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Your Ref:
Our Ref:
Direct Dial: 020 7901 7009
Email: stuart.cook@ofgem.gov.uk

Date: 27 February 2009

Dear Colleague

Transmission Access Review – Enhanced Transmission Investment Incentives Open Letter: Consultation on Short Term Measures

Notice under Section 11(2) of the Electricity Act 1989 of proposed modification of electricity transmission licences held by National Grid Electricity Transmission plc, SP Transmission Ltd and Scottish Hydro Electric Transmission Ltd

Purpose

The purpose of this Notice under Section 11(2) of the Electricity Act 1989 ("the Act") is to propose modifications to the transmission licences of National Grid Electricity Transmission plc (NGET), SP Transmission Ltd (SPTL) and Scottish Hydro Electric Transmission Ltd (SHETL) to insert additional provisions to enable recovery of certain pre-construction costs.

In summary, the effect of the proposed licence modifications is to introduce provisions which will enable the Licensees to recover expenditure for particular pre-construction activities associated with transmission reinforcement works for the financial year running from 1 April 2009 to 31 March 2010.

The provisions also specify the level of funding to be provided for the identified activities for the respective licensee. We propose to provide pre-construction funding for £10 million to NGET and £2.5 million to SPTL in respect of their respective project nominations. While SHETL has not requested ant pre-construction funding under the short term measures, we propose to incorporate the generic provisions into its licence for consistency with the other licensees.

Further detail on the reasons for the proposed modifications and project nominations is set out below. Any representations or objections to the proposed modifications should be made in writing on or before 27 March 2009.

Background

Through the Transmission Access Review (TAR) project we and the Department for Energy and Climate Change (DECC) are working with industry to support the government's 2020 climate change targets. The TAR project commenced following the publication of the Energy White Paper in May 2007 which asked Ofgem and Department for Business, Enterprise & Regulatory Reform (BERR; now DECC) to review the present technical, commercial and regulatory framework for the delivery of new transmission infrastructure and the management of the grid. The motivation for the review was to ensure that the grid arrangements remain fit for purpose as the proportion of renewable generation on the system grows[1]. TAR is intended to help remove the barriers to access to the transmission system faced by generators, including renewable and low carbon.

The TAR final report, published in June 2008, set out a package of measures that are targeted at helping facilitate the 2020 targets, by reducing or removing grid-related access barriers to connecting new generation. This is important in achieving the UK share of the 2020 EU renewable energy targets. The TAR package includes individual workstrands targeted at helping facilitate the achievement of the 2020 targets; designing an efficient and enduring solution to transmission access; and speeding up connections in the short term before the other arrangements are in place through GB Queue management and an interim form of "connect and manage".

The TAR final report noted that potentially long lead times for expanding transmission capacity could prevent Great Britain from meeting its renewable energy targets. In addition to the considerable work currently being undertaken in relation to the transmission access arrangements, the planning and development of new grid infrastructure also needs to be accelerated if we are to reach our targets.

To address the investment planning challenges, we concluded that two major workstrands should be initiated:

1. 2020 Transmission System Study - we asked the three electricity transmission asset owners (TOs), NGET, SPTL and SHETL to explore what the transmission system would need to look like to meet the 2020 targets and what investment would be required; we invited the Energy Networks Strategy group (ENSG) to provide a critical review of this study; and

2. Enhanced TO Incentives - to develop new financial incentives for the transmission companies to help deliver the necessary investment in a timely manner without exposing customers to excessive risk and/or inefficient costs.

These workstrands are ultimately complementary in nature, as the 2020 Transmission System Study (the "Transmission System Study") is an important vehicle in setting out the potential range of projects and their costs, to help information Ofgem and DECC of the regulatory issues that may arise in delivering a system fit for purpose in 2020. The Transmission System Study will shortly be published by the ENSG. The Enhanced TO

[1] For more information on TAR please visit the following link:
http://www.ofgem.gov.uk/NETWORKS/TRANS/ELECTRANSPOLICY/TAR/Pages/Traccrw.aspx

Incentives workstrand is being developed by Ofgem, and will serve to provide the appropriate funding framing for delivering successful anticipatory investment.

December consultation

On 19 December 2009, we published our initial consultation on TO Incentives (referred to as the "December consultation"), detailing a range of options for both short term measures and our indicative thinking on the appropriate framework for anticipatory investment.

Our December consultation represented the first step in our consultation process to take forward our work on TO incentives. It discussed the current funding arrangements for transmission investment and explained why we consider change is needed now to provide a framework for anticipatory investment, in order to address the challenges of meeting the 2020 targets.

In this context we referred to the initial findings of the ENSG 2020 Transmission Investment Study, referred to above, which had identified a large number of major transmission system projects that may be necessary to increase capacity and reinforce the system to ensure the system has sufficient capacity to meet the needs of new conventional and renewable generation. The transmission companies had forecast that the combined costs of these projects could be around £6 billion, in addition to the £4 billion of investment in new capacity and asset replacement allowed in the current electricity transmission price control that runs until 2012. We highlighted that the current framework, under which the TOs invest based on user commitment, may create a barrier to progressing investment in a timely manner, given the lead times for investment. We also noted it is important that high priority projects are not delayed through failure to invest in a timely way and equally that customers are protected form the risk of stranded investment.

We stated that in taking forward our work on TO incentives the first step is to consider the extent to which the existing funding arrangements may create barriers to investing ahead of need, and to take appropriate steps to address such barriers as soon as possible. The next step is to provide the right incentives on the TOs to make the decision to undertake investment ahead of need where it is more efficient to do so.

The consultation discussed a range of issues that need to be considered in developing a framework for anticipatory investment, which we suggested could be characterised as decisions based on anticipated (rather than actual contracted) demands from users. Building upon initial proposals we had received from the TOs, we considered a range of impediments to anticipatory investment and options for the design of an incentive mechanism with appropriate risk/reward options and efficiency tests. We noted that there is a broad spectrum of possible approaches to designing such an incentive mechanism.

We identified scope for short term work to address immediate barriers to investment, primarily associated with pre-works funding, which we proposed to implement by Spring 2009. We invited nominations from the transmission companies of projects for consideration as part of the proposed short term measures. We also proposed to consider, through further consultation later in 2009, whether further measures can be introduced by Winter 2009 to facilitate additional investments that could commence during the current transmission price control period which runs until 31 March 2012.

Having considered the issues raised by respondents to our December consultation, and the project nominations submitted by the TOs, which we discuss below, we remain of the view that it would be appropriate to put in place short term measures to address current barriers for specific projects.

The remainder of this open letter focuses on our proposed way forward for the short term measures, following on from the December consultation. For the reasons set out below, we propose to confine the short term measures, at this stage, to providing funding for pre-construction costs in 2009/10 for specific projects, for implementation in April 2009.

However, our work on TO incentives is ongoing and we also set out below how we propose to take forward further work in this area throughout 2009 including an update on our proposed consultation process towards potential implementation of further measures in Winter 2009.

Short term measures – options for pre-construction costs

At the time of the December consultation, the transmission companies argued there would be real benefit if they were able to conduct pre-construction works for certain projects that they expect to start work on in the near future, and if they were able to invest earlier to undertake feasibility studies and route investigations (in the case of new transmission lines). Whilst in some cases this would only reduce investment timescales by a few months, for certain large investment projects, the ability to conduct pre-construction works early could result in significant reductions in the timescale for completion of the project, with a consequential impact on the connection timescales for generation projects contingent on the completion of the transmission works.

In our December consultation, we stated that in the short term there are two potential approaches for providing earlier entitlement for pre-construction costs for specific projects, as follows:

- **A mixture of pass-through and incentivisation.** This approach is essentially the same approach as that adopted for the current baseline capital expenditure allowance. Our initial thought was that a mechanism that combined pass-through and incentivisation elements would benefit from being consistent with the incentive effect of the other provisions of the revenue drivers, and as such could be in the form of 75% pass through and 25% incentivisation. The incentive part of this approach would require Ofgem setting the allowed costs *ex-ante*.

- **A "logging-up" treatment.** Under this option, the TOs would undertake pre-construction works without explicit *ex-ante* funding under the current price control. Expenditure would be "logged-up" and assessed at the end of the current price control period. Efficient spend would be remunerated from the beginning of the next price control, i.e. April 2012. This approach would not need an *ex-ante* assessment of efficient costs. However, compared to the option above, there may be concerns that the approach will only provide relatively weak efficiency incentives and/or create a perception of regulatory funding certainty. It is also possible that the mechanism may put company finances under strain.

TOs' responses to the December consultation

Following publication of our December consultation, we have been working closely with the TOs to understand the practical measures that can be put in place relatively quickly such that those projects that have been identified by the TOs are subject to an appropriate funding regime.

NGET Response

NGET expressed its support for Ofgem's proposed approach to split the work between short term and longer term work, noting the importance of conducting pre-construction works on a range of candidate projects. NGET also expressed a need for policy steer from Ofgem in relation to the deliverables of the project, the links to the Transmission System Study, and noted its lack of support for a competitive approach for the provision of certain transmission projects.

NGET stated that Ofgem should set the size of the allowances and the broad deliverables at the outset for the range of projects set out in the Transmission System Study. It pointed to the work of the ENSG in helping to provide a degree of scrutiny for the projects that were identified, and considered this may help to provide reassurance that the costs were reasonable, in the absence of a full regulatory assessment.

It pointed to the ENSG process of exploring the costs and benefits of various projects helping to mitigate the risk of potentially lower levels of financial scrutiny relative to a traditional price control.

NGET identified a range of projects which they consider to be on the critical path for 2020, and set out a range of pre-construction costs items for these projects, summing to £10 million in financial year 2009/10.

NGET considers that the short term aim of the TO Incentives work should be to ensure that the programme of work to reinforce the network is on track to meet the 2020 targets, whilst maintaining a focussed delivery process. NGET further commented that an aspiration of the work should be for the enduring incentives to be finalised as quickly as possible.

SPTL Response

SPTL stated that it was willing to take on more investment risk to earn a commensurate level of return, but reiterated the need to be cautious given the current financial crisis and difficulties associated with the planning consent process. SPTL also stated that it was important to ensure that any proposal would result in a better deal to consumers.

SPTL identified a requirement for around £2.5 million of additional pre-construction funding for the Western HVDV link in financial year 2009/10. Based on the anticipated lead time, SPTL considers (and NGET concurs) that there is a need for pre-construction works to begin this year. SPTL stated that additional pre-construction funding should be provided as full pass through given the uncertainty associated with *ex-ante* forecasting for a relatively unusual project. SPTL stated that the potential regulatory concerns over full pass-through would be mitigated by the provision for a full *ex-post* efficiency review.

SHETL Response

SHETL's response to the December consultation focused primarily on the short term measures. They committed to providing Ofgem with a further submission on the appropriate incentive framework in due course. A key feature of SHETL's response was the need to ensure that the revenue driver mechanisms specifically for the deep reinforcement projects are better able to provide for anticipatory investment. SHETL therefore proposed to change the existing revenue driver triggers from being based on connected generation to contracted generation.

SHETL also focussed on the importance of clarifying the definition of pre-construction and construction works. There is no clear definition of these terms in the licence, although it could be argued that the break point between the two stages of a project's life is implicit.

Although SHETL has not identified any areas where additional pre-construction funding should be provided, its favoured position would be for pre-construction funding to be provided on equivalent terms to the baseline mechanism, and for it to be logged up until 2012, and thereafter assessed for efficiency before entering the Regulatory Asset Value (RAV).

Other responses to the December consultation

We received a number of responses to the December consultation, all of which are available on Ofgem's website. Respondents are generally in favour of a more strategic approach to transmission investment, and are very supportive of our proposed approach to taking forward our work on transmission investment incentives. Many are keen to see progress on short term measures by April 2009, consistent with the commitment originally set out in the TAR Final Report, while also agreeing that a longer timescale is appropriate for further measures. Respondents are also keen to see this work being integrated with a long term investment study, such as the 2020 investment study overseen by the ENSG.

Respondents do not envisage a need for further debate on barriers or impediments prior to taking forward short term measures. Some respondents are keen to see measures for construction works as well as pre-construction works, for projects where bringing work forward will allow generators to connect earlier, but think this needs strong regulatory oversight.

Respondents to the December consultation have also raised a number of issues relevant to our ongoing work on further measures, which will be discussed in more detail in a future document.

Project Nominations

We have already allowed a considerable amount of funding in the baseline price control allowance for all three TOs.

For example, although SHETL has not identified any areas where additional funding should be provided, our Transmission Price Control Review 2007-12 (TPCR4) pre-construction allowance already covers a broad range of costs.

However, in the process of taking forward the Transmission System Study, NGET and SPTL have both made the case to Ofgem that additional transmission investment projects have been identified, for which pre-construction funding has not been provided. In addition, other projects that currently have funding may require such funding to be made available earlier than anticipated.

Given the existing revenue driver provisions have the ability to remunerate additional spending in the event that the underlying generation connection and boundary flow patterns deviate from what was assumed in TPCR4, any funding mechanism for the project nominations proposed by the TOs needs to avoid the potential for double counting. Similarly where pre-construction funding is being advanced for specific projects that already have funding provisions in the existing revenue driver mechanisms, any advanced expenditure for pre-construction will need to be netted off from the remaining revenue driver allowances.

Project nominations and the Transmission System Study

The ENSG 2020 investment study has identified potential reinforcements to support connection of new generation in each of its areas of investigation, giving estimated total costs and completion timescales for those reinforcements. Taking into account uncertainty as to the volume and timing of new generation connections, and the degree of interaction between some of the reinforcements, the study highlights those reinforcements which the TOs consider are most likely to be required, and on which they consider work should start now. Further reinforcements are also identified for potential consideration in the future. The classification of the reinforcements has been supported by cost-benefit analysis based on the application of the current GB Security and Quality of Supply Standard (SQSS) and against the background of forecast constraint cost avoidance based on historical information. These projects will be kept under review as the generation pattern develops and to take account of the outcome of TAR and the GB SQSS review.

The ENSG report emphasises that due to many of the reinforcements adopting novel solutions and new technologies there is a need for early pre-engineering work to consider how best to integrate these reinforcements with the existing transmission network. The use of novel approaches means that the total costs (including the portion of those costs relating to pre-construction costs) are difficult to estimate until certain pre-engineering works are undertaken. In addition, the report notes that as part of the pre-construction works, the TOs intend to submit planning applications ahead of user commitment from any individual generators. The proposed rationale for starting now on pre-engineering works is therefore to both retain the ability to deliver the projects to the required timescales, taking into account the lead time required to develop robust engineering solutions and to obtain the necessary planning consents, and also to provide a basis for a more detailed estimate of project costs.

