Explanatory Paper for 2007/2008 Statement of Charges

1st November 2007 to 31st December 2008

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Document History

1. First published on the EirGrid website www.eirgrid.com on 26/08/2008.

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1 Introduction

This paper describes the structure of EirGrid's Transmission Use of System (TUoS) charging regime for the 14 month period[1] 1st November 2007 to 31st December 2008. The tariffs can be found in the 'Statement of Charges' which is available on EirGrid's website www.eirgrid.com. Version 1.0 of the Statement of Charges was approved by the Commission for Energy Regulation (CER) on 26th October 2007 and version 1.1 was approved by the CER on 21st December 2007.

To coincide with the introduction of the Single Electricity Market (SEM) the Commission for Energy Regulation (CER) and the Northern Ireland Authority for Utility Regulation (NIAUR), collectively the Regulatory Authorities (RAs), decided to harmonise the Public Electricity Supplier (PES) tariff year to begin each year on the 1st October and end on the following 30th September[2]. As the SEM began on the 1st November 2007 the first harmonised PES tariff period is the 11 month period from the 1st November 2007 to 30th September 2008. The tariff period was recently extended to the end of December 2008.

TUoS tariffs are designed to recover the total costs associated with the transmission business (i.e. the cost of both the Transmission System Operator (TSO) and Transmission Asset Owner (TAO) businesses). The total revenue to be recovered through TUoS is approved by the CER and for the calendar year 2007 amounts to €291.9M (CER Determination CER/06/199) and for calendar year 2008 amounts to €249.4M[3] (CER Determination CER/07/184). The transmission tariffs have been designed to fully recover the TUoS revenue requirement from transmission "users", which includes both generation and demand users connected directly to the transmission system or indirectly via the distribution system.

It should be noted that the demand tariffs approved for the period 2007/2008 have been derived consistent with the methodology used to derive the tariffs since 2000. Furthermore because this tariff period is split over two calendar years a blending of tariffs over the two years was carried out. This blending is explained in section 2.0.

The structure of this document is as follows:

- Section 2 details some of the SEM related amendments.
- Section 3 outlines the revenue requirement as approved by the CER for the years 2007 and 2008 and provides a breakdown of the proportions recovered from generation and demand users.
- Section 4 provides a description of the various charges that apply to demand users.
- Section 5 provides a detailed description of the generation tariff structure.

[1] Originally the tariff period was 11 months, from the 1st November 2007 to the 30th September 2008. However the tariff period was extended by the CER in their Decision paper "Decisions on Electricity Retail Tariff Inputs for 2008/2009", link: CER/08/136

[2] Link to RAs' PES Tariff Year Alignment Decision, AIP/SEM/07/93

[3] This excludes a net payback of €21M over the tariff period on system services charge. The net payback is a combination of an over recovery of approx €31.9M in 2007 and an under recovery of approx €10.9M in 2006.

- Section 6 deals with Autoproducers and Connection Offer Process Application Fees.
- Appendix 1 provides an example of how a user's metered energy is adjusted by the applicable distribution loss adjustment factor (DLAF) to derive the metered energy value as charged for.
- Appendix 2 presents a detailed explanation of the generation tariff calculation, the reverse MW-mile approach.

2 *SEM Related Amendments*

The introduction of the SEM has led to a number of consequential changes to the content and structure of the Statement of Charges, these are described below.

2.1 Blended Demand Tariffs

In order to produce a tariff across two calendar years[4] the 2007/2008 tariffs were calculated based on a blending of the tariffs over the two calendar years. This blending was done by getting a weighted sum of the tariffs over the two years. For each year the proportion of energy belonging to the 2007/2008 period was divided by the total energy for the 2007/2008 11 month period. These factors were then used to get the weighted sum for the 2007/2008 tariffs. These tariffs will also be applied for the final 3 months of 2008.

For example taking the Capacity Margin Charge, assume for 2007 the Capacity Margin Charge is €X/MWh and for 2008 it is €Y/MWh. Also assuming that of the total energy in the 2007/2008 11 month period the 2007 calendar year contributes A% and the 2008 calendar year contributes B%. Then the blended Capacity Margin Charge will be (X*A) + (Y*B).

2.2 All Island TUoS Revenue Harmonisation

It should be noted that for the 2007/2008 tariffs EirGrid's internal costs are shared between Network Charges (Controllable Costs e.g. system planning functions) and System Services Charges (External Costs e.g. system operation functions), whereas previously all internal costs were associated with Network Charges. This cost reallocation aligns EirGrid with the System Operator for Northern Ireland's (SONI) transmission revenue categorisation and ensures that revenue is recovered on a consistent basis across the island.

2.3 All Island Generator TUoS Tariff Harmonisation

The Regulatory Authorities (RAs) on behalf of the SEM Committee decided on 19/12/2007 to continue with the 2007 jurisdictional transmission use of system (TUoS) tariffs for generators and to defer the introduction of all-island locational TUoS tariffs with a view to implementation in the next tariff year commencing on the 1st October 2008[5]. However following the RAs' recent all island generator TUoS tariff consultation the introduction of all island tariffs has been postponed further. The 2007 generator TUoS tariffs in Ireland will remain in place until 31st December 2008[6].

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[4] Originally from November 2007 – September 2008, however following CER Decision CER/08/136 the 11 month tariff is being extended to 31st December 2008

[5] Link to RAs' decision on Generator Tariffs: RAs' Decision December 2007

[6] Link to RAs' decision on Generator Tariffs: RAs' Decision August 2008

2.4 Generator Commissioning Charge

The Generator Commissioning Charge has been removed from EirGrid's Statement of Charges and is now levied by the Single Electricity Market Operator (SEM-O).

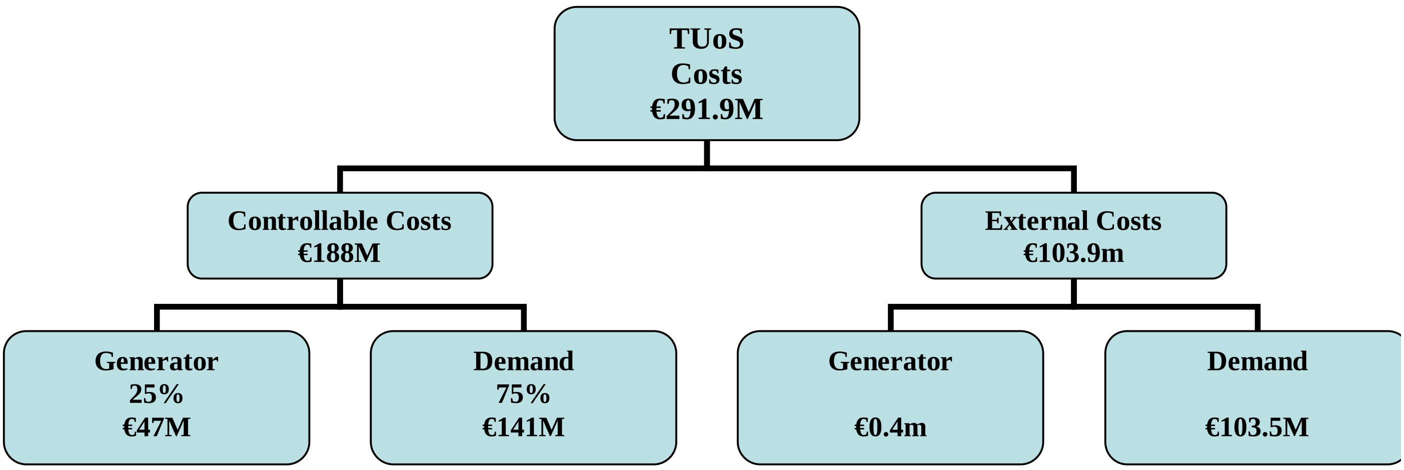
3 *Revenue requirement – 2007 and 2008*

Figure 1 provides an overview of how the total revenue requirement as allowed by CER for the year 2007 (in year 2007 terms), is recovered from Generators and Demand Users. As illustrated, the total revenue allowed to operate the transmission system for year 2007 is €291.9M. This consists of Controllable costs sometimes referred to as "wires" related costs, (which includes costs associated with deprecation, rate of return, transmission maintenance, capital expenditure and a portion of EirGrid's operating expenditure costs) totalling €188.8M and External costs or "non-wires" costs (which includes costs associated with Ancillary Services, Constraints, some DSO wires costs and a portion of EirGrid's operating expenditure costs) totalling €103.9M.

