Review of Supplier TUoS Tariff Methodology

In Northern Ireland

Consultation Paper

27th July 2010

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Glossary

Abbreviation	Definition
TUoS	Transmission Use of System
MEC	Maximum Export Capacity
NI	Northern Ireland
DUoS	Distribution Use of System
RA's	Regulatory Authorities in NI and ROI (UR & CER)
UR	Utility Regulator (Formerly known as NIAUR)
SONI	System Operator for Northern Ireland
DLF	Distribution Loss Adjustment Factor
TLAF	Transmission Loss Adjustment Factor

Table of Contents

1 Executive Summary

In January 2009 the Northern Ireland Authority for Utility Regulation (NIAUR) and the Commission for Energy Regulation (CER), collectively known as the RAs, jointly announced the commencement of an all-island review of Locational signals in the Single Electricity Market (SEM). The aim of the review, which is still ongoing, is to examine Transmission Use of System (TUoS) charging, for generation, and the treatment of Transmission losses in Northern Ireland (NI) and Ireland. Initially it was envisaged that this review would also include the examination of all-island Supplier TUoS tariff regimes, however the RAs subsequently determined that Supplier TUoS should no longer be included in the Locational Signals review project. Following on from this decision and as a result of the change in the off-peak NI Supplier TUoS tariffs for 2009/10, the Utility Regulator (UR) has requested that SONI undertake a full review of Supplier TUoS charging in NI with a view to implementing a new NI Supplier TUoS methodology from October 2011. SONI has been instructed to undertake a consultation process to engage with stakeholders, industry groups and all interested parties. This paper sets out SONI's proposal for a new methodology to calculate Supplier TUoS tariffs in NI. On receipt of responses, these shall be forwarded to the UR who will make any decisions in relation to the Supplier TUoS tariff methodology in NI.

SONI is of the opinion that any arrangements for Transmission charging should be consistent in their application to generation and demand parties in a particular region. Recently, as part of the All Island Locational Signals review mentioned above, EirGrid and SONI issued a consultation paper which explored the options for a locational charging methodology for all-island generator TUoS tariffs[1]. A decision is currently under consideration by the RA's. Consistent treatment of locational based charging is an essential element in providing both generators and consumers locational signals for investment. Any tariff model which is not based on consistent treatment of generation and demand customers within a region can be problematic, issues can arise with regard to the treatment of embedded generation, unequal treatment of user groups, and inconsistent cost signals sent to network users. This current review project examines only NI

[1] Available on www.allislandproject.org Reference (SEM-09-107)

therefore it is not possible to have all-island locational supplier tariffs at this time. Furthermore it is considered inappropriate to apply locational tariffs in NI for reasons discussed in section 4.2 of this paper. In the long-term an all-island supplier TUoS tariff methodology which is consistent with Generator TUoS may be the optimal solution but this requires further consideration, and would require a policy decision by the SEM oversight committee.

The existing NI supplier TUoS charging model has short-comings in terms of cost-reflectivity, transparency and the degree of complexity associated with it. It would therefore seem reasonable that until all-island harmonised supplier tariffs, which are derived on the same basis as generator tariffs, can be fully investigated then a replacement model to apply to NI Supplier TUoS tariffs would be a logical conclusion. The proposed NI Supplier TUoS tariff methodology will not treat generators and suppliers equally; however it will attempt to address the concerns and issues outlined by stakeholders, during informal consultation as part of the development of these proposals, concerning the existing tariff regime in NI. This review process aims to deliver a new methodology to meet the key objectives identified.

SONI has carried out research and analysis of alternative models and recommend the implementation of an energy based charging model with time of use tariffs for deriving Supplier TUoS Tariffs to apply from October 2011. This model will produce charges in a transparent manner, which reflects the costs of network investment. The recommended model incorporates tariffs to apply to all energy exchanged at the transmission-distribution interface. The model will incorporate a fixed tariff to recover any transmission costs which do not vary due to energy usage patterns as well as time-of-use tariffs to recover variable network investment costs which are driven by energy consumption patterns. It is proposed that generator imports shall be charged in the same manner as any other energy demanded from the system.

SONI believes the proposed model will achieve the primary objectives of all stakeholders as outlined in Section 4 and deliver a solution to the problems highlighted in Section 5 associated with the current Supplier TUoS approach in NI.

Currently in NI a transmission rebate is payable to any supplier who has a contract to purchase energy from an eligible generator connected to the distribution system, in order to offset their use of the transmission system. In the course of this project SONI carried out a number of system studies investigating the impact of the ever growing portfolio of distribution connected generation on the transmission system. The studies demonstrated that such generation is driving the need for investment on the transmission system and as such SONI are recommending the discontinuation of Transmission rebates.

2 Introduction

On 3rd November 2009, the Northern Ireland Authority for Utility Regulation (NIAUR), also known as the Utility Regulator (UR), announced that a review of NI Supplier TUoS tariffs would take place. The aim of this review is to put in place a Supplier Transmission tariff methodology which is appropriate for NI. This review shall give consideration to any issues or concerns highlighted with the current methodology used in NI and shall aim to deliver a new methodology that is reflective of the objectives of all key stakeholders as identified in section 4. This review is being carried out by the System Operator for Northern Ireland (SONI).

TUoS charges in NI recover the costs associated with provision, operation and maintenance of the transmission system. TUoS charges do not recover the costs associated with providing system support services or the operation of the TSO business, which are recovered separately via a System Support Services (SSS) Charge. This paper does not address any issues relating to SSS charges as these are being dealt with in the ongoing 'Harmonised All Island Ancillary services' project.

The current Supplier TUoS tariff methodology applied In NI has been described by many participants as being overly complex and lacking in transparency. It is also felt that the methodology, having been determined many years ago, is no longer reflective of the key drivers of network usage and investment. A complete review at this time has been deemed appropriate and this is particularly important given that a period of considerable development of the Transmission System is necessary in the coming years and tariffs must reflect the new investment drivers on the NI transmission system.

This document presents an overview of the work that is being carried out by SONI to devise a new methodology for the calculation of supplier TUoS tariffs. The choice of design objectives reflects input that has already been received by the project team from the UR and the wider industry in NI through feedback from bi-lateral meetings.

In order to design a viable methodology, the project team has carried out research on international best practice in the area of tariff design. Countries examined include Ireland, England, Scotland and Wales and Germany. A full description of the current methodology being used in NI is also outlined in this document.

The remaining sections of this document are structured as follows:

- The background and reasons for conducting this review are outlined in Section 3;
- The objectives of the project are discussed in Section 4 with a rationale for why each objective was chosen. Boundary conditions underlying the review process are also outlined in this section.
- Section 5 sets out the process that was implemented to complete the required research, and obtain an input from interested parties.
- Section 6 provides an overview of the current NI model
- Section 7 outlines alternative models or features of models that have been considered. The explanation of models applied elsewhere represents SONI's understanding based on publically available data.
- Section 8 outlines the proposed model to apply in NI from October 2011 onwards.
- Section 9 outlines other considerations relating to TUoS charging
- Section 10 details the next steps in this process.
- The appendices illustrate the timelines of the review project and provide examples of the proposed model and its calculations.

3 Background

This section of the paper provides background information relating to TUoS tariffs in NI and in the SEM. Section 3.1 has been included to provide a more in-depth discussion on Supplier TUoS for industry groups or interested parties who may have only recently become interested in the issue of transmission pricing and hence may not be as familiar with the TUoS tariff structures and developments in the area over recent years. It is important to note that while the transmission pricing regime aims to recover the annual transmission required revenue, known as the "Transmission Entitlement", as approved by the Utility Regulator, the key objective of the tariff methodology is to send signals to transmission system users of the long-term costs that their network requirements drive. The tariffs act as a proxy for the long-term requirements of users, in that, those users who are regarded as driving higher long-term network costs shall pay higher TUoS charges.

Northern Ireland Electricity Transmission and Distribution business (NIE T&D the NI Transmission System Asset Owner) provide SONI with the annual revenue requirement for the transmission system. This figure is determined through the NIE T&D Price Control process and following consultation with the regulator, UR approve an annual amount which is to be recovered collectively from Use of System charges known as the annual Transmission and Distribution Entitlement. Figure 1 below illustrates the approved annual Transmission and Distribution Entitlement and how this is split to reflect the costs associated with the transmission and distribution system. The split of 18 and 82 percent to Transmission and Distribution respectively is a historical split and SONI understands that the basis for it is being reviewed by UR as part of the next Transmission and Distribution Price control.

TUoS tariffs are designed to recover the total costs associated with the transmission system. The total revenue requirement for the transmission system as approved by UR for the year 2009/2010 amounts to approximately £35m. The transmission tariffs have been designed to fully recover this revenue requirement from all transmission "users", which includes both generation and demand users connected directly to the transmission system or indirectly via the distribution system. Under the current methodology the split of transmission revenue recovery between generation and Suppliers is 25% and 75% respectively. This is consistent with the recovery proportions applied in other countries including Ireland and it is very similar to the breakdown of revenue in England, Scotland and Wales, although in this model the revenue split is not pre-specified.

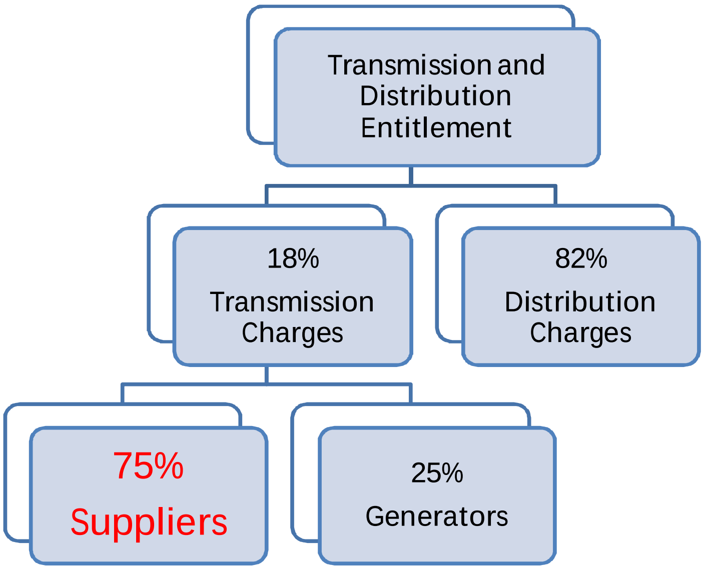


Figure 1: Recovery of Transmission and Distribution revenue entitlement

The introduction of the Single Electricity Market in 2007 has brought about a number of changes to SONI's license obligations. One of the additional responsibilities for SONI is the calculation of TUoS charges. SONI has calculated Supplier TUoS tariffs applied since October 2008. Prior to this both generator and supplier tariffs had been calculated and invoiced by NIE T&D. NIE T&D employed a single tariff model to derive combined Transmission and Distribution use of system charges. In March 2008 the transmission component of this model was provided to SONI and is described in section 6 within this document. The NIE T&D derived model has been used by SONI to calculate the supplier TUoS charges since tariff period 2008/2009 and these charges have subsequently been approved by UR.

This paper will focus on the 75% of the transmission revenue requirement collected from Suppliers in NI via Supplier TUoS tariffs. The treatment of generator tariffs is being analysed from an all-island perspective and a joint SONI/EirGrid project group is underway to establish options going forward. A draft decision on this separate consultation is expected in the coming weeks. The review of Supplier TUoS charges was originally included in the all-island review of locational signals which began in January 2009, however during the review project the RAs determined that Supplier tariffs would no longer be within the scope of this project. Following this decision NIAUR has requested that SONI undertake a separate review of NI supplier transmission tariffs with agreed recommendations to be implemented by October 2011.

3.1 Overview of Transmission Charging for Suppliers in NI

Transmission Use of system charges are amongst a number of charges passed on to electricity consumers. This section seeks to set out how Transmission charging for Suppliers fits into the overall customer tariff.

