1. Attendees

1. Frank Prashad (FP), RWE npower	9. Stuart Cotton (SC), Drax Power Limited
2. Ivo Spreeuwenberg (IS), NGET	10. Michael Dodd (MD), ESB International
3. James Anderson (JA), ScottishPower	11. Jonathan Hodgkin (JH), Ofgem
4. Angus McRae (AMc), SSE *alternate*	12. Anthony Mungall (AM), Ofgem
5. Louise Schmitz (LS), EDF Energy	13. Scott Hamilton (SH), Ofgem
6. Paul Jones (PJ), E.ON	**Apologies for absence:** Robert Longden (RL), Mainstream Renewable Power; Tim Russell (TR), REA; Garth Graham (GG), SSE; Guy Nicholson (GN), RenewableUK; Helen Snodin (HS), Scottish Renewables and HIE.
7. Simon Lord (SL), First Hydro	
8. Ricky Hill (RH), Centrica	

2. Overview of discussion

Ofgem opened the meeting, noting the purpose of the meeting was for the Technical Working Group (WG) to review all 6 Themes of Project TransmiT's TNUoS review and to put forward their recommendations on the form of the three charging models to be simulated by Redpoint. The models fall under the following three categories:

- Investment Cost Related Pricing (ICRP) *status quo*
- Improved ICRP
- Socialised/Postalised.

Review and feedback from WG meeting 4:

Ofgem circulated a draft note of WG meeting 4 and requested feedback from participants on their accuracy. Ofgem noted that it had received one set of comments, it was agreed that these comments would be considered for the final version of the meeting note.

Reviewing the action points from WG meeting 4:

Ofgem noted that action point 25, which required Ofgem to clarify the extent to which changes to demand charges are within the scope of the Project and the degree to which they are being modelled by Redpoint, remained outstanding. This would be clarified in the coming days and would be reported in the meeting note of WG 5, and cited as an additional action point in the action list (action 31). As a general point, Ofgem stated that demand charges were not 'outside the scope' of the modelling work and would be considered in the context of their relationship to generation charges, which were the primary focus of the SCR review. The WG noted that demand charges must be considered within the modelling analysis to some degree as they could not be entirely delineated from generation charge analysis. For the avoidance of doubt, Ofgem noted that demand tariffs would be produced as a modelling output.

- *Redpoint clarification about how demand will be dealt with in the modelling (action point 31):*

Redpoint subsequently provided the following written clarification. "*Electricity demand is an input to the TransmiT modelling. The hourly profile of demand is invariant across all policy options (perfectly inelastic). The Terms of Reference extend to the modelling of generation investment and retirement decisions, but not the modelling of changes to demand due to TNUoS charges. As such, the modelling approach is not designed to take account of the impact of changes to demand TNUoS charges, and demand tariffs will have no impact whatsoever on the modelling results.*

However, the Transport model produces demand tariffs as an output. Therefore we propose to record and report the demand tariffs, for information only and to use in the calculation of consumer bill impacts. The method for calculating demand tariffs will be unchanged from the current ICRP approach."

- Additional WG comments on action points:

Action point 10a, which required Redpoint to provide a question and answer document on their modelling work, and action point 11, requesting Ofgem provide the WG members with information on the modelling assumptions, had been circulated on 23/8. Ofgem requested feedback on these documents by 2/9.

Ofgem noted that action points 26 and 30 had also been completed, and that 24 (modelling the impact of different approaches to calculating relative impedance for HVDC) and 28 and 29 (the Working Group Report) would be discharged in the course of the day's meeting.

Stakeholder feedback:

No feedback was reported.

Update on Progress of the Modelling Themes:

Ofgem began the discussion by presenting an overview of the progress that had been made, thus far, on developing the detail of each of the 6 Themes for the three modelling scenarios: ICRP (status quo), Improved ICRP and Socialised/Postalised. Ofgem's summary included clarification of the choices that had been tentatively agreed, and those which remained outstanding.

Ofgem noted its hope that the WG would confirm its choices for each of the modelling scenarios by the end of the day. Ofgem added that it hoped that all the key relevant issues raised in the course of the TNUoS SCR would be captured in some way by each of the modelling scenarios.

MD noted that a point raised by GN at WG meeting 4, pertaining to connection charges, may have some validity but was not cited as one of the options under the Improved ICRP summary. Ofgem noted the reason for this was because connection charges fell outside the scope of Project TransmiT's SCR TNUoS review.