Figure 2 provides an overview of how the total revenue requirement as allowed by CER for the year 2008 (in year 2008 terms), is recovered from Generators and Demand Users. As illustrated, the total revenue allowed to operate the transmission system for year 2008 is €249.4M[7]. This consists of Controllable costs totalling €180.8M and External costs totalling €68.6M[8].

As shown in the figures below , 25% of the Controllable costs are recovered from generation and the remaining 75% from demand users. All External costs, with the exception of revenue received from generation trip payments, are recovered from demand users.

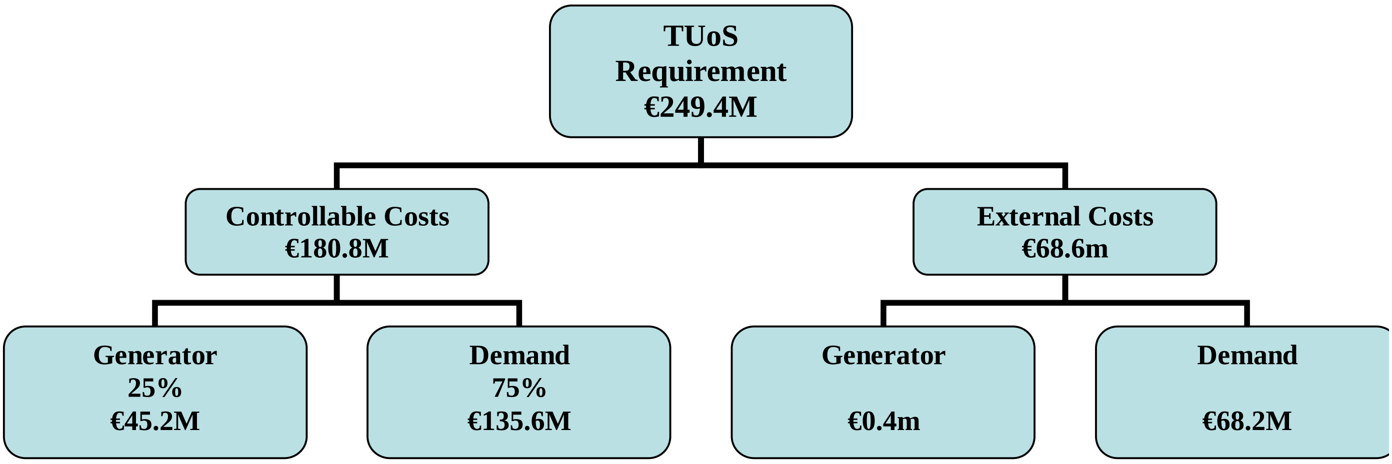
Figure 1: Transmission Revenue Requirement for year 2007



[7] This excludes a net payback of €21M over the tariff period on system services charge. The net payback is a combination of an over recovery of approx €31.9M in 2007 and an under recovery of approx €10.9M in 2006.

[8] It should be noted that constraints costs are now recovered on an all island basis by SEM-O.

Figure 2: Transmission Revenue Requirement for year 2008



4 *Description of the Various Transmission Related Charges*

This section provides a description of the structure of the various transmission tariffs that apply to demand users.

There are three classes of Demand Transmission Service (DTS) provided by EirGrid.

(1) Tariff Schedule DTS-T: applies to suppliers serving customers connected directly to the transmission system**.**

(2) Tariff Schedule DTS-D1: applies to suppliers serving customers connected to the distribution system and having a Maximum Import Capacity of 0.5MW or above (before adjusting for the appropriate distribution loss factor).

(3) Tariff Schedule DTS-D2: applies to suppliers serving all other customers connected to the distribution system who are not served under the other tariff schedules noted above.

Suppliers on each of the three demand tariff schedules above are liable to pay the various transmission related charges as shown in the respective schedule in the Statement of Charges.

Transmission related charges comprise Network Charges and System Services Charges.

Network Charges are primarily related to recovery of wires costs. These recover the costs for the use of the transmission system infrastructure for the transportation of electricity in Ireland. 75% of the total wires related costs are recovered from demand users and the remaining 25% from generators, see Figure 3 below.

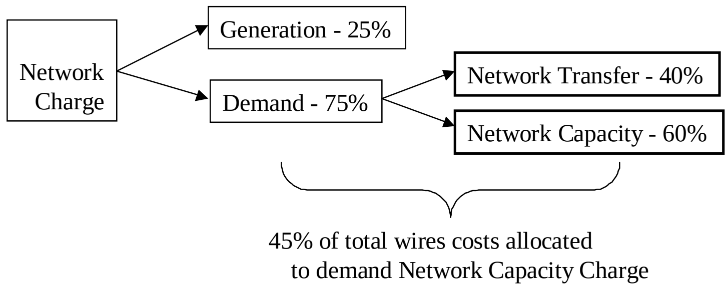
System Services Charges relate to the recovery of non-wires costs. These recover the costs arising from the operation and security of the transmission system. Specifically, these charges recover the costs associated with ancillary services and system support services[9]. EirGrid pays the costs of these services to the providers of such services and users pay EirGrid a System Services Charge in respect of these costs.

4.1 Network Charge

Of the allowed revenue associated with the Network Charge (or wires costs) 75% are recovered from demand customers[10]. However, the Network Charge recovered from demand customers is not recovered solely on a capacity basis but instead on a split basis between capacity and energy, 60% is recovered on a capacity basis, through 'Network Capacity Charge' and the remaining 40% on an energy basis through 'Network Transfer Charge'. This effectively amounts to 45% of the total wires costs being allocated to the Network Capacity Charge.

[9] It should be noted that constraints costs are now recovered on an all island basis by SEM-O.
[10] The remaining 25% is recovered from generation.

Figure 3: Network Charge (Wires Cost)



4.1.1 Network Capacity Charges

In relation to the allocation to Demand of the allowed transmission revenue associated with the wires related charges, 60% is allocated to Demand on a fixed basis through a per MW, Network Capacity Charge, or equivalent[11]. It is considered appropriate to recover a significant proportion of the charge on a fixed basis as the transmission network is primarily a fixed cost that, while designed to meet system "coincident peak"[12] at its core, must also be designed to meet the "non-coincident peak" at its extremities.

Network Capacity Charge - Tariff Schedule DTS-T

Transmission, or directly connected, customers are currently measured using profile (interval) metering and are contracted to a Maximum Import Capacity (MIC) under the Connection Agreement. This MIC value is used in assessing the capacity charges for each particular customer served by a supplier under Tariff Schedule DTS-T. The MIC value is the level to which EirGrid will design the transmission system to deliver electricity to the customer. The charge has been designed with a bandwidth to allow for a reasonable seasonal variation in demand.

Network Capacity Charge - Tariff Schedule DTS-D1

Distribution connected customers with a MIC of 0.5MW or above prior to adjusting for the appropriate distribution loss factor[13] are charged based on Tariff Schedule DTS-D1. This tariff schedule is very similar to Tariff Schedule DTS-T in that the distribution MIC value, after an adjustment for distribution losses, is used in assessing the capacity charge for each particular customer served by a supplier under this schedule. The charge has been similarly designed with a bandwidth to allow for a reasonable seasonal variation in demand.

