A Proposal for Transmission Pricing Methodology in Thailand Based on Exact Loss Contribution and Long-Run Average Incremental Cost

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ABSTRACT

In this paper, the transmission pricing methodology for bilateral transaction based on the exact loss contribution and long run average incremental cost (LRAIC) methodology in a New Electricity Supply Arrangement (NESA) of Thailand is proposed. The transmission pricing comprises the connection charges, the common service charge and the transmission use of system (TUOS) charges. The connection charges are intended to recover the costs of providing and maintaining connection assets by using capital recovery factor. The common service charge is charged for the approximation of metering costs such as billing and collection. The TUOS charges, based on LRAIC calculation for each voltage level, are used to recover all of transmission network expansion costs including the operational costs of using the grid and costs of losses.

The calculation of transmission loss for each voltage level could be obtained by multiplying the fixed percentage loss for each voltage level with the amount of energy transferred through the transmission system. For the TUOS charges, the users will be charged for the amounts of energy transferred including losses for each voltage level, which may not be fair to all users. Therefore, the exact energy and loss allocation for each transaction is proposed instead of using the fixed percentage loss methodology. To demonstrate its effectiveness, the transmission pricing methodology is applied to three simultaneous bilateral transactions located in different areas of the 424-bus Thai power system. Test results indicate that the proposed methodology can promote efficient utilization of the system, raise enough revenue for network expansion, and transparent to all users.

1. INTRODUCTION

The objective of restructuring of the Thailand's Electricity Supply Industry (ESI) is to improve efficiency, lower electricity price and tackle financial debts [1]. At present, the Thai ESI is vertically integrated. The plan is to introduce competition in generation and retailing sectors. In August 2002, the Energy Policy and Planning Office of Thailand (EPPO) proposed a New Electricity Supply Arrangement (NESA) for Thai's ESI [2, 3].

In 1999, PricewaterhouseCoopers (PwC) has proposed the transmission pricing based on long run average incremental cost (LRAIC) for EGAT Transmission Business Unit. This method can be used to recover the costs of transmission network expansion to meet future demand, and to raise the required revenue. However, the tariff is uniform using fixed percentage loss for each voltage level [4]. The calculation of transmission loss for each voltage level could be obtained by multiplying the fixed percentage loss for each voltage level with the amount of energy transferred through the transmission system. The users will be charged for the amounts of energy transferred including losses for each voltage level, which may not be fair to all users. In addition this pricing based on LRAIC does not provide the signal for siting generations and loads.

In 2001, Frontier Economics the international consultant for the Thailand Power Pool and ESI Reform-Phase 2, has suggested the alternative structure for transmission tariff comprising the connection charges and the use-of-system charges. The overall charges are used to recover all of the embedded, expansion, and operating and maintenance costs of transmission system [5]. Emphasizing on the use-of-system charges, several methods have been proposed such as the use-of-system pricing based on the National Uniform Tariff (NUT) as postage stamp method, the use-of-system pricing by sharing of network use as contract path method, and forward-looking use-of-system pricing as long run marginal cost method. Ultimately, the most favorable method will be selected depending on the objectives of the transmission tariff framework under the Thai ESI.

Recently, some comparisons of the transmission pricing methods proposed by PwC and Electricity Generating Authority of Thailand (EGAT) staff have been made [6]. They have suggested pricing structure consisting of the annual power fee and the transmission use of system charge. The transmission use of system charge is based on short run marginal cost (nodal pricing) which can recover approximately twenty percents of total revenue requirement while the rest can be recovered by the annual power fee. The annual zonal power fee is fixed charge rate based on the proportion of zonal generation and peak demand within a zone. Nevertheless, the pricing scheme is not efficiently sending the signal to all users in other zones.

In 2002, Limpasuwan *et al*. have developed the transmission pricing method by combining the electricity tracing with LRAIC [7]. The electricity tracing method is used to allocate the energy and loss to individual demand for each bus. The loss factor is determined by the ratio of energy loss during defined peak period by applying electricity tracing to load flow solutions and demand based on projected system condition that is used to calculate the transmission system usage cost of a particular demand. As a result, the transmission use of system charge can be allocated to that demand depending on the transmission system usage based on tracing. The results show that the pricing with electricity tracing method improves the charge allocation in terms of fairness, and reflects the geographical location and system conditions.

