CONSULTATION DOCUMENT

GB ECM-25

Review of intermittent generation charging

June 2010

Comments should be emailed to william.kirkwilson@uk.ngrid.com no later than **23rd July 2010**.

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1 Executive summary

Significant changes to Great Britain's generation capacity and technology mix are expected in the coming years, this includes a substantial increase in the connected capacity of wind powered generation. The Security and Quality of Supply Standard (SQSS) defines a process for determining the required amount of transmission network capacity to be developed. The SQSS is currently under review to cater for the increase in wind generation. The working group reviewing the SQSS issued a consultation[1] report which indicated that wind generation cannot be relied on to secure demand at any specific time e.g. at system peak. Consequently the working group recommended that when determining the requirement for new transmission capacity build, two separate criteria should be assessed:

- Demand security
  In this criteria, wind generation output will be very low. This will identify the minimum transmission capacity required to secure peak demand during periods when there is little wind.
- Cost benefit analysis (CBA)
  This criteria compares the operational savings as a result of building new transmission against the actual build cost to identify where building extra transmission is the efficient option for the end consumer.

The SQSS working group considered several options for implementing a cost benefit analysis process. However, due to the complexities involved and the uncertainty in input variables leading to volatility in output, it recommends a pseudo-CBA approach that uses a deterministic methodology that aligns with the findings of a more detailed CBA.

This consultation deals with the consequential charging changes to the that are required as a result of the preferred approach recommended by the SQSS review. This ensures that TNUoS methodology remains cost reflective. It takes the suggested two criteria approach recommended in the SQSS review and replicates that within the Transmission Network Use of System (TNUoS) tariff calculation methodology.

The charging proposal first establishes the investment driver for all lines as either demand security or pseudo CBA. The transport model then calculates a user's locational tariffs by adding an incremental MW. It then calculates the impact of the incremental MW on the investment driver of the line (either CBA or Demand security) and will apportion a cost consistent with the process set out in the SQSS review. This will ensure that user's tariffs reflect the impact that different types of generation have on the network and hence the different resulting transmission investment spend. Consequently, this process will create two sets of wider generation tariffs, one for intermittent generation and one for conventional.

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[1] The review on intermittent generation was published on 11th July and can be found on the National Grid website: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/fundamental/Wind+Integration/

The forecast impact of the proposal to current and future tariffs can be found in section 5.

This consultation only considers the charging changes required assuming the adoption of a pseudo CBA assessment from the SQSS review of intermittent generation. However if the SQSS review concludes that a full cost benefit analysis is required to assess each application rather than the pseudo cost benefit analysis currently recommended, National Grid will have to consider how this should be reflected within the charging methodology.

The proposed implementation date is 1st April 2011. However this date is subject to the Authority approving both the corresponding SQSS change and this proposal by 31st December 2010. If either decision is after this date, implementation will be agreed separately with the Authority.

This consultation document can be found on the National Grid website at the following link:

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

Comments and views are invited on all of the issues raised in this consultation document. To ensure that your comments and views are considered, responses should be emailed to **william.kirkwilson@uk.ngrid.com** by close of business on **23rd July 2010**. All comments will be published, unless clearly marked confidential within the response.

2 Introduction

National Grid is obliged under its Transmission Licence:

(i) to make revisions to the Charging Statements in order that the information set out in the statements shall continue to be accurate in all material respects;

(ii) to keep the Use of System charging methodology under review at all times;

(iii) to make such modifications to the Use of System charging methodology as may be required for the purpose of better achieving the relevant objectives, which are:

  (a) to facilitate effective competition in the generation and supply of electricity and (so far as is consistent therewith) to facilitate competition in the sale, distribution and purchase of electricity;

  (b) to result in charges which reflect, as far as reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and in accordance with the STC) incurred by transmission licensees in their transmission businesses; and

  (c) that, so far as is consistent with sub-paragraphs (a) and (b), the Use of System charging methodology, as far as is reasonably practicable, properly takes 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 update the methodology in light of a proposal to modify the SQSS with respect to investment levels required for intermittent generation. National Grid has assessed the proposal with a view to better meeting the relevant transmission licence objectives set out above and invite industry views on the proposal presented.

3 Background

The Security and Quality of Supply Standard (SQSS) defines the methodology to determine the required amount of transmission network capacity and hence the resulting required transmission investment level. However the existing SQSS was developed at a time when:

- Generation plant performance was predictable and controllable i.e. it was generally able to provide rated power when required;
- The total installed generation capacity was maintained at approximately 120% of peak demand.

Recent years have seen significant changes in the composition and behaviour of Great Britain's generation fleet and it is expected that the pace of change will increase in coming years. This is largely driven by government plans to facilitate the investment of approximately 35GW of new renewable generation in the UK between now and 2020 to allow the UK to meet its climate change targets. Consequently, large amounts of renewable and other low carbon generation are anticipated to connect to the power system, at the same time as the closure of 13.7GW of plant. This has two impacts:

- The location of new generation away from the main load centres will require significant network reinforcement;
- Much of this renewable generation will be intermittent in nature.

The existing SQSS, does not clearly differentiate between conventional and intermittent generation. However it is accepted that the overall level of transmission required for intermittent generation is generally less than that required for the same capacity of conventional generation. Therefore the current SQSS is under review to cater for the integration of an increasing amount of intermittent generation. The working group has issued a consultation report which sets out the proposals and seeks to codify this reduced transmission investment requirement for intermittent generation.

The level of investment links to transmission charges because charges are cost reflective. Cost reflective charges allow users to internalise the cost of transmission (comparatively) and make efficient locating decisions i.e. should it site close to a fuel source and increase the transmission investment required or closer to the demand incurring higher fuel cost, but reducing transmission costs. In the case of wind this can be considered as the choice between locating in remote areas where the load factor could be high, but would increase increased transmission cost or locating where the load factor is lower (reducing income) but closer to the load, (reducing transmission costs). Through this internalisation of costs the most efficient decisions are taken and the overall costs passed through to end consumers are minimised.

Peak based charging

Historically the transmission system has mostly been designed so that conventional plant can meet peak demand using a deterministic standard i.e. transmission will not unduly restrict generation from contributing to demand security. The standard against which the system is designed is published in the Security and Quality Supply Standard (SQSS) and Transmission Owners have a licence duty to meet this standard. The rational behind designing the system to cope with peak demands is that investing to meet peak demand generally triggers sufficient transmission capacity to avoid excessive constraints at other times of the year.

Due to the variability of its fuel source less reliance can be placed on wind generation contributing to meeting peak demand, commonly called it's capacity credit[3]. As wind generation has a lower capacity credit it will drive less transmission investment compared to conventional generation to meet peak demand. However, whilst it has a low contribution to peak security, its output at other times through the year will need to be accommodated. Generation whose output is restricted due to transmission are compensated and the system operator has to replace the reduced output from other sources. It is the cost of this restriction (constraint cost) that drives additional transmission investment. In order to determine the constraint costs, transmission owners analyse year round conditions rather than focusing solely on peak demand conditions.

In summary, whilst transmission investment for conventional plant is mostly driven by the need to meet peak demand, the transmission investment for wind plant is largely driven by balancing transmission investment costs with the risk of increased constraint costs.

Current methodology

The charging methodology is based on the principle of Incremental Cost Related Pricing (ICRP). This means that tariffs reflects the incremental cost of accommodating an additional MW of generation, or demand, at a point on the system. The calculation of the 'increment' is based on a DC Load flow (DCLF) at peak demand conditions. Within the methodology signals are grouped into zones to improve stability. There is also a flat element added on a non locational basis to ensure cost recovery aligns with the allowance set by the regulated price controls.

The load flow is peak based as historically most investment has been required to meet peak demand conditions and aligns with the current SQSS deterministic assessment which is carried out at system peak. The SQSS also includes year round analysis, but the main driver for incremental capacity has historically been peak based i.e. the level required at peak is generally sufficient year round.

The tariff is linked to charges through the access product. Whilst there are short term access products available, parties generally seek the annual product Transmission Entry Capacity, TEC. TEC is a financially firm product and gives users access to the system 24 hours a day 365 days a year.

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[3] How much thermal generation it can displace MW for MW without lowering demand security.

The diagram and text following provides an overview of the mechanics of the current TNUoS charging process. A more detailed explanation can be found in appendix 1 and 2. The diagram highlights the separate transport and tariff elements of the process, the inputs required and how the two are linked together by the transfer of Nodal Marginal Costs.

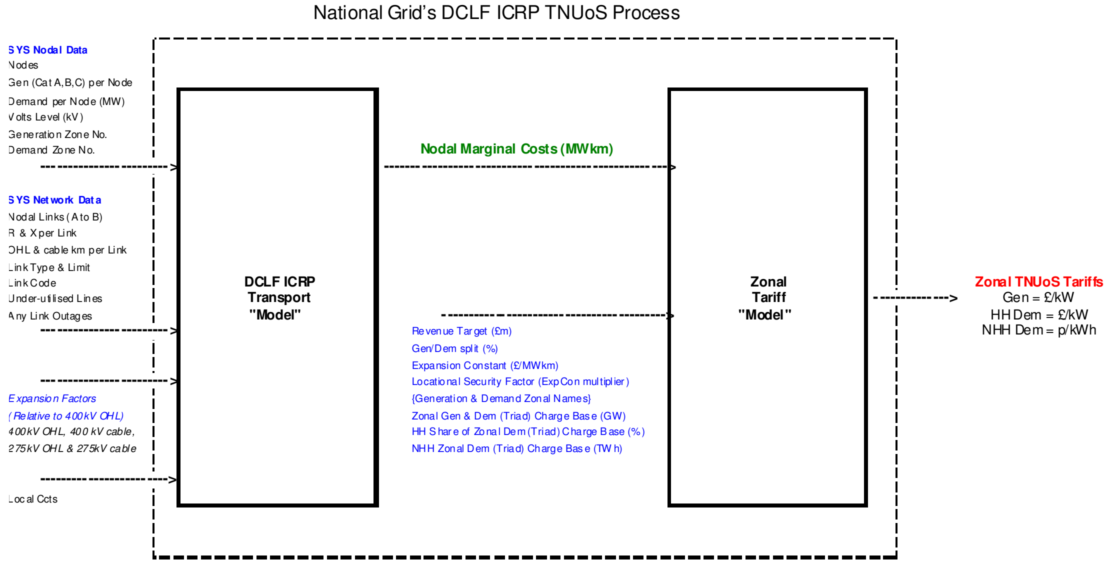

Figure 1 Overview of the process for the calculation of user's tariffs

The transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system. It calculates the marginal costs based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. Marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system, for a 1 MW injection to the system. This is then transferred to the zonal tariff model.