A typical electricity bill is made up of a number of elements to recover the costs incurred in supplying electricity to end users. The greatest component of any given bill can be attributed to the actual cost of generation, the remaining costs are reflective of the financial impact of transporting electricity to the customer such as costs for maintaining and developing infrastructure and ensuring the system is managed safely and economically. There are also a proportion of costs included for government obligations and administrative fees for the operation of the market. The cost components are described individually below.

The block elements of a customer tariff as outlined in UR Regulatory briefing Paper "NIE Energy Supply 1st Oct 09 tariff decrease" provides the breakdown as shown below in Table 1 for 2008/9 and 2009/10 tariffs.

Table 1: Block retail tariff elements with annual proportions for NIEES

	Generation Costs	MO & SSS Charges	PSO Levy	Use of System Charges	Supplier Charge	NIRO Costs	Correction Factor
09/10	57%	2%	4%	23%	6%	1%	7%
08/09	72%	1%	1%	18%	5%	1%	2%

Generation Costs: This is the cost of procuring electricity in the SEM including energy costs and capacity charges. It also includes the cost of suppliers hedging contracts.

MO & SSS Charges: Market Operator Charge is a charge levied on market participants intended to recover the costs and expenses of the Market Operator. SSS charges or System Support Services charge is a charge for system planning, operation and dispatch i.e. SONI's costs plus Ancillary Services.

PSO Levy: This is the Public Service Obligation levy which is included in tariffs to all customers on a flat p/kWh basis. It includes various costs such as the cost of maintaining the land bank, the excess costs of non-fossil fuel obligation (NFFO) contracts and the out of market costs of Power Purchase Agreements (PPA). It is the out of market costs of the PPA's which form the bulk of the PSO levy.

Use of System Charges: Charges for use of system are for the provision of access to the electricity network to transfer energy for trade within the market. Use of system charges are further divided into distribution use of system and transmission use of system.

Supplier Charge: Charges for billing, meter reading etc i.e. Supplier costs and margin.

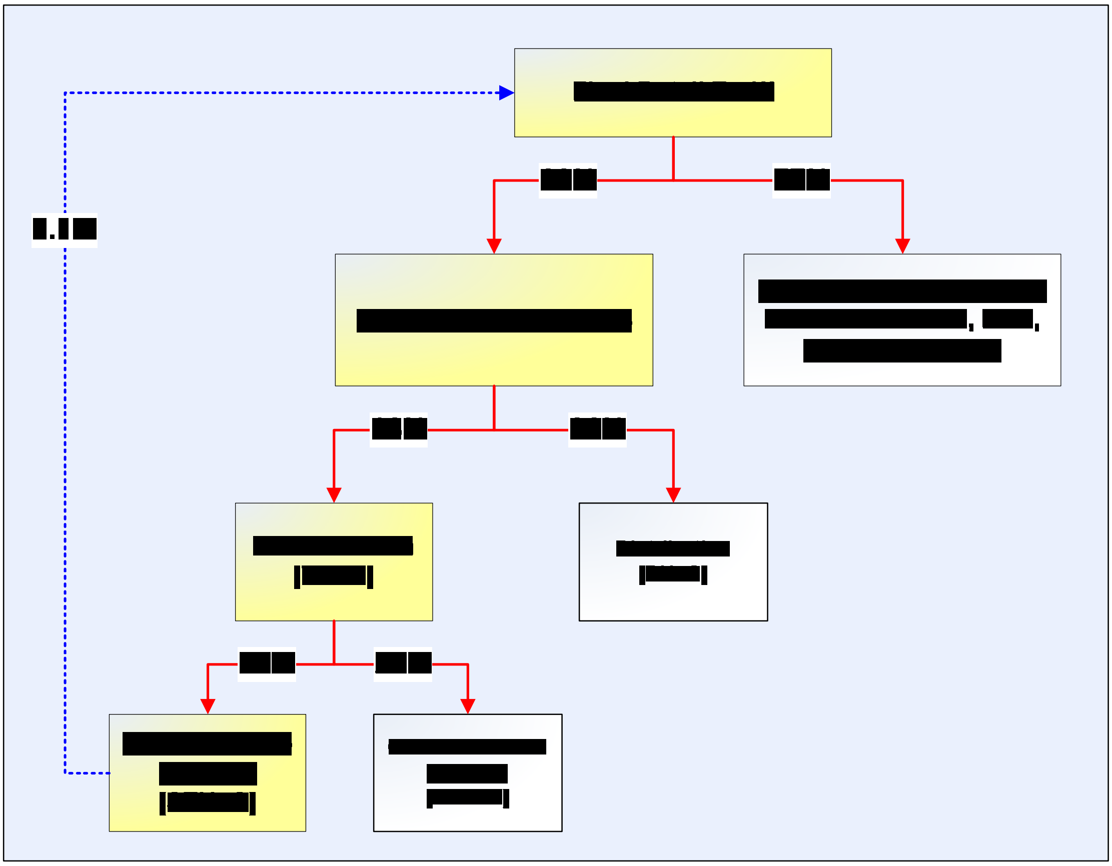
NIRO Costs: NIRO is the Northern Ireland Renewable Obligation – these are costs incurred via a government obligation for suppliers to sell a specified and increasing proportion of the electricity they supply as having been produced by a renewable source.

Correction Factor: The difference between allowed revenue and actual recovered revenue. This is a mechanism whereby differences between forecasts used for tariff setting and actual outturns can be re-couped or returned to customers.

The use of systems element of the bill charging structure as outlined above is the total use of system charges for both Distribution and Transmission. The percentage of a customer's TUoS and DUoS charges can vary depending on energy usage patterns. Total revenue to be recovered from TUoS charges represent 18% of Total use of system revenue, with this being further divided 75% to Supplier TUoS and 25% to Generator TUoS. Effectively Supplier Transmission use of system revenue represents 13.5% of total use of system revenue. Based on the figures illustrated in Figure 2 for NIEES, NI Supplier TUoS charges on average are approx 3.1% of total retail tariffs in 09/10, hence representing a very small proportion of overall retail tariff charges. This cost split is further illustrated in Figure 3 below.

Figure 2: TUoS component of Final Retail Tariff

(Based on percentage Total Revenue to be recovered from each charge in 09/10 as illustrated in table 1 above)



4 Objectives & Boundary Conditions

4.1 Primary objectives for New Supplier TUoS methodology

There are a number of objectives which have been articulated by the various stakeholders in the project. SONI has given careful consideration to the various objectives of each of the stakeholders based on the information provided. These objectives were identified from responses from Suppliers to a survey conducted by the System Operators in March 2009 as part of an all island review of TUoS tariffs, as well as objectives that were highlighted during the initial meetings with interested parties as part of this review process. It was decided to rank these in order of importance to determine a number of primary objectives, against which the proposed TUoS methodology can be assessed. The primary objectives of Supplier TUoS tariffs are shown in order of importance below.

1. Cost-reflectivity: any tariff methodology should be cost reflective in order to promote economic efficiency and to facilitate competition. SONI believe this is the most important objective of a tariff methodology and it is discussed in more detail below.
2. Transparency: the provision of information to stakeholders to ensure full transparency of the methodology.
3. Reduced volatility: where possible the methodology should avoid dramatic year on year fluctuations in tariffs.
4. Predictability: the methodology should enable the prediction of future tariffs within a reasonable level of accuracy.
5. Non-Discrimination: under similar circumstances individuals must be treated identically and under different circumstances individuals may be treated differently. Non-discrimination allows SONI to set different prices according to the costs different users impose.

Cost reflectivity is understandably considered as the most important objective of a tariff regime as cost reflective tariffs will provide the correct economic signals to users of the network. Cost-reflective tariffs can only be achieved by the correct design of the tariff methodology process.

There are a large number of ways to calculate a set of tariffs. Determining cost reflective tariffs that are fair and reasonable is no simple task. There are many approaches to pricing; for example, multi-part tariffs, postage-stamp tariffs, tariffs reflective of distances, Ramsey pricing[2] and many more. In general there is no single tariff design methodology that is correct for all circumstances; it depends on the particular situation. Applying a flawed methodology can provide poor economic signals. Each of the alternative tariff design methods can have positive and negative factors, for example, multi-part tariffs can be more difficult to derive and apply, while postage-stamp tariffs subsidize those who impose higher costs.

Cost reflective tariffs are calculated using a set of procedures that should ensure no cross-subsidies from one type of customer to another and no conflicts between economic efficiency and cost causation versus principles of equity and fairness. Cost-reflectivity must also include fair allocation mechanisms for common costs.

It is imperative that transmission tariffs reflect the costs imposed on the transmission network and also gives appropriate credit for the benefits provided. Cost reflective charging of transmission networks is concerned with sending price signals to users of the network with respect to the costs or benefits the users impose on network operation and investment. Efficient pricing distinguishes between different user locations and between different times of use as both location and patterns of use impact the need for network capacity. This is the fundamental reason why economically efficient TUoS charges should ideally be location and time-of-use specific. When cost reflective network charging is applied users are charged or rewarded with respect to cost or benefits they bring to the network. Economic development of the transmission network is promoted which simultaneously facilitates competition in generation and supply on a level playing field. This avoids cross subsidies between users at different locations and different times of network usage.

4.2 Consistent Treatment of Generation and Demand within a region

Following from the key principle of cost reflectivity it is important that generation and demand are treated equally within TUoS charging arrangements, taking account of the connection charging policies that apply to each. One MW of reduction in demand, at a particular location in the network, should not be treated differently to one MW of increase in generation, as the impact on the need for network investment will be exactly the same. In other words, location

[2] Ramsey's prices are calculated by charging inversely to elasticity of demand.

specific charges for demand and generation should be symmetrical, as unequal treatment of generation and demand would be discriminatory, contradict efficient network pricing and lead to inefficient network investment. Hence, the design of generation and supply TUoS tariffs should follow the same principles. In England, Scotland and Wales for example, the tariff differential for demand and generation are equal and opposite for each location (however the need to achieve appropriate revenue recovery is resolved through introduction of a location non-specific residual that is levied on demand only). Given the dominant North to South power flows, demand in Scotland pays lower TUoS charges than demand in England and the opposite is true for generators.

Recently proposals for all-island generator tariffs have been consulted upon and it is anticipated that an all-island approach to the treatment of generator TUoS tariffs shall apply from October 2011. The all-island methodology has not yet been selected however SONI and EirGrid have outlined in the preferred methodology Paper "SEM-09-107[3]" published on 26th November 2009 that they would recommend implementing a forward looking locational tariff methodology known as a "Dynamic signal model plus postage stamp" method. This type of tariff methodology is cost-reflective of future investment costs and provides a signal today about future costs.

In light of the above, in order to maintain the consistency between generation and supplier TUoS charges, it would be appropriate that supplier tariffs are derived from the same principles as generator tariffs on an all-Island basis. The Regulatory authorities have not included the option of all-Island Supplier TUoS tariffs at this time. There are a number of important points to consider in relation to consistency of TUoS charging.

Firstly it must also be noted that Transmission connected generators in NI pay shallow connection charges while Distribution connected Generation and demand customers pay full deep connection charges, therefore while the current connection charging policy is in place it is may not be appropriate to treat NI demand customers on the same basis as generation for TUoS purposes. The "connection to system" and "use of the system" charging policies together should be consistent. In addition, connection charging policy for generation and demand customers

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[3] Available on www.allislandproject.org

connected to the distribution system in Northern Ireland are not the same as the connection charging policy for those connected in Ireland. In order for full consistency to be achieved connection charging and use of system charges must be examined simultaneously. Furthermore, given that demand customers in NI pay full deep reinforcement costs (and 20 years of maintenance charges) at the time of connection it could be argued that connection charges are a sufficient locational signal for NI demand customers at this time.

