

CONSULTATION DOCUMENT

GB ECM-21

**Changing tariffs mid-year to implement the
Offshore Transmission regime**

December 2009

Comments should be emailed to william.kirkwilson@uk.ngrid.com no later than **8th January 2010**.

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1 Executive Summary

The introduction of the Offshore Transmission regime will create a number of Offshore Transmission Owners (OFTOs) responsible for building, owning and maintaining offshore transmission assets. The resulting OFTO costs will be passed to the industry through Transmission Network Use of System (TNUoS) tariffs.

Each OFTO will be identified through a tender process that will conclude after TNUoS tariffs have been published. For 2010/11, TNUoS tariffs will be published by the end of January 2010 whereas offshore regime go live is scheduled for June 2010. Therefore all tariffs will be based on forecast offshore costs as the actual costs are not known until the tender process concludes. It should be noted that this issue is not limited to 2010/11, but is likely to repeat in future offshore tender rounds until the enduring offshore regime has fully transitioned. Consequently consideration is required as to how to reflect the outcome of the offshore tender process within the charging arrangements. National Grid is not seeking to alter or modify the principles on which charges will be determined or derived, as this has already been amended (see ECM-08), simply the underlying process.

GB ECM-21 examines three options to accommodate data exchanges with OFTOs in the GB charge setting process (section 5):

- ❑ **Option 1: No mid-year tariff change (status quo)** – onshore and offshore TNUoS tariffs would be set in normal charge setting timescales and will not change mid-year;
- ❑ **Option 2: Limit mid-year tariff changes to offshore tariffs only** – onshore tariff publication would be as normal. Indicative offshore tariffs will be published along with onshore tariffs. Final offshore tariffs would be updated with information from the tender process; and
- ❑ **Option 3: Review all tariffs mid-year** – onshore tariffs will be published as normal. Indicative offshore tariffs will be published along with onshore tariffs. Both onshore and offshore tariffs would be updated mid year with information from the tender process.

National Grid concludes (section 6) that **Option 3** is the preferred option. It best meets the relevant transmission licence objectives because:

- ❑ It is the most cost reflective and therefore is least likely to create cross-subsidies between onshore and offshore generators, or between generation and demand.
- ❑ It is an extension of the current process and clarifies how the existing charging methodology would be implemented for multiple tariffs within year.
- ❑ It takes best account of the introduction of the offshore tender process in the charging processes and mirrors similar arrangements for onshore transmission owners.
- ❑ The reduction in tariff predictably can be mitigated through the publication of additional information.

The revenue impacts of all three options have been quantified using Monte Carlo analysis. The modelling assumptions underpinning the analysis are set out in section 4. **The impact on next year of a July tariff change are forecast in figure 5, page 17.**

Responses and queries should be sent to william.kirkwilson@uk.ngrid.com no later than 8th January. This consultation has been published on the National Grid charging website:

<http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/>

2 Introduction

As the transmission licensee, authorised to co-ordinate and direct the flow of electricity onto and over the transmission system within Great Britain, National Grid has duties under the Electricity Act to develop and maintain an efficient, co-ordinated and economical transmission system and to facilitate competition in generation and supply.

Along with these high level duties, National Grid is obliged under its transmission licence:

- to keep the Use of System Charging and Connection Charging Methodologies at all times under review;
- to make such modifications of the Use of System Charging Methodology as may be requisite for the purpose of better achieving the relevant objectives, which are:
 - a. to facilitate effective competition in generation and supply;
 - b. to result in charges which reflect, as far as reasonably practicable, the costs incurred by transmission licensees in their transmission businesses; and
 - c. in so far as is consistent with a) and b) above, as far as reasonably practicable, to properly take account of the developments in transmission licensees' transmission businesses.

In addition to the relevant objectives above, the transmission licence also prohibits National Grid from discriminating against any User or class of Users unless such different treatment reasonably reflects differences in the costs of providing a service.

Against this background, the purpose of this consultation is to describe how information from the offshore tender process can be accommodated within the charging methodology and charge setting process and to that end, how to determine a user's annual liability when there are multiple TNUoS tariffs within year. National Grid has assessed the various process options with a view to better meeting the relevant transmission licence objectives set out above and invite industry views on the options presented.

3 Background

3.1 Key roles and responsibilities

National Grid's transmission licence contains provisions that cover both the Transmission Owner (TO) and System Operation (SO) activities associated with the National Electricity Transmission System (NETS). National Grid is the only transmission licensee permitted to carry out both these activities.

The TO activity involves the provision of transmission network services to the SO, enabling the SO to meet its licence obligations. The provision of transmission network services is linked to providing transmission capacity by building, operating and maintaining transmission assets within a licensed area. The costs associated with this activity are recovered from the SO who is responsible, amongst other things, for the contractual interface with users of the NETS.

The revenue that TOs are allowed to recover is set by Ofgem as part of the price control review process. Each TOs allowed revenue is based on the efficient level of costs it will incur. National Grid as SO, sets connection charges and Transmission Network Use of System (TNUoS) charges to recover the total allowed revenue of all the TOs from users of the NETS. Each TO recovers its allowed revenue by levying charges on National Grid.

3.2 Requirement for change

The introduction of the Offshore Transmission regime will create a number of Offshore Transmission Owners (OFTOs) responsible for owning and maintaining offshore transmission assets. The costs an OFTO incurs in undertaking these activities will be recovered through charges it levies on National Grid, which in turn will be passed through to transmission users through TNUoS tariffs. This mirrors the arrangements for onshore TOs described above.

Each OFTO will be identified through a tender process that establishes its allowed revenue. This tender process is currently underway and the offshore go-live date is scheduled for June 2010, which is mid-way through a financial year, after TNUoS tariffs have been set for 1 April 2010.

The key dates for setting TNUoS Tariffs are defined by National Grid's transmission licence, the Connection and Use of System Code (CUSC), or the SO-TO Code (STC) and its associated procedures (STCPs). Using 2010/11 as an example year, the normal charge setting timetable would be:

- by 1st November 2009, Licence Condition C4 5(a) requires National Grid to provide the Authority 150 day's notice of the intention to change charges.
- on or before the 1st November 2009, STCP 13-1 and 14-1 requires each TO send National Grid their best forecast of their revenue requirement for the next financial year.
- during December 2009, National Grid publishes draft TNUoS tariffs.
- on or before the 25th January 2010, STCP 13-1 and 14-1 requires each TO to provide an updated revenue requirement.
- on or before the end of January 2010, CUSC 3.14.3 requires National Grid to publish the final TNUoS tariffs thereby giving the industry 2 months advanced notice.
- 1st April 2010, the updated TNUoS tariffs come into effect.