The zonal Tariff Model takes the nodal marginal costs produced by the transport model and converts these into final zonal tariffs for local/wider generation, HH demand and NHH demand. To enable this it requires the input of a target revenue, G:D split, Expansion Constant, Locational Security Factor and the identification of local circuits. It also clearly needs the appropriate zonal charge bases for generation and demand, including the relevant split per zone of HH/NHH triad demand and zonal NHH demand summed over the year between 16:00 to 19:00 hrs.

The Transport Model derives power flows in line with standard electrical theory, using SYS nodal and network data. It first scales nodal generation uniformly to ensure national generation matches national peak demand. It then derives power flows over the transmission network from this generation and demand pattern, based on the impedance values of the lines. This means that the pattern of power flows on individual circuits realistically reflect those that could be seen on the transmission network at peak.

The total MWkm figure for the base transport solution is then derived from these power flows multiplied by relative cost of the circuits over which they travel. The cost of circuits is assessed against the relative cost of 400kV overhead line and expressed in km.

This power flow background is then disturbed by the injection of 1MW of additional generation at a node. A corresponding additional 1MW of demand is taken off at the Reference Node to ensure total generation equals total demand. It is the difference in total MWkm between the base solution and this nodal injection "scenario" which creates the nodal marginal cost (MWkm) for that node. This process of injecting an incremental MW is repeated for each node in turn to derive a full list of nodal marginal costs for the prescribed network. These marginal costs (MWkm) are then used to derive TNUoS tariffs.

4 Proposal

This consultation deals with consequential changes to the charging methodology required to deal with the preferred approach recommended within the SQSS review for transmission investment. This proposal divides generation into two types, intermittent[4] and conventional and creates two different zonal tariffs, one for each type. The calculation of the two tariffs is a proxy for the different treatment, and hence different resulting transmission investment spend, that the two types drive within the SQSS.

The SQSS review's preferred option proposes using two criteria when determining the required transmission investments, a demand security assessment and a pseudo cost benefit analysis (CBA) assessment. This consultation proposes that these two assessments are reflected within the charging methodology. Currently when calculating a user's impact on the system the locational part of the tariff is calculated by running a single peak study, reflecting the impact a user has on at the time of system peak. Instead, it is proposed to run two load flows, a demand security (at system peak) and a pseudo cost benefit analysis reflecting the two criteria to be used in the proposed SQSS process. Having run these two load flows, two sets of generation tariffs will be calculated by looking at the impact of an extra MW of either intermittent or conventional generation on the limiting criteria on a circuit by circuit basis.

Creating the two scenarios

The Transport Model requires a set of inputs representative of the two assessment criteria that the SQSS review is suggesting. As currently, the nodal generation data for the Transport Model will be taken from the most recently published Seven Year Statement plus relevant updates (as current practice). The forecasts in the Seven Year Statement include all plant belonging to generators who have a Bilateral Connection Agreement (BCA) or Bilateral Embedded Generation Agreement (BEGA) with National Grid[5].

Two scenarios will be created from the contracted background (outlined above) by scaling the different generation types representative of the demand security and a pseudo cost benefit analysis scenario. The scaling of different generation types will be as stated following the conclusion of the SQSS review. Therefore if in the demand security assessment, the SQSS proposes modelling a nuclear station running at *x*% load factor, within the transport model demand security assessment, nuclear will also run at *x*%. The only difference between the criteria used within the transport model and as determined by the SQSS review will be that within the transport model, a merit order will not be used and no generation will be treated as non contributory. This is a continuation of the current methodology. Within the SQSS where the generation background is more than 20% greater than the forecast

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[4] The definition of intermittent is defined later, but will be as per the Grid code definition. This includes this includes wind generation, marine (tidal and wave) and solar.

[5] Bilateral Embedded Licence exemptable Large power station Agreement (BELLA) are treated as negative demand in the model to reflect their financial treatment.

maximum demand for the year, a merit order is used to identify non contributory plant and plant that is out of merit. Non contributory plant is then removed from the background when designing the system. Under planning timescales capping the plant margin at 120% and removing non contributory plant is necessary as plant margins are high due to the high volumes of plant contracted to connect. However when setting tariffs, the time horizon is much closer, hence the contracted background will more closely reflect the generation plant that is actually on the system in the time window that the charging model is representing. Therefore National Grid consider it appropriate to leave the current arrangement unchanged, to include all contracted generation within the generation background used to calculate tariffs and then scale different types as recommended under the SQSS review. Furthermore if National Grid were to cap the plant margin at 120%, this would impact user's tariffs in a manner that was subjective, non transparent and unstable.

Table 1 below shows the impact of using the proposed methodology on the generation background that was used to calculate 2010-11 TNUoS tariffs. The light grey percentage figures denote the generation that is scaled[6] uniformly to ensure that total national generation equals total national Demand. Whereas the solid dark percentage figures represent generation that has a fixed contribution as defined in the SQSS review and hence will receive the same treatment within the transport model.

The final definition and scaling of the generator types will mirror their treatment within the final SQSS proposal. Consequently individual generators will be classified into their generation types according to how they are classified within the SQSS.

Generator type	**TEC**	**Scenario A - Demand security**	**Scenario B - Pseudo CBA**
Intermittent	3,667	5%	70%
Nuclear	10,894	79%	85%
Interconnectors	3,268	0%	100%
Hydro & Pumped	3,427	79%	75%
Peaking	5,025	79%	0%
Other (Conventional)	58,986	79%	75%

Table 1 Generator type scaling constants for charging year 2010-11

As currently, nodal demand data for the Transport Model will be based upon the GSP demand that DNOs have forecast to occur at the time of National Grid Peak Demand as in the Seven Year Statement. This reflects the demand background that the SQSS review is proposing using in both assessments.

Circuit data representing the transmission routes will be unchanged and be taken from the Seven Year Statement. If certain route information is not explicitly contained in the Seven Year Statement, National Grid will use the best information available (as per the current process).

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[6] Some generation is not scaleable and its output is defined as a % of TEC or Registered Capacity within the SQSS review.

Calculating the nodal marginal km

The Transport Model takes the input data described above and then uses the transport algorithm (described in appendices 1 and 2) to derive the resultant pattern of power flows, based on the network circuit impedances and assuming no circuit rating limits. It then calculates the resultant total network MWkm, by multiplying the resulting power flows by the appropriate circuit expansion factors[7]. It will do this twice calculating the power flow and the resultant MWkm for both the demand security scenario and again for the pseudo CBA.

Having determined the optimal network required under both scenarios, it is then necessary to calculate the impact of incremental generation at each node. This is achieved by adding 1MW of generation at a node and adding 1MW of demand at the reference node. Then on a line by line basis, the impact of the MW is assessed against the limiting condition of the line, be it demand security or pseudo CBA. The impact is quantified by multiplying the power flow on the line by the appropriate circuit expansion factor and the relevant generation type scaling constant (described below and table 2) to establish a MWkm for each line resulting from the incremental MW for both types of generation. The limiting criteria of the line is determined by the absolute magnitude of the power flow. For example if the power flow on line A->B was 10MW in the demand security scenario, but was -30MW in the CBA (i.e. the power flow had reversed direction, but was larger), the CBA criteria would be considered the limiting constraint. Hence the impact of the additional MW would be assessed against the CBA criteria for that line. The rational for determining the limiting criteria by the absolute level of power flow is that having satisfied the worst case/limiting criteria, the remaining criteria is consequently also resolved and not binding. The output from this calculation will be an extra sets of wider MWkm, one for conventional generation (as currently), but an extra set for intermittent generation.

The marginal km cost for demand at each node is the equal and opposite of the nodal marginal km for conventional generation.

The total marginal km at each node would, as currently, be determined by summing the individual marginal km contributions from all the lines. It should be recognised that the marginal km costs can be positive or negative depending on the impact of generation on the total network.

Generation type scaling constant

As mentioned above, the impact a generator has on a limiting condition is calculated by multiplying the resultant power flow on the line, by the cost of the line and the relevant generation type scaling constant. The generation type scaling constant reflects the different impact the each type of generation has on the network and hence different resulting transmission investment spend. The actual numbers used will depend on the outcome of the SQSS review, but currently are:

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[7] Expansion factors are a proxy for the cost per MW carried on the line, expressed as a percentage compared to 400kV overhead line.

	Demand security	Pseudo cost benefit analysis
Wider TNUoS conventional	1	1
Wider TNUoS intermittent	0.05	0.7
Local TNUoS conventional	1	1
Local TNUoS intermittent	1	1
Demand	1	1

Table 2 Forecast generation type scaling constant

The generation type scaling constant is reduced for intermittent generation in its wider tariff to reflect the reduced need for investment triggered under chapter 4 of the SQSS. The different intermittent generation scaling constants for the demand security and the pseudo cost benefit analysis scenario reflect that intermittent generation will not add to (or alleviate) a demand security constraint and therefore this should be reflected in its marginal km. Put another way, if intermittent generation is behind a demand security constraint adding more intermittent generation into the area will not significantly add to the export transmission capacity requirement for the zone.