The charge has also been modified to reflect the fact that distribution connected customers, through diversity of their demands, do not have the same effect on the

[11] The Network Capacity Charge under Tariff Schedule DTS-D2 is based on a per MWh during day hours as a proxy for per MW charging (this is discussed in more detail below).
[12] Within system planning criteria.
[13] See appendix 1 of this document for more details on application of distribution loss factors.

transmission system at the Grid Exit Point[14] as would a directly connected customer. Consequently, the network capacity charge for customers under the DTS-D1 schedule is below the corresponding charge under the DTS-T charge.

It has not been possible to charge all distribution connected eligible customers on the basis of the DTS-D1 tariff, as information on both MICs and profiled energy consumption for some of these customers is not available. Therefore these customers are charged on the basis of the DTS-D2 tariff, as a proxy for the DTS-D1 tariff. In time it is envisaged that relevant information will become available to charge all appropriate users on DTS-D1 tariff schedule.

Network Capacity Charge - Tariff Schedule DTS-D2

Distribution connected demand customers with an MIC value below the threshold of 0.5MW (prior to adjusting for the appropriate distribution loss factor) are charged based on Tariff Schedule DTS-D2. Under Tariff Schedule DTS-D2 the Network Capacity Charge is levied on a variable basis of consumption, which occurs during Day Hours[15]. Day Hour recovery is considered an effective proxy for having MIC values for all DTS-D2 customers. The Network Capacity Charge for each user class can be found in the Statement of Charges which is available on the website www.eirgrid.com.

4.1.2 Network Transfer Charge

Of the allocation to Demand of the wires related costs, 40% is allocated to Demand on an energy basis through a, per MWh, Network Transfer Charge. Consequently, demand users (i.e. DTS-T, DTS-D1 and DTS-D2) are charged consistent with their associated usage.

Based on a forecast of total energy consumption and on the allowed revenue the Network Transfer Charge for the period, which is the same for all 3 classes of demand customer, can be found in the Statement of Charges (available on www.eirgrid.com). It should be noted that the appropriate distribution loss factor will also be applied.

4.2 System Services Charge

Costs associated with system services are recovered almost entirely from demand users. This cost is recovered on an energy basis through a per MWh charge and it is based on projections of system services costs and energy consumption. The Statement of Charges provides the System Services Charge for the tariff period which is the same for all 3 classes of demand customer. It should be noted that the appropriate distribution loss factor will also be applied.

[14] A Grid Exit Point is defined as being any point where transmission system meets the distribution system.

[15] Day Hours being 08:00 to 23:00 inclusive all days.

4.3 Capacity Margin Charge

The Capacity Margin Charge is designed to recover costs associated with demand side management schemes administered by EirGrid[16]. Capacity Margin revenue is not part of Transmission Use of System revenue. This cost is recovered fully from demand users. All 3 classes of demand users are eligible to pay this charge, which is noted in the Statement of Charges. It should be noted that the appropriate distribution loss factor will also be applied.

4.4 Unauthorised Usage Charge (applies to DTS-T users only)

In order to incentivise Demand Users to accurately predict their MIC values, so that EirGrid can develop the system cost effectively while meeting the necessary security standards, an unauthorised usage charge is applicable for demand users connected directly to the transmission system that exceed their MIC. This charge is provided in the Statement of Charges**.**

4.5 Change in level of MIC – (applies to DTS-T users only)

As approved by CER on 04 February 2003 a period of 18 months notice is required from all Transmission connected customers who want to reduce their MIC. Customers must submit a modification request through the connection offer process. This requires a departing or reducing customer to contribute reasonable revenues in respect of the capacity, which was once provided at their request, now being unutilised and would allow any MIC changes to be incorporated in tariff determination. This notice period ensures that customers requesting changes to MIC values are doing so as a result of permanent changing needs and not for the purpose of avoiding capacity charges in the short-term. During the notice period customers would be charged based on their existing MIC for the Network Capacity Charge, hence ensuring all customers pay a minimum of eighteen months capacity charges for the originally requested MIC which the network was built to facilitate. However if another user or connecting party at the same Connection Point wishes to avail of unused capacity resulting from an MIC reduction, during the 18 month period following the reduction, then the original customer will not be liable for capacity charges in respect of this proportion of MIC from the date when the other user starts paying for that capacity.

Customers who request an increase in MIC have less of an effect on tariffs. Where possible the network can be developed to meet their request and they will be charged capacity charges based on the higher MIC value when it is delivered. Customers who bring about the need to enhance the network would be required to apply for a modification to their connection agreement by going through the normal connection offer process and commit to the increased MIC by providing a guarantee bond before necessary network construction works begin. This bond will be calculated based on the increased MW requested multiplied by the Network Capacity Charge (DTS–T

[16] These are the Powersave and Winter Peak Demand Reduction Schemes.

tariff schedule) which applies on the date of the agreement multiplied by eighteen. Customers in this situation would also be required to pay any associated connection charges. Customers who request capacity that already exists will be granted the additional capacity without any connection costs being payable where there is no change to the shallow connection; network capacity charges will be payable based on the customer's higher MIC.

Please refer to "MIC Administration Policy for customers connected to the Transmission System" available on www.eirgrid.com, for the background to the Unauthorised Usage Charge and other issues related to MIC Administration Policy.

5 *Generation Transmission Service*

5.1 Generation Network Capacity Charges

Of the total allocation of network related costs, 25% is allocated to generation users. This cost is recovered using the Generation Capacity Charge.

Generators connected directly to the transmission system or indirectly via the distribution system[17] currently pay locational use-of-system charges, derived using the 'Reverse MW-mile' methodology. These charges, which are capacity based, are designed to provide efficient locational signals to generators in support of an overall efficient transmission system. The Statement of Charges provides firm generation tariffs for the year. A detailed explanation of the methodology used to derive these charges is provided in Appendix 2 of this document.

5.2 Treatment of embedded Generators (i.e. connected at distribution voltage)

Any generator connected to the distribution system with a capacity less than 10MW has a locational Network Capacity Charge rate of zero. Embedded generators greater than or equal to this threshold are liable for a site specific Generator Network Capacity Charge.

5.3 Treatment of Intermittent & Temporary Generation

TUoS charges are designed to provide efficient pricing signals to generators connecting to the grid system. In calculating tariffs using the 'Reverse MW-mile' methodology, EirGrid credits those generators upon whom it is able to call upon to provide tangible system benefits through offsetting flows to the direction of dominant flow on the transmission system, and which thereby have the potential to reduce the need for future investment in the system. This can result in some generators having a negative overall TUoS charge. However, to date a lower bound of zero has been applied to generation which does not provide the level of system security from a planning perspective necessary to offset future investment requirements – wind generation due to its intermittent nature, and therefore inability of the system operator to call upon it should the need arise, and so called 'emergency' generators due to the nature of their temporary connection to the system. Neither generation which is intermittent in nature, nor that which is likely to be connected for only a limited period, is able to provide the requisite level of system support to the system operator. Crediting these generators for offsetting flows, recognising they have the potential to provide some system benefits, but capping the value of any offsets such that their overall TUoS charge should be no lower than zero, given that the system operator is unable to rely upon this generation to provide system support is felt to represent a reasonable compromise position.

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[17] As discussed in section 5.2 embedded generators below the 10MW threshold have a zero rate for this charge.

5.4 Unit Trip Payments

Generators above 100MW are liable for two types of trip payments; the direct trip charge and the fast wind-down trip charge. These charges are payable each time a generator experiences a sudden and immediate loss of output. The Statement of Charges shows the charges per MW of trip output in excess of 100MW which generators will incur.

5.5 Volatility: Generation tariffs

The main objective of the reverse MW-mile methodology it to provide efficient locational signals to generators. However, a possible drawback of this approach from a generator's viewpoint is volatility resulting from the annual adjustments in tariffs faced by generators which result from changing network conditions and changing generation and load patterns. Bearing this in mind a slight modification, as described in section 5.5.1 below, to the tariff calculation methodology was introduced to calculate the 2006 Generator Network Capacity Charges. This modification was also implemented for 2007 tariffs. As noted in section 2.3 above the 2007 generator tariffs will apply until 31st December 2008.

