

Chapter 4 presents the second proposed approach where the DFETP method is integrated with the loss component in order to increase the efficiency of the TUoS charges. The losses are allocated by using existing Pro-Rata method integrated with JDF, GGJDFs and GLJDFs approach. This chapter also describes the methodology and mathematical model of the proposed approach. The proposed approach is tested on the 10-machine IEEE 39-bus (New England) system to evaluate its capability to provide sufficient revenue return to the transmission owner as well as a fair charge to the transmission user.

Chapter 5 discusses the issues and recommendations of TUoS charges for integrating renewable generators with the existing Australian grid system. This chapter consists of the existing Australian NEM transmission configurations of renewable generator and the AEMO cost allocation policy for new and existing terminal stations. The additional of TUoS charges for new entry of generation and the AEMO cost allocation policy are presented in this chapter. A modified version of the 59-bus system of the South East Australian power system has been simulated to verify the concept.

Chapter 6 presents the third proposed approach of the novel TUoS charging methodology for integration of renewable (wind) power to the existing network system. Two types of method were discussed which are the DFETP capacity-based cost approach and the DFETP energy-based cost approach. These two methods are tested on the modified version of the 59-bus system of the South East Australian power system to determine which scheme is superior and reflects a fair and equitable to the market users.

Chapter 7 concludes the research work in the thesis and suggests some recommendations for future research work.

Thesis gives a list of references cited in the various chapters.

A numerical example tested on a simple idealized 3-bus system is used to illustrate the Australian NEM TuOS charges methodology and the DFETP method which is explained detail in Appendix A and Appendix B, respectively. The Matlab programming chart for the DFETP method is presented in Appendix C.

CHAPTER 2 LITERATURE REVIEW ON TRANSMISSION USE OF SYSTEM CHARGING METHODOLOGIES

2.1 Introduction

The regulation of transmission pricing is extremely important for an electricity market. There must be enforceable access rights to transmission at non-discriminatory, transparent and efficient terms [9]. In [10], non-discrimination means that all equally placed customers are treated alike, in particular, that they have access on the same terms at the same transmission price as the incumbent supplier. Different systems of charging for transmission access and use will, however, have different effects on the degree of competition in the domestic market, and can therefore be designed either to protect incumbents or to promote competition for the benefit of consumers. Different systems of charging and granting access rights may also affect the profitability of new interconnectors, and hence influence the extent and efficiency of interconnection.

The fundamental principle of efficient pricing is that users should face prices that reflect the costs inflicted on others. In electricity systems, this requirement is complicated by two facts [10]:

1. It is in many respects very difficult to calculate true economic costs, taking into account how these depend on the entire configuration of installed capacity and power flows.
2. Tariffs set according to efficiency criteria typically do not raise enough revenue to cover all relevant costs. In order to ensure cost coverage, tariffs must therefore be raised above the levels dictated by efficiency criteria alone.

The charges for transmission services introduced in different countries that have restructured their power sectors are usually separated into three components [11]:

i) Connection charge (connection tariffs): This charge covers the cost of network reinforcements required to provide service to a transmission customer. It is characterized as 'deep' or 'shallow', depending on how far from the customer site the customer's liability extends.
ii) Transmission use of system charge (use of system tariffs / capacity charge): This charge compensates the transmission owner for the sunk costs of the existing

transmission system assets, as well as the transmission system operation and maintenance costs.

iii) Transmission operating charge (energy charge): This charge covers the costs incurred in the electricity market due to the existence of a 'non-perfect' transmission system. These are the costs of transmission losses and transmission limitations (congestion). The revenues collected from energy charges are used to compensate the providers of the corresponding services (generation adjustment to cover losses, generation or demand adjustment to relieve congestion).

The main focus in this research is on the TUoS charge, which constitutes the largest part of transmission service charges. There are two broad categories of TUoS charging methods [11]:

I) Non-locational / Uniform tariff method: This method (also referred to a postage-stamp method) uniformly charge all transmission customers, irrespective of their location within the grid, according to a measure of their usage of the transmission network; this is usually their system-peak-coincident demand (kW) or annual energy demand (kWh). The postage-stamp methods define a uniform tariff (in $/kW or $/kWh) for all grid users. They are simple, but fail to provide locational signals to the transmission customers. They are used in many countries, due to their simplicity, especially when combined with energy charges that provide the necessary locational signals to the customers.

