DEVELOPMENT OF A TRANSMISSION PRICING METHODOLOGY FOR SRI LANKA POWER SYSTEM

R.M.I.K.K. Rajapaksha

118687H

Degree of Master of Science

Department of Electrical Engineering

University of Moratuwa
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Thesis/Dissertation submitted in partial fulfillment of the requirements for the degree of Master of Science in Electrical Engineering

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DECLARATION

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Signature of the supervisor: Date:
Dr.Asanka Rodrigo
Senior Lecturer
Department of Electrical Engineering
University of Moratuwa

ABSTRACT

The electricity sector in Sri Lanka is governed by the Sri Lanka Electricity Act, No. 20 of 2009 (as amended), and the Public Utilities Commission of Sri Lanka (PUCSL) is empowered by the Electricity Act to regulate the electricity industry. Ceylon Electricity Board has license of Generation, Transmission and Distribution, while the Transmission Licensee is the Transmission System Operator and the Single Buyer. Five Distribution Licensees (DLs) buy electricity from the Transmission Licensee (TL). Tariffs and charges levied from the Distribution Licensees for purchasing of electricity from the Transmission Licensee are determined in pursuant to the Tariff Methodology approved by PUCSL. In addition to the five DLs there are a few customers directly served by the TL at 220kV and 132kV voltage level, but charged under the tariff imposed by DLs, since the presently approved tariff methodology is not properly address tariff calculation for the bulk customers connected at 132kV/220kV.

In this research, different power market models, transmission pricing principles and methodologies in different power markets were studied first, followed by transmission pricing methodologies in different countries. The study evaluated three main methodologies which can be implemented in Sri Lanka: (i) embedded cost based, (ii) marginal cost based and (iii) composite cost based methodologies. By analyzing data in each proposed model, the best suited methodology for Sri Lanka is recommended to be the embedded cost based method.

The new tariff scheme which is to be implemented should recover the cost of utility, simple, stable and easy to implement in existing framework. With this background it was proposed the embedded cost based tariff calculation model, as the most appropriate option for calculation the transmission tariff in Sri Lanka.

ACKNOWLEDGEMENTS

First and foremost, I would like to express my sincere gratitude to my supervisor Dr. Asanka Rodrigo for his continuous guidance, constructive feedback and support extended throughout this research. Despite his busy schedule, he always remained accessible and his guidance and advice, expertise and insights were by all means truly invaluable.

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I am grateful to my parents for all the sacrifices they have made along the way and for all the support given to me during various endeavors in my life.

R.M.I.K.K. Rajapaksha

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TABLE OF CONTENT

List of Figures

List of Tables

List of Abbreviations

AARR	Aggregate Annual Revenue Requirement
AFCR	Annual Fixed Charged Rate
ASRR	Annual Service Revenue Requirement
BST	Bulk Supply Tariff
CEB	Ceylon Electricity Board
Disco	Distribution Company
DNSP	Distribution Network Service Provider
ECOWAS	Economic Community of West African States
ERERA	ECOWAS Regional Electricity Regulatory Authority
ESI	Electricity Supply Industry
Genco	Generation Company
IMO	Independent Market operator
IPP	Independent Power Producer
ISO	Independent System operator
LRIP	Long Run Incremental Pricing
LRMCP	Long Run Marginal Cost Pricing
MC	Marginal Cost
NCRE	Non-Conventional Renewable Energy
NEM	National Energy Market
NEMMCO	National Electricity Market Management Company
O&M	Operation and Maintenance
OPF	Optimal Power Flow
ORC	Optimized Replacement Cost
PPA	Power Purchase Agreement
PSA	Power Sales Agreement
PUCSL	Public Utilities Commission Sri Lanka
SMO	System and Market Operator
SPP	Small Power Producer
SRIC	Short run Incremental Cost
SRMCP	Short run Marginal Cost Pricing
TNSP	Transmission Network Service Provider
TransCo	Transmission Company
TSO	Transmission System Operator
VIU	Vertically Integrated Unit
VSPP	Very Small Power Producer
WAPP	West African Power Pool
WACC	Weighted Average Cost of Capital

CHAPTER 1

1. INTRODUCTION

The Ceylon Electricity Board (CEB) established under the Ceylon Electricity Board Act, No. 17 of 1969 is under legal obligation to develop and maintain an efficient, coordinated and economical system of electricity supply in accordance with the licenses issued by PUCSL. CEB is the sole transmission licensee in the country while being responsible for most of the generation and distribution of electricity as well. CEB has been granted a license to generate electricity, a license to transmit electricity as well as four licenses to distribute and supply electricity. In addition, Lanka Electricity Company (Private) Limited (LECO), which is a subsidiary of the CEB, has been issued a license to distribute and supply electricity, and a number of Independent Power Producers and Small Power Producers have been granted licenses to generate electricity.

In terms of Section 9 and 13 of the Act No. 20 of 2009, the Transmission Licensee of the CEB is the only party authorized to procure (single buyer) electricity produced by Generators. The Transmission Licensee buys from Generators and sells to Distribution Licensees. Further, in terms of the Electricity Transmission and Bulk Supply License No. EL/T/09-002 issued to CEB in 2009, the Transmission Licensee is required to enter into Power Purchase Agreements and Power Sales Agreements with relevant parties. In terms of Section 56(1)(a) of the Act No. 20 of 2009, regulations may be made for the purpose of allowing and securing appropriate electricity trading arrangements between licensees.

The Sri Lankan power system has a total dispatchable installed capacity of approximately 3500 MW. The maximum demand recorded in 2014 was 2152 MW. A summary of generation statistics for 2014 is given in Table 1-1.

Table 1-1 Generation Statistics Sri Lanka

Ownership & Source		No. of Power Stations	Installed Capacity (MW)	Generation (GWh)
CEB	**Total**	**25**	**2824**	**8532**
	Hydro	17	1377	3632
	Thermal-Oil	6	544	1696
	Thermal-Coal	1	900	3202
	Wind	1	3	2
PPP	**Total**	**174**	**1108**	**3825**
	Hydro-small	144	288	902
	Thermal	6	671	2610
	NCRE	24	149	313
Total		**199**	**3932**	**12375**

Source: Statistical Digest -2014, CEB

The transmission network in Sri Lanka is operated at 220kV and 132kV to transmit electricity from generation points to distribution bulk supply points. Medium Voltage distribution network operates at 33kV and 11kV.

The electricity industry in Sri Lanka is governed by the Sri Lanka Electricity Act, No. 20 of 2009 (as amended). The Public Utilities Commission of Sri Lanka (PUCSL) is the regulator of the sector, established by the PUCSL Act No. 35 of 2002 and empowered by the Electricity Act to regulate the electricity industry.

Tariffs and Charges levied by the Transmission Licensee for the transmission and bulk sale of electricity to Distribution Licensees as well as the Tariffs and Charges levied by the Distribution Licensees for the distribution and supply of electricity to their customers are determined pursuant to the Tariff Methodology approved by the Public Utilities Commission of Sri Lanka in terms of the Section 30 of Sri Lanka Electricity Act No. 20 of 2009.

Accordingly, Bulk Supply Tariff (BST), for the sale of electricity from the transmission system includes the component of tariff related to the Transmission and the component related to the Electricity Generation, is calculated by the Transmission Licensee for every six month period, and submitted to PUCSL for approval pursuant to the Condition 32 of the Electricity Transmission and Bulk Supply License No. EL/T/09-002.

The component related to the transmission of electricity, i.e. the allowed revenue for the use of transmission system and the bulk supply and operation business is determined for a tariff period of 5 years by making a tariff filing in accordance with the approved Tariff Methodology. Similarly, allowed revenue for each Distribution Licensee is also determined for the 5 year tariff period.

Due to the applicable Uniform National Tariff and different cost structures and customer mixes of the Distribution Licensees, applying a single BST for all Distribution Licensees is not rational. An adjustment is required to the single BST to give five BSTs. Hence the calculated BST is adjusted through a tariff rebalancing mechanism to enable all Distribution Licensees to retain their allowed revenue corrected for over/under utilized capital expenditure, at the end of all transactions. Further adjustments are made quarterly to compensate the difference between the expected revenues and actual collected revenues ensuring that the distribution licensees retain their allowed revenue while giving due consideration to achieving the expected loss targets.

At present there are few customers directly served by the transmission system (transmission bulk customers) at 220kV/132kV levels in addition to the five Distribution Licensees. Distribution Licensees are charged at the Bulk Supply Tariff determined according to the Tariff Methodology. Although Condition 32 of Electricity Transmission and Bulk Supply License indicate that the requirement of differentiating between the charges for Distribution Licensees and Bulk Supply Customers still there is no proper methodology established to determine tariff applicable to Bulk Supply Customers directly connected to the transmission system.

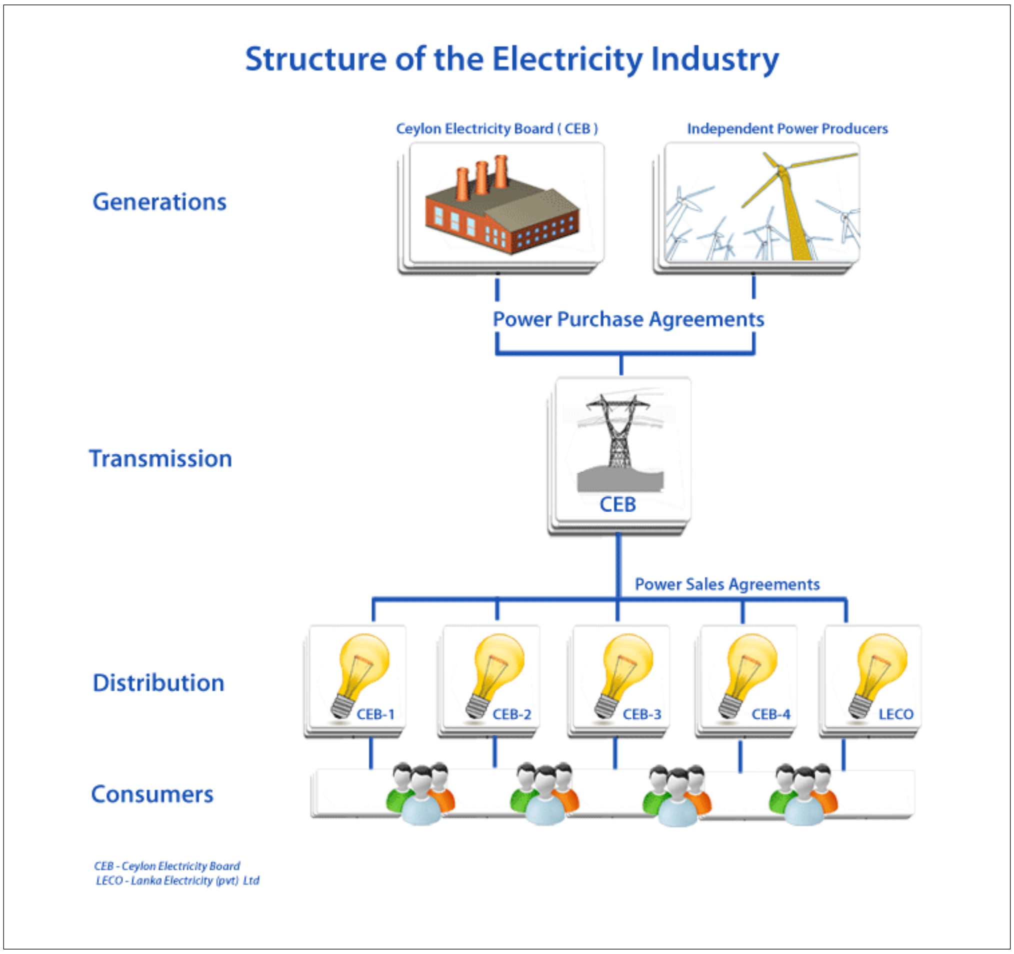

Figure 1-1 Structure of Electricity Industry
Source: PUCSL web site, www.pucsl.lk

Bulk supply customers who are connected to the Transmission network at 132kV/220kV are as Table 1-2. Ceylon Steel Corporation is a large industrial customer while other four customers are IPP s which connected to the transmission network and procure energy from CEB for their own consumption when those plants are not dispatched.

Table 1-2 Transmission Bulk Supply Customers

Customer	Voltage Level Connected
West Coast	220kV
Ace Embilipitiya	132kV
AES Kelanithissa	132kV
ASIA Power	132kV
Ceylon Steel Corporation	132kV

Presently these customers are charged upon the retail tariff category of Industrial Purpose 3, (PUCSL approved tariff) which is prepared for industrial customers connected at medium high voltage levels under the Distribution Licensees. Applicable tariff rates for the bulk supply customers' i.e. five distribution licensees, (effective from 1st July 2015) and the industrial customers, (effective from 15th November 2014) are as follows. The bulk supply customers are charged for the coincidence peak demand while the industrial customers are charged upon their maximum demand.

Table 1-3 Applicable tariff rates

<table>
<tr><th rowspan="2"></th><th rowspan="2">Voltage Level</th><th rowspan="2">Capacity Tariff</th><th colspan="3">Energy Tariff (LKR/kWh)</th></tr>
<tr><th>Day</th><th>Peak</th><th>Off-peak</th></tr>
<tr><td>Distribution Licensees (BST)</td><td>132/220kV-33kV Boundary</td><td>2,713.47 LKR/kW/Month</td><td>9.50</td><td>11.97</td><td>7.06</td></tr>
<tr><td>Industrial Customers (I3)</td><td>At 33kV or 400V</td><td>1,000 LKR/kVA/Month</td><td>10.25</td><td>23.50</td><td>5.90</td></tr>
</table>

Table 1-3 shows that the energy tariffs are somewhat high for the industrial customers compared to the distribution licensees. Charging upon industrial tariff (I3) to the customers connected in 132kV is not reasonable as those customers are connected to the transmission network.

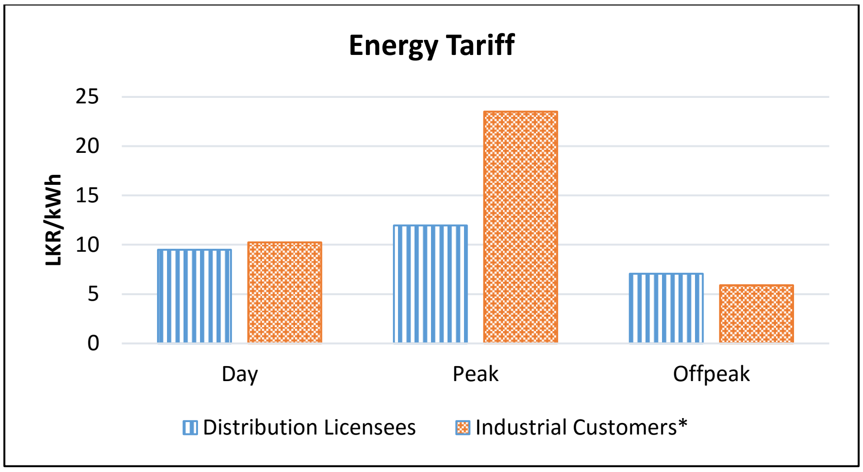

Figure 1-2 Comparison of Energy Tariff

Figure 1-3 shows the comparison of the collection of the revenue for the utility, CEB, from above said Transmission customers for the whole year 2015, if they were charged on Bulk Supply Energy tariff which is applicable for five distribution licensees.

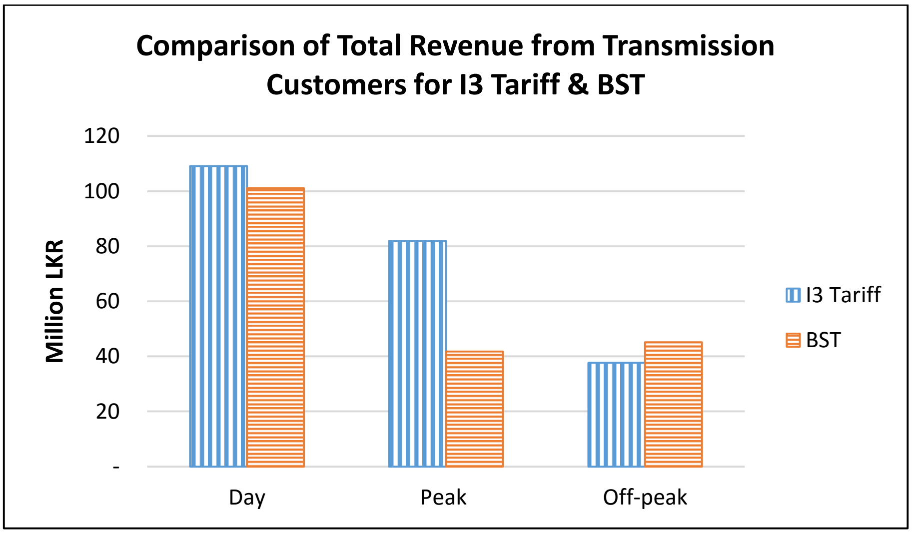

Figure 1-3 Comparison of Revenue from Transmission Customers 2015

Considering the capacity component, this cannot be directly compared as their pricing dominant is different as distribution licensees are charged for coincidence peak demand while the industrial customers are charged for their maximum demand. However the industrial customers cannot be charged for a coincidence peak demand as their load curve is not identical to distribution licensees so that contribution to the system peak from the transmission customers are not typically similar each other.

Figure 1-4, 1-5, 1-6 show the load curve of the distribution licensees and two other transmission customers at the day of system peak occurred in September 2015. (22^{nd}Sep 2015 at19.00hrs.)

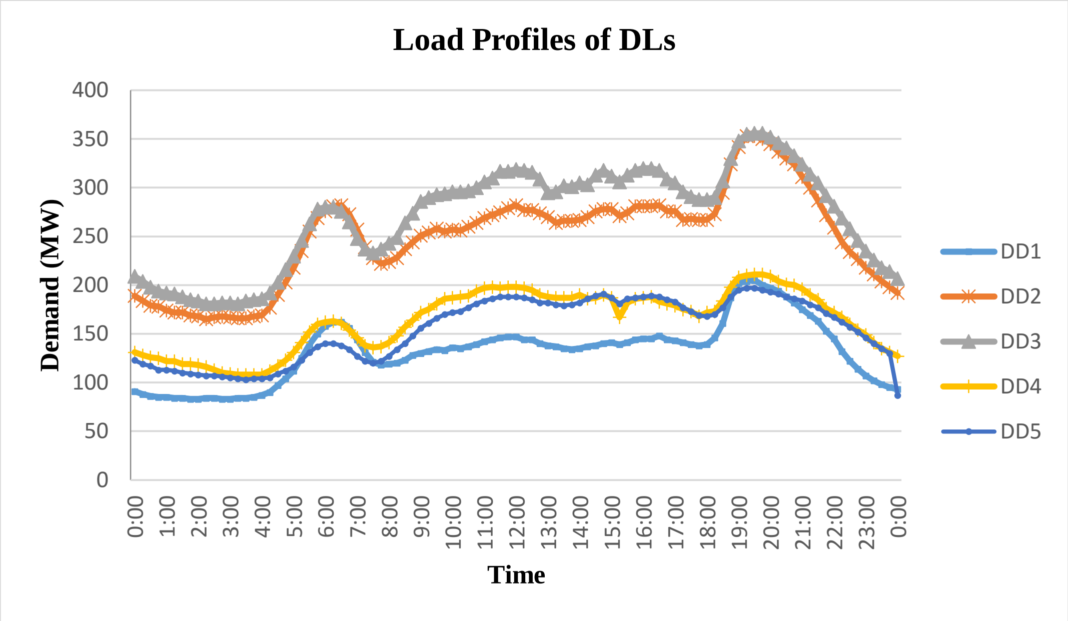

Figure 1-4 Load profiles of DLs

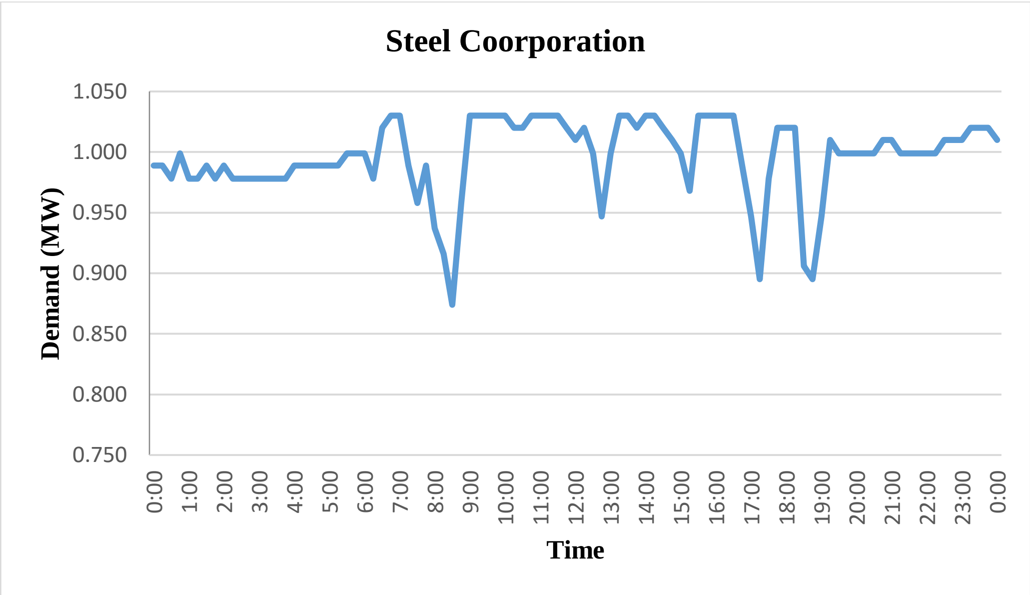

Figure 1-5 Load profile of Steel Corporation

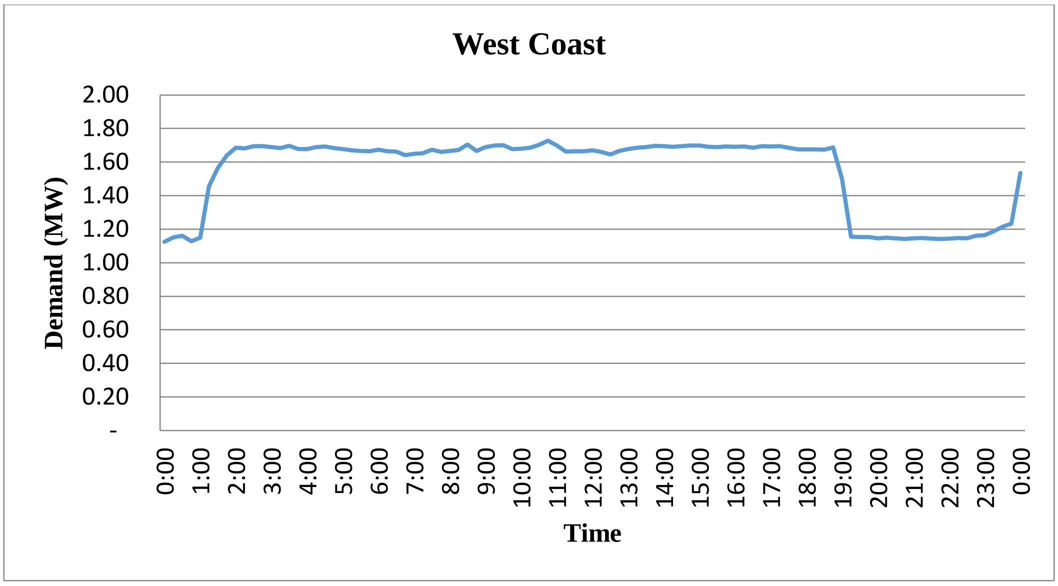

Figure 1-6 Load Profile of West Coast

1.1 Objective

The objective of this study is to propose a pricing methodology to calculate transmission tariff and propose a pricing model to calculate tariff for the transmission customers connected in 132/220kV voltage level, which is easy to introduce and implemented in Sri Lankan system.