5.5.1 Modification to the Methodology

The modification involves calculating the percentage utilisation of every transmission line. The cost of lines where less than 20% of their rated capacity is used is set to €0 in the cost model. The cost model lists the costs of all transmission lines based on their annual replacement cost. Thus the revenue normally recovered/rebated on these lines is instead dealt with in the Postage Stamp Coverage[18]. This modification should contribute to a less volatile tariff environment. Appendix 2 details the complete Generator TUoS methodology for a simple 6 bus system.

5.6 'Non firm' transmission tariffs

The methodology described above applies to those generators who have reached their deep operational date as specified in their connection agreement. Generators who have not reached their deep operational date are currently charged on a per MWh basis. These MWh charges are calculated using a site-specific charge per kilowatt per year (kW/year) calculated in the standard manner using the Reverse MW Mile approach. The kW charge is converted to a kWh charge by the application of an assumed availability factor. These tariffs are sometimes referred to as a non-firm transmission tariff. The 'non-firm' transmission tariff has historically been charged to all transmission connected dispatchable generators for output in excess of the shallow connection capacity following the shallow connection date. This has been applied to conventional generation since the Firm/Non-Firm CER direction of 19th June 2001

[18] The final tariff in the Statement of Charges is made up of the locational tariff and the postage stamp tariff. This postage stamp tariff may be added on or subtracted to ensure required revenue is recovered.

CER/01/72. Wind generators were not subject to the Firm/Non-Firm direction and so this charge was never applied to them. Neither were they entitled to connection until the Deep Operational Date had been reached and all the associated system reinforcements were in place.

Subsequent to the CER direction of 8th July 2005 CER/05/107 renewable generators will be charged on this energy based tariff following the Operational Date and also following the receipt of an Operational Certificate; they will have access rights to the system at that time prior to the completion of all the associated transmission reinforcements except not before short-circuit driven deep reinforcement works. This takes into account the time lag in delivering the transmission reinforcement works associated with the large volume of connection applications which have been processed under the group processing arrangements.

This energy based tariff was only ever envisaged to be charged on a short term basis. As we have indicated above a purely energy based tariff is not very reflective of the costs of providing the network which have a significant fixed, or capacity element. However, to provide for access arrangements to comply with the CER direction of 8th July 2005 it will be extended in the short term until a comprehensive non-firm policy is put in place.

5.6.1 Tariffs which apply to non-firm generators

The non-firm tariff is derived using the current generation location based network capacity charging methodology which calculates a site-specific charge per kilowatt per year (kW/year) (customers are charged on a monthly basis and therefore also listed in the Statement of Charges as €/MW/Month). This charge is then converted to a price per megawatt hour (MWh) in order to charge the generator a non-firm tariff based on the quantity of energy it produces. In converting the capacity charge to an energy charge a load factor for each generator is assumed. At the moment a load factor of 100% is assumed for conventional plant and a load factor of 33% for wind generators.

For example, assuming a load factor of X%, a capacity charge (€/kW/year) is converted to an energy charge (€/kWh) by dividing by the total number of hours in the year multiplied by X% i.e. 8760 hours[19] * X%. To convert from €/kWh to €/MWh it is required to multiply by 1000.

[19] Not a leap year.

6 *Other Issues*

6.1 Treatment of Autoproducers

On 17th April 2002, the CER published a direction CER/02/37 addressing the issue of how Autoproducers should be treated in the transmission charging regime. An autoproducer is defined as someone who produces electricity essentially for his own use. On 25th September 2003 CER issued a direction CER/03/237 extending this to apply to all CHP generators.

CER have ruled that Autoproducers and CHP generators will pay Network Capacity Charges as either a demand user or a generator, but not both. Other TUoS charges are payable as both a demand user and generator as outlined in the Statement of Charges.

Autoproducers and CHP generators connected to the transmission system will pay Transmission Use of System tariffs under tariff schedule ATS-T. A User connected to the distribution system who is deemed to be an Autoproducer will pay charges as outlined in tariff schedule ATS-D in the Statement of Charges.

6.2 Connection Offer Process Application Fees

Connection Offer Process Application Fees apply to applicants who enter the connection offer process and are outlined in Schedule COP1 in the Statement of Charges. The fee is dependent on the size (capacity) of the applicant's development and whether new shallow connection works are involved in dealing with the capacity required.

For further information please see the "Connection Offer Process" published on the EirGrid website. A separate schedule of Connection Offer Process application fees applies for Group Processing applicants. This schedule applies to parties that connect to the distribution or transmission system. These fees are also approved by the CER.

Appendix 1: Metered Energy Calculation

This appendix provides an example of how a user's metered energy is adjusted by the applicable distribution loss factor to derive the metered energy value, as defined in EirGrid's Statement of Charges. While it is not shown here capacity charges are also adjusted by the applicable distribution loss factor.

The metered data files generated by MRSO[20] contain average kW readings for each Demand Transmission customer for each fifteen minute interval, in each settlement day. The TUoS application system converts these kW readings to MWh readings by dividing each reading by 4000 (i.e. 1000*4).

For example, consider a customer with a demand of 1400 kW and 1200 kW in two consecutive 15 minute periods in a given trading interval (i.e. half hour period). These kW readings are converted to MWh readings as follows:

1400 kW-15avg/1000 kW/MW = 1.4 MW-15avg/4 MWh/MW-15avg = 0.35 MWh
1200 kW-15avg/1000 kW/MW = 1.2 MW-15avg/4 MWh/MW-15avg = 0.30 MWh

These MWh readings are then adjusted by the relevant distribution loss factor and summed together to provide the total metered energy value in that trading period. The settlement day is divided into day hours and night hours, with different Distribution Loss Factors (DLF) applicable to day and night readings. Day hours are defined as 08:00 to 23:00 with night being 23:00 to 08:00.

So in our example, if we assume that the user is connected at 38kV and is a D1 customer, then assuming that the trading interval has occurred during day time hours, the metered energy value is equal to (0.35 * 1.019) + (0.30 *1.019).

In a billing period (i.e. in a given month) the network transfer charge and the system services charge are then derived by multiplying this metered energy value by the network transfer tariff rate and the system services tariff rate, respectively.

Capacity related charges are also levied for each billing period (i.e. month in question) consistent with the rules as outlined in EirGrid's Statement of Charges.

Table 1: Distribution loss factors 2007/2008

Voltage	Day	Night
220 kV	1	1
110 kV	1	1
38 kV	1.019	1.016
MV	1.047	1.040
LV	1.096	1.082

Note: Day Hours = 08:00 to 23:00 hours inclusive on any day

[20] Meter Registration System Operator (MRSO) is responsible for the change of supplier process and the communication/aggregation of meter data required to support Trading and Settlement in the all island competitive electricity market.

Appendix 2: Tariff Calculation Example (Reverse MW-mile approach)

This Appendix presents a detailed explanation of the Reverse MW-Mile approach applied to an example small system, comprising 6 buses and 8 circuits. This approach is used to derive EirGrid's generation locational transmission charges. All calculations are carried out using a specialised software package called 'Integra'.

There are three main steps involved in deriving generation charges:

(1) the use of each circuit by each generator is determined using load flow analysis. This analysis requires the specification of generation and demand at each point on the network. The load flow study then calculates the flow of all power from generators to demand sinks, based on peak load conditions.

(2) transmission assets are valued based on replacement costs. The cost of each circuit includes a depreciation charge, operations and maintenance overheads plus an appropriate rate of return. Station costs are apportioned to each line connecting into that station on a per bay basis. Only lines where more than 20% of their rated capacity is used are included in the model.

(3) Generators are charged for each circuit in direct proportion to their contribution. A key feature of the Reverse MW-mile approach is that generators which off-set flows are rewarded, by crediting counter-flows. Due mainly to the lumpiness of transmission investment, at any given point in time, spare capacity (i.e. differences between the rated capacity of an asset and the extent to which is used by all network users) will exist on the transmission system. The cost associated with the spare capacity on all circuits is averaged across all users (as opposed to charging the full cost of a circuit to the specific users of each circuit).

