All-Island Generator TUoS Methodology Statement

SEM-11-079

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System Operator for Northern Ireland

Table of Contents

1 Document Overview

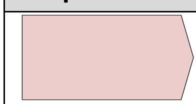
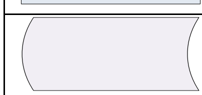
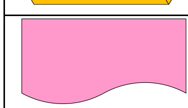
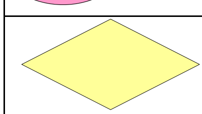
Document history

Version	Date	Comment	Author
2.0	19th August 2011	This version has been updated following consultation with the industry on the island of Ireland.	Mark Needham

Glossary

Abbreviation	**Definition**
TUoS	Transmission Use of System
MEC	Maximum Export Capacity
NI	Northern Ireland
ROI	Republic of Ireland
RAs	Regulatory Authorities in NI and ROI (NIAUR & CER)
NPV	Net Present Value
MEAV	Modern Equivalent Asset Valuation

Process Flowchart key

Shape	**Description**
	Process trigger
	Process Step
	System File
	Application
	Document
	Decision

2 Introduction

The SEM Committee decided on the tariff methodology in its decision paper "SEM-10-081 All-Island Generator Transmission Use of System Charges"[1]. Further details of the proposed methodology can be found in the "SEM-09-107 Preferred Options to be considered for the Implementation of Locational Signals on the Island of Ireland"[2] and "SEM-11-018 Locational Signals Project: All-Island Generator TUoS"[3]. Where matters in this latter consultation remain outstanding the indicative tariffs represent the status quo.

This User manual has been prepared to outline specific details concerning the production of generator tariffs based on the SEM-10-81. A high level overview of the tariff design can be found in the accompanying cover note.

The generator tariffs are set to recover a given revenue amount associated with the costs of building, operating and maintaining the all island transmission network. The proposed charging regime sets out to recover 25% of total network related costs on the island, as determined through the applicable transmission revenue controls.

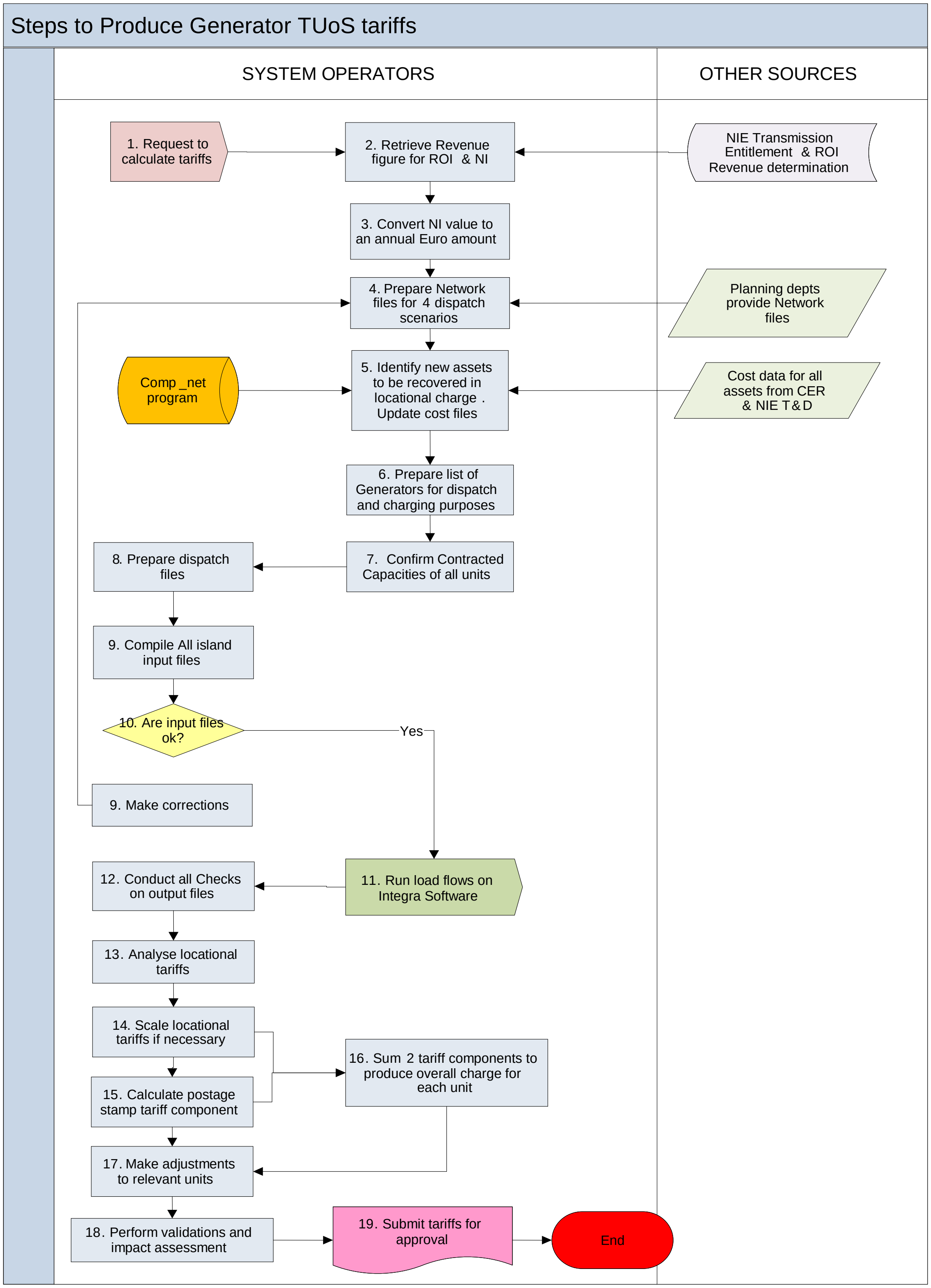
The flowchart below illustrates the high-level steps involved in preparing the tariffs from start to finish and the details of what is involved in completing each of these steps is outlined in more detail throughout this document.