Review and feedback from *ad hoc* meeting 2 (24 August):

As a lead into the formal discussions on the outstanding modelling options, IS provided the WG with a brief summary of the *ad hoc* WG meeting on 24 Aug which had been arranged in the course of WG meeting 4. The purpose of the *ad hoc* meeting was to consider Theme 1 options in relation to NGET's Improved ICRP model. It was noted that the *ad hoc* meeting had not been attended by the full WG and so it was helpful for IS to provide a summary to the WG members as to what had been discussed.

- ***Discounted options***

IS gave an overview of discounted options for Theme 1 thus far in order to clarify what options remained 'on the table'. IS noted that a number of explicit capacity sharing options and an option for implicit sharing based on full cost benefit analysis (CBA) based charging had been ruled out. NGET noted that its proposal made the assumption that generators implicitly share network capacity.

- ***Dual background***

NGET explained the current premise upon which they plan the network was on the basis of a peak security and year round assessment. For that reason, NGET was proposing a change from the existing 'single background' to a 'dual background' transport model which they believed better accounted for a user's characteristics in relation to the required investment in the network.

IS noted that, in the discussions, the *ad-hoc* meeting had generally accepted that it was appropriate to use dual (peak security and year round) backgrounds to derive MWkm from the transport model.

An important part of NGET's proposal rests on the process through which circuits are allocated to 'peak security' or 'year round' backgrounds. The *ad-hoc* meeting identified two options for allocating circuits:

- Binary – circuits either peak security or year round (NGET's proposal)
- Proportional – a proportion of each circuit allocated to each background in proportion to the MW flow in each background

IS stated that the consensus view at the *ad-hoc* meeting was to adopt a binary approach. One member noted there had been shown to be merit in using either approach, but because there was a lack of evidence to suggest there was a distinct advantage in using the more complex proportional approach, the more straightforward binary approach was agreed.

- ***Deriving the tariffs***

IS stated that the *ad-hoc* meeting had identified two options for converting MWkm from the transport model into tariffs:

- Option 1: Two part (peak security and year round) tariff. The *ad-hoc* meeting agreed that charges applied for peak security and year round would be TEC based.
- Option 2: Two part (peak security and year round) tariff. Peak security charged on the basis of TEC only, or TEC and load factor. Year round charged on the basis of TEC and load factor.

IS noted that the *ad-hoc* meeting agreed that under both options the peak security charge could be levied on all generators, conventional generators only or none. IS further noted that, in principle, if the peak security tariff applied to conventional generators only, then the year round tariff could not be extended to cover peaking plants, but that in practice a true peaking plant would have a load factor of < 1% and therefore not be liable for the vast majority of the year round tariff.

For Option 2 the *ad-hoc* meeting identified three options for levying the peak security tariff:

- TEC
- Ex-ante probability / % contribution at peak x TEC
- Ex-post contribution at peak, although it was noted this would potentially give generators perverse incentives to curb generation at peak.

IS noted that after lengthy discussion, the *ad-hoc* meeting identified five possible methods for calculating the year round tariff. These were deemed to fall within two categories, *generic* and *plant specific* options.

Ex-ante
1. TEC x generic historic load factor
2. TEC x background scaling
3. TEC x specific historic annual load factor (ALF)

Ex-post
4. TEC x requested load factor plus cash out
5. Ex post MWh

IS noted that the *ad-hoc* meeting had debated these options at length yet was unable to reach a consensus as to whether TEC alone or TEC multiplied by some derivation of load factor was a better indicator of a generator's likely contribution to network operation (eg constraint) costs.

Ofgem noted this update and invited LS, who had expressed concerns about the use of load factor in the derivation of tariffs during the *ad hoc* meeting, to deliver a presentation explaining the problems she perceived in NGET's proposals.

Key points of LS presentation:

- There was insufficient justification for considering de-linking transmission charging with the SQSS until the GSR009 had been approved.
- There was insufficient evidence to support the use of ALF in deriving transmission tariffs because the justification for it was based on an unsubstantiated link between constraints and investment.
- ALF may appear to be a 'reasonable proxy' in some instances, but much of NGET's analysis illustrated that a linear relationship does not exist in all cases across many zones and a further degradation in the correlation is apparent as more wind generators connect to the network in the medium to longer term.
- Changes at the EU level are at present unclear and could have either a substantial or limited impact on GB transmission charging. It is inappropriate to introduce a proxy which might only suffice for a limited period. The WG should develop changes to transmission charging which we can support in the medium to long-term.
- Presented a general conclusion that the WG had a choice; accept NGET's proposal as a "reasonable" proxy, or agree further justification is required, or take forward an alternative proposal, eg: uniform scaling/TEC only or zonal linear relationships