Meanwhile, they have proposed the new annual power fee based on electricity tracing for transmission pricing in Thai Power Pool [8]. It can be seen as a refinement of the crude fee based on the proportion of generation and demands within each zone in [6] because it takes into account how the zonal imbalance of generation and demand loads transmission facilities in other zones. In addition, the methodology combining zonal and nodal signals has proposed. Consequently, the annual power fee provides a right signal towards a balanced location of generation and demand within a zone.

In the proposed NESA system, there is a need to calculate the transmission charge for bilateral transactions. To send the correct signal in a fair manner, both the energy and loss should be exactly calculated. However, this is not generally the case [7, 9-14]. The problem addressed here is to determine actual energy and loss amount for each transaction toward improving economic efficiency.

In this paper, we propose a methodology for the exact energy and losses allocation and the tariff structure for bilateral transactions. The transmission pricing method based on exact loss contribution and LRAIC comprises the connection charges, the transmission charges and the common service charge. The exact energy and loss for each transaction can be calculated. The 424-bus Thai system is used to demonstrate with illustrative results.

The organization of this paper is as follows. Section 2 addresses the New Electricity Supply Arrangement (NESA) of Thailand. Section 3 presents the energy and exact loss allocation methodology for bilateral transactions in NESA. Section 4 proposes the transmission pricing methodology based on exact loss allocation and long run average incremental cost. Simulation results on EGAT system is given in Section 5. Lastly, conclusion is given.

2. THE NEW ELECTRICITY SUPPLY ARRANGEMENT (NESA) OF THAILAND

Since 2002, the EPPO has proposed the NESA system for Thai ESI. It is expected that under the new trading arrangement, the buyer and sellers are able to enter into bilateral contracts that are fully negotiated between two parties in order to achieve price stability and to ensure sufficient electricity supply. The NESA is designed to become more efficient and provide market participants more choices, while maintaining the operation of a secure and reliable electricity system. The trading proposals are based on bilateral trading between generators, suppliers, and customers. The trading arrangements include forward market, a real time balancing market, and a settlement process [3].

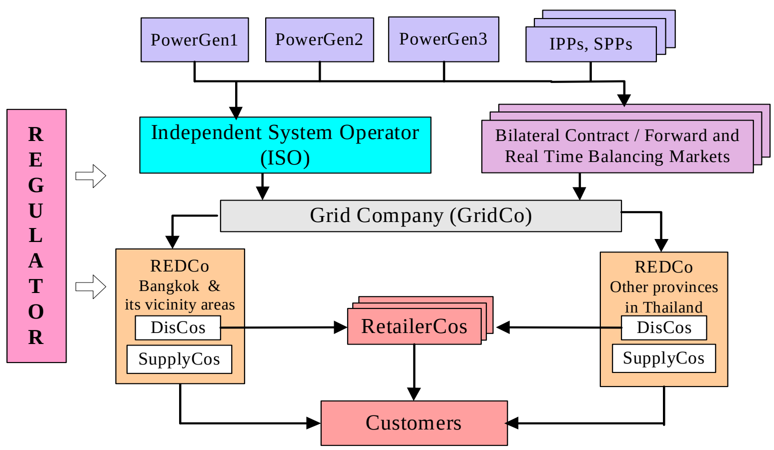

Fig. 1 The proposed structure of the NESA system for Thai ESI

2.1 Industry Structure

The NESA structure [2,3], see Fig. 1, encourages competition in the generation and distribution sectors, while the transmission system is to be managed as a monopoly entity. All participants will be regulated by the Independent Regulatory Body (IRB). EGAT who owns and operates the transmission grid and most of the generations, will be unbundled into competitive Generation Companies (GenCos) and the Grid Company (GridCo). GridCo, as a monopoly business, will be owned by a private transmission provider and will operate the high voltage transmission system, which in turn is controlled by an Independent System Operator (ISO). The ISO will be responsible for the transmission network with three main objectives: security maintenance, service quality assurance, and promotion of the economy efficiency and equity. GenCos will generate electricity and sell competitively to customers. The Independent Power Producers (IPPs) and Small Power Producers (SPPs) are private generation companies.

In the distribution sector, the Metropolitan Electricity Authority (MEA) and Provincial Electricity Authority (PEA) will be transformed into Regulated Electricity Delivery Electricity Companies (REDCos). Each REDCo consists of a Distribution Company (DisCo) and a Supply Company (SupplyCo). The DisCo owns and operates the low voltage distribution system while the SupplyCo's function is to sell the delivered energy to the small and captive customers. A RetailCo is an unregulated, competitive retailing entity that competes in selling electricity to large consumers and offers additional services such as price hedging and end use efficient.