II) Locational tariff method: This method differentiates the TUoS tariff according to the customers' location within the grid. Usually, they separate the entire network into different zones of charge, with a uniform tariff within each zone. The intention behind their design is to send long-term signals for the positioning of new generators and new loads in the grid, so as to avoid network reinforcements as far as possible.

One of the important issues in this TUoS charges are how to charge the users for the use of transmission facilities in a fair way and at the same time allowing the transmission utilities to recover their transmission costs. Several methodologies have been developed so far to recover the cost transmission services. There are also methods that have been developed to estimate the power contributed by single generating unit in lines and loads. In this section, the issues of transmission usage evaluation, allocating the charge percentage among the users and the transmission pricing method are discussed, as these are related to the pricing of the transmission services.

2.2 Transmission Usage Evaluation

Accurate knowledge of transmission usage is essentially important in the implementation of usage-based cost allocation methods. On one hand, due to the nonlinear nature of power flow equations, it is theoretically very difficult to decompose the network flows into components associated with individual customers. On the other hand, from an engineering point of view, it is possible and acceptable to apply approximate models or sensitivity indices to estimate the contributions to the network flows from individual users [6]. There are different allocation methods which have been formulated in recent years based on the "natural economic use" of the transmission system [12]. They aim considering the way the transmission system is impacted by generators and consumers by the simple fact of being connected to the network, irrespectively of their commercial contracts with other agents using the same network. In some countries, this framework gives birth to the "area of influence" concept [12].

Vertically integrated companies have to use full power flow to control their systems, as well as to plan the optimal economic operation of generation resources, either by means of optimal power flow or unit commitment [13]. Therefore, it is an extremely important to solve the load flow problem as efficiently as possible. Different methods have been suggested to identify the impact of each network users on the flow of a transmission line within a transmission network, as well as how much of each generator corresponds to each load. These methods include Z-bus distribution factor, distribution factors method, tracing algorithms, power flow decomposition, AC flow sensitivity indices, full AC power flow solutions, graph theory and cooperative game theory method. Table 2.1 summarized each of the existing method based on the author, either using DC or AC power flow solution and limitations.

Table 2.1: Summary of existing transmission usage evaluation methods

No	Method	Year / Author	Using DC or AC power flow solution	Limitations
1.	Z-Bus Distribution Factors [14, 15]	1991 – C. E. Lin, S. T. Chen and C. L. Huang [15]	AC power flow	• Complexity • Consume more calculation time
2.	Distribution Factors [4, 6, 12, 15-17] i. Generalized Shift Distribution Factors ii. Generalized Generation Distribution Factors iii. Generalized Load Distribution Factors	1995 – Hugh Rudnick, Rodrigo Palma and Enrique Fernandez [12]	DC power flow	• Computational time problem (different reference bus resulting different factors)
3.	Tracing Algorithms [4, 6, 17-19] i. Bialek Method (Node Method) ii. Kirschen Method (Common Method)	i. 1996 – J. Bialek [18] ii. 1997 – Daniel Kirschen, Ron Allan and Goran Strbac [19]	DC and AC power flow	• Counter flows are neglected • Consume more computational time for AC power flow
4.	Power Flow Decomposition [20]	1997 – Assef Zobian and Marija D. Ilic [20]	AC power flow	• Complexity • Consume more calculation time
5.	AC Flow Sensitivity Indices [21, 22]	1998 - Young Moon Park, Jong Bae Park, Jung Uk Lim and Jong Ryul Won [21]	AC power flow	• Complexity • Consume more calculation time
6.	Full AC Power Flow Solutions [23, 24]	1999 – Mesut E. Baran, Verkat Banunarayanan and Kenneth E. Garren [24]	AC power flow	• Complexity • Consume more calculation time
7.	Graph Theory [25]	2000 – Felix F. Wu, Yixin Ni and Ping Wei [25]	DC power flow	• Complex issues of fairness • Neglected the counter flow transactions
8.	Cooperative Game Theory [26-31]	2000 – K. L. Lo, Carlos A. Lozano and Juan M. Gers O. [26]	DC power flow	• Required negotiation among the users: which users want to involve in the game and which player want to make a coalition among them • Impractical: Have to calculate the new usage of network or facility from the side of player and the savings in MW, assigned to player which increased the computational time • Unfair: In some coalition, the savings, x_i will results in negative value, therefore some players will not be charged as the value of f_i' (the new usage of network or facility) is zero

A number of worldwide transmission utilities have implemented the DC power flow for the transmission usage evaluation as this method provides a simple power system analysis tool and practical to implement. A DC power flow is indeed an interesting alternative to classic power flow for techno-economic purposes [13]. Hence, in this research, the DC power flow specifically the Distribution Factors method are investigated as these factors can efficiently evaluate the transmission usage which takes into account the counter flow.