Following this, IS delivered a brief presentation to the WG outlining what he believed was additional evidence to support NGET's proposed use of ALF as a proxy in the derivation of tariffs. The central feature of IS's presentation was a series of slides that detailed comparative analysis which, he suggested, demonstrated that load factor had a greater correlation (but not a perfect linear relationship) with a generator's likely contribution to network operation costs than the current use of TEC. IS noted that while the correlation coefficients for either were not perfect (i.e. 1.0), there was, in every instance, a stronger correlation between ALF and constraints when compared with TEC. IS made the point that if it is accepted that NGET's proposal better reflects the incremental impact that users of the transmission system at different locations (and of different characteristics) have on constraint costs and is a better reflection of the assumptions made in the network capacity investment decision (when investing to avoid future constraint costs) then the use of ALF as a proxy for deriving tariffs was inherently more cost reflective than using TEC. IS made a further clarification noting that NGET's proposal was not seeking to modify the socialised recovery of constraint costs through the current BSUoS charge.

Some members of the WG agreed that, on the basis of the evidence IS had presented, it appeared that ALF was a better proxy than TEC and was a step towards a more cost reflective ICRP methodology. Others members of the WG preferred examining some of the other proxies discussed in the *ad hoc* meeting of the 24 August.

Ofgem noted that some WG members opposed the use of ALF as a proxy, but were not offering well-developed or substantiated alternatives. Ofgem sought to clarify with the WG that if they decided to model TEC as the proxy for the year round tariff then this would, in some sense, be tantamount to proceeding with the status quo. Some members stated that this was not the case because of the introduction of a two-part (peak security and year round) tariff and even the use of TEC in such a dual background approach would produce marginally different tariffs and would, therefore, still qualify as an Improved ICRP.

Update on Themes 2 (Geographical differentiation of costs) and 3 (Treatment of Security) for Status Quo and Improved ICRP modelling scenarios:

- *Theme 2 choices*

Ofgem noted that the choices for Theme 2 (Geographical/topological differentiation of costs) for both the status quo and Improved ICRP modelling scenarios had been agreed in principle at previous meetings. For both modelling scenarios this meant:

- Maintaining existing wider locational zoning criteria
- Maintaining existing local/wider boundary

- *Theme 3 choices*

Ofgem noted that the choices for Theme 3 (Treatment of Security) for both the status quo and Improved ICRP modelling scenarios had been agreed in principle at previous meetings, but there remained some key outstanding choices to be made in relation to island links.

Ofgem noted the WG had, in previous discussions on the subject, been of the broad opinion that the status quo modelling option should seek to apply the GB average Locational Security Factor (currently 1.8) to all circuits (including island links) considered to be directly connected to a MITS substation (ie the wider network) and not the expected Local Security of 1.0 (reflecting the likely situation that the loss of a single circuit would result in complete loss of access to the network).

During WG discussions, some members of the WG believed there was a growing case for special treatment of island links and the treatment of security provision within the TNUoS methodology. This was because the applicable onshore arrangements state that for a single circuit connection to a generator, it would be non-compliant with the onshore SQSS, and the generator would therefore have to accept uncompensated access restrictions in the event that the single circuit is unavailable as a result of a fault or maintenance outage. Typically, island links designed with little or no redundancy (ie non SQSS compliant) will have uncompensated access restrictions, however they would receive a reduced local TNUoS circuit charge if they do not meet the MITS boundary definition contained in the current TNUoS methodology. In a situation where generation on an island group is connected to a substation on the island that meets the MITS boundary definition then the island link will not have a local element of the TNUoS charge.

This will mean that the wider security factor value (currently 1.8) and not the local security factor value (1.0) will be used in the calculation of the applicable TNUoS tariff.

The WG debated the implications of this approach and discussed a range of alternative options, these included:

- Island generators paying a wider TNUoS tariff derived from the application of the global Security Factor of 1.8 and receiving compensation if the single sub-sea cable link between the MITS substation (located on the island group) and the next MITS substation (on the mainland) is lost.
- Island generators paying a wider TNUoS tariff derived from the application of the actual level of resilience, which might mean a security factor of 1.8 "on Island" and a security factor of 1.0 for the single sub-sea cable link. It was noted that the methodology could reflect the (lack of) redundancy associated with a single cable link in the zonal tariff calculation by modifying the specific expansion factor applicable to the sub-sea section of island connection by dividing the expansion factor value of the link by the average level of security across the system as a whole (currently 1.8). Application of the MITS security factor at a later stage in the zonal tariff calculation will produce a zonal tariff reflective of the specific security characteristics of the single sub-sea cable link included in this part of the wider network.