In our recent discussions with the TOs we have been clear that whilst the Transmission System Study is an important input to our work to develop an understanding of the future challenges that the networks face, it does not replace the TOs' 'business as usual' activity in terms of undertaking transmission system reinforcement works. We have therefore sought additional information from the TOs in relation to the needs-case for the specific projects that have been identified as requiring additional funding. We have focused on projects for which pre-construction works are due to commence in 2009/10. We asked NGET and SPTL to provide a list of which projects they consider require additional or earlier funding, and to provide details of the need case for such projects and the timetable over which costs are expected to be incurred.

The project nominations received from the TOs are those identified in the 2020 investment study for which they consider pre-construction works should start immediately in order to retain the widest range of future network options. As part of these nominations the TOs have provided cost information for these projects broken down by year and between pre-construction and construction costs. We have also asked the TOs to provide a detailed breakdown of costs for 2009/10 into specific pre-construction activities.

Drawing on this information, we have been able to identify which projects already have pre-construction and construction funding, the mechanism by which this funding has been provided, where there are gaps in the funding arrangements, and the timetable for expenditure on these projects.

In going through this process, we have identified and prioritised with the TOs a list of projects for which changes in the funding arrangements should be delivered by 1 April 2009. We have focused on projects where there is an imminent need to begin pre-construction work. The information we received from the TOs in response to our request for project nominations is provided in Annexes 5 and 6 and summarised below. In total, the combined cost of pre-construction works is around £12.5 million. As mentioned previously, SHETL has not identified any further requirement for pre-construction funding. The £12.5 million is split between £10 million for NGET and £2.5 million for SPTL.

NGET Project Nominations

NGET has identified the following investments that it considers should receive additional funding for pre-construction costs, with a combined total cost of around £10 million in 2009/10:

- Incremental works;
- Western HVDC link;
- Eastern HVDC link;
- North Wales;
- Humberside;
- East Anglia;
- South West;
- London, and
- Mid Wales.

SPTL Project Nominations

SPTL has requested pre-construction funding in relation to the Western HVDC link, with a total cost of £2.5 million in 2009/10. This includes SPTL's share of works which are shared with NGET, the remaining costs being included in NGET's submission.

SHETL Project Nominations

SHETL has not submitted any request for additional funding for pre-construction works, on the basis that the company already had sufficient funding under the current arrangements to progress necessary pre-construction works.

However, SHETL has nominated the following investments for consideration for construction (as opposed to pre-construction) work, with associated cost estimates:

- Knocknagael: new substation (£6 million in 2009/10);
- Western Isles: new HVDC link (£12 million in 2009/10);
- Beauly-Dounreay: second conductor and substation (£1 million in 2009/10), and
- Beauly-Blackhillock-Kintore: reconductor (£12 million in 2009/10).

The four projects listed above, summing to £31 million, have been identified by SHETL as likely to proceed to construction works in financial year 2009/10. Only the Western Isles project does not have provision under the existing transmission price control settlement for construction costs. However, SHETL stated that the existing revenue driver provisions, which would fund these projects (although the Western Isles was not included in the consideration of the design of the deep revenue drivers), are designed to remunerate investment expenditure in the event that generation connects, and were not designed to provide such funding on an anticipatory basis. SHETL considers that there is sufficient evidence that the above four projects will either be justified by the contracted background now or at some point in the near future, and intends to begin construction works this year. However, this would mean that the revenue driver triggers, which are designed to protect customers from inefficient investment in the event that the assets are not used or are under-used, would need to be amended to allow the TOs to build before a clear need case, in user commitment terms, has arisen.

SHETL has therefore proposed further development of the current deep revenue drivers to provide more clarity on the split between construction and pre-construction works and on the operation of the current trigger conditions. SHETL has also set out proposals to introduce an economic needs-case test to allow commencement of construction in advance of those trigger conditions being met. However, we consider that the proposed changes will be significant and will require considerably more time and resources than we have available prior to 1 April 2009. We are therefore proposing that such issues are progressed following implementation of the proposals set out in this open letter and section 11 notice, and will be considered as part of our next document on TO Incentives.

Ofgem's proposals for short term measures

In coming to our final proposals in relation to short term measures, we have identified, and worked through the consequences of a range of different approaches, which we set out below. The different approaches relate to:

- The scope of the short-term measures;
- Whether the investment is treated as opex or capex for funding purposes, and
- Whether funding allowances are set *ex-ante* or agreed *ex-post*.

Each of these points is discussed in more detail below.

For the avoidance of doubt, the conclusions that we reach for the revised treatment of pre-construction costs for the defined set of projects listed in this document should not create any expectation of the treatment of either the construction costs of these projects or the pre-construction or construction costs of other projects.

Issue 1 - Scope

Having considered the issues raised by respondents and the project nominations submitted by the TOs, we remain of the view that it would be appropriate to put in place short term measures to address current barriers to specific projects. We have considered the following options for the scope of the short term measures:

- Make provision for funding for pre-construction costs for specific projects;
- Introduce clear delineation of pre-construction and construction costs, and
- Clarify trigger conditions for construction costs under deep revenue drivers.

Given the timetable for the provision of robust information on construction works and the effort required for redefinitions of pre-construction and construction costs, we and the TOs believe that the greatest immediate benefit would be derived from focussing on developing the appropriate regime for pre-construction costs.

In our December document we set out two options in terms of the scope of funding for pre-construction costs:

- **Option 1 (2009/10)** – under this option the short term measures would be focussed on the costs of specific activities incurred in 2009/10 only; or
- **Option 2 (total pre-construction costs)** – where the focus would be on the full cost of pre-construction activities for the relevant projects.

Ofgem's proposal on Scope

Recognising the objectives of the short term measures, we consider that our key area of focus at this point in time should be on developing a simple, pragmatic approach to providing additional funding for the pre-construction costs associated with identified projects, noting that any measures introduced in the short term can potentially be further developed as part of ongoing work.

By focusing on the initial, pre-construction expenditure without making a commitment to fund further investment, our proposals will keep open a range of options at relatively modest cost whilst avoiding the potential for making sub-optimal decisions about the future funding of construction costs. We consider this is important, particularly in the light of the uncertainty surrounding the nature of the future electricity network. This approach is consistent with the findings of our work on Long-term Electricity Networks Scenarios (LENS)[2]. One of the key findings from the LENS project is that there is a wide range of potential future scenarios for GB electricity networks. We consider that it is important that decisions do not inadvertently "close-off" options for the evolution of electricity networks. By focusing on the initial, pre-construction expenditure without making a commitment to fund further investment, our proposals will keep open a range of options whilst allowing the flexibility to respond to future needs.

[2] For more information please visit the relevant section of our website at: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/lens/Pages/lens.aspx

Similarly, it may be difficult at this stage to agree an appropriate allowance for the total pre-construction costs for a given project (under Option 2 above) given that, as noted above, some elements - whether in terms of the activities to be undertaken or their associated costs - will only become clearer once some initial pre-engineering works are undertaken. Option 1 therefore has the further benefit of providing short term funding for specific activities which are reasonably well defined and known to be required at this stage, and will also put the TOs in a position to provide a more detailed needs-case and cost assessment for our further consideration in the next stage of the TO incentives work.

In the light of the arguments set out above, we are proposing to adopt Option 1, in other words to make provisions in relation to pre-construction costs for 2009/10 only.

Issue 2 - Opex or capex treatment

There are two potential approaches to addressing the funding of pre-construction activities:

- **Option A (capex treatment)** – under this option, the investment would be funded as capex and recovered over the relevant life of the assets, and
- **Option B (opex treatment)** – where the expenditure would be treated as opex, resulting in an immediate adjustment to allowed revenue which is equal to the full amount of the investment.

The TOs have indicated a preference for Option B (opex treatment) under Option 1 (2009/10). They consider this is appropriate because the relevant costs are limited in scope and have a relatively low materiality. They also consider this approach would simplify the design of the recovery mechanism because we would not need to address (at this stage) potential interactions with financing costs or with construction costs.

Ofgem's proposal on opex or capex treatment

Given the importance of rapidly developing and implementing a set of funding arrangements for pre-construction costs, we believe that an opex approach is the most appropriate mechanism, and propose to adopt Option B. Whilst Option B would result in higher, immediate charges to customers, we do not consider the impact will be material, given the limited scale of the expenditure. Were we to go down the route of treating it as capex, we would need to introduce clearer delineations between pre-construction and construction costs and undertake the associated revenue calculations. This additional work would make it harder to deliver change by April 2009, and could delay the TOs beginning pre-construction works.

Issue 3 - Ex-ante or ex-post costs

As we set out in the December consultation, there are two potential approaches for dealing with the timing and incentive properties of pre-construction funding:

- **Option X (*ex-ante*)** - Under this approach we would agree an allowance up front for specified projects. This allowance would be linked to the completion of specific activities. Any under- or over-spend would be reviewed at the end of the year, taking into account the work planned and completed, and would influence decisions on the level of future allowances.
- **Option Y (*ex-post*)** - An alternative option would be to an allowance for actually costs incurred following an efficiency review.

The TOs have expressed concerns that in the current financial climate, adopting an *ex-post* approach would be undesirable as it would require them to fund investments for the period between when the expenditure is incurred and when the regulatory funding is provided. This period could be as long as two years if costs are logged up and dealt with at the start of the next price control period.

Ofgem's proposal for ex-ante or ex-post

We have listened to the points made by the TOs, and agree that an *ex-post* approach would expose them to financing risk for an interim period until the regulatory funding commences, and note the concerns they have in relation to the global financial situation. We are not convinced that an *ex-post* treatment would expose the companies to a material financial strain; however, we consider there are other reasons why an *ex-ante* mechanism is the preferred approach to pre-construction costs. We consider that setting the pre-construction allowances in advance retains a degree of implicit incentivisation for the TOs. We are therefore proposing to set ex-ante allowances for the relevant projects that have been identified by NGET and SPTL, as per the above numbers, and propose to adopt Option X. However, it is important that these allowances are subject to ongoing review, and we are proposing to impose a requirement in the licence for the TOs to report to Ofgem outlining their progress for relevant projects. We consider that the TOs should be obliged to provide such a report to the Authority within three months of the end of the relevant year t, 2009/10.

Intent of the Proposed Licence Modification

The attached annexes depict Special Condition D5 of NGET's transmission licence and Special Condition J5 of SPTL's and SHETL's transmission licences. The annexes show in tracked red text the changes that we are proposing in this section 11 consultation document.

The first change proposed in paragraph 1 introduces a new term $RevApOx_t$, which is defined as the adjustment to revenues in respect of operating costs approved by the Authority. This term is added to the existing calculation of IP_t which feeds through into the revenue restriction in Special Condition D2 of NGET's transmission licence and Special Condition J2 of SPTL's and SHETL's transmission licences.

The definition of $RevApOx_t$ refers to its calculation in part 4 of NGET's licence and part 6 in SPTL's and SHETL's licences. These new sections of the licence define $RevApOx_t$ as being equal to $ApPreCon_t$, which takes the value of the approved pre-construction expenditures for relevant year t as set out in the subsequent table. For the avoidance of doubt, for SHETL the value of these terms is set at zero.

For the purpose of setting the value of $ApPreCon_t$ the scope of what qualifies as pre-construction work is essentially defined, with the subsequent table for NGET and SPTL setting out the relevant reinforcements and their approved expenditure.

The final paragraph of each of part 4 for NGET and part 6 for SHETL and SPTL sets out the requirement on the licensees to provide the Authority with a report describing the progress on each of the approved pre-construction work areas within three months of 31 March 2010. The Authority will then conduct an *ex-post* efficiency assessment.

Way forward and timetable

Short term measures

Following closure of this consultation on 27 March 2009, and detailed consideration of the consultation responses, the Authority will either determine that the changes set out in the annexes in this section 11 consultation document will be approved and the licence will be modified, or it will consult again and explain the reasons why it has chosen to do so. If implemented, the proposed modifications set out in the section 11 notice would take effect on and from 1 April 2009.

Further consultations on TO Incentives

We will continue to work with the TOs and engage industry on our developing thinking on TO Incentives, following on from the December consultation. Details of further work that needs to be taken forward in relation to construction costs, potential revisions to the revenue drivers or more detailed licence amendments, will be taken forward as part of our ongoing work on Enhanced Transmission Investment Incentives. We will also consider the treatment of costs beyond 2009/10 for the projects covered by the short term measures. We will continue the development of further measures to apply to additional transmission investments commencing within the current transmission price control period, which expires on 31 March 2012.

We intend to publish our next consultation on further measures in Spring/Summer 2009. This will potentially be followed by a further consultation in Autumn/Winter 2009 before we produce a statutory licence consultation to implement our proposed further measures.

Measures relating to investments undertaken under TCPR5 and beyond will be considered as part of the next transmission price control review, building on the recommendations of the RPI-X@20 project. We stated in our December consultation document, that we think it is appropriate for arrangements put in place for anticipatory investments that commence during TPCR4 to be unaffected by any proposed changes coming out of the RPI-X@20 project.

Consultation responses

Any representations or objections to the proposed modifications must be made in writing on or before 27 March 2009 to David Hunt at transmissionaccessreview@ofgem.gov.uk.

If you wish to discuss any of the issues raised in this open letter and associated section 11 consultation please contact David Hunt (david.hunt@ofgem.gov.uk), Cheryl Mundie (cheryl.mundie@ofgem.gov.uk) or myself.

Yours sincerely

Stuart Cook,
Director - Transmission

Annex 1 - NOTICE UNDER SECTION 11(2) OF THE ELECTRICITY ACT 1989

The Gas and Electricity Markets Authority (the "Authority") hereby gives notice pursuant to section 11(2) of the Electricity Act 1989 (the "Act") as follows:

1. The Authority proposes to modify the electricity transmission licence granted or treated as granted to National Grid Electricity Transmission plc ("NGET") (company number 2366977) the Licensee under section 6(1)(b) of the Act by amending Special Condition D5: "Incentive Payments" in the manner set out in Schedule 1 to this Notice.

2. The Authority proposes to modify the electricity transmission licence granted or treated as granted to SP Transmission Ltd ("SPTL") (company number SC189126) the Licensee, under section 6(1)(b) of the Act by amending Special Condition J5: "Restriction of transmission charges: Total incentive revenue adjustment" in the manner set out in Schedule 2 to this Notice.

3. The Authority proposes to modify the electricity transmission licence granted or treated as granted to Scottish Hydro Electric Transmission Ltd ("SHETL") (company number SC213461) the Licensee, under section 6(1)(b) of the Act by amending Special Condition J5: "Restriction of transmission charges: Total incentive revenue adjustment" in the manner set out in Schedule 3 to this Notice.