1.2 Methodology

In the process of achieving the objective of this study, as the first step studied the importance of the transmission pricing and main cost components associated with the transmission system which have to be recovered through cost reflective tariff. Further, studies were carried out on different methodologies that can be used to calculate the cost associates with the transmission network service. Transmission pricing methodologies implemented in different countries which have different kind of power market models vary from natural monopoly to total competitive models were studied. Finally, the best suited pricing model for Sri Lanka power system is proposed for calculation of tariff for the transmission customers connected at 132kV/220kV voltage level, which is simple and easy to implement in present system by analyzing three applicable methodologies.

1.3 Outline of the Thesis

Chapter 2 describes the different power market models and their main operational attributes appearing in the world which varies from natural monopoly to wholesale competition. This was studied in electricity supply point of view as well as electricity trading point of view.

Further it describes various types of transactions in transmission network, main cost components associates with the transmission network depending on the nature of the transaction type and main transmission pricing principles followed by tariff determination experts.

In addition, it explains the transmission pricing methodologies implemented in countries which have different power market models such as power pools, competitive wholesale markets and single buyer.

Chapter 3 proposes and explains three transmission pricing methodologies based on studied principles for calculation of transmission tariff in Sri lanka by identifying related cost components in each methodology.

Chapter 4 analyses the data relevant to three pricing methods proposed and discuss above best suit transmission pricing methodology to Sri Lanka.

Chapter 5 concludes the study with explaining recommendations and the future developments of the model proposed.

CHAPTER 2

2. LITRETURE REVIEW

With the concept of restructuring the power sector, it removes the monopoly and the competitiveness is appeared in various levels of Generation, Transmission and Distribution. Generators enter into contracts with distribution companies or customers to sell power in the pool, while customers can bid with their demand requirement and the price. This makes the electricity power sector more competitive and based on this background it can be identified market models with their own attributes in electricity supply industry as well as trading industry.

2.1 Power Market Models

There are four models which can be defined as the path of evolution of the electricity supply industry from a regulated monopoly to full competition. [11], [16], [18]

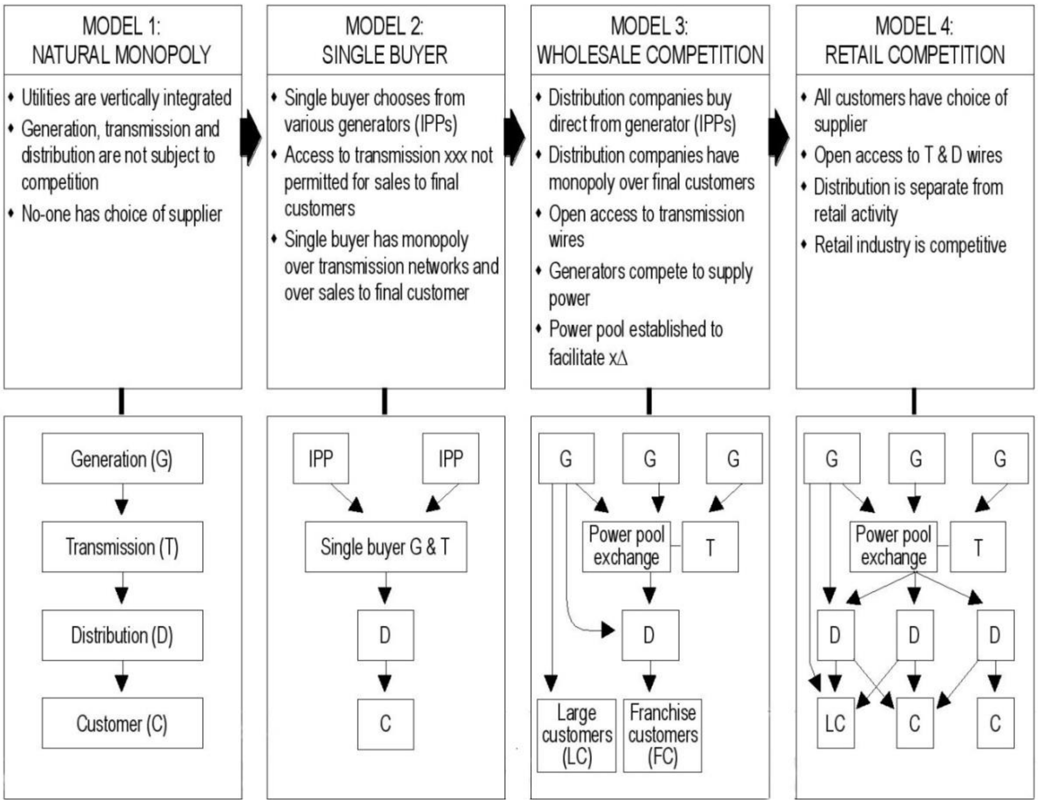

Figure 2-1 Power Market Models
Source: Extracted from [11]

The models are as follows: [16], [18]

i. Monopoly/ Vertically Integrated Unit
ii. Purchasing Agency/ Single Buyer
iii. Wholesale Competition
iv. Retail Competition

2.1.1 Monopoly/Vertically Integrated Unit (VIU)

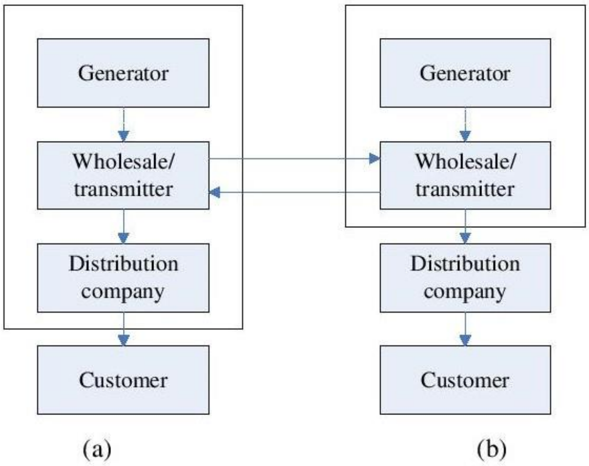

Figure 2-2 Vertically Integrated Model

Figure 2-2 (a) shows the utility integrates the generation, transmission, and distribution of electricity. While in Figure 2-2 (b) shows generation and distribution monopoly by one utility, which sells the energy to the distribution companies

2.1.2 Purchasing Agency/Single Buyer

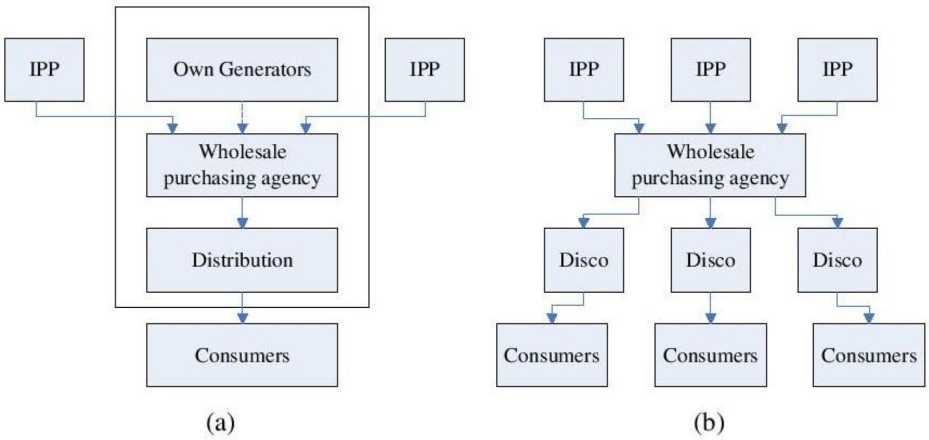

Figure 2-3 Single Buyer Model

For this model, Independent Power Producers (IPP) are introduced to generate electricity and sell it to the national power company. Figure 2-3 (a) shows integrated version of single buyer model where competition only occurs at the generation sector. Figure 2-.3 (b) shows a disaggregated version where the utility no longer owns any generation capacity and purchases all its energy from the IPPs. The distribution and retail activities also disaggregated .Wholesale Purchase Agency then will sell to the Distribution Companies as it will distribute to the customers. The price rates that set by the Wholesale Purchasing Agency must be regulated because it has monopoly power over the Distribution Companies.

2.1.3 Wholesale Competition

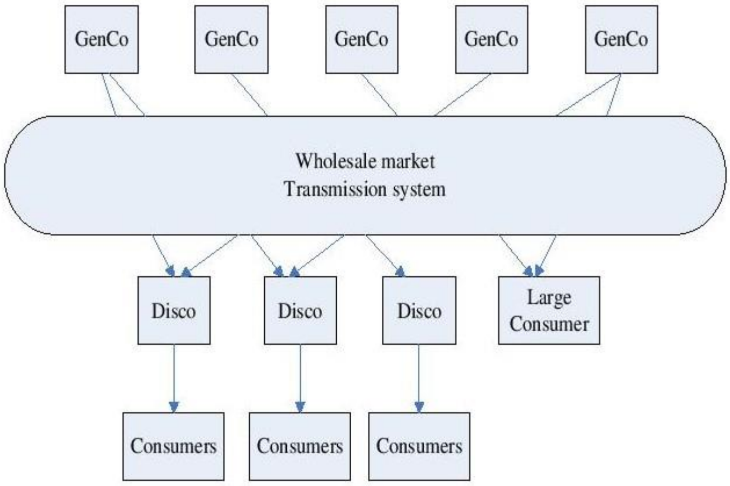

Figure 2-4 Wholesale Competitive market Model

Wholesale Competition does not have a central organization to be responsible towards provision of electrical energy. As shown in the Figure 2-4, Disco will purchase the electricity directly from generating companies to supply their customers. These transactions are done through a wholesale electricity market. The largest customers are allowed to purchase electrical energy directly from the wholesale market. So, generating companies will compete with each other to sell their electricity directly to any distribution companies and brokers or offer it in a power exchanges. At the wholesale level, the only functions remain centralized are the operation of the spot market, and the operation of the transmission network.

2.1.4 Retail Competition

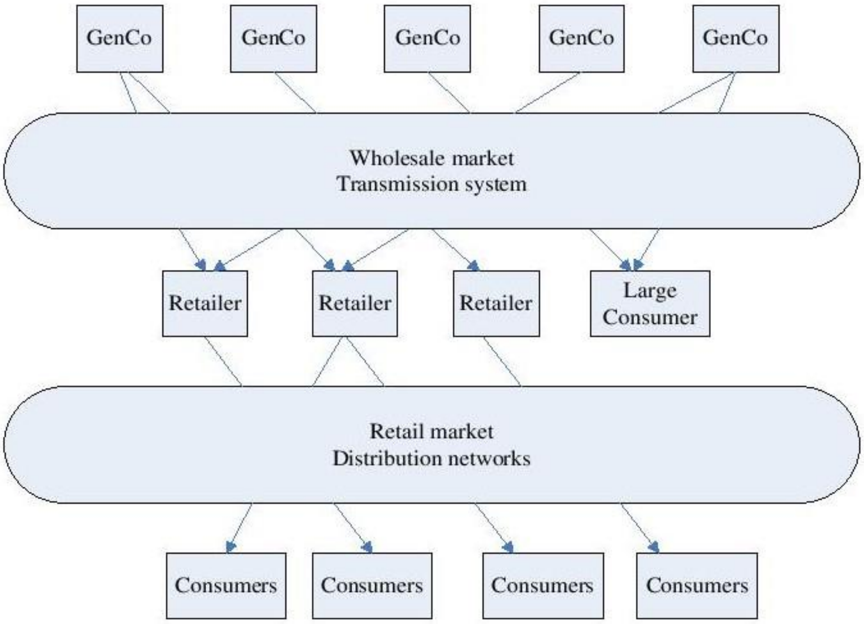

Figure 2-5 Retail Competitive Market Model

Figure 2-5 illustrate a competitive electricity market where customers can choose their supplier. The largest customers are allowed to purchase energy directly from the wholesale market, while small and medium customers can purchase it from retailers. In this model distribution companies are separated from their retail activities because they no longer have a local monopoly for the supply of electrical energy. When sufficient competitive market have been established, the retail price no longer has to be regulated because small customers can change retailer when they have an offer on better price.

2.2 Electricity Trading Arrangement

Electricity trading arrangement point of view, four another market models can be derived depending on the requirement. These models have been created to improve transparency and non-discriminatory nature of the electricity markets.[11], [16], [18]

i. Single Buyer Model
ii. Pool Market Model
iii. Bilateral Model
iv. Hybrid Model

2.2.1 Single Buyer Model

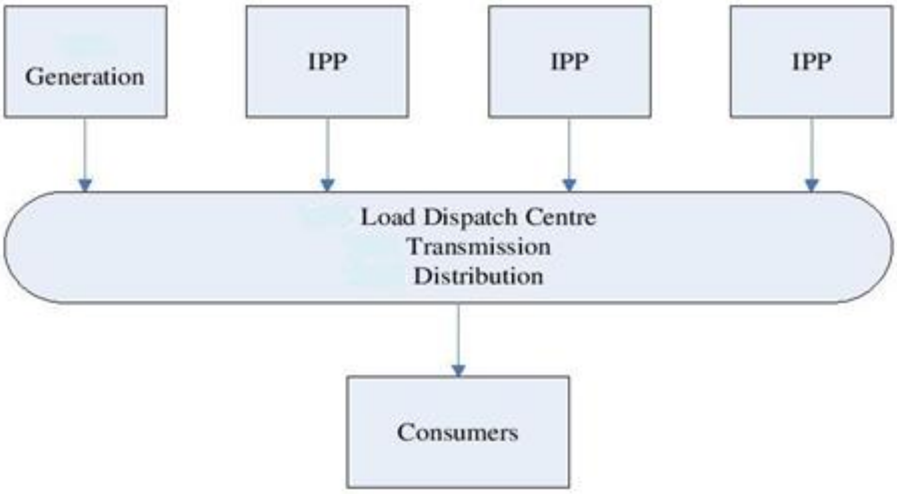

Figure 2-6 Single Buyer Trading Model

Private power plants sell their energy through the long term power purchase agreements. Payments include a fixed capacity charge to protect investors from market risks.

2.2.2 Pool Trading Model

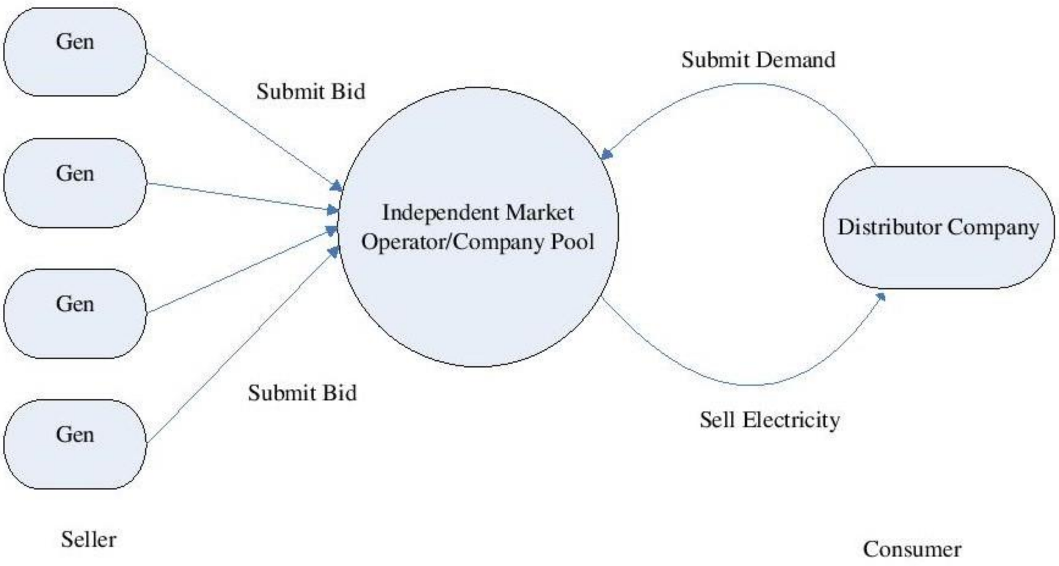

Figure 2-7 Pool Trading Model

In this model all energy supply is controlled and coordinated by a single pool operator who is normally known as Independent Market Operator (IMO) or Pool Company as illustrated in Figure 2.7. The buyer customers and seller interact with each other through IMO. IMO is responsible as a medium between producers/supplier and customers/consumers. The seller will submit the bids to the IMO/Pool Company for a large amount of power that they want to trade in the market. Sellers in the power market would compete each other but not for a specific customers.

2.2.3 Bilateral Model

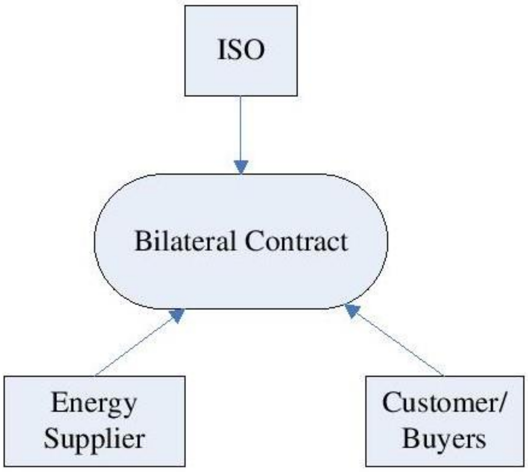

Figure 2-8 Bilateral Trading Model

In this model, transaction only involves two market participants which is buyer and seller that made a contract between them. The buyer will directly purchase the electricity from the generation. In this context, buyer can be identified as a distribution company/eligible customer while seller as a generations company. The buyer will demand some amount of power electricity for their enterprise at the best price that can be negotiated and seller will sell their energy at the highest price as much as can achieve. In this model, after the transaction between buyer and seller are settled, they need to inform ISO in order to ensure that the sufficient transmission capacity exist to complete the transactions and maintain the transmission security.

2.2.4 Hybrid Model

In hybrid model, it combines both, bilateral and pool market. Customer would be allowed to choose their trading through bilateral and pool model. Pool Company also could serve the buyers and sellers who have not signed the bilateral contracts.

2.2.5 Characteristics of Trading Models

There are several characteristics that generation, transmission and distribution companies play in single buyer and pool trading model. Following table shows an analysis of different parties in each market model in an economics point of view. [15],[19],[20]

Table 2-1 Different parties in Market Models

Model	Single Buyer Model	Pool Trading Model
Generation Company(GenCo)	a) Power sells from(GenCo) is guaranteed through PPA b) Long term PPA are signed.	a) Power sells to PoolCo is based on the merit order; the least cost generator will be sold first. b) Only based on energy price c) Create competition among generators as they will submit the lowest demand
Transmission Company(TransCo)	a) No access fee and cost is covered by the purchasing agency	a) Only provide power transmission facilities and maintenance services.
Distribution Company(DisCo)	a) Buy power from one source only(TransCo) b) The energy price is stable and it is easy for end customers to make investment decision.	a) Buy power from Independent Market Operator (IMO)

2.3 Power market models in different countries

Emerging of power market concept in the world diminishes power market monopoly and more liberalized markets were created. However the rate of the movement of different countries is different so that their market structures cannot be clearly defined because some of them are at intermediate state in between the market monopoly and totally competitive market structure. It's worthy to have a look on electricity supply and trading market models of different countries since their pricing methodology also varies based on this. Following table summarize such market models identified. [17], [19]

Table 2-2 Power markets in Different Countries

Country	Type of Model	Retail business to Customers
Australia	Wholesale electricity market	Through national electricity market.
Brazil	Combination of a competitive market with a single buyer model	Large customers can buy directly From generators. Small customers buy from regional monopoly distributors
China	Government controlled vertically integrated monopoly, little private sector involvement	On a regional basis
India	Vertically integrated monopoly with some competition for generation	Distributors have state monopoly
Indonesia	Vertically integrated monopoly with some competition for generation	But as an integrated utility
Italy	Fully competitive generation and retail markets	Single buyer only for some captive customers
Japan	Vertically integrated monopoly with little competition for	Through 10 integrated utilities

	generation	
Malaysia	Vertically integrated monopoly with some competition for generation	Single integrated utility
Mexico	Vertically integrated monopoly with some competition for generation	Single integrated utility
Pakistan	Vertically integrated monopoly with some competition for generation	Two integrated utilities
Philippine	Competitive Wholesale energy market	Through spot market
South Africa	Vertically integrated monopoly with some competition for generation	Single integrated utility
Vietnam	Vertically integrated monopoly with some competition for generation	Single integrated utility

2.4 Transmission Pricing

Electricity transmission service pricing is becoming more important and complex when the trend is increased towards unbundling and competitive bulk power markets. Electric power utilities need to know the actual cost of providing unbundled services in order to make correct economic decisions on the various types of services they should promote or curtail while considering their service obligations. Utilities also need to know such costs in order to make correct economic and engineering decisions on upgrading and expanding their generation, transmission and distribution facilities. Finally, utilities may use the costs of service that they provide for pricing purposes.

Transmission service refers to the services given by main transmission network i.e. transmit power from Power Plants to Distribution network. Transmission transaction refers to the transmission component of the service provided by an electric utility -- e.g., the transmission service associated with a power sale, a power purchase or a wheeling transaction. There are various categories of Transmission transactions based on the available Market Structure. [8], [4]

2.4.1 Categories of Transmission Transactions

Transmission pricing are mainly based on the type of transmission transaction taken place and four main transmission transaction types are as follows. [4]

- Firm transmission transactions

Firm transmission transactions are also known as reserved transactions since they entail reservation of capacity on transmission facilities to meet transaction needs. Transmission service provided as part of a firm power sale is an example of a firm transmission transaction. Firm transmission transactions are engaged when contractual agreements are signed between utility and transmission customers.

- Non-firm transmission transactions

These transactions may be curtailable or as-available. Curtailable transactions are ongoing transactions that may be curtailed at the utility's discretion. As-available transactions are short-term, mainly economic transactions that take place when transmission capacity becomes available at specific areas of the system at specific times.

- Long-term transmission transactions

A long-term transaction takes place over a period spanning several years. The duration of a long-term transmission transaction is usually long enough to allow building new transmission facilities. Transmission service provided as part of long term firm power sales is an example of long-term transmission transaction. Long-term wheeling transactions are the result of contractual agreement between the utility and the wheeling customers.

- Short-term transmission transactions

A short-term transmission transaction may be as short as a few hours to as long as a year or two and as such are not generally associated with transmission reinforcements. Short-term transactions may be provided under a bilateral contract or as part of a pooling arrangement.

2.4.2 Importance of Transmission service and Pricing

Transmission facility should clearly ensure the reliable transport of energy from seller to buyer while impartially recovering the cost of providing this service. So that before determining the factors or components of the cost of transmission pricing its worthy to identify the main elements which satisfies the requirement of the transmission pricing. The customers (Generators & Loads) have to be charged a price, which can be defined clearly to allow correct economic and engineering decision on upgrading and expanding Generation, Transmission & Distribution facilities. In addition this methodology should be more transparent and should be allocated among all transmission users fairly. Hence pricing of Transmission service should meet the requirements of, [2]

1. Promoting economic efficiency
2. Compensating grid companies fairly for providing transmission services
3. Allocate transmission cost reasonably among all transmission users, native load and third party
4. Maintaining reliability of transmission grid

2.5 Transmission pricing principals

Energy Modeling Forum of Stanford University on electricity restructuring and competition led to a list of six principles which should be followed when designing electricity transmission prices [5],[9]

2.5.1 Promote the efficient day-to-day operation of the bulk power market

This implies that transmission pricing should ensure the most possible lowest cost while ensuring the proper coordination of generators allowing the users of system to have reliable and uninterruptable power supply. Once generation is dispersed across the transmission system, economic dispatch must take the marginal costs of transmission into account. These are of two kinds-the actual cost of the system losses and opportunity cost of transmission constraints.