IS noted that it was important to be mindful of setting precedents when developing a policy of special treatment for islands links that meet the MITS boundary definition. He noted that it was important that any special provisions fall within universal principles that will be enduring.

The WG debated two broad options:

i. That island connections with redundancy in the sub-sea cable link between a MITS substation located on the island group and a MITS substation located on the mainland will be subject to the wider security factor, which will be applied in the calculation of the zonal TNUoS tariff.

ii. Modified treatment for island links directly connected to a MITS substation where export is dependent on a single sub-sea cable linking the MITS substation located on the island group to the next MITS substation on the mainland. The methodology will reflect the (lack of) redundancy associated with a single cable link in the zonal tariff calculation by modifying the specific expansion factor applicable to the sub-sea section of island connection by dividing the expansion factor value for the sub-sea link by the average level of security across the system as a whole (currently 1.8). Application of the MITS security factor at a later stage in the zonal tariff calculation will produce a zonal tariff reflective of the specific security characteristics of the single sub-sea cable link included in this part of the wider network.

The WG agreed that option (ii) should apply for the purposes of Redpoint's modelling, with some members suggesting that it be applied in the status quo option (and option i to apply in the improved ICRP option).

IS noted that the above arrangement was intended to only apply to very specific (island) circuits and recognised that further consideration is required to ensure that the arrangements do not apply unintentionally to other local circuit links where it would not be appropriate to do so.

Theme 4 Update:

IS summarised the four options for calculating relative impedance discussed at WG4:

Options for calculating power flow on single boundaries:

1. Optimal Power Flow (*Derive power flow from optimal operation calculation – complex)*
2. Transmission Routes (*Assume equal power flow on each double circuit equivalent route)*
3. Transmission Circuits (*Assume equal power flow on each major circuit)*
4. Circuit Ratings (*Pro-rata flows based on circuit ratings)*

IS noted that WG4 had agreed that Option 4 was most appropriate, but there were two sub options: 4a, which examined circuit ratings at the most constrained boundary only; and 4b, which took account of circuit ratings at all boundaries crossed by the HVDC link. IS presented results for options 2, 3, 4a and 4b. It was noted that there was a difference between the results for options 4a and 4b, however 4b was determined to be the most theoretically correct approach and therefore should be adopted for the TNUoS modelling across the status quo and improved ICRP options.

Ofgem reminded the WG that a key outstanding issue within this theme concerned the treatment of converter station costs, ie should the full cost of the link, including converter station costs, be subject to the locational signal?

Ofgem noted that in previous discussions, some members of the WG proposed that for the improved ICRP model converter costs should be excluded from the locational charge calculation and spread across all users through the residual charge element. Conversely, some WG members preferred to include all HVDC costs, including converter costs, in the locational signal. Ofgem noted the precedent of offshore arrangements whereby converter station costs are included in the calculation of the locational signal. Some WG members believed that a more consistent approach would be for the cost of the offshore converter station to be included in the offshore generator's local substation charge and for the onshore converter station cost to be included in the residual tariff. This would mirror the treatment of similar types of assets, such as transformer costs for AC offshore solutions.

The WG noted that one of the difficulties with Theme 4 was that HVDC 'bootstraps' were not due to come online until 2015, therefore clearly establishing the 'baseline' (ie status quo) was problematic. Consequently, one of the decisions to be made was whether to treat HVDC the same for both the current ICRP methodology and the Improved ICRP, or to devise alternative arrangements for each scenario. The WG noted that while the precedent for offshore was to include converter costs in the expansion constant, some members were of the opinion HVDC 'bootstraps' were inherently different (ie will operate in parallel with the MITS whereas offshore links will be radial) and thus there were grounds for treating them differently in the definition of the baseline. Other members considered that the baseline should be based on the public analysis which National Grid had carried out up to this point which assumed the inclusion of the cost of the converter stations into the expansion factor for the bootstraps.