Tariff model

There will be no change to the current tariff model calculation for demand and local tariffs.

The wider generation tariff will be modified to cater for the two sets of generation nodal marginal MWkm. Two sets of wider generation tariffs will be calculated, one for intermittent and one for generation not defined as intermittent. The current underlying process and principles will be maintained, however the tariff calculation will run on both sets of MWkm and each calculation will be based on the appropriate generation type i.e. when calculating the intermittent generation tariff, the intermittent MWkm and the intermittent zonal/nodal generation will be used. When calculating the conventional generation tariff, the conventional MWkm and the conventional zonal/nodal generation will be used. Therefore the zonal marginal km for intermittent generation will be calculated by:

$$WNMkm_j = \frac{NMkm_j * Gen_j}{\sum_{j \in Gi} Gen_j}$$

$$ZMkm_{Gi} = \sum_{j \in Gi} WNMkm_j$$

Where:

G_i = Generation zone
j = Node
NMkm = Intermittent Wider nodal marginal km from transport model
WNMkm = Weighted intermittent nodal marginal km
ZMkm = Intermittent Zonal Marginal km
Gen = Intermittent Nodal Generation from the transport model

The zonal marginal km for generation other than intermittent will be calculated using the same formula but substituting the conventional equivalents as below:

Where:
G_i = Generation zone
j = Node
NMkm = Conventional Wider nodal marginal km from transport model
WNMkm = Weighted conventional nodal marginal km
ZMkm = Conventional Zonal Marginal km
Gen = Conventional Nodal Generation from the transport model

Annual liability

The method for determining a user’s final annual liability will be unchanged and be its chargeable capacity multiplied by its applicable tariff.

Definition of intermittent generation

The definition for Intermittent generation will be as in the Grid Code, this includes wind generation, marine (tidal and wave) and solar.

For the avoidance of doubt, cascade hydro will not be defined as intermittent. This reflects its proposed treatment within the SQSS where cascade hydro is classed with hydro and pumped storage. However National Grid invites industry views as to whether this treatment is appropriate.

Chargeable capacity

For generation other than generation defined as intermittent, there will be no change to its chargeable capacity.

Currently it is undecided within the SQSS as to whether intermittent generators will be modelled using TEC or registered capacity. The commercial treatment of intermittent generators in positive wider TNUoS zones should reflect their treatment within the SQSS, therefore this proposal will mirror the outcome of the SQSS review. Theoretically the chargeable capacity should be defined as equal to their registered capacity. This reflects their true generation capacity and avoids double counting the reduced output an intermittent generator gives. However practically there are advantages to using TEC as TEC is the current access product available. In the short to medium term, it would be expected that the TEC and registered capacity for intermittent generators will be approximately the same. However if National Grid saw a divergence between the two, then the definition for chargeable capacity could be re-examined. National Grid invites views on how such generators should be treated and whether the above approach is appropriate.

The chargeable capacity for intermittent generators in negative zones will be calculated in an identical manner to conventional generators in negative zones, i.e. it will be the average of the capped metered volumes during the three settlement periods separated from each other by at least 10 clear days, between November and February of the relevant Financial Year. These settlement periods do not have to coincide with the Triad.

Local TNUoS

The SQSS intermittent generation review does not alter the asset investment required for local circuits. Therefore the local build for intermittent generators will be identical to conventional generators. Consequently, as outlined above, the generation type scaling constant for both intermittent and conventional generators will be unity.

However for both intermittent and conventional generation, the calculation line by line of their local nodal MWkm impact will be collared at 0. This reflects asset investment as the connection of a generator will increase the amount of transmission infrastructure needed and will only in *very* rare circumstances offset infrastructure build. Therefore a generator should not receive a benefit in its local tariff for offsetting infrastructure build. Currently only three generators have a negative local tariff, therefore the impact of this modification to local charges will be relatively small.

Zoning

National Grid proposes to leave the current generation zoning methodology unchanged and base zones on the conventional nodal MWkm. Intermittent zones will be aligned with conventional generation zones. Aligning intermittent generation zones with conventional generation is necessary in the short to medium term because the current low penetration of wind generation would make intermittent zones unstable until the degree of wind penetration grew. However National Grid is open to views as to whether a separate set of zones should be created and invites industry comment.

If the Authority chooses not to veto this charging proposal, National Grid will evaluate whether the current charging zones meet the zoning criteria and if not, will modify the zones to increase cost reflectivity. This is a normal part of charge setting as National Grid keeps the zones under review and can rezone under exceptional circumstances. National Grid consider the review of the SQSS and the subsequent changes to the charging methodology an exceptional circumstance. However National Grid has examined the impact on zoning of this proposal against the generation background used to calculate the current tariffs and it implementation would not of itself require a rezoning to existing zones.

Short term access products

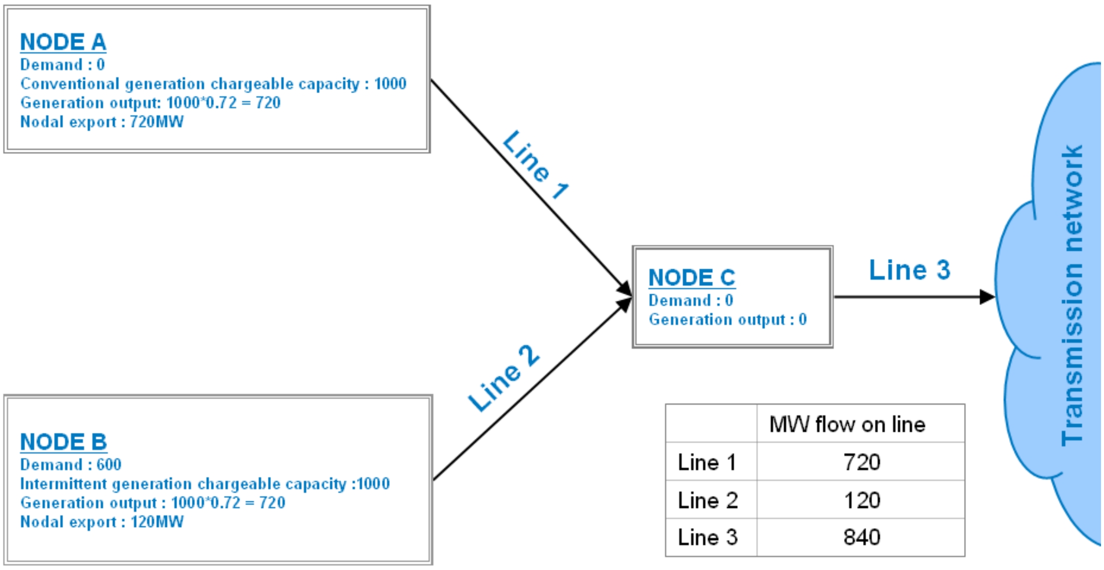
National Grid propose to leave the current arrangements for short term access products unchanged. The liability for a generator with a positive final tariff wishing to purchase either Short Term Transmission Entry Capacity (STTEC) or Limited

Duration Transmission Entry Capacity (LDTEC) will be the multiple of the user's chargeable capacity and the relevant tariff.

As currently, the LDTEC or STTEC tariffs for generators with negative final tariffs is set to 0 to prevent user's receiving greater than 100% of the annual TNUoS payment that would have been received for that capacity under a firm TEC.

If the outcome of the SQSS review is that chargeable capacity for intermittent generation is to be modelled using registered capacity then as stated above, the chargeable capacity for intermittent generation will also be registered capacity. In such a case, it will not be possible to trade intermittent TEC to conventional plant.

Worked example – current methodology



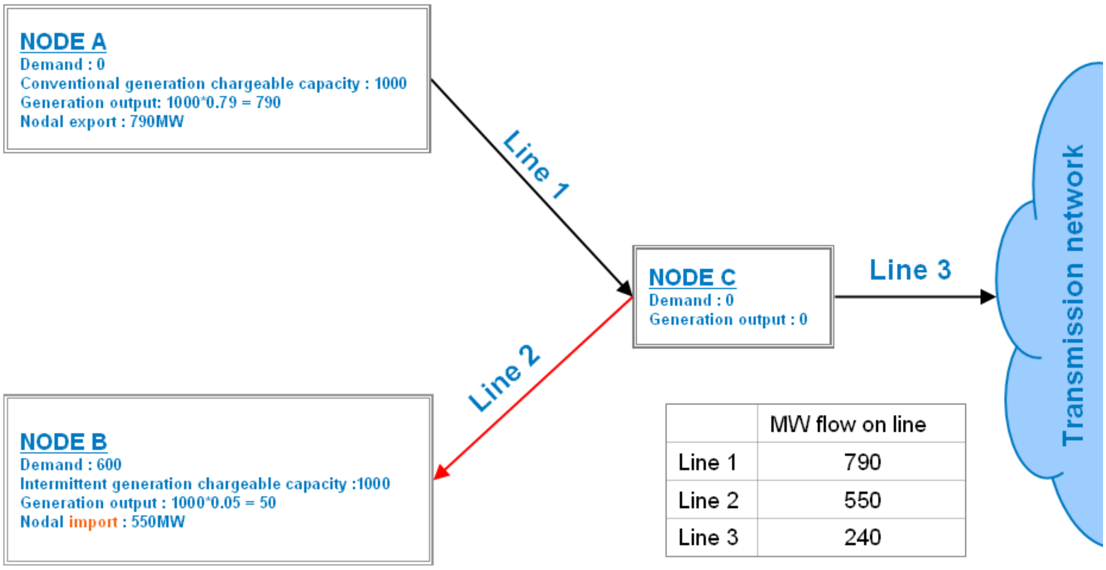
	MW flow on line
Line 1	720
Line 2	120
Line 3	840

Figure 2 Simplified example of the background power flows as calculated using current methodology

The diagram above shows a simplified network and will be used to explain how the current methodology calculates marginal MWkm. The power flows on the diagram represent a snapshot of the power flows at system peak. All circuits are considered wider for this example. The generation scaling constant used is 72% which is the same as the current transport model.