Secondly the UR has stated that it is of the view that the scale of demand in NI is such that it cannot react in any significant way to a long term signal in relation to the transmission system. This is due to the small amount of demand that is under the control of any one individual (i.e. one small factory closing or one family moving house to a different area will not have any effect on the cost of the transmission system). The only effects are at the margin, and this is covered in NI by the deep connection policy for distribution.

Finally if locational supplier TUoS charges were to be implemented on an all-island basis for distribution connected customers, this would be contrary to the current SEM Memorandum of Understanding (MoU), which was agreed between both RA's, therefore changes to the SEM MoU would be necessary. It is also possible given that NI is roughly the size of one TUoS tariff zone in GB, if locational supplier charges were to be adopted in an all-island context it could occur that all of NI would be considered as one zone.

For the reasons discussed above, the objective of consistency in treatment of suppliers and generator TUoS charging is not attainable at this time. In the long-term this position may change if an all-island harmonised approach for Supplier TUoS and Connection charging is to be adopted.

Each model shall be assessed against the five agreed objectives of Cost-reflectivity, Transparency, reduced volatility, predictability and non-discrimination.

4.3 Boundary Conditions

There are a number of significant factors that determine the type of methodology that can be applied in Northern Ireland, these include the following:

1. The methodology should be implemented by October 2011,
2. The review is restricted to NI and therefore the possibility of all-island supplier tariffs are not considered as part of this review.
3. It is not possible to maintain consistency between generator tariffs and supplier tariffs given that this is a 'NI only' review and generator tariffs are part of the all-island locational signals project.
4. For the reasons listed in Section 4.2 only non-locational methodologies shall be considered.
5. National and EU legislation must be adhered to.
6. The methodology must be consistent with other policies in NI and the SEM in particular the SEM high level design, SEM Memorandum of Understanding (MoU) and Connection charging policies.
7. The new methodology must be workable with metering data that shall be available by October 2011.
8. The new model shall allow for different revenue amounts and be adaptable to fully recover the annual transmission required revenue in each tariff period.

5 Research Methodology

In order to devise potential new methodologies it was decided to firstly review the current arrangements to identify opportunities for improvement. This was completed by SONI with input from a number of bi-lateral meetings with individual stakeholders which were carried out in mid November. International approaches were also examined although in many cases data on tariff models was not readily available and hence SONI were restricted in the number of models that could be examined. SONI also engaged with academics and experts to help identify alternative ways of calculating supplier use of system tariffs. The purpose of conducting research on methodologies applied in other markets is to determine if a methodology applied elsewhere, or under consideration by another System Operator, could be applied in NI in order to achieve the maximum number of objectives as set out in Section 4 of this document. SONI examined the tariff methodologies applied in Ireland, England, Scotland and Wales and Germany as well as some other European markets.

The various models and particular features of models which have been considered for NI are outlined in Section 7 and Section 8 of this document. Each potential model or model feature is described and then assessed in terms of applicability to the NI market structure.

5.1 Feedback from Interested parties

On 3rd November the UR announced the Supplier TUoS review project and interested parties were invited at this stage to meet with SONI to discuss any issues regarding the current treatment of supplier TUoS tariffs and discuss proposals for a future methodology. SONI invited market participants to articulate their position on the current methodology and outline key objectives for any new methodology to be introduced. SONI welcomed the opportunity to meet with interested suppliers and found it very useful to gain an understanding of their views on TUoS tariff methods. During these meetings the following issues were raised by various supplier groups.

a) Many suppliers highlighted that they had no additional concerns over and above complexity and lack of transparency of the current supplier TUoS tariffs. Suppliers informed SONI that they directly pass these charges fully on to customers and this process is expected to continue.

b) One supplier highlighted that if tariffs are to be based on a transmission tariff that does not distinguish between connection voltages then Suppliers will need to account for distribution losses, similar to the practice in ROI. This is discussed further in section 9. No supplier indicated that there would be any issue in applying tariffs in this way, either by adjusting volumes or tariffs, however early communication from SONI to Suppliers in regard to this would be appreciated to allow any possible amendments to the supplier billing systems.

c) April is a key date for suppliers and indicative tariffs at this time would be extremely beneficial. While suppliers expressed their understanding that indicative tariffs would be made available for information purposes only and would be subject to change, an indication of key trends in tariff movements for various types of customers would be extremely helpful at this stage. Obviously indicative tariffs will be based on best estimates of input data requirements and the revenue recovery amount will be subject to change as the annual transmission revenue entitlement will not have been determined at this time.

d) SONI outlined that capacity based charges would be investigated. No groups expressed concerns with combining capacity based charging with energy charges, however a number of suppliers indicated that rules around capacity based charging should be simple and easy to apply.

e) SONI outlined that the continued use of time-banding would be investigated. One supplier said they would be in favour of maintaining time-bands for tariffs providing this is cost-reflective. Other industry groups indicated no objection to using time-bands and only one Supplier was against the continued use of time-bands; this supplier felt that cost-reflectivity was not an important objective of TUoS tariffs.

f) No industry group felt that it was necessary that the TUoS charging structure would need to resemble the DUoS charging regime, although the signals from TUoS charges should not contradict other market mechanisms.

g) One industry group requested that no additional complexity be added to the time-bands. It would be acceptable for TUoS to amalgamate the DUoS time-bands into fewer time-bands but problems would be encountered if time slots were changed or any change resulted in more divergence from DUoS time-band structure.

h) Objectives of new model were discussed along with the appropriate ranking of these. SONI presented a list of ranked objectives which included cost-reflectivity, transparency, predictability and lack of volatility.

i) One Supplier suggested including non-discrimination. This has now been included as an objective. These are discussed in more detail in section 4.1 above. SONI requested that suppliers consider the rankings/weightings that they would attach to each objective in order to assess the importance of each objective.

j) SONI requested information on any features in a new model which would be favourable/unfavourable or not implementable for suppliers. No supplier was in favour of locational 'NI only' charges.

Subsequent to the meetings a number of interested parties submitted further thoughts on possible features for a new model. SONI appreciate the input from all industry groups and this has been fully considered when assessing potential new tariff models.

6 Current Supplier Tariff Model applied in Northern Ireland

6.1 Background

Until the introduction of SEM in November 2007 demand TUoS Tariffs had been calculated by NIE T&D using a single tariff model to derive both Transmission and Distribution use of system charges. In March 2008 the transmission component of this model was provided to SONI by NIE T&D and this was used by SONI to derive the Supplier TUoS charges since tariff period 2008/2009. For this reason the current Supplier TUoS charges have a similar charging structure as the Distribution Use of System charges in NI.

Supplier tariffs are recovered based entirely on energy usage. The tariff methodology does not take into account the location of demand. All suppliers within the same tariffs category pay the same charges irrespective of where they are located on the network. Ten different schedules of tariffs are produced; these are published in the SONI Statement of Charges document available on www.soni.ltd.uk.

6.2 Purpose

The aim of the Supplier TUoS tariff is to recover a given revenue amount associated with the costs of building, operating and maintaining the NI transmission network. The current charging regime aims to recover 75% of total Transmission revenue for NI from all demand users. Customers are grouped in a manner which is designed to align with the costs they impose on the network and are thus charged on the schedule of tariffs applicable to their category.

6.3 Energy Forecast & Profile data

The tariff model uses energy forecast data and profile data to determine the probable spread of demand across each tariff group. The energy forecast is an extremely important element of the tariff derivation process as this is a key determinant in the new tariff rates. Regression analysis is used to create an energy forecast for the tariff year for each of the high level groups. These high level groups are set out below in Table 2:

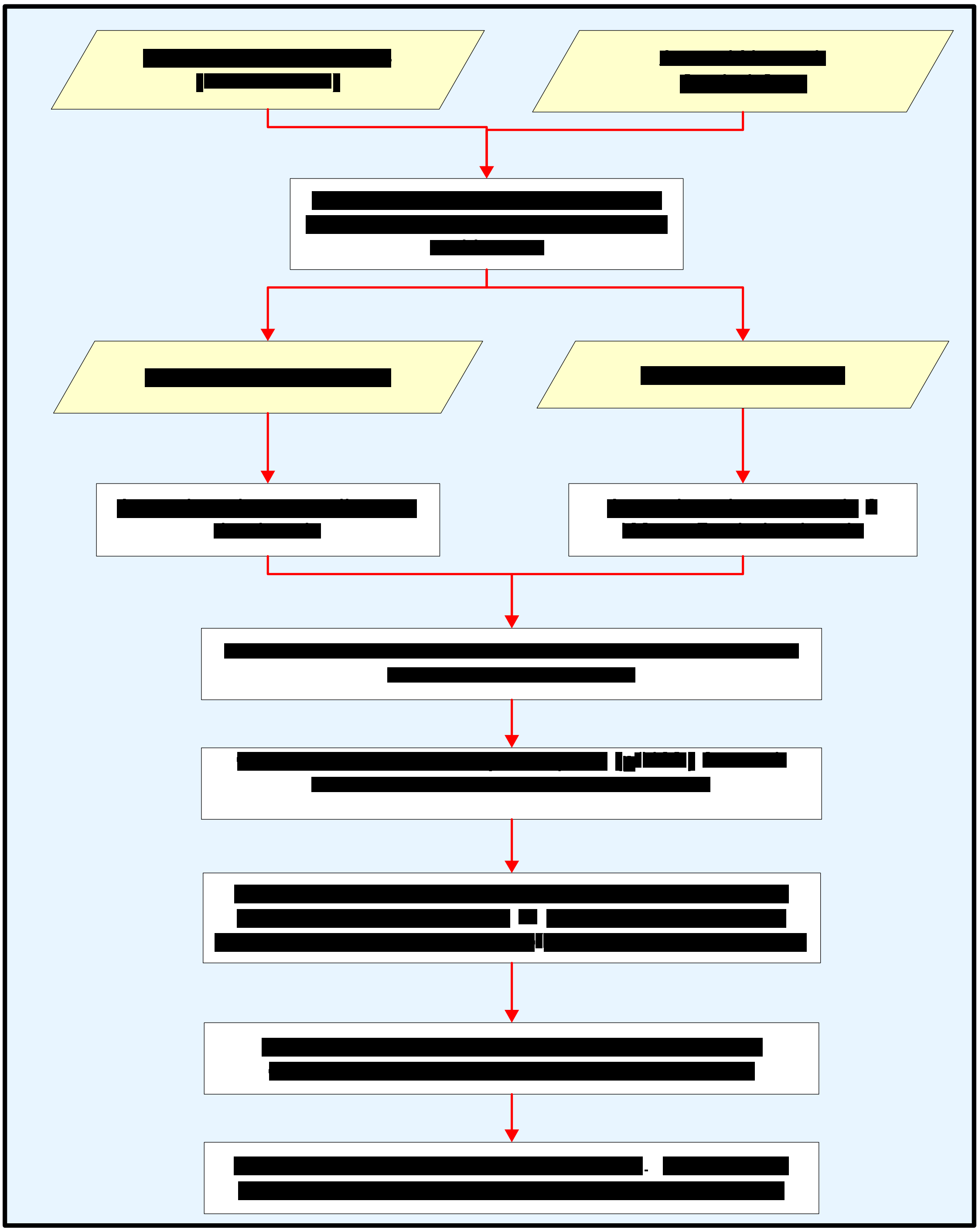
Table 2: Current customer tariff categories

Customer Grouping	Description
Domestic and Farm/Combined	Supply of electricity for use exclusively for domestic purposes, flats and combined residential/farms
Domestic and Farm/ Combined Economy 7	Supply of electricity for use exclusively for domestic purposes, flats and combined residential/farms using Economy 7
Commercial & Industrial /Ind 3.1 & 3.3 <70KVA	Supply of electricity for commercial, industrial and miscellaneous premises where the max power does not exceed 70KVA
Commercial/Industrial E7 3.2/3.4	Supply of electricity for commercial, industrial and miscellaneous premises where maximum power does not exceed 70KVA using economy 7
Off Peak	Preserved Tariffs
Public Lighting	Supply for Public lighting
MV<1MW	Supply for Non Domestic Customers where supplies are less than 70kVA and taken at Medium Voltage
HV<1MW	Supply for Non Domestic Customers where supplies are less than 70kVA and taken at High Voltage
EHV<1MW	Supply for Non Domestic Customers where supplies are less than 70kVA and taken at Extra high voltage
MV>1MW	Supply for Non Domestic Customers where supplies are taken at Medium Voltage
HV>1MW	Supply for Non Domestic Customers where supplies are taken at High Voltage
EHV>1MW	Supply for Non Domestic Customers where supplies taken at Extra high voltage

6.4 Cost allocation

The objective of the current tariff model is to attribute annual network capital costs and load related operating costs to the various users of the transmission system in proportion to the estimated usage that these users make of the transmission system. In order to do this, details of the annuitized network costs associated with a 500MW load on the system are obtained as well as annual operating costs. These costs are then scaled to equal the required transmission revenue to be recovered from Supplier TUoS. These costs are then allocated across voltage levels and customer groups such that the resulting network charges are somewhat cost reflective. Network capital costs are allocated based on estimated peak usage only and therefore are allocated to only the two peak time-bands in each customer connection level. Load related operating costs are allocated to all time-bands based on estimated load duration. A total cost is then summed for each time-band at each of the customer connection levels. An illustration of the cost allocation is outlined in Figure 3 below. In order to determine a single tariff rate for relevant tariff categories profile allocations are used.