2.5.2 Signal locational advantages for investment in generation and demand

The most important factor that affect the cost of transmission is the location of generation and demand, and the system coordinator can do little about this in short term, however, it may be possible to influence the location of power stations, and of energy intensive industries. If the generation and demand are sited closer together, the costs of transmission will be lower, but this does not necessarily mean that it is always best to be so. There may be no need for a separate signal for investment decisions if the prices paid and received for energy vary with the cost of transmission.

2.5.3 Signal the need for investment in the transmission system

Transmission investment is often an alternative to moving a planned investment in generation or on the demand side. Prices will only produce a useful signal, however, if they are based on marginal costs. If the marginal cost at two adjacent nodes is very different, that is likely to imply that the flow between them affects a transmission link which is not strong enough. Further there are 3 potential problems in using high price differentials as the signal for investment,

1. Most investments are lumpy, and will lead to significant changes in flows, and hence prices.
2. Transmission ownership and investment is divided among several companies, and the actions of one could create significant externalities.
3. Transmission owner is likely to earn significant amounts of revenue from marginal cost pricing in the presence of heavily loaded lines which cause constrains or high losses.

2.5.4 Compensate the owners of existing transmission assets

This objective has figured heavily in the design of transmission pricing systems-existing participants are invariably involved in the negotiation which create the new system, and they are concerned about their future incomes. Future investments depend upon a credible promise that those who finance it will receive an appropriate return on their investment. If potential investors see the effective expropriation of existing assets, they will be unwilling to invest. The overall level of transmission charges is generally set to allow transmission owners to recover a regulated level of revenue. The allowed revenue is typically much greater than the amount which would be recovered from the "signaling" prices.

2.5.5 Simple and transparent

If transmission prices are to send useful signals, it is important that they are understandable. If users do not know how much they are paying for transmission, they cannot change their actions in response to the charges. At the same time, if prices are to reflect marginal costs, which are complicated, they cannot be overly simple. The use of zones rather than nodes for pricing purpose is a common simplification.

2.5.6 Politically and socially implementable

Unlike other principles it is hard to map a corresponding benefit with this principle, but it is of great importance. To put it fairly, if too many influential agents are likely to lose from a proposed pricing system, they will make sure that it will never be implemented.

2.6 Transmission pricing components

The major components which should be considered for the cost of transmission transactions are can be derived as follows. [8], [13]

2.6.1 Operating cost

The operating cost of a transmission transaction is the production (fuels) cost that the utility incurs in order to accommodate the transaction. The operating cost is due to generation scheduling or dispatch. Generation scheduling is impacted by factors such as the start-up time and start-up cost of generating unit and the spinning reserve requirements. The operation and maintenance costs for transmission system hardware facilities (hardware O&M cost) do not include as part of the operating cost of the transmission transaction except for such incremental O&M costs that are directly attributable to the transaction. This is included in another cost component called Reinforcement cost.

In a totally liberalized market (wholesale competition is appeared), the hour by hour operating cost of a transmission transaction can be estimated using an optimal power flow (OPF) model that accounts for all operating constraints including transmission system constraints, generation scheduling constraints and security considerations. The cost function for the optimal power flow corresponds to the operating objectives of the utility. In most instances, the objective is to minimize the overall production cost. The operating cost may be calculated using two different approaches.

Differential Approach**:** In this approach. Optimal Power Flow (OPF) studies are performed with and without the transaction in order to identify the variation in overall production cost due to the transaction. For a single transaction with a large amount of transacted power, this method is more accurate than the sensitivity approach, described below. On the other hand, the differencing approach has some disadvantages. One important disadvantage is the need for performing two OPF studies for every transaction being studied.

Sensitivity Approach: The cost per MW of transacted power can be estimated as the difference in the optimal cost of power at all points of delivery and points of receipt for that transaction [4]:

The sensitivity approach has the advantage of being straightforward both in implementation and application to all types of transactions. The disadvantage of this approach is that its results may become inaccurate if the size of transactions under study is large compared to the native load and generation in the transmission system.

2.6.2 Opportunity cost

Basically, the opportunity cost of a transmission transaction corresponds to the benefits unrealized due to operating constraints that are caused by the transaction (cost of lost opportunities). The benefits unrealized due to lost opportunities may arise through one or both of the following mechanisms: [8]

- If the utility could not bring in cheaper energy due to operating constraints, a transmission transaction causing such constraints may results in lost benefits and hence incurs some cost. The opposite is also true. If a transaction mitigates transmission congestions allowing additional transactions to take place, it provides some benefits and reduces cost.
- Unrealized contribution to the cost of existing transmission system by all potential firm transactions that are forgone due to operating constraints. Since part of the cost of existing facilities are allocated to firm transactions, their loss results in lost

benefits. Hence, a transaction causing the transmission constraints incurs cost for transactions already on the system.

With this background, opportunity cost is calculated by taking the difference of cost of operating with transactions that can be optimally accommodated on existing system with valid criteria such as minimizing the overall cost to all utility customers subject to all operating constraints and the utility's service obligations, and cost of operating of transactions being implementing, which are optimally accommodated on the existing system without violating operating constraints.

2.6.3 Reinforcement cost

The reinforcement cost of a transmission transaction corresponds to the cost of all transmission reinforcements necessary to accommodate that transaction. Reinforcement cost can also be the cost of planned transmission reinforcements that are deferred by the transmission transaction. This component of cost is applied only to the firm transactions.

2.6.4 Existing system cost

The existing system cost of a transmission transaction corresponds to the cost of existing transmission system that is to be allocated to that transaction. The cost of existing transmission system is the cost associated with the investment made in building and the expenses incurred in maintaining the existing transmission system and for example include the embedded and the O&M costs of transmission system. [8]

Since the transmission system is already being built, this cost is already incurred and this existing system cost component should cover not the incurred cost but the allocation of the cost of existing transmission system to those who use the system.

Because the cost of existing transmission system is generally large, the existing system cost of a transmission transaction is usually the largest component of the overall cost of the transaction. So this is a cost component which all utilities and regulatory authorities pay their high attention.

2.7 Transmission Pricing Methods

Pricing of transmission or wheeling services is an unresolved issue. It is impossible to have a pricing methodology that can be used in all circumstances. Each methodology has its own specific strengths and weaknesses. Different pricing methodologies are suitable for different circumstances and different requirements under which transmission services are being provided though the diversity is too high. The primary objective of pricing is to ensure economic efficiency. Furthermore determination of prices must be transparent, clear and the pricing regime must be practical to implement.

There are mainly three transmission pricing methods proposed by different authors. [5], [13]

- Embedded cost based transmission pricing methods
- Marginal / Incremental cost based transmission pricing methods
- Composite embedded and incremental cost based transmission pricing methods

2.7.1 Embedded cost Based (Rolled in Transmission Pricing)

In this method, Costs are based on the specific path agreed for an individual wheeling transaction. All costs are summed up in to single number and sum of the costs is allocated to the various system users. This method allocates the system total costs among the transmission users based on 'extent of use' rule. 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. Following sub types are used under this method.[1], [13]

- Postage Stamp
- Contract paths
- Distance based MW-km (distance)
- Power flow based MW-km

2.7.1.1 Postage Stamp

In this method it is assumed that entire transmission system is used by wheeling irrespective of the actual facilities used by the customer. The distance of a particular customer is connected is not considered. That is why this method is called the Postage Stamp method. Hence the postage stamp rate of the Transmission service is calculated by summing up all transmission costs and divide it by system peak demand thus producing a flat amount per MW [3], [4], and [7].

A simplified algorithm is listed as follows. [4]

1) Calculate the annual fixed charge rate (AFCR), which is obtained from the company's cost data including long term debt, preferred stock, common equity, weighted cost of capital per year, operating and maintenance costs, taxes, administrative and general expenses, and insurance.

2) Calculate the Net Plant Cost (NP),

$$NP = BC - DR$$

Where BC is the developed book cost for each line, and DR is the developed depreciation reserve for each line.

3) Calculate per-MW annual wheeling costs

$$\frac{\text{Annual Wheeling Cost}}{\text{MW}} = \text{AFCR X} \sum \frac{\text{NPi}}{\text{i(Peak Demand + Wheeling Increment)}}$$

Where i = transmission lines.

4) Total annual wheeling cost is,

$$\text{Annual Wheeling Cost} = \text{Annual Wheeling Cost per MW X Wheeling Increment}$$

Advantages:

- In this method, entire historic cost is recovered by encouraging the efficient level of investment.
- This has got very simple algorithm of calculating the cost and charges are stable throughout the year.
- An improved ability to signal the costs of decisions of individuals

Disadvantages:

- The main issue of this method is that it does not take into account the utilization of system so that it is lack of incentive for system users. All the users are considered to be having equal impact for each power transfer.
- This method doesn't reflect the potential discrimination between users

- Low economic efficiency as it may lead to investments out of contract path as well.

2.7.1.2 Contract paths

In this method, specific path between transmission service provider and customer is selected for the wheeling transaction and this path is called “contract path”. This contract path interconnects the points of receiving and delivering virtually without load flow studies and all or portion of the cost related to the wheeling transaction on this specific path is considered as cost of transaction. In contrast to the postage stamp method, contract path method considered the distance between the injection and the consumption. But this methodology also ignores the actual system operation so that the actual cost relates to the transaction is not emphasized. [1], [4], [13]

A simplified algorithm is listed as follows. [4], [13]

1) Determine lowest MW capability of facilities along specified path.
2) Calculate the AFCR and NP which are the same as in the postage stamp method.
3) Calculate the annual wheeling costs per MW,

$$\frac{\text{Annual Wheeling Cost}}{\text{MW}} = \text{AFCR X} \sum \frac{\text{NPk}}{\text{MW per Path}}$$

   Where k= Transmission lines per path

4) Calculate the annual wheeling costs

$$\text{Annual Wheeling Cost} = \text{Annual Wheeling Cost per MW X Wheeling Increment}$$

5) Boundary flow method:

   This method is used when the changes in MW boundary flows of the wheeling company due to a power transfer, either on a line basis or on a net interchange basis, influence on the cost of wheeling. Two power flows, executed successively for every year with and without the transaction, yield the changes in either individual boundary line or net interchange MW flows. The load level represented in the power flows can be at peak load or at other appropriate load levels.

$$\text{Annual Wheeling Cost} = \text{Annual Wheeling Cost per MW X } \frac{1}{2}\sum \Delta \text{ MWi}$$

$$\text{Annual Wheeling Cost(Interchange)} = \text{Annual Wheeling Cost per MW X } \frac{1}{2}\sum \Delta \text{ Net Intk}$$

Where i = boundary lines, k = all net interchange

Annual wheeling cost per MW is calculated as same as in postage stamp method.

6) Line-By-Line Methods:

The line-by-line methods consider the changes in MW flows due to the wheeling in all transmission lines of the wheeling companies, and the line length in miles. Two power flows executed successively, with and without the wheeling, yield the changes in MW flows in all transmission lines. The costing methodology is described as follows.

   a) Calculate the AFCR and NP (the same as the postage stamp method)
   b) Calculate the per-MW-mile annual wheeling costs

$$\frac{\text{Annual Wheeling Cost}}{\text{MW} - \text{mile}} = \text{AFCR X} \sum \frac{\text{NPi}}{\text{MW} - \text{miles i}}$$

$$\text{Annual Wheeling Cost} = \text{Annual Wheeling Cost per MW X } \sum \Delta \text{ MWi} - \text{miles}$$

Where i = Transmission lines

Advantages:

1. Compared with the postage stamp method, contract path method considers the distance between energy injection and receiving point.

Disadvantages:

1. The actual path taken by wheeled power may be different from those identified in the contract path.
2. The wheeling costs may correspondingly not reflect the actual wheeling costs incurred by all the companies affected by the transaction.

2.7.1.3 Distance based MW-km (distance)

In this method embedded transmission charges are determined based on the km distance between injection and receipt and the magnitude of the transmitted power. [4]

$$\text{Total transmission capacity cost} = \text{Total transmission chargers X } \frac{\text{Distance X power magnitude}}{\sum \text{Total distance in transmission system}}$$

The total transmission charges refer to the annual expenses to maintain transmission system, taxes, etc. This methodology ensures the full recovery of fixed transmission costs and reflects, to some extent, the actual usage of transmission systems.

2.7.1.4 Power flow based

In this method the actual network conditions using power flow analysis, forecast loads and generation configuration is purely considered to calculate the transmission prices. The cost allocation of each customer is calculated based on the extend of use of each facility in the transmission network. According to the Thilo Krause [13], power flow of each line in the circuit is calculated based on the load pattern of the each customer and cost allocation is done consecutively based on the proportion of the ratio of power flow and the circuit capacity.

The main issue of this method is, it may not recover the all embedded cost since the transmission cost is allocated through a ratio of the power flow caused by the customer. In addition this method does not cover the cost of reserve capacity. [5], [4]

2.7.2 Marginal/ Incremental Pricing Methods

Marginal cost is the revenue requirements need to pay for any new capacity on the transmission business. Whereas incremental cost can be defined as the revenue requirements needed to pay for any new facilities that are specifically attributed to the transmission service customer. These facilities must be identified for all years across the life of the contract for transmission service. To calculate incremental transmission prices following four methods are used.[13]

- Short run incremental cost pricing
- Long run incremental cost pricing
- Short run marginal cost pricing
- Long run marginal cost pricing

The difference in incremental pricing methods compared to others is that they do not include embedded costs but the additional transmission cost a transaction causes. In these respect two major viewpoints has to be differentiated. [13]

- Considered Period

  This is not specified in terms of pre-defined time interval. The distinction refers to a common economical approach for cost evaluation. Long-run incremental or long-run marginal cost includes the reinforcement and expansion cost as well as the operating cost. Short-run incremental or short-run marginal cost only reflects the operating cost of the existing facilities.
- Type of cost

  Two cost types can be identified; namely, Incremental Cost and Marginal Cost. Marginal Cost is the additional cost incurred by an additional transmission of one unit whereas Incremental Cost is calculated by reviewing the transmission system costs with and without the entire transmission transaction.

2.7.2.1 Short-Run Marginal Cost Pricing (SRMCP)

The general idea of SRMCP is to,

- Model an electricity market with its various economical and technical specifications
- Optimize the system which is synonymous to maximizing social welfare.

One crucial outcome of the optimization procedure is the price at each node (nodal or spot prices) reflects the temporal and local variations of the energy pricing relating to the energy demand.

The optimization problem regarding this method can be formulated as, [13]

$$\text{Maximise} = \sum_{k} B(d_k) - \sum_{j} C(g_j)$$

Subject to:

(a) Optimise the energy balance

$$\sum_k d_k + losses - \sum_j (g_i) = 0$$

(b) Optimise the line flow constraints

$$|z_i| \leq z_i^{max}$$

(c) Optimise the individual generation constraints

$$g_i \leq g_j^{max}$$

(d) Optimise the individual generation constraints

$$\sum_j g_j \leq g_{crit}$$

With:

d_k	demand at node k
g_i	generation at node j
$B(d_k)$	customers' benefit
$C(g_k)$	producers' generation cost
g_i^{max}	amount of generation capacity at node j
z_i	flow along line i
z_i^{max}	maximum flow along line i

2.7.2.2 Long-Run Marginal Cost Pricing (LRMCP)

In SRMCP the transmission capacity is assumed to be fixed. For long-run approaches this supposition is removed and transmission capacity is allowed to change. This approach bases on the general economic theory on long-run marginal pricing. For long run considerations there is by definition no fixed cost. Long-run marginal costs are the costs of increasing the production of one unit, allowing changes in the overall system capacity. For the optimal capacity long-run marginal cost and short-run marginal cost are equal. All transmission expansion projects are identified and the cost over a long time horizon of several years is divided over the total power magnitude of all new planned transactions to calculate the marginal reinforcement cost.

The LRMCP schemes serves as an approach for the evaluation of capacity reinforcements of the transmission system expansion plans and are mostly driven by the system operators' objective to improve bulk systems' reliability and to reduce short term operating problems. [4]

2.7.2.3 Short-Run Incremental Pricing

Generally incremental pricing methodologies differ from marginal costing methodologies by definition of costs. Unlike marginal costing, in incremental costing incremental transaction is evaluated. There are two main drawbacks in incremental costing. [4], [13]

1 Since more than one customer may be responsible for incremental costs an allocation method has to be obtained.
2 Short-run transmission prices may be subjected to high volatility

2.7.2.4 Long-Run Incremental Pricing (LRIP)

The concerns of SRIC also apply to the LRIP scheme. There are no major deviations, except that, with the introduction of long-run view; reinforcements of the network are also considered. In the reinforcement, change in cost between long-run transaction plans and current transaction cost are included. [4], [13]

If marginal cost based pricing is used to price transmission services, an additional difficulty arises as the income will not be sufficient for financing the investment (past or future), given the economies of scale i.e. a supplement revenue generation is required.
In this context in May 1995 Rudnick et al. [6] suggested need for the collection of a supplement to finance the transmission system above the marginal cost based pricing. Because pricing scheme is not able to support financially to transmission service providers. Author also describes the difficulties faced in allocating the supplementary cost among parties involved. Alternative methods for defining the allocation have also been formulated.

2.7.3 Composite Embedded & Incremental Cost Based

This pricing method includes both the existing system cost and the incremental costs of transmission transactions in evaluating overall transmission charges. [1]
Hence the price of a transmission service is determined based on the sum total of the embedded and incremental costs of providing the service. The embedded cost of a transmission transaction is part of the existing system cost that is allocated to that transaction. In this method, the embedded charges of a transmission transaction is

evaluated based on one of the allocation methodologies described in above section 2.7.1 and the incremental cost is calculated using one of the methodologies described in Section 2.7.2

2.8 Transmission pricing methods in different countries

Transmission pricing methodologies in different power markets models have different methodologies based on their transactions and services offered. Countries were selected which has different electricity trading models.

Table 2-3 Countries studied the tariff methodologies

Country	Power Market Model
Ghana (WAPP)	Wholesale Competition
Tasmania	Wholesale Competition
Thailand	Vertically Integrated Single buyer model
Ireland	Single Buyer model

2.8.1 Transmission Pricing in West African Power Pool (WAPP) -Ghana Experience

Due to the fact that natural resources in Africa has not evenly distributed throughout the continent, there are some areas with very low access rate of electricity. This has led the Regional Corporation and integration through energy pooling and cross border energy trading.

There are five main power pools operating in African continent namely South, North, West, East and Central. Ghana is a member country of WAPP and regional transmission pricing methodology is studied and analyzed.

2.8.1.1 West African Power Pool (WAPP)

West African region has lower electric power production which is accounted only 9% of the total Africa's installed capacity and about7% of the total electricity generation in the continent. [31]

West African Power Pool has been established in January 2006, with the objective of promoting energy trade between member countries through the integration of the national power systems in order to provide stable, reliable and affordable electricity supply. West Africa power pools comprise of fourteen countries including, Benin, Côte d'Ivoire, Burkina Faso, Ghana, Gambia, Guinea, Guinea Bissau, Liberia, Mali, Niger, Nigeria, Senegal, Sierra Leone, and Togo.

Currently WAPP has 26 member utility companies, consisting of public and private generation, transmission and distribution companies involved in the operation of electricity in West Africa. Main trading platform in the WAPP is in the form of long – term contracts and allocation of excess production among members. WAPP took nearly half decade to establish trading framework as its installed capacities are low as well as poor infrastructure among the member nations.

Regional market rules approved by ECOWAS Regional Regulatory Authority and govern the all electricity trading across international borders between the participating countries in the region.

System and Market Operator is responsible for regional market operation functions, additionally some system operation functions such as coordination and allocation of the transmission capacity. [25], [31], [34]

Transmission operator is responsible for maintaining the assets of the transmission grid while the Transmission System Operator (TSO) is responsible for both system and transmission operations.

The Transmission Tariff methodology used by the regional system of the West African Power Pool (WAPP) is developed by the System and Market Operator (SMO). The tariff submitted by the SMO has to be approved by the ECOWAS (Economic Community of West African States) Regional Regulatory Authority (ERERA).

Power market structure of it’s one of member country (Ghana) is as follows.

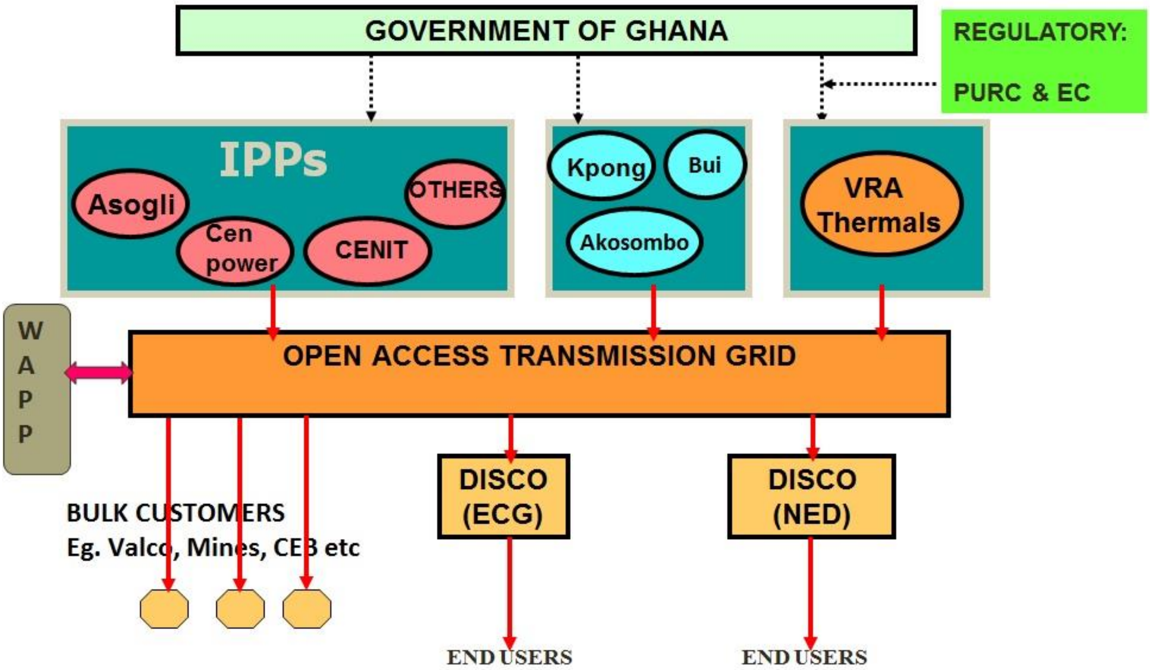

Figure 2-9 Power Market Structure in Ghana
Source: [25]

2.8.1.2 Regional Transmission Tariff calculation Method in WAPP

Steps of the Regional tariff calculation methodology can be summarized as below. [34]

1. Determine regional transmission assets and asset value
2. Calculate annual revenue requirements for each Transmission System Operator (TSO) asset used for regional bilateral trading
3. Calculate cost of use of transmission system and associated transmission losses for each regional bilateral trade
4. Calculate transmission revenue requirements for each TSO for regional bilateral trades
5. Calculate transmission tariff and transmission losses for the purchaser of each regional bilateral trade

Step 1: Determine regional transmission assets and asset value

Regional transmission assets are the interconnected assets in regional transmission network whose service voltage is greater than 132kV. Interconnected assets are all the assets that are regionally interconnected between two or more countries even if there are two or more synchronous areas. This does not include supplying a domestic demand from one country to another.