The WG noted that a further consideration was the potential problem where the modelling treated HVDC differently in the status quo scenario compared with the Improved ICRP scenario, meaning it would potentially obscure observation of the impact of either HVDC treatments when enmeshed with other variables.

Ofgem noted the WG was unable to arrive at a consensus on a definitive approach to be progressed in the modelling work. The 2 broad options the WG had identified for defining the baseline were:

- Option 1: Include the costs of onshore and offshore HVDC links and converter station costs (at each end of the circuit) in the calculation of the expansion factor and locational signal. (Noting that this is consistent with the current precedent of offshore converter cost treatment - para 4.30 of NGET's conclusions report ECM-24).

- Option 2: Cost treatment based on consideration of whether the link will parallel the MITS or not. Proposed approach is to exclude the costs of converter stations of the bootstrap links that run parallel to the MITS from the locational signal (recover through the residual element). The costs of converter stations associated with offshore radial HVDC links - that do not parallel the MITS - will be included in the expansion factor calculation as now.

One member of the WG noted that, in his opinion, these options had been identified for the purposes of Redpoint's modelling and should not be construed as an endorsement of long-term arrangements for treatment of HVDC without further review.

Update on Theme 6 (G/D Split of Revenue):

Ofgem began discussion by noting that in the course of WG meeting 4 the WG had noted that a change to the current GB G:D split may be required in the medium-term to remain compliant with the European Tarification Guidelines, namely that the value of the 'annual national average G' within Great Britain (plus the Republic of Ireland and Northern Ireland) should not exceed a value of €2.5/MWh. Ofgem also noted that the WG had agreed that there could only be a change to the current (27:73) G:D split arrangements if there was convincing evidence to justify such a change.

It was agreed, therefore, that IS would calculate average GB generation charges in accordance with the European Tarification Guidelines over the medium term to illustrate when the existing GB arrangements are likely to become in breach of the binding European Tarification Guidelines (Action Point 26).

IS explained that the value of the 'annual national average G' (no greater than €2.5/MWh) is the annual total transmission charges paid by generators divided by the total measured energy injected annually by generators to the transmission network. Annual average G shall exclude any charges paid by generators for physical assets required for the generators connection to the system (or upgrade of the connection) as well as any charges paid by generators related to ancillary services or any specific network loss charges paid by generators. IS concluded that the tarification guideline limit for the 'annual national average G' (€2.5/MWh) would be breached by 2018/19 based on the following central assumptions:

- MAR based on RIIO business plan submissions
- 9GW of offshore (at £400m/GW and a build rate of 1GW/annum)
- BSUoS not included
- Total energy injected of 320 TWh
- No allowance for inflation of the limit
- Current exchange rate

IS noted that using "worse case" assumptions indicated that GB could be in breach of the European Tarification Guidelines €2.5/MWh limit by as early as 2015/16.

Ofgem noted IS's contribution and clarified with the WG that there were 3 broad options for consideration:

- No change (maintain 27/73 split)
- Single change from 27/73 to another ratio
- Phased changed (eg dropping G% and increasing D% gradually)

Following some discussion the WG agreed that a change to the G:D split would be required, but there were differing views about whether the objective should be simply to remain compliant with the European Tarification Guidelines or aim to move over time to G=0 or some other target.

WG comments included:

- One of the difficulties in deciding what G:D split was appropriate was the lack of comparative data with neighbouring EU charging regimes. For example, it was noted that the majority of comparable European charging regimes operate under a G/D split of 0/100, but this was distorted by the lack of data on transmission connection charge arrangements and other transmission cost recovery arrangements within those regimes.
- Exchange rate variations between the £ and € had a sizeable impact upon GB's level of compliance. It was pointed out that in recent times the movement in the exchange rate had reduced 'annual national average G' making it easier to remain within the €2.5/MWh ceiling. Nonetheless, it was still recognised that some material change in the G:D split was required in the medium-term.
- Some members of the WG also noted that, as a general rule, if the development of renewable generation is the key focus of this review then the proportion of costs recovered from generators should be set at 0% to encourage a higher proportion of marginal plant to develop. Other members noted that the issue of support for renewables is entirely separate from any specific change to the TNUoS charging methodology and the TransmiT SCR process, and decisions on whether to adjust the level of support is a matter for DECC.

Ofgem reminded the WG that if they felt strongly about these analytical points they should, as a matter of course, be included in the WG Report.