Illustrative Example

A simple 6 bus system illustrated below is used to provide an understanding of the workings of the Reverse MW-mile approach.

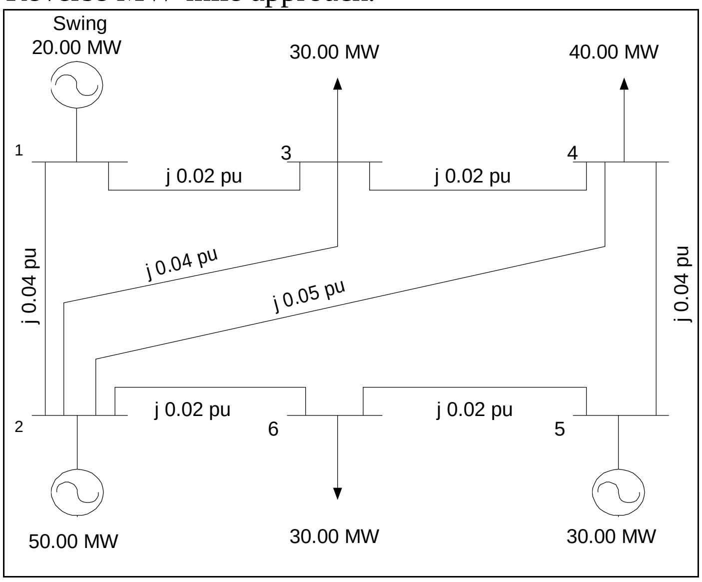


Figure 2 – System Example

This system is assumed to have 3 generators serving a total system demand of 100MW. For simplicity the capacity of all circuits is assumed to be 50MW and the annual value (i.e. includes depreciation, RoR and O&M) of each circuit is assumed to be €50,000.

Step 1(a) – Load Flow Calculation

A DC power flow is calculated to identify the circuit flows of the system. It is important to determine the direction of the flow in each circuit caused by each generator. If the circuit flow caused by the generator and the total circuit flow in a circuit are in the same direction, the flow is called 'dominant'. If the flows are in opposite direction to the dominant flow, the flow is called 'reverse'. When the generator is responsible for a dominant flow, then that generator is increasing the flow in the circuit, and pays for its use. However, if a generator is responsible for a reverse flow, then that generator is reducing the flow in the circuit, and receives credit for postponing the expansion of the transmission system.

To determine the contribution of each generator to circuit flows it is necessary first to run a load flow that matches total system demand and generation.

The formulation of the linear power flow (DC approach) is presented below:

$P_{ij} = x_{ij}^{-1} \cdot \theta_{ij}$ $\quad$ P_{ij} = circuit flow (pu) – base 100 MVA

x_{ij} = circuit reactance (pu)

θ_{ij} = angle between the buses i and j (rad)

$$P_i = \sum x_{ij}^{-1} \cdot \theta_{ij}$$

$$P_i = \left(\sum x_{ij}^{-1}\right) \cdot \theta_i + \left(\sum - x_{ij}^{-1}\right) \cdot \theta_j$$

P_i = net injection = $P_{Gi} – P_{Li}$ (pu)

In matrix form:

$$P = B \cdot \theta \qquad B_{ij} = -x_{ij}^{-1} \qquad B_{ii} = \sum x_{ij}^{-1}$$

Using the numerical values of the system example:

$$P = B \cdot \theta$$

$$\begin{bmatrix} 0.20 \\ 0.50 \\ -0.30 \\ -0.40 \\ 0.30 \\ -0.30 \end{bmatrix} = \begin{bmatrix} 75 & -25 & -50 & 0 & 0 & 0 \\ -25 & 120 & -25 & -20 & 0 & -50 \\ -50 & -25 & 125 & -50 & 0 & 0 \\ 0 & -20 & -50 & 95 & -25 & 0 \\ 0 & 0 & 0 & -25 & 75 & -50 \\ 0 & -50 & 0 & 0 & -50 & 100 \end{bmatrix} \cdot \begin{bmatrix} \theta_1 = 0 \\ \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix}$$

However, the matrix B is singular, so it doesn't have an inverse. Consequently, it is necessary to reduce the matrix by the terms of the swing bus (bus 1).

$$P = B'\theta$$

$$\begin{bmatrix} 0.50 \\ -0.30 \\ -0.40 \\ 0.30 \\ -0.30 \end{bmatrix} = \begin{bmatrix} 120 & -25 & -20 & 0 & -50 \\ -25 & 125 & -50 & 0 & 0 \\ -20 & -50 & 95 & -25 & 0 \\ 0 & 0 & -25 & 75 & -50 \\ -50 & 0 & 0 & -50 & 100 \end{bmatrix} \cdot \begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix}$$

To calculate the value of the angle, θ_{ij}, and after that the circuit flow P_{ij}, it is necessary to solve this equation:

$$\theta = (B')^{-1} \cdot P$$

$$\begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix} = (B')^{-1} \cdot P = \begin{bmatrix} 0.0013 \\ -0.0046 \\ -0.0062 \\ 0.0005 \\ -0.0021 \end{bmatrix}$$

The flow in each circuit is obtained by the expression:

$$P_{ij} = -B_{ij} \cdot \theta_{ij}$$

Also included below is the percentage utilisation of each circuit based on the line capacities of 50MW.

$$P_{12} = -B_{12} \cdot q_{12} = 25 \cdot (-1.284 \cdot 10^{-3}) = -0.0321 pu = -3.21 MW \rightarrow \frac{3.21}{50} = 6.42\%$$

$$P_{13} = -B_{13} \cdot q_{13} = 50 \cdot (4.642 \cdot 10^{-3}) = 0.2321 pu = 23.21 MW \rightarrow \frac{23.21}{50} = 46.42\%$$

$$P_{23} = -B_{23} \cdot q_{23} = 25 \cdot (5.924 \cdot 10^{-3}) = 0.1481 pu = 14.81 MW \rightarrow \frac{14.81}{50} = 29.62\%$$

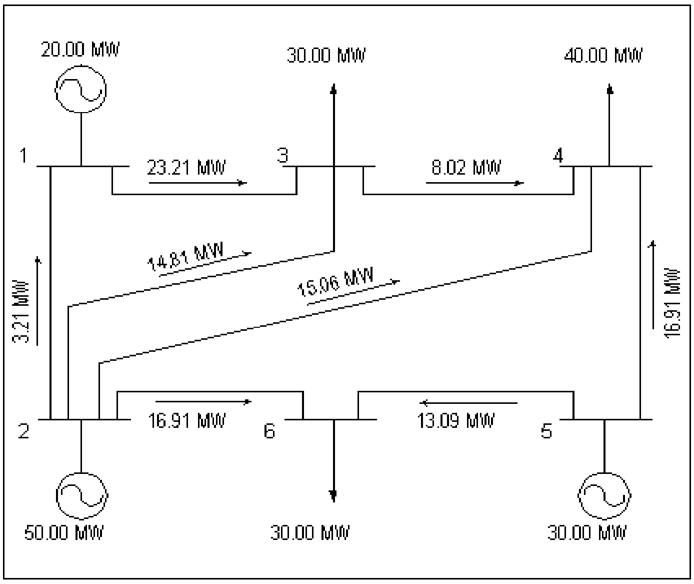
$$P_{24} = -B_{24} \cdot q_{24} = 20 \cdot (7.530 \cdot 10^{-3}) = 0.1506 pu = 15.06 MW \rightarrow \frac{15.06}{50} = 30.12\%$$

$$P_{26} = -B_{26} \cdot q_{26} = 50 \cdot (3.382 \cdot 10^{-3}) = 0.1691 pu = 16.91 MW \rightarrow \frac{16.91}{50} = 33.82\%$$

$$P_{34} = -B_{34} \cdot q_{34} = 50 \cdot (1.604 \cdot 10^{-3}) = 0.0802 pu = 8.02 MW \rightarrow \frac{8.02}{50} = 16.04\%$$

$$P_{45} = -B_{45} \cdot q_{45} = 25 \cdot (-6.764 \cdot 10^{-3}) = -0.1691 pu = -16.91 MW \rightarrow \frac{16.91}{50} = 33.82\%$$

$$P_{56} = -B_{56} \cdot q_{56} = 50 \cdot (2.618 \cdot 10^{-3}) = 0.1309 pu = 13.09 MW \rightarrow \frac{13.09}{50} = 26.18\%$$



Circuit Flows

System Generation = Generation Bus1 + Generation Bus2 + Generation Bus5
System Generation = 20 + 50 + 30 = 100 MW

Step (1b) – Power flow caused by each generator

To calculate the circuit flow caused by each generator we run a power flow representing all generators except the one we are studying. The total system load should be reduced proportionally to match the system dispatch. The flow in each circuit caused by the generator we are studying is equal to the total flow in the circuit (i.e. basecase scenario) minus the flow we obtain when running a loadflow without the generator under study.