[1] SEM-10-081 All-Island Generator Transmission Use of System Charges, Decision Paper, 15th December 2010http://www.allislandproject.org/en/transmission_decision_documents.aspx?article=5b96c825-702f-4e71-9ddc-7f655c4817d0

[2] SEM-09-107 Preferred Options to be considered for the Implementation of Locational Signals on the Island of Ireland Consultation Paper November 26th 2009
http://www.allislandproject.org/en/transmission_current_consultations.aspx?article=c4fdb48e-4a1a-44d6-848d-af13746ddcb8

[3] SEM-11-018 Locational Signals Project: All-Island Generator TUoS, 11 April 2011
http://www.allislandproject.org/GetAttachment.aspx?id=70f43b54-3fed-4386-8a5f-864312ada3b1

3 Methodology for Calculating TUoS charges



Flowchart 1: High level overview of Tariff process

3.1 Process Steps: Calculate TUoS tariffs

Ref #	Step	Input	Description
1	Trigger: SOs requirement to calculate annual tariffs	None	The SOs will prepare TUoS tariffs using revenue requirements for the forthcoming tariff period.
2	Retrieve revenue figures for both NI & ROI	1. EirGrid revenue determination 2. NIE T&D revenue entitlement	Based on the annual revenue that each RA has set out to be collected from TUoS tariffs the SOs will calculate the all-island revenue to be recovered from Generator TUoS. This is based on 25% of network related costs in ROI and 25% of the transmission entitlement in NI (which only includes network costs).
3	Convert NI revenue to a Euro amount	Exchange rate	All island tariffs will be prepared in Euro. The approach taken to convert the NI revenue requirement into Euro is consistent with the approach taken to calculate the SEM Capacity Payment mechanism.
4	Prepare Network files for each scenario	Planning data	A network snapshot for each scenario must be prepared. This data is obtained from the planning PSSE software and it is based on the information prepared by each SO and published in SONI's "Seven Year Transmission Statement" and EirGrid's "Transmission Forecast Statement". These statements provide the most accurate publically available data concerning each network's development. The network file includes a list of all nodes as well as the characteristics of the circuits between them.