Reflecting on the agreed need for change, the WG agreed the following treatment of G:D split in the modelling scenarios:

- 2011 - (March) 2015: The total revenue to be recovered from generation is calculated as 27% of total TO TNUoS target revenue for the financial year (ie as now).
- (April) 2015 - 2030: Reduce G proportion to 15% (from 27%) to comply with the European Tarification Guidelines (and increase the D proportion to 85%).

RH Presentation on Local Charges and G:D Split:

RH explained that NGET's target revenue (TNUoS) recovery will increase further in the future to reflect the growth in OFTO regime and associated revenue streams. Presently, all demand users recover 73% of the total allowed revenue and the total amount recovered from all generators cannot exceed 27%, meaning if offshore generators are paying large local charges, the residual element paid by all generators has to be reduced to maintain the overall 27% split. RH explained the correction is delivered by reducing the residual charge paid by all generators using the onshore network (ie is applicable to offshore generators as well).

At WG meeting 4, GN gave a presentation on options for dealing with onshore-offshore transmission charge imbalances. GN's presentation outlined a number of potential options for change:

1. Offshore local assets charged G=100% D=0% (similar to a "deep" connection charge).
2. Offshore local asset charged G=27% D=73%

3. Offshore local assets charged G=90% but local charge based on 400kV OHL cost (i.e. expansion factor 1).
4. No Local assets

RH explained that his analysis was a revision of the previous 'solutions' proposed by GN at working meeting 4 on the basis that Centrica viewed the problem somewhat differently from RenewableUK. As an alternative, RH proposed 'solution 1a' where local charges were removed from the G:D split, and the split of revenue from remaining charges is adjusted to maintain the overall 27:73 split.

RH explained that his proposal functioned on the same principle as GN's solution 1 but reduces the proportion (27%) G pays onshore. Consequently, the proportion (27%) that G pays onshore would need to be reviewed periodically, in effect "fixing" the residual element for a set number of years. RH noted the result corrected the deficiencies in GN's proposal in the following ways:

a) Prevents the windfall gains for onshore generators (from the offshore local asset charges)
b) Prevents the onshore residual from falling
c) Improve parties' ability to forecast tariffs

The WG noted the arguments put forward by RH. Similar to WG 4, the WG was not convinced that there was an issue to resolve. Ofgem noted RH's contribution and advised that his analysis should be included in the WG Report.

Update on Socialised/Postalised strawman proposal:

Ofgem noted that the key outstanding issues for the Socialised/Postalised strawman proposal were as follows:

- MW, MW * Load Factor or MWh charges elements
- Maintain or remove existing local / wider boundary
- Applies to Generation TNUoS only or to both DTNUoS and GTNUoS.

Ofgem noted that the WG currently had 3 separate socialised/postalised models under consideration. The key features are summarised in the table below.

	Capacity or Energy	**Local/Wider Boundary**	**Treatment of Demand**
GG	Ex-ante MWh with ex-post reconciliation Uniform GTNUoS tariff for use of wider network	As defined in 14.15.17 of the The Statement of the Transmission Use of System Charging Methodology	Retain locational differentiation on generator charges under ICRP methodology. No change to 27:73 split.
SC	Ex-ante MWh charge (based on volume delivered) with ex-post reconciliation Uniform GTNUoS and DTNUoS tariff for use of wider network.	As defined in 14.15.17 of the The Statement of the Transmission Use of System Charging Methodology [This could change if	The manner in which demand charges are currently allocated remains the same, other than the value of the charge, which would be flat, non-locational charge. Payment based on the same methodology as it is today (a mixture of MW and MWh/kWh

		the group identifies a robust justification to change the current practice for this].	charges) to maintain the Triad signal. No change to 27:73 split.
PJ	Ex-ante MW with no ex-post reconciliation [This could change to MWh with robust justification] Uniform GTNUoS and DTNUoS tariff.	Remove local asset distinction and socialise costs (no locational differentiation on the local network)	The manner in which demand charges are currently allocated remains the same, other than the value of the charge, which would be flat, ie the £/kW and p/kWh rates for HH and NHH demand respectively are not differentiated by location, but charged on a flat rate. No change to 27:73 split.

Some members of the WG noted that there had been a distinct lack of consensus on the socialised/postalised options thus far, meaning it was unlikely the WG would arrive at a mutually agreeable model to be simulated.

Similar to WG 4, there was some agreement that the decision to remove or retain the local / wider boundary was, in some sense, dependent on the significance given to ICRP principles within a socialised/postalised model, ie is retaining a local boundary necessary to ensure that charges more accurately reflect a user's impact upon the network?