Figure 3: Overview of Current Supplier Tariff Methodology



6.5 Multi-Rate Time-bands

Tariffs for domestic customers, with the exception of Economy 7, are all based on a flat rate and do not vary on the basis of time of day (this is the only option as currently domestic customer metering is not time banded). The tariffs for half hourly metered non domestic customers however consist of prices for seven separate time-bands. These tariffs are designed to have some influence on non domestic customer's usage patterns and correspond with the impact on the system at these times. The time-bands outlined in the statement of charges are set out below.

Table 3: Description of current TUoS charging time-bands

Time-band Name	Details of Time-band
Night	Night time hours from 10.30pm – 8am
Peak December and January Day	Peak hours during weekday Days in the months of December and January. Peak hours are from 4pm to 7pm and exclude Public Holiday and the Christmas period from 24th December to 1 January
Peak November and February day	Peak hours during weekday Days in the months of November and February. Peak hours are from 4pm to 7pm and exclude Public Holiday.
December and January day	Weekday hours in the months of December and January. Weekday hours are from 8am to 8.30pm except for Peak Times, which are described above. Also excluded are Public Holidays and the Christmas period from 24th December to 1 January.
November and February day	Weekday Days in the months November and February. Weekday hours are from 8am to 8.30 pm except for Peak Times, which are described above. Also excluded are Public Holidays
Other Day	Weekday hours in the months March to October inclusive. Weekday hours are from 8am to 8.30pm and exclude Public Holidays.
Evening & Weekend	All Evenings 8.30pm – 10.30pm as well as Weekends, Public Holidays and Christmas period from 24 Dec to 1 Jan 8am - 10.30pm

7 Potential new models for implementation in NI

In determining a new methodology to replace the existing tariff regime SONI has considered charging models which adopt the economic principles of cost reflectivity, simplicity, transparency, predictability and facilitation of competition. The new charging model that will replace the current model should accurately reflect transmission costs and incentivise efficient usage and development of the system. In order to achieve this it is essential for SONI to identify all key cost drivers and incorporate these into the charging model. As far as possible the cost drivers should be incorporated into the new charging methodology in a simple and transparent manner. Three alternative types of transmission charging models have been considered as part of this review. The three tariff models are:

Model 1: A model which combines Capacity and Energy based charging

Model 2: A locational charging model

Model 3: An Energy based Time of Use charging model which charges all energy exchanged at the transmission-distribution interface. This is SONI's proposed model as outlined in section 8.

Each of these alternative models and their main features are described in turn. The various models have been assessed in terms of how each achieves the objectives as set out in section 4. Positive and negative factors of each approach are discussed and SONI's reasons for either recommending implementation or rejecting the given model are stated.

7.1 Model 1: Combined Capacity and Energy based charges

7.1.1 Description

Transmission revenue can be recovered in a number of ways. In many cases the charges are levied solely on an energy basis as currently applied in NI. In other TUoS charging models charges are based on a capacity charge or a combination of capacity and energy based charges. Models that recover supplier TUoS revenue via a combined energy charge and capacity charge are applied by EirGrid in ROI and by the System Operator in Germany. In order to assess this type of model we shall first discuss the EirGrid model and how it recovers revenue through each of the charges. Note that it is assumed time-banding is not applied to the energy based charges in Model 1.

In Ireland, 75% of network related costs are recovered from demand customers through charges levied to suppliers. The network costs are recovered on a split basis between capacity and energy. 60% of the Supplier TUoS required revenue is recovered on a fixed basis, through a per MW, 'Network Capacity Charge', as 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. The remaining 40% is recovered on a variable basis through the energy based 'Network Transfer Charge'.

EirGrid have three separate schedules of charges which apply to various suppliers depending on the type of customer the supplier serves. One relates to transmission connected customers, one to distribution connected customers with a Maximum Import Capacity (MIC) of 0.5 MW or above, prior to adjusting for Distribution Loss Factor (DLF), and the third schedule relates to smaller distribution connected customers, with MIC less than 0.5 MW. Within each of these Tariff categories there exists a capacity based charge and an energy based charge, both of which are payable. Due to limitations relating to MIC data and profile metering for smaller distribution connected customers a proxy charge is used for the Capacity Charge, this is levied on a variable basis of consumption, which occurs during Day Hours.

Each customer's MIC value is used in assessing the capacity charge for that particular customer. In addition the charge has been designed with a bandwidth to allow for a reasonable seasonal variation in demand, therefore in cases where a customer does not import up to its MIC, in a particular charging period, the capacity charge may be reduced.

The remaining 40% of network costs attributed to suppliers is allocated on an energy basis through a, € per MWh, Network Transfer Charge. Consequently, demand users are charged consistent with their associated usage. Details on EirGrid charging methodology can be found on their website at www.eirgrid.com.

Similar to the Ireland charging methodology the mechanism for Germany consists of both an energy and capacity element. This is calculated on either an annual or monthly basis depending on the usage patterns of the customer. Customers with a temporary high demand and relatively low or no demand for the remainder of the year may opt for the monthly charging mechanism.

The key information used in calculating charges is:

- Maximum Power (metered in ¼ hr time intervals)
- Energy consumed over the year/month in kWh
- Voltage level of connection point

7.1.2 Assessment of including a Capacity based charge

There is an argument for including a capacity based charging component in Transmission tariffs. However it is important to assess the benefits from doing so with the costs or disadvantages associated with managing and implementing such a charging model. In this section we assess the pros and cons of capacity based charging in order to assess if there is merit in proposing such a charge to be incorporated into the new tariff model for NI.

As stated above, a significant amount of transmission costs arise from providing and operating the network to serve users and this cost is in most cases a fixed cost. It is important that users who bring about the need to develop the network in order to meet their needs pay towards doing so via TUoS charging. Capacity based charging has the advantage that it ensures users pay towards the capacity on the system that each has requested to be provided. In the case where a user requests that the system be built to deliver a given Maximum Import Capacity (MIC) but the user has much lower demands on the system that anticipated, the user will continue to pay higher TUoS charges, to contribute towards the costs imposed, through the capacity based charge compared to the situation if charges were based solely on energy usage. In the case of solely energy based charging the users benefits from lower energy charges, when demand is lowered, and does not bear any burden of the greater costs that it imposed on the network.

The argument above for implementing capacity based charges only applies however if the capacity charging methodology is accompanied with a policy to ensure that users must pay capacity based charges based on their requested MIC for a significant time period, irrespective of changing their MIC. There is also a question regarding the relevance of MICs, in the situation that maximum import does not coincide with peak flows which are relevant for future network investment. What is important for network design, and hence pricing, is the demand during network peak flows, rather than the absolute value of MICs. In other words, time dimension of demand may be relevant, not only absolute peak. MIC would of course be relevant for the design of the local connection, but it is not necessarily directly related to the design of interconnected transmission network. In addition, NI demand customers currently pay 100% deep connection charging costs, compared to 50% connection charging costs in Ireland, therefore the possibility of users requesting a higher MIC than necessary or trying to reserve or book capacity for future is not a significant problem in NI. The current connection charging policy in NI therefore reduces the need for capacity charging based on MIC in NI.

Suppliers have indicated that they would prefer to have capacity based charges that do not have complex rules relating to their application. A simple alternative to apply Capacity based charges is to levy these based on Highest Metered Demand (HMD) over the previous number of months, perhaps 18 months. This again has the drawback that a new customer, who might initially request a large import capability but actually has much lower consumption, will only pay capacity based charges based on actual usage and not system capacity that has been made available. An additional drawback of using HMD to levy capacity based charges is that it allows no bandwidth for seasonal fluctuations in demand, whereas a policy using MICs can be set to charge based on a proportion of a users MIC, similar to EirGrid's approach.

There are a number of potential disadvantages to capacity based charges. Firstly, a proportion of the required revenue will be recovered via these charges hence the energy based charges will contribute to a lower percentage of the overall TUoS invoice of any Supplier. In the case where energy based charges are signaling drivers of network investment in different times bands, the price signal can be somewhat dampened by the inclusion of a capacity based charge. A user who reacts to the price signal and changes consumption patterns will not be rewarded to the same degree as they would if only energy based charges existed. So put simply the capacity component can serve to dilute the price signal intended from the energy based charge.

Secondly, Poyry in their recent review of retail tariffs[4] commented that the continued use of block tariff structures where the average rate declines with use or maximum demand charges that reflect the costs at times of highest demand would no longer seem appropriate. These types of charging favour customers who have higher use of the system. This paper related to retail tariff structures but the same argument may hold, that is, we want to avoid rewarding higher usage.

Thirdly, not all customers have an agreed MIC or Chargeable Service Capacity (CSC) value therefore a proxy for this type of charge must be devised for some customer groups. This can lead to unequal treatment of transmission users.

Finally, if a capacity based charge, implemented on the basis of MIC, is applied a separate policy to deal with MIC administration is required to outline how TUoS charges are applied in various situations. It may also be necessary to implement a charge to be applied should a user's consumption exceed its MIC in order to avoid possible perversity.

In summary, Capacity based charges have the benefit of ensuring that those responsible for driving network investment will contribute a fixed amount towards these costs, providing policy decisions are consistent with this; however there are a number of possible negative factors to consider. Taking account of all of the factors discussed above as well as the design of current connection charging policy in NI, the new tariff model being recommended by SONI in section 8 is based only on energy charges.

[4] Poyry – Retail Tariff Structure Review – A report to CER & NIAUR June 2009

7.2 Model 2: Locational model such as applied in England, Scotland and Wales

7.2.1 Description

National Grid's Transmission Network Use of System (TNUoS) tariff is comprised of two separate elements. Firstly, a locationally varying element derived from the Direct Current Load Flow (DCLF) Investment Cost related Pricing (ICRP) transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transport of power to and from different locations. Secondly, a non-locationally varying element related to the provision of residual revenue recovery. The combination of both these elements forms the TNUoS tariff.

The underlying rationale for including a locational use of system charge is that the differential in charges should reflect the impact that users of the transmission system at different locations would have on the transmission owner's costs, if they were to increase or decrease their use of the transmission system. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy. The inclusion of a postage stamp, or residual tariff, is to ensure that the full amount of the annual required transmission revenue is recovered from transmission system users via the tariffs.