Against this background power flow a marginal MW is added on a node by node basis to assess the additional “cost” to the total network. In the above network, when the 1MW is added at node A, it flows down line 1 and line 3, adding to the background power flow. Consequently, the costs of line 1 and line 3 will be added to the marginal MWkm at node A. When an additional MW is added to node B, it flows down lines 2 and 3, also adding to the background power flows. Therefore the marginal MWkm for node B include the costs of line 2 and line 3.

Worked example – proposed methodology

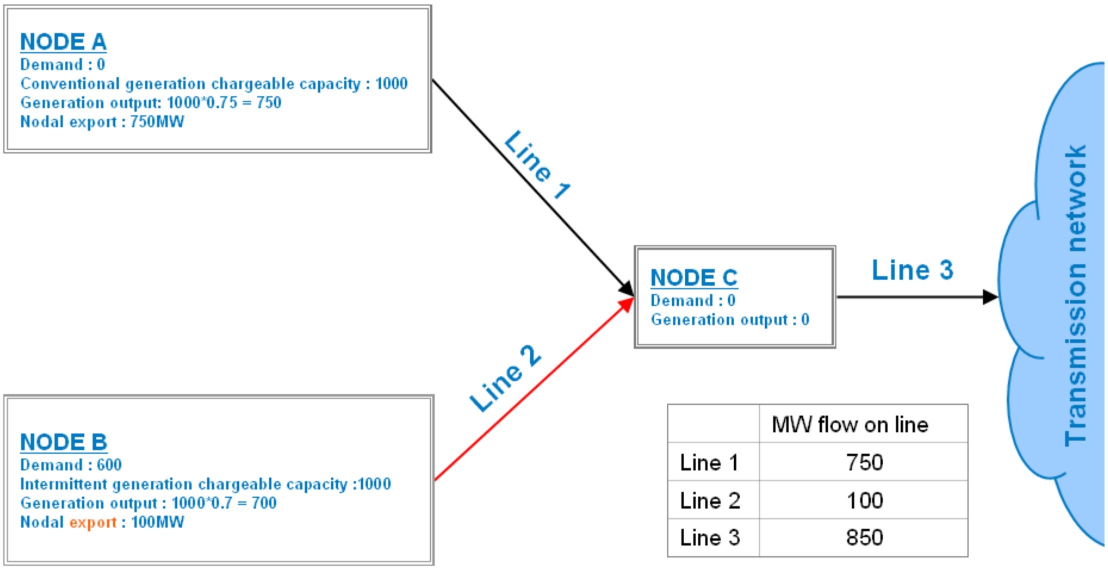


	MW flow on line
Line 1	790
Line 2	550
Line 3	240

Figure 3 Simplified network showing the power flow representing the demand security scenario

As explained previously, this proposal suggests running two power flows representative of the two SQSS criteria. The above diagram represents a simplified example of the power flows that would be expected from the demand security criterion. As before, all circuits are considered wider for this example. The generation scaling constants are those calculated previously see table 1.

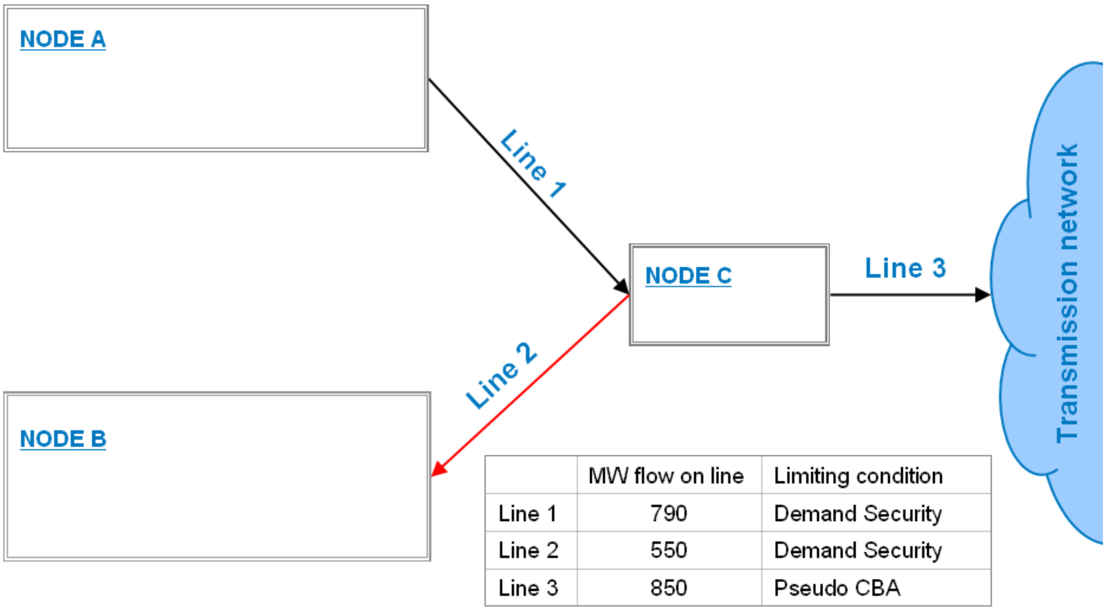
As is evident, the wind generation has been scaled back significantly, this has caused the power flow on line 2 to switch direction (compared to the system peak power flow) and node B is now importing.



	MW flow on line
Line 1	750
Line 2	100
Line 3	850

Figure 4 Simplified network showing the power flows representing the pseudo cost benefit analysis scenario

Having run the demand security power flow, the next step is to run the pseudo cost benefit analysis power flow. The above diagram is representative of the power flows that would be expected under this scenario. As can be seen, the wind generation input has increased significantly and is now supplying the demand at node B and the spill is exporting along line 2. Hence node B becomes an exporting node. The conventional generation at node A has been scaled back to offset the additional wind generation now in the generation background.



	MW flow on line	Limiting condition
Line 1	790	Demand Security
Line 2	550	Demand Security
Line 3	850	Pseudo CBA

Figure 5 Combining both power flows

Having run both power flows, both backgrounds are combined to determine the limiting condition, line by line. The limiting condition is determined by the absolute level of the power flow on a line. For example, the biting constraint for line 2 is in the demand security scenario. This is because under the pseudo CBA, the line flow is 100MW exporting, however under the demand security it is 550MW importing. Effectively this indicates that the triggering requirement for line 2 is to support the demand at node B, rather than to allow the wind generator to export to the transmission network.

The final step is to calculate the nodal marginal MWkm for intermittent and conventional generators by calculating their impact against this combined background. Adding a MW at node A would add to the power flows on line 1 and 3. Therefore the marginal MWkm for a generator at node A would include the costs of line 1 and 3 multiplied by their relevant scaling constants. The scaling constants reflect the impact the different generation technologies have on the level of asset investment required to accommodate their connection. In the above example, it is easier to add additional intermittent generation to node A than conventional. This is because the limiting constraint on line 1 is an exporting demand security one on which intermittent generation would only have a limited impact.

Adding a MW at node B would reduce the power flow on line 2 but add to the power flow on line 3. Therefore the marginal MWkm for a generator at node B would be the relevant scaling constant multiplied by the cost of line 3, but reduced by the cost of line 2. As the scaling constant for conventional generation is currently 1, adding a MW of conventional generation to node B helps reduce the import requirement in the demand security background and hence helps reduce the need for investment in line 2. However adding intermittent generation to node B would only minimally alleviate this limiting constraint on line 2. This is reflected by the reduced scaling constants for intermittent generation in the demand security scenario.

The table below shows the different scaling constants that would be used when calculating the marginal MWkm for each node.

		Line 1	Line 2	Line 3
Node A				
	Intermittent	+0.05	n/a[8]	+0.7
	Conventional	+1	n/a	+1
Node B				
	Intermittent	n/a	-0.05	+0.7
	Conventional	n/a	-1	+1

Table 3 Generation type scaling constants

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[8] N/a indicates where a line will not impact the marginal MWkm of a node

5 Analysis

The impact of the proposed methodology change has been analysed by looking at the changes it would have made to current 2010/11 TNUoS charges. These are shown below in figures 8 to 10. The impact on 2014/15 charges is also assessed as this examines the effect of increasing the penetration of intermittent generation (see figure 12).

Impact on current 2010/11 TNUoS tariffs

The pie chart below splits the total network MWkm by the limiting constraint. Therefore for current tariffs (2010/11), 27% of the total network MWkm are being constrained by the demand security scenario, but the bulk of the network is being constrained by the pseudo CBA scenario.

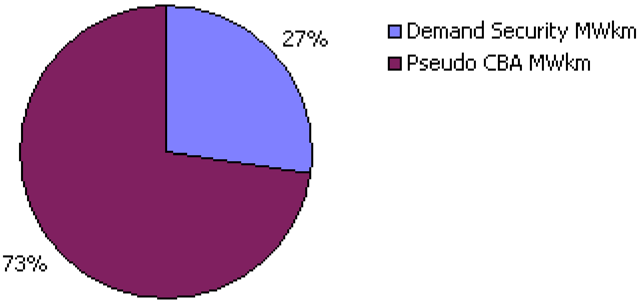


Figure 6 Total network MWkm split by constraining criteria

The impact of the proposal to the residual is small and is below. The change to the residual arises because the revenue from the localional element of the generation tariff decreases due to the reduced contribution from intermittent generation.

Residual	Current	Proposal	Diff
Residual Charge for Generation(£/kW)	3.48	3.76	0.28
Residual Charge for Demand (£/kW)	18.56	18.61	0.05

Figure 7 Impact to the residual

A table of the forecast tariffs can be found in appendix 4. Figures 8 to 10 forecast the zonal changes to current tariffs in £/kW of the proposed methodology change for generation and demand customers. The forecast changes to tariffs include both locational and residual changes. Zonal intermittent tariffs have only been calculated where such generation exists in a zone. For this analysis intermittent tariffs have not been calculated where there is no such generation in the zone, this is because such tariffs are misleading and can change significantly depending on where an intermittent generator locates within the zone.