This timetable ensures that by the end of January during a normal charge setting year, National Grid has received the information about each TO's allowed revenue, which enables TNUoS tariffs to be calculated and fixed for the next financial year in the knowledge that these are targeted to recover the correct total allowed revenue for National Grid and all TOs.

However, the charging timeline is not consistent with the offshore tendering timeline, illustrated in figure 1, where Preferred Bidders are announced after the standard charge setting process has concluded. Accordingly the charging processes must be amended if data from the offshore tender process is to be used when setting TNUoS tariffs and determining users' liabilities.

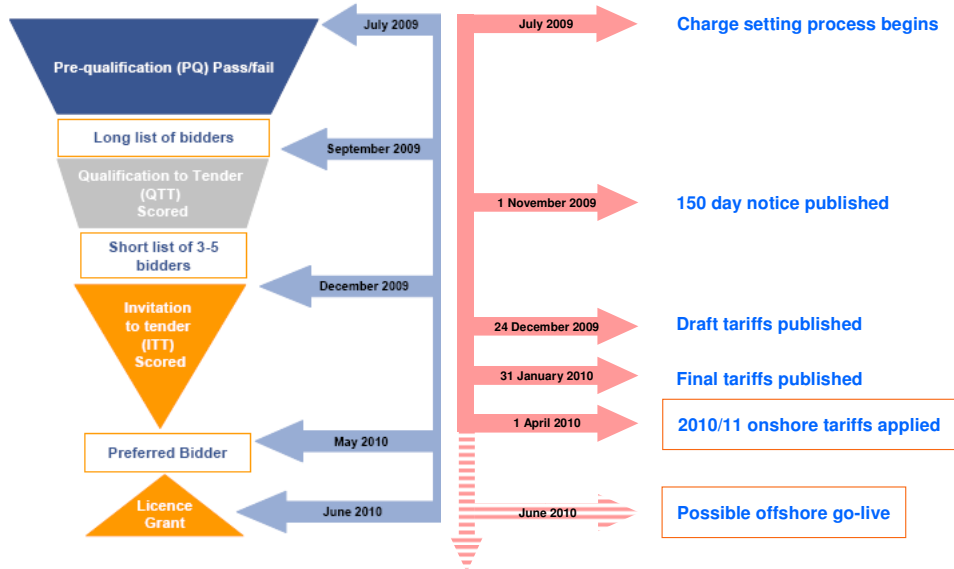


Figure 1 - Offshore tender round timeline compared to TNUoS charge setting timeline

Against this background, it should be noted that this situation is not limited to 2010/11 and is likely to repeat itself in future offshore tender rounds until the enduring regime has fully bedded in, after which there will be a time lag between the appointment of the OFTO and the need to publish onshore and offshore tariffs (i.e. the delay caused by the time needed to construct the offshore assets).

3.3 Dealing with uncertainties when charge setting

Implicit in the charge setting process is the need to make forecasts when calculating allowed revenue. For example, National Grid forecasts the outturn of its reliability incentive for performance in year y in order to include the correct revenue adjustment for the tariffs in year $y+1$. As there is still a significant portion of the incentive period left to run after setting tariffs for year $y+1$ in January, an unexpected event in this period will lead to a change in allowed revenue. Therefore by the end of year $y+1$ there may be differences between actual allowed revenue and the allowed revenue forecast when charge setting.

These differences (either positive or negative) are carried through to next years allowed revenue with interest through a mechanism called Kt. This interest may be at a penal rate for over-recoveries over a certain threshold. All TOs have this Kt mechanism in their licence and it ensures that TOs are appropriately funded in line with their price control and that each TO is incentivised to make accurate forecasts of their allowed revenue. Against this background, all TOs have the risk that their allowed revenue may change mid-year without being able to modify their cash flow. This is unavoidable and is a consequence of fixing tariffs at the start of the year.

National Grid carries an additional cash flow risk compared to other TOs, as not only can its allowed revenue change throughout the year, but also the revenue recovered from users can differ from the charge setting forecast. For example, National Grid may forecast that the revenue from demand customers is £xm but it may outturn at £ym because it is a warmer or colder winter than originally forecast. Therefore by the end of the year there will be differences between allowed revenue and collected revenue. This difference is also carried through to next years allowed revenue through Kt¹.

During the period until the enduring offshore transmission regime has taken full effect, the offshore regime will introduce significant new uncertainties into the tariff setting process. This uncertainty arises as the revenue requirements of the OFTO and other key charging information (such as asset values and ratings) are only known after the standard charge setting process has concluded.

3.4 Possible charging options to facilitate charge setting

Against this background, a mid-year change to TNUoS tariffs may be needed to ensure that National Grid can recover the correct offshore transmission costs (reflected in the allowed revenue of each OFTO) within the financial year in which they occurred. However the GB Charging Methodology is silent on how to implement mid-year TNUoS tariff changes, as the underlying assumption in the methodology is that tariffs change once a year in line with the start of the fiscal year.

National Grid therefore believes that the existing charging methodology should be clarified firstly to state if National Grid should be able to change tariffs mid-year (noting that there is nothing in the transmission licence or the CUSC that prohibits multiple tariffs in a year) and if it can, to describe how multiple TNUoS tariffs within year could be implemented to facilitate the offshore transmission regime timetable.

GB ECM-21 examines the following three options:

- ❑ **Option 1: No mid-year tariff change (status quo)** – National Grid would forecast the offshore parameters needed to set onshore and offshore TNUoS tariffs in normal charge setting timescales and would not change tariffs mid-year;
- ❑ **Option 2: Limit mid-year tariff changes to offshore tariffs only** – National Grid would publish onshore tariffs as normal and indicative offshore tariffs based on estimates of offshore parameters; only offshore tariffs would be updated with information from the tender process; and
- ❑ **Option 3: Review all tariffs mid-year** – National Grid would publish onshore tariffs as normal and indicative offshore tariffs based on estimates of offshore parameters; both onshore and offshore tariffs would be updated with information from the tender process.

¹ National Grid has a best endeavours clause in its licence to not exceed allowed revenue and penal interest is applied if over-recoveries are greater than 2.75% of allowed revenue.

4 Modelling methodology

4.1 Modelling techniques used

National Grid has used Monte Carlo modelling throughout this consultation to assess the cost reflectivity of each charging methodology option and the resultant impact on users' charges and tariffs. This technique is particularly useful where there are uncertainties in multiple input values.

The diagram below illustrates the key unknown factors, shown in blue, and how these link into the calculation of offshore and onshore tariffs.