4. The purpose and effect of these licence modifications is to implement changes to Special Condition D5 of NGET's transmission licence, and Special Condition J5 of both SPTL's and SHETL's transmission licences by inserting additional provisions to enable recovery of certain pre-construction costs.

5. The reasons why the Authority proposes to modify these Special Conditions are set out in the Authority's consultation letter dated 27 February 2009 and entitled "Transmission Access Review – Enhanced Transmission Investment Incentives Open Letter: Consultation on Short Term Measures" which accompanies this Notice. In summary, the effect of the proposed licence modifications is to introduce provisions which will enable the Licensees to recover expenditure for particular pre-construction activities associated with transmission reinforcement works for the financial year running from 1 April 2009 to 31 March 2010.

6. Additional information on the purpose and effect of the proposed modification can be found in the consultation document published by the Authority on 19 December 2008 entitled Transmission Access Review – Initial consultation on enhanced transmission investment incentives. A printed copy of the document is available free of charge from the Ofgem library, 9 Millbank, London, SW1P 3GE.

7. Any representations or objections to the proposed modifications must be made in writing on or before 27 March 2009 to David Hunt at the Office of Gas and Electricity Markets (Ofgem), 9 Millbank, London SW1P 3GE, or via e-mail to transmissionaccessreview@ofgem.gov.uk.

Stuart Cook

Director, Transmission
Authorised on behalf of the Authority

Date

27 February 2009

Annex 2 – Modification of Special Condition D5: Incentive Payments of NGET's Electricity Transmission Licence

Special Condition D5: Incentive Payments

1. For the purposes of paragraph 2 of special condition D2 (Restriction on Transmission Network Revenue) IP_t is derived from the following formula:

$$\cancel{IPt = RIt + IFIt + SFIt}$$

$$IP_t = RI_t + IFI_t + SFI_t + RevApOx_t$$

where:

RI_t	means the revenue adjustment term, whether of a positive (subject to paragraph 3 of this condition) or of a negative value, reflecting the licensee's performance against a transmission network reliability incentive in the relevant incentive period relating to year t, and derived in accordance with Part 1 of this condition;
IFI_t	means the revenue adjustment term in relevant year t in respect of expenditure pursuant to the Innovation Funding Incentive and shall be calculated in accordance with Part 2 of this condition; ~~and~~
SFI_t	means the revenue adjustment factor in respect of rates of leakage of SF_6 and shall be calculated in accordance with Part 3 of this condition; and
$RevApOx_t$	means the revenue adjustment term in respect of approved operating costs calculated in accordance with Part 4 of this condition.

Part 1 – Adjustment to Transmission Network Revenue Restriction due to Transmission Network Reliability Incentive Scheme

2. For the purpose of paragraph 1, the term RI_t shall be derived from the following formula:

$$RI_t = PR_{t-1} \times RAF_y$$

where:

RI_t — in the relevant year t is the transmission network reliability incentive performance during incentive period y which shall equate to the relevant year t-1;

PR_{t-1} — shall, in respect of the relevant year commencing on 1 April 2007, take the value £1,000,380,000. In the relevant year commencing 1 April 2008 and in each subsequent relevant year, PR_{t-1} shall take the value of PR_t calculated in accordance with the formula specified in paragraph 2 of special condition D2 (Restriction on Transmission Network Revenue) in respect of the relevant year t-1; and

RAF_y — is the revenue adjustment factor based on the licensee's performance against the transmission network reliability incentive during incentive period y, and is derived from the following formula:

If $RIP_y < RILT_y$:

$$RAF_y = RIUPA_y \left[\frac{RILT_y - RIP_y}{RILT_y} \right]$$

If $RIP_y > RIUT_y$:

$$RAF_y = \max\left(RIDPA_y, RIDPA_y\left[\frac{RIP_y - RIUT_y}{RICOL_y - RIUT_y}\right]\right)$$

Otherwise:

$RAF_y = 0$

where:

$RILT_y$ is the lower incentivised loss of supply volume target in respect of incentive period y, which has the value as specified in the following table:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Incentive Period y	1 April 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RILT_y$	**248MWh**	**237MWh**	**237MWh**	**237MWh**	**237MWh**	**237MWh**

$RIUT_y$ is the upper incentivised loss of supply volume target in respect of incentive period y, which has the value as specified in the following table:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Incentive Period y	1 April 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIUT_y$	**274MWh**	**263MWh**	**263MWh**	**263MWh**	**263MWh**	**263MWh**

$RIUPA_y$ is the maximum upside percentage adjustment in respect of incentive period y, which, subject to paragraph 3, has the value as specified in the following table:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Incentive Period y	1 April 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIUPA_y$	**1.0%**	**1.0%**	**1.0% (subject to paragraph 3)**	**1.0% (subject to paragraph 3)**	**1.0% (subject to paragraph 3)**	**1.0% (subject to paragraph 3)**

$RIDPA_y$ is the maximum downside percentage adjustment in respect of incentive period y, which has the value as specified in the following table:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Incentive Period y	1 April 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIDPA_y$	**-1.5%**	**-1.5%**	**-1.5%**	**-1.5%**	**-1.5%**	**-1.5%**

$RICOL_y$ is the incentivised loss of supply collar in respect of incentive period y which has the value as specified in the following table:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Incentive Period y	1 April 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RICOL_y$	**653MWh**	**619MWh**	**619MWh**	**619MWh**	**619MWh**	**619MWh**

RIP_y is the sum of the volumes of unsupplied energy in all incentivised loss of supply events in incentive period y; and

max (A,B) means the value equal to the greater of A and B.

3. For the purposes of calculating RAF_y, $RIUPA_y$ shall take the value specified in the relevant table in paragraph 2 above before 1 April 2009 or such later date as the Authority may direct. After 1 April 2009 or such later date as the Authority may direct, $RIUPA_y$ shall take the value specified in the relevant table in paragraph 2 above for relevant years during which the licensee implements an approved network output measures methodology in accordance with standard condition B17 (Network Output Measures), and shall take the value zero for relevant years during which the licensee fails to implement the methodology, unless otherwise directed by the Authority.

4. The licensee shall prepare and maintain a transmission reliability incentive methodology statement approved by the Authority, setting out the methodology by which the licensee will determine the volume of unsupplied energy in each incentivised loss of supply event.

5. The licensee shall use reasonable endeavours to apply the methodology set out in the statement in calculating the volume of unsupplied energy in relation to any incentivised loss of supply event.

6. Before revising the methodology referred to in paragraph 4, the licensee shall submit to the Authority a copy of the proposed revisions to the methodology.

7. Unless the Authority otherwise directs within 1 month of the Authority receiving any proposed revisions to the methodology under paragraph 6, the licensee shall use reasonable endeavours to apply the methodology revised in accordance with such proposed revisions.

8. For the purposes of this special condition "incentivised loss of supply event" shall mean any event on the licensee's transmission system that causes electricity not to be supplied to a customer subject to the following exclusions:

   (a) any such event that causes electricity to not be supplied to 3 or less directly connected parties;

   (b) any unsupplied energy resulting from a shortage of available generation;

   (c) any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment under an event of default as defined in the CUSC;

(d) any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code;

(e) any unsupplied energy resulting from a planned outage as defined in the Grid Code;

(f) any unsupplied energy resulting from emergency de-energisation by a user as defined in the CUSC; and

(g) any unsupplied energy resulting from an emergency de-energisation or disconnection of a user's equipment necessary to ensure compliance with the Electricity Safety, Quality and Continuity Regulations 2002, as amended from time to time, or to otherwise ensure public safety.

9. For the purpose of paragraph 8, a "directly connected party" is any party with a direct connection to the licensee's transmission system with the exception of any connection to a distribution system.

10. Where:

(a) the licensee considers that any event on the licensee's transmission system that causes electricity not to be supplied to a customer has been wholly or partially caused by an exceptional event;

(b) the licensee has notified the Authority of such event within 14 days of its occurrence;

(c) the licensee has provided details of the volume of unsupplied energy that the licensee considers resulted from the exceptional event and such further information, if any, as the Authority may require in relation to such an exceptional event; and

(d) the Authority is satisfied that the event notified to it under sub-paragraph (b) is an exceptional event

the Authority may, by notice to the licensee, direct that, for the purpose of calculating the volume of unsupplied energy for the relevant incentivised loss of supply event the constituent data relevant to that event shall be adjusted as specified in that direction.

11. For the purpose of paragraph 10, the adjustment directed by the Authority shall be based on the extent to which the Authority is satisfied that the licensee had taken reasonable steps to prevent the event having the effect of interrupting supply and to mitigate its effect (both in anticipation and subsequently).

12. A direction under paragraph 10 shall not have effect unless, before it is made, the Authority has given notice to the licensee:

    (a) setting out the terms of the proposed direction;

    (b) stating the reasons why it proposes to issue the direction; and

    (c) specifying the period (not being less than 14 days from the date of the notice) within which the licensee may make representations or objections

    and the Authority has considered such representations or objections and given reasons for its decision.

13. For the purpose of paragraph 10, an "exceptional event" means an event or circumstance that is beyond the reasonable control of the licensee and which results in or causes electricity not to be supplied to a customer and includes (without limitation) an act of the public enemy, war declared or undeclared, threat of war, terrorist act, revolution, riot, insurrection, civil commotion, public demonstration, sabotage, act of vandalism, fire (not related to weather), any severe weather event resulting in more than 50 faults being recorded by the licensee on the licensee's transmission system in any 24 hour period, governmental restraint, Act of Parliament, other legislation, bye law or directive (not being any order, regulation or direction under section 32, 33, 34 and 35 of the Act) or decision of a Court of competent authority or the European Commission or any other body having jurisdiction over the activities of the licensee provided that lack of funds shall not be interpreted as a cause beyond the reasonable control of the licensee.

Part 2 – Calculation of charge restriction adjustments arising from the innovation funding incentive scheme

14. The purpose of this part of this condition is to provide for adjustments to maximum revenue to reflect performance of the licensee in relation to its investment in innovation under the Innovation Funding Incentive (IFI) scheme.

15. For the purposes of paragraph 1, IFI_t, is derived for the relevant year t from the formula:

$$IFI_t = ptri_t \times \left(min\left(IFIE_t, \left(max\left(500{,}000 + KIFI_t, \left(0.005 \times PR_t\right)\right) - KIFI_t\right)\right)\right)$$

where:

$IFIE_t$	means the eligible IFI expenditure for the relevant year t as reported in the IFI annual report for that year;
PR_t	means the regulated transmission revenue in the relevant year t as determined in accordance with paragraph 2 of special condition D2 (Restriction on Transmission Network Revenue);
$ptri_t$	is the pass-through factor applicable for the relevant year t and shall in the relevant year commencing 1 April 2007 and each subsequent relevant year take the value 0.8; and
$KIFI_t$	is the carry forward in relation to the innovation funding incentive scheme as set out in the IFI annual report for relevant year t-1, and is calculated in accordance with the following:

if $IFIE_{t-1} \leq 0.5 \times max\left(500{,}000, \left(0.005 \times PR_{t-1}\right)\right)$:

$$KIFI_t = 0.5 \times \left(max\left(500{,}000, \left(0.005 \times PR_{t-1}\right)\right)\right)$$

if $IFIE_{t-1} > \left(0.5 \times max\left(500{,}000, \left(0.005 \times PR_{t-1}\right)\right)\right)$

and $IFIE_{t-1} \le max\left(500{,}000, \left(0.005 \times PR_{t-1}\right)\right)$:

$$KIFI_t = max\left(500{,}000, \left(0.005 \times PR_{t-1}\right)\right) - IFIE_{t-1}$$

if $IFIE_{t-1} > \left(max\left(500{,}000, \left(0.005 \times PR_{t-1}\right)\right)\right)$:

$$KIFI_t = 0$$

where, for the relevant year commencing 1 April 2007, $KIFI_t$, shall be zero.

16. For the purposes of this condition:

"eligible IFI expenditure" means the amount of expenditure spent or accrued by the licensee in respect of eligible IFI projects;

"eligible IFI projects" means those projects that meet the requirements described for such projects;

"IFI annual report" means the report produced each year by the licensee, in a format agreed with the Authority, in respect of expenditure and innovation; and

in each case above, all as more fully set out in the revenue reporting regulatory instructions and guidance for the time being in force under standard condition B16 (Price Control Revenue Reporting and Associated Information) in relation to the innovation funding incentive scheme.

Part 3 - Adjustment to restriction of transmission charges due to SF_6 incentive

17. The purpose of this condition is to provide for adjustments to allowed revenue to reflect performance of the licensee in relation to its Sulphur Hexafluoride (SF_6) incentive scheme.

18. For the purposes of paragraph 1, SFI_t, shall where $ALK_t < TLK_t$ be calculated in accordance with the following formula:

$$SFI_t = 0.002 \times PR_t$$

otherwise: SFI_t shall take the value zero.

where:

PR_t means the licensee's base transmission revenue, as defined in paragraph 2 of special condition D2 (Restriction on Transmission Network Revenue);

ALK_t means the actual leakage rate of SF_6 gas in relevant year t as a percentage of inventory of SF_6 gas as reported by the licensee pursuant to the revenue reporting regulatory instructions and guidance issued in accordance with standard condition B16 (Price Control Revenue Reporting and Associated Information); and

TLK_t means the target leakage rate of SF_6 gas in relevant year t as a percentage of inventory of SF_6 and shall take the values in the table below:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12
TLK_t	3.00%	2.75%	2.50%	2.25%	2.00%

19. The licensee shall on or before 1 April 2007 or such later date as the Authority may direct, submit to the Authority a leakage rate of SF_6 methodology statement consistent with best industry practice, setting out the methodology by which the licensee will determine the leakage rate of SF_6 gas, required for the calculation of the actual leakage rate of SF_6 gas, ALK_t, and the target leakage rate of SF_6 gas, TLK_t.

20. Unless the Authority directs otherwise within 2 months of the date on which the licensee submits the statement to the Authority in accordance with paragraph 19, the licensee shall use reasonable endeavours to apply the methodology set out in that statement.

21. Before revising the methodology referred to in paragraph 19 the licensee shall submit to the Authority a copy of the proposed revisions to the methodology.

22. Unless the Authority otherwise directs within 1 month of the Authority receiving any proposed revisions to the methodology under paragraph 21, the licensee shall use reasonable endeavours to apply the methodology revised in accordance with such proposed revisions.

23. Where:

(a) the licensee considers that any event on the licensee's transmission system that causes leakage of SF_6 gas has been wholly or partially caused by an exceptional event;

(b) the licensee has notified the Authority of such event within 14 days of its occurrence;

(c) the licensee has provided details of the exceptional event and such further information, if any, as the Authority may require in relation to such an exceptional event; and

(d) the Authority is satisfied that the event notified to it under sub-paragraph (b) is an exceptional event

the Authority may, by notice to the licensee, direct that the actual leakage of SF_6 gas and the value of ALK_t in relevant year t shall be adjusted as specified in that direction. In directing the value of any adjustment to ALK_t in relevant year t pursuant to this paragraph, the Authority shall reserve the right to modify the value of any proposed adjustment notified by the licensee that may be made to ALK_t in relevant year t.