Ref #	Step	Input	Description
5	Identify assets to include in the locational tariff calculations and include these in the ROI or NI cost database	Integra program “Comp Net” Previous Network file.	Each SO has a database of all existing /planned assets in the network and a cost associated with each as well including a date that the assets is due to be built or is built. The cost database must be consistent with the network files, therefore any changes in the network must be mirrored in the cost file, such as the inclusion of a new circuit, a change in bus number, or a change in configuration of the connection of an asset. In order to keep the cost file consistent with the network file, each year that a new network file is obtained, it is compared with the previous version of the network file for that scenario and the changes are identified. This comparison of two networks is done using a specialised Integra program. The Planning departments assist in providing necessary details on the network changes.
6	Prepare a list of generators that will be charged TUoS and that will be used in compiling dispatch files		It is necessary that the list of generators eligible to pay TUoS is updated with commissioning/retiring dates etc. It is also necessary for dispatch purposes that all new transmission generators and any new distribution connected generators over 5MW are also included. The proposed tariff model includes dispatch assumptions for all units connected to the network in the tariff period; it does not include future generation as the model does not wish to derive a tariff for future generators as this cannot be applied. To clarify, the model looks at network requirements in 5 years time and charges these based on the current generation meeting the current demand, i.e. looking at existing use of the future network.
7	Confirmed contracted capacities of all units	TUoS agreements	Given that TUoS charges are levied based on maximum contracted export capacity of each unit it is vital that these are updated and incorporate any changes that may have occurred.
8	Prepare dispatch files for each scenario	Plexos data	The dispatch files are prepared using a list from Plexos with each unit and its generation costs. Units are dispatched in order of price, starting with lowest, until demand is met.
10	Are all input files ok?		If there are any errors identified in the input files (Integra may detect these when files are loaded up) these must be amended

Ref #	**Step**	**Input**	**Description**
9	Make corrections to any input files as necessary		Amend errors then • loop back to step 4
11	Run load flow studies on Integra	Network file Cost file Dispatch file	The network file, cost file and dispatch file for each scenario in turn must be loaded into Integra and the load flow is performed
12	Conduct all checks on output files		Integra produces a number of output files and it is essential that each of these are checked in detail. The outputs include a list of any circuits which may not have a cost attributed with it – many of these will be correct but it is important to verify that no new assets that have not been paid for by a generator are on this list. Other checks include ensuring no serious overloads have occurred on any circuit.
13	Analyse locational tariffs		Tariff movements must be analysed and it must be confirmed that the tariff movement is logical – for example if a units tariff has increased this can be investigated by comparing the flows on each circuit that this unit has contributed to the previous tariff period, and the costs associated with these circuits.
14	Scale locational tariffs if necessary		If aggregate locational tariff recovery exceeds the limit pre-set then the scaling mechanism using a multiplier should be applied to reduce the revenue recovery from the locational tariff component
15	Calculate postage stamp tariffs	Total revenue requirement	The residual revenue should be calculated and allocated across all eligible units.
16	Combine locational and postage stamp tariff components		The locational tariff component and the postage stamp tariff component should be combined to produce the final charge for each unit.
17	Make adjustments to relevant units		Take account of relevant generators with negative tariff. See section 7.3.
18	Perform validations and impact assessment		See section 7.1

Ref #	Step	Input	Description
19	Submit tariffs for approval		Tariffs once prepared and checked are submitted to RAs in line with the SOs' license obligations.

Table 1: Process Steps

4 Dispatch and load flow issues

4.1 Dispatch scenarios

A dispatch file exists for each scenario that is examined as part of the TUoS tariff methodology as under different system conditions the generation amounts for each unit will vary to meet system demand.

The following are the four generation scenarios which EirGrid and SONI have agreed are plausible system running conditions that, in aggregate, represent the spectrum of operating conditions used in investment planning analysis.