The forecast tariffs show that for all zones the change to a conventional generation tariff is less than ± £2/kW. For most zones the intermittent generation tariff is ≈30% less than the conventional tariff. This reflects that the bulk of current network investment is being driven by CBA criteria and against this background, intermittent generation drives less investment than conventional.

The impact of the new methodology on generation tariffs in Zone 17 (South East/Thames Estuary) is unusual. The forecast conventional tariff is £0.53/kW, whereas the intermittent tariff is -£0.24/kW i.e. the conventional tariff is positive, whereas the intermittent tariff is negative. This difference between tariffs is due to a demand security export constraint out of the zone. Several of the zonal export circuits are most heavily loaded under the demand security scenario as there is a significant amount of local peaking plant in this area exporting into central London. Therefore adding extra intermittent generation will only minimally add to this constraint and this should be reflected through into its tariffs. This reflects the assessment that will be made under the SQSS.

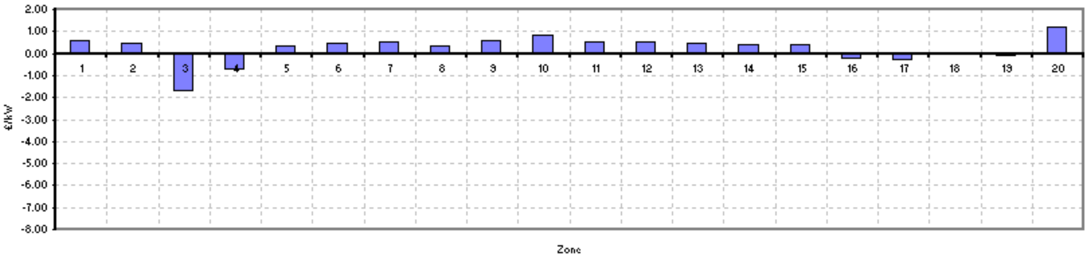


Figure 8 Forecast impact to conventional generation

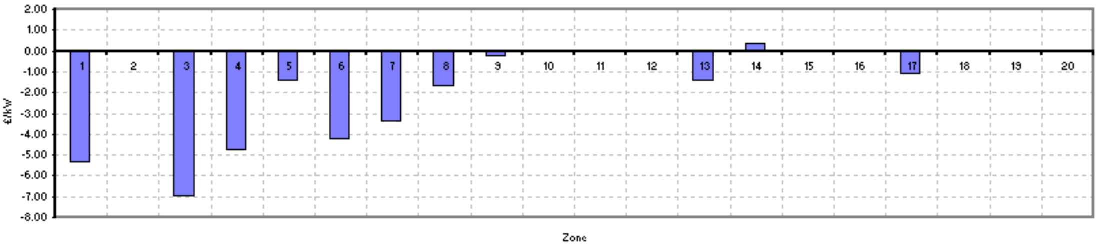


Figure 9 Forecast impact to intermittent generation

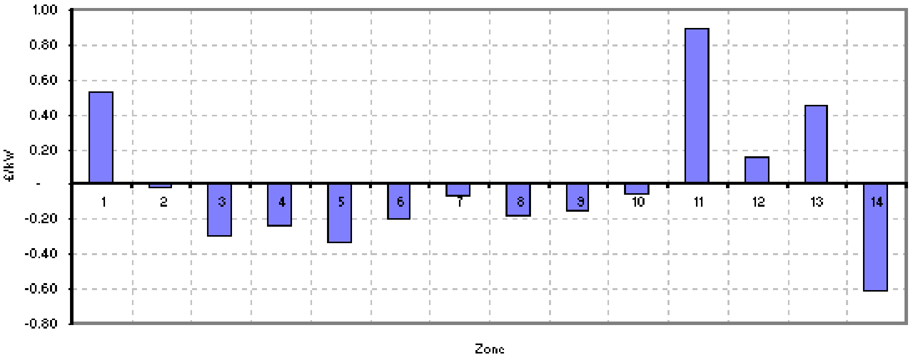
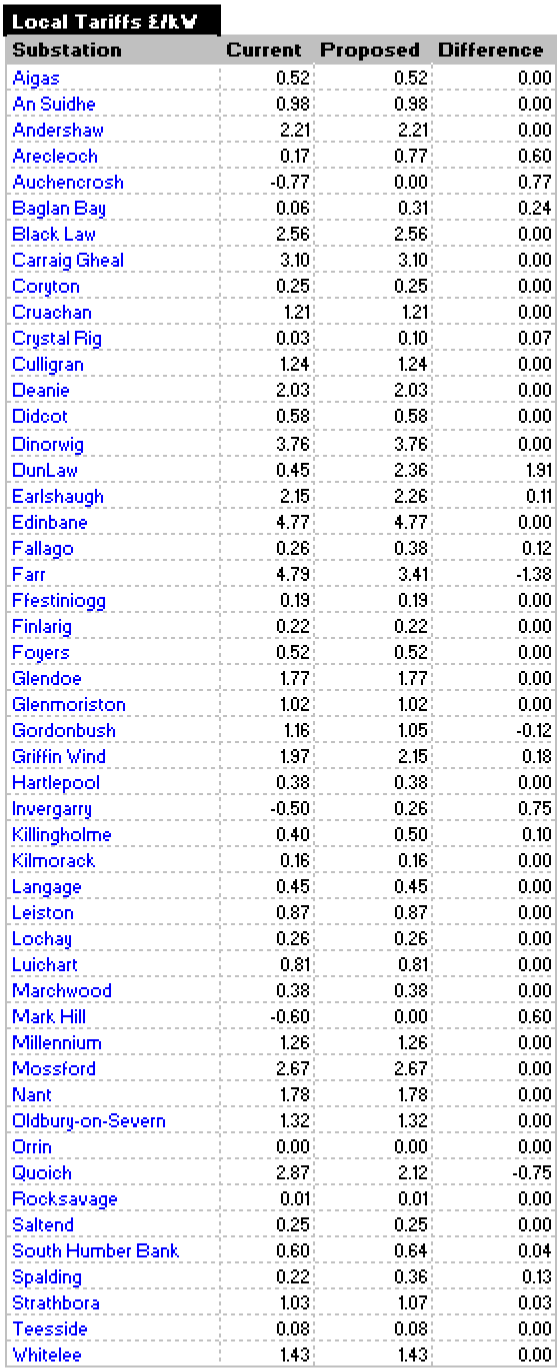


Figure 10 Forecast impact to HH demand customers

The impact of the new methodology on generation local tariffs is shown below. As can be seen the bulk of the local tariffs do not change or show little movement. However there are no longer any negative local tariffs, this is because local circuit MWkm impacts are collared at 0. This reflects asset investment as the connection of a generator will increase the amount of transmission infrastructure needed and will only in *very* rare circumstances offset infrastructure build. Therefore a generator should not receive a benefit in its local tariff for offsetting local infrastructure build. Other local tariffs also change because some local circuit power flows reverse due to changes in the power flow background against which local tariffs are assessed.



Local Tariffs £/kW

Substation	Current	Proposed	Difference
Aigas	0.52	0.52	0.00
An Suidhe	0.98	0.98	0.00
Andershaw	2.21	2.21	0.00
Arecleoch	0.17	0.77	0.60
Auchencrosh	-0.77	0.00	0.77
Baglan Bay	0.06	0.31	0.24
Black Law	2.56	2.56	0.00
Carraig Gheal	3.10	3.10	0.00
Coryton	0.25	0.25	0.00
Cruachan	1.21	1.21	0.00
Crystal Rig	0.03	0.10	0.07
Culligran	1.24	1.24	0.00
Deanie	2.03	2.03	0.00
Didcot	0.58	0.58	0.00
Dinorwig	3.76	3.76	0.00
DunLaw	0.45	2.36	1.91
Earlshaugh	2.15	2.26	0.11
Edinbane	4.77	4.77	0.00
Fallago	0.26	0.38	0.12
Farr	4.79	3.41	-1.38
Ffestiniogg	0.19	0.19	0.00
Finlarig	0.22	0.22	0.00
Foyers	0.52	0.52	0.00
Glendoe	1.77	1.77	0.00
Glenmoriston	1.02	1.02	0.00
Gordonbush	1.16	1.05	-0.12
Griffin Wind	1.97	2.15	0.18
Hartlepool	0.38	0.38	0.00
Invergarry	-0.50	0.26	0.75
Killingholme	0.40	0.50	0.10
Kilmorack	0.16	0.16	0.00
Langage	0.45	0.45	0.00
Leiston	0.87	0.87	0.00
Lochay	0.26	0.26	0.00
Luichart	0.81	0.81	0.00
Marchwood	0.38	0.38	0.00
Mark Hill	-0.60	0.00	0.60
Millennium	1.26	1.26	0.00
Mossford	2.67	2.67	0.00
Nant	1.78	1.78	0.00
Oldbury-on-Severn	1.32	1.32	0.00
Orrin	0.00	0.00	0.00
Quoich	2.87	2.12	-0.75
Rocksavage	0.01	0.01	0.00
Saltend	0.25	0.25	0.00
South Humber Bank	0.60	0.64	0.04
Spalding	0.22	0.36	0.13
Strathbora	1.03	1.07	0.03
Teesside	0.08	0.08	0.00
Whitelee	1.43	1.43	0.00

Figure 11 Forecast impact to generation local 2010/11 TNUoS tariffs

Impact on 2014/15 TNUoS tariffs

The following table forecasts the zonal changes to current tariffs in £/kW of the proposed methodology change for generation and demand customers. It compares the 2014/15 tariffs as calculated in the Condition 5 report[13] against those that would be calculated using this proposal. This is showing the impact of increasing the penetration of wind within the generation background. It should be noted that 2014/15 is the furthest year out that publicly available contracted data is available, therefore this is why this year is assessed. As before tariffs have not be calculated for zones without any generation.