24. For the purpose of paragraph 23, any adjustment directed by the Authority shall take account of the extent to which the Authority is satisfied that the licensee had used reasonable endeavours to prevent the event from resulting in the leakage of SF_6 and to mitigate its effect (both in anticipation and subsequently).

25. A direction under paragraph 23 shall not have effect unless, before it is made, the Authority has given notice to the licensee:

(a) setting out the terms of the proposed direction;

(b) stating the reasons why it proposes to issue the direction; and

(c) specifying the period (not being less than 14 days from the date of the notice) within which the licensee may make representations or objections

and the Authority has considered such representations or objections and given reasons for its decision.

26. For the purpose of paragraph 23, an "exceptional event" means an event or circumstance that is beyond the reasonable control of the licensee and which results in, causes or prohibits the timely prevention of the leakage of SF_6 gas and includes (without limitation) an act of the public enemy, war declared or undeclared, threat of war, terrorist act, revolution, riot, insurrection, civil commotion, public demonstration, sabotage, act of vandalism, fire (not related to weather), governmental restraint, Act of Parliament, any other legislation, bye law or directive (not being any order, regulation or direction under section 32, 33, 34 and 35 of the Act) or decision of a Court of competent authority or the European Commission or any other body having jurisdiction over the activities of the licensee provided that lack of funds shall not be interpreted as a cause beyond the reasonable control of the licensee.

27. Without prejudice to paragraph 26, an "exceptional event" may include circumstances where a significant danger to the public gives rise to the licensee prioritising health and safety over the reduction of leakage of SF_6 gas at a particular site.

Part 4 - Adjustment to restriction of transmission charges due to approved operating expenditure

28. The purpose of this part of this condition is to provide for an adjustment to the maximum revenue to reflect approved operating expenditure.

29. For the purpose of paragraph 1, RevApOxt shall be calculated in accordance with the following formula:

$$RevApOx_t = ApPreCon_t$$

Where:

$ApPreCon_t$ means the pre-construction transmission reinforcement expenditure for relevant year t as described in paragraph 30.

30. For the purpose of paragraph 29, $ApPreCon_t$ shall have the value of £10,000,000 for relevant year t commencing on 1 April 2009 and shall have the value of zero in each subsequent relevant year unless directed otherwise by the Authority in writing. The pre-construction transmission reinforcement expenditure shall comprise the required network analyses, technical design studies, site selection and preliminary environmental assessments necessary for the reinforcement works on the licensee's transmission system identified in the following table:

Identifier	Reinforcement description	Approved expenditure
1	Develop transmission capacity between Scotland and England by means of reconductoring existing circuits and the addition of reactive compensation	£2,000,000
2	Develop transmission capacity between Scotland and England by means of a new western HVDC transmission link.	£2,900,000
3	Develop transmission capacity between Scotland and England by means of a new Eastern HVDC transmission link.	£200,000
4	Develop transmission capacity between Anglesey, North Wales and England by means of new circuits and substation extensions.	£950,000

5	Develop transmission capacity and additional generation/offshore network connection opportunities between Humber and Walpole.	£900,000
6	Develop transmission capacity and additional generation/offshore network connection opportunities between Walpole, Norwich and Bramford.	£1,000,000
7	Develop transmission capacity for power exports from the South West of England by means of new circuits.	£700,000
8	Develop transmission capacity into east of London by increasing circuit operating voltages	£700,000
9	Develop transmission capacity to central Wales by means of new circuits.	£650,000

31. The licensee shall provide the Authority with a report describing the progress achieved by the licensee on each of the pre-construction reinforcement work areas identified in the table above not later than 3 months after the end of the relevant year t commencing 1 April 2009.

Annex 3 – Modification of Special Condition J5 - Restriction of transmission charges: Total incentive revenue adjustment of SPTL's Electricity Transmission Licence

Special Condition J5 - Restriction of transmission charges: Total incentive revenue adjustment

1. For the purposes of paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services), IP_t is derived from the following formula:

$$\cancel{IP_t = RI_t + RevDrvSP_t + IFI_t + SFI_t + RCI_t}$$

$$IP_t = RI_t + RevDrvSP_t + IFI_t + SFI_t + RCI_t + RevApOx_t$$

where

RI_t means the revenue adjustment term, whether of a positive (subject to paragraph 3) or of a negative value, reflecting the licensee's performance against a transmission network reliability incentive in the relevant incentive period relating to year t, and derived in accordance with part 1 of this condition.

$RevDrvSP_t$ means the adjustment to revenues pursuant to variations between actual and assumed volumes of connected generation and demand and shall be calculated in accordance with part 2 of this condition.

IFI_t means the revenue adjustment term in respect of expenditure pursuant to the Innovation Funding Incentive and shall be calculated in accordance with part 3 of this condition.

SFI_t means the revenue adjustment term in respect of rates of leakage of SF6 and shall be calculated in accordance with part 4 of this condition.

RCI_t means the revenue adjustment term in the relevant year t in respect of the five year rolling capital and operating cost incentive mechanisms calculated in accordance with part 5 of this condition.

$RevApOx_t$ means the revenue adjustment term in respect of approved operating costs calculated in accordance with Part 6 of this condition.

Part 1 – Adjustment to Transmission Network Revenue Restriction due to Transmission Network Reliability Incentive Scheme

2. For the purpose of paragraph 1, the term RI_t shall be derived from the following formula:

$$RI_t = PR_{t-1} \times RAF_y$$

Where:

RI_t in the relevant year t is the transmission network reliability incentive performance during incentive period y which shall equate to the relevant year t-1.

PR_{t-1} shall be the value of PR_t calculated in accordance with the formula specified in paragraph 3 of Special Condition J2 (Restriction of transmission charges: revenue from transmission owner services) in respect of the relevant year t-1.

RAF_y is the revenue adjustment factor based on the licensee's performance against the transmission network reliability incentive during incentive period y, and is derived from the following formula:

If $RIP_y < RILT_y$:

$$RAF_y = RIUPA_y \left[\frac{RILT_y - RIP_y}{RILT_y} \right]$$

If $RIP_y > RIUT_y$:

$$RAF_y = \max\left(RIDPA_y, RIDPA_y \left[\frac{RIP_y - RIUT_y}{RICOL_y - RIUT_y} \right] \right)$$

Otherwise:

$RAF_y = 0$

Where:

$RILT_y$ is the lower incentivised loss of supply event target in respect of incentive period y, which is the number of events specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RILT_y$	**10**	**8**	**8**	**8**	**8**	**8**

$RIUT_y$ is the upper incentivised loss of supply event target in respect of incentive period y, which is the number of events specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIUT_y$	**12**	**10**	**10**	**10**	**10**	**10**

$RIUPA_y$ is the maximum upside percentage adjustment in respect of incentive period y, which, subject to paragraph 3, has the value as specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIUPA_y$	**0.50%**	**0.50%**	**0.50% (subject to paragraph 3)**	**0.50% (subject to paragraph 3)**	**0.50% (subject to paragraph 3)**	**0.50% (subject to paragraph 3)**

$RIDPA_y$ is the maximum downside percentage adjustment in respect of incentive period y, which has the value as specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIDPA_y$	**-0.75%**	**-0.75%**	**-0.75%**	**-0.75%**	**-0.75%**	**-0.75%**

$RICOL_y$ is the incentivised loss of supply collar in respect of incentive period y which is the number of events specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13

Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RICOL_y$	**26**	**22**	**22**	**22**	**22**	**22**

RIP_y is the number of incentivised loss of supply events in incentive period y.

max (A,B) means the value equal to the greater of A and B.

3. For the purposes of calculating RAFy, RIUPAy shall take the value specified in the relevant table in paragraph 2 above before 1 April 2009 or such later date as the Authority may direct. After 1 April 2009 or such later date as the Authority may direct, RIUPAy shall take the value specified in the relevant table in paragraph 2 above for relevant years during which the licensee implements an approved network output measures methodology in accordance with standard condition B17 (Network Output Measures), and shall take the value zero for relevant years during which the licensee fails to implement the methodology, unless otherwise directed by the Authority.

4. For the purposes of this condition, "incentivised loss of supply event" shall mean any event on the licensee's transmission system that causes electricity not to be supplied to a customer subject to the following exclusions:

(a) any such event that causes electricity to not be supplied to 3 or less directly connected parties;

(b) any unsupplied energy resulting from a shortage of available generation;

(c) any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code;

(d) any unsupplied energy resulting from emergency de-energisation of part of the licensee's transmission system, either as a consequence of a user's request for emergency de-energisation of its equipment or the user carrying out an emergency de-energisation of its equipment;

(e) any unsupplied energy resulting from a planned outage as defined in the Grid Code;

(f) any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment necessary to ensure compliance with an instruction by the system operator to the licensee pursuant to the STC; and

(g) any unsupplied energy resulting from an emergency de-energisation or disconnection of a user's equipment necessary to ensure compliance with the Electricity Safety, Quality and Continuity Regulations 2002, as amended from time to time, or to otherwise ensure public safety.

5. For the purpose of paragraph 4, a "directly connected party" is any party with a direct connection to the licensee's transmission system with the exception of any connection to a distribution system.

6. Where:

(a) the licensee considers that any event on the licensee's transmission system that causes electricity not to be supplied to a customer has been wholly or partially caused by an exceptional event;

(b) the licensee has notified the Authority of such event within 14 days of its occurrence;

(c) the licensee has provided details of the exceptional event and such further information, if any, as the Authority may require in relation to such an exceptional event; and

(d) the Authority is satisfied that the event notified to it under sub-paragraph (b) is an exceptional event

the Authority may, by notice to the licensee, direct that the number of incentivised loss of supply events in incentive period y shall be adjusted as specified in that direction.

7. For the purpose of paragraph 6, the adjustment directed by the Authority shall be based on the extent to which the Authority is satisfied that the licensee had taken reasonable steps to prevent the event having the effect of interrupting supply and to mitigate its effect (both in anticipation and subsequently).

8. A direction under paragraph 6 shall not have effect unless, before it is made, the Authority has given notice to the licensee:

(a) setting out the terms of the proposed direction;

(b) stating the reasons why it proposes to issue the direction; and

(c) specifying the period (not being less than 14 days from the date of the notice) within which the licensee may make representations or objections

and the Authority has considered such representations or objections and given reasons for its decision.

9. For the purpose of paragraph 6, an “exceptional event” means an event or circumstance that is beyond the reasonable control of the licensee and which results in or causes

electricity not to be supplied to a customer and includes (without limitation) an act of the public enemy, war declared or undeclared, threat of war, terrorist act, revolution, riot, insurrection, civil commotion, public demonstration, sabotage, act of vandalism, fire (not related to weather), any severe weather event resulting in more than 7 faults being recorded by the licensee on the licensee's transmission system in any 24 hour period, governmental restraint, Act of Parliament, any other legislation, bye law or directive (not being any order, regulation or direction under section 32, 33, 34 and 35 of the Act) or decision of a Court of competent authority or the European Commission or any other body having jurisdiction over the activities of the licensee provided that lack of funds shall not be interpreted as a cause beyond the reasonable control of the licensee.

Part 2 – Revenue Drivers

10. For the purposes of paragraph 1, the maximum revenue allowed to the licensee as a consequence of works to accommodate generation seeking connection in respect of relevant year t ($RevDrvSP_t$) shall be derived in accordance with this condition, where:

relevant generation capacity	means the cumulative amount of generation connection capacity (but excluding high cost projects) for which attributable transmission reinforcement works are completed and commissioned (in accordance with the System Operator Transmission Owner Code, STC) after 31 March 2005;
generation connection capacity	means the connection capacity that transmission reinforcement works have been contracted and constructed to deliver in the relevant Transmission Operator Connection Agreements between the licensee and the system operator pursuant to the STC;

high cost project — means local infrastructure works where the licensee, estimates, using reasonable endeavours, that the capital expenditure incurred in completing the relevant set of local infrastructure works will exceed £163,000 (in 2004/05 prices) per megawatt of predicted capacity;

local infrastructure works — means sole user triggered transmission reinforcement works associated with the connection of new or additional generation capacity to a part of the licensee's transmission system (or connected to a distribution system which in turn connects to a part of the licensee's transmission system) as specified in relevant agreements between the licensee and the system operator pursuant to the STC; and

deep reinforcement works — means infrastructure works other than local infrastructure works as specified in relevant agreements between the licensee and the system operator pursuant to the STC.

11. For the purposes of paragraph 1, $RevDrvSP_t$ shall be calculated in accordance with the following formula:

$$\mathrm{Re}vDrvSP_t = \left[RDDep_t + \left(\left(\frac{RDO_t + RDC_t}{2} \right) \times RD\mathrm{Re}t \right) + \left(RDGAV_t \times 0.01 \right) \right] \times PIT_t$$

where:

$RDDep_t$ — means an allowance, expressed in 2004/05 prices, for depreciation in relevant year t and shall be calculated in accordance with the formula below:

$$RDDep_t = 0.05 \times RDGAV_t$$

RDO_t means the value, expressed in 2004/05 prices, of the revenue driver RAV on 1 April of the relevant year t and shall, in respect of the relevant year commencing 1 April 2007 take a value of zero. In respect of the relevant year commencing 1 April 2008 and each subsequent relevant year t, RDO_t shall be calculated in accordance with the following formula:

$$RDO_t = RDC_{t-1}$$

RDC_t means the value, expressed in 2004/05 prices, of the revenue driver RAV on 31 March of the relevant year t. In the relevant year commencing 1 April 2007 and in each subsequent relevant year RDC_t shall be calculated in accordance with the following formula:

$$RDC_t = RDO_t + RDAdd_t - RDDep_t$$

where

$RDAdd_t$ means the total additions, expressed in 2004/05 prices, to the revenue driver RAV that occur in relevant year t and shall be calculated in accordance with the formula in paragraph 12 of this condition.

RDRet means the pre-tax rate of return expressed in real terms allowed on the revenue driver RAV and, for the purposes of this condition, shall take a value of 6.25% for all relevant years;

$RDGAV_t$ means the cumulative gross value of the Revenue driver RAV, expressed in 2004/05 prices, as at 31 March in relevant year t-1 and shall be calculated in accordance with the following formula:

$$RDGAV_t = \sum_{p=t-z}^{p=t-1} RDAdd_p$$

where:

p shall means the relevant year commencing 1 April;

$RDAdd_p$ shall take the value of $RDAdd_t$ for relevant year t=p, where $RDAdd_t$ shall take the same meaning as given in the definition of RDC_t above;

p=t-z means the relevant year commencing 1 April 2004; and

PIT_t shall take the same meaning as given in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services).