The asset database contains all assets per class and per TSO, physical data for each network branch, (including line lengths, numbers of circuits, line types, tower types, voltages, switchgear type and voltage, transformer rating and voltage, etc.) The asset database is maintained and kept with the System Market Operator (SMO) and this is updated annually based on the information provided by the Transmission System Operator (TSO)

Step 2: Calculate annual revenue requirements for each Transmission System Operator (TSO) asset used for regional bilateral trading

Capital costs of network elements and operation and maintenance costs are mainly covered.

Calculation of capital costs:

First, annual asset values is calculated and this is similar to depreciated replacement cost i.e. the cost of replacing specific parts of the transmission line (transformer, switch gear) at current asset value. Then calculate the weighted average cost of capital.

Operation and maintenance costs are to be recovered by allowing a predetermined margin on the capital costs of equipment, to cover an appropriate amount of the operation and maintenance costs of each asset on an annual basis.

Step 3: Calculate use of transmission system and associated transmission losses for each regional bilateral trade.

This step recognizes the actual transmission assets utilized and associated transmission losses for each regional bilateral trade. A load flow methodology is adopted. A load flow, contingency analysis and dynamic stability study are performed for each proposed regional bilateral trade and ensure there is sufficient transmission access for the regional bilateral trade before it is approved. Furthermore, each year a load flow is done for the forecast maximum generation hour for the next year and this is the load flow solution proposed for the method. The base case is the peak generation case for the following year.

Step 4: Calculate transmission revenue requirements for each TSO for regional bilateral trades

The calculation of the revenue requirements to each TSO ensures that they receive their full revenue requirement by apportioning the costs to each user of the system.

The apportioning is calculated based on the percentage use of each asset for regional trades of the transmission network as follows:

$$\text{TSO bilateral trades revenue for asset(i)} = \sum_{j=1}^{m} \delta(i,j) X \text{ TSO revenue requirement for asset}$$

Where:

j is the regional bilateral trade
m is the total number of regional bilateral trades of the TSO
i is the transmission asset of the TSO used for regional bilateral trades
δ(i,j) is the percentage use of asset (i) for the regional bilateral trade (j)

The TSO revenue requirements for assets (i) are determined in step 2. The percentage of use of each asset (i) for each regional bilateral trade (j) is determined in step 3.

This allocates each TSO, the portion of each transmission asset utilized by all the regional bilateral trades. When the bilateral agreement has a low power factor, the relative annual load factor will have to be considered for the asset. The sum of TSO revenue for all assets used for regional bilateral trades is the total revenue due to the TSO.

Transmission loss also has to be considered,

$$TSO\ transmission\ losses\ revenue = \Sigma\ transmissionflowforbilateraltrade\ (j) \times \alpha\ (j) \times PriceforLossesm$$

Where

α (j) is the loss factor for bilateral trade (j)
j is the regional bilateral trade
m is the total number of regional bilateral trades of the TSO

Step 5: Calculate Transmission Tariff and Transmission Losses for the purchaser of each Regional Bilateral Trade

The sum of the costs of individual asset for each bilateral charge is paid by the purchaser of the regional bilateral trade.

$TSORevenueforabilateraltrade\ (j)$ =

$$\sum_{i=1}^{p} \delta(i,j) \text{ X TSO revenue requirement of asset(i)}$$

Where:

j is the regional bilateral trade
i is the transmission asset of the TSO used for regional bilateral trades
p is the total transmission assets of the TSO used for the regional bilateral trade
δ(i,j) is the percentage use of asset (i) for the regional bilateral trade (j)

The costs are charged at a rate per kWh based on hourly scheduled (contracted) energy. The transmission losses are paid by the purchaser of the regional bilateral trade. The price payable for the energy losses is determined by ERERA.

2.8.2 Transmission Pricing in Australia

Common wholesale electricity market in Australia is responsible for the supply of electricity to retailers and end users. This National Energy market (NEM) which is the world largest interconnected system, has been established in 1998, linking Victoria, New South Wales, Queensland, the Australian Capital Territory and South Australia. In 2005 Tasmania joined the NEM as the sixth region. [31]

NEM stretches for more than 4000 km from Port Douglas in the north of Queensland, to Port Lincoln in South Australia and via the Basslink undersea cable between Victoria and Tasmania.

The NEM operates in accordance with the National Electricity Rules that govern all aspects of the operation of the market. These include the dispatch rules, provision of obligations on market participants and service providers, the responsibilities of the system operator, the National Electricity Market Management Company (NEMMCO), and the operation of the spot market, prudential requirements and the procedures for dealing with network losses and constraints.[23]

As independent system operator, NEMMCO has responsibility for the implementation and continued operation of the wholesale market, and a mandate to continually improve its functions whilst maintaining system security. It functions as a non-profit body corporate whose members are the state governments of the NEM. Structure of the NEM is as follows. [21], [22]

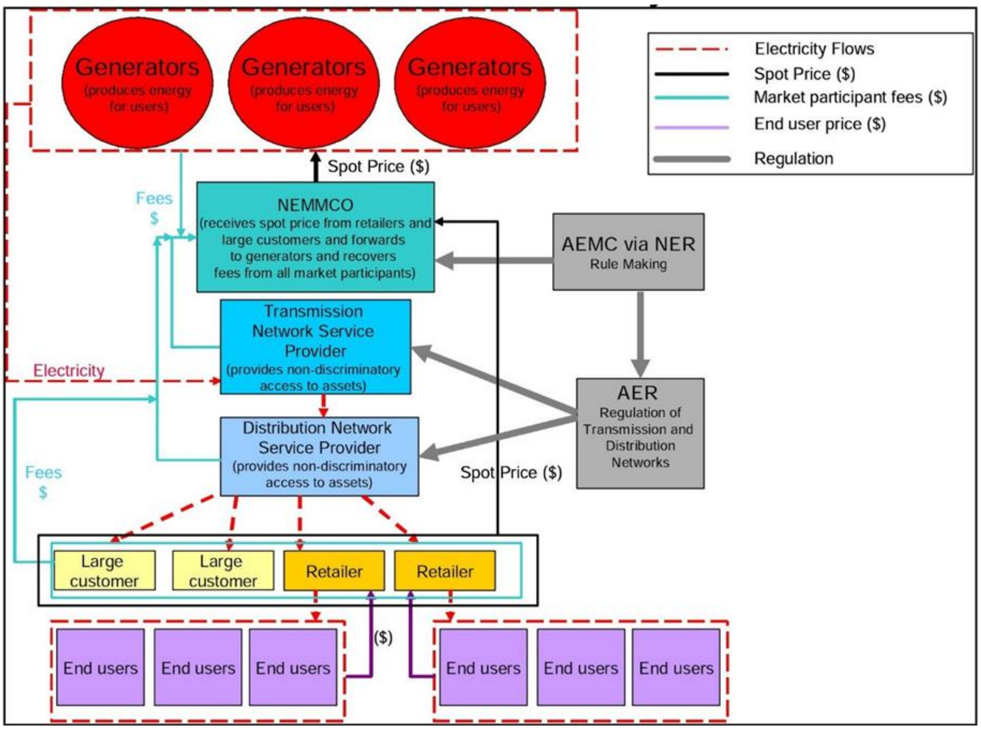

Figure 2-10 Structure of national Energy market Australia
Source: Extracted from [21]

Generators own and operate electricity plants to convert energy from a fuel source into electricity. In Australia, the main fuel types used are coal, water, natural gas and wind.

NEMMCO schedules generators based on these characterizations and the capacity they can offer into the interconnected network. The electricity network consists of high voltage transmission lines that transport electricity from generators to customers via a local distribution network. TNSPs provide access to the high-voltage cables that move electricity from large generators to load centers. DNSPs receives electricity from the transmission network and transforms it to lower voltages that are more suitable for use by electricity customers. They are responsible for the operation and maintenance of their local distribution network. Both TNSPs and DNSPs are responsible for maintaining system security on their portion of the network and facilitating new connections. [21]

2.8.2.1 Tasmanian Experience

The electricity transmission network in Tasmania is operated by Transend, a state-owned corporation that operates a network of 3,500 kilometers of transmission lines. Aurora Energy is the distribution network service provider in Tasmania and is also state-owned. It provides distribution services to approximately 260,000 customers throughout Tasmania. The integration of Tasmania into the NEM has been achieved through the construction of the Basslink interconnector, connecting Tasmania with Victoria. The Basslink interconnector is a DC interconnector, with a capacity of 600MW into Victoria and 300MW from Victoria and has been in operation since April 2006. Tasmanian Networks Pty Ltd (TasNetworks) is the electricity Transmission Network Service Provider (TNSP*)* in Tasmania. [24]

TasNetwork provides following services and transmission tariff relates to said services. [24]

- Provides shared transmission services to customers directly connected to the transmission network and connected Network Service Providers
- Provides connection services to connect the distribution network to the transmission network.
- Provides connection services to Generators and customers directly connected to the transmission network.
- Provides services that equivalent benefits to all Transmission Customers without any differentiation based on their location, and therefore cannot be reasonably allocated on a locational basis.

TasNetworks is the sole provider of prescribed transmission services within Tasmania and is responsible for the allocation of the Aggregate Annual Revenue Requirement (AARR) within Tasmania. AARR is calculated by adjusting the maximum allowed revenue that transmission network service provider may earn. The revenue that a

TNSP may earn in any regulatory year of a regulatory control period from the provision of prescribed transmission services is known as the maximum allowed revenue.

Based on the services provides, there are four service categories available. TasNetworks' AARR is recovered from transmission charges for those categories of prescribed transmission services. [24]

1. Entry services, which include services provided by assets that are directly attributable to serving a generator or group of generators at a single connection point and are deemed to provide a prescribed transmission service by virtue of the operation
2. Exit services, which include services provided by assets that are directly attributable to serving a Transmission Customer or group of Transmission Customers at a single connection point
3. Common transmission services, which are services that provide equivalent benefits to all Transmission Customers without any differentiation based on their location, and therefore cannot be reasonably allocated on a locational basis
4. Transmission use of system (TUOS) services, which include services that provide benefits to transmission customers depending on their location within the transmission system, that are shared to a greater or lesser extent by all users across the transmission system and are not prescribed common transmission services, prescribed entry services or prescribed exit services

2.8.2.2 Transmission Pricing Methodology

The determination of prescribed transmission service prices involves steps: [24]

1. Allocation of the costs of transmission system assets to the categories of prescribed transmission service, to the extent to which assets are directly attributable to the provision of a category of prescribed transmission services

2. Calculation of the attributable cost shares

3. Calculation of the Annual Service Revenue Requirement (ASRR) by the allocation of the Aggregated Annual Revenue Requirement to each category of prescribed transmission services in accordance with the attributable cost share for that category of prescribed transmission services
4. Allocation of the Annual Service Revenue Requirement for prescribed services, to each transmission network connection point in accordance with the principles set out.
5. Calculation of prices for each category of prescribed transmission service

Detailed description of above steps is as below.

Step 1: Allocation of Costs

A cost allocation process is used to assign the optimized replacement cost (ORC) of all prescribed transmission service assets to each category of prescribed transmission services such as transmission lines, transformers, circuit breakers, common service assets (such as communications, reactive support, office buildings.); and substation local assets (ancillary equipment, civil work, and establishment). In the case of a shared connection asset, such as a transformer, serving multiple connections and providing prescribed transmission services, cost is allocated based on the percentage of agreed maximum demand supplied to each customer upon total demand of all categories of prescribed transmission services at that location.

Step 2: Calculation of the attributable cost shares

The attributable cost share for each category of prescribed transmission services is calculated as ratio of the costs of the transmission system assets directly attributable to the provision of that category of prescribed transmission services to the total costs of all the transmission network service provider’s transmission system assets directly attributable to the provision of prescribed transmission services

Step 3: Calculation of the Annual Service Revenue Requirement (ASRR) by the allocation of the Aggregated Annual Revenue Requirement (AARR)to each category

$$ASRR = AARR\ X\ Attributable\ Cost\ Share$$

Step 4: Allocation of the Annual Service Revenue Requirement (ASRR) for prescribed services, to each transmission network connection point

The whole of the ASRR for prescribed entry services is allocated to each transmission network connection point in accordance with the attributable connection point cost share for prescribed entry services that are provided by the TNSP at that connection point.

The attributable connection point cost share for prescribed entry services is the ratio of the costs of the transmission system assets directly attributable to the provision of prescribed entry services at that transmission network connection point to the total costs of all the TNSP's transmission system assets directly attributable to the provision of prescribed entry services.

The whole of the ASRR for prescribed exit services is allocated to each transmission network connection point in accordance with the attributable connection point cost share for prescribed exit services that are provided by the TNSP at that connection point.

The attributable connection point cost share for prescribed exit services is the ratio of the costs of the transmission system assets directly attributable to the provision of prescribed exit services at that transmission network connection point to the total costs of all the transmission system assets directly attributable to the provision of prescribed exit services.

The prescribed TUOS (shared network) services ASRR is recovered from the prescribed TUOS services (locational component and the adjusted non-locational component). The share of the ASRR is allocated between connection points on the basis of the estimated proportionate use of the relevant transmission system assets by each customer using the modified Cost Reflective Network Pricing (CRNP) methodology. The CRNP methodology allocates a proportion of shared network costs to individual customer connection points.

Step 5: Calculation of prices for each category of prescribed transmission service

Entry and Exit Service Price:

Entry and exit services prices are calculated to recover the prescribed entry and prescribed exit services ASRRs from the Network Users who are served by the relevant connection assets.

The prescribed entry services ASRR is recovered as a fixed annual charge for each relevant connection point. Similarly, the prescribed exit services ASRR is recovered as a fixed annual charge for each relevant connection point. This amount will be recovered by a fixed dollar amount per month.

Locational Service Price:

Locational prices are determined on the basis of contract agreed maximum demand. The cost reflective network pricing methodology used above to calculate locational ASRR gives lump sum figure to be recovered at each point. This lump sum amount for each connection point is divided by the product of the number of days in the forthcoming financial year and the contract agreed maximum demand (prevailing at the time transmission prices are published) to calculate the locational price for each connection point7 and is expressed as $/MW/day.

Non Locational Service Price:

Prices for recovery of the adjusted non-locational component of prescribed TUOS services is set on a postage stamp basis to be determined on the basis of contract agreed maximum demand or historical energy and calculated annually as follows

- An energy based price that is a price per unit of historical metered energy or current metered energy at a connection point expressed as $/MWh; and

- A contract agreed maximum demand price that is a price per unit of contract agreed maximum demand at a connection point expressed as $/MW/month.

Either the energy based price or the contract agreed maximum demand price will apply at a connection point providing prescribed TUOS services except for those connection points where a Transmission Customer has negotiated reduced charges for the adjusted non-locational component of prescribed TUOS services

2.8.3 Transmission Pricing in Thailand

The Thai electricity supply industry (ESI) is based on a state owned single buyer scheme. The single buyer, Electricity Generating Authority of Thailand (EGAT), a State-owned enterprise that was established in 1968, purchases electricity from public and private power producers, and then sells it to unbundled distribution companies and a few large direct customers. EGAT is not only the single buyer but also acts as an electricity generator. [26], [30]

Although EGAT and its subsidiaries still dominate in terms of electricity generation, the last decade saw important opportunities emerge for the private sector: since 1992, programs for IPP's and SPP's allow private operators to generate and sell electricity to EGAT. IPP's must generate an excess of 90 MW per plant. Small power producers (SPP's) and Very small power producers (VSPP's), those producing less than 90 MW and less than 10 MW per plant, respectively, make up the remaining. In addition to power generated by EGAT and private producers, Thailand relies on power from neighboring countries such as Lao and Malaysia.

Structure of the electricity industry in Thailand with the market share is as figure 2-11.

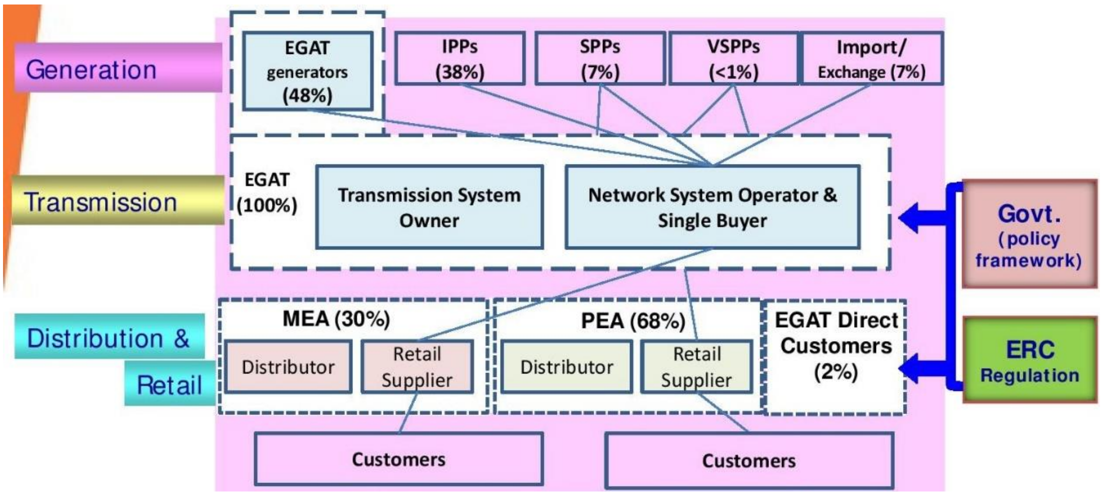

Figure 2-11 Structure of Electricity Industry in Thailand
Source: Extracted from [26]

EGAT= Electricity Generating Authority of Thailand

MEA= Metropolitan Electricity Authority

PEA= Provincial Electricity Authority

IPPs= Independent Power Producers (Cap. sold to EGAT □ 90 MW)

SPPs=Small Power Producers (Cap. sold to EGAT < 90 MW)

VSPPs=Very Small Power Producers (Cap. sold to MEA/PEA < 10 MW)

National Energy Policy Office (NEPO) is at the core of the institutional structure in the Thai energy sector. NEPO is the operating arm of the NEPC (National Energy Policy Council). NEPC and NEPO are responsible for all policies related to IPPs, privatization and tariff structure.

National Energy Policy Council (NEPC) is the final authority that makes the strategic decisions on energy policy in the country. For example, the current policy of privatization is based on a number of resolutions passed by the NEPC in 1997. NEPO serves as the implementation arm of the Council.

Thailand has taken a series of initiatives to restructure its institutional arrangements in the energy sector to make the sector more competitive. The initiatives are based on the premise that the deregulated markets and best practice private investment is better positioned to deal with a crisis.

Post crisis, the Royal Thai Government set a Committee on the Electric Power Tariff restructuring to deal with the problem of devising a sustainable tariff policy in view of the recent experiences. [30]

Electricity supply in Thailand is the responsibility of three public sector firms at this stage. EGAT (Electricity Generating Authority of Thailand) is responsible for generation and transmission and MEA (Metropolitan Electricity Authority) and PEA (Provincial Electricity Authority) for distribution in the Metropolitan (Bangkok, Nonthaburi and SamutPrakan) and Provincial (rest of the country) areas, respectively. EGAT is also responsible for supply to some large customers.

EGAT does have some local and foreign power producers supplying its electricity requirements. EGCO is the biggest supplier with its share being over two-thirds of EGAT's purchases. EGAT is responsible for the operation and development of the country's transmission system including the load dispatch control.

The industry structure of ESI in Thailand could be characterized as one in transition, wherein the value chain has been unbundled, but there is hardly any competition in the industry. The challenge is in ensuring that the unbundled value chain is managed effectively by multiple competitive and monopoly entities simultaneously in the industry.

Price regulations are still in place and some of the customer segments are being provided cross-subsidies. However, the privatization initiative is expected to focus on economic efficiency and financial viability of the energy supply industry.

While the tariffs are regulated, Thailand has adopted differential tariffs to reflect the usage characteristics in terms of the timing, voltage and connected load.

Tariff determination methodology process is as follows according to the Energy Industry act 2007.[29]

2.8.3.1 Transmission pricing methodology

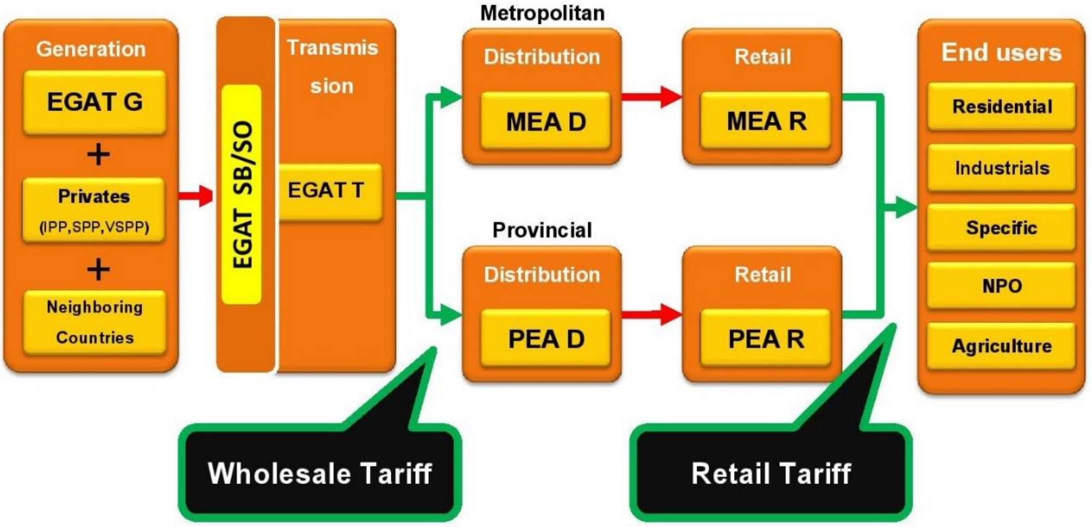

Figure 2-12 Electricity Pricing Structure in Thailand
Source: Extracted from[30]

The whole sale electricity tariff structure has got two components of Base tariff and automatic tariff adjustment component.[26], [29],[30]

Base tariff:

Base tariff reflects investment costs of utilities in developing power plants, transmission lines, distribution lines and energy costs with certain assumptions related to fuel prices, inflation rates (or CPI), exchange rates. Base Tariff will be reviewed every 3-5 years.

Automatic Tariff Adjustment component:

The Automatic Tariff Adjustment (Ft) is a mechanism for adjusting the power tariff so that it reflects the actual fuel cost for power generation at a given period of time, thus making the tariff charged on customers fair, transparent and reflects the actual power supply cost. (Ft) will be adjusted in line with changes in EGAT fuel cost, the power purchase cost and the impact of policy expense which are beyond control of the Power Utilities. This factor is adjusted in every four month period.

$Ft = (FAC + AF) / EU$

FAC	=	Fuel Adjustment Cost
AF	=	Accumulated factor
EU	=	Energy Units

Fuel adjustment factor is calculated by taking the sum of Fuel adjustment cost (The difference between the "Estimation" and the "Base" of fuel cost for the present four month period) and the accumulated factor (difference between the "actually calculation-derived Ft" and the "Ft charged" in the previous four month period) divided by total energy units generated.