The results show that the impact on the conventional tariffs is stable and within ± £2/kW for all zones. For intermittent generation, the reduction in tariffs is ≈30-40% for the majority of zones.

Again, the impact of the new methodology on generation tariffs in Zone 17 (South East/Thames Estuary) is unusual. The forecast conventional tariff is -£0.55/kW, whereas the intermittent tariff is £2.34/kW i.e. the conventional tariff is negative, whereas the intermittent tariff is positive. This difference is due to a demand security export constraint into London (mainly on the Elstree-St Johns Wood cables). Conventional generation would ease this constraint, however intermittent generation would not. Consequently, conventional tariff reflects this potential benefit, but intermittent does not.

£/kW		Condition 5	New methodology	
Zone No.	Zone Name	Forecast	Conventional	Intermittent
1	North Scotland	19.21	19.16	11.80
2	Peterhead	18.69	18.37	
3	Western Highland & Skye	19.05	17.76	11.83
4	Central Highlands	17.00	15.74	10.47
5	Argyll	14.16	13.47	9.43
6	Stirlingshire	13.61	13.51	7.58
7	South Scotland	12.46	13.03	7.27
8	Auchencrosh	12.35	11.28	7.81
9	Humber & Lancashire	5.06	5.28	2.59
10	North East England	8.46	9.33	
11	Anglesey			
12	Dinorwig	5.43	5.53	
13	South Yorks & North Wales	2.98	3.34	1.49
14	Midlands	0.99	1.24	2.03
15	South Wales & Gloucester	1.39	1.66	-1.53
16	Central London	-7.98	-7.80	
17	South East	-0.75	-0.55	2.34
18	Oxon & South Coast	-2.95	-2.68	
19	Wessex	-4.18	-4.09	
20	Peninsula	-3.22	-4.23	-0.28

Figure 12 Forecast impact on 2014/15 generation tariffs

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[13] Every year National Grid publish a 5 year forecast of the locational element of TNUoS tariffs. This can be found on the National Grid's website: http://www.nationalgrid.com/uk/Electricity/Charges/gbchargingapprovalconditions/5/

6 Assessment

When developing a proposal National Grid has to ensure that it better facilitates its relevant licence objectives which are 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.

National grid has assessed the proposal and has made the following initial assessment of the proposal against the current methodology. In the table '✓' indicates that the option better meets that relevant object; '-' indicates that the option is neutral to meeting that objective; and '×' indicates that the option does not meet that objective.

Facilitates Competition			**Cost Reflectivity**			**Developments in the transmission business**
Transparency	Predictability	Stability	Services provided	Incremental	Practical cost	
-	-	✓	-	✓	-	✓

Table 4 Initial assessment of the proposal against the relevant objectives

The above assessment is based the arguments set out below and within this consultation:

- The SQSS drives the amount of transmission network asset investment required. The SQSS is currently being updated to reflect the reduced investment that intermittent generation drives. Consequently, as charges are cost reflective, apportion the cost of assets investment back to user's and are forward looking, if the drivers for investment are changing, this needs to be reflected within user's tariffs. Consequently, National Grid believe that this proposal reflects developments in the transmission business as it is reflecting the review of the SQSS through into the charging methodology;

- National Grid believe that this consultation closely mirrors the approach taken within the preferred option of the SQSS review, therefore the resultant tariffs will reflect the asset investment undertaken and hence be cost reflective. However the extra complexity introduced into the calculation will be contained within the transport model that National Grid already supplies to the industry. Therefore National Grid believe the extra complexity of the tariff calculation will not prove a barrier for industry and strikes an appropriate balance between cost reflectivity, complexity and transparency;
- National Grid believe that the proposal leaves the process for calculating user's tariffs largely unaltered and simply extends the current underlying methodology and principles. Therefore National Grid believe that the proposed methodology is an incremental change to the current methodology;
- National Grid believe that the proposal is implementable and practical. Minimal extra public domain information is required for tariff setting and as the proposal mirrors the existing process, minimal changes to industry billing systems and tools would be needed;
- National Grid note that this proposal should improve stablility of tariffs for generation connected on spurs. Spur connected generation can see tariff step changes if background power flows on the spur reverse direction. However as spurs are generally built for demand security reasons, these power flows are likely to be more stable and greater in magnitude than the flows under the current methodology where local generation (generally intermittent) can offset local demand. Therefore the tariffs for spur connected generation should prove more stable.

Impact on other industry documents

If a particular technology is paying for TEC at a reduced, but more cost reflective, rate it does not appear appropriate that they should be able to trade between technology types or alternatively, that the difference in charging should be taken account for in the calculation of exchange rates. This is not specifically a charging issue, but a combination of SQSS and charging changes resulting in a potential change to a CUSC process. National Grid welcomes industry views on this.

7 Implementation

This proposal will be subject to the parallel SQSS intermittent generation review being accepted and that the review recommending that a pseudo CBA methodology is adopted to assess the CBA criteria. Assuming both the above, the implementation date of the modification is proposed to be the 1st April 2011, subject to the Authority not vetoing the proposal in accordance with the licence. The exact timetable for implementation will be agreed separately with the Authority. National Grid welcome views on the proposed implementation strategy.

8 Responses

Comments and views are invited on all of the issues raised in this consultation document. To ensure that your comments and views are considered, responses must be received by close of business on **23rd July 2010**. Responses will be considered public domain and published unless clearly indicated otherwise.

If you wish to provide comments on this consultation document, responses are preferred via email to: william.kirkwilson@uk.ngrid.com

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

Appendix 1 – Detailed explanation of the current methodology

This appendix explains in detail the process to derive nodal marginal costs, including simplifying assumptions and the consequent algorithm used for the DC Load Flow calculation(s) and the use of multi-voltage expansion factors in defining effective circuit length.

Calculation of nodal marginal costs using the Transport Model

The Transport Model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system, for a 1 MW injection to the system.

The Transport Model requires the following set of inputs representative of peak conditions on the transmission system:

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes
- The associated impedance (X) values of these circuits
- The associated lengths of these circuits, including the length of which is overhead line (OHL) or cable and their voltage level
- The ratio of each of 275kV OHL, 275kV cable and 400kV cable to 400V OHL costs, to give circuit expansion factors
- Routes with significant spare capacity (i.e. deemed to be under-utilised)
- Identification of a reference node.
- Identification of local circuits.

The nodal generation data for the Transport Model for charging year "t" is taken as the Transmission Export Capacity (TEC), at each node (based on the forecast for year "t" in the April Seven Year Statement in year "t-1" plus updates to the October of year "t-1"). The forecasts in the Seven Year Statement include all plant belonging to generators who have a Bilateral Connection Agreement or Bilateral Embedded Generation Agreement with National Grid.

Nodal demand data for the DCLF ICRP Transport Model for year "t" is based upon the GSP demand that DNOs have forecast to occur at the time of National Grid Peak Average Cold Spell (ACS) Demand for year "t" in the April Seven Year Statement for year "t-1" plus updates to the October of year "t-1".

Transmission routes for charging year "t" are defined as the existing wayleaves for the year "t" with the associated circuit lengths, impedance and voltage levels, indicated for year "t" in the April Seven Year Statement for year "t-1" plus updates to

October of year "t-1". If certain route information is not explicitly contained in the Seven Year Statement, National Grid will use the best information available.

The circuit lengths included in the Transport Model are solely those which relate to assets defined as 'infrastructure' assets i.e. for which use of system charges are levied.

The circuit expansion factor reflects the difference in cost between (i) cabled routes and overhead line routes, (ii) 275kV and 400kV routes and (iii) uses 400kV OHL as the base (i.e. 400kV OHL circuit expansion factor = 1). As the Transport Model expresses cost as marginal km (irrespective of nature of circuit), some account needs to be made of the fact that investment in these other types of circuit is more expensive than for 400kV OHL. This is done by effectively 'lengthening' these circuits by using the circuit expansion factor. This makes them more expensive for the model to use and hence reflects the additional costs of investing in these routes.

A reference node is required as a basis point for the calculation of marginal costs. It determines the magnitude of the marginal costs but not the relativity. For example, if the reference point were put in the North of the country, all nodal generation marginal costs would likely be negative. Conversely, if the reference point were defined at Land's End, all nodal generation marginal costs would be positive. However the relativity of costs between nodes would stay the same. When running the Transport Model, it defaults to automatically selecting the reference node to maximise the efficiency of the DCLF and is typically a central highly connected node (e.g. Grendon). However it can be “forced” to assume another GSPs, if a user so chooses.

The Transport Model takes the inputs described above and scales the nodal generation capacity uniformly such that total national generation equals total national ACS Demand. The model then uses the transport algorithm (described below) to derive the resultant pattern of power flows based on the network impedance and assuming no circuit limits. Then it calculates the resultant total network MWkm, using the relevant circuit expansion factors.

Using this optimal network, the model calculates for a given injection of 1MW of generation at each node and a corresponding 1MW offtake (demand) at the reference node, the increase or decrease in total MWkm of the whole network, from the resulting change in network power flows. For simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node. The marginal km cost for demand at each node is the equal and opposite of the nodal marginal km for generation. Note the marginal km costs can be positive or negative depending on the impact the injection of 1MW of generation has on the total route km.

Assumptions & calculations in the Transport Model’s DCLF algorithm

As explained above the Transport Model determines power flow on a defined network for a given market background using the impedance (X) values of the circuits comprising the network.

In addition to X, a comprehensive DC load flow study would fully take into account line resistance (R), and potential large variations in phase angles (theta) as well as considering the impact of running arrangements and contingencies.

Whilst the aim of using load flow techniques is to derive nodal marginal costs for charging purposes in a more cost reflective manner, it is recognised that it is important to retain an appropriate degree of model transparency and thus a suitable level of complexity. Also it is important to make the Transport Model relatively quick and easy to use for both internal NGC users and external customers who wish to undertake their own tariff modelling.

