Novel Transmission Pricing Methodologies with Integration of Renewable Generation for Australian NEM

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Abstract: The expanded Renewable Energy Target (RET) scheme has been introduced by the Australian government which targeting 20% of Australia's electricity supply is generated from renewable sources by 2020. Consequently, this will drive large changes which will effect on behaviour and investment in Australia's market environment especially transmission use of system (TUoS) charging scheme. Hence, this paper is intended to explore the existing TUoS charging methodologies in the Australian National Electricity Market (NEM) to the development of renewable generation. There are some aspects related to the existing TUoS charging methodology which can be improved especially in the issues of transmission usage evaluation, percentage of transmission services allocation for the market users and also the transmission pricing methods. Therefore, in this paper, novel transmission pricing methodologies and mathematical formulation of the proposed approaches were introduced. There are two proposed schemes for allocations of TUoS charges for the renewable energy which called Distribution Factors Enhanced Transmission Pricing (DFETP) capacity-based method and DFETP energy-based method. Both methods were tested on the 59-bus system of the South East Australian power system in order to determine which approach provides a better TUoS charges allocation scheme.

Keywords: Renewable Energy Target (RET) scheme, transmission use of system (TUoS) charges, renewable generation, transmission pricing methods and transmission usage evaluation.

1. Introduction

The Australians are relying around 80% of coal for their electricity needs and this account for more than one third of Australia's current greenhouse gas emissions [1]. Therefore, in August 2009, the legislation for the expanded RET was passed by the Australian Parliament in order to provide 20% of its energy generated from the renewable sources by 2020 [2-7]. Renewable energy sources such as wind, solar, geothermal heat and wave power will have a key role in moving Australia to the clean economy of the future. Currently, based on [8] many new generation projects are seeking access to the Victorian Electricity Declared Shared Network. AEMO has received 5,000MW of connection applications and enquiries wanting to connect to the Victorian transmission system. Of these, about 3,600 MW are expected to be connected to the 500kV lines between Moorabool and Heywood and the rest to the 220 kV lines out of Ballarat. These new generation development proposals are aiming to capitalize on Victoria's substantial wind and gas resources while utilizing the existing electricity infrastructure along the south-western coast of Victoria and in the Ballarat region.

The expanded RET has significantly impacts to the network system. As indicated, the expanded RET will stimulate investment in new renewable generation capacity. This new generation is likely predominately wind-powered, clustered in specific geographical areas and often remote from the grid. The result for networks will be an increase in connection applications for remote renewable and requirements for investment in the shared network [4]. In Australia, three types of transmission configurations have been introduced in order to connect the generator of a remote generation cluster to the existing grid that are spaghetti network, Scale Efficient Network Extension (SENE)-simple approach and SENE-hub approach. The Regulatory Investment Test for Transmission (RIT-T) is applied to assess the merits of different generation connection options [9-11]. It accompanies AEMO's cost allocation methodology, which explains how AEMO will allocate shared network costs between generation connection applicants (applicants) connecting to the same terminal station [10]. However, the existing Australian NEM TUoS charging methodologies have limitation in some issues such as:

1. Transmission usage evaluation: Using the DC power flow and the average participation method (tracing algorithm) where this method is not accurately determined the contribution of each user in the transmission line as it resulting in positive flows only without considering the counter flows;
2. Percentage of cost allocation: 100% charges to the load and it is not fairly treated to the loads as the generators also using the transmission services to transfer the electricity in order to meet the required demand;
3. Transmission pricing method: Locational charges using the usage proportion where it is based on postage-stamp basis. This method does not accurately evaluate the actual usage cost of each user. Meanwhile for non-locational charges, postage-stamp is adopted. This method can accurately cover the total revenue but it seems not fair and equitable if there is a local load case in the transmission network system.

Hence, in this paper, novel transmission pricing methodologies for Australian NEM were proposed where all the main issues were addressed.

2. The Transmission Use of System (TUoS) Charging Schemes Integrated with Renewable Generation for Australian NEM

There are two types of transmission pricing methodologies that have been adopted by Australian NEM which are the Cost Reflective Network Pricing (CRNP) and Modified Cost Reflective Network Pricing (MCRNP) method. The Transmission Network Service Providers (TNSPs) that use CRNP method such as Transend Networks, TransGrid and Vencorp while ElectraNet uses MCRNP method for transmission charging [12]. In addition, the AEMO has introduced the additional TUoS charges which incorporated with the CRNP or MCRNP method for charging the demands due to the integration of renewable generator in the existing grid.