- Winter Peak demand, Merit Order dispatch, 0% Wind
- Summer Peak demand, Merit Order dispatch, 80% Wind
- Summer Peak demand, Merit Order dispatch, 0% Wind
- Summer Min demand, Merit Order dispatch, 80% Wind

The main reason for the use of the 80% capacity factor is to test the network for a credible and onerous condition which the TSOs are obliged to consider. Based on historical data the occurrence of up to 80% wind during summer is a frequent enough event to consider this a credible dispatch.

In each of these dispatches the North South tie-line flow is determined by the Merit Order and the generation and demand pattern, it is not adjusted to reflect a predetermined flow. All the dispatch scenarios are based on unconstrained dispatches and network conditions

For the purpose of calculation of the indicative tariffs a 5MW[4] threshold for dispatch purposes is assumed reasonable as this captures the majority of small units.

To create each of the dispatch files a merit order stack is used. The merit order stack is sourced from the Plexos database and it lists each unit on the island in order of generation cost. For each scenario the units are put in order of price with the lowest cost units at the top, such as wind generators and hydro units, since these units are the first to be dispatched. It is assumed that all units are available to export

[4] For dispatch purposes all generators greater than 5MW are included in the dispatch model. However, for charging purposes for embedded generation, only generators greater with a MEC above 10MW are liable for TUoS charges. The SEM Committee is currently considering the lowering of this 10MW threshold as outlined in SEM-11-018.

at 100% of their installed capacity, except for wind units which are treated differently. Wind units are dispatched at either 80% of their installed capacity, in the two scenarios with high wind, and wind units are assumed to be dispatched at zero in the two scenarios with no wind. For scenarios that model 80% wind the assumed dispatch of the wind generator is calculated first. In the "Winter Peak" and "Summer Peak 0% wind" scenarios all wind generators should be set equal to zero output. In the "Summer Minimum" and "Summer Peak 80% wind" scenarios all the wind generators should be dispatched at 80% of their MEC. The units are dispatched at their MEC and the cumulative total is noted until the required demand is satisfied. In order to make the threshold smoother/fairer between the generators that are dispatched, all generators of a similar type are scaled by the same amount in order to meet the demand (e.g. if the threshold lies within the group of wind generators, all wind generators are dispatched at a scaled rate of their MEC, rather than some wind generators being dispatch fully, while others are not dispatched at all).

Moyle[5] interconnector[6] is treated slightly differently from other generators in that it is dispatched at a level that is appropriate for each scenario, based on actual flows, and not at the full 400MW in each scenario. The hydro storage units at Turlough hill are dispatched in some scenarios as a demand bus and others as a generator depending on whether the unit is expected to be pumping, hence demand, or generating.

4.2 Load-flow analysis

The locational charge is derived using the "Reverse MW Mile "methodology based on an intact network, that is, no network outages are considered. The methodology charges each generator in proportion to the usage it makes of new assets[7] on the transmission system. This involves identifying the particular assets that a generator uses, attributing a cost to the new assets, and then apportioning a share of this cost to each generator that uses the new assets. In addition to this the reverse MW mile method also

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[5] Moyle is currently included as the TSOs planners include it in their studies. The network needs to be built to allow for all the power flows on the system including Moyle.

[6] EWIC (East West Interconnector) will be included when it becomes operational

[7] Assets to be built in the coming 5 years or going forward that have been built in the previous 7 years

rewards any generators which offset dominant flows on a circuit. To determine the contribution of each generator to circuit flows it is necessary first to run a load flow that matches system demand and generation, this load flow is called the 'base-case model' and determines the dominant flows on the network.

To calculate the circuit flow caused by each generator another power flow is run representing all generators except for the one we are studying referred to as the 'generator specific model'. In this model the total system load is reduced proportionally at each node with demand to match the new system dispatch. The flow in each circuit caused by the generator we are studying is equal to the total flow in the circuit (from the 'base-case model') minus the flow we obtain when we run a load flow without the generator (from the 'generator specific model'). This process is applied to all generators that are dispatched on the network resulting in a transmission use of system tariff for all generators that are dispatched.