12. The term $RDAdd_t$ shall be calculated in accordance with the following conditions:

If $RG_{t-2} \leq 1734 < RG_{t-1}$ then:

$$\begin{aligned} RDAdd_t = {} & \left(\frac{RG_{t-1} - 1734}{RG_{t-1} - RG_{t-2}} \right) \times \left(0.75 \times \left(RDCLCpx_t - (1 + RDRet) \times RDCLCpx_{t-1}\right)\right) \\ & + \left(\left(RG_{t-1} - 1734\right) \times \left(\left(LRD \times 1.13\right) \times 0.25\right)\right) \\ & + 0.75 \times \left(RDCDCpx_t - (1 + RDRet) \times RDCDCpx_{t-1}\right) \\ & + \sum_c \left(OFlag_{c,t} \times \left(\left(ORD_c \times 1.13\right) \times 0.25\right)\right) \\ & + \sum_h \frac{RDHCP_{h,t}}{PIT_t} \end{aligned}$$

If $1734 < RG_{t-2} \leq RG_{t-1}$, then:

$$
\begin{aligned}
RDAdd_t = {} & 0.75 \times \left(RDCLCpx_t - (+RD\mathrm{Ret}) \times RDCLCpx_{t-1} \right) \\
& + \left(RG_{t-1} - RG_{t-2} \right) \times \left(LRD \times 1.13 \right) \times 0.25 \\
& + 0.75 \times \left(RDCDCpx_t - (+RD\mathrm{Ret}) \times RDCDCpx_{t-1} \right) \\
& + \sum_c \left(DFlag_{c,t} \times \left(DRD_c \times 1.13 \right) \times 0.25 \right) \\
& + \sum_h \frac{RDHCP_{h,t}}{PIT_t}
\end{aligned}
$$

In all other cases:

$$
\begin{aligned}
RDAdd_t = {} & 0.75 \times \left(RDCDCpx_t - (+RD\mathrm{Ret}) \times RDCDCpx_{t-1} \right) \\
& + \sum_c \left(DFlag_{c,t} \times \left(DRD_c \times 1.13 \right) \times 0.25 \right) \\
& + \sum_h \frac{RDHCP_{h,t}}{PIT_t}
\end{aligned}
$$

where:

RG_{t-1}	means the relevant generation capacity as at 31 March of relevant year t-1;
RG_{t-2}	means the relevant generation capacity as at 31 March of relevant year t-2;
$RDCLCpx_t$	means the cumulative capital expenditure, expressed in 2004/05 prices, (adjusted for financing costs) incurred by the licensee prior to 1 April of relevant year t in respect of local RD qualifying projects for relevant year t, and shall be calculated in accordance with the formula in paragraph 14;

$RDCLCpx_{t-1}$ is equal to the value of $RDCLCpx_t$ for the preceding relevant year;

local RD qualifying project means local infrastructure works being undertaken by the licensee:

(a) which result, or have resulted, in the volume of relevant generation capacity first exceeding 1734 megawatts; or

(b) will be, or have been, completed and commissioned after the point at which the volume of relevant generation capacity is equal to or exceeds 1734 megawatts;

to provide generation connection capacity where the licensee has, or will have, prior to 1 April of relevant year t, committed to spend not less than 25 per cent of the capital expenditure that it estimates, using reasonable endeavours, will be incurred in completing the set of relevant local infrastructure works;

LRD shall take the value £52,000 (expressed in 2004/05 prices);

$RDCDCpx_t$ means the cumulative capital expenditure, (expressed in 2004/05 prices) incurred by the licensee prior to 1 April of relevant year t in respect of deep RD qualifying projects;

$RDCDCpx_{t-1}$ is equal to the value of $RDCDCpx_t$ for the preceding relevant year;

deep RD qualifying project means deep reinforcement works being undertaken by the licensee:

1. which are relevant to the conditions set out in Table 1 of paragraph 13, and
2. for which the licensee will have, prior to 1 April of relevant year t, committed to spend not less than 25 per cent of the capital expenditure that it estimates, using reasonable endeavours, will be incurred in completing these works;

$DFlag_{c,t}$ shall take the value 1 if deep reinforcement project c was completed and commissioned in the relevant year t, and otherwise it shall take the value 0;

DRD_c shall take the corresponding value (expressed in 2004/05 prices) in Table 1 of paragraph 13 in respect of each specified area c; and

$RDHCP_{h,t}$ means the capital expenditure incurred by the licensee during relevant year t in respect of high cost project h, as defined in paragraph 10.

13. **Table 1**

c	**Conditions**	**Thresholds (MW)**	**DRD_c (£m, 2004/05 prices)**
	This table is deliberately blank subject to the provisions of paragraph 13		

The Authority may direct changes to Table 1 where the licensee provides a report to the Authority setting out how material changes in flows on the licensee's network or other relevant factors have resulted in change in the costs of deep reinforcement on its network and an up-to-date estimate of the efficient costs of relevant works. Following receipt of such report, the Authority will consult with interested parties prior to issuing a direction.

14. $RDCLCpx_t$ shall be calculated in accordance with the following formula:

$$RDCLCpx_t = \sum_i \sum_{s=T-z}^{s=T-1} \left[\left(\frac{1}{PIT_s} \right) \times \left(RDALCpx_{i,s} \times \left(1 + RD\mathrm{Re}t \right)^{(T-S)+0.5} \right) \right]$$

where

i	refers to each set of local infrastructure works which is a local RD qualifying project for year t;
s	refers successively to each relevant year from that commencing 1 April 2005 to that preceding relevant year t;
$RDALCpx_{i,s}$	means the capital expenditure incurred by the licensee during relevant year s on project i ;
T	shall take a value equal to the calendar year in which relevant year t ends, e.g. for relevant year commencing 1 April 2007 the value of T shall be 2008;
T-z	refers to the relevant year commencing 1 April 2005;
S	shall take a value equal to the calendar year in which relevant year s starts e.g. for relevant year 2007/08 the value of S shall be 2007; and
PIT_s	shall take the value of PIT_t for relevant year t=s, where PIT_t shall take the same meaning as given in paragraph 3 of special condition J2

(Restriction of transmission charges: revenue from transmission owner services).

15. RDCDCpx$_t$ shall be calculated in accordance with the following formula:

$$RDCDCpx_t = \sum_c \sum_{x=T-p}^{x=T-1} \left[\left(\frac{1}{PIT_x} \right) \times \left(RDADCpx_{c,x} \times \left(1 + RD\mathrm{Re}t \right)^{(T-S)+0.5} \right) \right]$$

where

c refers to each set of deep reinforcement works which is a deep RD qualifying project for year t;

x refers successively to each relevant year from that commencing 1 April 2007 to relevant year t;

T-p refers to the relevant year commencing 1 April 2007;

T shall take a value equal to the calendar year in which relevant year t ends, e.g. for relevant year commencing 1 April 2007 the value of T shall be 2008;

S shall take a value equal to the calendar year in which relevant year x starts e.g. for relevant year 2007/08 the value of S shall be 2007;

RDADCpx$_{c,x}$ means the annual capital expenditure incurred by the licensee in relevant year x on project c; and

Part 3 – Calculation of charge restriction adjustments arising from the innovation funding incentive scheme

16. The purpose of this condition is to provide for adjustments to allowed transmission owner revenue to reflect performance of the licensee in relation to its investment in innovation under the Innovation Funding Incentive (IFI) scheme.

17. For the purposes of paragraph 1, IFIt is derived for the relevant year t from the formula:

$$IFI_t = ptri_t \times \left(\min\left(IFIE_t, \left(\max\left(\left(500{,}000 + KIFI_t\right), \left(0.005 \times \left(PR_t + TIRG_t\right) + KIFI_t\right)\right)\right)\right)\right)$$

where:

$IFIE_t$ means the eligible IFI expenditure for the relevant year t as reported in the IFI annual report for that year.

PR_t means the base transmission revenue in year t as determined in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services);

$TIRG_t$ means the annual revenue allowance in year t as determined in special condition J3 (Restriction of transmission charges: Transmission Investment for Renewable Generation);

$ptri_t$ is the pass-through factor applicable for the relevant year t and shall in the relevant year commencing 1 April 2007 and each subsequent relevant year take the value 0.8; and

$KIFI_t$ is the carry forward in relation to the IFI scheme as set out in the IFI annual report for relevant year t-1, and is calculated from the following formula:

If $IFIE_{t-1} \leq 0.5 \times \max\left(500{,}000, \left(0.005 \times \left(PR_{t-1} + TIRG_{t-1}\right)\right)\right)$:

$$KIFI_t = 0.5 \times max\left(£500{,}000, \left(0.005 \times \left(PR_{t-1} + TIRG_{t-1}\right)\right)\right)$$

If $IFIE_{t-1} > 0.5 \times max\left(£500{,}000, \left(0.005 \times \left(PR_{t-1} + TIRG_{t-1}\right)\right)\right)$ and

$$IFIE_{t-1} \leq max\left(£500{,}000, \left(0.005 \times \left(PR_{t-1} + TIRG_{t-1}\right)\right)\right):$$

$$KIFI_t = max\left(£500{,}000, \left(0.005 \times \left(PR_{t-1} + TIRG_{t-1}\right)\right)\right) - IFIE_{t-1}$$

If $IFIE_{t-1} > max\left(£500{,}000, \left(0.005 \times \left(PR_{t-1} + TIRG_{t-1}\right)\right)\right):$

$$KIFI_t = 0$$

where, for the year commencing 1 April 2007, $\underline{KIFI_t}$, shall be zero

18. For the purposes of this condition:

"eligible IFI expenditure"	means the amount of expenditure spent or accrued by the licensee in respect of eligible IFI projects;
"eligible IFI projects"	means those projects that meet the requirements described for such projects; and
"IFI annual report"	means the report produced each year by the licensee, in a format agreed with the Authority, in respect of expenditure and innovation.

in each case above, all as more fully set out in the revenue reporting Regulatory Instructions and Guidance for the time being in force under standard condition B16 (Price Control Revenue Reporting and Associated Information) in relation to the IFI scheme.

Part 4 - adjustment to restriction of transmission charges due to SF_6 incentive

19. The purpose of this condition is to provide for adjustments to allowed revenue to reflect performance of the licensee in relation to its Sulphur Hexafluoride (SF_6) incentive scheme.

20. The licensee shall within 3 months of receiving a notice from the Authority submit to the Authority a leakage rate of SF_6 methodology statement consistent with best industry practice, setting out the methodology by which the licensee will determine the leakage rate of SF_6 gas, required for the calculation of the actual leakage rate of SF_6 gas, ALK_t, and the target leakage rate of SF_6 gas, TLK_t.

21. Unless the Authority directs otherwise within 2 months of the date on which the licensee submits the statement to the Authority in accordance with paragraph 20, the licensee shall take all reasonable steps to apply the methodology set out in that statement.

22. Before revising the methodology referred to in paragraph 20 the licensee shall submit to the Authority a copy of the proposed revisions to the methodology.

23. Unless the Authority directs otherwise within 1 month of the Authority receiving any proposed revisions to the methodology under paragraph 22, the licensee shall take all reasonable steps to apply the methodology revised in accordance with such proposed revisions.

24. The provisions of paragraphs 26 to 31 of this special licence condition shall not take effect until such time as directed by the Authority.

25. For the purposes of paragraph 1 of this special condition, SFI_t shall take the value zero until such time as the Authority directs that the provisions of paragraphs 26 to 31 shall take effect.

26. For the purposes of paragraph 1, where $ALKt < TLKt$, SFI_t shall be calculated in accordance with the following formula:

$$SFI_t = 0.002 \times PR_t$$

otherwise: SFI_t shall take the value zero (0).

Where:

PR_t means the licensee's base transmission revenue, as defined in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services)

ALK_t means the actual leakage rate of SF_6 gas in relevant year t as a percentage of inventory of SF_6 gas as reported by the licensee pursuant to the revenue reporting Regulatory Instructions and Guidance issued in accordance with standard condition B16 (Price Control Revenue Reporting and Associated Information)

TLK_t means the target leakage rate of SF_6 gas in relevant year t as a percentage of inventory of SF_6 and shall take the values in the table below:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
TLK_t	[]	[]	[]	[]	[]

27. Where:

(a) the licensee considers that any event on the licensee's transmission system that causes leakage of SF_6 gas has been wholly or partially caused by an exceptional event;

(b) the licensee has notified the Authority of such event within 14 days of its occurrence;

(c) the licensee has provided details of the exceptional event and such further information, if any, as the Authority may require in relation to such an exceptional event; and

(d) the Authority is satisfied that the event notified to it under sub-paragraph (b) is an exceptional event

the Authority may, by notice to the licensee, direct that actual leakage of SF_6 gas and the value of ALK_t in relevant year t shall be adjusted as specified in that direction. In directing the value of any adjustment to ALK_t in relevant year t pursuant to this paragraph, the Authority shall reserve the right to modify the value of any proposed adjustment notified by the licensee that may be made to ALK_t in relevant year t.

28. For the purpose of paragraph 27, any adjustment directed by the Authority shall be based on the extent to which the Authority is satisfied that the licensee had taken reasonable steps to prevent the event from resulting in the leakage of SF_6 and to mitigate its effect (both in anticipation and subsequently).

29. A direction under paragraph 27 shall not have effect unless, before it is made, the Authority has given notice to the licensee:

(a) setting out the terms of the proposed direction;

(b) stating the reasons why it proposes to issue the direction; and

(c) specifying the period (not being less than 14 days from the date of the notice) within which the licensee may make representations or objections and the Authority has considered such representations or objections and given reasons for its decision.

30. For the purpose of paragraph 27, an "exceptional event" means an event or circumstance that is beyond the reasonable control of the licensee and which results in or causes the leakage of SF_6 gas and includes (without limitation) an act of the public enemy, war declared or undeclared, threat of war, terrorist act, revolution, riot, insurrection, civil commotion, public demonstration, sabotage, act of vandalism, fire (not related to weather), governmental restraint, Act of Parliament, any other legislation, bye law or directive (not being any order, regulation or direction under section 32, 33, 34 and 35 of the Act) or decision of a Court of competent authority or the European Commission or any other body having jurisdiction over the activities of the licensee provided that lack of funds shall not be interpreted as a cause beyond the reasonable control of the licensee.

31. Without prejudice to paragraph 30, an "exceptional event" may include circumstances where a significant danger to the public gives rise to the licensee prioritising health and safety over the reduction of leakage of SF_6 gas at a particular site.