2.1 Cost Reflective Network Pricing (CRNP) Method

In the CRNP method, the total transmission revenue is divided equally between the locational and non-locational charges. The CRNP methodology generally involves the following steps [13]:

1. Determining the annual costs of the individual transmission network assets in the optimised transmission network;
2. Determining the proportion of each individual network element utilised in providing a transmission service to each point in the network for specified operating conditions.
3. Determining the maximum flow imposed on each transmission element by load at each connection point over a set of operating conditions.
4. Allocating the costs attributed to the individual transmission elements to loads based on the proportionate use of the elements.
5. Determining the total cost (lump sum) allocated to each point by adding the share of the costs of each individual network attributed to each point in the network.

2.2 Modified Cost Reflective Network Pricing (MCRNP) method

The MCRNP methodology is an allocation process that involves replacing step 1 of the CRNP methodology referred to in clause S6A.3.2 (1) with the following three steps [14]:

1. Allocating the Annual Service Revenue Requirement (ASRR) allocated to prescribed use of system services to each transmission system asset used to provide prescribed TUoS services based on the ratio of the optimised replacement cost of the that asset to the optimised replacement cost of all transmission system assets used to provide prescribed TUoS services. The amount allocated to each asset is the asset’s gross network asset cost.
2. Adjusting individual gross network asset costs: the individual gross network asset costs determined in subparagraph (1) must be multiplied by a factor (between 0 and 1) that depends on the utilisation of each asset. The resulting amount for each asset is the locational network asset cost while the remainder is the non-locational network asset cost.
3. Determining the non-locational component: the sum of the non-locational network asset cost represents the pre-adjusted non-locational component of the ASRR for prescribed TUoS services.

3. The AEMO Additional TUoS Charges for New and Existing Terminal Stations

The AEMO has outlined the cost allocation policy for new and existing terminal stations. In determining this policy, AEMO has also been guided by the national electricity objective, which seeks to promote the efficient operation and investment in the market for the long-term benefit of consumers, taking account of price, reliability, security and safety [9].

In [10], the RIT-T can be used to find out which location and design of terminal station would provide the greatest net benefit to the NEM. The RIT-T guidelines, published by the Australian Energy Regulatory (AER), outline the example of when a TNSP may find it efficient to configure connection assets in such a way as to allow them to be easily augmented in the future should additional demand for connections arise, so this application of the RIT-T is already accepted. However, the RIT-T cannot be used to determine what proportion of generation connection costs should be negotiated versus prescribed. The RIT-T is indifferent to who is paying costs or providing benefits (that is, the TNSP or Applicant) – all costs are assumed to be passed through to the end-user.

The terminal station will have exactly the same net benefits under a RIT-T if the TNSP pays for the entire connection, if the connecting applicants pay for the entire connection or if the costs are shared across the parties. Because the RIT-T can give no guidance on how the total costs of connecting generating plant at a terminal station should be shared across applicants, this decision needs to be made outside the RIT-T framework. However, it should be noted that a RIT-T comparing generation connection options should not be used to subsidise a generation connection or, in other words, make a generating plant commercially-viable if it would not otherwise have been. If an option assessed in the RIT-T is changing the commercial decision of an applicant, then the RIT-T moves into justifying the generating plant itself. This is a very different application of the RIT-T.

At a high level, this would mean that if an applicant was prepared to pay $X for an individual connection at its preferred location, the RIT-T should only be used to justify costs over and above $X. However, because the premise of a multi-connection terminal station is that it is less expensive overall than individual connections, by definition the total amount paid by the connecting applicants will be less at the multi-connection terminal station – on a probability-weighted basis. This rule is not easy to apply in practice.

A further change under the multi-connection terminal station option is the share of the costs paid between connecting applicants. The first connecting applicant pays more than it would under the individual connection option and subsequent applicants pay less than they would under the individual connection option. Whilst AEMO has a cost allocation methodology to share the overall cost of connection between the first applicant and subsequent applicants, the probability of subsequent applicants connecting at multi-connection terminal stations is uncertain and the first applicant has no incentive to shoulder the risks if subsequent applicants do not connect. The RIT-T provides a framework for a TNSP to value the opportunities and risks associated with different connection options and to make the appropriate investment for the overall NEM. The RIT-T then enables the establishment of an economically-efficient terminal station without requiring connecting applicants to bear additional risk.

The RIT-T assumes that the TNSP will cover:

- Any additional costs incurred up front to correctly size the terminal station to allow for anticipated future connections
- The costs involved to correctly locate the terminal station over and above what the first applicant would pay to connect at its preferred location with an individual connection

This means that if the first applicant pays $X to connect at its preferred location with an individual connection, it will still pay $X to connect at the terminal station. Any additional costs to establish the terminal station will be covered under the RIT-T and hence be recovered through prescribed charges. Subsequent applicants will then pay to connect at the terminal station, including the costs required to relocate to the terminal station and their share of the non-prescribed cost of establishing the terminal station, under the standard cost-allocation methodology. The advantages of this approach are:

- As long as the terminal station is correctly located, the maximum any applicant will pay to connect at the terminal station is the amount they would have paid to connect with an individual connection at their preferred location.
- Each applicant will pay equal shares of the non-prescribed terminal station establishment costs so there is no first-mover disadvantage.
- Each applicant will have an incentive to locate as close to the terminal station as possible to reduce their connection costs.