2.8.4 Transmission pricing in Northern Ireland

The island of Ireland was divided into two distinct electricity markets until the creation of the Single Electricity Market (SEM). In Northern Ireland there was a small market with approximately 0.7m customers and a peak demand of around 2000 MW, interconnected with both Scotland and with the Republic of Ireland. In the Republic of Ireland peak demand is around 5000 MW and there are around 1.8m customers. [31]

However the benefits of interconnection between the two systems were well understood, in terms of the reduced need for spinning reserve capacity in the island of Ireland. [19],[31] Further the non-coincident peaks on the two systems, leading to differential prices and the different generation mixes within the two systems; which led to marginal plants alternating between North and South. The emergence of wind as a major source of generation across the island of Ireland has also significantly increased the value of interconnection.

In 2004 the two utility regulators laid out principles for the establishment of a single wholesale electricity market in Ireland which was approved in 2005. The market is claimed to be a world first: the first market between sovereign countries to operate with multiple currencies.

The Single Electricity Market Operator (SEMO) sought to deliver a larger market, transparency, a stable investment environment, greater security of supply and greater efficiency. The SEM is overseen by the SEM committee (SEMC) which has representatives from Utility Regulator in Northern Ireland (UREGNI), Commission for Energy Regulation (CER) and an independent member. It involves marginal cost based bids from all generators in the island. These bids are then aggregated and matched to electricity demand to give a single half hourly trading price. There is also a capacity payment. This is fixed in each year as the total required MW forecast by the transmission system owner (which is now EirGrid for the whole of Ireland) times the cost of a MW on new peak capacity. This amount is then divided up among generators over the year on the basis of their half hourly availability.

One important feature of SEM is that it is designed in a way that strategically mitigates participants' abuse of market power. The pool imposes Directed Contracts on generators with significant market power, and enforces a license condition on generators to strictly adhere to a bidding code of practice. Generators viewed as possessing substantial market share are compelled to enter into forward contracts with suppliers for a specified volume at a pre-determined price. This is done to prevent those generators from withholding capacity for the purpose of influencing the market price. In addition, the pool has a Market Monitoring Unit (MMU) which constantly monitors participants' bidding behavior in order to ensure participants' compliances with the market rules.

2.8.4.1 Transmission Use of System tariff

Transmission tariff (Transmission use of system tariff) for the island of Northern Ireland is as proposed by the System operator can be describes as below. [31]

Step 1: Define a set of several generation scenarios in aggregate which represent the spectrum of operating conditions used in investment planning analysis.

Step 2: For each scenario, perform a load flow analysis. Each load flow will represent as operating condition that makes heavy usage of the transmission system with identifying the system reinforcement and calculate a value of transmission use of system tariff for each generator on the transmission system using the MW-Distance method.

Step 3: For each generator, take the maximum positive value of the tariff which calculated in step (2).

Step 4: Take the tariff comprised of the maximum value in step 3 for each generator, calculate the revenue recovery and shift the tariff (as expressed in €/kW) uniformly across all generators to obtain the target revenue recovery for the two jurisdictions combined. The resulting shifted tariff is the transmission use of system tariff.

3. TRANSMISSION PRICING MECHANISM FOR SRI LANKA

3.1 Power market Model Sri Lanka

Sri Lankan power sector operates on a vertically integrated single buyer model. The present structure of the Power Sector, which explains how the system is being operated, is given below.

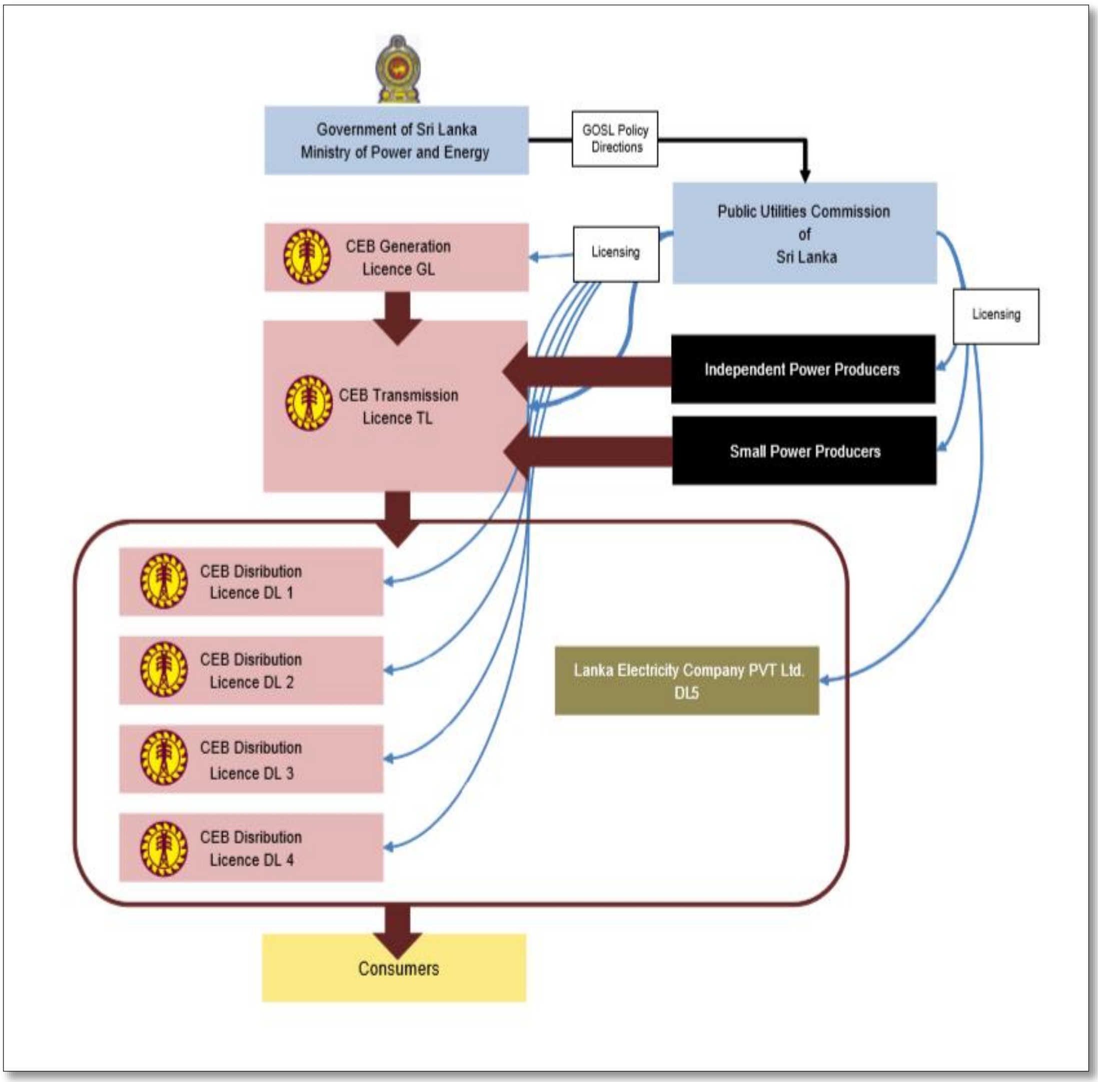

Figure 3-1 Power market model in SL
Source: CEB Website (www.ceb.lk)

3.2 Power and Energy Trading Process

Inter- licensee Bulk supply transactions take place according to the Bulk Supply Transaction Guidelines of April 2011, issued by the PUCSL. The overall bulk supply transaction process given in these Operating Guidelines is illustrated in the Figure given below.

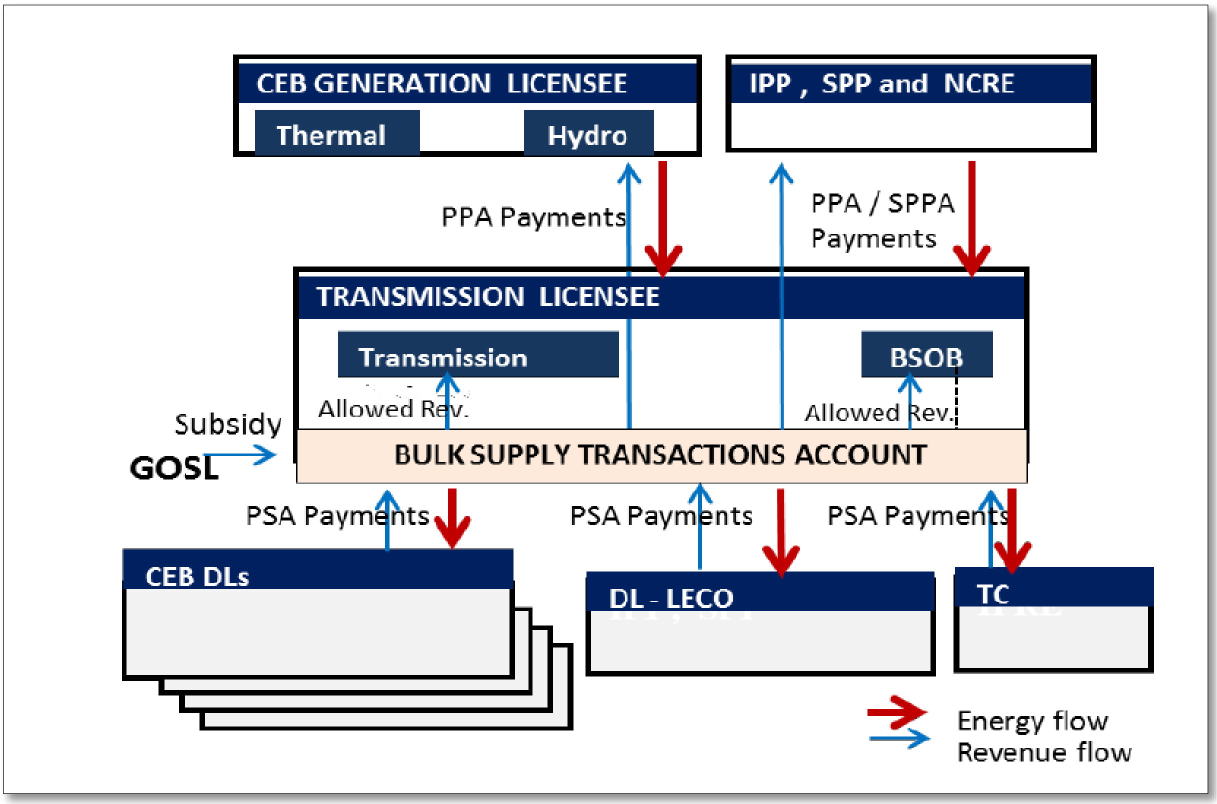

Figure 3-2Bulk Supply Transaction Process-SL
Source: Extracted from [36]

3.2.1 Transactions between Transmission Licensee and Generators

1. The Bulk Supply and Operations Business of the Transmission Licensee purchases electricity produced by the Generators (CEB Generation Licensee, Independent Power Producers, Small Power Producers and exempted Generators) according to the operational criteria stipulated under the license/exemption order conditions and applicable Power Purchase Agreements (PPA).
2. Transmission Licensee dispatches the available generation according to the Dispatch Methodology approved by the Commission.

3. The Generators submit monthly invoices (or ‘transactions notes’ as applicable) to the Transmission Licensee, Bulk Supply and Operations Business, in accordance with the applicable Power Purchase Agreements.
4. The Transmission Licensee verifies invoices submitted by Generators and settle the invoices (or ‘transaction notes’ as applicable) in accordance with the terms of the applicable PPAs.

3.2.2 Transactions between the Transmission Licensee and Distribution Licensees

1. The Transmission Licensee supplies bulk power and energy requirements of the Distribution Licensees in accordance with the relevant license conditions and applicable Terms and conditions of delivery and acceptance of electricity between Transmission Division and Distribution Divisions.
2. The Transmission Licensee submits monthly invoices (or ‘transaction notes’ as applicable) to Distribution Licensees and Transmission Customers.
3. The Distribution Licensees and Transmission Customers verify invoices (or transaction notes as applicable) submitted by the Transmission Licensee and make arrangements for settlement of the invoices (or ‘transaction notes’ as applicable) in accordance with the Terms and conditions of delivery and acceptance of electricity between Transmission Division and Distribution Divisions.

At the end Distribution Licensees distribute the electricity purchased by them and supply to their customers at a Uniform National Tariff published by PUCSL.

3.3 Tariff for Transmission Customers

Before determining a pricing methodology it's important to understand the main desires that should be full filled by the tariff proposed to the transmission customers.

- **Cost recovery**

The tariff methodology should allow the transmission licensee to collect sufficient revenue to finance an efficient investment programme and to cover efficiently incurred operation costs, including an appropriate return commensurate with the risks of its business. For that, it should be needed to familiarize with the costs associated with the demand of the particular customers on the electricity network in terms of use of the networks. The cost associated shall be passed through to its customers by means of cost reflective tariff while encouraging the customers to utilize the system complying with system operating principals. All the cost incurred shall be adjusted to loss factors applicable to each customer. In such system, tariff can influence changing the load pattern of the customers at system peak time by introducing high energy tariff at the peak period and also can indirectly encourage customers to maintain good power factor by introducing tariff to reactive power usage. This conclude that proper pricing methodology shall recover all the cost incurred by the system to supply electricity to the customers while enhancing the quality of the power system in various aspects.

- **Simplicity**

Proposed tariff methodology should be understood by customers. Number of transmission customers is few and they should be able to understand and respond to more complex price signals than small customers.

- **Stability**

The tariff regime should be relatively stable to give producers and customers' confidence to make investment decisions based on the tariff price signals.

- **Ease of implementation**

The tariff methodology should ensure that it may implemented without complex changes with the existing system of calculation of Bulk Supply Tariff but it should enhanced the prevailing system by adding improvement factors such as introducing tariff to different voltage levels along with considering the loss factors.

3.4 Analysis of Transmission Pricing Methods for Sri Lankan Electricity Market

There are three main methods discussed above to calculate the Transmission Tariff, Embedded cost based, Marginal/Increment cost based and Composite of Embedded and Marginal/Increment cost based methods. All the transmission pricing models are cost based except the transmission transactions based on bidding process. Goal of the each methods discussed above is allocating the all existing and new cost of transmission system to wheeling customers. Embedded cost based methods emphasis on revenue requirements need to pay for all existing facilities and to facilitate any new facilities added to the power system to serve transmission customer while the marginal cost based method are emphasis revenue requirements need to pay for any new facilities that are specifically attributed to the transmission customer. Composite method includes both existing system cost and the incremental costs of transmission transactions.

There are four methods discussed which can be used to allocate the cost to the wheeling customers under the embedded cost based method. Postage stamp method was considered under the embedded cost based transmission pricing calculations while contract path and the distance flow based methods were not considered as these methods are engaging in competitive market model pricing so that it cannot be directly applied to Sri Lankan electricity market model as customers have no direct contract with generation companies hence specific path for the energy delivery cannot be clearly defined. In addition marginal/incremental cost based method and composite cost based methods were also considered.

3.4.1 Embedded Cost Based Method

Considering the costs associated with the transaction of energy to the transmission customers, it can be identified that it includes the cost of network and cost of generation. In addition the cost of supply that is the cost incurred regardless of energy delivered should also be included. The propose tariff shall recover all mentioned cost components.

Considering the revenue requirement of embedded cost based method, it was identified that cost of generation shall include,

- All fixed operation and maintenance costs of power plants
- Any debt services associated
- Fuel costs and other operational expenses

Further network or the transmission cost shall include,

- Cost experience in facilitating addition or extending of new transmission facilities
- All other operational expenses

Considering the cost component associated above, proposed tariff shall have tariff components as in Figure 3-3 to satisfy the said requirement.

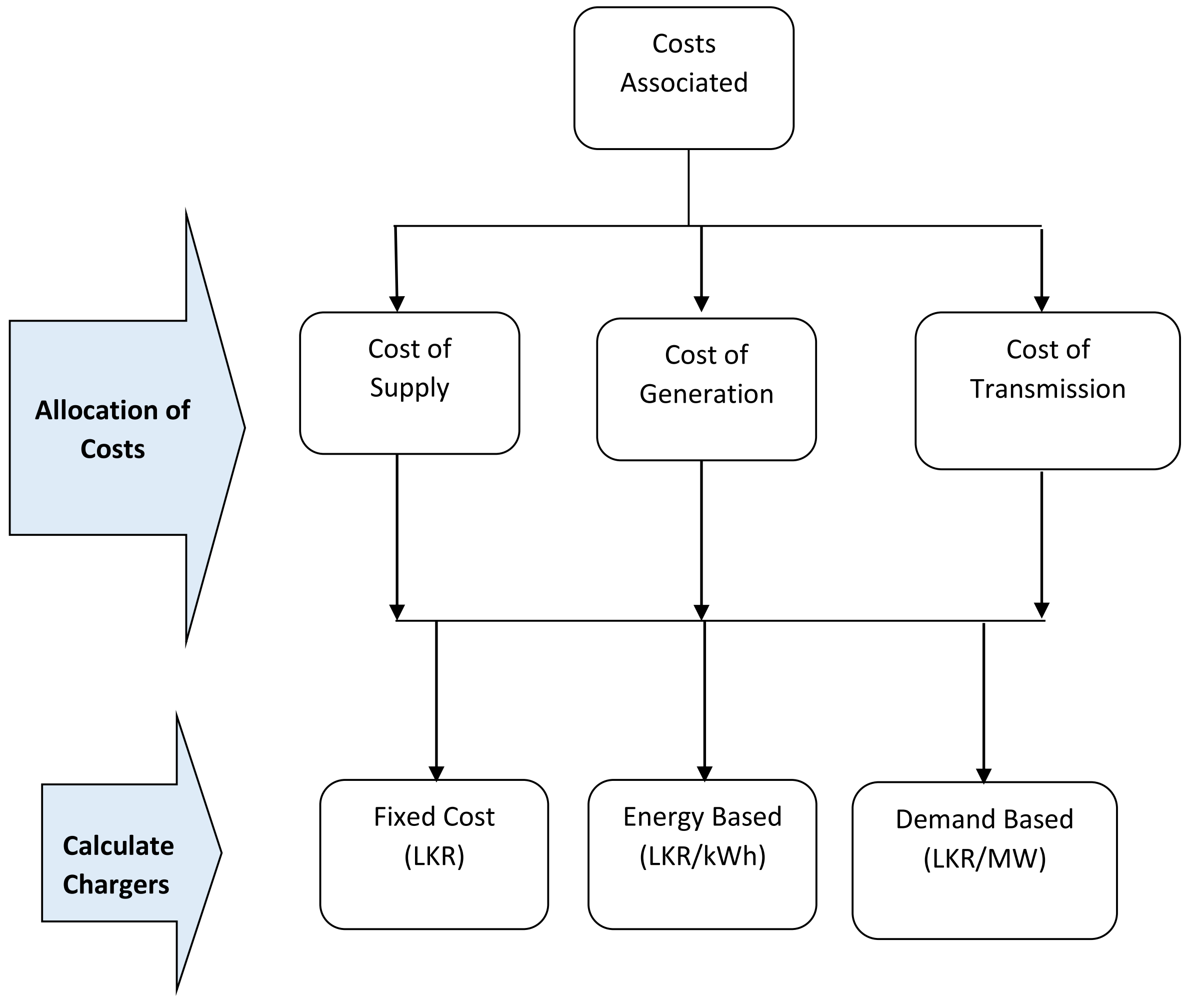

Figure 3-3 Structure for the pricing model

3.4.1.1 Embedded Cost Based Methods – Proposed Methodology I

Step1: Calculation of major cost components associates both generation and network costs.

It was identified that the most important step is to identifying the cost components associated with supply of electricity to the transmission customers in terms of easy computation without conflicting the prevailing system. Considering the type of business, customers generators connected to the transmission system can be categorized into two groups as Independent Power Producers (IPP) and other customers.

The proposed tariff shall recover the cost of energy generated and delivered to the particular customer. In addition, the cost of capital expenditures incurred in maintaining the transmission network and the generators shall be recovered. Further the cost of metering, billing and collection of the revenue also should be covered.

Step 2: Allocation of the cost among all transmission customers according to the voltage level at which the supply is metered.

Before allocating of cost among transmission customers, the load patterns of each customer in specific month was observed.(Figures, 1-3, 1-4, and 1-5).Load profiles are generated in a same day for transmission customers. By observing the load curves it reveals that, except the distribution customers others have their own load curve which cannot be forecast. So that the cost incurred in using the transmission network cannot be evenly distributed as they connected to the system in different voltage levels.

When allocating the cost to the each customer, there should be a fair basis for all users at same voltage level. The capacity cost of generators is allocated based on the demand at each voltage level while transmission and bulk supply operation business cost is allocated based on the share of the asset base which is directly associates of delivering the energy to the transmission customers. Energy Charge shall be metered and charged in three time intervals as per the approved Tariff Methodology

Step 3: Calculation of prices for each category of transmission users based on voltage level.

Energy Charge

Energy Cost will be passed through to each customer taking into consideration the transmission loss applicable to voltage level of connection and as per the time of their consumption.

Energy Charge = (1+ TLF) x Generation Energy Charge

TLF - Transmission Loss (%)

Capacity Charge

Generation Capacity Cost is allocated at each voltage level considering the power loss along the transmission system. Cost of using transmission network and services are allocated for each voltage level based on the share of fixed assets at each level. Figure 3-4 shows an example of power flow along the network with power loss.

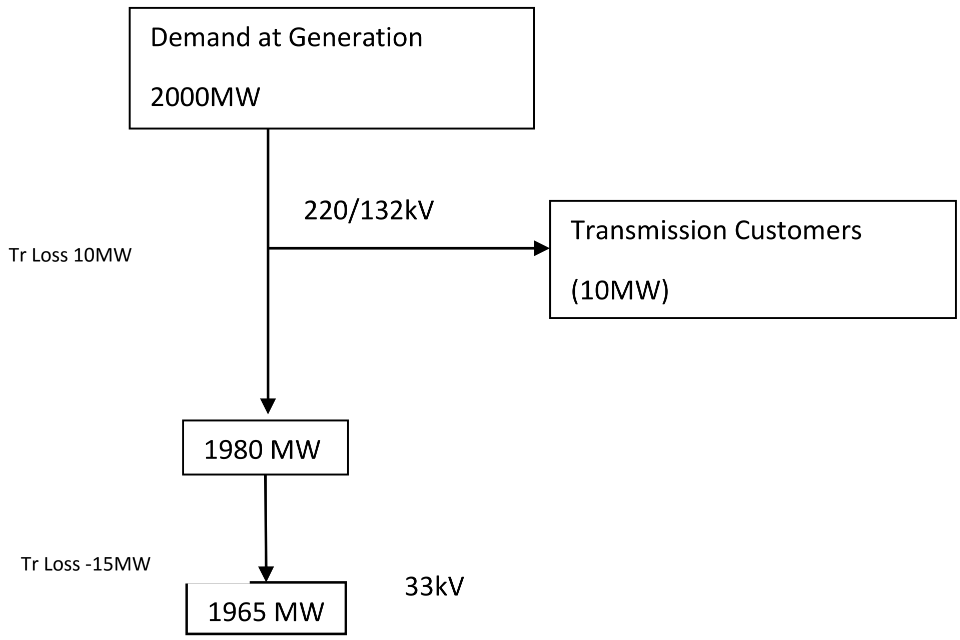

Figure 3-4 Power flow

The capacity cost allocations as per previous step, derive a capacity charge per kW of the demand coincident on system peak demand.

In the case of transmission customers, the transmission system should have reserved capacity to cater for their maximum demand which can be occurred at any time.

Accordingly, in consideration with the load patterns and the reactive power usage of transmission customers, Capacity Charge will be charged on their maximum demand in kVA.