2.3 Allocating Percentage of Usage

The transmission utilities differ in justification of their methods to allocate the use of system charges to the users. In this context, the users can be defined as generators, and loads. Thus, it has to be decided who has to pay the charges. Three characteristics are possible: (1) all charges are assigned to the generator (2) all charges are assigned to the load (3) the charges are shared between the generator and the load. However, in order to create a fairness environment in transmission pricing, the allocation schemes should have the following properties such as; it provide complete cost recovery of the transmission services and the allocation is based on the actual usage of the service, i.e. generators or loads are charged for transmission services based on their actual use of each transmission network.

The allocation of costs between generation and load differ from country-to-country. In Australia, 100% transmission service charges based on usage were allocated to the loads. On the other hand, in both Chile and Argentina, who are amongst first set of countries to deregulate, chose to allocate the charges only to the generators. This was justified with the belief that transmission services are required by the generators to reach consumers and compete [32]. Meanwhile, England and Wales allocate the charges between generators and loads approximately in the ratio of 27:73. Table 2.2 shows the use of system charges allocation schemes used by some countries around the world [33].

Table 2.2: Use of system charges allocation schemes

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Generators	0%	27%	100%	50%	100%	36%	50%
Loads	100%	73%	0%	50%	0%	64%	50%

Meanwhile, in this research, the charges allocated between generators and loads are considered in the ratio of 50/50 to maintain the balance of overall transmission revenue.

2.4 Transmission Pricing Methods

While discussing about transmission pricing, it is necessary to define what is meant by or included in the transmission services. In general, transmission pricing methodologies determine transmission prices for individual customers. In [34, 35], the following definition is given: "The transmission function will facilitate a competitive electricity market by impartially providing energy transportation services to all energy buyers and sellers, while fairly recovering the cost of providing those services." In [36], in order to develop the transmission pricing methodologies, six principles which should be followed are:

1. Promote the efficient day-to-day operation of the bulk power market;
2. Signal locational advantages for investment in generation and demand;
3. Signal the need for investment in the transmission system;
4. Compensate the owners of existing transmission assets;
5. Be simple and transparent; and
6. Be politically implementable.

For cost recovery the customers (generators and / or loads) have to be charged a price, which has to be defined clearly to allow correct economic and engineering decisions on upgrading and expanding generation, transmission and distribution facilities. Three main categories of transmission pricing method can be distinguished as: marginal cost methods, incremental pricing methods and rolled-in / embedded pricing methods.

2.4.1 Marginal Cost Methods

In [7], marginal cost is defined as the revenue requirements needed to pay for any new capacity on the transmission system. The facilities must be identified for all years across the life of the contracts for transmission service. For any new facilities that the transmission system required, the transmission users have to pay the allocated share of the cost and it will be done through the usage calculation. On an annual basis, the marginal cost of transmission service transaction is defined as [7]

$$MCC = \sum_{f \in F_N} \frac{|\Delta MW_{f,1}| * MC_f}{\sum_{s \in S_M} |\Delta MW_{f,s}|} \tag{2.1}$$

Where

$\Delta MW_{f,1}$ the change in MW flow due to the contracted transmission service on new facility *f*

$\Delta MW_{f,s}$ the change in MW flow due to transmission service on new facility *f* for all marginal sales *s*

MC_f the cost of new facility *f* which is the sum of depreciation on facility *f*, marginal cost of capital, marginal taxes and marginal expenses for any year of the transaction

F_N, S_M the sets of all new facilities and marginal sales, respectively

Marginal cost methods are distinguished to two types; Short-Run Marginal Cost (SRMC) and Long-Run Marginal Cost (LRMC). For uniform transmission services, which is defined as the transmission services in ideal deregulated competitive marketplace, the SRMC is the least cost of providing an additional unit of the service on condition that the current network cannot be reinforced while LRMC is the least cost of providing an additional unit of the service on condition that the current network can be reinforced [37].