After calculating the circuit flows, and determining whether flows are dominant or reverse, we calculate the locational signal (MW-Mile Tariff before applying the Postage Stamp Coverage) associated with each generator.

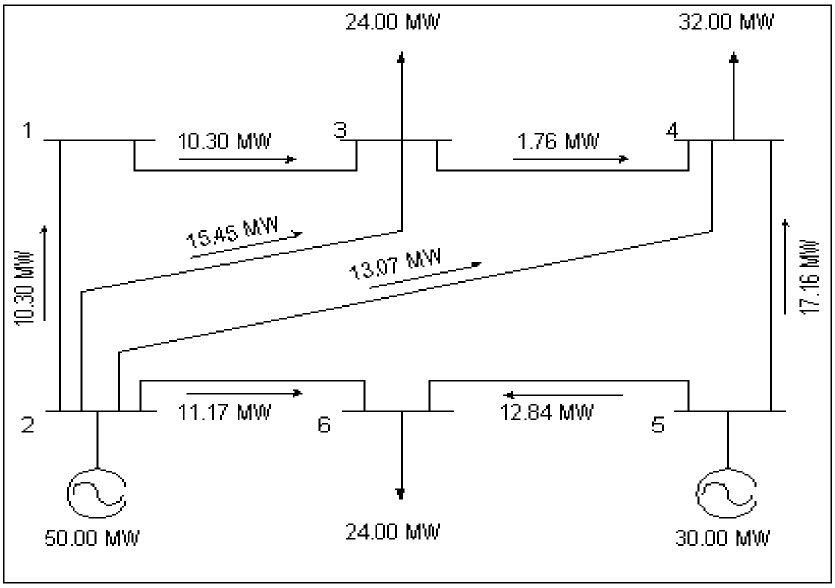
Generator at Bus 1 – Calculating Circuit Flows

System Generation = 80 MW = 0.80 pu
Generation at Bus 1 = 0 MW = 0.00 pu
Generation at Bus 2 = 50 MW = 0.50 pu
Generation at Bus 5 = 30 MW = 0.30 pu

Load at Bus 3 = 30% x 80MW = 24 MW = 0.24 pu
Load at Bus 4 = 40% x 80MW = 32 MW = 0.32 pu
Load at Bus 6 = 30% x 80MW = 24 MW = 0.24 pu

$$\begin{bmatrix} q_2 \\ q_3 \\ q_4 \\ q_5 \\ q_6 \end{bmatrix} = B^{-1} \cdot P = B^{-1} \cdot \begin{bmatrix} 0.50 \\ -0.24 \\ -0.32 \\ 0.30 \\ -0.24 \end{bmatrix} = \begin{bmatrix} 4.1218 \\ -2.0609 \\ -2.4132 \\ 4.4543 \\ 1.8881 \end{bmatrix} \cdot 10^{-3}$$

$$P_{12} = -B_{12} \cdot \theta_{12} = 25 \cdot (-4.1218 \cdot 10^{-3}) = -0.1030\text{pu} = -10.30\text{MW}$$
$$P_{13} = -B_{13} \cdot \theta_{13} = 50 \cdot (2.0609 \cdot 10^{-3}) = 0.1030\text{pu} = 10.30\text{MW}$$
$$P_{23} = -B_{23} \cdot \theta_{23} = 25 \cdot (6.1827 \cdot 10^{-3}) = 0.1545\text{pu} = 15.45\text{MW}$$
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (6.5350 \cdot 10^{-3}) = 0.1307\text{pu} = 13.07\text{MW}$$
$$P_{26} = -B_{26} \cdot \theta_{26} = 50 \cdot (2.2337 \cdot 10^{-3}) = 0.1117\text{pu} = 11.17\text{MW}$$
$$P_{34} = -B_{34} \cdot \theta_{34} = 50 \cdot (0.3523 \cdot 10^{-3}) = 0.0176\text{pu} = 1.76\text{MW}$$
$$P_{45} = -B_{45} \cdot \theta_{45} = 25 \cdot (-6.8675 \cdot 10^{-3}) = -0.1716\text{pu} = -17.16\text{MW}$$
$$P_{56} = -B_{56} \cdot \theta_{56} = 50 \cdot (2.5663 \cdot 10^{-3}) = 0.1284\text{pu} = 12.84\text{MW}$$



Circuit Flows Obtained Without Generator 1

Report of Circuit Flows:

CIRCUIT	TOTAL (MW)	GENERATOR 2 + GENERATOR 5 (MW)	GENERATOR 1 (MW)
1 – 2	-3.21	-10.30	+7.09 (R)
1 – 3	23.21	10.30	+12.91 (D)
2 – 3	14.81	15.45	-0.64 (R)
2 – 4	15.06	13.07	+1.99 (D)
2 – 6	16.91	11.17	+5.74 (D)
3 – 4	8.02	1.76	+6.26 (D)

4 – 5	-16.91	-17.16	+0.25 (R)
5 – 6	13.09	12.84	+0.25 (D)

Note: The circuit flow caused by generator 1 is calculated as the total circuit flow minus the circuit flow caused by the generators 2 and 5. “R” and “D” denote reverse and dominant flows respectively. If the flow caused by generator 1 is in the same direction as the total flow then it is a dominant flow. If the flow caused by generator 1 is in the opposite direction to the total flow then it is a reverse flow.

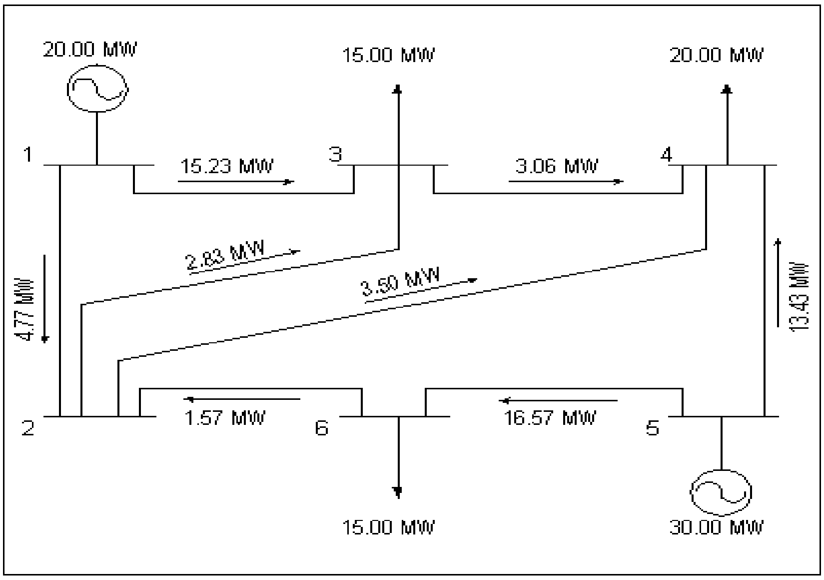
Generator at Bus 2 – Calculating Circuit Flows