Capacity Charge (Rs/kVA) = Capacity Charge (Rs/kW) / Av. Power Factor

Fixed Cost

Connection cost of meter reading, billing and collection of revenue is equally distributed among all customers.

3.4.1.2 Cost Components

According to the above proposed methodology, cost components were separately identified as follows.

a) The component related to electricity generation

b) The component related to the use of transmission system and to continue other duties of single buyer operations.

c) The component related to supply of electricity

(a) Generation Cost

As per the Section 2.2 of the approved Tariff Methodology, single buyer buys electricity from the generators and it's priced according to the power purchase agreements between the generators and the single buyer which is energy and capacity based prices. Price formula for the CEB owned thermal generator comprises of two parts of tariffs which is capacity based covers the components of debt services, cost of operation and maintenance of fixed assets and cost of services provided by generation headquarters, while energy based part covers variable operation and maintenance cost, fuel costs and startup costs. Hydroelectric capacity prices comprises debt services, operation and maintenance fixed costs and cost of services provided by generation headquarters. Prices for the independent power producers and small power producers based on the power purchases agreements signed.

(b) Cost of Transmission System

This component refers the cost of transmission system which is allowed to collect from the users of the transmission network, as described in section 2.3.1 in the PUCSL approved Tariff Methodology. According to the section 2.3.2 of the PUCSL approved Tariff Methodology [35], this has two components called based allowed revenue and large infrastructure developments. Based allowed revenue is calculated in multiyear tariff system considering the components of,

- Efficient Operational Expenditure (OPEX)
- Initial Regulatory Asset Base (RAB)
- Rolling forward RAB, considering Minor CAPEX
- Depreciation
- Return on Capital
- Taxes

Efficient Operational Expenditure (OPEX)

OPEX component includes the expenditure requirement of the licensee such as taxes, insurance and all other expenses incurred to operate transmission system. OPEX is forecasted based on demand increase and the audited accounts of last financial year.

Initial Regulatory Asset Base

Net book value as per the audited accounts of last financial year is used as initial RAB. And the RAB is determined for each year in the tariff period by adding CAPEX additions during the year and deduction depreciation during the year.

Depreciation

Depreciation is calculated on the straight line method using the same rates that have been used in annual accounts.

CAPEX

The Capital investments are separated into Minor CAPEX Development and Large Infrastructure Development (LID) as required by the Tariff Methodology.

Non –load related CAPEX such as vehicles, land & building, office equipment etc. has been considered under minor CAPEX.

Large CAPEX all investments related to the expansion of Transmission System.

Only Minor CAPEX is included in the calculation of rolling forward asset base, as per the Tariff Methodology. [35]

Large Infrastructure Development (LID)

Based on the recent tariff filling 2016-2020, the working capital requirement (Project Administration costs, import taxes and duties and other levies with respect to Large Infrastructure Development) for LID is included under WIP in the Allowed Revenue calculation. i.e. only the CEB funded amount.

These working capital requirements for LID will be incorporated into the Regulatory Asset Base and reconciled upon commissioning of each LID. i.e a separate filing has to done upon commissioning of each LID for a corresponding Capital Allowance.

Rate of Return on Assets

The rate of Return on assets is defined as 2%*.

Taxes

The corporate tax rate is assumed as 28%*, pursuant to the present rate of income tax in accordance with the Law.

*****based on recent tariff filling (2016-2020)

Technical Losses

Technical losses in the Transmission System will be allowed to be the passed-through to Bulk Supply as per [35].The Transmission loss for this Tariff Period 2016-2020 has been forecast as 3%.

Cost of Bulk Supply Operation Business

This cost component covers the revenue allowed for the transmission licensee to collect from the transmission users in order to recover the costs of performing the duties of single buyer, system operator and bulk supplier as transmission licensee. Base allowed revenue is calculated in multiyear tariff system and will be adjusted annually as per the clause 2.4.1, Tariff methodology [35].

This methodology is propose to calculate the capacity cost for six month period along with the bulk supply tariff and take the six month average capital cost of forecasted for next consecutive period. Energy cost also shall be calculated for six month period based on existing pricing formula in approved tariff methodology and adjusted with appropriate loss factors at 132kV/220kV voltage level.

3.4.2 Long Run Marginal/Incremental Cost based Method

In general, marginal cost is referred to the change in total cost resulting from producing an additional unit of output while the incremental cost refers to total additional cost associated when expanding the output. In simple manner, electricity prices calculate with the Long Run Marginal Cost (LRMC) over time will ensure that new generation investments receive sufficient revenues so as to recover both the operating and capital costs of the investment. With this explanation, Long run marginal pricing is used to calculate Generation capacity cost component and Transmission cost component is calculated using long run incremental pricing method. Generation energy cost component is calculated using long run marginal pricing method. Steps of the proposed methodology are as follows.

3.4.2.1 LRMC based Method - Proposed methodology II

Step 1: Development of demand forecast plans.

By the definition of marginal cost implies that the cost shall be calculated to generate one additional unit of electricity. As the first step of actualizing this process generation demand shall forecast for the period of data analysis in two different scenarios i.e. Base case and the demand increment case (apply hypothetical demand increase).

Step 2: Development of investment and implementation plan compatible for two demand forecast scenarios.

Since the demand is growing over the period, new generation plants have to be constructed to meet the new demand and this add additional investment cost and fixed operation and maintenance cost to the system. Hence generation capacity costs and fixed operation and maintenance schedule for the period of data analysis shall be formulate which satisfies the demand forecast for next ten years for both cases. All cost shall be annuitized by taking the net present value.

Step 3: Calculation of LRMC of generation capacity and operation

Calculate the long run marginal cost as the present value of change in the capital cost program with the operating costs, divided by the present value of the revised demand forecast compared to the initial demand forecast.

$$\mathrm{LRMC} = \frac{\begin{array}{c}\text{Present Value (optimal capex plus opex(Increased demand case)} - \\ \text{optimal capex plus opex(based case))}\end{array}}{\text{Present Value(increased demand} - \text{base demand)}}$$

Step 4: Development of investment and implementation plan for transmission capacity costs

Develop least cost program for transmission capacity expansion plan for ten years that ensures the demand can serve to each customer.

Step 5: Calculate Long run incremental transmission capacity cost

Estimate long run incremental transmission capacity cost as the present value of expected costs of optimal schedule of investment divided by the present value of the additional demand supplied.

$$\text{Long run incremental cost of Transmission} = \frac{\text{Present Value (new transmission capacity)}}{\text{Present Value(additional demand served)}}$$

Step 6: Calculation of the marginal energy costs

Develop the power plant schedule with the ranking order from most expensive to least expensive cost of operation, based on the base case demand forecast for the period of analysis and then calculate the average generation costs by using the specific cost and the calculated plant factor of each power plant. The time of use energy costs shall be calculated by considering the percentages of time of the day used.

3.4.2.2 Cost Components

Cost components identified for the calculation of the transmission tariff based on LRMC method are:

a) The component related to electricity generation which includes cost of developing capacity of generating facilities to meet future forecast demand.

b) The component related to fuel cost.

c) The component related to development of network when increasing the capacity of transmission network.

(a) Generation cost - capacity

This generation capacity shall cover all the costs which will spend to extend the generating capacity of the system with respect to the demand increment. Power system extension plan is based on the approved long term generation plan and it refers to the base case demand forecast and the demand increment case which is forecasted with hypothetical peak demand increment. This demand increment causes to change dispatch of generating stations and results new generation plant schedule. So that this will cause to have more investments for building up the power plants and invest more on fixed operation cost of power plants. In addition have to consider the cost of un-served energy and savings in fuel costs in the increased demand case. Therefore Marginal capacity cost can be derived, [34]

$$\text{Marginal Generation Capacity cost} = \frac{\begin{array}{c}\text{Present Value(increase in investment + increase in OM costs} \\ \text{+increase in unserved energy costs} \\ \text{− Fuel saving)}\end{array}}{\text{Present Value (Demand increment)}}$$

All the cost and the demand increment should be annuitized over the period of analysis.

(b) Generation cost – fuel

Generation cost is calculated based on the dispatch schedule prepared considering the least expensive fuel cost of operation over the period of analysis. This is calculated based on the energy dispatch schedule prepared for the base case in approved Long Term Generation Plan. Based on the base case dispatch schedule plant factors of each plant is calculated and average generation cost is calculated based on plant factor and the calculated specific cost of each power plant. Generation cost for the time of use energy is calculated based on actual percentage of time of use energy consumption.

(c) Transmission cost

The simple method is to calculate the average increment transmission capacity cost is divide the average increment cost of expansion the transmission network to meet the demand forecast (Base case) in Long Term Generation Plan, by demand increment at voltage level over the period of analysis. Transmission cost component is calculated based on Long Term Transmission Development Plan for the same period.

3.4.3 Composite cost based Method

By the definition itself composite method considers the existing system cost and the incremental costs of transmission transactions in calculation of transmission charges. The embedded cost of a transmission transaction is part of the existing system cost that is allocated to that transaction. The tariff shall comprise of two components, i.e. network component and generation component.

3.4.3.1 Composite Cost based Method – Proposed methodology III

Step 1: Calculation of network charge

The network component includes the operational expenditures incurred of maintaining the existing network (existing system cost) and investment done for expanding the capacity of the transmission network. For the calculation of existing system cost, embedded costing with postage stamp cost allocation method is used while the future expansion cost is calculated by use of average incremental cost method.

$$\text{Existing system cost} = \frac{\begin{array}{c}\text{Total cost incurred for the maintenance of the transmission network at}\\ \text{specific voltage level}\end{array}}{\text{Total demand at specific voltage level}}$$

$$\text{Average incremental cost of Transmission} = \frac{\text{Present Value (new transmission capacity)}}{\text{Present Value(additional demand served)}}$$

Step 2: Calculation of Generation charge

Generation cost includes the generation capacity cost and the energy cost components. Generation capacity cost includes the fixed operational and maintenance cost incurred in power plants and relevant debt components. Energy component includes cost of fuel and start stop chargers for the each power plant dispatched. Energy component is linked only with the thermal power plants.

$$\text{Generation capacity cost} = \text{Fixed operational \&maintenance Cost} + \text{Debt Services} + \text{Overheads}$$

$$\text{Energy charge} = \text{Fuel cost} * \text{Energy Delivered} * \text{Heat rate}$$

3.4.3.2 Cost components

a) Capacity component
    - The component related to electricity generation which includes cost of fixed operation and maintenance.
    - The component related to development of network when increasing the capacity of transmission network.

b) The component related to fuel cost.

a) Capacity component

This component reflects the investment costs of the transmission network (based on Long term Transmission Development Plan) and operation and maintenance costs of the fixed assets in transmission as well as in generation. In addition it recovers the cost of debt service components of CEB owned power plants and the overhead costs of transmission and the generation licensees. This can be calculated and revised for a long period (5Years).

b) Fuel cost

This reflects the actual fuel cost for power generation at a given period of time, hence it makes the tariff charged on customers fair, transparent and reflects the actual power supply cost. This can be adjusted monthly by using actual fuel costs and fuel consumption of each plant.

CHAPTER 4

4. ANALYSIS OF DATA

4.1 Analysis of Data – Proposed Methodology I (Embedded Cost based Method)

Sample calculation of the tariff for the Transmission Customers for the month of March 2016

1. Capacity Component:

   Capacity component comprises of two main elements of generation, transmission and bulk supply operation business elements. Generation capacity components of CEB power plants was taken as per the Agreed values- 2016, prepared according to the Terms and Conditions for Delivery and acceptance of Electricity Between Generation and Transmission Division of CEB, and capacity components of the IPP power plants was taken as per the payment forecast prepared (based on PSA) for bulk supply tariff for April-Sep 2016 period. Transmission capacity cost component and the BSOB costs are as per the tariff filling for the 2016-2020.Forecast system coincident peak based on the dispatch schedule (63% wet) issued by the System control, CEB for 2016.Power consumption at 132kV level was forecasted based on time trend analysis. Asset share at 132kV/220kV level was assessed based on the asset database prepared by considering the appropriate depreciation percentage. Since the asset share at 220kV is smaller compared with the total assets, there is no significant difference between 132kV and 220kV levels. The asset share calculation and the prepared database is annexed in Annexure I.

Inputs		
Generation capacity cost (LKR/Month)	4,788,610,131.24	
Transmission Capacity Cost (LKR/month)	401,179,526.68	
Cost of BSOB (LKR/Month)	363,933,102.50	
System coincidence peak (Forecast) MW	2,315	
Power Consumption at 132/220kV(Forecast) MW	11.53	
Transmission loss % (assumption)	2% At 132/220kV	1% at 33kV
Share of assets at 132/220kV (Calculated)	40%	60%
PF (Forecast)	0.88	

1. **Computation of the Generation cost allocation:**

Generation capacity cost at 132kV level is calculated by applying the postage stamp cost allocation.

- Generation capacity cost at 132kV voltage level

$$\textbf{Allocation of Generation capacity cost}(\textbf{At 132kV}) = \frac{\textbf{Total Generatin capacty cost}}{(\textbf{System Coincidence peak} * (\textbf{1} - \textbf{Tr Loss at 132kV}\%)}$$

= 4,788,610,131.24/ (2,314.84*(1-0.02))

= 2,110.87LKR/kW/Month

- Generation capacity cost at 33kV voltage level

$$\textbf{Allocation of Generation capacity cost}(\textbf{At 33kV}) = \frac{\textbf{Total Generation capacty cost} - \textbf{Expected revenue from 132kv Tr Customer}}{(\textbf{input demand at 33kV}) * (\textbf{1} - (\textbf{Tr Loss 33kV}\,\%))}$$

= **(**4,788,610,131.24-2,110,872.84*11.53)/ (2,257.01 *(1-0.01))

= 2,132.19 LKR/kW/Month

2. **Computation of the Transmission cost allocation:**

Transmission capacity cost is allocated based on the share of assets at each level.

- Transmission capacity cost at 132kV voltage level

$$\textbf{Allocation of Transmission capacity cost}(\textbf{At 132kV}) = \frac{\textbf{Total Transmission capacty cost} * \textbf{Asset share at 132kV}}{(\textbf{System Coincidence peak} * (\textbf{1} - \textbf{Tr Loss at 132kV}\%)}$$

= 401,179,526.68*0.4/ (2,314.84*(1-0.02))

= 176.84 LKR/kW/Month

- Transmission capacity cost at 33kV voltage level

$$\textbf{Allocation of Transmission capacity cost}(\textbf{At 33kV}) = \frac{(\textbf{Total Transmission capacty cost} * \textbf{Asset share at 33kV}) + (\textbf{Tot Tr cost at 132kv after the allocation for consumption})}{(\textbf{input demand at 33kV}) * (\textbf{1} - (\textbf{Tr Loss 33kV}\,\%))}$$

= (401,179,526.68*0.6+(401,179,526.68*0.4

176,844.42*11.53))/(2,257.01*(1-0.01))

= 447.95LKR/kW/Month

3. **Computation of the BSOB cost allocation:**

- BSOB capacity cost at 132kV voltage level

$$\textbf{Allocation of BSOB cost}(\textbf{At 132kV}) = \frac{\textbf{Total BSOB cost} * \textbf{Asset share at 132kV}}{(\textbf{System Coincidence peak} * (\textbf{1} - \textbf{Tr Loss at 132kV}\%)}$$

= 363,933,102.50*0.4/(2,314.84*(1-0.02))

= 160.43LKR/kW/Month

- BSOB capacity cost at 33kV voltage level

$$\textbf{Allocation of BSOB cost}(\textbf{At 33kV}) = \frac{(\textbf{Total BSOB cost} * \textbf{Asset share at 33kV}) + (\textbf{Tot BSOB cost at 132kv after consumption})}{(\textbf{input demand at 33kV}) * (\textbf{1} - (\textbf{Tr Loss 33kV}\,\%))}$$

= 363,933,102.50*0.6+ (363,933,102.50-160,425.78*11.53)/(2,257.01*(1-0.01))

=406.36LKR/kW/Month

4. **Total Capacity Cost at each voltage levels:**

- Total capacity cost at 132kV voltage level

$$\textbf{Total Capacity cost at 132kv} = (\textbf{Generation} + \textbf{Transmission} + \textbf{BSOB})\ \textbf{costs at 132kV}$$

= 2,110,872.84+ 176,844.42 +160,425.78

= 2,448.14 LKR/kW/Month

Hence Capacity Charge (Rs/kVA)

= Capacity Charge (Rs/kW) / Av. Power Factor

= 2,448.14 LKR/kW/Month/0.88

= 2,781.98 LKR/kVA/Month

- Total capacity cost at 33kV voltage level

$$\textbf{Total Capacity cost at 33kv} = (\textbf{Generation} + \textbf{Transmission} + \textbf{BSOB})\ \textbf{costs at 33kV}$$

= 2,132,194.79 + 447,945.67 +406,357.37

= 2,986.50LKR/kW/Month

Hence Capacity Charge (Rs/kVA)

= Capacity Charge (Rs/kW) / Av. Power Factor

= 2,986.50LKR/kW/Month/0.88

= 3,393.75 LKR/kVA/Month

Proposed model for the calculation of capacity tariff component is annexed in Annexure II and summary of the Capacity costs calculated for Oct 2015 – Mar 2016 is as Table 4-1.

Table 4-1 Calculated capacity costs

Month	Capacity cost at 132kV (LKR/kW/Month)	Capacity cost at 33kV (LKR/kW/Month)
Oct-15	2,647.48	3,357.55
Nov-15	2,601.64	3,157.53
Dec-15	2,746.40	3,496.38
Jan-16	2,700.42	3,297.26
Feb-16	2,649.51	3,236.76
Mar-16	2,448.14	2,986.50

Hence the capacity tariff component at the 132kV voltage level for the period of Oct 2015 - April 2016 was calculated based on forecasted power factor at the 132kV voltage level.

	LKR/kW/Month	LKR/kVA/Month
Capacity cost at 132kV	2,632.26	2,991.21

2. Energy Component:

	BST for Oct 2015-March 2016 (LKR/kWh)	Proposed Tariff at 220kV /132kV	
		(LKR/kWh)	Loss *
Day	10.12	10.02	1.00%
Peak	13.06	12.93	1.00%
Off-peak	6.64	6.57	1.00%

Energy cost component is calculated by making loss adjustment to the bulk supply tariff prepared for each six month period. Above loss figures were assumed at the 132kv voltage level.

4.2 Analysis of Data - Proposed Methodology II (LRMC based Method)

1. Annual demand forecast for next ten years for two scenarios, base case and demand increment should be developed. Base case demand forecast is projected by using the actual demand of previous years and relevant economic factors while demand increased case is emphasizes on how the demand pattern is varies if higher demand is occurred over base case.

Table 4-2 Demand forecast for 10 years

Year	Capacity (MW)	
	Base Case	Demand Increment case
2013	2451	2451
2014	2692	2727
2015	2894	2970
2016	3017	3178
2017	3193	3392
2018	3383	3615
2019	3556	3846
2020	3731	4089
2021	3920	4345
2022	4125	4614
2023	4287	4898

Source: Long Term generation Plan 2013-2032

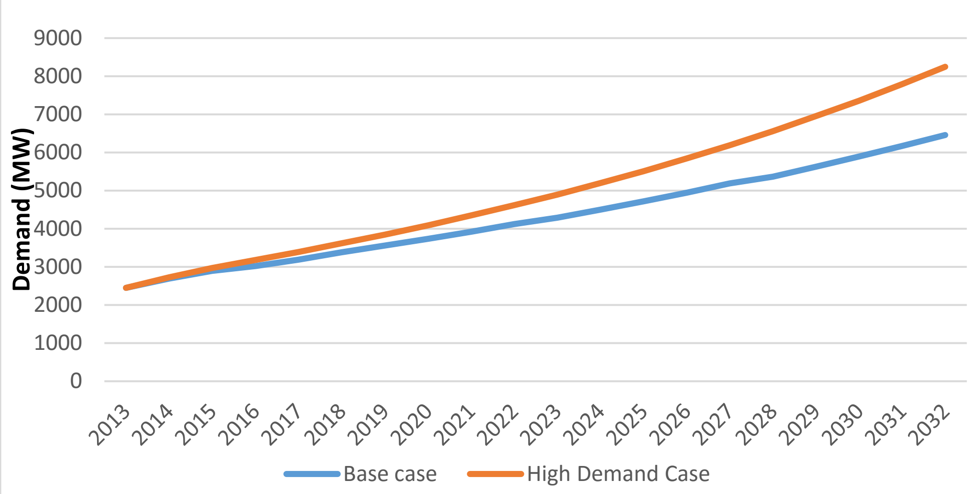

Figure 4-1 Demand forecast for Base case and Increased demand scenario

2. Calculation of capital expenditures and fixed operation and maintenance costs for the next ten years.(for both Base case and Demand increment case)

The Long term generation plan includes the schedule of new generation plant additions for the next ten years to cater the forecast demand in Based case and Incremental demand increased case. Total Capital expenditures for the building up and installation of new plants for the next ten years for the both cases were can be calculated and the fixed operation and maintenance costs can also be calculated for the same plant schedule with the net present values for the total schedule.

Table 4-3 Capex and Fixed O&M for Base case and Demand Increment case

Year	Capital Cost (million USD/Year)		O&M Cost (million USD/Year)	
	Base Case	Inc. Case	Base Case	Inc. Case
2013	11.70	17.10	27.63	28.13
2014	174.90	218.10	27.63	28.13
2015	372.80	447.36	28.79	29.29
2016	827.50	921.10	28.79	29.29
2017	640.30	888.60	29.43	29.93
2018	530.00	645.00	27.41	27.41
2019	562.80	597.30	27.54	31.21
2020	562.80	738.00	31.21	34.87
2021	562.80	883.60	34.87	38.54
2022	533.50	635.90	38.54	42.20
2023	415.40	498.48	41.75	49.08

In addition cost of energy not served and the cost of fuel saving is needed to be calculated but this was not calculated since the unavailability of data required and also these two components are considered as negligible.

3. Taking the net present value of generation capacity costs associated and the demands, calculated the long run marginal cost of generation capacity costs. Discount rate was considered as 10%.

Table 4-4 Total Annuitized costs of capital

Year	Capital Cost			O&M Cost			Total increase	Annuitized Cost
	Base Case	Inc. Case	Increase	Base Case	Inc. Case	Increase	million USD/Year	million USD/Year
2013	11.70	17.10	5.40	27.63	28.13	0.50	5.90	5.90
2014	174.90	218.10	43.20	27.63	28.13	0.50	43.70	39.73
2015	372.80	447.36	74.56	28.79	29.29	0.50	75.06	62.03
2016	827.50	921.10	93.60	28.79	29.29	0.50	94.10	70.70
2017	640.30	888.60	248.30	29.43	29.93	0.50	248.80	169.93
2018	530.00	645.00	115.00	27.41	27.41	0.00	115.00	71.41
2019	562.80	597.30	34.50	27.54	31.21	3.67	38.17	21.54
2020	562.80	738.00	175.20	31.21	34.87	3.67	178.87	91.79
2021	562.80	883.60	320.80	34.87	38.54	3.67	324.47	151.37
2022	533.50	635.90	102.40	38.54	42.20	3.67	106.07	44.98
2023	415.40	498.48	83.08	41.75	49.08	7.33	90.41	34.86
	5,194.50	***6,490.54***	***1,296.04***	***343.59***	***368.08***	***24.50***	***1,320.54***	***764.24***

Table 4-5 Net present value of the demand forecast

	Capacity (MW)			
	Base case	High Demand Case	Difference	Net Present value
2013	2451	2451	0	0.000
2014	2692	2727	35	31.818
2015	2894	2970	76	62.810
2016	3017	3178	161	120.962

2017	3193	3392	199	135.920
2018	3383	3615	232	144.054
2019	3556	3846	290	163.697
2020	3731	4089	358	183.711
2021	3920	4345	425	198.266
2022	4125	4614	489	207.384
2023	4287	4898	611	235.567
			2,876.00	***1,484.19***

5. Calculation of Long run marginal cost of generation,

$$\mathbf{LRMC} = \frac{\begin{array}{c}\textbf{Present Value }(\textbf{optimal capex plus opex}(\textbf{demand increased case}) - \\ \textbf{optimal capex plus opex}(\textbf{based case scenario}))\end{array}}{\textbf{Present Value}(\textbf{inceased demand} - \textbf{base case demand})}$$

= (764.24/ 1484.19) Million USD/MW/Year

= 514 Million USD/kW/Year

= 6307.76 LKR/kW/Month*

*Used exchange rate as 147LKR/USD

- Generation capacity cost at 132kV and 33kV voltage level

  Long run marginal cost of generation calculated in above step 5 is the cost at the generation level, hence it was adjusted by assuming the transmission loss at respective voltage levels.