2.2 Market Arrangement

Currently, large customers are instructed to buy their electricity from either MEA or PEA; they have no ability to plan or schedule their high energy usage toward ensuring stable supplies during particular industrial processes; and they are unable to "shop" for lower-priced energy because of price controls. With NESA's market mechanisms [2,3], IPPs and SPPs are encouraged to compete with GenCos in the generation and selling of electricity to the customers in the bilateral contract market. It provides more choices for the large customers to select their supplier under partial liberalization.

In NESA system, there is essentially no change for small customers who will continue to buy their electricity exclusively from SupplyCos as a package, including energy, network, and retail services; however, for large customers, the changes will be significant.

Prior to the real time operation, the quantity traded in the bilateral transactions will be requested to ISO so that transaction facilities for the relevant amounts of energy will be provided. If there is no static and dynamic transmission security violations, the ISO simply dispatches all requested transactions and charges for the transmission services.

Imbalances between contractual and physical positions of those buying and selling electrical energy will be taken care by balancing mechanism. Again, ISO will maintain the required system balances of generation and demand. Ultimately, the excess or shortage energy of both of generator and demand can be sold or bought to or from real time balancing market.

In NESA, once the energy for each transaction is transferred through the transmission network, the sellers and buyers will be charged by ISO for the transmission system usage. Therefore, ISO needs to know transaction quantities via the network, in order to fairly allocate an appropriate portion of their energy flow, losses and costs to that trade.

3. ENERGY AND LOSS ALLOCATION FOR BILATERAL TRANSACTION IN NESA

The bilateral contract is a long-term physical contract between participants for the purchase or sale of energy. The transmission energy and loss allocation for each transaction becomes the major concern for all market participants. It is possible to compute the energy and loss allocation corresponding to bilateral transaction.

3.1 Review of Transmission Loss Allocation

Several methods were used to compute the energy and losses for bilateral transactions. For example, load flow based loss allocation method [9-10] starts with a standard load flow program or state estimation program and traces specific component load flow on distribution system. The losses are allocated by apportion-sharing between different consumers at a given a location in with using evaluation of loss adjustment factors. However, this method has some disadvantages:

- Derived loss allocation results are dependent on the slack bus whenever the load flow program is called.
- It is only applicable to radial distribution networks, in which complicated loop flow and parallel flows do not exist.
- It always results in positive loss either for individual generator or load. It can not account for loss reduction; accordingly, no incentive can be obtained to reduce the loss.

Optimal power flow (OPF) based incremental loss evaluation methods [11,12] can be applied in the evaluation of incremental loss for each transaction in the transmission system, which is independent of slack bus. The concept accounts for the transaction injection charges of both sending and sinking buses. However, it has limitations:

- For simultaneous transactions, incremental losses scheme will encounter transaction-sequencing problem; calculated losses are highly sensitive to the ordering sequences of the transactions.
- The method will relocate all transaction costs including all existing transactions, which is time consuming.

The sensitivity factor based loss estimation method with two sensitivity factors for pricing transmission costs was proposed by Rudnick H. *et al.* 1995 [13]. The Generalized Generation Distribution Factor (GGDF) and Generalized Load Distribution Factor (GLDF), both depending on a standard load flow case, were presented to allocate transmission system losses and marginal operating costs of individual transaction. The sensitivity factors are computationally efficient.

In J.S. Calacton *et al*. 1999 [14], the Penalty Factors were introduced to evaluate the wheeling losses. By these methods with transposed power flow Jacobian matrix, the loss penalty factor can be readily worked out, while the distribution factors can be easily derived from constant nodal matrix (DC) and known operating point. However, they have some drawbacks:

- For a large transaction, derived estimation errors are unacceptable; then it needs more consideration on the adjustable and correctable scheme.
- Both of distribution factors and loss penalty factors are closely related to slack bus. Different choices for slack bus can lead to different wheeling loss allocation.

Recently, for the simultaneous bilateral transactions under the deregulation environment, the Loss Distribution Based Power Flow method was proposed to calculate the transmission losses and costs for each transaction pair [15]. This approach achieves fair allocation of loss independent of slack bus selection. For example, real and reactive power can be easily allocated. Moreover, both positive and negative losses can be accounted for, leading to economic efficiency.

3.2 Methodology

To allocate transmission energy and losses for bilateral transactions, an algorithm comprises the Newton-Raphson power flow solution and the associated energy losses for the each transaction.