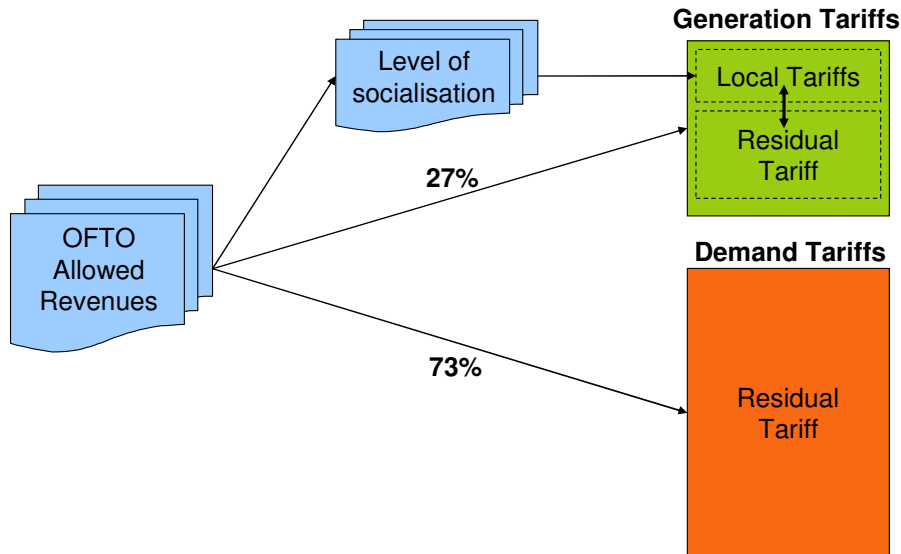


Figure 2 – Illustration of how OFTO revenues and offshore socialisation impacts TNUoS tariff components

National Grid has had to take a view on the factors that impact an OFTO's allowed revenue, as this determines the cost to generators (27%) and to suppliers (73%). National Grid has also had to take a view on the level of socialisation of offshore costs. Socialisation arises when the offshore generator tariff does not cover the entire annual revenue requirement of the OFTO and reflects situations where the offshore user does not use the full capacity of the offshore assets or where there are OFTO assets that are not part of the local offshore tariff. The socialised component of offshore costs is passed through to onshore tariffs through the residual component. Therefore the level of socialisation of a project affects the proportion of the offshore costs the offshore generator will pay through its local tariff and that which all other generators will pay through the generation residual tariff.

4.1.1 OFTO allowed revenues

For OFTOs participating in the first offshore transitional tender, National Grid has had to make forecast about each OFTO's cost of capital and level of operating costs, to determine its revenue requirement for a full financial year. This has then been adjusted to take account of when the OFTO is expected to start recovering its revenue based on a forecast Go-live date. The capital cost of each OFTO network has been based on Ofgem's Estimated Project Values published in offshore tender preliminary information memorandums.

Where multi-year analysis has been undertaken, in addition to the above forecasts, National Grid has calculated an Estimated Project Value for the offshore network, as these have not yet been published. This has been done by determining the unit

capital cost of offshore networks constructed (or being constructed) for the offshore projects in the first offshore transitional tender and applying this unit cost to future generation schemes.

4.1.2 Level of socialisation

National Grid has assessed a possible range of offshore cost socialisation using information from illustrative offshore local tariffs prepared for industry participants and 'dummy' offshore data provided by Ofgem. Clearly without complete information about the capability of offshore assets and the gross asset value of offshore assets, there still remains considerable uncertainty in the level of socialisation. However, some of this uncertainty may be reduced in the near future following a recent informal information request National Grid has made to offshore developers.

4.2 Key modelling assumptions

The table below shows the assumptions made in this analysis for the following independent variables that have been used during the Monte Carlo simulations.

Variable	High limit	Central	Low limit	Distribution type
OFTO Revenue				
Cost of Capital (% of ETV)	12%	9%	4.5%	Triangular
Operating costs (% of ETV)	8%	5%	3%	Triangular
Unit offshore capital costs (£/MW)	0.67	0.51	0.29	Normal
Go-Live date movement (months)	1	0	0	Triangular
Socialisation				
Socialisation level (%)	40%	33%	10%	Triangular

Table 1 Key modelling assumptions used in Monte Carlo simulations

It should be noted that the assumptions are bounded by their high and low limit, for example the maximum cost of capital of an OFTO has been capped at 12%, but it is conceivable that higher costs of capital may be required.

The same forecasts (e.g. generation base, demand bases, etc) that were used when charge setting for 2009/10, have been used to turn OFTO revenue streams into their impact on tariffs.

5 Charging options considered

5.1 Option 1 – No mid-year tariff change (status quo)

5.1.1 Implementation

National Grid would publish onshore generation and demand TNUoS tariffs in January as normal. National Grid would also publish offshore tariffs in January. Both onshore and offshore tariffs would be based on the best available data which would include forecast offshore allowed revenues. The forecasts would be made by National Grid based on incomplete data, as the actual data is confidential, commercially sensitive, or unavailable. All tariffs would apply for the whole financial year.

Under this option National Grid would be required to forecast:

- each OFTO's annual allowed revenues, comprised briefly of:
 - financing costs the offshore assets,
 - controllable operating costs, and
 - pass through costs
- technical information about the offshore assets, such as ratings;
- the gross asset value of certain types of offshore assets; and
- the go-live date of the offshore regime (for 2010/11 only).

Any difference between National Grid's actual allowed revenue (representing the sum of all the TOs and OFTOs individual allowed revenues) and the revenue collected from users through TNUoS charges, and hence National Grid's over or under recovery, would be included within National Grid's Kt mechanism and passed through to the industry the following year. There is no limit to the size of Kt although, as noted previously, incentives exist to minimise revenue over recoveries.

5.1.2 Discussion

Facilitates competition

This option has the advantage that TNUoS tariffs are fixed and therefore predictable within year. Of the three options examined, this option gives industry participants the earliest visibility of firm TNUoS tariffs. However, the trade off between fixing tariffs and not amending them in the light of better information is increased tariff volatility between successive years as subsequent revenue under or over recoveries are taken into account the following year through the Kt mechanism.

Tariff volatility may be more evident for local offshore tariffs, as offshore tariffs will be set using forecast data for the first year and then subsequent tariffs will be set using firm contractual data. Consequently there could be a step change in tariffs between the first and subsequent years purely due to data changes.

Cost reflectivity

As stated above, there would be considerable uncertainty in the information needed to calculate tariffs if National Grid were to set final onshore and offshore tariffs in January. This uncertainty would reflect in the cost reflectivity of the published tariffs.