System Generation = 50 MW = 0.50 pu
Generation at Bus 1 = 20 MW = 0.20 pu
Generation at Bus 2 = 0 MW = 0.00 pu
Generation at Bus 5 = 30 MW = 0.30 pu

Load at Bus 3 = 30% x 50 MW = 15 MW = 0.15 pu
Load at Bus 4 = 40% x 50 MW = 20 MW = 0.20 pu
Load at Bus 6 = 30% x 50 MW = 15 MW = 0.15 pu

$$\begin{bmatrix} \theta_2 \\ \theta_3 \\ \theta_4 \\ \theta_5 \\ \theta_6 \end{bmatrix} = B^{-1} \cdot P = B^{-1} \cdot \begin{bmatrix} 0.00 \\ -0.15 \\ -0.20 \\ 0.30 \\ -0.15 \end{bmatrix} = \begin{bmatrix} -1.9095 \\ -3.0453 \\ -3.6584 \\ 1.7160 \\ -1.5967 \end{bmatrix} \cdot 10^{-3}$$

$$P_{12} = -B_{12} \cdot \theta_{12} = 25 \cdot (1.9095 \cdot 10^{-3}) = 0.0477\text{pu} = 4.77\text{MW}$$
$$P_{13} = -B_{13} \cdot \theta_{13} = 50 \cdot (3.0453 \cdot 10^{-3}) = 0.1523\text{pu} = 15.23\text{MW}$$
$$P_{23} = -B_{23} \cdot \theta_{23} = 25 \cdot (1.1358 \cdot 10^{-3}) = 0.0283\text{pu} = 2.83\text{MW}$$
$$P_{24} = -B_{24} \cdot \theta_{24} = 20 \cdot (1.7490 \cdot 10^{-3}) = 0.0350\text{pu} = 3.50\text{MW}$$
$$P_{26} = -B_{26} \cdot \theta_{26} = 50 \cdot (-0.3127 \cdot 10^{-3}) = -0.0157\text{pu} = -1.57\text{MW}$$
$$P_{34} = -B_{34} \cdot \theta_{34} = 50 \cdot (0.6132 \cdot 10^{-3}) = 0.0306\text{pu} = 3.06\text{MW}$$
$$P_{45} = -B_{45} \cdot \theta_{45} = 25 \cdot (-5.3745 \cdot 10^{-3}) = -0.1343\text{pu} = -13.43\text{MW}$$
$$P_{56} = -B_{56} \cdot \theta_{56} = 50 \cdot (3.3127 \cdot 10^{-3}) = 0.1657\text{pu} = 16.57\text{MW}$$



Circuit Flows Obtained Without Generator 2

Report of Circuit Flows:

CIRCUIT	TOTAL (MW)	GENERATOR 1 + GENERATOR 5 (MW)	GENERATOR 2 (MW)
1 – 2	-3.21	4.77	-7.98 (D)
1 – 3	23.21	15.23	+7.98 (D)
2 – 3	14.81	2.83	+11.98 (D)
2 – 4	15.06	3.50	+11.56 (D)
2 – 6	16.91	-1.57	+18.48 (D)
3 – 4	8.02	3.06	+4.96 (D)
4 – 5	-16.91	-13.43	-3.48 (D)
5 – 6	13.09	16.57	-3.48 (R)

Note: The circuit flow caused by generator 2 is calculated as the total circuit flow minus the circuit flow caused by the generators 1 and 5.

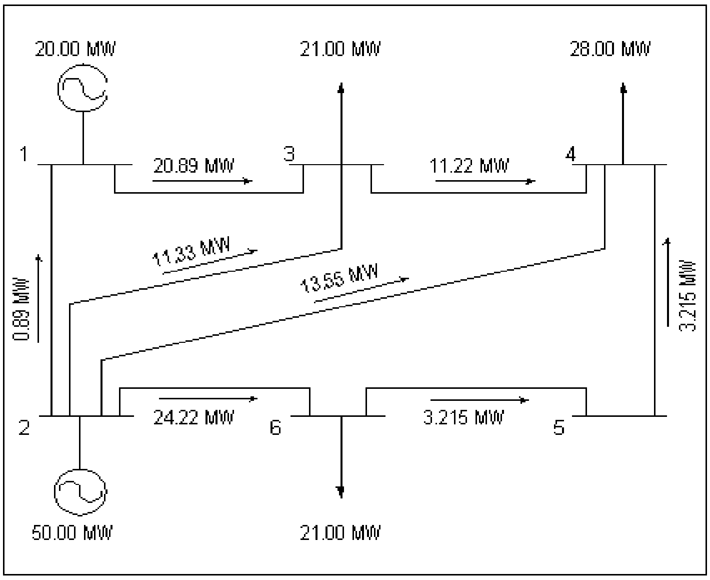
Generator at Bus 5 – Calculating Circuit Flows

System Generation = 70 MW = 0.70 pu
Generation at Bus 1 = 20 MW = 0.20 pu
Generation at Bus 2 = 50 MW = 0.50 pu
Generation at Bus 5 = 0 MW = 0.00 pu

Load at Bus 3 = 30% x 70 MW = 21 MW = 0.21 pu
Load at Bus 4 = 40% x 70 MW = 28 MW = 0.28 pu
Load at Bus 6 = 30% x 70 MW = 21 MW = 0.21 pu

$$\begin{bmatrix}\theta_2\\\theta_3\\\theta_4\\\theta_5\\\theta_6\end{bmatrix} = B^{-1}\cdot P = B^{-1}\cdot\begin{bmatrix}0.50\\-0.21\\-0.28\\0.00\\-0.21\end{bmatrix} = \begin{bmatrix}0.3555\\-4.1778\\-6.4222\\-5.1333\\-4.4889\end{bmatrix}\cdot 10^{-3}$$

$$P_{12} = -B_{12}\cdot\theta_{12} = 25\cdot(-0.3555\cdot 10^{-3}) = -0.0089pu = -0.89MW$$
$$P_{13} = -B_{13}\cdot\theta_{13} = 50\cdot(4.1778\cdot 10^{-3}) = 0.2089pu = 20.89MW$$
$$P_{23} = -B_{23}\cdot\theta_{23} = 25\cdot(4.5333\cdot 10^{-3}) = 0.1133pu = 11.33MW$$
$$P_{24} = -B_{24}\cdot\theta_{24} = 20\cdot(6.7778\cdot 10^{-3}) = 0.1355pu = 13.55MW$$
$$P_{26} = -B_{26}\cdot\theta_{26} = 50\cdot(4.8444\cdot 10^{-3}) = 0.2422pu = 24.22MW$$
$$P_{34} = -B_{34}\cdot\theta_{34} = 50\cdot(2.2444\cdot 10^{-3}) = 0.1122pu = 11.22MW$$
$$P_{45} = -B_{45}\cdot\theta_{45} = 25\cdot(-1.2889\cdot 10^{-3}) = -0.03215pu = -3.215MW$$
$$P_{56} = -B_{56}\cdot\theta_{56} = 50\cdot(-0.6444\cdot 10^{-3}) = -0.03215pu = -3.215MW$$



Circuit Flows Obtained Without Generator 5

Report of Circuit Flows:

CIRCUIT	TOTAL (MW)	GENERATOR 1 + GENERATOR 2 (MW)	GENERATOR 5 (MW)
1 – 2	-3.21	-0.89	-2.32 (D)
1 – 3	23.21	20.89	+2.32 (D)
2 – 3	14.81	11.33	+3.48 (D)
2 – 4	15.06	13.55	+1.51 (D)
2 – 6	16.91	24.22	-7.31 (R)
3 – 4	8.02	11.22	-3.20 (R)
4 – 5	-16.91	-3.215	-13.70 (D)
5 – 6	13.09	-3.215	+16.31 (D)

Note: The circuit flow caused by generator 5 is calculated as the total circuit flow minus the circuit flow caused by the generators 1 and 2.