The process can also be described as follows, firstly the 'base case model' described above determines the dominant flows on the network. The impact of a specific generator on all the system power flows is then obtained by setting zero values for all generator dispatches except for the generator of interest, and by running a DC[8] power flow for this condition. To run the power flow it is necessary to balance generation and load, therefore all loads are decreased on a pro-rata basis to match the generation dispatch at the generator of interest. If a generator's power flow is in the same direction or is in opposite direction (reverse) to the dominant flow then the generator is charged or credited respectively. This process is applied to all generators that are dispatched on the network resulting in a transmission use of system tariff for all generators that are dispatched.

For each of the 4 dispatch scenarios, the load flow analysis described above is performed. Each load flow is used to calculate a value for the transmission use of system tariff for each generator on the transmission system using the reverse MW-mile methodology.

[8] There is significant international use of DC tools for this purpose. Academic papers generally conclude that while there is a loss of accuracy using DC approximation, the results from a DC power flow are still acceptably accurate.

For any generator that does not produce a tariff under any of the scenarios (i.e. because they are not dispatched in the merit order) these generators will have a tariff derived using a dispatch of 1MW[9] in order to derive a tariff for every unit in all scenarios. Adding each generator at 1MW in turn results in a negligible change to the base case. The tariff that results for the 1MW generator is an "indicative" tariff for that generator under the scenario at hand and it does not affect the tariffs for the generators that are already dispatched. Demand is scaled up by 1MW at the chosen "swing" bus to balance generation and demand.

4.3 Selecting the tariffs from each scenario

The proposed all island tariff methodology requires that a tariff be calculated for each generator unit for each of the four agreed scenarios. For each individual generator, the maximum tariff i.e. the most positive value for each unit across the four scenarios is taken and this is used as the basis for the final tariff. The rationale for this approach is that any of the individual scenarios can drive the need for transmission system investment in respect of any given generator. Taking a generator maximum value across the scenarios will reflect this.

5 Network issues

5.1 Preparation of Network File

The network file comes from the investment planning process. The file originally derived from PSSE software is converted into a format suitable for input into Integra, it contains all technical data in relation to the transmission system. The network file is made up of four parts.

1. This contains a list of the names and numbers of all buses on the transmission system and indicates if the bus is a generator or demand bus. The data also includes the voltage at which the bus is connected and the level of generation or demand that is modelled at the bus as well as the area where the bus is located.

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[9] The 1MW incremental dispatched is used in order to reflect the generator's access to the market schedule. While the generator may not be physically dispatched, it still has to pay for the potential access that it could have if it were dispatched. The network still has to be in place in the event that it was dispatched. This provides a locational signal to the existing plant and furthermore a locational signal to any potential future plant.

2. This contains a list of all the circuits in the network with the circuit number, resistance, reactance and summer and winter line ratings.
3. The area number
4. This contains the installed capacity or MEC value for each generator unit.

The network data used to prepare the 2011/12 indicatives is based on Winter Peak 2016/17, Summer Peak 2017 and Summer Minimum 2017 data.

5.2 When is an Asset classed as “Built”

When an asset has been added to the network it is important to know when the 7 years of charging for the asset begins and ends. An asset is classified as built from its commissioning date onwards.

The tariffs for a given year set out to recover the allowed revenue for that year only, as determined through the applicable transmission revenue controls.

6 Cost Issues

6.1 Preparation of the Cost File

In accordance with the approved methodology a load flow is performed which establishes the flow on each circuit on the transmission system. Since the tariff methodology apportions costs of new and recently built assets to generators in relation to the use that each generators makes of each circuit it is necessary to establish the NPV of the cost for each of the relevant circuits. Circuit costs are a sum of all the costs of all individual assets which make up part of the circuit, for example these shall include overhead line and switchgear as well as a share of the station costs for the two stations at either end of the circuit. Integra then attributes the cost of the circuit to the generator using the circuit. For example the methodology will establish if generator X is causing a flow of 10MW on a line with total capacity of 100MW and the flow from generator X is in the dominant direction of the flow on the line then this generator will pay 10% of the annual NPV replacement cost of the circuit. In order to perform this calculation Integra needs details of the annualised costs for all circuits listed in the network file.