Some members of the WG were of the opinion that a 'pure' postalised model that removed local boundaries was, in principle, the most logical option in the sense that it adhered to the spirit of a postalised approach. Some members considered that adopting a socialised model that sought to retain what is considered to be the sharpest cost-reflective signal within the current methodology (i.e. local tariff) would not be consistent with the spirit of an approach that sought to remove locational differention in tariffs. A few members noted that a potential outcome of retaining a local locational charge (but applying a uniform tariff to the use of the MITS) may incentivise potential generators seeking connection to the transmission network to request a connection design with more redundancy in its "local" design than it would have under the current ICRP baseline in order to meet the MITS boundary definition, hence avoiding the application of a sharp local cost signal and spreading these "local" costs across all users of the network through a wider uniform tariff. This would be preferable to a lower security design that would be subject to a cost-reflective local tariff signal levied on the individual generator. The potential result is that more "local" transmission assets would be built above what is considered to be an efficient level at greater cost to the end consumer. One member also noted the potential negative impact on island connections under a socialised approach that sought to retain the local boundary definition relative to a pure postalised approach (ie under the former a single sub-sea cable link between a substation located on the island group that did not meet the MITS boundary definition and a MITS substation on the mainland would be subject to a local TNUoS tarff reflective of the costs of this link).

Summary of Agreed Models:

Ofgem summarised discussion of the 6 Themes by asking the WG to assist in the development of a 'slide deck' which would clarify for each modelling scenario the choices which had been agreed for each Theme. Ofgem noted that where the WG was unable to reach a formal decision it would indicate this in the slides. Ofgem indicated that the slides would be circulated along with the note of the meeting as a record of what had been agreed by the WG.

Draft Working Group Report:

Ofgem noted that the WG had offered to assist IS with the development of the WG Report. To progress the WG Report's development, IS requested volunteers to contribute to the various sections of the Report. IS agreed to circulate a list of those assigned to contribute to each section.

Ofgem informed the WG that the Action List circulated as part of the meeting note (minutes) would detail the agreed deadlines and milestones for the drafting of the WG Report.

Transition Issues:

Ahead of the formal discussion of transition issues in WG meeting 6 (9 Sep), it was agreed that it would be beneficial to review the initial log of potential transitional issues developed at WG meeting 4. It was hoped this would ensure that the agenda for WG meeting 6 would capture all the key transitional issues identified by the WG.

In addition to the issues identified at WG 4 (detailed in the meeting note), the WG highlighted the following areas to be considered;

- Contractual arrangements between generators and NGET would need to be reviewed to analyse the impact of changes to transmission charges.
- Examine the potential impact upon 'non-regulated' contracts
- Consider the potential for the transition process in itself to present unfair advantages to different types of generators (i.e., some generators types may be able adjust quicker than others which may leave other generators at an unfair competitive disadvantage)
- The impact of tolling agreements
- The WG noted that most contracts contain clauses on 'regulatory changes', this would need to be investigated to see if it also covered changes to transmission charges.
- There was some agreement amongst the WG that the transition to a fully postalised charging regime could threaten the viability of some plants in the South East of England due to the significant changes it would bring to tariffs.
- One WG member countered this point by suggesting that the transition to an improved ICRP charging regime could threaten the viability of some plants in the North of England and Scotland due to the significant changes it would bring to tariffs.

Ofgem noted that in advance of WG meeting 6, WG members (GG/AMc, FP, SC, PJ & HS) would prepare and circulate short papers on transitional issues for postalised and improved ICRP charging models (including contract, commercial, mid-year changes etc) covering:

- What the issues are
- Their scale/materiality
- Potential solutions consistent with earliest possible introduction of changes

3. Future meetings

The updated and current WG schedule is set out below.

WG 6 (9th Sep)	Group discussion will focus on transitional issues.