  Long run marginal cost of generation at 132kV voltage level:

  = 6,436.49 LKR/kW/Month

  Long run marginal cost of generation at 33 kV voltage level:

  = 6,502.33 LKR/kW/Month

4. Calculation of Long run incremental cost of transmission

This is based on the Long term transmission development plan for the 2013-2022 and investment and implementation plan is as below.

Table 4-6 Investment plan for long term transmission development

Year	Investment Costs (million LKR)			
	Transmission Developments	Power Plant Connections	Discounted Transmission Developments	Discounted Power Plant Connections
2013	21,248	1,682	21,248	1,682
2014	13,122	6,094	11,929	5,540
2015	34,516	1,613	28,525	1,333
2016	64,859	3,042	48,729	2,286
2017	17,515	9,802	11,963	6,695
2018	2,806	4,527	1,743	2,811
2019	4,773	10,955	2,694	6,184
2020	2,353	3,017	1,207	1,548
2021	4,054	5,083	1,891	2,371
2022	568	726	241	308
			130,170	30,758

Source: Long term Transmission Development Plan 2013-2022

The total transmission system development cost shall be allocated to the customers in different voltage level base on the asset share of each voltage level. This also based on the asset database annexed in annexure I.

Total cost of transmission capacity at 132kV/220kV

= (130,170+30,758)*0.40 million LKR/Year

= 64,371.20 million LKR/year

Total cost of transmission capacity at 33kV

= (130,170+30,758)*0.60 million LKR/Year

= 96,556.80 million LKR/year

5. Calculation of demand increment.

Table 4-7 Demand Increment

Year	Base case (MW)	High Demand Case (MW)	Difference	PV*
2013	2451	2451	0	0.000
2014	2692	2727	35	31.818
2015	2894	2970	76	62.810
2016	3017	3178	161	120.962
2017	3193	3392	199	135.920
2018	3383	3615	232	144.054
2019	3556	3846	290	163.697
2020	3731	4089	358	183.711
2021	3920	4345	425	198.266
2022	4125	4614	489	207.384
2023	4287	4898	611	235.567
				1484.188

*Annuity factor was taken as 10%

Demand increment = 1,484 MW

6. So that increment cost of Transmission,

Incremental cost of Transmission at 132kV voltage level,

$$\textbf{Long run incremental cost of Transmission} = \frac{\textbf{Present Value (Transmission capacity investment at 132kV voltage level)}}{\textbf{Present Value(additional demand served)}}$$

= 64,371.20 million LKR / (1,484*(1-0.02)) MW

= 3,688.51 LKR/kW/Month

Incremental cost of Transmission at 33kV voltage level,

$$\textbf{Long run incremental cost of Transmission} = \frac{\textbf{Present Value (Transmission capacity investment at 33kV voltage level)}}{\textbf{Present Value(additional demand served)}}$$

= 96,556.80 million LKR/ (1,484*(1-0.01)) MW

= 5,476.87 LKR/kW/Month

7. Total capacity cost component is the sum of Long run marginal cost of generation investment cost and the Transmission capacity increment cost.

So, Total Capacity component at 132kV

= 6,436.49 +3,688.51 LKR/kW/Month

= 10,124.99LKR/kW/Month

= 11,505.67LKR/kVA/Month*

Total Capacity component at 33kV

= 6,502.33 +5,476.87 LKR/KW/Month

= 11,979.20 LKR/kW/Month

= 13,612.73 LKR/kVA/Month*

*Based on the calculated power factor at 132kV voltage level

8. Calculation of Long run marginal cost of energy

Ranking of power plants were based on highest to least expensive cost of generation. When calculating the generation cost of each plant, heat rate was taken as per the agreed values 2016 and existing fuel price were taken.

Table 4-8 Calculated cost of generation in generation stations

Power Plant	Cost at 132kV Level Rs./kWh	Rank based on Least expensive Gen cost
GT OLD	60.80	1
Gas Turbine 75MW	33.61	2
Gas turbine 105 MW	33.52	3
Sapu Old	24.82	4
Asia Power	24.31	5
Embilipitiya	23.79	6
Nothern Power	24.51	7
GTNEW	23.41	8
BARGE	22.67	9
Sapu Ext.	22.30	10
UthuruJanani	22.10	11
Dendro	21.48	12

Heladhanavi	20.76	13
Kerawalapitiya CC	19.23	14
KPS-JBIC	17.65	15
AES CCP	17.19	16
Lakvijaya	6.79	17
Coal 300 MW	6.41	18
Coal Trinco	6.04	19

Based on the dispatch schedule of the Base case scenario in the Long Term Generation Plan 2013-2032, plant factors of the each plant over the period of analysis was calculated.

$$\text{Plant factor} = \frac{\text{Actual energy generated in particular powerplant in Year i}}{\text{potential energy generation in particular power plant in Year i}}$$

Average cost of energy was calculated based on the availability factors of each plant over the year. Calculated plant factors and coefficients of availability are as follows.

Table 4-9 Calculated Plant Factors

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
No. days in the Year	*365*	*365*	*365*	*365*	*365*	*365*	*365*	*365*	*365*	*365*	*365*	*365*
GT OLD	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Turbine 75MW	0.00	0.00	0.22	0.22	0.24	0.09	0.06	0.05	0.03	0.01	0.02	0.01
Gas turbine 105 MW	0.00	0.00	0.12	0.12	0.28	0.10	0.09	0.06	0.04	0.02	0.03	0.01
Sapu Old	0.72	0.67	0.72	0.72	0.73	0.49	0.00	0.00	0.00	0.00	0.00	0.00
Asia Power	0.76	0.66	0.76	0.76	0.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Embilipitiya	0.79	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nothern Power	0.00	0.55	0.58	0.58	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GTNEW	0.25	0.23	0.26	0.25	0.29	0.11	0.08	0.05	0.02	0.01	0.00	0.00
BARGE	0.80	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sapu Ext.	0.78	0.77	0.77	0.77	0.78	0.56	0.49	0.38	0.25	0.15	0.06	0.04
UthuruJanani	0.00	0.87	0.87	0.87	0.87	0.72	0.67	0.52	0.44	0.31	0.20	0.15
Dendro	0.08	0.15	0.23	0.31	0.39	0.40	0.43	0.38	0.37	0.34	0.26	0.24
Heladhanavi	0.79	0.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kerawalapitiya CC	0.49	0.35	0.43	0.48	0.48	0.25	0.21	0.16	0.13	0.08	0.06	0.05
KPS-JBIC	0.32	0.27	0.34	0.36	0.44	0.17	0.16	0.09	0.07	0.04	0.04	0.02
AES CCP	0.27	0.21	0.29	0.32	0.37	0.16	0.14	0.08	0.05	0.04	0.00	0.00
Lakvijaya	0.23	0.44	0.69	0.69	0.70	0.60	0.57	0.57	0.58	0.58	0.59	0.60
Coal 300 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.28	0.42	0.54	0.66
Coal Trinco	0.00	0.00	0.00	0.00	0.00	0.62	0.82	0.83	0.84	0.84	0.85	0.86

Table 4-10 Calculated figures of fraction of availability time in the margin

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
GT OLD	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gas Turbine 75MW	0.00	0.00	0.22	0.21	0.23	0.09	0.06	0.05	0.03	0.01	0.02	0.01
Gas turbine 105 MW	0.00	0.00	0.00	0.00	0.04	0.01	0.02	0.01	0.01	0.01	0.01	0.00
Sapu Old	0.71	0.67	0.50	0.50	0.45	0.39	0.00	0.00	0.00	0.00	0.00	0.00
Asia Power	0.04	0.00	0.04	0.04	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Embilipitiya	0.03	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Nothern Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GTNEW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
BARGE	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sapu Ext.	0.00	0.00	0.01	0.01	0.00	0.07	0.41	0.32	0.21	0.13	0.03	0.03
UthuruJanani	0.00	0.08	0.10	0.10	0.09	0.16	0.17	0.14	0.20	0.16	0.15	0.11
Dendro	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.06	0.09
Heladhanavi	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Kerawalapitiya CC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
KPS-JBIC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AES CCP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lakvijaya	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.13	0.24	0.33	0.36
Coal 300 MW	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06
Coal Trinco	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.26	0.26	0.26	0.26	0.20

Figure 4-2 shows the most expensive power plants operate in the margin in a particular year (2016).

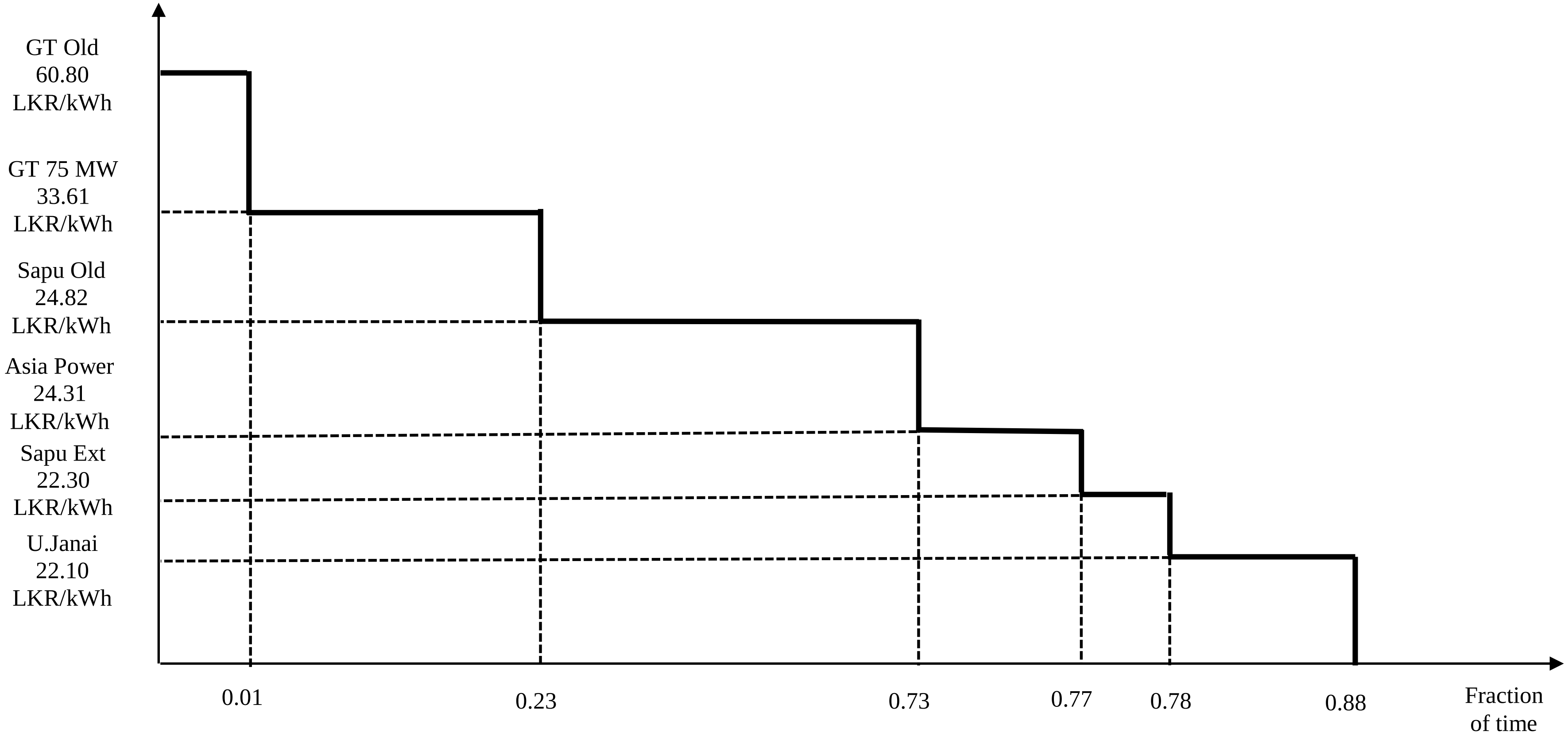

Figure 4-2 Power plants operated in Margin

Table 4-11 Calculated average cost of energy

Year	Average Energy Cost (LKR/kWh)
2013	20.03
2014	21.49
2015	23.36
2016	23.46
2017	24.11
2018	18.08
2019	16.68
2020	14.17
2021	12.76
2022	11.01
2023	9.82

Table 4-12 Summary of the calculated TOU Energy price

Year	LKR/kWh		
	Day	Peak	off-peak
2013	19.92	24.89	14.94
2014	21.37	26.71	16.03
2015	23.23	29.04	17.43
2016	23.33	29.16	17.50
2017	23.98	29.97	17.98
2018	17.98	22.47	13.48
2019	16.59	20.74	12.44
2020	14.09	17.62	10.57
2021	12.69	15.86	9.51
2022	10.94	13.68	8.21
2023	9.77	12.21	7.32
2024	9.34	11.67	7.00

Time of use energy price calculation is annexed in Annexure III. Block factors of Day, Peak and Off-peak are based on actual percentages of time of energy use in previous months in Sri Lanka. Energy cost at 132kV and 33kV voltage levels is adjusted with the transmission energy loss at each voltage level.

Table 4-13 TOU Energy cost at 132kV voltage level

Year	LKR/kWh		
	Day	Peak	Off-peak
2013	20.12	25.15	15.09
2014	21.58	26.98	16.19
2015	23.47	29.34	17.60
2016	23.57	29.46	17.68
2017	24.22	30.28	18.17
2018	18.16	22.70	13.62
2019	16.76	20.94	12.57
2020	14.24	17.80	10.68
2021	12.81	16.02	9.61
2022	11.06	13.82	8.29
2023	9.87	12.33	7.40
2024	9.43	11.79	7.07

4.3 Analysis of Data - Proposed Methodology III (Composite cost based Method)

1. Calculation of increment of transmission capacity cost

This is same as calculation of increment cost of transmission in previous Long run marginal cost based method. Investment costs are as per the Long term Transmission Development plan 2013-2022. Reference year was considered as 2013. Demand increment is also same as the Table 4-7.

Table 4-14 Investment Plan forTransmission development

Year	Investment Costs (million LKR)			
	Transmission Developments	Power Plant Connections	Discounted Transmission Developments	Discounted Power Plant Connections
2013	21,248	1,682	21,248	1,682
2014	13,122	6,094	11,929	5,540
2015	34,516	1,613	28,525	1,333
2016	64,859	3,042	48,729	2,286
2017	17,515	9,802	11,963	6,695
2018	2,806	4,527	1,743	2,811
2019	4,773	10,955	2,694	6,184
2020	2,353	3,017	1,207	1,548
2021	4,054	5,083	1,891	2,371
2022	568	726	241	308
			130,170	30,758

Source: Transmission Development Plan 2013-2022

Long run incremental cost of Transmission

$$= \frac{\textbf{Present Value (Transmission capacity investment at 132kV voltage level)}}{\textbf{Present Value(additional demand served)}}$$

= 64,371.20 million LKR/ (1,484*(1-0.02)) MW

= 3,688.51 LKR/kW/Month

Transmission incremental cost at 132kV

= 3,688.51 LKR/kW/Month

Transmission incremental cost at 33kV

= 5,476.86 LKR/kW/Month

2. Calculation of fixed operation and maintenance cost of existing transmission network.

   This is as per the data assed in tariff filling 2016-2020.

Table 4-15 Operational expenses for fixed assets in Transmission System

Year	O&M Expenses	PV of fixed O&M	Peak demand Forecast (MW)	PV
	million LKR	million LKR		Demand
2015	2,450	2450	2192	2192
2016	2,573	2339	2281	2073
2017	2,701	2233	2428	2006
2018	3,058	2298	2582	1940
2019	3,211	2193	2746	1875
2020	3,372	2094	2920	1813
		13,607		11,900

$$\textbf{Total fixed operation cost of transmission} = \frac{\textbf{PV}(\textbf{forecast cost of o}\&M\ fixed\ assets\ n\ Transmission)}{\textbf{Total demand over considered period}}$$

= ((13,607*1000)/11,900)/12 LKR/kW/Month

= 95.29 LKR/kW/Month

3. Calculation of Total Transmission capacity cost,

Total Transmission capacity cost at 132kV voltage level,

$$\textbf{Total transmission capacity cost} = (\textbf{Transmission investmet cost at 132kV voltage level}) + (\textbf{Fixed O}\&M\ at\ 132kv\ voltage\ level\textbf{)}$$

= (3,688.51 + 95.29*0.40)LKR/kW/Month

= <u>3,726.62 LKR/kW/Month</u>

Similarly, Total Transmission capacity cost at 33kV voltage level,

= (5,476.87 + 95.29*0.60) LKR/kW/Month

= <u>5,534.04 LKR/kW/Month</u>

4. Calculation of Generation capacity cost

Calculation of generation capacity costs of each power plants based on the Agreed values 2016.

Plant	Unit	April 2016	May 2016	June 2016	July 2016	Aug 2016	Sep 2016
Mahaweli	LKR/Month	548,600,434	548,600,434	548,600,434	548,600,434	548,600,434	548,600,434
Laxapana	LKR/Month	301,847,055	301,847,055	301,847,055	301,847,055	301,847,055	301,847,055
Other Hydro	LKR/Month	228,898,137	228,898,137	228,898,137	228,898,137	228,898,137	228,898,137
GT Small	LKR/Month	53,821,858	53,821,858	53,821,858	53,821,858	53,821,858	53,821,858
Sapugaskanda OLD	LKR/Month	119,344,409	119,344,409	119,344,409	119,344,409	119,344,409	119,344,409
Sapugaskanda Ext	LKR/Month	134,262,460	134,262,460	134,262,460	134,262,460	134,262,460	134,262,460
Kelanitissa GT 7	LKR/Month	72,817,808	72,817,808	72,817,808	72,817,808	72,817,808	72,817,808
New Chunnakam	LKR/Month	60,199,167	60,199,167	60,199,167	60,199,167	60,199,167	60,199,167
Kelanitissa CCY	LKR/Month	185,905,392	185,905,392	185,905,392	185,905,392	185,905,392	185,905,392
Coal Puttlam	LKR/Month	1,523,438,383	1,523,438,383	1,523,438,383	1,523,438,383	1,523,438,383	1,523,438,383
Barge	LKR/Month	70,970,750	70,970,750	70,970,750	70,970,750	70,970,750	70,970,750
AES Kelanitissa	LKR/Month	45,033,841	45,033,841	45,033,841	45,033,841	45,033,841	45,033,841
Asia Power	LKR/Month	169,180,461	169,180,461	169,180,461	169,180,461	169,180,461	169,180,461
West Coast	LKR/Month	729,041,954	729,041,954	729,041,954	729,041,954	729,041,954	729,041,954
Nothern Power	LKR/Month	74,414,001	74,414,001	74,414,001	74,414,001	74,414,001	74,414,001
TOTAL	**LKR/Month**	4,317,776,111	4,317,776,111	4,317,776,111	4,317,776,111	4,317,776,111	4,317,776,111

Coincident peak forecast (MW)	2,109	2,068	1,878	1,929	1,912	1,942
LKR/MW/Month	2,047,523	2,088,362	2,298,903	2,238,749	2,258,727	2,223,916
LKR/kW/Month	2,048	2,088	2,299	2,239	2,259	2,224

At 132kV						
LKR/kW/Month	2,089.31	2,130.98	2,345.82	2,284.44	2,304.82	2,269.30
At 33kV						
LKR/kW/Month	2,068.20	2,109.46	2,322.12	2,261.36	2,281.54	2,246.38

- Total capacity cost at 132kV voltage level

Total Capacity cost	=	Total Transmission Capacity cost + Generation Capacity Cost
	=	3,766.22 LKR/kW/Month +2,237.45 LKR/kW/Month
	=	5,964.07 LKR/kW/Month
	=	6,777.35 LKR/kVA/Month

- Total capacity cost at 33kV voltage level

Total Capacity cost	=	Total Transmission Capacity cost + Generation Capacity Cost
	=	5,534.04 LKR/kW/Month +2,214.85 LKR/kW/Month
	=	7,748.89 LKR/kW/Month
	=	8,805.55 LKR/kVA/Month

5. Calculation of Energy cost

Energy cost calculation is each power plant is based on the Terms and conditions for Delivery and acceptance of Electricity between Generation division and Transmission Division CEB- 2010 Oct. Present fuel prices were applied. Generation costs of IPP are based on PPA.

Table 4-16 Energy Cost of Generation

Plant\Month	Unit	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
GT Small	GWh	0.00	0.00	0.00	0.00	0.00	0.00
	LKR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
Sapugaskanda Old	GWh	0.00	0.00	0.00	0.00	0.00	0.00
	LKR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
Sapugaskanda Ext	GWh	36.94	38.17	35.57	0.00	0.00	0.00
	LKR/kWh	18.78	18.87	18.91	0.00	0.00	0.00
Kelanitissa GT 7	GWh	0.00	0.00	0.00	0.00	0.00	0.00
	LKR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
New Chunnakam	GWh	14.69	14.42	1.13	11.06	1.26	6.15
	LKR/kWh	20.61	20.65	44.54	21.27	41.86	23.38
Kelanitissa CCY	GWh	84.50	86.88	0.00	50.38	0.00	0.00
	LKR/kWh	21.27	21.25	0.00	22.05	0.00	0.00
Coal Puttlam	GWh	509.13	350.74	509.55	516.74	490.73	337.20
	LKR/kWh	5.97	6.14	5.96	5.96	5.98	6.17
Barge	GWh	0.00	0.00	0.42	0.48	1.06	1.01
	LKR/kWh	0.00	0.00	0.00	65.88	41.27	42.28
AES Kelanitissa	GWh	88.02	100.27	0.00	3.40	9.10	48.95
	LKR/kWh	21.19	21.18	0.00	24.03	22.03	21.11
Asia Power	GWh	0.00	0.00	0.00	0.00	0.00	0.00
	LKR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
West Coast	GWh	99.18	40.97	0.00	0.00	0.00	18.10
	LKR/kWh	24.98	25.37	0.00	0.00	0.00	26.35
Nothern Power	GWh	0.00	0.00	0.00	0.00	0.00	0.00
	LKR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
RENW	GWh	34.00	30.00	34.00	22.00	24.00	24.00
	LKR/kWh	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL generated energy	**GWh**	**866.46**	**661.45**	**580.67**	**604.06**	**526.15**	**435.41**

Average energy cost calculated and the TOU energy calculated are as Table 4-17.

Table 4-17 Average Energy Cost of generation

	Unit	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
Generation Energy cost	LKR/kWh	11.74	12.37	6.48	7.51	6.14	8.67

Time of use energy cost calculated at 132kV voltage level is as Table 4-18.