The RIT-T application guidelines describe the steps involved in applying the RIT-T as follows [10]:

Step 1: Identify a need for the investment (known as the identified need)

Step 2: Identify the base case and a set of credible options to address the identified need

Step 3: Identify a set of reasonable scenarios that are appropriate to the credible options under consideration

Step 4: Quantify the expected costs of each credible option

Step 5: Quantify the expected market benefits of each credible option – calculated over a probability weighted range of reasonable scenarios

However, in this paper step 4 will be further discussed as it is related to the TUoS charges for new entrance of generation.

The costs in a RIT-T are defined as the present value of the direct costs or incremental costs of a credible option. The incremental costs include the [8, 10]:

- Costs incurred in constructing or providing the option
- The operating and maintenance costs in respect of the operating life of the credible option
- The costs of complying with any mandatory requirements in relevant laws, regulations and administrative requirements

It is necessary to define “the option” before calculating the incremental costs. The identified need under this RIT-T is to connect multiple generating plants in an economically efficient way, and to do this requires:

- Correct sizing of connection and shared network assets at the terminal station
- Correct location of the terminal station

Given that the identified need of this RIT-T is not a need to supply additional generation capacity; the RIT-T should not be used to justify any costs an applicant would pay to connect without the terminal station. The option and the incremental costs will therefore consist of only the difference between the works required to connect the first applicant at its preferred location and the works required to establish the terminal station. This difference in costs will be allocated to prescribed transmission services and subtracted from the costs of establishing the terminal station. The remaining non-prescribed costs of establishing the terminal station will be shared between future connecting applicants under the standard cost allocation methodology.

4. Distribution Factors Enhanced Transmission Pricing (DFETP) method

This section describes the concept and formulation of the DFETP method [12]: modification on existing Generalized Generation Distribution Factors (GGDFs) and Generalized Load Distribution Factors (GLDFs) by replacing Generalized Shift Distribution Factors (GSDFs) with Justified Distribution Factors (JDF) in order to estimate the contributions to the network flows from individual users, and charging the transmission user by using the MW-mile (negative-flow sharing approach) plus tracing-based postage-stamp method.

An efficient transmission pricing mechanism should recover transmission costs by allocating the costs to transmission line system in proper way. In order to implement the usage-based cost allocation methods, it is essentially important to determine accurately the transmission usage. However, due to the nonlinear nature of power flow, it is difficult to determine an accurate transmission usage. On the other hand, from an engineering point of view, it is possible and acceptable to apply approximate models or sensitivity indices to estimate the contributions to the network flows from individual users [15]. The distribution factors approach which traditionally used in power systems for security and contingency analysis can be used to overcome this allocation problem. However, this method has some weaknesses since they rely on some conditions. For instance, the set of distribution factors for a pair of nodes found using a particular reference bus differs from the one using another bus [16]. This could cause more time used to generate new set of distribution factors if the users request to use different reference node to accommodate their transactions [16]. To overcome this problem, a new technique has been successfully implemented independent of the references bus by making use of the properties of the distribution factors which is called JDF. In this method, the result generated from the JDF, is used in GGDFs and GLDFs in order to calculate the contribution of each market participant to the transmission line system.

4.1 Justified Distribution Factors (JDF)

JDF was introduced in [16] where this method is originally used to solve the congestion curtailment in bilateral trading. This factor, which is derived in [16], has advantages over the original distribution factors [17], whereby the elements in the distribution matrix do not vary with the reference bus position [18]. In this paper, JDF is formed by adding a justification factor J_{ij} to the original DFs, so that distribution factors for line *i-j* at bus *i* and bus *j* have the same magnitudes but opposite signs, where mathematically [16]:

$$J_{ij}^{m} = -\frac{DF_{ij}^{m}(i) + DF_{ij}^{m}(j)}{2} \qquad (1)$$

$$JDF_{ij}^{m} = DF_{ij}^{m} + J_{ij}^{m}(1) \qquad (2)$$

Arithmetic shows that:

$$JDF_{ij}^{m}(i) = JDF_{ij}^{m}(j) \qquad (3)$$

In [16], it has been shown that JDF does not only have the advantage that it is independent of the reference bus, but it also shows localized and meaningful numeric values. The JDF corresponding to the starting and ending nodes of the line in question are equal in magnitude and opposite to each other and their magnitude is larger than those of any other JDF for the same line.

According to [18], JDF is used to trace the power flows in transmission lines for the base case and transaction-related flows. The power flow in line *i* can be traced using (4):

$$P_i = \sum_j^m JDF_i^j . P_j \qquad (4)$$

Where JDF_i^j is the factor for line *i* with respect to bus *j*, P_j is the net injection power at bus *j* and *m* the number of buses.