National Grid has modelled the impact of different forecast assumptions on the total OFTO revenue requirements for a number of years, together with an estimate of the

uncertainties that National Grid would be required to manage when setting TNUoS tariffs. The OFTO revenue uncertainty is a reflection of the OFTO cost uncertainty. Note the OFTO revenue figures predicted are the incremental revenues required in their first year of operation².

Tariff Year	National Grid Forecast of OFTO revenue £m	5 th percentile £m	95 th percentile £m	90% confidence range of National Grid OFTO revenue forecast £m
2010/11	78	62	94	32
2011/12	90	71	110	40
2012/13	63	43	84	41
2013/14	71	51	92	41
2014/15	59	42	78	37

Table 2 - Range of offshore revenue flows that would be unknown when setting TNUoS tariffs

As can be seen, there is considerable uncertainty in the OFTO revenue requirements, which would be reflected in the cost reflectivity of users' tariffs. For all transmission users this would be apparent in the accuracy of the residual component of TNUoS tariffs. For example, if in a given year TNUoS tariffs were set to recover £20m more than the actual total OFTO revenue requirement this would be socialised across all users. Generation and demand will have over paid by £5.4m and £14.6m respectively, due to the 27 / 73 revenue recovery split.

The impact is greater still for offshore users, as a given user's offshore local tariff is directly proportional to the relevant OFTO's allowed revenue. In this case, if the National Grid's forecast error represented 20% of the OFTO's allowed revenue, the offshore user's local tariff would be inaccurate by 20%. This could represent a significant change in to the tariff rate and the amount charged.

Developments in the transmission business

Option 1 would not properly take account of developments in National Grid's transmission business for the following reasons:

- ❑ the charge setting process would be undertaken in isolation to the offshore transmission tender process to identify each OFTO and the efficient OFTO revenue requirement.
- ❑ the charging methodology would potentially undermine National Grid's incentive to accurately recover its allowed revenue. Specifically, penal interest charges in the Kt mechanism could be incurred or avoided by incorrectly forecasting OFTO revenues which are outside its control, whereas National Grid should be incentivised to manage parameters that it can directly control or influence.

² National Grid is forecasting total OFTO revenue in 2010/11 to be £78m +/- £16m for 90% of scenarios, 5% of scenarios the OFTO revenue will be less than £62m, and a further 5% of scenarios the OFTO revenue will be greater than £94m. It should be recognised that the table shows the uncertain element of the revenues in each year as the total OFTO revenue will be considerably more. For example, in 2014/15 National Grid will be recovering approximately £544m per annum for all offshore TOs.

- ❑ the charging methodology would essentially transfer revenue recovery risks from OFTOs to National Grid, which is both inappropriate and inefficient, as National Grid is not best placed (or able) to manage these risks whereas the OFTO (or Preferred Bidder) is. Such an arrangement would also be inconsistent with the onshore charge setting arrangements between TOs and National Grid.

5.2 Option 2 - Limit mid-year tariff changes to offshore tariffs only

5.2.1 Implementation

Under Option 2, National Grid would publish onshore generation and demand tariffs as normal and within the usual timescales. Onshore tariffs would include forecast offshore costs. Indicative offshore TNUoS tariffs would be published at the same time. Whilst there would be no mid-year change to onshore tariffs, updated final offshore tariffs for generators connecting within year would be published as soon as practical after Preferred Bidders had acceded to the STC. This would allow National Grid to use information provided by Preferred Bidders to set revised offshore tariffs before offshore parties commence use of the transmission system. This may lead to situations where National Grid would require the consent of the Authority to update offshore tariffs with less than 2 months notice to the users, as is normally required by the CUSC.

The updated offshore tariffs would be fixed for the remainder of the financial year. National Grid notes that Preferred Bidders may need to make certain forecasts of their own to provide National Grid with information (as all onshore TOs are required to make). Any subsequent changes to the Preferred Bidder's assumptions would not be used to make further updates to offshore tariffs within year. Any resultant over or under recoveries would be adjusted the following year through the relevant Kt mechanism. This is the same process used for the onshore tariffs.

Each offshore user's annual liability would be based on the user's highest TEC within year (as per the onshore charging arrangements) and the sum of the relevant offshore and onshore tariffs.

Example

The diagram below shows two scenarios of a 100MW generator connecting to an offshore network. The total onshore tariff is £5/kW and the total offshore tariff is £45/kW. In both scenarios, the total annual liability is identical, it is the monthly payments that differ. In Scenario A the generator connects before offshore Go-live (assumed to be June); and in Scenario B the offshore generator connects after offshore Go-live. In both cases, the annual liability of the generator is £5m. In Scenario A the monthly charge would be £42k per month from April rising to £542k per month after Go-Live. In Scenario B the monthly charge would be £833k per month. This approach mirrors how onshore monthly liabilities are determined when a user connects mid-year.

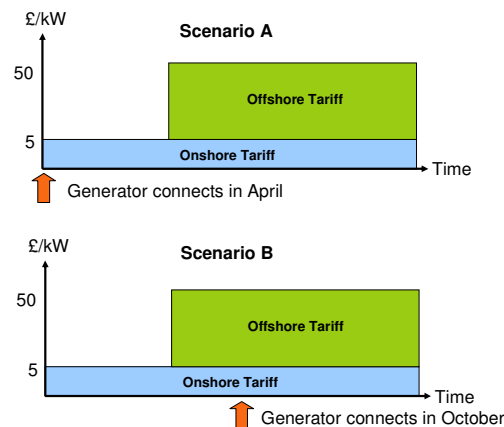


Figure 3 - Illustration of how total annual liability of offshore tariffs would be calculated

National Grid will provide offshore users details of the underlying assumptions used to determine indicative tariffs. This is important as the underlying assumptions impact the tariffs, so affected generators can create their own forecasts based on their own alternative projections.

5.2.2 Discussion

Facilitates competition

The advantage to onshore users of Option 2 is that it provides fixed tariffs within year and in line with the normal publication timescales. However as for Option 1, onshore tariffs will include forecast offshore costs with the same underpinning forecasts and assumptions. Therefore, although tariffs within year will be stable for onshore users, the tariff changes between years are likely to be greater as the impact of National Grid's forecast errors unwind.

Offshore users will benefit from a local tariff that is less likely to change between years. However as they also pay the generation residual tariff, they too will be exposed to larger year-on-year change (compared to Option 3).

Cost reflectivity

Building on the analysis presented for Option 1, National Grid has modelled the uncertainty in the costs (revenue) that would be recovered from offshore local tariffs (comprising both circuit and substation elements), the generation residual and the demand residual. The same modelling assumptions have been used as outlined in section 4. The uncertainty can be used to assess the degree to which Option 2 would impact the cost reflectivity of TNUoS tariffs.