Like most Transmission System Operators National Grid are required to operate, plan and develop an efficient transmission system and to meet specified network security standards; capital investment requirements are largely driven by the need to conform to these standards. It is this obligation, which provides the underlying rationale for using the ICRP approach to derive locational tariffs, i.e. for any changes in generation and demand on the system, National Grid must ensure that it satisfies the requirements of the Security Standard. The DCLF ICRP transport model calculates the increase (or decrease) in capacity that is needed for a MW increment in generation at each node. This value for each individual node is then multiplied by the annual capital and maintenance cost of a MW.km of transmission capacity to give the transport charge for generation at each node. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of km of the transmission system for a 1MW injection to the system. The demand charge is equal and opposite to the generation charge at the node.

The charging method examines the peak condition because the security standards identifies requirements on the capacity of the system given the expected generation and demand at each node such that all reasonable demands for energy can be met. Historically, demand and generation levels at peak have driven up to 90% of investment.

The underlying principle of the nodal prices is that they should reflect the incremental or decremental cost associated with changes in demand and generation at that node. Given the Industry requirement for relatively stable cost messages and administrative simplicity, nodes are assigned to zones based on their geographical and electrical proximity and their tariff range. The effect of this is to dampen fluctuations that would otherwise be observed at a given node caused by changes in generation and demand patterns. There exists 21 generation zones and 14 demand zones, these zones are typically not reviewed more frequently than once every price control period to provide additional stability.

7.2.2 Assessment

It has been decided that locational TUoS charges for NI shall not be considered for October 2011. The current SEM Memorandum of Understanding states that "Section 6 of the SEM Memorandum of Understanding states that "CER and OFREG (UR) will apply a transparent, consistent and harmonised approach to the regulation of the wholesale market and retail markets in a manner which supports effective competition and equal treatment of customers' regardless of location." UR has advised SONI that this precludes the use of location TUoS charges for suppliers in respect of customers connected to the distribution system. It is also considered that the connection charging methodology in NI, as discussed earlier, provides a sufficient locational signal at this time.

In addition Locational supplier charges to be applied correctly should be on an all-island basis and be consistent with the treatment of generator TUoS charges; connection charging also has to be considered. UR has indicated that this may be examined further in coming years. SONI are also mindful that industry groups expressed no support for locational 'NI only' based charges hence the introduction would not serve to deliver the objectives of industry groups. For these reasons and those listed in section 4.2, a location tariff model will not be considered for NI in October 2011.

8 Proposed Methodology:

Model 3: Energy Based Time of Use Charging Model

8.1.1 Description

This model has been specifically designed by SONI to deliver tariffs that meet the objectives outlined in section 4. Like the current model, discussed in section 6, this model is an energy based charging model that incorporates time of use charges, however a number of distinct differences are proposed. Three main features of the proposed model are:

1. Removal of different charges depending on connection voltage level. This will be replaced with a single charge for each time-band applied to energy exchanged at the transmission-distribution interface.[5]

2. Optimized number of cost-reflective time-bands to apply

3. Separate treatment of fixed and variable transmission costs

The rationale for each of these key features is discussed in turn in the following sections. Appendix 2 contains an illustration of this proposed methodology.

8.1.2 Remove Charging by Connection Voltage level

The current NI supplier tariff model, as described in Section 6, is known as a Distribution Reinforcement Model (DRM) and has been used in the past in other electricity markets including England, Scotland and Wales. DRM models are based on time-of-use tariffs that are non location specific.

DRMs traditionally have been employed to evaluate the long run marginal cost of expanding, maintaining and operating the distribution system. This is achieved by calculating the network cost of adding an additional 1MW to an equivalent 500MW system model. This incremental £/MW cost is then allocated across voltage levels and customer groups.. Cost allocation is achieved by identifying the contribution of each customer group to the long-term distribution

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[5] Currently there are no customers connected directly to the transmission system. Should a new demand customer connect to the transmission the appropriate charging regime will be subject to review to ensure cost reflectivity exists.

system cost. The resulting tariff takes the form of maximum demand and/or unit related charges. Maximum demand charges are used for levels of the system close to customers. This is based on the argument that customers will fully occupy the capacity of the local network to which they are connected. On the other hand, unit based charges reflect the impact on the network costs further up the system. This approach is supported by the argument that the customer individual maximum demand is less likely to coincide with the system maximum demand[6].

It is important to bear in mind that use of system tariffs using DRM models have been developed for customers who take power from the network rather than for customers who inject power into the network. In the context of the objective to facilitate the developments in distribution connected generation it becomes important to develop a pricing regime that will recognise the impact that distributed generation makes on network costs. One of the key issues is the economic efficiency of tariffs and their ability to reflect cost streams imposed by the users, particularly distributed generation.

The impact of embedded generation on distribution networks (in terms of costs and benefits) is site specific, it may vary in time, will depend on the availability of the primary sources (important for some forms of renewable generation), size and operational regime of the plant, proximity of the load, layout and electrical characteristics of the local network, etc. It is not, therefore, surprising that the relatively simplistic DRM tariff structure, with network charges being averaged across customer groups and various parts of the network, cannot reflect the cost impact of embedded generation on the distribution network. DRM tariffs have no real ability to capture the impact of multi-directional flows (caused by the presence of embedded generation) and cannot deal with the temporal and spatial variations of cost streams. Hence alternative propositions have been developed elsewhere to take into account changes in directions of power flows that may be driven by distribution connected generation. Locational charging methods are required in order to do efficiently manage treatment of distribution connected

[6] Although the tariffs are design to be cost reflective a number of simplifying compromises are made in the implementation phase. For example, urban and rural customers pay the same charges, although costs of supplying rural customers are generally higher than those of urban. This cross-subsidy is considered socially desirable.

generation. In the absence of a location specific charging model it is not possible to appropriately deal with embedded generation and its impact on the transmission network.

Based on the reasons above it is no longer reasonable to produce transmission charges that differentiate between various connection voltage levels on the distribution system and charge different amounts depending on that basis. The new methodology that SONI propose will not produce different tariffs to apply to different voltage levels but rather a single tariff to apply at the transmission/distribution interface which all transmission users would pay. For customers with interval metering in place the tariff will vary depending on time-of-use. Obviously account must be taken of the relevant distribution loss adjustment factors (see Section 9.1.1) when settling energy at the transmission-distribution interface.

8.1.3 Time-banding of Tariffs

The current NI model incorporates multi rate seasonal time of day (STOD) tariffs for users over 70kVA. The temporal nature of electricity usage implies that time of use charges provide the best framework for reflecting costs and the price signals encourage efficient use of the transmission system. Generation is scheduled by the TSO so cannot react to a time of use signal by withdrawing availability at high cost times however demand can react to the signal and adjust demand accordingly. Poyry, having recently undertaken a review of retail market structure in NI and Ireland, outlined in their report to CER and NIAUR[7] that "The continued use of block tariff structures where the average rate declines with use, or maximum demand charges that reflect the cost at times of highest demand would no longer seem appropriate and might be better replaced with time of use tariffs. The use of multi rate seasonal time of day tariffs would be a better option for reflecting changing wholesale costs". Obviously this refers to retail tariffs however the same rationale could be applied to transmission tariffs.

In England, Scotland and Wales National Grid apply the Triad charging philosophy which is a form of time-band charging. The Triad describes the three settlement periods of highest transmission system demand, namely the half hour settlement period of system peak demand and the two half hour settlement periods of next highest demand, which are separated from the system peak demand and from each other by at least 10 clear days, between November and

[7] Published on CER website, June 2009 (www.cer.ie)

February of the Financial Year inclusive. Throughout the year users' monthly demand charges will be based on their forecasts of half-hourly metered demand to be supplied during the Triad for each Supplier Unit, multiplied by the relevant zonal £/kW tariff; and non-half hourly metered energy to be supplied over the period 16:00hrs to 19:00hrs inclusive every day over the Financial Year for each Supplier Unit, multiplied by the relevant zonal p/kWh tariff. Users' annual TNUoS demand charges are based on these forecasts and are split evenly over the 12 months of the year.

In NI due to availability of meter data it is only possible to charge time of use tariffs to Suppliers serving customers with appropriate metering. Customers without half-hourly metering cannot react to a pricing signal therefore it is deemed inappropriate to charge based on this. It is only considered appropriate to apply time of use charges if a customer can respond to these and have the opportunity to reduce its TUoS costs. For this reason, time of use charges will not apply to customers without interval metering; instead it will be necessary to continue to use profiling to derive a flat charge for all energy consumption for these users. Whether there will be one flat charge for all non-metered energy consumption or more than one is still under consideration. It may be possible to identify a few different customer classes that use the network in distinctly different ways; in this case we can calculate the network costs each customer class drives and then allocate a corresponding flat charge that recovers the relevant proportion of network costs they are responsible for. This would require the identification of different classes of customer and profiles associated with each. SONI shall carry out analysis to determine if there are a small number of distinct groups that can be identified and if disaggregation is warranted. If it is the case that one majority group of non-metered users is evident it may not be beneficial to have more than one flat tariff, administration costs etc may out weight the associated benefit of increased cost-reflectivity. The residual calculation for the treatment of unbilled energy shall continue under these proposals.

It has been suggested that if time of use charging cannot be applied to all user classes then it should not be applied to any users. However, by not charging customer with meter data based on their time of usage, this is in fact removing the opportunity for such customers to react to price signal and aim to reduce their costs and hence reduce overall system costs. It is therefore deemed more efficient that where possible to continue to give customers the choice and the incentive to change usage pattern and reduce costs through the use of time banded tariffs.

Obviously the continuation of time of use tariffs for relevant users should only occur if it is justified that the use of these contribute to greater cost-reflectivity and improve overall efficiency. In order to determine if this is the case SONI has been conducting analysis to determine whether transmission network costs are influenced by usage at different times of day/year and if so, to what extent. The aim of the time-band analysis undertaken is to also identify the most influential time bands that contribute to increased network investment costs. If a time-band contributes very little towards overall costs it would seem reasonable that it is not included in the model. The analysis can be based on existing network assets, called a static network or on future network assets which are required, namely a dynamic network which is based on projections of demand and generation in future years and the reinforcements required. It is also possible to include both existing and future asset in the analysis i.e. the costs associated with provision of the existing network as well as the expected future investments, perhaps looking at the network that shall exist in 5 years time. While the use of dynamic costs would be consistent with the proposed Generator TUoS tariff methodology, the argument for using only dynamic costs for calculating Supplier tariffs is weakened by the fact that the tariffs will not be location specific. For time-of-use non-locational specific tariffs inclusion of existing network assets may be more appropriate.

8.1.4 Selecting Appropriate Time-bands

Time-band analysis involving specialist software which performs a load flow on the network under a large number of scenarios of generation and demand has been carried out by SONI and work is still ongoing in this area. The analysis involves examining scenarios which are consistent with the current time-bands applied to DUoS and TUoS tariffs to determine if it is justifiable to continue with these. In addition, given the importance of designing transmission pricing which is consistent with transmission planning of the system, the analysis has also considered new scenarios which are employed by transmission system planners in designing the future network. The results of the analysis will help establish if new time-bands should be included in the charging model to reflect the cost drivers that exist today.

In conducting the analysis different types of generation, including flows on Moyle and the North-South Interconnector, has been dispatched under various system demand conditions. The NI transmission system as of 2009 was modeled with all circuits and generating units deemed to be available at full capacity. Studies shall also be conducted using future networks. For each scenario[8] a load flow was performed and the flow on each individual circuit was determined. For each individual circuit the maximum flow was then identified and the associated scenario responsible for the maximum flow was highlighted. The costs associated with each individual circuit[9] was then attributed to the scenario with the maximum flow, as it is deemed that the scenario that produces the maximum flow on a circuit is the scenario that drives investment on that circuit. Using maximum flow on the line as a determinant of driving investment needs is used by National Grid UK as well as a number of other System Operators. The cost of each circuit was based on an annuitized modern equivalent asset value (MEAV).