4.2 Generalized Generation Justified Distribution Factors (GGJDFs) or JD Factors

The steps to obtain GGJDFs or JD factors are still same as GGDFs approach except they use JDF to replace A factors [19]:

$$JD_{i-j,g} = JDF_{i-j,g} + JD_{i-j} \qquad (5)$$

where JD_{i-j} is calculated by:

$$JD_{i-j} = \frac{(F_{i-j} - \sum_g JDF_{i-j,g} \times G_g)}{(\sum_g G_g)} \qquad (6)$$

JD factors, $JD_{i-j,g}$ relates generation G_g in a given bus *g* with actual power flow F_{i-j} in a line *i-j*:

$$F_{i-j} = \sum_g JD_{i-j,g}\, G_g \qquad (7)$$

4.3 Generalized Load Justified Distribution Factors (GLJDFs) or JC Factors

GLJDFs is also formulated based on JDF instead of using A factors and mathematically written as [19]:

$$JC_{i-j,d} = JC_{i-j} - JDF_{i-j,d} \quad (8)$$

where $JC_{i-j} = \frac{(F_{i-j} - \sum_d JDF_{i-j,d} \times L_d)}{(\sum_d Ld)}$ (9)

The actual power flow $F_{i\text{-}j}$ in a line *i-j* can be traced by relating the JC factors with load, L_d in a given bus *d*:

$$F_{i-j} = \sum_j C_{i-j,d} L_d \quad (10)$$

The transmission utilities differ in justification of their methods to allocate the use of system charges to the users. In this context, the users can be defined as generators and demands. Thus, it has to be decided that who has to pay the charges. Three characteristics are possible: (1) all charges are assigned to the generator (2) all charges are assigned to the load (3) the charges are shared between the generator and the load. However, in order to create a fair environment in transmission pricing, the allocation schemes should have the following properties such as; it provides complete cost recovery of the transmission services and the allocation is based on the actual usage of the service, i.e. generators or demands are charged for transmission services based on their actual use of each transmission network. In this paper, the percentages of charging between the users are considered to be divided equally which is 50% to the loads and 50% to the generators. In practice, the cost would be shared between the generator and the consumer in certain ratio, which would be determined by the regulatory authority [20].

The transmission pricing methods are distinguished to two parts: (1) Locational charges (2) Non-locational charges. The most common method for locational charges that has been implemented by the utilities is the MW-mile method. The issue in this method is concerning with the counter flows contributed from the users. This issue is still being debated on what basis the credit or reward should be given to the transmission user who reduces the total net flow of the transmission system. However, many transmission utilities felt uncomfortable with the idea of providing a service and in addition paying the users for using it. The reason is clear because by giving the credit to the transmission users for their contribution in counter flows could cause difficulties to the transmission utilities to recover the revenue requirements. Hence, the MW-mile method (negative-flow sharing) was introduced in [18]. For the non-locational charges, the postage-stamp coverage method has been used by the transmission utilities for instance Electricity Supply Board National Grid (EirGrid)-Republic Ireland, and Transend-Australia to cover the total transmission revenue. This method can accurately cover the total revenue but it seems not fair and equitable if there is a local load case in the transmission network system. Therefore, a tracing-based postage-stamp method is introduced in the DFETP method where the individual users are charged based on their actual usage of transmission lines system even the network system consists local load case or not. The mathematical formulations for locational and non-locational charges assigned to market users are as follows:

4.4 Locational charges: MW-mile (negative flow-sharing method)

The power-flow based MW-mile method is the first concept to consider the real network conditions using power flow analysis, forecasted loads and the generation configuration. The cost allocated to the customer is calculated on the basis of the "extent of use" of each network facility. Equation 11 shows the cost allocation principle of the method [21].

$$R(u) = \sum_{all\ k} C_k \frac{f_k(u)}{\overline{f_k}} \quad (11)$$

Where:

$R(u)$	allocated cost to customer u
C_k	cost of circuit k
$f_k(u)$	k-circuit flow caused by customer u
$\overline{f_k}$	k-circuit capacity
$\sum_{all\ k} C_k$	total cost

In the negative flow-sharing method, the transmission owner and the users will share the benefits of the counter flow using the profit-sharing approach. The concept and formulation of the approach in detail is explained in [18]. In this method, the negative value of *fk(u)* is shared between the transmission owner and users using profit sharing factor, *r*. This factor is determined according to the willingness of the transmission owner to share profit with the transmission users. The formulation mathematically written as [18]:

$$f_k(u) = +f_k(u) + \frac{1}{r}\left|-f_k(u)\right| \quad (12)$$

4.5 Non-locational charges: Tracing-based postage-stamp method

The purpose of this method is to trace the actual usage of an individual user in the transmission line and charge them based on the actual amount of power usage in the transmission network. This method can be implemented to both network systems either with or without local load case in order to determine a fair and equitable transmission charges for market users [22]. The mathematical equations of this method for the market users are as follows:

For generator:

$$PS_{Gi} = \frac{(P_c \sum_{k=1}^{nl} C_k) - \sum_{i=1}^{n} R_{Gi}}{\sum_{i=1}^{n} P_{GiT}} \quad (13)$$

Where:

P_c percentage cost allocation of each network user

R_{Gi} total charge remunerated to generator G_i for using the set of circuit k's

P_{GiT} total power from generator at bus i, Gi, injected to transmission line

For load:

$$PS_{Li} = \frac{(P_c \sum_{k=1}^{nlin} C_k) - \sum_{i=1}^{n} R_{Li}}{\sum_{i=1}^{n} P_{LiT}} \quad (14)$$

Where R_{Li} is the total charge remunerated to load, Li for using the set of circuit k's and P_{LiT} is the total power load at bus i used the transmission line.

5 Proposed Approaches

This section describes the concept and formulation of the proposed approaches: the DFETP capacity-based method and DFETP energy-based method. Both methods are based on the combination of the traditional DFETP method introduced by [12] and the AEMO additional prescribed transmission charges.

5.1 DFETP capacity-based method

In this method, the DFETP method is used incorporated with the prescribed transmission services from the AEMO cost allocation policy. Firstly, the JDF, GGJDFs and GLJDFs are used as the method for determining the contribution of each user to the transmission lines. Then, the additional TUoS charges for the network expansion due to the integration of renewable generation are calculated based on the AEMO policy. The new total transmission revenue is determined by adding the existing the existing TUoS charges with the additional TUoS charges. The new total transmission revenue is divided 50% to the generators and 50% to the loads. Finally, the TUoS charges are distributed to the users by using the MW-mile (negative-sharing) method for locational charges and tracing-based postage stamp method for non-locational charges. In this method, the wind energy is considered based on the full capacity. The mathematical formulations for this method are similar as the existing DFETP method.

5.2 DFETP Energy-based method

Similar to the DFETP capacity-based method, the DFETP energy-based method also is a combination of existing DFETP method with the additional TUoS charges introduced by the AEMO. The difference between both methods is the DFETP energy-based method considering the capacity factor component. In [23], the capacity factor is the ratio of a generation over a period of time and its potential output if it had operated at full capacity the entire time. The formulation is shown in (15):

$$\% CF = \frac{\text{Generation over a period of time}}{\text{Full capacity}} \times 100\% \quad (15)$$

Capacity factors differ substantially for individual generators as shown in Table 1. The based load power plants (coal and nuclear) have very high capacity factors where sometimes exceeding 90%. Peaking technologies such as natural gas combustion turbines often have much lower capacity factors approximately below 10%. Of the renewable energy resources, biomass and geothermal often act as base load facilities, with relatively high capacity factors. In contrast, wind, photovoltaic and solar thermal power plants typically have lower capacity factors because of resource constraints. They are also classified as intermittent because the output of these facilities fluctuates due to uncontrollable natural causes.

Table 1 Typical operating characteristics of renewable generations

Technology	Typical Capacity Factor	Intermittent?
Biomass	70%	No
Geothermal	85%	No
Wind	35%	Yes
Solar (PV and Solar Thermal)	25%	Yes

The capacity factor (CF) of wind generation which is 35% was considered in the DFETP energy-based method. Steps to be taken in this method are:

- Calculate the new power generated by renewable generator, G_{Re} taken into account the percentage of CF:

  $$G_{Re} = CF \times \text{Full capacity} \quad (16)$$

- Additional power generation need to be covered by other generator:

  $$APG = G_{ws} - G_{Re} \quad (17)$$

- Distribute the additional power generation to the others individual generator based on percentage of generation:

  $$\% G_{i\,new} = \left(G_i \Big/ \left(\sum_n G_{area\,n} - G_{Re} \right) \right) \quad (18)$$

  $$\text{Additional } G_i = \% G_{i\,new} \times APG \quad (19)$$

  $$\text{New } G_i = \text{Existing } G_i + \text{Additional } G_i \quad (20)$$

  Where:

  G_i Power generation at bus i

  $\sum_n G_{area\,n}$ Total power generation in area n which the renewable generation is located

- Use the JDF, GGJDFs and GLJDFs to determine the power contribution of each users to the transmission line using the new power generation
- Calculate the locational charges using the existing MW-mile (negative flow-sharing) method
- Calculate the non-locational charges using new tracing-based postage stamp method. The mathematical formulation for generator is:

$$PS = \left(P_c \sum_{k=1}^{nlin} C_k\right) - \sum_{i=1}^{n} R_{Gi} \Big/ \sum_{i=1}^{n} P_{Gi} \quad (21)$$

Where F_{Ge} is the MW energy based for each generator.