Definitions

Transaction pair consists of a sending bus (delivering power) and associated receiving buses (consuming power) corresponding to a bilateral energy. An ideal transaction pair is self-balancing for instance, its net real power generation should be equal to sum of its real power demand and its active loss. A single transaction is introduced to simplify this method, which comprises several buses, whether sending bus or sinking bus.

where, ns = Set of sending buses in the system,
nb = Set of sinking buses in the system,
nz = Set of nodes with zero net injections in the system,
n = Set of all buses in the system ($n = ns+nb+nz$),
nl = Set of all branches (lines and transformers) in the system,
nt = Set of bilateral transactions in the system,
T_k = k^{th} bilateral transaction (transaction pairs),
$E_i = |V_i|e^{(j\delta_i)}$ = Complex voltage value at bus i,
I_i = Complex injected current value at bus i,
$I_{branch(ij)}$ = Complex branch current value of branch (ij),

$S_i = P_i + jQ_i$ = Net complex power in term of bus i, and
$Y_{ij} = G_{ij} + B_{ij} = |Y_{ij}| e^{(j\theta_{ij})}$ = The element of Y_{bus}.

The energy and loss allocation method starting with nodal power balance equations are shown in (3.1), (3.2) and (3.3),

$$\text{For each } k \in ns \quad \begin{cases} P_k = V_k \sum_{j=1}^{n} V_j (G_{kj} \cos\delta_{kj} + B_{kj} \sin\delta_{kj}) \\ Q_k = V_k \sum_{j=1}^{n} V_j (G_{kj} \sin\delta_{kj} - B_{kj} \cos\delta_{kj}) \\ \delta_{kj} = \delta_k - \delta_j \end{cases} \tag{3.1}$$

$$\text{For each } m \in nb \quad \begin{cases} -P_m = V_m \sum_{j=1}^{n} V_j (G_{mj} \cos\delta_{mj} + B_{mj} \sin\delta_{mj}) \\ -Q_m = V_m \sum_{j=1}^{n} V_j (G_{mj} \sin\delta_{mj} - B_{mj} \cos\delta_{mj}) \\ \delta_{mj} = \delta_m - \delta_j \end{cases} \tag{3.2}$$

$$\text{For each } l \in nz \quad \begin{cases} 0 = V_l \sum_{j=1}^{n} V_j (G_{lj} \cos\delta_{lj} + B_{lj} \sin\delta_{lj}) \\ 0 = V_l \sum_{j=1}^{n} V_j (G_{lj} \sin\delta_{lj} - B_{lj} \cos\delta_{lj}) \\ \delta_{lj} = \delta_l - \delta_j \end{cases} \tag{3.3}$$

The above is the same as the classical power flow model, except that generation of each sending bus is left undecided. Meanwhile, we incorporate pairs into real power flow equation set. New constraints, transaction balance equations, are addressed as:

For each $T_k \in nt$

$$\begin{aligned} &P_k = \sum P_m + P_{Loss}^{(Tk)}, k \in \{T_k \cap ns\} \textit{and } m \in \{T_k \cap nb\} \\ &\textit{where} \quad P_{Loss}^{(Tk)} - \text{transaction loss of } T_k \end{aligned} \tag{3.4}$$

To bypass non-linear coupling between real and reactive power flow equations, we first translate all power injections into complex injected currents as follows:

$$I_i = \frac{S_i^*}{E_i^*} = \frac{P_i - jQ_i}{V_i e^{-j\theta_i}}, i \in ns \qquad or$$

$$I_i = -\frac{S_i^*}{E_i^*} = \frac{-P_i + jQ_i}{V_i e^{-j\theta_i}}, i \in nb \tag{3.5}$$

In the context of transaction pairs, we further decouple network-injected currents into nt subsets corresponding to nt transactions. That means

$$I_{bus} = \sum_{Tk=1}^{nt} I_{bus}^{(Tk)}, \left(I_{bus} = \{ I_1, I_2, ..., I_i, ..., I_n \} \right) \tag{3.6}$$

Considering a bilateral transaction, denoted by T_k, which consists of a sending-bus k and a sinking bus m, we have

$$I_{bus}^{(Tk)} = \{ 0, 0, ..., I_k, ..., I_m, ..., 0 \} \tag{3.7}$$

Complex branch current components imposed by individual transaction can be readily identified under the assumptions that nodal admittance matrix $[Y_{bus}]$ with $n \times n$ is constant and nonsingular. Applying simple matrix manipulations, we have:

$$I_{branch\ (ij)}^{(Tk)} = y_{ij} \times \left\{ I_k (Z_{ik} - Z_{jk}) - \sum_{m \in Tk \cap nb} I_m (Z_{im} - Z_{jm}) \right\} \tag{3.8}$$

where, y_{ij} = the admittance of the branch (ij), and
Z_{ik} = the i_k^{th} entry of the bus impedance matrix.