A database exists which contains the details of all NI and ROI transmission assets. This database is updated each year to reflect any changes in the network. From this cost database cost files are prepared and inputted to Integra. This database takes account of network reconfigurations that are not necessarily based on building all new assets but instead make use of some existing assets. An example is provided in Appendix 1.

Updated MEAV replacement costs for ROI are based on the CER approved standard charges where appropriate. For NI they are based on costs obtained from NIE T&D each year to reflect current replacement costs. If the costs are not available for the tariff year then it may be that the previous year's costs are used and inflation is applied to convert these costs to the tariff year.

6.2 Assets to be included in the dynamic cost files

The cost of all new assets will be included in the model except for like for like replacement of old assets reaching the end of their life. Inter-jurisdictional tie-lines which are paid for in the same way as other transmission assets, such as the planned second North South tie-line shall be included in the cost files and treated in the same way as any other asset.

When planned up-rating occurs (voltage or new conductors or re-tensioning of existing conductors etc) then the cost of this will be included as if it were a new circuit. If an up-rating is due to a like for like replacement but the standard sizes have changed then if the nearest available higher size than the existing is used then it will not be included in the cost calculations but if a higher capacity than this is used then the marginal cost of this above that of the nearest available to the existing will be included as a reinforced circuit.

6.3 Treatment of assets that are delayed or cancelled

From time to time future reinforcement may be delayed or cancelled altogether. Delays or cancellations of assets will be reflected in the network and cost files and will undoubtedly impact on the tariffs of units that would have been making use of the new assets. Therefore, once assets are introduced into the cost file they will only be removed 7 years post-commissioning or 12 years since they were first introduced, whichever occurs first. Table 2: Treatment of Assets below outlines a number of scenarios that cover the treatment of assets that are delayed or cancelled. In each case a more detailed explanation is given below.

Scenario	Impact on files
Projects are terminated	The assets are removed from the network and cost files
Project is delayed but is within 5 years	The asset remains in the files but the NPV is adjusted
Project is delayed outside of 5 years but within 12 years	The asset remains in the files but the NPV is adjusted noting that a generator is only ever charged for an asset for a maximum of 12 years
Project is delayed to a date outside of 12 years	The assets are removed from the network and cost files
Project brought forward or delivered early (See 6.4)	The assets are included as soon as possible and remain included for 7 years post-commissioning. NPV is adjusted accordingly

Table 2: Treatment of Assets

Projects that are terminated

Assets that form part of projects that are terminated are removed from the network and cost files.

Delay which does not impact inclusion in the 5 year future horizon

Firstly, if a delay in the expected completion time of a new reinforcement does not have the effect of moving that reinforcement outside of the 5 year future horizon then the impact will be minimal and it would seem logical to account for the delay and simply amend the NPV calculation to reflect the lower NPV cost. For example if a new circuit was expected to be built in 2017 and this was included in the files used to prepare 2011/12 tariffs, then after 2011/12 tariffs have been published this circuit is moved out to a completion date of 2018, this will have very little impact on tariffs as the 2012/13 tariff will include all assets to be built up to 2018 and hence the new circuit will still appear in the next year’s tariffs.

Delay which pushes an asset outside the 5 year horizon

Those assets that are delayed beyond the 5 year horizon, up to a maximum of 12 years from introduction, remain in the cost file. However, the discount for the assets takes the new target date into account and adjusts accordingly. Therefore, generators using the asset are never charged for more than 12 years.

Using the example above where tariffs being calculated are for 2011/12. If an asset is pushed out from 2016 to 2022 which is beyond the 5 year horizon, it remains in the cost file and is discounted using 10 years instead of 4.

6.4 Treatment of assets that are not forecast 5 years in advance

The situation may arise where a new asset is planned and gains approval less than 5 years before the expected completion date. In this situation the new asset will be included in the next tariff calculation,. Obviously this asset will be included in the locational tariff component for less than 12 years but it is unlikely to be less than say 9 or 10 years, as normally assets require capital approval at least a few years before being built and will remain in the locational cost database for the usual 7 years after being built.