Meanwhile, the formulation of tracing-based postage-stamp method for load is similar to the DFETP capacity-based method.

The summarization of the step-by-step to be taken in the proposed Australian NEM TUoS charging methodologies for integrating the renewable generation to the exiting grid are as follows:

- Calculate the net power flow for each line using JDF approach
- The power contribution from each generator to line is calculated using the GGJDFs method
- The GLJDFs method is adopted to determine the utilization of the demands to the particular line
- Calculate the AEMO new TUoS charges (refer to Figure 1) for the network expansion due to the integration of the renewable generation
- Allocating charge percentage to the market users where in this paper 50% is allocated to the generators and 50% to the loads
- For the DFETP-capacity based method, full capacity of renewable generation is considered while for the DFETP energy-based method, the capacity factor of the renewable generation is taken into account
- Calculate locational charges by using MW-mile (negative-flow sharing) method with r = 3
- Determine the total non-locational charges by subtracting the new TUoS charges with the total locational charges
- Distribute the total non-locational charges by using the tracing-based postage stamp method.

6 Case Study

6.1 Test modeling system

A modified version of the 59-bus system of the South East Australian power system as shown in Fig. 1 has been simulated to verify the concept. This case study is based on DC power flow where losses are neglected. The generators serve a total system demand of 22300MW and detail parameters can be found in [24] with 800MW of wind power as new generation entry.

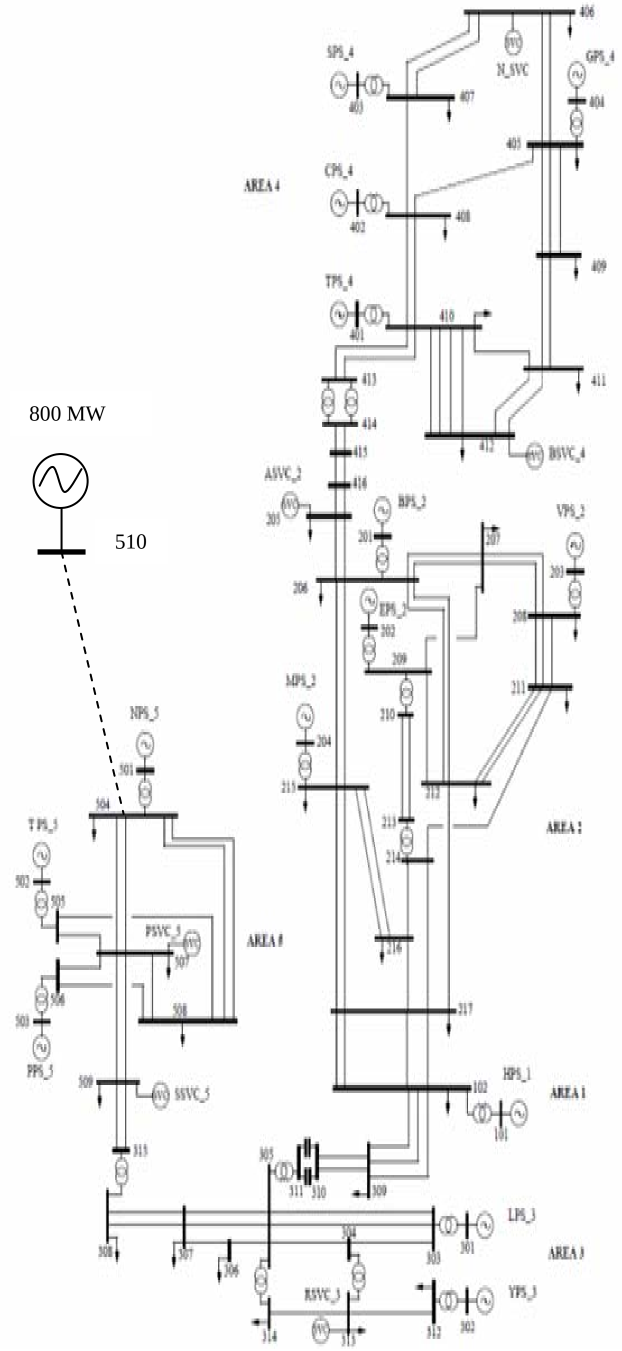

Fig. 1 The modified 59-bus system of the South East Australian Grid

Table 2 present the generation data for the base and modified system after addition of 800MW wind generation. The modified system data is used for the DFETP capacity-based method. For calculating the new TUoS charges, the assumed capital costs for applicant shown in Fig. 2 are used. Let the transmission revenue is $20,500,700 and the Aggregate Annual Revenue Requirement (AARR) is $23,296,250.