Note that the decomposed branch current is exact solution from Kirchoff's Laws. Accordingly, both real and reactive losses, $P_{Loss}^{(T_k)}$ and $Q_{Loss}^{(T_k)}$ incurred by T_k can be calculated by:

$$\begin{aligned} P_{Loss}^{(Tk)} &= \sum_{ij \in nl} P_{Loss(ij)}^{(Tk)} = \sum_{ij \in nl} Re\left\{ I_{branch(ij)}^{(Tk)} \times (E_i^* - E_j^*) \right\} \\ Q_{Loss}^{(Tk)} &= \sum_{ij \in nl} Q_{Loss(ij)}^{(Tk)} = -\sum_{ij \in nl} Im\left\{ I_{branch(ij)}^{(Tk)} \times (E_i^* - E_j^*) \right\} \end{aligned} \tag{3.9}$$

Substituting $P_{Loss}^{(T_k)}$ from (3.9) into (3.4), we obtain an expanded power flow equation set consisting of (3.1)-(3.4). Mathematically, this property has ($2n+nt-1$) independent nonlinear equations, and it may solve ($2n-1$) state variables and nt transaction losses by the Newton-Raphson power flow method.

The flow chart of transaction energy and loss allocation calculation is shown in Fig. 2.

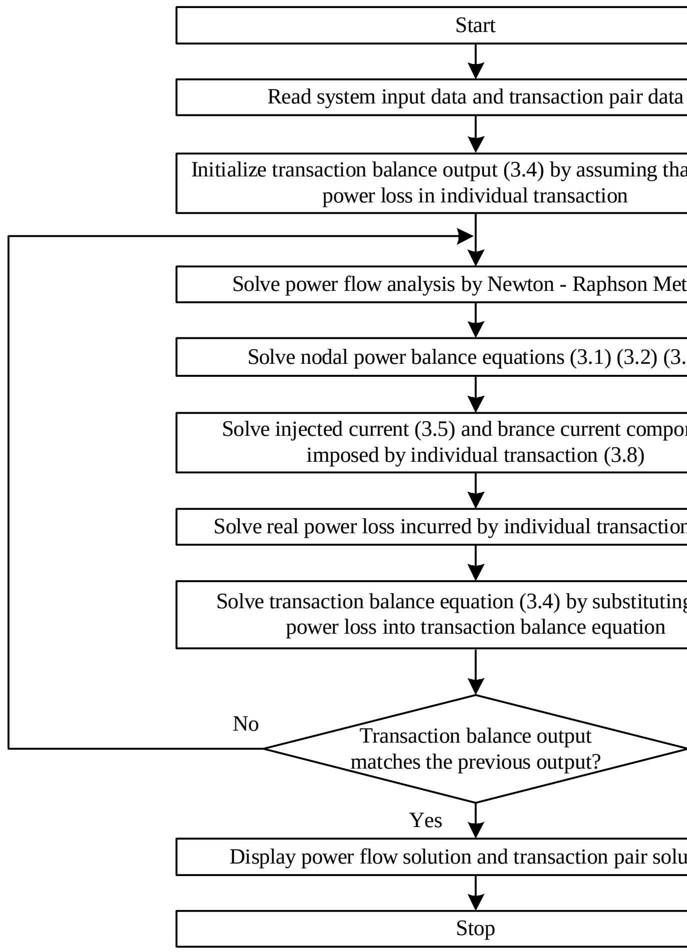

Fig. 2 Flow chart of transaction energy and loss allocation calculation

4. TRANSMISSION PRICING FOR BILATEAL TRANSACTION IN THE NESA

PwC proposed the transmission pricing that is a uniform transmission marginal cost for the whole country. It comprises marginal capacity cost, marginal transmission losses, and marginal connection and service costs [4]. The marginal transmission costs and marginal transmission losses are shown in Tables 1 and 2.