Table 4-18 Time of Use Energy Cost of generation

	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16
Day (LKR/kWh)	11.79	12.43	6.50	7.55	6.17	8.71
Peak(LKR/kWh)	14.74	15.53	8.13	9.44	7.71	10.89
Off-peak(LKR/kWh)	8.85	9.32	4.88	5.66	4.63	6.53

4.4 Discussion

Three methodologies were analyzed to calculate the transmission tariff for Sri Lankan electricity sector. All methodologies proposed have two tariff components of capacity and energy. When allocating the cost among customers and taking their allocation, the voltage level they are connected shall be considered. When considering the customers connected to the transmission system in SL, only one customer is connected in 220kV voltage level, four customers are connected in 132kV voltage level while the five distribution Licensees are connected in 33kV voltage level. Since the difference of the cost allocation in 132kV and 220kV is minimum, it was decided that this voltage levels to consider as similar. Hence only one tariff is proposed to both 132kV and 220kV voltage levels.

Table 4-19 and Figure 4-3, 4-4summarizes the calculated tariff in different methodologies and the tariff imposed presently for the Transmission customers.

Table 4-19 Summary of Calculated Tariff

	Embedded Cost Based Method	**Marginal Cost Based Method**	**Composite Method**	**I3 tariff (Present)**
	LKR/kVA/Month			
Capacity Charge	2,991.20	11,505.67	6,777.35	1000.00

Energy Charge	LKR/kWh			
Day	10.02	23.57	8.86	10.25
Peak	12.93	29.46	11.07	23.50
off-peak	6.57	17.68	6.64	5.90

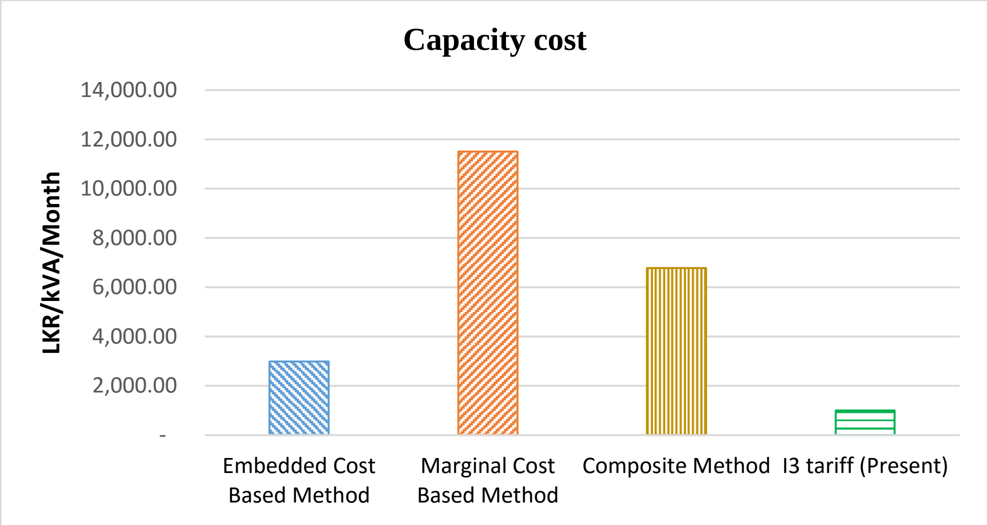

Figure 4-3 Summary of Capacity Tariff component

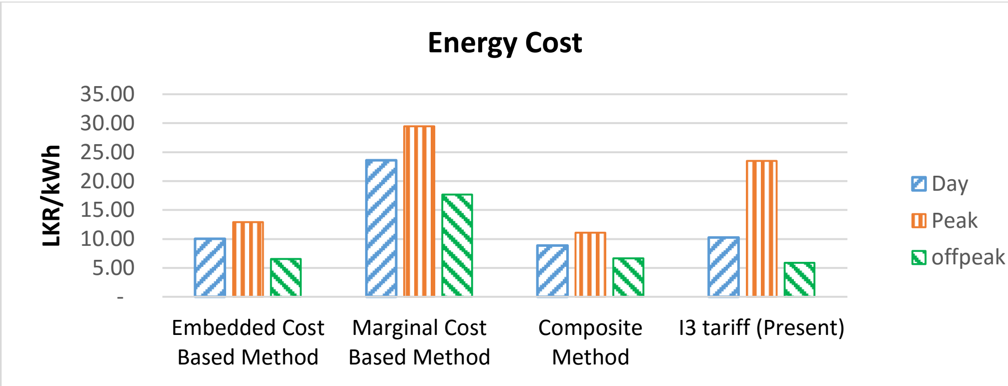

Figure 4-4 Summary of Energy Tariff component

Considering the capacity component of the proposed tariffs, marginal cost based tariff is the highest while the embedded based method has the lowest. Considering the energy component, composite method has the lowest tariff and marginal based tariff has the highest.

Finally the propose methodology for the transmission customer should entertain both the customer and the utility. From the utility point of view, it shall ensure at least the present revenue earned from the presently imposed tariff and shall recover its cost of service, while the customer point of view; new tariff shall not be very high. In addition, new tariff should be able to implement in the present system without any complexity.

With this background, marginal cost based method cannot be accepted as the both component of this tariff is high. Considering the embedded cost based and the composite methods, embedded cost based method ensures the recovery of historic cost as well as the future cost. Further it ensures that implementation of this method does not make complex the tariff preparation process of the Bulk Supply tariff. So that it's easy to implement within the presently practicing framework. So that embedded cost based method is recommended for the calculation of the Tariff for Transmission customers. Although the capacity component of the tariff for Bulk Supply customers (Distribution Licensees) is imposed over system coincident peak demand, it's recommended to impose the same for maximum demand for other Transmission customers. This is calculated and summarized in the section of 4.1.

Figure 4-5 and 4-6 show the difference of the revenue collection for the utility in proposed tariff and existing tariff.

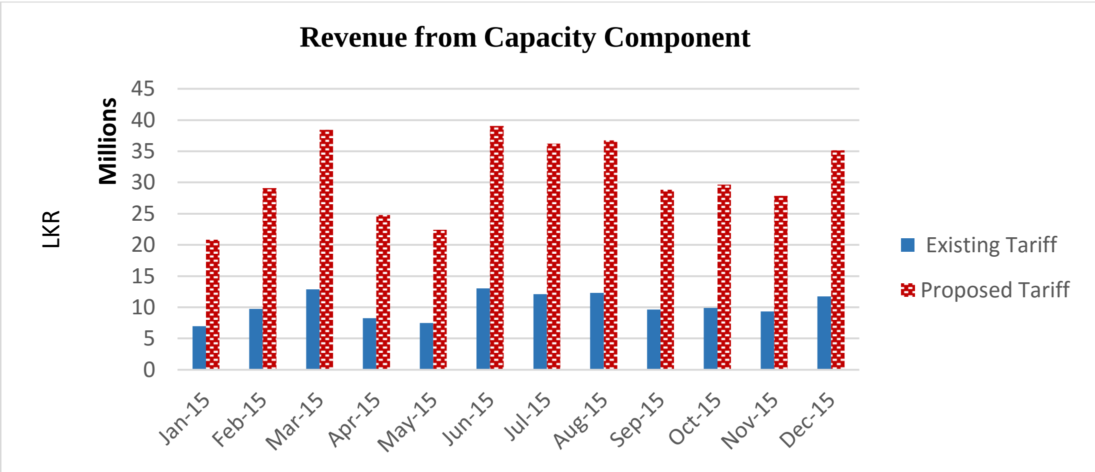

Figure 4-5 Comparison of Capacity tariff component

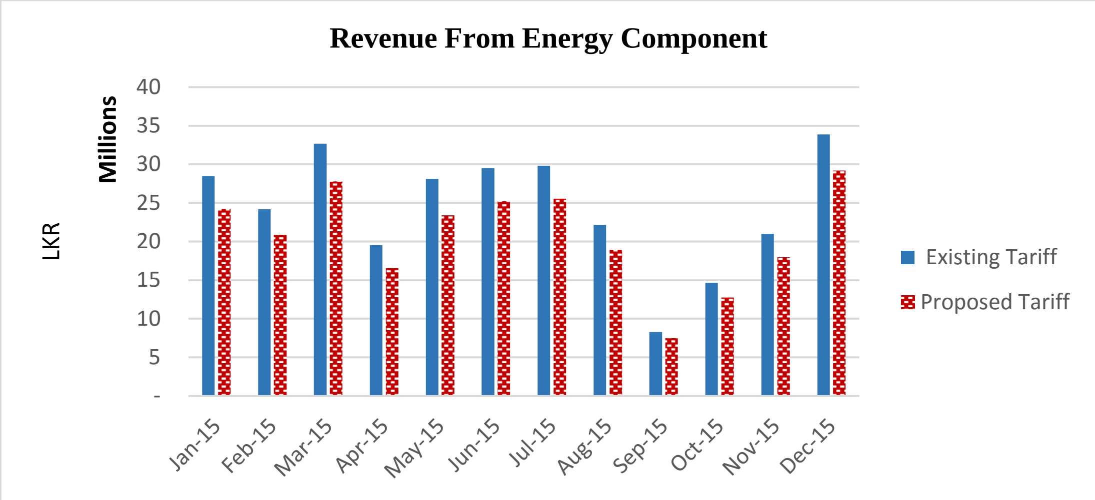

Figure 4-6 Comparison of Energy Tariff Component

This reveals that although the revenue from the energy component is reduced with the proposed tariff, the revenue from the capacity tariff is increased to the utility.

CHAPTER 5

5. CONCLUSION

Cost reflective tariff methodology signals the actual cost of developing and maintaining the power system while diminishing the risk of market operation. The research mainly focused on the study and analyzes the transmission pricing methodologies practicing in various power market models in the world and finally proposes a suitable methodology for the Sri Lanka power system. A study reveals that the common principal of almost all pricing methodologies are based on the cost recovery option. The key step of such methodologies is to clearly find out all the costs associate with the operation and maintenance of the network and enhancing the network services and allocation of the identified cost to the customers. When it comes to the customers connected in different voltage levels, it has to be considered the transmission loss factors too.

The research carried out studies on the transmission pricing methodologies, (i) embedded cost based, (ii) marginal cost based and (iii) composite cost based methodologies, and describes the real time transmission pricing methodologies applying in West Africa Power Pool, National Energy Market in Australia and Northern Ireland which operates in a competitive wholesale market model, and Thailand which operates in single buyer market model. Three main transmission pricing methodologies were analyzed while identifying cost components in each methodology relates to the Sri Lanka power system. Further the pricing models with respective to each methodology were developed and transmission tariff components were calculated, obtained results as in Table 4-19. Marginal/Incremental and Composite cost based pricing methodology options which are based on future expansion cost in determining transmission service prices results high capacity charges compared to the existing tariff. Marginal energy charges are the highest among three options calculated. Most suitable transmission tariff methodology was selected based on criteria that the tariff should be able to recover the costs of existing system and future expansions while not imposing additional burden to its customers

Analysis of data based on criteria above, the most appropriate methodology for calculation the transmission tariff for Sri Lanka is the embedded cost based method. According to the calculations, the tariff components are as Table 5-1.

Table 5-1 Proposed tariff components

	Proposed Methodology - Embedded Cost Based Method
	LKR/kVA/Month
Capacity Charge	2,991.20
Energy Charge	LKR/kWh
Day	10.02
Peak	12.93
Off-peak	6.57

Further analyses showed that in the year of 2015, the utility Ceylon Electricity Board had the total revenue of million LKR 415.66 while this would be increased to million LKR 618.97 if the proposed tariff was charged.

5.1 Recommendations

Proposed tariff methodology is using the transmission loss factors at 132kV/220kV and 33kV voltage levels based on assumptions. So a further study is needed to be done to figure out the actual transmission loss applied in different voltage levels. In addition energy component of the tariff is calculated based on forecast generation schedule and this shall be reconciled based on actual generation at each consecutive tariff period and adjusted.

5.2 Study Limitation and Suggestions for Future work

Time of use energy tariff in marginal/increment pricing methodology in 4.2 was calculated based on the power plants operated in the margin in each year of the period of analysis but without considering the power plants operated in the time period of the day (Day, Peak, Off-peak). So it’s recommended to calculate time of use marginal energy prices by considering power plants operated at margin of the day in each time interval of the day.

Further suggests proposing a cost reflective retail by studying principles of pricing for retail tariffs and retail tariff methodologies in different power market structures in the world.

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Appendix I: Estimation of asset shares in different voltage levels.

	Life-time	2015 Gross value million LKR	2015 Acc. Dep	2015 Net value	Asset allocation factors 220kV	Asset allocation factors 132kV	Asset allocation factors 33kV	Asset allocation factors Sum	Cost of Assets 220kV	Cost of Assets 132kV	Cost of Assets 33kV	Cost of Assets Sum
Buildings & land		**1,621**	**402**	**1,218**					**122**	**366**	**731**	**1218**
Land	N/A	66		66	10%	30%	60%	100%	7	20	40	66
Buildings	30	891	156	735	10%	30%	60%	100%	74	221	441	735
Civil structures	30	663	246	417	10%	30%	60%	100%	42	125	250	417
Network Switching & Operation		**5,830**	**1,168**	**4,662**					**875**	**1100**	**2687**	**4662**
Civil structures	30	1,224	245	978	20%	30%	50%	100%	196	294	489	978
220 kV lines	30	850	170	679	100%	0%	0%	100%	679	0	0	679
132 kV lines	30	773	155	618	0%	100%	0%	100%	0	618	0	618
33 kV lines	30	636	127	508	0%	0%	100%	100%	0	0	508	508
Substations (including all Transformers, switching & control equipment)	30	2,345	470	1,875	0%	10%	90%	100%	0	188	1688	1875
Meters & Communication Equip	10	2	0	2	10%	30%	60%	100%	0	1	1	2

Vehicles			**230**	**134**	**96**						**10**	**29**	**58**	**96**
	Heavy vehicles	10	230	134	96	10%	30%	60%	100%		10	29	58	96
	Light vehicles	10	-	-	-	10%	30%	60%	100%		0	0	0	0
Office equipment			**649**	**340**	**309**						**31**	**93**	**186**	**309**
	Computers & accessories	6.7	239	125	114	10%	30%	60%	100%		11	34	68	114
	Printers	6.7	-	-	-	10%	30%	60%	100%		0	0	0	0
	Photocopiers	6.7	-	-	-	10%	30%	60%	100%		0	0	0	0
	Overhead projectors	6.7	-	-	-	10%	30%	60%	100%		0	0	0	0
	Software	5	188	98	90	10%	30%	60%	100%		9	27	54	90
	Telecoms	10	139	73	66	10%	30%	60%	100%		7	20	40	66
	Other office equipment	10	39	21	19	10%	30%	60%	100%		2	6	11	19
	Furniture & fixtures	10	44	23	21	10%	30%	60%	100%		2	6	12	21
Tools			**173**	**90**	**82**						**8**	**25**	**49**	**82**
	Tools	10	136	71	65	10%	30%	60%	100%		6	19	39	65
	Electrical equipment	10	37	19	18	10%	30%	60%	100%		2	5	11	18
TOTAL			**8,502**	**2,135**	**6,368**						**1046**	**1612**	**3710**	**6368**

Appendix II: Proposed model of tariff calculation for the embedded cost based method

			Loss %	Oct-15 MW	Nov-15 MW	Dec-15 MW	Jan-16 MW	Feb-16 MW	Mar-16 MW
Generation				1,981.20	1,923.41	1,911.72	2,101.40	2,119.41	2,314.84
Transmission	at 132 kV/220kV			1,981.20	1,923.41	1,911.72	2,101.40	2,119.41	2,314.84
		132kV loss	2.0%	39.62	38.47	38.23	42.03	42.39	46.30
		input to 132kV		1,941.58	1,884.94	1,873.48	2,059.37	2,077.02	2,268.55
		consumption		8.87	8.35	10.72	6.23	8.71	11.53
	33kV	input to 33kV		1,932.70	1,876.59	1,862.77	2,053.14	2,068.31	2,257.01
		tr loss	1.0%	19.33	18.77	18.63	20.53	20.68	22.57
				1,913.38	1,857.83	1,844.14	2,032.61	2,047.63	2,234.44

Oct-15

	Allocation of Gen Cost		Allocation of Tr Cost		Allocation of BSOB		Total Cost
	LKR/Month	LKR/MW	LKR	LKR/MW	LKR	LKR/MW	LKR/MW
Generation	4,268,638,106.31	2,154,570.83					
Transmission							
Cost at 220/132 kV		2,198,541.66	292,026,489.72	150,406.85	579,621,739.13	298,531.41	**2,647,479.92**
			290,691,929.76		576,972,869.95		
			438,039,734.58		869,432,608.70		
Cost at 33kV	4,249,130,446.12	2,220,749.16	728,731,664.34	380,861.51	1,446,405,478.65	755,943.78	**3,357,554.45**

Nov-15

	Allocation of Gen Cost LKR/Month	LKR/MW	Allocation of Tr Cost LKR	LKR/MW	Allocation of BSOB LKR	LKR/MW	Total Cost LKR/MW
Generation	4,247,983,153.82	2,208,565.12					
Transmission							
Cost at 220/132 kV		2,253,637.88	292,026,489.72	154,925.75	363,933,102.50	193,073.61	**2,601,637.23**
			290,732,782.28		362,320,841.36		
			438,039,734.58		545,899,653.75		
Cost at 33kV	4,229,164,150.74	2,276,401.89	728,772,516.87	392,271.16	908,220,495.11	488,861.34	**3,157,534.40**

Dec-15

	Allocation of Gen Cost LKR/Month	LKR/MW	Allocation of Tr Cost LKR	LKR/MW	Allocation of BSOB LKR	LKR/MW	Total Cost LKR/MW
Generation	4,273,678,106.31	2,235,517.26					
Transmission							
Cost at 220/132 kV		2,281,140.07	292,026,489.72	155,873.54	579,621,739.13	309,381.83	**2,746,395.44**
			290,356,304.77		576,306,712.77		
			438,039,734.58		869,432,608.70		
Cost at 33kV	4,254,629,446.18	2,317,435.98	728,396,039.35	394,978.55	1,445,739,321.47	783,963.66	**3,496,378.19**

Jan-16

	Allocation of Gen Cost LKR/Month	LKR/MW	Allocation of Tr Cost LKR	LKR/MW	Allocation of BSOB LKR	LKR/MW	Total Cost LKR/MW
Generation	4,796,044,452.38	2,282,312.22					
Transmission							
Cost at 220/132 kV		2,328,890.02	401,179,526.68	194,806.99	363,933,102.50	176,720.67	**2,700,417.67**
			399,966,463.54		362,832,662.91		
			611,798,778.18		545,899,653.75		
Cost at 33kV	4,781,542,454.24	2,352,414.16	1,011,765,241.72	497,766.34	908,732,316.66	447,076.40	**3,297,256.89**

Feb-16

	Allocation of Gen Cost LKR/Month	LKR/MW	Allocation of Tr Cost LKR	LKR/MW	Allocation of BSOB LKR	LKR/MW	Total Cost LKR/MW
Generation	4,737,960,616.12	2,235,512.09					
Transmission							
Cost at 220/132 kV		2,281,134.79	401,179,526.68	193,151.58	363,933,102.50	175,218.95	**2,649,505.32**
			399,497,311.63		362,407,068.14		
			601,769,290.02		545,899,653.75		
Cost at 33kV	4,718,093,528.88	2,304,176.56	1,001,266,601.64	488,988.83	908,306,721.89	443,589.99	**3,236,755.37**

Mar-16

	Allocation of Gen Cost LKR/Month	LKR/MW	Allocation of Tr Cost LKR	LKR/MW	Allocation of BSOB LKR	LKR/MW	Total Cost LKR/MW
Generation	4,788,610,131.24	2,068,655.38					
Transmission							
Cost at 220/132 kV		2,110,872.84	401,179,526.68	176,844.42	363,933,102.50	160,425.78	**2,448,143.04**
			399,140,439.81		362,083,329.12		
			601,769,290.02		545,899,653.75		
Cost at 33kV	4,764,270,923.03	2,132,194.79	1,000,909,729.83	447,945.67	907,982,982.87	406,357.37	**2,986,497.82**

	LKR/MW/Month	*LKR/MVA/ Month*
Capacity cost at 132kV	2,632,263.10	2,991,208.07

Note: Capacity Cost is allocated for 132kV level based on the share of asset base.

Power loss - assumed

Appendix III: TOU Energy cost calculation for Composite based Method

	Annual Energy Generation (Thermal)						
	Unit	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**
	GWh	866	661	581	604	526	435

Average Generation Energy cost							
	Unit	**Apr-16**	**May-16**	**Jun-16**	**Jul-16**	**Aug-16**	**Sep-16**
Generation Energy cost	SLR/kWh	11.74	12.37	6.48	7.51	6.14	8.67

Apr-16				
Block	**Energy generated (GWh)**	**Block Factor**	**Adjusted Factor**	**Charge (LKR/kWh)**
Day	492.15	1.00	0.99	11.68
Peak	196.69	1.25	1.24	14.60
Offpeak	177.63	0.75	0.75	8.76
Total Average cost	Mn. LKR	10173.97		
Total Block cost	Mn. LKR	10173.97		
Difference	Mn. LKR	0.00		
Adjustment factor		0.99		

May-16				
Block	**Energy generated (GWh)**	**Block Factor**	**Adjusted Factor**	**Charge (LKR/kWh)**
Day	375.71	1.00	0.99	12.30
Peak	150.15	1.25	1.24	15.38
Offpeak	135.60	0.75	0.75	9.23
Total Average cost	Mn. LKR	8181.98		
Total Block cost	Mn. LKR	8181.98		
Difference	Mn. LKR	0.00		
Adjustment factor		0.99		

Jun-16				
Block	**Energy generated (GWh)**	**Block Factor**	**Adjusted Factor**	**Charge (LKR/kWh)**
Day	329.82	1.00	0.99	6.44
Peak	131.81	1.25	1.24	8.05
Off-peak	119.04	0.75	0.75	4.83

Total Average cost	Mn. LKR	3776.57
Total Block cost	Mn. LKR	3776.57
Difference	Mn. LKR	0.00
Adjustment factor		0.99

Jul-16				
Block	**Energy generated (GWh)**	**Block Factor**	**Adjusted Factor**	**Charge (LKR/kWh)**
Day	343.11	1.00	0.99	7.47
Peak	137.12	1.25	1.24	9.34
Off-peak	123.83	0.75	0.75	5.61

Total Average cost	Mn. LKR	4539.27
Total Block cost	Mn. LKR	4539.27
Difference	Mn. LKR	0.00
Adjustment factor		0.99

Aug-16				
Block	**Energy generated (GWh)**	**Block Factor**	**Adjusted Factor**	**Charge (LKR/kWh)**
Day	298.85	1.00	0.99	6.11
Peak	119.44	1.25	1.24	7.64
Offpeak	107.86	0.75	0.75	4.58
Total Average cost	Mn. LKR	3231.67		
Total Block cost	Mn. LKR	3231.67		
Difference	Mn. LKR	0.00		
Adjustment factor		0.99		

Sep-16				
Block	**Energy generated (GWh)**	**Block Factor**	**Adjusted Factor**	**Charge (LKR/kWh)**
Day	247.31	1.00	0.99	8.63
Peak	98.84	1.25	1.24	10.78
Offpeak	89.26	0.75	0.75	6.47
Total Average cost	Mn. LKR	3776.57		
Total Block cost	Mn. LKR	3776.57		
Difference	Mn. LKR	0.00		
Adjustment factor		0.99		