In the situation where the maximum flow on a circuit occurs in more than one scenario, the cost of that circuit is shared between the scenarios in proportion to the duration of the scenario. The duration of the scenario is the number of hours in the year that the scenario encompasses. Similarly, if one or more scenarios have a flow very close to the maximum flow on a circuit, within a pre-set range, the cost of the circuit is shared in the same way as if both scenarios had an equal flow. The rationale for such is that in the event that two or more scenarios have similar flows, it would not be appropriate to allocate the cost of the circuit to one scenario rather than another based on a small difference in flow. It would follow that usage on the circuit at times other than maximum flow, or within the pre-set range, does not drive investment. An example of how the costs are allocated is provided in Appendix 4.

After conducting load flow analysis and determining the maximum flow on each circuit under the various scenarios we can see which scenario has been attributed the greater proportion of transmission network costs. We can then conclude that the scenario with the highest percentage of total costs drives more of the investment on the network. The scenario with least share of total transmission costs is driving the least investment costs.

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[8] A scenario refers to a typical demand/generation case such as Winter Peak or a Summer Night
[9] The circuit cost includes any over headline, cable and any associated switchgear and share of station costs at either end of the circuit.

A number of scenarios have already been examined as part of the analysis and the results indicate that it is justified to continue to use a number of time-bands as it is evident that usage at different times of the day/year has a very direct impact on the requirement for investment in the network and hence the impact on transmission costs. In order for tariffs to be cost-reflective it is important that the scenarios that drive network development are captured in the tariff model design. Meter data availability for energy usage within the various time periods is one area which is currently under examination. SONI are conscious that the introduction of any changes to the time-bands should not cause any administration difficulties or undue administration costs for suppliers hence SONI would welcome all views on the proposed introduction of any new time-band such as those listed in Table 4. Please note it is not SONI's intention to introduce all the time-bands listed, these are currently ongoing analysis in order to determine the times of use on the transmission system that are most influential times on transmission costs.

Once time-bands are decided, the tariff model would then apportion the relevant percentage of annual network related costs to the time-bands based on the amount of transmission investment that each time band is found to drive. For example, if analysis shows that Winter Peak period drives the maximum flow on transmission assets which account for say 60% of the total cost of transmission assets to be recovered via TUoS, then 60% of the network related costs (capital costs) would be allocated to the Winter Peak time band and allocated to users who consume energy in this time period. This example is illustrated in appendix 2; the percentages are purely for demonstration and are not suggestive of the allocations which will be made. The proportion of transmission costs to be allocated to each time-band will only be decided once a decision on the applicable time-bands has been made. Details on the proposed final time-bands and the proportion of costs allocated to each shall be made available in a later consultation paper to be published by UR in November.

It is only possibly to apply time-banded tariffs directly to energy which is metered on a half hourly basis. At present in NI half hourly meters are not installed for all customers, these are only installed for customers over 70kVA. Invoicing of domestic energy and non metered energy is carried out on the basis of a flat charge. For customers who do not have interval metering in place Figure 5 demonstrates the additional steps required to convert the time-of-use tariffs into a flat charge which would apply in all time-bands.

To re-iterate, further analysis is being carried out on the network drivers to quantify the effects of usage in each of the scenarios and ensure that all relevant time-bands are captured in the model. For these reasons and based on the analysis that has been completed to date SONI indicates that it is appropriate to maintain the use of time bands for customers with interval metering. Going forward, in order to ensure that the tariffs remain cost-reflective an annual assessment of the time-bands and the apportionment of costs to each time-band should be completed as part of the annual tariff preparation. The intention would not be to change the time-bands each year but rather to ensure that the cost allocated to each continues to be appropriate. This continued assessment will not only ensure that the resulting tariffs continue to be cost reflective of the drivers of transmission costs but it will also ensure that the tariff trends move gradually rather than being allowed to drift year on year then require a extensive shift at some stage in order to bring these in line with cost drivers.

The following scenarios are among those currently being examined, it is not intended that the entire list of scenarios below would be included in the final tariff model, the intention is to reduce the number of time-bands from the current number, however as discussed in Section 8.1.3 it is important to examine each possibility and eliminate those time-bands that show no evidence of imposing investment costs. SONI requests views on the possible inclusion of the following time-bands in the new tariff model:

Table 4: Time-bands under analysis to assess impact on Transmission costs

It is not SONI's intention to apply all of the time-bands below, merely to identify the most influential times-of-use for driving investment costs and apply higher tariffs at these times.

Time-band under examination	Description	Notes
Winter Peak	Maximum demand in December & January and Maximum demand in November & February	Existing time-bands at present
Night-time in each season	Typical demand levels during • Summer night – system minimum • Winter night • Spring night • Autumn night	Currently specified time-bands for each season do not exist. All night-time hours are currently charged at one rate
Winter Day	Maximum daytime demand in December & January and maximum day time demand in November & February outside peak hours	Existing time-band at present
Summer peak	Maximum demand in Summer	Not currently a specified time-band
Evening, Weekend or holiday for each season	Maximum demand in evening/ weekend for spring, summer, winter & autumn.	Not currently specified time-bands that vary by season. Just one evening/weekend/holiday rate
Day peak in Autumn and day peak in spring	Maximum demand during day hours in Spring and in Autumn	Not currently specified time-bands

8.1.5 Separate treatment of Fixed and Variable Transmission Costs

In the current model load related operating costs are applied to all time-bands reflecting that these do not vary depending on usage patterns. Network capital costs are currently allocated to only the two winter peak time-bands. The two sets of costs are then amalgamated to produce the overall charge for each tariff category and each time-band. An alternative approach to deal with such costs and in order to promote transparency in the model is to separate fixed costs,by which we mean costs which do not vary depending on time-of-use, for example administration costs, billing costs, staff and buildings costs, from costs which do vary depending on usage patterns, mainly network capital costs, and allocate these depending on the drivers of these costs.

For example, network related costs, as we have explained above, tend to be driven by time of use of energy consumption. Winter peaks in particular have been influential in driving the need for reinforcement of the network and hence it is cost-reflective that tariffs for usage of the transmission system during this time would be subject to higher charges.

On the other hand some costs associated with the transmission business do not vary depending on usage and hence it would not be equitable to charge these costs to users depending on time of use. These types of costs can be referred to as fixed costs and in order for tariffs to be cost-reflective it is vital that these types of costs are apportioned correctly. It is deemed that fixed costs should be levied via a uniform charge to all users in all time periods.

Figure 6 in Appendix 4 shows how fixed costs would be levied via a fixed tariff which is constant in all time-bands. Time-of-use tariffs vary for each time band. The final tariff for any time band is the sum of the fixed charge and time-of-use charge. The chart is purely for illustration purposes and does not imply that any time-band will have higher or lower charges.

A further step could also be applied, if deemed valuable, in order to promote transparency. The two separate charges, to recover fixed cost items and non-fixed costs items, could be displayed as two separate tariffs in the Statement of Charges document and TUoS invoices could include separate line items for each charge. In order to treat the various transmission costs appropriately and derive separate charges for fixed and non-fixed costs SONI has requested data from UR and from the Transmission Asset Owner, detailing the breakdown of transmission costs. Only with a breakdown of the necessary transmission cost data will SONI be able to treat fixed and non-fixed costs separately.

Respondents should indicate in their responses if separate charges would be desirable or if they feel this is an unnecessary level of detail.

9 Other Considerations

9.1.1 Treatment of Distribution Loses

Given that tariffs for each voltage level will no longer be calculated, a single tariff will be charged for all units on the transmission system, similar to Ireland methodology, therefore it will be necessary for energy amounts supplied from the meter data provider to be scaled up by the appropriate Distribution Loss Factors (DLFs) before the TUoS tariff is applied. SONI will have no role in calculation of DLFs but will merely apply the approved DLF to the meter data in order to bring energy calculations to the transmission distribution interface where the tariff is to be applied. Since the transmission loss adjustment factor (TLAF) for all suppliers is 1, as defined in the Trading and Settlement Code, no further adjustment is required for transmission losses[10].

For example, if a customer has consumed 100 kWh of energy at the meter/connection point and the appropriate DLF for this customer's connection voltage is 1.041, then the energy amount that the new TUoS tariff will be levied on in respect of this customer is 100*1.041 = 104.10kWh

9.1.2 TUoS billing data

In terms of the data used for settlement of TUoS invoices SONI have explored the idea of using data from the SEM systems rather than using meter data which is not currently available on a half-hourly basis for all customers. A number of benefits have been highlighted if market data could be applied to TUoS settlement including that half hourly energy data per supplier would be readily available and could be used and hence time-banding could be applied to all energy consumption. However a number of drawbacks are also evident, these include;

- TUoS settlement data would not be consistent with DUoS settlement data: We are aware that suppliers/customers carry out comparisons of the energy quantities for TUoS and DUoS charges and the energy amounts may no longer be consistent given that these will originate from two different sources. DUoS uses meter point data and SEM systems use trading point data. The key issue with the ability in such data comparison would arise from the need to consider loss factors and timing of data availability.

[10] If changes occurred that Suppliers had a share of transmission losses this may also need to be accounted for

- This type of approach would be diverging further from ROI approach, suppliers have requested that this not be the case
- Difficult to justify charging for all energy based on time of use when a large proportion of customers do not have the opportunity to react to the signal and reduce their costs due to restrictions in meter availability.
- Re-settlement would need to occur in line with re-settlement of the SEM Energy market, this creates additional billing administration costs.
- Using this source of data for NI TUoS settlement has not been done before and would require further consideration, impact assessment and testing prior to recommendation or implementation.

SONI are not recommending using the SEM data or any other alternative source of data for TUoS calculations at this time. SONI, while not involved, is aware of the work ongoing in relation to the "Enduring Solution" as well as Global Aggregation and will monitor any changes which result from these processes which might impact on TUoS billing calculations. In future any consideration for a change of input data for the settlement of TUoS invoices will of course be communicated to the industry before any change is implemented.

9.1.3 Revenue reconciliation

It is intended that any under or over recovery of transmission revenue shall be treated in same way as currently done whereby the under/over recovery is rolled forward to the next revenue period. The future adjustment of this over/under recovery can be applied in a cost reflective way when using two separate charges for fixed and variable costs. SONI could identify under/over recovery from each cost category and apportion this to the next year's target recovery of the appropriate cost.

9.1.4 Transmission Losses

It is assumed that transmission Losses will continue to be allocated fully to generators hence it is not necessary to consider this any further in this paper. The treatment of transmission losses in NI and Ireland is currently under review and details can be found in the current consultation paper (SEM-10-039) available on the all-island project website http://www.allislandproject.org/

10 Assessment of proposed TUoS model: Model 3

The proposed models as outlined in Section 7 and section 8 above have been assessed in terms of how each can achieve the objectives of the charging methodology, as illustrated in Table 4 below.

Table 4: Assessment of potential models against each Objective

Objective	Model 1 Energy & capacity charges (No time-of use)	Model 2 Locational	Proposed New model Model 3 Energy based charging with time of use tariffs based on updated time-bands
Cost-reflectivity	✗	✓	✓
Transparent	✓	✓	✓
Reduced Volatility	✓	✗	✓
Predictable	✓	✗	✓
Non discriminatory	✗	✓	✓
Consistent with Generator tariffs[11]	—	—	—

[11] Assuming some method of all island locational charging is adopted by October 2011.