4. List of Actions

	Action	Date for completion	Owner	Status
1.	Circulate link to 'GSR009' Report.	20/07/11	IS/AM	*completed*
2.	Circulate links to relevant papers (in particular, from ACER) discussing European developments (ie, issues NOT within scope of TransmiT).	20/07/11	AM	*completed*
3.	Publish Ofgem and NGET presentations from WG1.	20/07/11	AM	*completed*
4.	Verbal update at WG 2 on Ofgem process for GSR009.	01/08/11	AM	*completed*
5.	Develop 'socialised charging' strawman, identifying key choices to be made under each of the 6 themes Ofgem has identified.	09/08/11	HS	*completed*
6.	NGET to arrange briefing session for interested parties in the WG to explain NGET's potential options for change (in particular in relation to theme 1 – reflecting characteristics of users) in more detail; explore possibility of this being held Ofgem's Millbank office on 28 July, following the CAP192 workshop.	28/07/11	IS/AM	*completed*
7.	Email any comments on modelling work terms of reference, for discussion with Redpoint at WG 2.	31/07/11	All	*completed*

8.	Clarify the issues each of the six themes is intended to address	09/08/11	Ofgem	*completed*
9.	Clarify in the minutes and at the wider stakeholder event that: • Repoint's work for Project Transmit will address TNUoS charges only, and that LMP is a separate piece of work (albeit using the same model) that will follow later • Redpoint will carry out only three model runs – the status quo, one postalised charging approach and one improved ICRP charging approach	11/08/11	Ofgem	*completed*
10.	Email any comments on Redpoint's modelling approach	05/08/11	All	*completed*
10a.	Produce Q&A on modelling approach	12/8/11	Redpoint	*completed*
11.	Circulate key modelling assumptions	24/08/11 (originally 19/08/11)	Ofgem	*completed*
12.	Email any comments on key modelling assumptions	02/09/11	All	
13.	Circulate worked numerical examples of NGET's improved ICRP approach for generic plant types	02/08/11	IS	*completed*
14.	Email alternatives/builds on NGET's improved ICRP proposals	09/08/11	TR/All	*completed*
15.	Collate and circulate a list of outstanding issues with National Grid's improved ICRP proposal for theme 1, separately identifying major	11/08/11	LS	*completed*

	"philosophical" issues and those of detail			
16.	Update National Grid improved ICRP proposal for theme 1 addressing issues raised in Action 15. and providing more detail on tariffs	16/08/11	IS	*completed*
17.	Circulate initial draft Working Group report	12/08/11	IS	*completed*
18.	Email any issues missing from Ofgem's paper arising from Action 8.	16/08/11	All	*completed*
19.	Circulate proposal for changing the G:D split for offshore generators	10/08/11	GN	*completed*
20.	Circulate paper providing more detail of the postalisation proposal presented to WG3, including worked examples for charging and reconciliation	12/08/11	GG	*completed*
21.	Write up, further develop (including dealing with multiple boundaries) and circulate National Grid's proposal for HVDC	12/08/11	TR	*completed*
22.	Circulate presentation on operation of SECULF	10/08/11	IS	*completed*
23.	Circulate information showing the distribution of nodes around the average security factor of 1.8 and for nodes more than 1 or 2 standard deviations from the mean indicate the zone they are in	12/08/11	IS	*completed*

24.	Model the impact of different approaches to calculating relative impedance for HVDC and table at next WG meeting	30/08/11	IS	*completed*
25.	Clarify the extent to which changes to demand charges are in scope and are being modelled by Redpoint	30/08/11	Ofgem	*See Action 31*
26.	Calculate average GB generation charges and compare to the European tariffication guideline	24/08/11	IS	*completed*
27.	Circulate link to ENTSOE report	18/08/11	IS	*completed*
28.	Circulate matrix of sections of WG report with proposed drafting delivery dates (note IS's section to precede others in order to provide a guide on style and length etc)	19/08/11	IS	*completed*
29.	Nominate yourself to draft a section of the WG report (see A.28)	26/08/11	All	*completed*
30.	Circulate agenda for sub group meeting on 24/08/11	19/08/11	IS	*completed*
31.	Clarify exactly how Redpoint will deal with demand and include in notes of WG5 meeting	02/09/11	Ofgem	
32.	Finalise and circulate slides summarising the final position reached for status quo, postalised and improved ICRP charging models	31/08/11	AM	
33.	Circulate initial draft of WG Report – Improved ICRP, Theme 1	01/09/11	IS	
34.	Confirm which policy options Redpoint have been asked to model	Ofgem	09/09/11	
35.	Deliver initial WG Report section drafts to IS	06/09/11	Draftees	
36.	Prepare and circulate short papers on transitional issues for postalised and improved ICRP charging (including contract, commercial, mid-year changes etc) covering: • What the issues are	07/09/11	GG (AMc), FP, SC, PJ, SL	

	• Their scale/materiality • Potential solutions consistent with earliest possible introduction of changes			
37.	Circulate extracts from CMP195 relevant to dealing with transitional issues	07/09/11	SC	