Table 2 Generation data for base system

Generator	Technology	Capacity (MW)	% Generation
G101	Gas	317.2	1.4
G201	Coal	3600 [3200]*	16.1 [14.3]*
G202	Coal	2500	11.2
G203	Coal	1500 [1400]*	6.7 [6.3]*
G204	Coal	2770.2	12.4
G301	Coal	4200	18.8
G302	Gas	939.9	4.2
G401	Gas	1400 [1200]*	6.3 [5.4]*
G402	Gas	837	3.8
G403	Hydro	1400 [1300]*	6.3 [5.8]*
G404	Hydro	1549.8	6.9
G501	Hydro	600	2.7
G502	Hydro	576.9	2.6
G503	Hydro	109	0.5
G510	Wind	[800]*	[3.6]*
Total		22300	100

*After addition of 800MW of wind generation

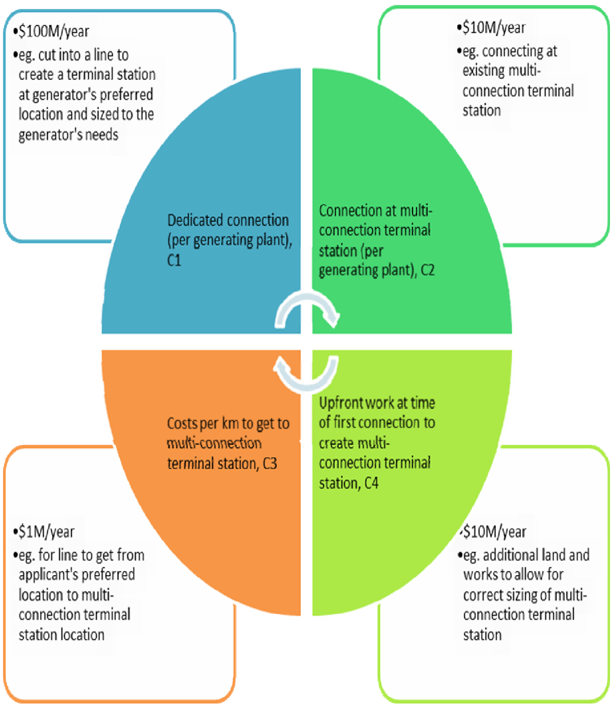

Fig. 2 The assumed capital costs for applicant

The spaghetti and SENE-simple topology is simulated for 100 km transmission length. For the SENE-hub, the length for the transmission line is reduced to 60 km. The transmission cost is considered $1M per km.

Table 3 Generation data for DFETP capacity-based method

Gi	Power generated, MW
G1	317.2
G3	3200
G4	2500
G5	1400
G6	2770.2
G20	4200
G21	939.9
G35	1200
G36	837
G37	1300
G38	1549.8
G51	842.6
G52	810.2
G53	153.1
G60 (Gwe)	280

Table 3 presents the generation data for the modified system after addition of 800MW wind generation for DFETP energy-based method. It clearly shows that after considering the capacity factor component, the power generated by the wind generator is decreased from 800MW to 280MW. Significantly, the others generation in area 5 which are G51, G52 and G53 are increased in order to cover the total generation for area 5.

Three types of network connections which are the "spaghetti network", SENE-simple and SENE-hub are considered in this case study. This modified network system is tested on the existing Australian NEM transmission pricing methods (CRNP and MCRNP) and the proposed approaches (DFETP capacity-based method and DFETP energy-based method). The comparison results of all methods are discussed details in next section.

Fig. 3 shows that for the CRNP and MCRNP methods, the generators do not pay the TUoS charges as full cost is covered entirely by the loads. In other hands, by using the proposed methods, the TUoS charges are introduced to the generators. Hence, the loads will not be burden with high transmission charges as clearly shown in Fig. 4. The TUoS charges allocated for loads are varied depending on the amount of power flows in particular lines based on the new generations.

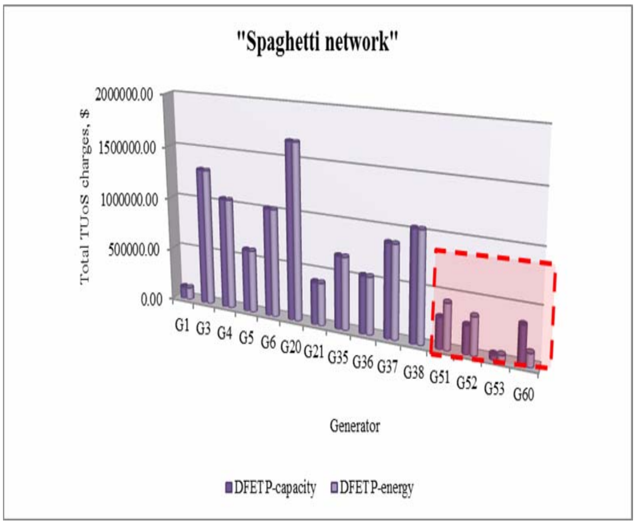

Fig. 5 Comparison on the total TUoS charges for each generator using DFETP capacity-based and DFETP energy-based methods for "spaghetti network"