Hence, a number of simplifying assumptions were made in defining the “simple DCLF” algorithm, namely;

(i) security is not considered i.e. the network is treated as intact with the impact of contingencies not assessed

(ii) operational arrangements are not considered i.e. substations are run solid and line limits do not constrain power flows (this latter aspect is unlikely to be a factor at peak in any event)

(iii) R is assumed to be much smaller than X for each circuit on a per unit (pu) basis

(iv) The phase angles (theta) in radians are assumed to be small

Given the above assumptions, the power equation which forms the basis of the simple DCLF algorithm used in the Transport Model is;

P = theta/X

= theta * Y, where Y = 1/X

where;

P = power

Theta = phase angle

X = impedance

Given that the Transport Model models a multi-node network this becomes a matrix equation;

$\underline{P}$ = $\underline{\text{theta}}$ * $\underline{Y}$

where;

P = matrix of power injections (plus or minus) for all nodes

Theta = matrix of effective phase angles for all circuits connected to each node

Y = 1/X where X = matrix of impedance values for all circuits

The user provides the Transport Model with Y via the input of individual circuit impedance. P is also known via derivation from nodal generation and demand input data. Specifically the nodal power injection is calculated by subtracting scaled nodal generation, from nodal demand. Note that the total of the nodal P values should be zero given that generation has been scaled to exactly equal demand.

Hence the DCLF algorithm, solves for theta using the following equation;

$$\underline{\text{theta}} = \underline{Y(-1)} * \underline{P}$$

to derive the individual theta (phase angle) values for each node.

Given this calculation the algorithm then determines the network power flows by considering the following equation for any circuit connecting node M to node N;

$$\text{Power Flow}_{MN} = [\text{theta}_M - \text{theta}_N] * Y_{MN}, \text{ where } Y = 1/X_{MN}$$

In this way the algorithm derives the baseline power flows for the entire network. However because Y is a singular matrix, it can only be inverted by removing a row in the matrix. The algorithm removes the row that maximises the efficiency of the calculation, which should be that relating to the most interconnected node (unless forced to do an alternative specific node by the user) and this node is defined as the reference node, with its nodal theta set to zero.

This means there will be a very small, non-zero, total power flow when deriving nodal marginal costs. This does not affect the validity of the overall solution as long as the input data is correct. (Note the DCLF ICRP Transport Model contains a check to monitor and ensure this).

From this baseline of network power flows, circuit expansion factors are used as appropriate (see section above) to calculate the baseline system cost as measured in MWkm.

The algorithm then follows this identical process to derive consequent network power flows resulting from injecting 1MW of extra generation at a given node (balanced by 1MW of demand at the reference node) and the associated total system cost.

It is this new total system cost that is compared with the baseline system cost to derive the marginal cost (plus or minus, in MWkm) for that node.

Example of Simple DCLF Algorithm for a 3 Node Network

To illustrate the above, consider a 3 node example, consisting of nodes A, B and C with connections AB, AC and BC. The respective nodal power injections are P_A, P_B, P_C and the respective circuit impedance are X_{AB}, X_{AC} and X_{BC} such that the reciprocals are Y_{AB}, Y_{AC} and Y_{BC}. Also assume C is the reference node. Then;

$$\text{Power Flow}_{AB} = (\text{theta}_A - \text{theta}_B) * Y_{AB}$$

$$\text{Power Flow}_{AC} = (\text{theta}_A - \text{theta}_C) * Y_{AC}$$

$$\text{Power Flow}_{BC} = (\text{theta}_B - \text{theta}_C) * Y_{BC}$$

And;

$$P_A = \text{Power Flow}_{AB} + \text{Power Flow}_{AC}$$

$= [(\text{theta}_A - \text{theta}_B) * Y_{AB}] + [(\text{theta}_A - \text{theta}_C) * Y_{AC}]$

$P_B = -\text{Power Flow}_{AB} + \text{Power Flow}_{BC}$

$= [-(\text{theta}_A - \text{theta}_B) * Y_{AB}] + [(\text{theta}_B - \text{theta}_C) * Y_{BC}]$

$P_C = -\text{Power Flow}_{AC} - \text{Power Flow}_{BC}$

$= [(\text{theta}_A - \text{theta}_C) * Y_{AC}] + [(\text{theta}_B - \text{theta}_C) * Y_{BC}]$

Therefore this can be represented as;

$$\begin{pmatrix} P_A \\ P_B \\ P_C \end{pmatrix} = \begin{pmatrix} Y_{AB}+Y_{AC} & -Y_{AB} & -Y_{AC} \\ -Y_{AB} & Y_{BC}+Y_{AB} & -Y_{BC} \\ -Y_{AC} & -Y_{BC} & Y_{AC}+Y_{BC} \end{pmatrix} \text{x} \begin{pmatrix} \textbf{theta}_A \\ \textbf{theta}_B \\ \textbf{theta}_C \end{pmatrix}$$

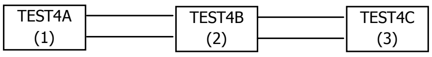
We already know Y_{AB}, Y_{AC} and Y_{BC} (derived from the reciprocals of X_{AB}, X_{AC} and X_{BC}) as well as P_A, P_B and P_C via derivation from the net sum of scaled generation and demand at each node. Hence using matrix inversion you can solve for theta_A, theta_B and theta_C.

Hence the Power Flows for AB, AC and BC can be derived for the baseline and, given effective circuit lengths, the baseline total system cost in MWkm.

To derive the nodal marginal cost for A, add 1MW of power injection at A and a balancing 1MW of demand at the reference node C, resolve for the power flow using the above process and derive a new total system cost in MWkm. The difference between this new total system cost and the baseline total system cost determines the nodal marginal cost at A. Repeating this for B and C derives their nodal marginal costs, although obviously as the reference node C will have a marginal cost of zero (since 1MW of generation and demand is added at the same node and thus cancel)

Appendix 2 – Worked example of the current methodology

Calculating the powerflows down the lines between the nodes



Input Data - Nodal data

	Generation	Demand	Units		Generation	Demand	Units
TEST4A	0	100	MW		0	1	
TEST4B	0	0	MW	Converting to PU →	0	0	
TEST4C	100	0	MW		1	0	

assuming generation is +ve, power vector is:
* note PU standards for Per Units
* note it is standard to use a power base of 100MW, therefore divide by 100
* note the power vector is called Bus transfer in the transport model

$$\begin{pmatrix}-1\\0\\1\end{pmatrix}$$

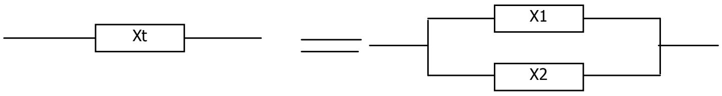
Input Data - Circuit data

		R	X	units		R	X	units
TEST4A	TEST4B	0.1	1	% on 100MVA base	Converting to PU →	0.001	0.01	in pu
TEST4A	TEST4B	0.1	1	% on 100MVA base		0.001	0.01	in pu
TEST4B	TEST4C	0.2	2	% on 100MVA base		0.002	0.02	in pu
TEST4B	TEST4C	0.2	2	% on 100MVA base		0.002	0.02	in pu

Converting into admittances (Y= 1/X) - *Ignoring R*

100
100
50
50

As $1/X_t = 1/X_1 + 1/X_2$, where:



Therefore:

Y_{21} 200
Y_{23} 100

Using DC type analysis assumptions the equation to calculate the loadflow becomes:
* note in the transport model θ is called VAng (short for Voltage Angle)

$$\Delta P = Y\Delta\theta$$

We have two nodal connections therefore 2 equations

$$P_{21} = 200*(\theta_2-\theta_1)$$
$$P_{23} = 100*(\theta_2-\theta_3)$$

By inspection we know the power flowing along P_{21} is 100MW (or 1in PU) as that is the power flowing out of node 1 (TEST4A)
Further we also know that P_{23} is -100MW (or -1PU) as that is the power flowing out of node 3 (TEST4C)
Finally we will make θ_1 the reference node (i.e. $\theta_1 = 0$)

Therefore the simultaneous equations become:

$$1 = 200*\theta_2$$
$$\theta_2 = 0.005 \text{ radians}$$

$$-1 = 100*(\theta_2-\theta_3)$$
$$\theta_3 = 0.015 \text{ radians}$$

Therefore

$$\theta_1 = 0 \text{ radians}$$
$$\theta_2 = 0.005 \text{ radians}$$
$$\theta_3 = 0.015 \text{ radians}$$

To calculate the powerflows along individual lines substitute θ back into

$$\Delta P = Y\Delta\theta$$

		Y (in pu)	Powerflow (in pu)	Converting back into MW
TEST4A	TEST4B	100	-0.5	50
TEST4A	TEST4B	100	-0.5	50
TEST4B	TEST4C	50	-0.5	50
TEST4B	TEST4C	50	-0.5	50

* note the negative powerflow indicates the power is flowing from node 2 to node 1.
* note to calculate the lineloss, square the line flow, multiply by resistance (R) then divide by 10,000
However line loss is not used anywhere, so ignored in this example.

Now to calculate the above using matrices (and then also calculate the marginal km):

Since this method for calculating a loadflow is an APPROXIMATION, it is not going to solve exactly.
What this means is that for big matrices, if you sum the MW into the network and the MW coming out of the network they will not = 0. Therefore we will call this mismatch 0 and take it off at the reference node.
Therefore we will NOT write any power equations and solve them for the reference node.
However for the example below I will write them and then delete them before solving.