Summary Report of Circuit Flows

CIRCUITS	TOTAL	GENERATOR 1 (20 MW)	GENERATOR 2 (50 MW)	GENERATOR 5 (30 MW)
1 – 2	-3.21	+7.09 (R)	-7.98 (D)	-2.32 (D)
1 – 3	23.21	+12.91 (D)	+7.98 (D)	+2.32 (D)
2 – 3	14.81	-0.64 (R)	+11.98 (D)	+3.48 (D)
2 – 4	15.06	+1.99 (D)	+11.56 (D)	+1.51 (D)
2 – 6	16.91	+5.74 (D)	+18.48 (D)	-7.31 (R)
3 – 4	8.02	+6.26 (D)	+4.96 (D)	-3.20 (R)
4 – 5	-16.91	+0.25 (R)	-3.48 (D)	-13.70 (D)
5 – 6	13.09	+0.25 (D)	-3.48 (R)	+16.31 (D)

Step 2 Costs associated with each circuit

For simplicity (as discussed above) it is assumed that the value of each circuit is equal to €50,000 except those circuits where less than 20% of their capacity is used. These circuits have an assumed value of €0.

CIRCUIT	COST (€)	CAPACITY (MW)
1 – 2	0	50
1 – 3	$50 \cdot 10^3$	50
2 – 3	$50 \cdot 10^3$	50
2 – 4	$50 \cdot 10^3$	50
2 – 6	$50 \cdot 10^3$	50
3 – 4	0	50
4 – 5	$50 \cdot 10^3$	50
5 – 6	$50 \cdot 10^3$	50

Step 3: Deriving generation locational charges

Given the results of the loadflow analysis and using the cost assumptions provided above, in this section we derive the locational signals for the simple system under study.

Generator at bus 1

CIRCUIT	COST (€)	CAPACITY (MW)	GENERATOR'S POWER FLOW (MW)	DIRECT (D) OR REVERSE (R)	LOCATIONAL SIGN PAYMENT (€)
1 – 2	0	50	7.09	R	0
1 – 3	$50 \cdot 10^3$	50	12.91	D	12910.00
2 – 3	$50 \cdot 10^3$	50	-0.64	R	-640.00
2 – 4	$50 \cdot 10^3$	50	1.99	D	1990.00
2 – 6	$50 \cdot 10^3$	50	5.74	D	5740.00
3 – 4	0	50	6.26	D	0
4 – 5	$50 \cdot 10^3$	50	0.25	R	-250.00
5 – 6	$50 \cdot 10^3$	50	0.25	D	250.00
				TOTAL	20000.00

$$p_i = \frac{\sum_{k=1}^{nlin} \frac{c_k}{k_k} \cdot w_k^i}{G_i} \quad (€/kW) \tag{1}$$

$$R_i = p_i . PG_i^{MAX} \ (€) \tag{2}$$

where

p_i = locational tariff for generator i
c_k = cost of circuit k
k_k = capacity of circuit k
w^i_k = circuit flow caused by generator i on circuit k
G_i = dispatch of generator i
R_i = amount paid by the generator at bus i
PG_i^{MAX} = MEC of generator i

Applying the formulas (1) and (2) above to the generator at bus 1:

$$p_1 = \frac{\sum_{k=1}^{nlin} \frac{c_k}{k_k} \cdot w_k^1}{G_1} = \frac{50 \cdot 10^3 (€)}{50MW} \cdot \frac{(12.91 - 0.64 + 1.99 + 5.74 - 0.25 + 0.25)MW}{20MW}$$

p_1 = €1.0000/kW

$R_1 = p_i . PG_i^{MAX}$ = €1.0000 / kW.(20MW) = €20,000

Generator at bus 2

CIRCUIT	COST (€)	CAPACITY (MW)	GENERATOR'S POWER FLOW (MW)	DIRECT (D) OR REVERSE (R)	LOCATIONAL SIGN PAYMENT (€)
1 – 2	0	50	-7.98	D	0
1 – 3	$50 \cdot 10^3$	50	7.98	D	7980.00
2 – 3	$50 \cdot 10^3$	50	11.98	D	11980.00
2 – 4	$50 \cdot 10^3$	50	11.56	D	11560.00
2 – 6	$50 \cdot 10^3$	50	18.48	D	18480.00
3 – 4	0	50	4.96	D	0
4 – 5	$50 \cdot 10^3$	50	-3.48	D	3480.00
5 – 6	$50 \cdot 10^3$	50	-3.48	R	-3480.00
				TOTAL	50000.00

Applying the formulas (1) and (2) above to the generator at bus 2:

$$p_2 = \frac{\sum_{k=1}^{nlin} \frac{c_k}{k_k} \cdot w_k^2}{G_2} = \frac{50 \cdot 10^3 (€)}{50MW} \cdot \frac{(7.98 + 11.98 + 11.56 + 18.48 + 3.48 - 3.48)MW}{50MW}$$

p_2 = €1.0000

$$R_2 = p_2 . PG_2^{MAX} = €1.0000 / kW.(50MW) = €50{,}000$$

Generator at bus 5

CIRCUIT	COST (€)	CAPACITY (MW)	GENERATOR'S POWER FLOW (MW)	DIRECT (D) OR REVERSE (R)	LOCATIONAL SIGN PAYMENT (€)
1 – 2	0	50	-2.32	D	0
1 – 3	$50 \cdot 10^3$	50	2.32	D	2320.00
2 – 3	$50 \cdot 10^3$	50	3.48	D	3480.00
2 – 4	$50 \cdot 10^3$	50	1.51	D	1510.00
2 – 6	$50 \cdot 10^3$	50	-7.31	R	-7310.00
3 – 4	0	50	-3.20	R	0
4 – 5	$50 \cdot 10^3$	50	-13.70	D	13700.00
5 – 6	$50 \cdot 10^3$	50	16.31	D	16310.00
				TOTAL	30010.00

Applying the formulas (1) and (2) above to the generator at bus 5:

$$p_5 = \frac{\sum_{k=1}^{nlin} \frac{c_k}{k_k} \cdot w_k^5}{G_5} = \frac{50.10^3(€)}{50MW} \cdot \frac{(2.32+3.48+1.51-7.31+13.70+16.31)MW}{30MW}$$

$$p_5 = €1.0003/kW$$

$$R_5 = p_5.PG_5^{MAX} = €1.0003/kW.(30MW) = €30{,}010$$

Postage Stamp Coverage

The locational sign is not sufficient to recover the total transmission system cost. To cover the total transmission system cost, it will be necessary to share among the generators the costs associated with unused capacity. The Postage Stamp (or average) coverage is the methodology used to distribute this cost among the generators. This methodology is presented below:

Transmission Revenue: 8 circuits x $50 \cdot 10^3$ (€) = $400 \cdot 10^3$ (€)

Total Revenue by Locational Sign = $R_1 + R_2 + R_5$ = $(20.00+50.00+30.01) \cdot 10^3$ = $100.01 \cdot 10^3$ (€)

Transmission system cost not remunerated: $400 \cdot 10^3 - 100.01 \cdot 10^3 = 299.99 \cdot 10^3$ (€)

Postage Stamp: $\Delta = \frac{299.99 \cdot 10^3 (€)}{100 \cdot 10^3 kW} = 2.9999(€)/kW$

BUS NUMBER	LOCATIONAL SIGNAL TARIFF (€/KW)	POSTAGE STAMP TARIFF (€/KW)	TOTAL TARIFF (€/KW)
1	1.0000	2.9999	3.9999
2	1.0000	2.9999	3.9999
5	1.0003	2.9999	4.0002

Report of Total Generation Payment:

BUS NUMBER	GENERATION (MW)	LOCATIONAL SIGN PAYMENT (€)	POSTAGE STAMP PAYMENT (€)	TOTAL PAYMENT (€)
1	20	20000	59998	79998
2	50	50000	149995	199995
5	30	30010	89997	120007
TOTAL	100	100010	299990	400000