The charts below show the distribution of the offshore costs that would be recovered from each tariff component in 2010/11. The width of the distributions is an indication of the possible cost-reflectivity of the tariffs – a narrow distribution would suggest more cost-reflective charges, and a wider distribution would show a less cost reflective charge.

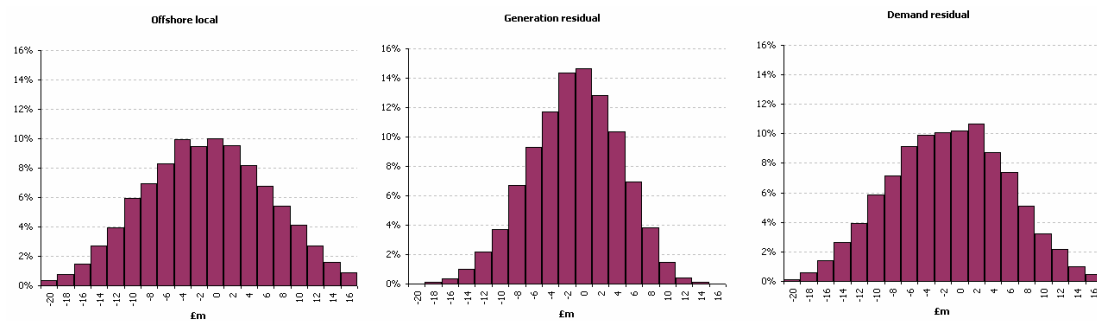


Figure 4 - Uncertainty in tariff components in 2010/11

Option 2 would enable National Grid to calculate more cost reflective local offshore tariffs, as the uncertainty in offshore costs (revenues) would be removed when the tariff was re-calculated i.e. the uncertainty in this tariff component would reduce by c£36m (the width of the offshore revenue distribution shown above in the first chart). However the inaccuracies in the fixed residual tariff components would not change, which would impact the cost reflectivity of charges for all generators (onshore and offshore) and suppliers. This is because the demand residual still funds 73% of the original forecast OFTO costs and generation 27% of the original forecast OFTO costs.

A further undesirable consequence of being able to change the offshore local tariffs but not the residual is that the required G / D split is not maintained. For instance, if the error in offshore local tariff resulted in additional generation revenue collection of £20m, the G / D split would change by +/-1%. The 'correct' split between generation and demand has been determined to be 27% / 73% and therefore this proposal would depart from the agreed underlying cost recovery principles contained in the charging methodology.

Nevertheless, Option 2 would reduce the uncertainties in National Grid's over or under revenue recovery. For instance, if the OFTO revenues were lower than National Grid had originally forecast, the revenue recovered from the offshore local charges would also be reduced (unlike Option 1). The extent to which this will occur depends on the level of socialisation of offshore costs between onshore and offshore generators. Specifically, where there is a high degree of asset utilisation (and therefore low cost socialisation) there would be a much stronger link between changes in OFTO revenue and changes in National Grid's collected revenues.

Developments in the transmission business

Option 2 would not properly take account of developments in National Grid's transmission business for the following reasons:

- whilst the charge setting process would take some account of the offshore transmission tender process to identify each OFTO and its efficient revenue requirements, the ability of National Grid to act on important new information would be limited.
- it would potentially undermine National Grid's incentive to accurately recover its allowed revenue. Specifically, penal interest charges in the Kt mechanism could be incurred or avoided for incorrectly forecasting OFTO revenues which are outside its control, whereas National Grid should be incentivised to manage parameters that it can directly control or influence.
- it would essentially transfer revenue recovery risks from OFTOs to National Grid, which is both inappropriate and inefficient. National

Grid is not best placed (or able) to manage these risks whereas the OFTO (or Preferred Bidder) is. Such an arrangement would be inconsistent with the onshore charge setting arrangements between TOs and National Grid.

5.3 Option 3 – Review all tariffs mid-year

5.3.1 Implementation

In this option, National Grid would publish onshore generation and demand tariffs as normal and within the usual timescales. The onshore tariffs would include forecast offshore costs. National Grid would also publish indicative offshore generator tariffs at the same time based on the same forecast information as used in Option 1 and Option 2.

Once the offshore tender process had identified a Preferred Bidder and it had acceded to the STC, National Grid would obtain charge setting information from the Preferred Bidder that would enable National Grid to as soon as practical publish:

- updated final offshore tariffs; and
- revised onshore generation and demand TNUoS residual tariffs.

There may be situations where National Grid would require the consent of the Authority to update tariffs with less than 2 months notice, as is normally required by the CUSC, where the time gap between information is provided by the Preferred Bidder and the user being charged is less than 2 months.

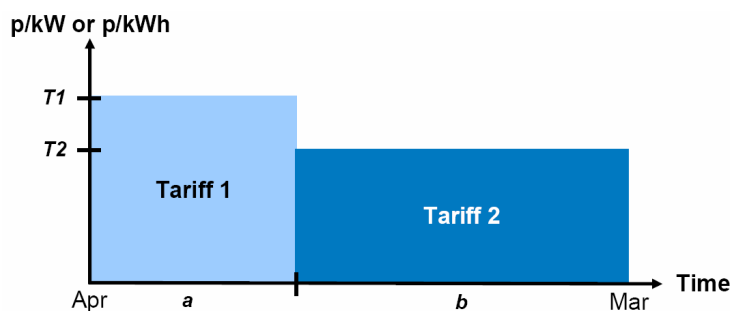
National Grid does not propose amending the transport model. The tariff model will be updated to reflect new information. This means that the onshore zonal differentials will remain unaltered and only the non-locational residual part of the tariff will change.

These updated tariffs would be fixed for the remainder of the financial year. National Grid notes that Preferred Bidders may need to make certain forecasts to provide National Grid with information (in line with onshore TOs). Any subsequent changes to the Preferred Bidder's revenue assumptions would not be used to make further updates to onshore or offshore tariffs within year. Any resultant over or under recoveries would be adjusted the following year through the relevant Kt mechanism. This is the same process used for onshore tariffs.

A customer's annual liability would be calculated by prorating the tariffs across the months that they are applicable for, in this way tariffs and charges would not be back dated. Specifically, a user's annual liability would be:

$$\text{Annual Liability} = \text{Chargeable Capacity} \times \left(\frac{a \times \text{Tariff 1}}{12} + \frac{b \times \text{Tariff 2}}{12} \right)$$

where:



There would be no change in how monthly charges would be determined, which would continue to be calculated by dividing a users' remaining annual liability over the number of months remaining in the financial year. Appendix A shows how this would work in practice in a number of scenarios.