As before:

$\Delta P = Y \Delta \theta$

Therefore

$\sum P_1 = -P_{21} + \text{mismatch}$
$\sum P_2 = P_{21} + P_{23}$
$\sum P_3 = -P_{23}$

Expanding this out (as before!)

$$
\begin{array}{llll}
P_1 = & -200*(\theta_2-\theta_1) & = & -200*\theta_2 + \text{mismatch} \\
P_2 = & 200*(\theta_2-\theta_1)+100*(\theta_2-\theta_3) & = & (200+100)*\theta_2-100*\theta_3 \\
P_3 = & -100*(\theta_2-\theta_3) & = & -100*\theta_2+100*\theta_3
\end{array}
$$

Writing this as matrices:
* note Y is referred to as the admittance matrix
* note admittance matrix is SYMMETRICAL AND SPARSE

$$
\begin{array}{cccc}
\Delta P & = & Y & * \quad \Delta\theta \\
\begin{pmatrix} -1+\text{mismatch} \\ 0 \\ 1 \end{pmatrix} & = & \begin{pmatrix} 200 & -200 & 0 \\ -200 & 300 & -100 \\ 0 & -100 & 100 \end{pmatrix} & \begin{pmatrix} \theta_1 \\ \theta_2 \\ \theta_3 \end{pmatrix}
\end{array}
$$

However as before $\theta_1 = 0$ and removing row for reference node.

$$
\begin{array}{cccc}
\Delta P & = & Y & * \quad \Delta\theta \\
\begin{pmatrix} 0 \\ 1 \end{pmatrix} & = & \begin{pmatrix} 300 & -100 \\ -100 & 100 \end{pmatrix} & \begin{pmatrix} \theta_2 \\ \theta_3 \end{pmatrix}
\end{array}
$$

Solving for θ

$$Y^{-1} * \Delta P = \Delta\theta$$

Inverting admittance matrix (Y)
* note DCLF uses clever matrix manipulation to reverse matrix as it is necessary to invert an n by n matrix where n is the number of nodes in the system. This is computationally hard therefore the dclf uses clever matrix manipulation to solve.

determinant= 0.00005

$$
\begin{array}{cc}
100 & 100 \\
100 & 300
\end{array}
$$

$$
Y^{-1} = \begin{pmatrix} 0.005 & 0.005 \\ 0.005 & 0.015 \end{pmatrix}
$$

Therefore

$$
\begin{array}{cccc}
Y^{-1} * & \Delta P & = & \Delta\theta \\
\begin{pmatrix} 0.005 & 0.005 \\ 0.005 & 0.015 \end{pmatrix} & \begin{pmatrix} 0 \\ 1 \end{pmatrix} & & \begin{pmatrix} \theta_2 \\ \theta_3 \end{pmatrix}
\end{array}
$$

Therefore same answer as before:

$\theta_1 = 0$ radians
$\theta_2 = 0.005$ radians
$\theta_3 = 0.015$ radians

However now you have inverted the admittance matrix, you can inject any power into P and see how it affects θ and hence calculate the effect on the power flows. The DCLF goes through every row in the P matrix, injecting 1MW (which will come off at the reference node as it will be seen as a mismatch). It then calculates the resulting incremental flows and hence the MWkm for the node.

To calculate the MWkm at node 2

* note that this method would be then be used on every other node in the model.

Inject 1MW at node 2

(converting 1MW into PU = /100)

$$\begin{array}{cccc} Y^{-1} * & \Delta P & = & \Delta\theta \\ \begin{pmatrix} 0.005 & 0.005 \\ 0.005 & 0.015 \end{pmatrix} & \begin{pmatrix} 0.01 \\ 0 \end{pmatrix} & & \begin{pmatrix} \; \\ \; \end{pmatrix} \end{array}$$

θ_1 = 0 radians

θ_2 = 0.00005 radians

θ_3 = 0.00005 radians

Therefore calculating the powerflows along individual lines substitute θ back into

$\Delta P = Y \Delta\theta$

		Y (in pu)	Powerflow (in pu)	Powerflow (in MW)
TEST4A	TEST4B	100	-0.005	0.5
TEST4A	TEST4B	100	-0.005	0.5
TEST4B	TEST4C	50	0	0
TEST4B	TEST4C	50	0	0

Therefore calculating the MWkm/MW of the line, multiply the lengths by the appropriate expansion constant.

Expansion constants from transport model

Expansion Constant Parameters				
Projected Relative Cost	**Pure GB**	**NGC**	**SP**	**SSE**
400kV cable factor		22.390	22.390	22.390
275kV cable factor		22.394	22.394	22.394
132kV cable factor		30.220	30.220	27.790
400kV line factor		1.000	1.000	1.000
275kV line factor		1.137	1.137	1.137
132kV line factor		2.796	2.796	2.238

		OHL length	Cable lengt	TO region	Cct flow "cost"/MW
TEST4A	TEST4B	10	0	NGC	10
TEST4A	TEST4B	10	0	NGC	10
TEST4B	TEST4C	20	0	SP	20
TEST4B	TEST4C	20	0	SP	20

* note that the voltage is derived from the 5th character of the node (here 4)

* note 4 = 400, 2 = 275, 1 = 132

Therefore to calculate the MWkm of the node, multiply the power flow on the line, by the cct flow cost then sum over all the lines

		MWkm
TEST4A	TEST4B	5
TEST4A	TEST4B	5
TEST4B	TEST4C	0
TEST4B	TEST4C	0
	Total, MWkm at Node 2 =	10

To calculate the MWkm at node 3

$$\begin{array}{cccc} Y^{-1} * & \Delta P & = & \Delta\theta \\ \begin{pmatrix} 0.005 & 0.005 \\ 0.005 & 0.015 \end{pmatrix} & \begin{pmatrix} 0 \\ 0.01 \end{pmatrix} & & \begin{pmatrix} \; \\ \; \end{pmatrix} \end{array}$$

θ_1 = 0 radians

θ_2 = 0.00005 radians

θ_3 = 0.00015 radians

Therefore calculating the powerflows along individual lines substitute θ back into

$\Delta P = Y \Delta\theta$

		Y (in pu)	Powerflow (in pu)	Powerflow (in MW)
TEST4A	TEST4B	100	-0.005	0.5
TEST4A	TEST4B	100	-0.005	0.5
TEST4B	TEST4C	50	-0.005	0.5
TEST4B	TEST4C	50	-0.005	0.5

		MWkm
TEST4A	TEST4B	5
TEST4A	TEST4B	5
TEST4B	TEST4C	10
TEST4B	TEST4C	10
	Total, MWkm at Node 3 =	30

Therefore MWkm for network is

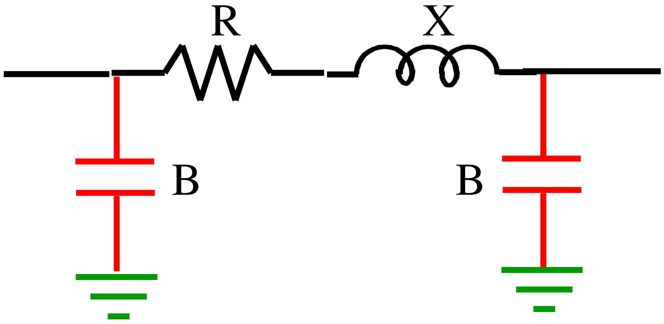
$$\begin{array}{l} \text{TEST4A} \\ \text{TEST4B} \\ \text{TEST4C} \end{array} \qquad \begin{pmatrix} 0 \\ 10 \\ 30 \end{pmatrix}$$

Appendix 3 – Assumptions underpinning DC analysis

The following assumptions are used to turn AC equations (assuming a basic pi circuit model) governing power flow down lines into what is termed DC equations:

1. Neglect reactive power flow,
2. Ignore resistance and susceptance of circuit branches,
3. Assume a flat voltage profile (ie all voltages are 1.0),
4. Assume all voltage angles are small,
5. Ignore losses.

Assuming a basic pi circuit model:



The power flow between nodes can be written as:

$$P_k^I - \sum_{i=1}^{N} V_k V_i [G_{ki} \cos(\theta_k - \theta_i) + B_{ki} \sin(\theta_k - \theta_i)] = 0$$

$$Q_k^I - \sum_{i=1}^{N} V_k V_i [G_{ki} \sin(\theta_k - \theta_i) - B_{ki} \cos(\theta_k - \theta_i)] = 0$$

Ignoring reactive power and neglect R, this becomes:

$$P_k^I - \sum_{i=1}^{N} V_k V_i B_{ki} \sin(\theta_k - \theta_i) = 0$$

Assume a flat voltage profile:

$$P_k^I - \sum_{i=1}^{N} B_{ki} \sin(\theta_k - \theta_i) = 0$$

Assume all angles differences are small:

$$P_{ki} = \frac{(\theta_k - \theta_i)}{x_{ki}}$$

The above power flow equation is solved in the DCLF and is referred to as a DC load flow.

Appendix 4 – Forecast impact to 2010/11 TNUoS generation tariffs

£/kW		2010/11 FINAL	New methodology	
Zone No.	Zone Name	Current	Conventional	Intermittent
1	North Scotland	20.08	20.67	14.78
2	Peterhead	18.71	19.14	
3	Western Highland & Skye	22.79	21.12	15.85
4	Central Highlands	17.63	16.91	12.92
5	Argyll	13.34	13.66	11.94
6	Stirlingshire	13.44	13.89	9.26
7	South Scotland	12.49	13.04	9.11
8	Auchencrosh	10.91	11.24	9.27
9	Humber & Lancashire	5.42	6.01	5.19
10	North East England	8.79	9.60	
11	Anglesey	6.17	6.71	
12	Dinorwig	5.50	6.04	
13	South Yorks & North Wales	3.59	4.06	2.18
14	Midlands	1.56	1.95	1.95
15	South Wales & Gloucester	0.39	0.78	
16	Central London	-6.41	-6.64	
17	South East	0.81	0.53	-0.24
18	Oxon & South Coast	-1.36	-1.30	
19	Wessex	-2.64	-2.72	
20	Peninsula	-5.87	-4.69	