Model 3, which incorporates a charge for energy at the transmission-distribution interface based solely on energy usage but with time of use tariffs would appear to meet all the objectives of the tariff model. The new model brings about a number of benefits including increased transparency and reduced complexity by reducing the large number of tariff categories and user groups which are not necessary for transmission charging. A model which does not differentiate between connection voltage levels on the distribution system is considered more appropriate for the reasons outlined in Section 8.1.2.

Incorporating Time of use tariffs for different times of day or year sends a signal regarding the cost users impose on the transmission system and recover these costs from those users that are responsible for the costs, hence the inclusion of a number of time-bands for half hourly metered customers, are a cost reflective method of charging for transmission costs. This proposed new model will charge all half-hourly metered users of the transmission system a multi-rate tariff which varies by time of day/year. A flat charge will be applied to non half-hourly metered customers which is derived on the same cost assumptions but incorporates profile allocations, so that in effect a weighted average tariff is applied to the non metered energy based on the costs/tariffs in each time-band multiplied by the percentage allocation of consumed energy to that time-band. The time-bands applied will be more reflective of the current and/or future cost drivers on the network. If deemed necessary capacity based charges could be incorporated into the proposed methodology however it is not envisaged that the use of capacity based charges at this stage will further enhance the cost-reflectivity of the model without reducing the attainability of other objectives therefore it has been recommended to continue with energy only charges.

The recommended model will deliver tariffs that will be non-volatile and predictable, to the extent that the revenue determinations and energy forecasts are predictable. The model will be transparent and the transparency will be enhanced by various proactive measures to be undertaken by SONI, including the production of explanatory documentation outlining the tariff methodology, regular meetings or workshops with suppliers and interested groups and the provision of indicative tariffs for a number of future years. Annual analysis of the cost drivers of transmission costs and updating of the model will ensure that tariffs remain cost reflective on a year to year basis.

The methodology aims to treat all users equally, to the extent that available meter data permits, and will ensure similar types of transmission system users are treated identically, for example all half-hourly metered energy will be charged the same rate irrespective of connection voltage level .

The only primary objective that cannot be achieved by this model is consistency with Generator TUoS. A locational supplier tariff model has the potential, if applied on an all-island basis, to achieve one additional objective that the proposed model cannot, this is consistency with the generator tariff regime. This is an extremely important consideration however as outlined in Section 4.2 this is beyond the capability of this review but may be further examined in the long-term along with connection charging policy.

Based on the discussion above and the relevant positive and negative factors of each potential methodology as well as the ability of the models to meet the primary objectives, SONI believe that Model 3 is the most appropriate model to implement for October 2011. This model will address each of the short comings highlighted in relation to the current tariff model.

11 Transmission Rebates and Generator Imports

11.1 Transmission rebates

Currently in NI a transmission rebate is payable to any supplier who has a contract to purchase energy from an eligible generator connected to the distribution system in order to offset their use of the transmission system. Full details of the conditions are outlined in the SONI Statement of Charges document and in the retail market procedure NI 109. Suppliers must apply to SONI for transmission rebates providing the necessary information in relation to nominated distribution generator sites. The generator connection must be below 10MW to be eligible for transmission rebate payment and the generator must not export onto the transmission system.[12]

In the past the rationale for these payments was that the energy purchased from the eligible distribution connected generators is deemed to not have used the transmission system, suppliers therefore, who have paid TUoS on the full amount of their energy usage are rebated TUoS charges in respect of this energy purchased from these generators, which is assumed did not flow on the transmission system. This assumption is no longer pragmatic given that all embedded generators, even smaller units, can impose requirements on the transmission system. In addition, embedded generation in NI is not distributed throughout the network, it tends to be connected at close proximity and for this reason, it is does not resemble demand and hence it would be inappropriate to treat embedded generation as negative demand. The embedded generation is location specific and hence it is more appropriate to treat this as generation rather than negative demand.

Transmission rebates were introduced at a time when relatively few small[13] distribution generators were connected to networks. The combined impact of these small generators on exporting power onto the transmission system was minimal at this time. These small generators were mainly supplying local distribution system load and hence were not required to contribute towards transmission costs. In recent years however, government policies to reduce CO_2 emissions have lead to UK and Irish government renewable energy targets of 15% and 16% respectively by 2020. Subsequently many new connections have been provided for small

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[12] Validation criteria for transmission rebate nominations can be found in the Retail Market Procedure NI109

[13]In this paper " Small" refers to a unit with Maximum export capacity of less than 10MW

generators to connect to the distribution system, in particular wind farms. The aggregate effect of these small generators exporting onto the transmission system is believed to have a significant impact and one which is growing year on year. The transmission system has to be designed and built to facilitate the increased generation exported from the distribution connected generators onto the transmission system.

As part of this review process SONI has given consideration to the issue of transmission rebates. Ideally in a situation whereby the transmission charging of demand and generation users within a region is consistent and location specific, it is possible to identify areas where the existence of embedded generation is beneficial to the transmission network in off-setting transmission investment and reward such users through locational charging. This is not currently the case in NI and as such it would seem unreasonable to simply assume that all embedded generation, less than 10MW, are not requiring transmission network and reward the existence of this, through rebates of supplier TUoS charges, when there is no evidence that this type of generation brings about decreased need for future transmission investment.

Revenue paid out in transmission rebates has to be recovered from other demand users, in order to ensure all users are treated fairly SONI has carried out high level analysis of the impacts of embedded generation on the transmission system. In the absence of locational charges all of NI has to be considered as one region which must be treated in the same manner. The aim of this analysis was to establish if in NI this type of generation typically requires transmission network developments. The initial results of the analysis supports the view that embedded generation, due to the increasing volumes and location contributes to the requirement for transmission investment. It has been found that typically distribution connected generators contribute to increased transmission system development at particular times of day/year. Given that results show that distribution connected generators drive transmission system investment, SONI is of the view that it is no longer reasonable to issue rebates of transmission charges in respect of energy supplied by any eligible distribution connected generators. SONI recommends that Transmission rebates are discontinued from October 2011.

11.2 Generator import charges

When a generator is importing electricity over electric lines or electrical plant comprising a part of the transmission system, a charge for use of the transmission system will be levied on the registered supplier. It is envisaged that any generator connected to the distribution system or transmission system who imports electricity shall be charged exactly the same rates as any other demand user, given that the generator has exactly the same impact on the network as a demand user consuming energy. For a generator connected to the distribution system the relevant DLF shall be applied to volumes of metered energy imported, see Section 9.1.1 for details. The charges will apply to all imports with the exception of reactive imports requested by SONI to provide network support.

12 Next steps

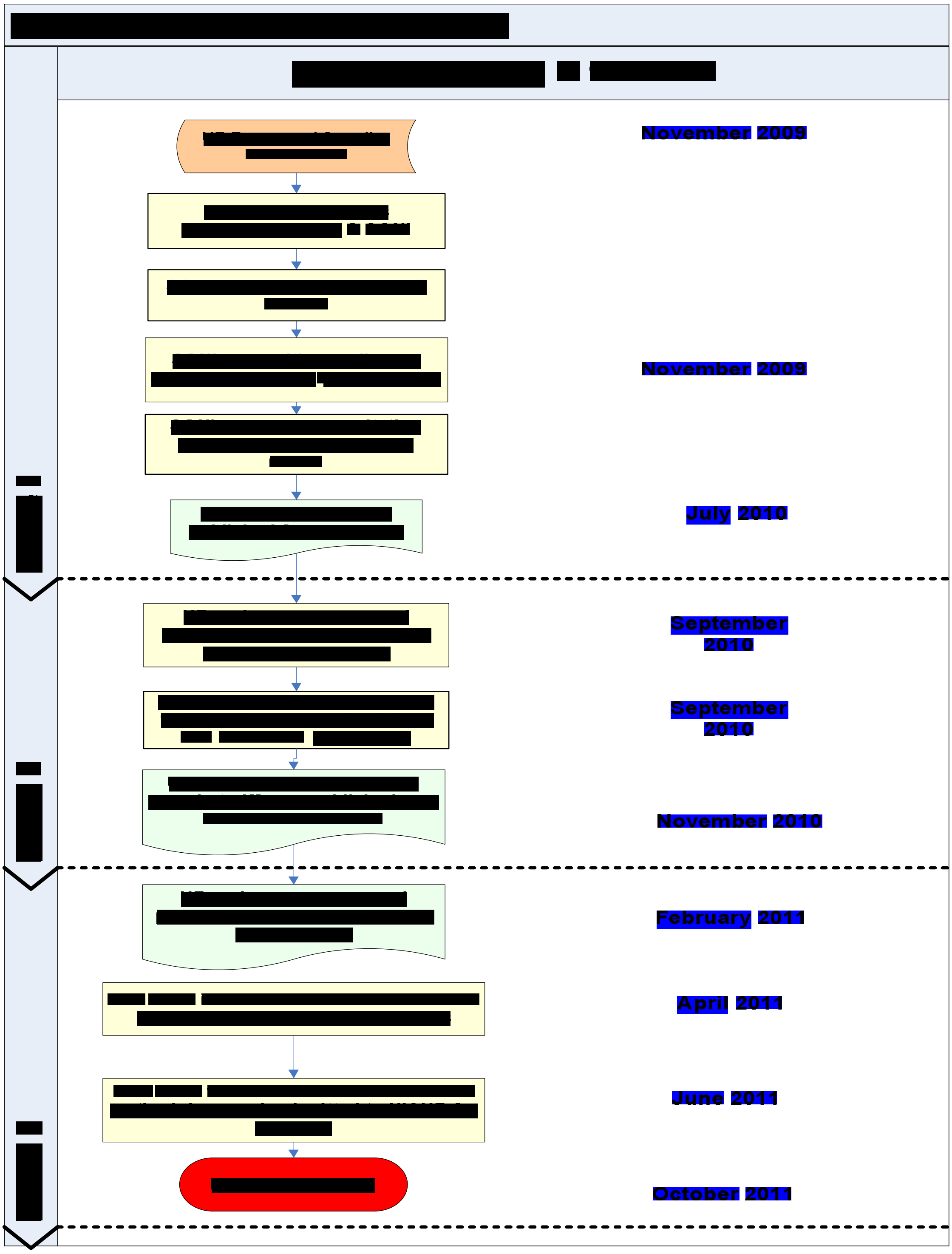
Interested parties are invited to respond to this paper with their views. Parties should clearly state their views on the preferred model (Model 3) as outlined in Section 8 above: In particular respondents should indicate if in their view-

- The model will satisfy the objectives and deliver an enduring approach for NI
- They support Energy only based charging or a combination of capacity and energy based charging
- They feel it is reasonable to no longer charged on a voltage level basis
- Charging at the transmission /distribution interface is workable
- It is appropriate to include time-banding as outlined in Section 8.1.3
- Possible new time-bands should be adopted and the implications of this, if any
- costs should be allocated to time-bands based on the costs associated with the existing network or based on the drivers of future investment, or both.
- Separate charges for fixed costs and non-fixed costs is preferable.
- Discontinuation of Transmission rebates is supported

Please also include any additional comments or issues that you would like to be considered. We would encourage parties to respond as fully as possible by 5pm on Friday September 3rd at the latest. Responses should be forwarded electronically to Raymond Skillen at Raymond.Skillen@soni.ltd.uk and copied to Helen Magorrian at Helen.Magorrian@Soni.ltd.uk. Any respondent who wishes to keep part or all of its response confidential should highlight this when submitting the response.

To request clarification or further information on any aspect of the discussions in this paper please feel free to contact either Helen Magorrian by email to Helen.Magorrian@Soni.ltd.uk or Elaine Roberts by email to Elaine@elaineroberts.co.uk.

Appendix 1: Project Timeline



Appendix 2: Overview of proposed methodology.