Each offshore user's annual liability would be based on the user's highest TEC within year (as per the onshore charging arrangements) and the sum of the relevant offshore and onshore tariffs.

Users would not incur an interest charge at generation or demand reconciliation because of the introduction of mid-year tariff change. Therefore as normal, if a user does not change its chargeable capacity during the year, no interest charge will be incurred.

5.3.2 Illustrative impact of TNUoS tariffs

Under Option 3, onshore generation and demand TNUoS tariffs would be updated for changes in OFTO allowed revenue and offshore cost socialisation. This would mean that generation and demand residuals would change and hence remain cost reflective.

The following diagram show the distribution of residual tariff changes that might be needed to ensure charges remain cost reflective once information from the offshore tender process is available i.e. the tariff change needed to avoid the cost over / under recovers illustrated previously in Figure 4. The changes are based on the same modelling assumptions outlined previously and are based on a tariff change in July 2010, i.e. the month after Go-live.

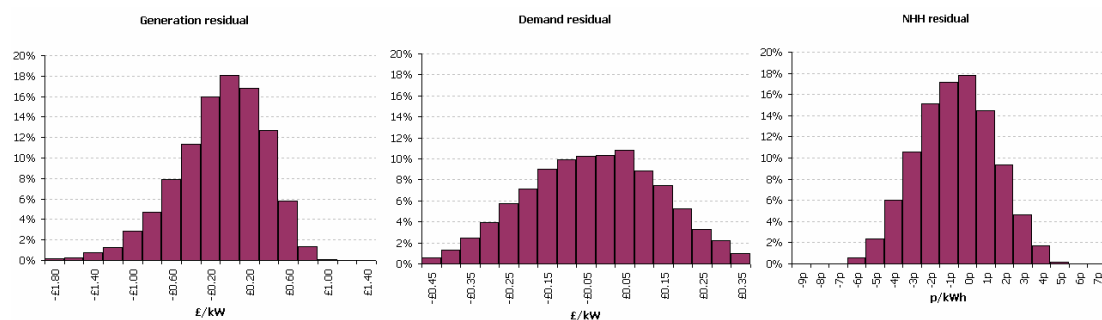


Figure 5 - Changes in residual tariffs to ensure that they remain cost reflective

These changes can be compared against the 2009/10 generation residual of £3.79/kW and for HH demand of £16.94/kW. To put these changes further into context, the impact of a +/- £0.30/kW change in July of the generation and demand residual would be:

- for a 2GW generator +/- £450k. If it were connected in zone 9 this would equate to a +/- 3% of its annual liability; and
- for the largest supplier +/- £2.7m or 1% of its annual liability.

As noted above, the charts indicate the range of tariff movements under the scenarios outlined in section 4 (ie reflecting errors in National Grid's forecast of OFTO revenues and levels of socialisation). However, the following gives users a sense of the direction of tariff charges in two particular circumstances:

- if OFTO revenues increased or decreased relative to National Grid's forecast but the forecast level of socialisation was broadly correct, all residual tariffs would tend to increase or decrease in the same direction.

- ❑ if the level of socialisation decreased but National Grid's forecast of the OFTO revenue was broadly correct, the demand residuals would not be affected but the generation residual would decrease (as the offshore generator would make a relatively larger contribution to the generation proportion offshore costs³).

5.3.3 Discussion

Facilitates competition

Whilst Option 3 would introduce multiple TNUoS tariffs within a year for all users, rather than a subset of users under Option 2, this in itself is not an indication of tariff instability i.e. for a given change in inputs, TNUoS tariffs would change in a known and proportionate way. However Option 3 does make users' charges less predictable, as generators and suppliers would not know final TNUoS tariffs until part way through the year. This reduction in predictability could be partially mitigated by the provision of indicative mid-year tariffs together with supporting information to allow users to understand the sensitivity of these to different assumptions.

The methodology for determining annual liabilities for a user under Option 3 is only marginally more complex than Option 1 and Option 2. National Grid notes that the proposed methodology for dealing with multiple tariffs is similar to how revised annual and monthly liabilities are determined when suppliers amend their forecast chargeable volumes or when generators increase TEC within year. In addition, the core underlying charging methodology has not changed. Therefore this option clarifies how the existing procedures would be extended to cover mid year charge changes without changing the underlying charging methodology. Against this background, National Grid does not expect Option 3 to significantly reduce transparency of the calculation of TNUoS tariffs and monthly / annual charges.

National Grid also notes that Option 3 would change the non-locational generation and demand residuals for all users part way through the year. As this tariff component is the same for each class of user, assuming all users have access to the same indicative tariff information, a mid-year tariff change is less likely to significantly affect the relative competitiveness of generators and between suppliers.

Cost reflectivity

Option 3 delays setting revised final tariffs until a better forecast of OFTO revenues can be made by the Preferred Bidder, who is best placed to assess its own costs, as it will have access to commercially privileged information to assess its capital financing and operating costs. Use of this better information will enable National Grid to set:

- ❑ more accurate local offshore tariffs; and
- ❑ more accurate residual tariffs, which ensures that:
 - all National Grid's allowed costs are recovered from users; and
 - the sum of all TO revenue streams are recovered in the correct proportions between generation and demand.

Against this background, Option 3 will result in more cost reflective tariffs than either Option 1 or Option 2.

³ This effect was discussed at National Grid's October User Seminar. Slides for this can be found on National Grid's industry website: <http://www.nationalgrid.com/NR/rdonlyres/0B3536FD-825F-435D-AD07-44CCC1CD65AB/37441/UserSeminarsOctober2009PresentedSlides.pdf>

Developments in the transmission business

Option 3, more than any of the other options, enables National Grid to take full account of information produced through the OFTO tender process. Specifically, by delaying the publication of final revised tariffs until a substantive milestone in the tender process has been reached, information from Preferred Bidders can be used in the charge setting process. Until that point, the information available to National Grid is incomplete and charges would be set without any regard of the tender results. Accordingly Option 3 takes best account of the introduction of an offshore tender process in the GB charge setting process.

Option 3 also ensures that risks between National Grid, TOs and OFTOs remain appropriately allocated. Under the existing onshore arrangements, National Grid is not financially exposed to each TOs' ability to forecast its allowed revenues, since any change to a TO's allowed revenue will be dealt with through its own Kt mechanism. National Grid considers the same incentives should apply to both onshore and offshore TOs. Option 3 is most consistent with this approach, as the Preferred Bidder will be providing this information to National Grid with the expectation that it will become the OFTO. Against this background, Option 3 best ensures that the charge setting process does not inappropriately reallocate risks from OFTOs to National Grid, which in turn would be expected to reduce the overall cost of transmission to consumers.