2.4.1.1 Short-Run Marginal Cost (SRMC)

In [38], SRMC is an extension of spot-pricing theory and depends heavily on system running costs. If MC_S and MC_B are the marginal prices of electricity at a particular time at the seller (S) and buyer (B) busbars, the marginal transmission price (MC_S - MC_B) is a measure of what it costs the transmission grid to accept an additional unit of energy at S and to deliver it at B. In [39], the SRMC of wheeling between two buses is defined as the difference in the costs of producing an additional MW at each bus. Expressed in terms of partial derivatives this is:

$$marginal\ cost = \left(\frac{\partial f_1}{\partial MW_1} - \frac{\partial f_2}{\partial MW_2}\right) \qquad (2.2)$$

Where:

f_1 production cost rate, \$/hour at bus 1

MW_1 MW injection at bus 1

f_2 production cost rate, \$/hour at bus 2

MW_2 MW injection at bus 2

The quantities $\frac{\partial f_1}{\partial MW_1}$ and $\frac{\partial f_2}{\partial MW_2}$ are defined as the spot prices at bus 1 and bus 2, respectively. These marginal costs are readily available from OPF. This is because OPF algorithms inherently use partial derivatives to minimize the objective function. If the objective function is production cost, the partial derivatives of the cost with respect to real power can be easily obtained for each bus in the system. The marginal cost of wheeling power between two buses is simply the difference between these partial derivatives.

The advantages of SRMC pricing method is that it can increase system efficiency as it provides necessary information for operation and expansion of the transmission network and it gives correct price signals to generators and loads for efficient location and operation. However some limitations have been observed in its application to transmission system charges such as [38, 40, 41]:

- SRMC recovers operating costs only. It not accounted the recoveries of transmission system capital costs.
- In the presence of constraints, SRMC will over recover revenue for making good losses and generation rescheduling.
- Since the marginal costs of transmission are normally lower than average costs, it may not be possible for the revenues to recover the cost of reinforcement. Moreover, because of the revenues decrease when the transmission system is expanded, SRMC prices may deter the transmission provider from expanding the transmission system.
- Depends on system scenarios and hence evaluations across a range of system scenarios are necessary.
- SRMC has to predict operating cost when the provision of temporal pricing signals to the network users is needed. This requires projecting future fuel price and operating conditions. The longer the projection time, the lower the accuracy of the prediction.
- No allowances are made for the reliability contribution of a line.
- Prices are volatile and it is difficult for long-term users to make efficient economic decisions.
- In wheeling, if the magnitude of the wheel is large compared to the magnitude of the native load, SRMC may not follow the actual operating cost of the transmission transaction.

2.4.1.2 Long-Run Marginal Cost (LRMC)

In LRMC calculation, the important consideration is the amount of future resources used or saved by consumer decisions [42]. It is used to support a marginal increase in demand at different locations in the system, based on peak scenarios of future demand and supply growth [38]. In [43], the calculation of the LRMC of transmission is related to the construction of an optimum transmission network. The optimum network is the minimum cost network that serves the users under specified reliability standards. The LRMC of transporting electric power to (from) a user is the reinforcement cost of the optimum network, required for servicing a unit increase in demand (production) of the particular user. The LRMC of transmission is calculated by sensitivity analysis around the solution of the problem of constructing the optimum transmission network. There are two methods for the approximate calculation of LRMC of transmission which are the investment cost-related pricing (ICRP) [44, 45] and DC load flow pricing (DCLFP) [43].

ICRP method was developed by the British National Grid Company (NGC) [43]. Some of the basic assumptions used for constructing the optimum network by ICRP method are [11]:

i) The optimum network is constructed using only the existing routes of the current network.

ii) The optimum network is constructed assuming peak demand conditions. The system load is allocated to the generators in proportion to their registered capacity (pro-rata), with no regard to economic criteria. The underlying assumption is that maximum transmission system stress occurs under peak demand conditions, which is not always correct.

iii) All the lines of the optimum network are of the same type. Their cost is proportional to their length. The length of the cables is scaled up, to reflect their higher price relative to that of the overhead lines.

iv) The transmission capacity of the lines of the optimum network is taken to be precisely equal to the power transport from generators to loads at peak demand conditions. The construction of the optimum network does not take into account the required network redundancy (N-1 or higher) and ignores the fact that network expansions take place in discrete quantities.

v) When constructing the optimum network, it is assumed that the electric power can be routed on the existing routes. The flow of electric power in the optimum network conforms to the real power balance equations, but ignores Kirchhoff's voltage law. Consequently, many routes of the existing network become useless, and the optimum network is very sparse; in fact, it is radial. The shorter routes are being used, whereas the longer routes are not used and do not contribute to the optimum network construction cost.