Part 5 – Adjustment to the Restriction of Transmission Charges in respect of the Capital and Operating Expenditure Incentive Mechanisms

32. For the purposes of paragraph 1, RCI_t is derived for the relevant year t from the formula:

$$RCI_t = ARCI_t \times PIT_t$$

where:

$ARCI_t$ means the allowance, in 2004/05 prices, made by the Authority in respect of rolling incentive revenues and shall take the value given in the table below:

Relevant year t commencing on 1 April	2007	2008	2009	2010	2011
$ARCI_t$	Nil	Nil	Nil	Nil	Nil

PIT_t shall take the same meaning as given in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services).

Part 6 - Adjustment to restriction of transmission charges due to approved operating expenditure

33. The purpose of this part of this condition is to provide for an adjustment to the maximum revenue to reflect approved operating expenditure.

34. For the purpose of paragraph 1, RevApOxt shall be calculated in accordance with the following formula:

$$RevApOx_t = ApPreCon_t$$

Where:

$ApPreCon_t$ means the pre-construction transmission reinforcement expenditure for relevant year t as described in paragraph 35.

35. For the purpose of paragraph 334, $ApPreCon_t$ shall have the value of £2,500,000 for relevant year t commencing on 1 April 2009 and shall have the value of zero in each subsequent relevant year unless directed otherwise by the Authority in writing. The pre-construction transmission reinforcement expenditure shall comprise the required network analyses, technical design studies, site selection and preliminary environmental assessments necessary for the reinforcement works on the licensee's transmission system identified in the following table:

Identifier	Reinforcement description	Approved expenditure
1	Develop transmission capacity between Scotland and England by means of a new western HVDC transmission link.	£2,500,000

36. The licensee shall provide the Authority with a report describing the progress achieved by the licensee on the pre-construction reinforcement work area identified in the table above not later than 3 months after the end of the relevant year t commencing 1 April 2009.

Annex 4 – Modification of Special Condition J5 - Restriction of transmission charges: Total incentive revenue adjustment of SHETL's Electricity Transmission Licence

Special Condition J5 - Restriction of transmission charges: Total incentive revenue adjustment

1. For the purposes of paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services), IPt is derived from the following formula:

$$\cancel{IP_t = RI_t + RevDrvSHE_t + IFI_t + SFI_t + RCI_t}$$

$$IP_t = RI_t + RevDrvSHE_t + IFI_t + SFI_t + RCI_t + RevAPOx_t$$

where

RI_t means the revenue adjustment term, whether of a positive (subject to paragraph 3) or of a negative value, reflecting the licensee's performance against a transmission network reliability incentive in the relevant incentive period relating to year t, and derived in accordance with part 1 of this condition.

$RevDrvSHE_t$ means the adjustment to revenues pursuant to variations between actual and assumed volumes of connected generation and demand and shall be calculated in accordance with Part 2 of this condition.

IFI_t means the revenue adjustment term in respect of expenditure pursuant to the Innovation Funding Incentive and shall be calculated in accordance with Part 3 of this condition.

SFI_t means the revenue adjustment term in respect of rates of leakage of SF6 and shall be calculated in accordance with Part 4 of this condition.

RCI_t means the revenue adjustment term in the relevant year t in respect of the five year rolling capital and operating cost incentive mechanisms calculated in accordance with Part 5 of this condition.

$RevApOx_t$ means the revenue adjustment term in respect of approved operating costs calculated in accordance with Part 6 of this condition.

Part 1 – Adjustment to Transmission Network Revenue Restriction due to Transmission Network Reliability Incentive Scheme

2. For the purpose of paragraph 1, the term RIt shall be derived from the following formula:

$$RI_t = PR_{t-1} \times RAF_y$$

Where:

RI_t in the relevant year t is the transmission network reliability incentive performance during incentive period y which shall equate to the relevant year t-1.

PR_{t-1} shall be the value of PR_t calculated in accordance with the formula specified in paragraph 3 of Special Condition J2 (Restriction of transmission charges: revenue from transmission owner services) in respect of the relevant year t-1.

RAF_y is the revenue adjustment factor based on the licensee's performance against the transmission network reliability incentive during incentive period y, and is derived from the following formula:

If $RIP_y < RILT_y$:

$$RAF_y = RIUPA_y \left[\frac{RILT_y - RIP_y}{RILT_y} \right]$$

If $RIP_y > RIUT_y$:

$$RAF_y = \max\left(RIDPA_y, RIDPA_y \left[\frac{RIP_y - RIUT_y}{RICOL_y - RIUT_y} \right] \right)$$

Otherwise:

$RAF_y = 0$

Where:

$RILT_y$ is the lower incentivised loss of supply event target in respect of incentive period y, which is the number of events specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012

$RILT_y$	**14**	**10**	**10**	**10**	**10**	**10**

$RIUT_y$ is the upper incentivised loss of supply event target in respect of incentive period y, which is the number of events specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIUT_y$	**16**	**12**	**12**	**12**	**12**	**12**

$RIUPA_y$ is the maximum upside percentage adjustment in respect of incentive period y, which, subject to paragraph 3, has the value as specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIUPA_y$	**0.50%**	**0.50%**	**0.50% (subject**	**0.50% (subject to**	**0.50% (subject to**	**0.50% (subject to**

			to paragraph 3)	**paragraph 3)**	**paragraph 3)**	**paragraph 3)**

$RIDPA_y$ is the maximum downside percentage adjustment in respect of incentive period y, which has the value as specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RIDPA_y$	**-0.75%**	**-0.75%**	**-0.75%**	**-0.75%**	**-0.75%**	**-0.75%**

$RICOL_y$ is the incentivised loss of supply collar in respect of incentive period y which is the number of events specified in the following table:

Relevant year t	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Incentive Period y	1 January 2006 to 31 March 2007	1 April 2007 to 31 March 2008	1 April 2008 to 31 March 2009	1 April 2009 to 31 March 2010	1 April 2010 to 31 March 2011	1 April 2011 to 31 March 2012
$RICOL_y$	**37**	**27**	**27**	**27**	**27**	**27**

RIP_y	is the number of incentivised loss of supply events in incentive period y.
max (A,B)	means the value equal to the greater of A and B.

3. For the purposes of calculating RAFy, RIUPAy shall take the value specified in the relevant table in paragraph 2 above before 1 April 2009 or such later date as the Authority may direct. After 1 April 2009 or such later date as the Authority may direct, RIUPAy shall take the value specified in the relevant table in paragraph 2 above for relevant years during which the licensee implements an approved network output measures methodology in accordance with standard condition B17 (Network Output Measures), and shall take the value zero for relevant years during which the licensee fails to implement the methodology, unless otherwise directed by the Authority.

4. For the purposes of this condition, "incentivised loss of supply event" shall mean any event on the licensee's transmission system that causes electricity not to be supplied to a customer subject to the following exclusions:

   (a) any such event that causes electricity to not be supplied to 3 or less directly connected parties;

   (b) any unsupplied energy resulting from a shortage of available generation;

   (c) any unsupplied energy resulting from a user's request for disconnection in accordance with the Grid Code;

   (d) any unsupplied energy resulting from emergency de-energisation of part of the licensee's transmission system, either as a consequence of a user's request for emergency de-energisation of its equipment or the user carrying out an emergency de-energisation of its equipment;

(e) any unsupplied energy resulting from a planned outage as defined in the Grid Code;

(f) any unsupplied energy resulting from a de-energisation or disconnection of a user's equipment necessary to ensure compliance with an instruction by the system operator to the licensee pursuant to the STC; and

(g) any unsupplied energy resulting from an emergency de-energisation or disconnection of a user's equipment necessary to ensure compliance with the Electricity Safety, Quality and Continuity Regulations 2002, as amended from time to time, or to otherwise ensure public safety.

5. For the purpose of paragraph 4, a "directly connected party" is any party with a direct connection to the licensee's transmission system with the exception of any connection to a distribution system.

6. Where:

(a) the licensee considers that any event on the licensee's transmission system that causes electricity not to be supplied to a customer has been wholly or partially caused by an exceptional event;

(b) the licensee has notified the Authority of such event within 14 days of its occurrence;

(c) the licensee has provided details of the exceptional event and such further information, if any, as the Authority may require in relation to such an exceptional event; and

(d) the Authority is satisfied that the event notified to it under sub-paragraph (b) is an exceptional event

the Authority may, by notice to the licensee, direct that the number of incentivised loss of supply events in incentive period y shall be adjusted as specified in that direction.

7. For the purpose of paragraph 6, the adjustment directed by the Authority shall be based on the extent to which the Authority is satisfied that the licensee had taken reasonable steps to prevent the event having the effect of interrupting supply and to mitigate its effect (both in anticipation and subsequently).

8. A direction under paragraph 6 shall not have effect unless, before it is made, the Authority has given notice to the licensee:

(a) setting out the terms of the proposed direction;

(b) stating the reasons why it proposes to issue the direction; and

(c) specifying the period (not being less than 14 days from the date of the notice) within which the licensee may make representations or objections

and the Authority has considered such representations or objections and given reasons for its decision.

9. For the purpose of paragraph 6, an “exceptional event” means an event or circumstance that is beyond the reasonable control of the licensee and which results in or causes electricity not to be supplied to a customer and includes (without limitation) an act of the public enemy, war declared or undeclared, threat of war, terrorist act, revolution, riot, insurrection, civil commotion, public demonstration, sabotage, act of vandalism, fire (not related to weather), any severe weather event resulting in more than 7 faults being recorded by the licensee on the licensee’s transmission system in any 24 hour period, governmental

restraint, Act of Parliament, any other legislation, bye law or directive (not being any order, regulation or direction under section 32, 33, 34 and 35 of the Act) or decision of a Court of competent authority or the European Commission or any other body having jurisdiction over the activities of the licensee provided that lack of funds shall not be interpreted as a cause beyond the reasonable control of the licensee.

Part 2 – Revenue Drivers

10. For the purposes of paragraph 1, the maximum revenue allowed to the licensee as a consequence of works to accommodate generation seeking connection in respect of relevant year t (RevDrvSHEt) shall be derived in accordance with this condition, where:

relevant generation capacity	means the cumulative amount of generation connection capacity connected to a part of the licensee's transmission system or connected to a distribution system which in turn connects directly to a part of the licensee's transmission system (but excluding high cost projects) for which attributable transmission reinforcement works are completed and commissioned (in accordance with the System Operator Transmission Owner Code, STC) after 31 March 2005;
generation connection capacity	means the connection capacity that transmission reinforcement works have been contracted and constructed to deliver in the relevant Transmission Operator Connection Agreements between the licensee and the system operator pursuant to the STC;
relevant embedded	

generation capacity	means the total registered capacity of Small Power Stations (as defined in the Grid Code) connected to a distribution system which in turn connects directly to a part of the licensee's transmission system, for which attributable distribution connection works are completed and commissioned after 31 March 2005, as reported by the GB System Operator to the licensee in the most recent Week 24 report provided in accordance with its obligations under the STC;
high cost project	means local infrastructure works where the licensee, estimates, using reasonable endeavours, that the capital expenditure incurred in completing the relevant set of local infrastructure works will exceed £130,000 (in 2004/05 prices) per megawatt of predicted capacity;
local infrastructure works	means sole user triggered transmission reinforcement works associated with the connection of new or additional generation capacity to a part of the licensee's transmission system (or connected to a distribution system which in turn connects to a part of the licensee's transmission system) as specified in relevant agreements between the licensee and the system operator pursuant to the STC; and
deep reinforcement works	means infrastructure works other than local infrastructure works as specified in relevant agreements between the licensee and the system operator pursuant to the STC.

11. For the purposes of paragraph 1, RevDrvSHEt shall be calculated in accordance with the following formula:

$$\mathrm{Re}vDrvSHE_t = \left[RDDep_t + \left(\left(\frac{RDO_t + RDC_t}{2} \right) \times RD\mathrm{Re}t \right) + \left(RDGAV_t \times 0.01 \right) \right] \times PIT_t$$

where:

$RDDep_t$ means an allowance, expressed in 2004/05 prices, for depreciation in relevant year t and shall be calculated in accordance with the formula below:

$$RDDep_t = 0.05 \times RDGAV_t$$

RDO_t means the value, expressed in 2004/05 prices, of the revenue driver RAV on 1 April of the relevant year t and shall, in respect of the relevant year commencing 1 April 2007 take a value of zero. In respect of the relevant year commencing 1 April 2008 and each subsequent relevant year t, RDO_t shall be calculated in accordance with the following formula:

$$RDO_t = RDC_{t-1}$$

RDC_t means the value, expressed in 2004/05 prices, of the revenue driver RAV on 31 March of the relevant year t. In the relevant year commencing 1 April 2007 and in each subsequent relevant year RDC_t shall be calculated in accordance with the following formula:

$$RDC_t = RDO_t + RDAdd_t - RDDep_t$$

where

$RDAdd_t$ means the total additions, expressed in 2004/05 prices, to the revenue driver RAV that occur during in relevant year t and shall be calculated in accordance with the formula in paragraph 12 of this condition.

RDRet means the pre-tax rate of return expressed in real terms allowed on the revenue driver RAV and, for the purposes of this condition, shall take a value of 6.25% for all relevant years.

$RDGAV_t$ means the cumulative gross value of the Revenue driver RAV, expressed in 2004/05 prices, as at 31 March in relevant year t-1 and shall be calculated in accordance with the following formula:

$$RDGAV_t = \sum_{p=t-z}^{p=t-1} RDAdd_p$$

where:

p shall means the relevant year commencing 1 April;

$RDAdd_p$ shall take the value of $RDAdd_t$ for relevant year t=p, where $RDAdd_t$ shall take the same meaning as given in the definition of RDC_t above;

p=t-z means the relevant year commencing 1 April 2004; and

PIT_t shall take the same meaning as given in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services).