Table 1 Marginal transmission costs based on LRAIC

Voltage level	Cost per kW-yr		Cost per KWh-yr	
	Baht	$US	Baht	$US
Generator to exit 500:230 kV	939	26.1	0.36	0.99
Exit 500:230 kV to exit 230:115/69 kV	1053	29.2	0.40	1.11
Exit 230:115 kV to end 115 kV lines	1173	32.6	0.45	1.24
End 115 kV lines to exit 115:MV	573	15.9	0.22	0.61

Table 2 Marginal transmission losses

Voltage level	Energy Loss (% of Energy at Entry)	
	On - Peak	Off - Peak
Generator to exit 500:230 kV	3.64%	2.42%
Exit 500:230 kV to exit 230:115/69 kV	0.30%	0.20%
Exit 230:115 kV to end 115 kV lines	3.39%	2.26%
End 115 kV lines to exit 115:MV	0.23%	0.15%

The estimated marginal connection costs are related to maximum capacity installed at the point of connection, while the estimated service cost is also proposed to be an equal charge for all customers [4].

However, transmission pricing based on marginal transmission costs does not reflect the differential transmission losses in all regions. In this paper, we apply this pricing scheme with the exact loss contributions for bilateral transactions in the NESA.

The transmission pricing proposed for the NESA is divided into three categories. Firstly, Connection Charges are intended to recover the costs of providing and maintaining connection assets. Secondly, Transmission Use of System Charges are used to recover all of transmission network costs including the operational costs of using the grid and costs of losses. Finally, Common Service Charge is charged for the metering costs such as billing and collection.

4.1 Connection Charges

Connection charges recover the marginal connection costs, including the costs of providing and maintaining assets connected to the transmission systems. The costs of connection assets are associated with the point of sending and receiving power to the grid, for example, dedicated transformers, switchgear, associated plant such as installed reactive plant, land and building, any bus ties at transmission voltage level, and any services. These costs are invariant with the usage and should be recovered as fixed charges levied on the connected users. To promote efficiencies in the provision of assets and other costs, transmission owner's connection charges encourage users to share connection sites, which can be realized and shared between users.

The annual connection charges are equal to the summation of annualized capital costs and operation and maintenance costs. The calculation of estimated connection costs associated with specific assets is shown as follows:

- 50,000 Baht/MVA per year for connections at the 230 kV, 115 kV and 69 kV levels, based on an estimated substation investment of 90 MBaht for a 200 MVA capacity increment, and
- 100,000 Baht/MVA per year for connections at the 33 kV and 22 kV levels, based on an estimated substation investment of 45 MBaht for a 50 MVA capacity increment.

The EGAT's transmission investment costs do not separate out the costs of connection and services from those of transmission lines and substations; therefore, discount rate is 10%, which includes 2% O&M annual costs and is annualized over 25 years.

4.2 Transmission Use of System Charges

Transmission use of system (TUOS) charges reflect the cost of investing, operating and maintaining the transmission system. These activities are undertaken to provide the capability to allow the flow of bulk transfers of power between connection sites and to provide transmission system security.

These charges are taken to recover a part or all of network costs, which are related to the share of use of transmission network assets through use of system prices, and set to recover the maximum allowed revenue as set by the price control. Transmission usage charges are essentially energy and loss charges collected by injecting or withdrawing power from the network at the connection points.

The transmission pricing should reflect the transmission marginal cost that is categorized in each voltage level and the transmission service charge must cover the revenue corresponding to financial requirement.

PwC proposed a method based on Long-Run Average Incremental Cost (LRAIC), which is a uniform transmission marginal cost for the whole country for each voltage level. The methodology of calculation for the LRAIC of system expansion involves four main steps:

- To prepare projections of the new demand at each voltage level for future years;
- To estimate the optimal incremental investment and Operating and Maintenance (O&M) costs required to meet this new demand;
- For each voltage level, to discount the incremental costs and the incremental demand in each year, to produce a present value of each; and
- To divide the discount costs by the discounted demand to derive the LRAIC.

These costs should be allocated to the 09.00-22.00 hours peak period on all weekdays (except public holidays) over all months of the year. The transmission charge should raise revenue according to the following financial requirements:

- Self Financial Ratio (SFR) >= 25%
- Dept to Equity Ratio (D/E) <= 1.50
- Dept Service Converage Ratio (DSCR) >= 1.30
- (Short + Medium Term)/(Total Dept) <= 15%

The calculated results of LRAIC are shown in Table 1 for EGAT's transmission system for each voltage level. After adjusting of the base for allowed revenue, the results of LRAIC are scaled down by the 71% scaling factor as shown in Table 3. At each voltage level, the LRAIC is calculated on the basis of a 20-year payback with a 7% discount rate and currency exchange rate of 36 BHT=1USD.