The optimum network is constructed by solving the optimisation problem below [43]:

$$\min \omega = \sum_{ij} \ell_{ij}|f_{ij}| \; [MW.km] \tag{2.3}$$

$$subject\ to \sum_{j} f_{ij} = P_i, \;\; for\ every\ node \tag{2.4}$$

Where:

ℓ_{ij} length of line *ij* (km)

f_{ij} power flow of line *ij* (MW)

P_i net real power injection at node *i* (MW) (peak demand conditions)

According to the optimisation theory, the LRMC of transporting electric power to node *i* is the Lagrange multiplier λ_i, associated with the power balance equation at node *i* (equation 2.4); this gives the sensitivity of the optimum network construction cost with respect to the power demand at node *i*:

$$\lambda_i = \frac{\partial \omega *}{\partial P_{Di}} \; [km] \tag{2.5}$$

Hence, the LRMC of power transport to node *i* is calculated by multiplying λ_i with the network expansion constant $\bar{c}$ (average annual transmission cost):

$$LRMC_i = \bar{c}.\lambda_i \; [\$/MW/year] \tag{2.6}$$

For the DCLFP approach, the following simplifying assumptions are used for the construction of the optimum network [11]:

i) The optimum network is identical to the existing network as far as the topology and the electrical characteristics of transmission lines are concerned.

ii) The optimum network is constructed assuming peak demand conditions. The system peak load is allocated to generators either pro-rata or based on economic criteria.

iii) The cost of the optimum network is computed based on either of the following:

   a) the requirement cost of the optimum network is the replacement cost of the equipment of the existing network

   b) all the lines of the optimum network are of the same type; their cost is proportional to their length; the length of the cables is scaled up to reflect their higher price relative to that of overhead lines

iv) The transmission capacity of the lines of the optimum network is taken to be precisely equal to the power transported from generators to loads at peak demand conditions. The construction of the optimum network does not take into account the required network redundancy (N – 1 or higher) and ignores the fact that network expansions take place in discrete quantities.

v) The optimum network satisfies Kirchhoff's laws. DC load flow simplifications are assumed.

The optimum network for DCLFP method is constructed by solving the optimisation problem:

$$\min \nu = \left(\sum_{ij} \ell_{ij} \frac{S_B}{x_{ij}} \tilde{e}_{ij}\right) . \theta \ [MW.km] \tag{2.7}$$

$$subject\ to\ \ B'.\theta = \frac{1}{S_B} P \tag{2.8}$$

Where:

S_B system power base (MVA)

x_{ij} reactance of line *ij* (p.u)

θ voltage phase angle vector (reference node is excluded)

P real power injections vector (reference node is excluded)

B' negative of network admittance matrix: $[B_{ij}] = -1/x_{ij}, [B_{jj}] = \sum_j 1/x_{ij}$

(row and column that correspond to reference node are excluded)

e_{ij} vector with all its element zero, except for the element that corresponds to node i, which equals +1, and the element that corresponds to node *j*, which equals -1

$$\tilde{e}_{ij} = \begin{cases} e_{ij}, & if\ \theta_i \geq \theta_j \\ -e_{ij}, & if\ \theta_i < \theta_j \end{cases}$$

Using sensitivity analysis around the solution of the base case load flow, the LRMCs of all nodes of the system can be calculated more efficiently, requiring only one forward-back substitution. Equation (2.7) is differentiated with respect to the power demand vector, P_d to get:

$$\lambda^T = \frac{\partial v}{\partial P_D} = -\frac{\partial v}{\partial P_D} = -\left(\sum_{ij} \ell_{ij} \frac{S_B}{x_{ij}} \tilde{e}_{ij}^{-T}\right) \cdot \frac{\partial \theta}{\partial P} \tag{2.9}$$