12. The term RDAddt shall be calculated in accordance with the following conditions:

If $RG_{t-2} \leq 1489 < RG_{t-1}$ then:

$$
\begin{aligned}
RDAdd_t = {} & \left(\frac{RG_{t-1} - 1489}{RG_{t-1} - RG_{t-2}}\right) \times \left(0.75 \times \left(RDCLCpx_t - \left(1 + RD\mathrm{Ret}\right) \times RDCLCpx_{t-1}\right)\right) \\
& + \left(RG_{t-1} - 1489\right) \times \left(\left(LRD \times 1.13\right) \times 0.25\right) \\
& + 0.75 \times \left(RDCDCpx_t - \left(1 + RD\mathrm{Ret}\right) \times RDCDCpx_{t-1}\right) \\
& + \sum_c \left(OFlag_{c,t} \times \left(\left(ORD_c \times 1.13\right) \times 0.25\right)\right) \\
& + \sum_h \frac{RDHCP_{h,t}}{PIT_t}
\end{aligned}
$$

If $1489 < RG_{t-2} \leq RG_{t-1}$, then:

$$
\begin{aligned}
RDAdd_t = {} & 0.75 \times \left(RDCLCpx_t - \left(1 + RD\mathrm{Ret}\right) \times RDCLCpx_{t-1}\right) \\
& + \left(RG_{t-1} - RG_{t-2}\right) \times \left(\left(LRD \times 1.13\right) \times 0.25\right) \\
& + 0.75 \times \left(RDCDCpx_t - \left(1 + RD\mathrm{Ret}\right) \times RDCDCpx_{t-1}\right) \\
& + \sum_c \left(OFlag_{c,t} \times \left(\left(ORD_c \times 1.13\right) \times 0.25\right)\right) \\
& + \sum_h \frac{RDHCP_{h,t}}{PIT_t}
\end{aligned}
$$

In all other cases:

$$
\begin{aligned}
RDAdd_t = {} & 0.75 \times \left(RDCDCpx_t - \left(1 + RD\mathrm{Ret}\right) \times RDCDCpx_{t-1}\right) \\
& + \sum_c \left(OFlag_{c,t} \times \left(\left(ORD_c \times 1.13\right) \times 0.25\right)\right) \\
& + \sum_h \frac{RDHCP_{h,t}}{PIT_t}
\end{aligned}
$$

where:

RG_{t-1}	means the relevant generation capacity as at 31 March of relevant year t-1;
RG_{t-2}	means the relevant generation capacity as at 31 March of relevant year t-2;
$RDCLCpx_t$	means the cumulative capital expenditure, expressed in 2004/05 prices, (adjusted for financing costs) incurred by the licensee prior to 1 April of relevant year t in respect of local RD qualifying projects for relevant year t, and shall be calculated in accordance with the formula in paragraph 14;
$RDCLCpx_{t-1}$	is equal to the value of $RDCLCpx_t$ for the preceding relevant year;
local RD qualifying project	means local infrastructure works being undertaken by the licensee: (a) which result, or have resulted, in the volume of relevant generation first exceeding 1489 megawatts; or (b) will be, or have been, completed and commissioned after the point at which the volume of relevant generation is equal to or exceeds 1489 megawatts; to provide generation connection capacity where the licensee has, or will have, prior to 1 April of relevant year t, committed to spend not less than 25 per cent of the capital expenditure that it estimates, using reasonable endeavours, will be incurred in completing the set of relevant local infrastructure works;

LRD	shall take the value £32,000 (expressed in 2004/05 prices);
$RDCDCpx_t$	means the cumulative capital expenditure, (expressed in 2004/05 prices) incurred by the licensee prior to 1 April of relevant year t in respect of deep RD qualifying projects;
$RDCDCpx_{t-1}$	is equal to the value of $RDCDCpx_t$ for the preceding relevant year;
deep RD qualifying project	means deep reinforcement works being undertaken by the licensee:
	which are relevant to the conditions set out in Table 1 of paragraph 13, and
	for which the licensee will have, prior to 1 April of relevant year t, committed to spend not less than 25 per cent of the capital expenditure that it estimates, using reasonable endeavours, will be incurred in completing these works;
$DFlag_{c,t}$	shall take the value 1 if deep reinforcement project c was completed and commissioned in the relevant year t, and otherwise it shall take the value 0;
DRD_c	shall take the corresponding value (expressed in 2004/05 prices) in Table 1 of paragraph 13 in respect of each specified area c; and
$RDHCP_{h,t}$	means the capital expenditure incurred by the licensee during relevant year t in respect of high cost project h, as defined in paragraph 10.

13. **<u>Table 1</u>**

c	Conditions – relevant generation capacity and relevant embedded generation capacity in areas (as identified in Annex A to this condition)	Thresholds (MW)	DRD_c (£m, 2004/05 prices)
1	North of North West boundary	1850	52
2	North of North of Beauly boundary	300	47
3	South of Port Ann within the South West zone	85	89
4	North of Inverary within the South West zone	105	52

The Authority may direct changes to Table 1 where the licensee provides a report to the Authority setting out how material changes in flows on the licensee's network or other relevant factors have resulted in changes in the costs of deeper reinforcement on its network and an up-to-date estimate of the efficient costs of relevant works. The Authority will consult with interested parties prior to issuing a direction.

14. RDCLCpxt shall be calculated in accordance with the following formula:

$$RDCLCpx_t = \sum_i \sum_{s=T-z}^{s=T-1} \left[\left(\frac{1}{PIT_s} \right) \times \left(RDALCpx_{i,s} \times \left(1 + RD\mathrm{Re}t \right)^{(T-S)+0.5} \right) \right]$$

where

i refers to each set of local infrastructure works which is a local RD qualifying project for year t;

s refers successively to each relevant year from that commencing 1 April 2005 to that preceding relevant year t;

$RDALCpx_{i,s}$ means the capital expenditure incurred by the licensee during relevant year s on project i ;

T shall take a value equal to the calendar year in which relevant year t ends, e.g. for relevant year commencing 1 April 2007 the value of T shall be 2008;

T-z refers to the relevant year commencing 1 April 2005;

S shall take a value equal to the calendar year in which relevant year s starts e.g. for relevant year 2007/08 the value of S shall be 2007; and

PIT_s shall take the value of PIT_t for relevant year t=s, where PIT_t shall take the same meaning as given in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services).

15. RDCDCpxt shall be calculated in accordance with the following formula:

$$RDCDCpx_t = \sum_c \sum_{x=T-p}^{x=T-1} \left[\left(\frac{1}{PIT_x} \right) \times \left(RDADCpx_{c,x} \times \left(1 + RD\mathrm{Re}t\right)^{(T-S)+0.5} \right) \right]$$

where

c refers to each set of deep reinforcement works which is a deep RD qualifying project for year t;

x	refers successively to each relevant year from that commencing 1 April 2007 to relevant year t;
T-p	refers to the relevant year commencing 1 April 2007;
T	shall take a value equal to the calendar year in which relevant year t ends, e.g. for relevant year commencing 1 April 2007 the value of T shall be 2008;
S	shall take a value equal to the calendar year in which relevant year x starts e.g. for relevant year 2007/08 the value of S shall be 2007;
$RDADCpx_{c,x}$	means the annual capital expenditure incurred by the licensee in relevant year x on project c.

Part 3 – Calculation of charge restriction adjustments arising from the innovation funding incentive scheme

16. The purpose of this condition is to provide for adjustments to allowed transmission owner revenue to reflect performance of the licensee in relation to its investment in innovation under the Innovation Funding Incentive (IFI) scheme.

17. For the purposes of paragraph 1, IFIt is derived for the relevant year t from the formula:

$$IFI_t = ptri_t \times \left(\min\left(FIE_t, \left(\max\left(\left(£500{,}000 + KIFI_t \right), \left(0.005 \times \left(PR_t + TIRG_t \right) \right) + KIFI_t \right) \right) \right) \right)$$

where:

$IFIE_t$ means the eligible IFI expenditure for the relevant year t as reported in the IFI annual report for that year.

PR_t means the base transmission revenue in year t as determined in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services);

$TIRG_t$ means the annual revenue allowance in year t as determined in special condition J3 (Restriction of transmission charges: Transmission Investment for Renewable Generation);

$ptri_t$ is the pass-through factor applicable for the relevant year t and shall in the relevant year commencing 1 April 2007 and each subsequent relevant year take the value 0.8; and

$KIFI_t$ is the carry forward in relation to the IFI scheme as set out in the IFI annual report for relevant year t-1, and is calculated from the following formula:

If $IFIE_{t-1} \le 0.5 \times max(500{,}000, 0.005 \times (PR_{t-1} + TIRG_{t-1}))$:

$$KIFI_t = 0.5 \times max(500{,}000, 0.005 \times (PR_{t-1} + TIRG_{t-1}))$$

If $IFIE_{t-1} > 0.5 \times max(500{,}000, 0.005 \times (PR_{t-1} + TIRG_{t-1}))$ and

$IFIE_{t-1} \le max(500{,}000, 0.005 \times (PR_{t-1} + TIRG_{t-1}))$:

$$KIFI_t = max(500{,}000, 0.005 \times (PR_{t-1} + TIRG_{t-1})) - IFIE_{t-1}$$

If $IFIE_{t-1} > max(500{,}000, 0.005 \times (PR_{t-1} + TIRG_{t-1}))$:

$$KIFI_t = 0$$

where, for the year commencing 1 April 2007, $KIFI_t$, shall be zero

18. For the purposes of this condition:

“eligible IFI expenditure”	means the amount of expenditure spent or accrued by the licensee in respect of eligible IFI projects;
“eligible IFI projects”	means those projects that meet the requirements described for such projects; and
“IFI annual report”	means the report produced each year by the licensee, in a format agreed with the Authority, in respect of expenditure and innovation.

in each case above, all as more fully set out in the revenue reporting Regulatory Instructions and Guidance for the time being in force under standard condition B16 (Price Control Revenue Reporting and Associated Information) in relation to the IFI scheme.

Part 4 - adjustment to restriction of transmission charges due to SF_6 incentive

19. The purpose of this condition is to provide for adjustments to allowed revenue to reflect performance of the licensee in relation to its Sulphur Hexafluoride (SF6) incentive scheme.

20. The licensee shall within 3 months of receiving a notice from the Authority submit to the Authority a leakage rate of SF6 methodology statement consistent with best industry practice, setting out the methodology by which the licensee will determine the leakage rate of SF6 gas, required for the calculation of the actual leakage rate of SF6 gas, ALKt, and the target leakage rate of SF6 gas, TLKt.

21. Unless the Authority directs otherwise within 2 months of the date on which the licensee submits the statement to the Authority in accordance with paragraph 20, the licensee shall take all reasonable steps to apply the methodology set out in that statement.

22. Before revising the methodology referred to in paragraph 20 the licensee shall submit to the Authority a copy of the proposed revisions to the methodology.

23. Unless the Authority directs otherwise within 1 month of the Authority receiving any proposed revisions to the methodology under paragraph 22, the licensee shall take all reasonable steps to apply the methodology revised in accordance with such proposed revisions.

24. The provisions of paragraphs 26 to 31 of this special licence condition shall not take effect until such time as directed by the Authority.

25. For the purposes of paragraph 1 of this special condition, SFIt shall take the value zero until such time as the Authority directs that the provisions of paragraphs 26 to 31 shall take effect.

26. For the purposes of paragraph 1, where ALKt < TLKt, SFIt shall be calculated in accordance with the following formula:

$$SFI_t = 0.002 \times PR_t$$

otherwise: SFI_t shall take the value zero (0).

Where:

PR_t	means the licensee's base transmission revenue, as defined in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services)
ALK_t	means the actual leakage rate of SF_6 gas in relevant year t as a percentage of inventory of SF_6 gas as reported by the licensee pursuant to the revenue

reporting Regulatory Instructions and Guidance issued in accordance with standard condition B16 (Price Control Revenue Reporting and Associated Information)

TLK_t means the target leakage rate of SF_6 gas in relevant year t as a percentage of inventory of SF_6 and shall take the values in the table below:

Relevant year t	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**
TLK_t	[]	[]	[]	[]	[]

27. Where:

(a) the licensee considers that any event on the licensee's transmission system that causes leakage of SF_6 gas has been wholly or partially caused by an exceptional event;

(b) the licensee has notified the Authority of such event within 14 days of its occurrence;

(c) the licensee has provided details of the exceptional event and such further information, if any, as the Authority may require in relation to such an exceptional event; and

(d) the Authority is satisfied that the event notified to it under sub-paragraph (b) is an exceptional event

the Authority may, by notice to the licensee, direct that actual leakage of SF6 gas and the value of ALKt in relevant year t shall be adjusted as specified in that direction. In directing the value of any adjustment to ALKt in relevant year t pursuant to this paragraph, the Authority shall reserve the right to modify the value of any proposed adjustment notified by the licensee that may be made to ALKt in relevant year t.

28. For the purpose of paragraph 27, any adjustment directed by the Authority shall be based on the extent to which the Authority is satisfied that the licensee had taken reasonable steps to prevent the event from resulting in the leakage of SF6 and to mitigate its effect (both in anticipation and subsequently).

29. A direction under paragraph 27 shall not have effect unless, before it is made, the Authority has given notice to the licensee:

(d) setting out the terms of the proposed direction;

(e) stating the reasons why it proposes to issue the direction; and

(f) specifying the period (not being less than 14 days from the date of the notice) within which the licensee may make representations or objections

and the Authority has considered such representations or objections and given reasons for its decision.

30. For the purpose of paragraph 27, an “exceptional event” means an event or circumstance that is beyond the reasonable control of the licensee and which results in or causes the leakage of SF6 gas and includes (without limitation)an act of the public enemy, war declared or undeclared, threat of war, terrorist act, revolution, riot, insurrection, civil commotion, public demonstration, sabotage, act of vandalism, fire (not related to weather), governmental restraint, Act of Parliament, any other legislation, bye law or directive (not being any order, regulation or direction under section 32, 33, 34 and 35 of the Act) or decision of a Court of competent authority or the European Commission or any other body

having jurisdiction over the activities of the licensee provided that lack of funds shall not be interpreted as a cause beyond the reasonable control of the licensee.

31. Without prejudice to paragraph 30, an “exceptional event” may include circumstances where a significant danger to the public gives rise to the licensee prioritising health and safety over the reduction of leakage of SF6 gas at a particular site.

Part 5 – Adjustment to the Restriction of Transmission Charges in respect of the Capital and Operating Expenditure Incentive Mechanisms

32. For the purposes of paragraph 1, RCIt is derived for the relevant year t from the formula:

$$RCI_t = ARCI_t \times PIT_t$$

where:

$ARCI_t$ means the allowance, in 2004/05 prices, made by the Authority in respect of rolling incentive revenues and shall take the value given in the table below:

Relevant year t commencing on 1 April	2007	2008	2009	2010	2011
$ARCI_t$	£0.4 million	£0.2million	-£0.1 million	Nil	Nil

PIT_t shall take the same meaning as given in paragraph 3 of special condition J2 (Restriction of transmission charges: revenue from transmission owner services).

Part 6 - Adjustment to restriction of transmission charges due to approved operating expenditure

33. The purpose of this part of this condition is to provide for an adjustment to the maximum revenue to reflect approved operating expenditure.

34. For the purpose of paragraph 1, $RevApOx_t$ shall be calculated in accordance with the following formula:

$$RevApOx_t = ApPreCon_t$$

Where:

$ApPreCon_t$	means the pre-construction transmission reinforcement expenditure for relevant year t as described in paragraph 35.

35. For the purpose of paragraph 34, $ApPreCon_t$ shall have the value of zero unless directed otherwise by the Authority in writing.