Table 3 Calculation of LRAIC results with base adjusted for allowed revenue

Voltage level	Cost per kW-yr		Cost per kWh-yr	
	Baht	$US	Baht	$US
Generator to exit 500:230 kV	667	18.53	0.25	0.70
Exit 500:230 kV to exit 230:115/69 kV	748	20.73	0.28	0.79
Exit 230:115 kV to end 115 kV lines	833	23.15	0.32	0.88
End 115 kV lines to exit 115:MV	407	11.29	0.15	0.43

Moreover, the users will be charged depending on their network usage behavior. For example:

Case 1: Both seller and buyer use the same voltage level. In other words, they use the transmission system in only such voltage level.

Case 2: Seller and buyer are connected to the different voltage levels. Therefore, the energy flows through more than one voltage level.

Case 3: Both seller and buyer are connected to the same voltage level but they need to use other voltage levels for their energy transportation.

4.3 Common Service Charge

In addition to connection and network charges, customers have to pay for common service charge including metering, billing and collection services. These costs are fixed on every customer. PwC estimated these costs at the bulk supply points. The estimation of connection service charge is 135,000 Baht/yr per user for metering costs, including CTs and VTs, inclusive of capital costs and O&M costs.

5. SIMULATION RESULTS

The Thai system consists of 424 buses, 466 lines, 278 transformers, and 146 generators. We assume that there are three simultaneous transactions in NESA's operation. The transmission pricing is calculated by applying such losses together with the energy flows based on each transaction. The losses originated by the transaction are real time simulated (may be on the hourly basis). Detailed transaction data are presented in Table 4.

Table 4 The transaction pairs data of the base case in the 424 bus Thai power system

Pairs	Sending Bus			Sinking Bus				
	No.	Name	Volt (kV)	No.	Name	Volt (kV)	Pload (MW)	Qload (MVar)
1	339	RB-C1	230	105	RB2	115	125.890	39.500
2	383	COCO-T1	115	129	BL	115	76.190	27.000
3	286	MM-T7	230	194	CM2	115	45.000	14.490

5.1 Transmission Loss Allocation Aspects

For the aspect of loss allocation, the transactions are simulated under five different scenarios, as follows:

Scenario 1: Base case (Trade 1, Trade 2 and Trade 3)
Scenario 2: Increasing load (Trade 1 and Trade 2)
Scenario 3: Decreasing load (Trade 1 and Trade 2)
Scenario 4: Short distance (Trade 2)
Scenario 5: Long distance (Trade 2)

Table 5 Transaction energy and loss allocation results

Scenario	Trade No.1			Trade No.2			Trade No.3		
	Generator (MW)	Demand (MW)	Losses (MW)	Generator (MW)	Demand (MW)	Losses (MW)	Generator (MW)	Demand (MW)	Losses (MW)
1	RB-C1 126.350	RB2 125.890	0.460	COCO-T1 80.684	BL 76.190	4.494	MM-T7 49.514	CM2 45.000	4.514
2	RB-C1 145.461	RB2 145.000	0.461	COCO-T1 84.499	BL 80.000	4.499	MM-T7 49.514	CM2 45.000	4.514
3	RB-C1 100.458	RB2 100.000	0.458	COCO-T1 64.473	BL 60.000	4.473	MM-T7 49.514	CM2 45.000	4.514
4	RB-C1 126.350	RB2 125.890	0.460	SHC-T1 78.900	BL 76.190	2.710	MM-T7 49.514	CM2 45.000	4.514
5	RB-C1 126.350	RB2 125.890	0.460	BCC-T1 81.703	BL 76.190	5.513	MM-T7 49.514	CM2 45.000	4.514

5.2 The Transmission Pricing

The transmission charges are calculated by applying transaction energy and exact loss allocation results as well as transmission tariff at the point of connection. The base case is demonstrated for the calculation of transmission pricing.

5.2.1 Connection Charges

The yearly connection charges are based on the annual maximum MVA of the transaction. It is assumed that the contracted capacities of three bilateral contracts are 150, 100, 75 MVA, respectively.