Using equation (2.8),

$$\lambda^T = \frac{\partial v}{\partial P_D} = -\frac{\partial v}{\partial P_D} = -\left(\sum_{ij} \frac{\ell_{ij}}{x_{ij}} \tilde{e}_{ij}^{-T}\right) . (B')^{-1}\ [km] \tag{2.10}$$

By using equation (2.10), all of nodes λ_i of the LRMCs are computed, except for the reference node which equals to zero. The calculation involves only one forward-back substitution of the vector inside the large parentheses in equation (2.10) with the triangular factors of matrix B'. The nodal LRMCs in ($/MW/yr) are computed using equation (2.6). Some of the advantages of LRMC pricing method are [38]:

- Less volatile and the calculation methodology relatively simple.
- Gives correct price signals to generators and loads for efficient location.
- Correctly signals to users the long-run incremental cost of transmission services over several transmission expansion cycles during which congestion charges could fluctuate up and down many times.
- Generates investment capital for future growth.

However, in [38] some drawbacks have been identified for this pricing approach such as:

- Pricing may be too high during light load periods and hence economically efficient power transactions during these periods are not promoted. On the other hand, these prices may not be high enough to limit transmission service usage during peak load periods.
- No allowances made for reliability contribution of a line.
- Pricing may be too high in small systems at an early stage of development since the existing consumer base too small to support essential transmission expansion.

2.4.2 Incremental Transmission Pricing Paradigms

The incremental transmission pricing paradigms are referred to the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission service customer [7, 35]. According to the paradigm, the customer pays the full cost for any new facilities that the transaction requires, i.e. the incremental cost [35]. The incremental cost can be defined as [7]

$$ICC = \sum_{y \in Y} \sum_{f \in F_I} \frac{|\Delta MW_{f,1,y}| * IC_{f,y}}{\sum_{s \in S} |\Delta MW_{f,s,y}|} * PWF_y \tag{2.11}$$

Where

$\Delta MW_{f,1,y}$	the change in MW flow due to the contracted transmission service on incremental facility *f* for year *y*
$\Delta MW_{f,s,y}$	the change in MW flow due to transmission service on facility *f* for all incremental customer *s* in year *y* that requires this incremental facility
$IC_{f,y}$	the incremental cost of facility *f* in year *y* which is the sum of depreciation on facility *f*, incremental cost of capital, incremental taxes and incremental expenses
F_I, S, Y	the sets of incremental facilities, incremental customer sales, and service life years of each incremental facility, respectively
PWF_y	the appropriate present worth factor

To calculate the incremental transmission prices two methods have been proposed; short-run incremental cost pricing (SRIC) and long-run incremental cost pricing (LRIC). In [46], SRIC are the incremental costs of variable costs which include transmission losses, congestion costs and ancillary services costs. The LRIC includes incremental cost of both variable and fixed costs. Marginal costs and incremental costs differ in the way they are evaluated. Marginal costs can be defined as the additional cost incurred by an additional transmission of one unit (e.g. one MWh), whereas incremental costs are calculated by reviewing the transmission system costs with and without the entire transmission transaction [35, 41].

2.4.2.1 Short Run Incremental Cost (SRIC)

In [41], the SRIC methodology evaluating and assigning the operating costs associated with a new transmission transaction. An OPF model is used to estimate the transmission transaction operating costs that accounts for all operating constraints including transmission system (static or dynamic security) constraints and generation scheduling constraints. It should be noted that SRIC of a transmission transaction can be negative.

There are several concerns associated with the SRIC pricing methodology due to serious technical challenges involved in accurately evaluating the operating costs [41]:

I) The SRIC should forecast operating costs in order to provide timely economic signals to transmission customers. This would require forecasting future operating scenarios which can become less and less accurate as the forecast time horizon extends farther into the future.

II) The allocation of the SRIC among several transactions that is collectively responsible for changes in operating costs.

III) The volatility of transmission prices determined using this methodology for long term transactions. These factors make it difficult to make efficient economic decision for long-term transmission transaction based on SRIC prices.

Since revenues collected through SRIC methodology only compensate for the operating cost incurred by a transaction, this pricing could discourage host utilities from expanding their transmission system [41].

2.4.2 Long Run Incremental Cost (LRIC)

LRIC is for the change in total costs incurred by the wheeling companies in providing wheeling service [47]. The change in total cost includes:

i) The investment costs for reinforcements to accommodate the wheel, or credit for delaying or avoiding reinforcements; and

ii) The change in operating (production) costs and incremental operation and maintenance costs incurred due to wheel.