6 Assessment against the Relevant Objectives

National Grid has considered three options to enable information from the offshore tender process to be included within the charge setting process and hence, other than preserving the status quo, the need to clarify how users' annual charging liabilities would be calculated if there were multiple TNUoS tariffs within a financial year. National Grid notes that the proposals do not change the underlying methodology or principles by which onshore or offshore TNUoS tariffs are calculated.

National Grid has assessed whether the status quo or the process change options better facilitate it meeting its licence objectives: to facilitate competition, for charges to be cost-reflective, and for charges to take into account developments in the transmission business.

In setting and reviewing Use of System charges, National Grid has a number of further objectives contained in the Statement of Use of System Charging Methodology. These are to:

- offer clarity of principles and transparency in the methodology;
- inform existing Users and potential new entrants with accurate and stable cost messages;
- promote the optimal use of, and investment in, the transmission system by charging on the basis of services provided and incremental rather than average costs; and
- be implementable within practical cost and time-scales.

Based on the arguments set out in Section 5, National Grid has made the following initial assessment against the relevant objectives. In the table '✓' indicates that the option better meets that relevant object; '-' indicates that the option is neutral to meeting that objective; and 'x' indicates that the option does not meet that objective. The options have also been assess from the perspective of offshore users and onshore users (both generation and demand).

Option / User		Facilitates Competition			Cost Reflectivity			Developments in the transmission business
		Transparency	Predictability	Stability	Services provided	Incremental	Practical cost	
1	Onshore Users	✓	✓	✓	x	-	-	x
	Offshore Users	✓	✓	✓	x	x	-	x
2	Onshore Users	✓	✓	✓	x	-	-	x
	Offshore Users	✓	x	x	x	✓	-	✓
3	Onshore Users	✓	x	x	✓	-	-	✓
	Offshore Users	✓	x	x	✓	✓	-	✓

Option 1 (the Status Quo) has been discounted because it fails to better facilitate meeting the relevant objectives. Specifically whilst onshore and offshore tariffs are the most predicable they are also the least cost reflective and take no account of

developments in the transmission business, for example, the introduction of a tender process to identify OFTOs and its efficient costs.

Whilst Option 2 and Option 3 appear reasonably balanced, National Grid considers **Option 3 best meets the relevant objectives** because:

- the reduced predictability of tariffs in Option 3 can be mitigated through the publication of information that enables industry participants to assess alternative scenarios and sensitivities;
- the drawbacks of Option 2 in terms of cost reflectivity cannot be mitigated, as tariff components would be fixed before information from the tender process becomes available;
- Option 2 would result in tariffs that deviated from the established methodology to target 27% / 73% of costs to generation and demand users, respectively;
- Option 3 is the most cost reflective and therefore is least likely to create cross-subsidies between onshore and offshore generators, or between generation and demand;
- since Option 3 does not create unjustified cross-subsidies, it is also more likely to facilitate competition;
- Option 3 takes best account of the introduction of the offshore tender process in National Grid's transmission business; and
- Option 3 clarifies how the existing processes could cover multiple tariffs within year without changing the core charging methodology.

6.1 Impact on Other Industry Documents

It is not anticipated that the proposed modification will require amendments to any other industry documents, although National Grid would welcome any industry views on this.

Separately, National Grid shall consider:

- any potential impacts on its Transmission Licence that might be required to implement its non-preferred options; and
- the need for shorter notice periods under the CUSC to change users' tariffs and how this could best be facilitated.

6.2 Implementation Date

The implementation date for the proposed change will be on the date of the Authority's decision to veto or not veto the proposed charging proposal.

7 Responses

Whilst comments and views are invited on all of the issues raised in this consultation, National Grid would welcome particular views on:

1. the modelling assumptions used;
2. the ability of different classes of user to respond to mid-year price changes;
3. shorter notice periods to implement mid-year tariff changes; and
4. alternative charging means to address the uncertainty cause by misaligned charging and offshore tender processes.

To ensure that your comments and views are considered as part of National Grid's Conclusions Report to the Authority, responses must be received by close of business on the 8th January 2010.

If you wish to provide comments on this consultation document, responses are preferred via email to: william.kirkwilson@uk.ngrid.com. Alternatively, Users can send their comments in writing, addressed to:

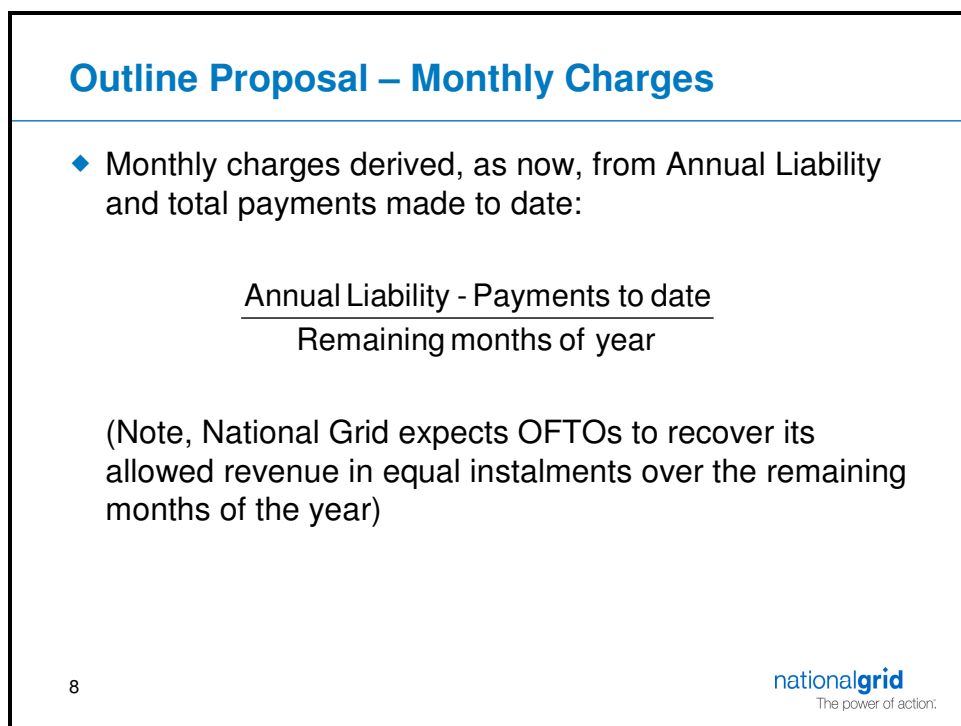
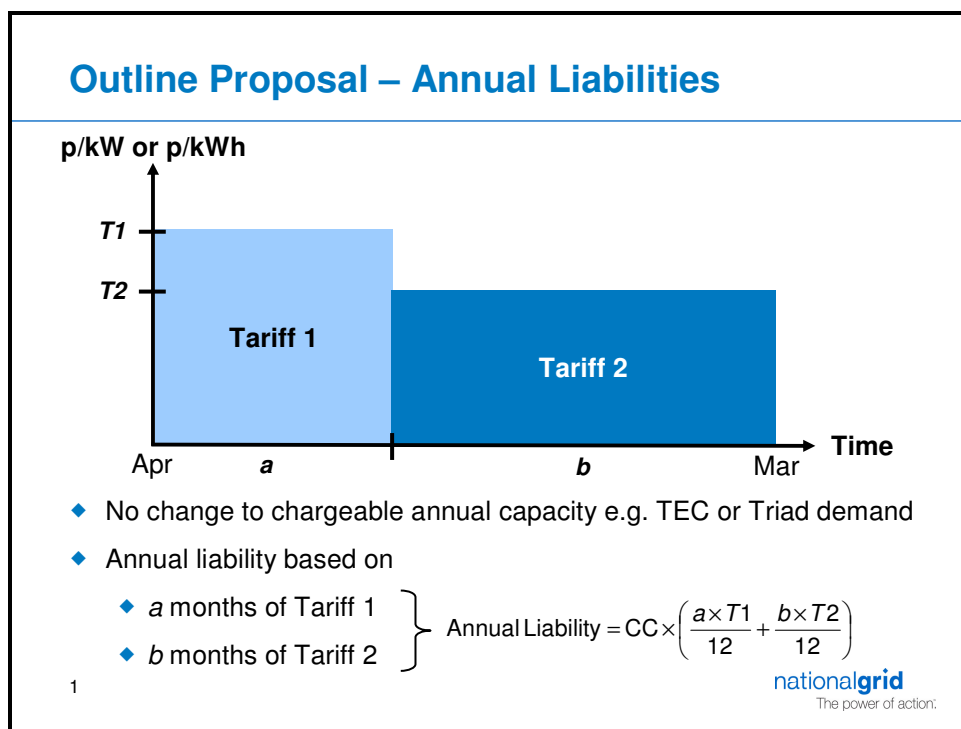
William Kirk-Wilson
Regulatory Frameworks
Transmission Commercial
National Grid House
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Gallows Hill
Warwick
CV34 6DA

If you have further queries, please do not hesitate to contact William Kirk-Wilson on 01926 655424.

Appendix A: Examples of how Option 3 would work for Generation and Demand

Examples extracted from slides presented at the September TCMF.

<http://www.nationalgrid.com/uk/Electricity/Charges/TCMF/>



Example – Demand TNUoS (Within Year)

- ◆ HH and NHH based on **forecast** chargeable capacity demand or 4 – 7pm consumption (both use the same

Month	Wider Zonal Tariff £/MW	Triad (kW)	Initial Annual Liability (£k)	Revised Annual Liability (£k)	Monthly Liability £k
Apr	6	2000	12000	-	1000
May	6	2000	12000	-	1000
Jun	6	2000	12000	-	1000
Jul	9	2000	-	16500	1500
Aug	9	2000	-	16500	1500
Sep	9	2000	-	16500	1500
Oct	9	2000	-	16500	1500
Nov	9	2000	-	16500	1500
Dec	9	2000	-	16500	1500
Jan	9	2000	-	16500	1500
Feb	9	2000	-	16500	1500
Mar	9	2000	-	16500	1500
					16500

→ Increase aligns with obligation to commence payments to the OFTO and 'expansion' of the system

$$\frac{16500 - 3000}{9}$$



Example – Demand TNUoS (Reconciliation)

- ◆ HH and NHH are reconciled using **actual** chargeable capacity

Month	Wider Zonal Tariff £/MW	Forecast Triad (kW)	Actual Triad (kW)	Initial Monthly Liability (£k)	Reconciled Monthly Liability (£k)	Reconciliation (before interest) (£k)
Apr	6	2000	2100	1000	1050	50
May	6	2000	2100	1000	1050	50
Jun	6	2000	2100	1000	1050	50
Jul	9	2000	2100	1500	1575	75
Aug	9	2000	2100	1500	1575	75
Sep	9	2000	2100	1500	1575	75
Oct	9	2000	2100	1500	1575	75
Nov	9	2000	2100	1500	1575	75
Dec	9	2000	2100	1500	1575	75
Jan	9	2000	2100	1500	1575	75
Feb	9	2000	2100	1500	1575	75
Mar	9	2000	2100	1500	1575	75
				16500	17325	825



Example – Generation TNUoS (1)

- ◆ No TEC change throughout the charging year

Month	Wider Zonal Tariff £/MW	TEC	Initial Annual Liability (£k)	Revised Annual Liability (£k)	Monthly Liability £k
Apr	10	120	1200	-	100
May	10	120	1200	-	100
Jun	10	120	1200	-	100
Jul	10	120	1200	-	100
Aug	5	120	-	800	50
Sep	5	120	-	800	50
Oct	5	120	-	800	50
Nov	5	120	-	800	50
Dec	5	120	-	800	50
Jan	5	120	-	800	50
Feb	5	120	-	800	50
Mar	5	120	-	800	50
					800

$$120 \times \left(\frac{12 \times 10}{12} \right)$$

$$120 \times \left(\frac{4 \times 10}{12} + \frac{8 \times 5}{12} \right)$$

$$\frac{800 - 400}{8}$$

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Example – Generation TNUoS (2)

- ◆ New station commissioning mid-year or TEC change

Month	Wider Zonal Tariff £/MW	TEC	Initial Annual Liability (£k)	Revised Annual Liability (£k)	Monthly Liability £k
Apr	10	0	-	-	0
May	10	0	-	-	0
Jun	10	0	-	-	0
Jul	10	0	-	-	0
Aug	5	0	-	-	0
Sep	5	0	-	-	0
Oct	5	0	-	-	0
Nov	5	120	-	800	160
Dec	5	120	-	800	160
Jan	5	120	-	800	160
Feb	5	120	-	800	160
Mar	5	120	-	800	160
					800

$$120 \times \left(\frac{4 \times 10}{12} + \frac{8 \times 5}{12} \right)$$

$$\frac{800 - 0}{12}$$

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