Figure 4 below provides an illustration of the proposed Supplier TUoS methodology. Supplier TUoS revenue requirement is first split into two components, one which relates to recovery of fixed costs and the other relating to recovery of Network related costs which are driven by time-of-use. Fixed costs are recovered via a fixed charge payable by all users for consumption at all times of day/year. Time-of-use dependent costs are recovered using cost reflective time-bands to allocate the costs to the time of day/year that drives the transmission investment. This results in cost-reflective tariffs that send a signal to consumers about their behavior. In the illustration below three time bands are shown. WP is winter peak, SP is Summer peak and OT is all other times outside of winter peak and summer peak.

It is found for example, that winter peak time is responsible for 60% of the cost of network investment, Summer Peak is responsible for 20% of investment and usage at other times is accountable for the remaining 20%. The share of Supplier TUoS revenue allocated to network related costs is hence allocated to the 3 time-bands in these proportions. Tariffs for usage in these time-bands are then calculated based on the energy forecast for each of these time-bands. The resulting tariff is a pence/kWh charge for usage in each time-band.

The final tariff applied is any time band is the sum of the relevant time-of-use tariff (WP, SP or OT) as well as the fixed tariff (shown as D). Please note that all values and time-bands are for illustration purposes only and will change in the final tariff model once further time-band and costing analysis has been complete. These time-of-use tariff will be applied to all users with half-hourly metering in place. The time-of-use tariffs for all other customers must be converted into a flat charge, which will serve as a proxy for the time-of-use charges. The process for deriving the flat charge is shown in Figure 5.

The calculations shown in Figure 4 below could be represented in an alternative format which would produce the same final tariffs. We could begin by allocating the full network circuit costs between the different time-bands, these network costs can then be divided by the energy forecast for each time-band to produce a unit charge for each time-band. Understandably the recovery from these tariffs will not match the required revenue, in most cases it will likely over-recover transmission revenue and hence the tariff in each time-band would be scaled back to ensure only the required revenue is recovered from the tariffs. In relation to scaling the tariffs a multiplier or additive scaling factor could be applied. SONI would propose the use of a multiplier scaling which is also consistent with the scaling mechanism in the proposed Generator TUoS tariff model. Different scaling methods have different advantages and disadvantages and the choice generally depends on external factors. With a multiplier scaling factor the signal can become diluted whereas with an additive scaling factor the signal remains as strong but the result can be to produce negative tariffs in some time-bands which may not be desired. Using the approach of starting with network costs and then applying a scaling factor will produce exactly the same final tariffs as using the method illustrated in figure 4. Given that Suppliers and all industry participants in NI are more familiar with the illustration shown below, which uses the transmission entitlement revenue as a starting point in calculating tariffs, it was felt more suitable to illustrate the calculations using this approach.

Figure 4: Overview of Proposed Model

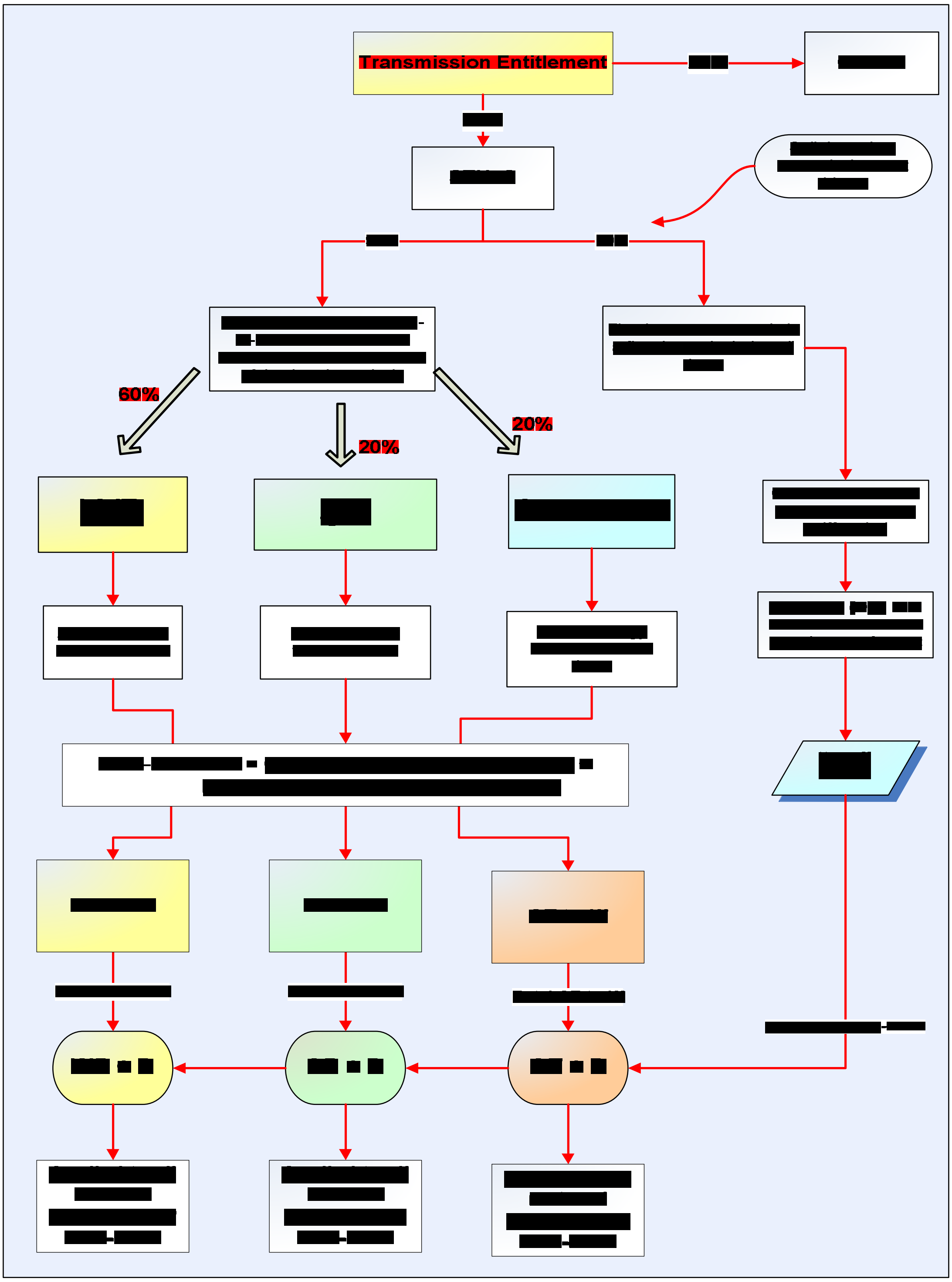
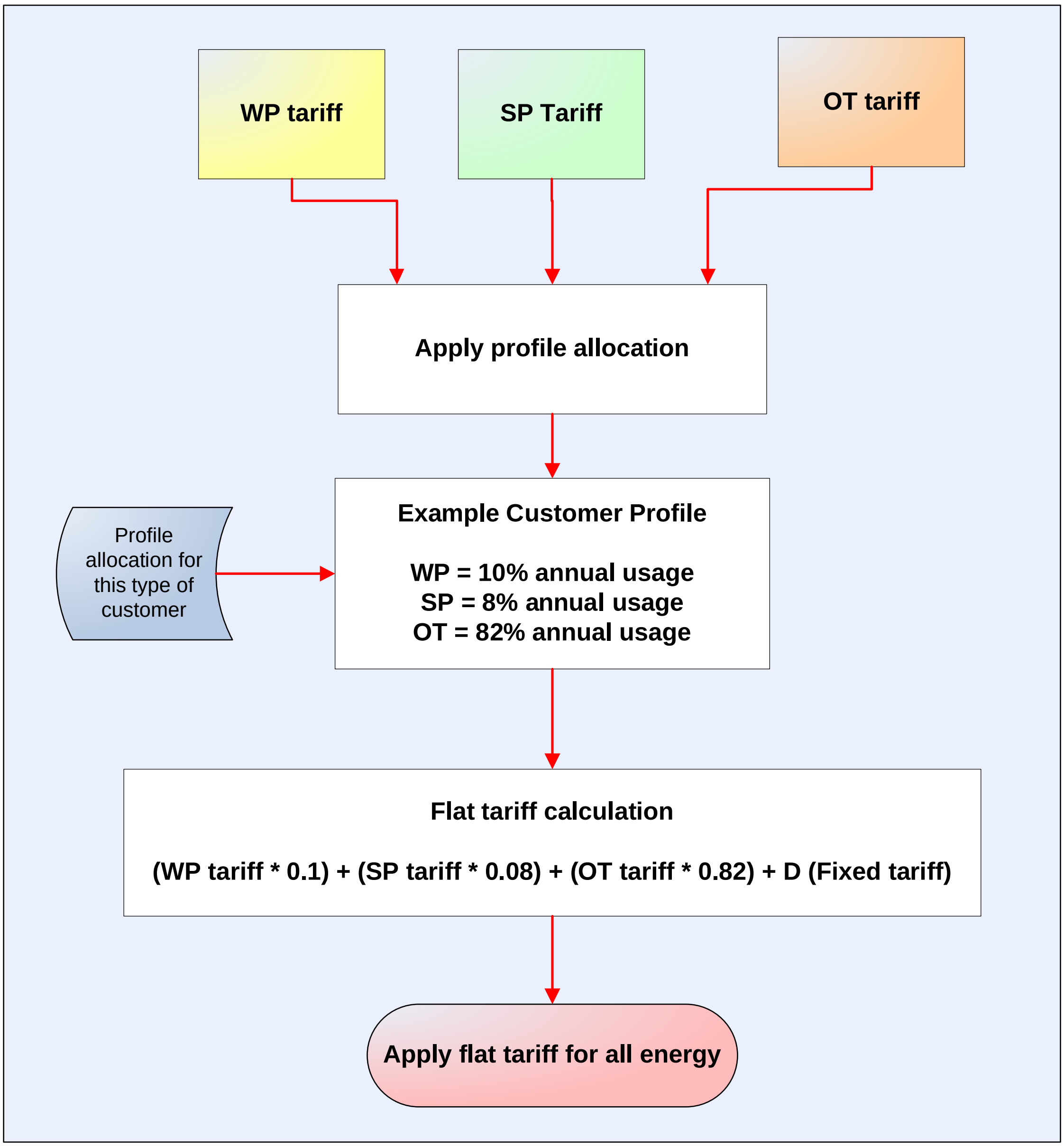


Figure 5: Apply profile allocations to derive a flat charge for non-half hourly metered customers



Appendix 3: Example of cost allocations to time-bands

Consider a five circuit system with three time-bands under examination, Winter Peak, Summer peak and all other times. For simplicity we shall assume that the time-bands all span the same number of hours in the year.

Circuit	Scenario with max flow	Annual circuit cost (£m)	Share of costs attributed to each time-band
1-2	Summer peak	0.2	0.2 to Summer Peak
2-3	Winter peak	0.7	0.7 to Winter peak
3-4	Winter peak	0.8	0.8 to Winter Peak
4-5	Summer peak	0.1	0.1 to Summer Peak
1-5	Same flow in Winter Peak and Summer Peak	0.6	0.3 to Summer Peak 0.3 to Winter Peak
3-5	Other Times	0.6	0.6 to other time
Total		3.0	

Total circuit costs that are driven by a maximum flow in Winter Peak are £1.8m (60%), total circuit costs that are driven by a maximum flow in Summer Peak are £0.6m (20%), and total circuit costs that are driven by a maximum flow in Other times are £0.6m (20%). Based on this 60% of the required annual revenue to be recovered from the time-of-use tariff would be allocated to the winter peak time-band , 20% to the Summer Peak time-band and the remaining 20% to the Other Times. The final tariff for each time-band would then be calculated by dividing the required revenue recovery in each time by the forecast energy in that time-band.

Appendix 4: Fixed tariff and Time-of-Use tariffs

Figure 6: Recovery of fixed costs and Network related (time-of-use dependent) costs