The operating cost component may be evaluated based on the same principles as SRIC [41]. The reinforcement cost component of a transmission transaction can be evaluated based on the changes caused in long-term transmission plans due to the transmission transaction. Similar to operating costs, reinforcement costs could be negative indicating that the transaction have resulted in the deferral of planned transmission reinforcements. Although the concept of reinforcement cost is straightforward, its evaluation is very difficult as it involves solving the least cost transmission expansion problem. Here again, there are concerns related to allocation of the reinforcement costs among multiple transactions that collectively cause such costs [41].

2.4.3 Rolled-in / Embedded Transmission Pricing Methods

In [35, 48], the embedded pricing methods, all cost are summed up (rolled-in) into a single number. Cost types are not distinguished. All cost components are included. The sum of cost is allocated to the various system users. Therefore, it is necessary to define the "extent of use" of the transmission system by every user. In other words, 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 [7]. The allocation of the embedded cost is done through the usage calculation. On an annual basis, the embedded capacity cost (ECC) of a transmission service transaction can be defined as [7]:

$$ECC = \sum_{f \, \varepsilon \, F} \frac{\left|\Delta MW_{f,1}\right| * EC_f}{\sum_{s \, \varepsilon \, S}\left|\Delta MW_{f,s}\right|} \tag{2.12}$$

Where:

$\Delta MW_{f,1}$ the change in MW flow due to the connected transmission service #1 on facility f

$\Delta MW_{f,s}$ the change in MW flow due to transmission transaction s on facility f

C_f the annual embedded cost of facility f which is the sum of depreciation, embedded cost of capital, taxes and expenses

S, F the sets of all sales S and facilities F in a given year

The pricing approach has been the preferable method to be implemented in deregulated market environment because of the advantages stated below [38]:

- Based on the extent of the usage of the transmission system.
- Recovers investments in the existing system and provides sufficient compensation to transmission owners.
- Easy calculation and implementation.
- An equitable method of remunerating transmission providers.
- Transmission system is a natural monopoly. Embedded cost pricing can prevent the transmission provider from obtaining monopolistic profits.

Despite of the benefits, this pricing method also have some limitations which are [38]:

- Only the costs of existing transmission facilities are considered and users are not informed of the long-run costs of transmission expansion.
- The changes in operating costs as a result of redispatch due to the impact of transmission services are not accounted for.
- Does not provide economic incentives for efficient operation of the transmission system. A new transmission transaction is 'transmission-inefficient' if it requires significant transmission reinforcements. However, embedded cost pricing may fail to signal this inefficiency to the offending transaction since the cost of the new reinforcements is distributed among all transmission users.
- Owing to economies of scale and indivisibilities, the cost of transmission facilities may change abruptly from year to year.
- The method does not consider various ancillary costs.
- Embedded cost pricing is too high during periods of excess transmission capacity and hence an economically efficient power transaction during these periods is not

being promoted. On the other hand, embedded cost pricing is too low to finance expansion when the network has little or no excess transmission capacity.

There are several methods proposed for embedded costs [43, 49-55]. Brief discussion of each method is as follows:

1. Postage-stamp method
2. Contract path method
3. Boundary flow method
4. Z-Bus based method
5. Distance based MW-mile concept
6. Power flow based MW-mile concept
7. MVA-mile method
8. MW-cost and MVA-cost method

2.4.3.1 Postage-Stamp Method

Postage-stamp method is traditionally used by electric utilities to allocate the fixed transmission cost among the users of firm transmission service. This method does not require power flow calculations and is independent of the transmission distance and network configuration. In other words, the charges associated with the use of transmission system determined by postage-stamp method are independent of the transmission distance, supply, and delivery points or the loading on different transmission facilities caused by the transaction under study. The method is based on the assumption that the entire transmission network is used, regardless of the actual facilities that carry the transmission service. The method allocates charges to a transmission user based on an average embedded cost and the magnitude of the user's transacted power [4]. The wheeling charge for this scheme can be mathematically written as [35]:

$$R_t = TC \times (P_t/P_{peak}) \tag{2.13}$$

Where:

R_t transmission price for transaction *t*

TC total transmission charges

P_t power of transaction

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