7 Other issues

7.1 Validation of Tariffs

The network file, cost file and relevant dispatch file are prepared and inputted into Integra in order to produce tariffs. Once the Integra application has been run the output files produced must be checked in detail and the tariffs must be analysed to ensure these are reasonable and concur with changes in the network and cost files and any changes in patterns of generations and demand.

7.2 Adjusting to the required locational/postage stamp split

The tariffs have been designed to recover a maximum of 30% of allowed revenue from the locational element. The remaining amount will be collected through a postage stamp methodology.

If the locational tariff recovers more than the pre-set percentage of total revenue requirement, a multiplier is applied to all tariffs to decrease these by the appropriate percentage.

Once locational tariffs have been calculated, the revenue from these shall be computed by multiplying the tariffs by the relevant MEC of each unit. At this stage, the tariff for any retiring/new generators, which may not be paying TUoS for the entire year, is modified.

Any revenue not recovered by the locational tariff component will be smeared across all units by a flat €/MW charge to obtain a postage stamp charge. All units connected to the transmission system and all those connected to the distribution system with contracted capacity greater than or equal to 10MW[10] will be levied the postage stamp charge in addition to the locational charge.

7.3 Treatment of Generators with negative tariffs

For generators that receive negative tariffs, the SOs will set tariffs for wind generators at zero[11]. The rationale is that wind generators are not offsetting the need for investment because of their intermittent nature. To apply this in the proposed all island methodology the relevant generators with negative tariff will be set to zero and all other tariffs scaled down (using a multiplier) accordingly to ensure exactly the required revenue is recovered.

7.4 Required Revenue

In order to produce generator charges it is necessary to establish the revenue which is required to be recovered from the tariffs in any given tariff period from both SOs. It has been discussed as part of the current consultation process that it may also be necessary to include under or over recovery amounts of generator TUoS charges in the previous tariff period. This is discussed further in the SEM-11-018. In order to calculate an all-island recovery amount both jurisdictions must have the required revenues in the same currency so the NI required revenue is converted to a Euro amount. The approach taken to convert the NI revenue requirement into Euro is consistent with the approach taken to calculate the SEM Capacity Payment mechanism.

7.5 Currency Risk

The currency risk issue is currently under consultation and outlined in SEM-11-018.

[10] The 10MW threshold level in under consideration as outlined in SEM-11-018

[11] Also in the past a lower bound of zero applied to temporary generators in Ireland due to the nature of their temporary connection to the system.

7.6 Managing Cross Border Flows

The topic is currently under consultation and outlined in SEM-11-018.

7.7 Generators due to commence or retire part way through the year.

In order to derive the generator tariffs it is necessary to include all new transmission connected generators and any new distribution connected generators with an MEC equal to or over the current TUoS threshold of 10MW, which have already connected or are expected to connect during the new tariff period.

An additional adjustment of the final tariffs will be necessary to ensure the full recovery of TUoS revenue if any of the generators included in the tariff calculations are commencing part way through the tariff period. This is necessary to account for the fact that the new generator unit shall not be liable to pay TUoS until the connection date.

7.8 Non-Firm Tariffs

The topic is currently under consultation and outlined in SEM-11-018.

8

9 Appendix 1

New circuits which utilise existing assets

Consider we have an existing circuit built 10 years ago which consists of 20km of overhead line from node A – B below. This will have zero cost in the tariff calculations as it is pre-existing for more than 7 years.

Now assume the line between A-B is looped into a new station C. In this situation all the existing line from A – C will not have to be retired, assume some of this remains in use in the new configuration. Two new segments of line will have to be built from area X to C to produce circuits from A-C and C-B below. The total combined line length from A-C is 12 Km and from C-B is 12Km, each of these lines consist approximately of 8Km of old (existing) line (A-X and B-X) and 4Km of new line (X-C).

Given that the circuit only contributes to the need for 8km of new line, the cost of the full 24km (2*12km) of new circuit will not be included in cost calculation but only 8km (2* 4km) of new circuit that is actually required.