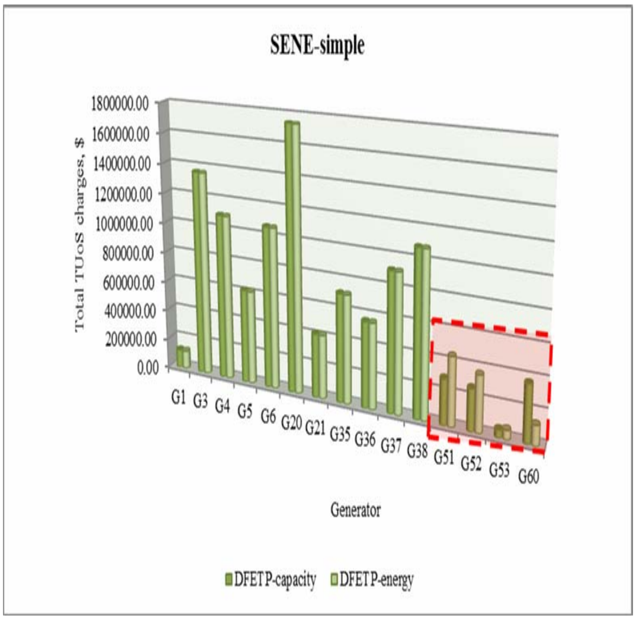

Fig. 6 Comparison on the total charges for each generator using DFETP capacity-based and DFETP energy-based methods for SENE-simple connection

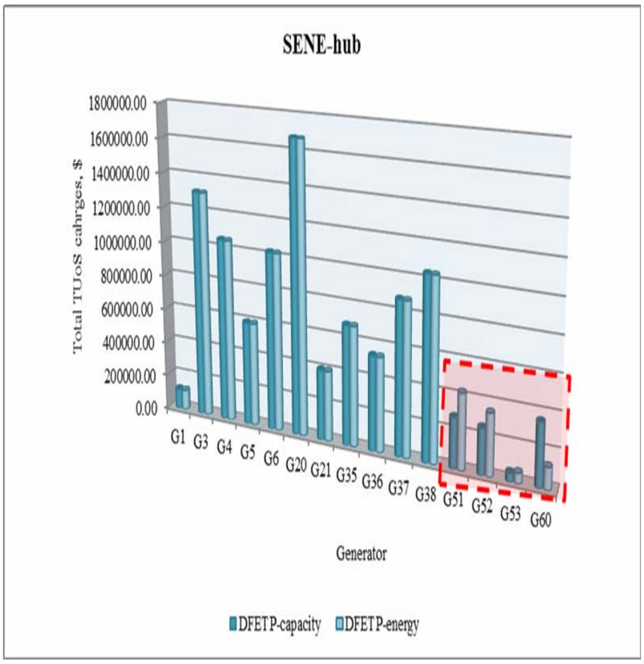

Fig. 7 Comparison on the total charges for each generator using DFETP capacity-based and DFETP energy-based methods for SENE-hub connection

Figures 5-7 show the comparison on the total TUoS charges for each generator using the DFETP capacity-based and DFETP energy-based methods for different types of connection which are the "spaghetti network", SENE-simple connection and SENE-hub connection. From these figures, it clearly shown that the TUoS charges allocated to wind power, G60 was decreased by using the DFETP energy-based method as the capacity factor is considered in this approach. Significantly, the charges for other generators in area 5 were increased in order to cover the additional power generation that actually have to be generated by the wind power. For this method, G60 has to pay the total charges of $125,391 for "spaghetti network", $130,928 for SENE-simple and $126,028 for SENE-hub. Less transmission charges for the "spaghetti network" due to no additional transmission lines are developed. However, the generation capital cost for this network topology is the highest as full cost is covered by the generator. The highest transmission cost is charged to the SENE-simple as a new 100 km of transmission line is built compared to the SENE-hub where only 60 km of new transmission line is needed.

7 Conclusion

This paper presents the methodology and the mathematical formulation of the TUoS charges for integrating the renewable generator to the existing grid. The DFETP capacity-based and DFETP energy-based approaches are developed based on the integration of the DFETP method and the additional transmission charges recommended by the AEMO. Full capacity of renewable energy is considered in the DFETP capacity-based method while for the DFETP energy-based method, the capacity factor is taken into account. From the obtained results, can be concluded that the DFETP energy-based method reflects a fair and equitable transmission charging method as the generators are charged based on the actual power of generation injected to the transmission line systems. In addition, with the implementation of this method, it will encourage the development of green technology.

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