Table 6 Connection charge results

Pairs	Generators				Demands			
	Name	MVA	MBaht/ MVA-yr	Total MBaht-yr	Name	MVA	MBaht/ MVA-yr	Total MBaht-yr
1	RB-C1	150	0.05	7.5	RB2	150	0.05	7.5
2	COCO-T1	100	0.05	5	BL	100	0.05	5
3	MM-T7	75	0.05	3.75	CM2	75	0.05	3.75

5.2.2 The Transmission Pricing

Transmission use of system charges based on LRAIC are separately charged to both buyer and seller for each level whenever the energy flows through. The following examples illustrate Scenario1.

For example, TUOS of Trade 1 is calculated as follows:

- For the seller (RB-C1), the injected energy including losses through 230 kV transmission is 126.350 MW. The TUOS of 230 kV is equal to 748 Baht/kW-yr. Therefore, 230 kV TUOS charge for this amount of energy is equal to 94.510 MBaht.
- For the buyer (RB2), the 125.89 MW energy is drawn via 115 kV transmission facilities. The TUOS of 115 kV is 833 Baht/kW-yr. Therefore, 115 kV TUOS charges is equal to 104.866 MBaht.

Similarly, the seller (MM-T7) and the buyer (CM2) in Trade 3 pay TUOS charges amount of 37.036 MBaht and 37.485 MBaht, respectively. Both Trades 1 and 3 illustrate Case 2 presented above.

Trade 2's TUOS charges are as follows:

- The seller (COCO-T1) is connected to 115 kV transmission line. The TUOS for this seller is 833 Baht/kW-yr. The 80.684 MW-seller capacity is charged in total an amount equal to 67.209 MBaht a year.
- The buyer (BL) is connected to 115 kV transmission level. The TUOS for this load is 833 Baht/ kW-yr. The 76.190 MW-buyer capacity is charged in total amount equal to 63.466 MBaht a year.

Since they use the same voltage level, to avoid the double computing of charges for such transmissions, only one-half the highest amount of TUOS is levied equally to both seller and buyer. This illustrates Case1 above

Table 7 Transmission use of system charge results

Pairs	Generators		Demands	
	Name	MBaht-yr	Name	MBaht/yr
1	RB-C1	94.510	RB2	104.866
2	COCO-T1	33.600	BL	33.600
3	MM-T7	37.036	CM2	37.485

5.2.3 Common Service Charge

The yearly common service charge is at a fixed rate applied to both sellers and buyers connected to each voltage level. Regardless of the point of connections, the common service charge is set at 135,000 Baht per customer per year.

Table 8 Common service charge results

Pairs	Generators		Demands	
	Name	Baht/yr	Name	Baht/yr
1	RB-C1	135,000	RB2	135,000
2	COCO-T1	135,000	BL	135,000
3	MM-T7	135,000	CM2	135,000

Table 9 Total transmission charges results

Transmission Charges (MBaht/yr)	Trade No.1		Trade No.2		Trade No.3	
	Seller	Buyer	Seller	Buyer	Seller	Buyer
	RB-C1	RB2	COCO-T1	BL	MM-T7	CM2
Connection Charge	7.5	7.5	5	5	3.75	3.75
TUOS Charge	94.510	104.866	33.600	33.600	37.036	37.485
Common Service Charge	0.135	0.135	0.135	0.135	0.135	0.135
Total Charges	101.645	112.501	38.735	38.735	40.651	41.370

5.3 Observations

The loss allocation scheme provides business incentives for economic operation of the system since transaction pairs can generate either negative or positive losses. When transactions take place, the losses in the system can be either decreased or increased.

The allocated loss of a specific trade fairly reflects the effects on both quantities and distances of any transaction for instance,

- In Scenarios 2 and 3, the higher demand causes the higher losses.
- In Scenarios 4 and 5, the longer distance incurs the higher losses.

6. CONCLUSIONS

In this paper, the transmission pricing methodology for bilateral transaction based on the exact loss contribution and long run average incremental cost methodology is efficiently implemented on the Thai transmission system in NESA model. Test results indicated that the proposed methodology can promote efficient utilization of the system, raise enough revenue for network expansion, and transparent to all users.

To increase economic signals at all points of the grid, the TUOS charges could be calculated on the basis of investment in transmission assets for each such region. Therefore the TUOS charges will vary depending upon location. If the locational demand is relatively high, the requirement for recovering transmission assets is high, leading a higher zonal price. The zonal TUOS charges will provide more equitable charge allocation, correct signals reflecting zonal condition, and price incentives for new demands.

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