Annex 5 – NGET project information

Work 2009

Sector : **Incremental – Scottish export**

Scope:	Reconductor Harker – Quernmore, 116km install 2x GAP conductor Series Compensation : install in Harker- Hutton circuits 300MVAr Harker- Stella circuits 150MVAr Stella- Spennymoor circuits 300MVAr	Shared Cost NG-SP	SP Cost	NG Cost
Involvement		Budget £k	Budget £k	Budget £k
Program Manager				[redacted]
System Design	Network studies, define technical performance and scope. Review stability performance, network performance and QoS issues associated with installation of series compensation. Purchase specialist software, and training. System studies to analyse and resolve system performance to enable definition of scope of DC and series compensation systems. Network modelling and studies to define control system performance and operation. Harmonic studies, DC filter design, stability and voltage studies etc. Work with suppliers to confirm detailed system models/ use supplier systems to validate designs Additional software and training. Multiple studies of alternative network solutions to support /demonstrate validity of design proposals/ option selection. Scheme process, documentation, management of design process and records, integration of works into planned schemes. Sanction process			[redacted]
Contractors	Technical support to network modelling, outline design and budget. Commercial response to procurement process	[redacted]		
Land & Development	Site selection and high level environmental constraints identification for series compensation sites. High level consultation to identify preferred site locations. Surveys and EIA work, land purchase option and commence work towards planning application Support line re-conductor works			[redacted]
Engineering	Develop outline designs and consider impact to existing			

	projects, identify solutions, cost and programme implications, determine preferred solutions. Outline design site installations and overhead line access arrangements Iterative design solution in consultation with consents process and requirements , programme and budget. Create specifications and tender documents for series compensation, respond to technical questions, and evaluate responses. Evaluate overhead line route for re-conductor and programme/ budget works. Produce policies and standards for DC systems and Series Compensation installations and systems –sub-systems. Audit and review of specifications and tender proposals Produce policies and standards for DC systems and Series Compensation installations and systems –sub-systems. Audit and review of specifications and tender proposals.	[redacted]		[redacted]
Consultants & Support	Technical consultant support Employ specialist environmental /planning consultants, commence environmental assessments. Appoint Community Relations consultants and develop communications strategy.	[redacted]		[redacted] [redacted]
Commercial	Develop procurement strategy and issue EU PIN notices for technical support and purchase process for series compensation.			[redacted]
	Total	1000-1500		980-1195

Work 2009

Sector: **West Coast DC link**

Scope:	Deeside: New 400kV 21 bay GIS substation together with line entry and generator connection rationalisation. DC converter ~2GW capacity installation at Deeside (and Hunterston) DC cable connection from Deeside to Hunterston, 340km, submarine and land sections.	Shared Cost NG-SP	SP Cost	NG Cost
Involvement		Budget £k	Budget £k	Budget £k
Program Manager			[redacted]	[redacted]
System Design	System modelling, network performance studies. Determine technical performance specification for DC system, in conjunction with SP.		[redacted]	[redacted]

	System studies to analyse and resolve system performance to enable definition of scope of DC and series compensation systems. Network modelling and studies to define control system performance and operation. Harmonic studies, DC filter design, stability and voltage studies etc. Work with suppliers to confirm detailed system models/ use supplier systems to validate designs Additional software and training. Multiple studies of alternative network solutions to support /demonstrate validity of design proposals/ option selection. Scheme process, documentation, management of design process and records, integration of works into planned schemes. Sanction process Purchase specialist software, and training.			
Contractors	Engage contractors to support technical study work to provide detailed network modelling and performance optimisation studies. Commence on identifying filter design and connection configuration. Provide outline designs of converter installations and integrate with existing site designs.. Produce policies and standards for DC systems and Series Compensation installations and systems – sub-systems. Produce policies and standards for DC systems and Series Compensation installations and systems – sub-systems. Audit and review of specifications and tender proposals. Support cable route studies and identification of preferred routes. Support environmental assessment. Appointment of Preferred supplier and secure manufacturing/resources	[redacted] [redacted]		
Land & Development	Design options review. Initiate route and landing site selection and high level environmental constraints identification. Initiate high level stakeholder engagement on options Input to scheme team of 400kV substation design/ location.		[redacted]	[redacted]
Engineering	Develop specifications and standards for DC converter installations. Determine optimal layout, line entry changes and generator connection design for Deeside 400kV substation with DC converter included. Detailed design of 400kV substation. Support planning permission process for DC converter. Create optimal phasing of connections/ land use to enable DC converter construction to meet required	[redacted]	[redacted]	[redacted] [redacted] [redacted]

	programme. Produce policies and standards for DC systems and Series Compensation installations and systems –sub-systems. Audit and review of specifications and tender proposals DC converter tender specification, project management and tender process progress. Programme and budget management.			
Consultants & Support	Appoint consultants to undertake specialist Cable route surveys (marine and land). Cable Route Studies and identification of Preferred routes. (e.g. Metoc or others) Appoint specialist environmental and planning aspects consultants. Commence Environmental Assessment Engage Community relations consultants and develop communications strategy. Engage specialist DC system designers. Sea bed marine survey, (if required in 2009/10)	[redacted] [redacted] [redacted] [redacted]	[redacted] [redacted] [redacted]	[redacted] [redacted] [redacted]
Commercial	Develop commercial procurement strategy and EU PIN notice / procurement procedure. Embark on staged tendering and appointment process, tender evaluation, appoint preferred supplier. Commence negotiations with Deeside Power regarding any connection changes. (NB Excludes, external legal fees, if required)	[redacted]	[redacted]	[redacted] [redacted]
	Total	2960-3310	800-1050	990-1240

Notes :

2. Commitment may equal [redacted] but, not necessarily all expended in 2009, required to maintain programme for Converter + cable.
3. The Mechanism for engaging Contractors will be subject to an agreed procurement and delivery strategy.
4. Spend in 09/10 will be determined by the time taken to secure a contract for the works.

Work 2009

Sector: **North Wales**

Scope:	New 400kv Overhead Line Wylfa - Pentir, • 35km 3x700sq.mm double circuit overhead line • Extension of Pentir 400kV substation • Modification of Wylfa 400kv substation. Establish a second Pentir – Trawsfynydd 400kV circuit by; • Rationalising the existing SP Manweb owned 132kV circuit, strung between Trawsfynydd and tower 4ZC70, for operation at 400kV by re-conductoring the circuit using 2x700mm^2 conductor. • Create a new 400/132kV Single Switch GSP to supply SP Manweb. • Establish a 3 bay single switch mesh substation at Penisarwaun to	

	allow the tee connection of the Trawsfynydd leg of the new Pentir – Trawsfynydd circuit. • Reconfiguration and extension of Pentir 400kV substation by 1 bay • At Trawsfynydd 400kV connect the circuit by utilising the spare line disconnector bay on Mesh corner 3. • Installation of approximately 5.8km of 2x2500mm^2 400kV XLPE cable to cross the Glaslyn Estuary. Re-conductor Trawsfynydd- Deeside with 2XGAP conductor, 78km. Install Series Compensation in Trawsfynydd- Deeside circuits 120MVAr	
Involvement		Budget £k
Program Manager		[redacted]
System Design	Optimise design as generation pattern develops, determine stability limits and undertake a full QoS issues System studies to analyse and resolve system performance to enable definition of scope of DC and series compensation systems. Network modelling and studies to define control system performance and operation. Harmonic studies, DC filter design, stability and voltage studies etc. Work with suppliers to confirm detailed system models/ use supplier systems to validate designs Additional software and training. Work with DNO to develop a integrated approach to development in north Wales. Multiple studies of alternative network solutions to support /demonstrate validity of design proposals/ option selection. Scheme process, documentation, management of design process and records, integration of works into planned schemes. Sanction process	[redacted]
Contractors	Support to Harmonic, NPS ans SSR analysis	[redacted]
Land & Development	Options review. Initiate OHL routeing study and high level environmental constraints identification. Initiate high level stakeholder engagement on options [as required under IPC]. Site selection and high level environmental constraints identification for series compensation site. High level consultation to identify preferred site locations. Site specific surveys and EIA work on preferred route corridor	[redacted] [redacted]
Engineering	Develop outline designs and consider impact to existing projects Outline Design site installations and overhead line access arrangements Iterative design solution in consultation with consents process and requirements, programme and budget. High level design of new overhead line route and consideration of design options. Determine preferred options. Evaluate overhead line route for re-conductoring and programme/ budget, modify existing project works, and arrange system access requirements. Project Management	[redacted]
Consultants & Support	Line routing studies. Environmental impact assessments and line routeing studies.	[redacted]

	Substation siting study for series compensation. Appoint Community Relations consultants and develop communications strategy.	[redacted]
Commercial	Negotiate and Agree connection arrangements with SP Manweb. Develop procurement strategy and issue EU PIN notices for technical support and purchase process for series compensation	[redacted]
	Total	705-955

NB Need to commit to Deeside 400kV asset replacement in early 2010, estimated £80M

Work 2009

Sector: **Humberside**

Scope:	New 400kV 12-14 Bay 400kV substation and overhead line entry changes, south of existing Killingholme 400kV substation. Re-Build of Walpole 400kv substation with new 21 bay 400kV substation. DC converters ~2GW capacity at Walpole and new Humber substation location. New DC circuit(s) between Walpole and New Humber substation 130km.	
Involvement		Budget £k
Program Manager		[redacted]
System Design	Optimise design as generation pattern develops, determine stability limits and undertake a full QoS issues	[redacted]
Contractors	Engage with suppliers to investigate study and compare alternative design options, and issues regarding multi-terminal operation, construction and operational aspects. Costs for specialist service.	[redacted]
Land & Development	Design options review. Initiate routeing study (i.e on land or off shore option) and high level environmental constraints identification. Initiate high level stakeholder engagement on options [as required under IPC]. Design options review. Site selection and high level environmental constraints identification for works at substation and converter station works at Killingholme and Walpole.	[redacted] [redacted]
Engineering	Explore and high level design/programme/budget alternative design options. Investigate alternative costs, designs, and high level impacts of different Cable or Overhead line DC connection options. Design outline site installations and overhead line access arrangements Iterative design solution in consultation with consents process and requirements, programme and budget. Draft specifications and tender documents for DC Systems, respond to technical questions, and evaluate responses. High level design of new DC route and consideration of design options. Determine preferred options.	[redacted] [redacted]
Consultants & Support	Employ specialist environmental /planning consultants.: routing study Killingholme - Walpole siting studies – Killingholme / Walpole siting studies – converter stations	[redacted]

	submarine cable route study	[redacted]
Commercial	Develop procurement strategy and issue EU PIN notices for technical support and purchase process for DC links.	
	Total	885-1205

Work 2009

Sector: **Anglia**

Scope:	Reconductor Walpole-Norwich-Bramford with 3x700 conductor 140km. Install Series Capacitors in Norwich- Bramford circuits 300MVAr Extend Bramford 400kV substation to accommodate turn-in of Norwich - Sizewell circuits and 2 new bays for new 400kV route to Twinstead, plus associated protection and control system changes at remote ends of connections. New 400kV overhead line Bramford-Twinstead, 3x 700, 35km. Install Quadrature Booster units in Walpole- Burwell- Pelham route, 2x	
Involvement		Budget £k
Program Manager		[redacted]
7System Design	Optimise design as generation pattern develops, determine stability limits and undertake a full QoS issues, liaise with DNO to develop a co-ordinated reinforcement strategy	[redacted]
Contractors		
Land & Development	Design options review. Initiate OHL routeing study and high level environmental constraints identification. Initiate high level stakeholder engagement on options [as required under IPC]. [tenders received contract to be placed ASAP] Site selection and high level environmental constraints identification for series compensation site/QB. High level consultation to identify preferred site locations. Lands Officer support to re-conductor project	[redacted] [redacted]
Engineering	Develop outline designs and consider impact to existing projects for substation changes and extensions, identify solutions, cost and programme implications, determine preferred solutions. Design site installations and overhead line access arrangements Iterative design solution in consultation with consents process and requirements, programme and budget. Create specifications and tender documents for series compensation, respond to technical questions, and evaluate responses. High level design of new overhead line route and consideration of design options. Determine preferred options. Evaluate overhead line route for re-conductoring and programme/ budget, Project Management	[redacted] [redacted]
Consultants & Support	Employ specialist environmental /planning consultants: routing study Bramford-Twinstead tee siting studies for series compensation siting studies for QBs	[redacted]
Commercial		

	Total	775-1030

NB Need to commit to Bramford 400kV asset replacement by early 2010, estimated £90M

Work 2009

Sector: East Coast DC Link

Scope:	DC converter ~2GW capacity installation at Hawthorn Pit (and Peterhead) DC cable connection from Hawthorn Pit to Peterhead, 360km, submarine and land sections Hawthorn Pit: establish new 400kV substation 9 bay plus 1 additional 400/275kV SGT connected to existing Hawthorn Pit 275kv. Modify line entries. Uprate existing Hawthorn Pit to Norton 275kv circuit to 400kV operation, transfer into 400kV substations Extend Norton 400kV GIS by 1 bay for new Hawthorn Pit circuit.	
Involvement		Budget £k
System Design	Integration Studies	[redacted]
Contractors		
Land & Development	Input to scheme team developing scheme – as programme assume no routeing or constraints mapping work until 2010.	[redacted]
Engineering	Outline designs Hawthorn Pit/ Norton – identify land / site issues. Explore DC rating options. Project Management	[redacted] [redacted]
Consultants & Support	Submarine cable high level route study	
Commercial	Commercial strategy, in conjunction with other DC links	[redacted]
	Total	160

Work 2009

Sector: Hinkley-Seabank New Route

Scope:	New 400kV 18 bay GIS substation, Hinkley Circuit Changes to connect to new 400kV Hinkley substation New 400kV overhead line to Seabank 43km, cutting into existing Hinkley-Melksham route to create Hinkley-Seabank, plus Melksham – Bridgewater. Uprate section to Melksham to 2x 500 Extend Seabank substation by 2 bays Modify Bridgewater substation, install two 400/132kv SGT's to uprate to 400kv operation	
Involvement		Budget £k
Program Manager		[redacted]
System Design	Optimise design as generation pattern develops, determine stability limits and undertake a full QoS issues, liaise with DNO to develop a co-	[redacted]

	ordinated reinforcement strategy	
Contractors		
Land & Development	Initiate OHL routeing study and high level environmental constraints identification. Initiate high level stakeholder engagement on options [as required under IPC]. [Work on substation extension options Site specific surveys and EIA work on preferred route corridor to commence on IPC application process.	[redacted] [redacted] [redacted]
Engineering	Outline design and support consents process / option selection of overhead line route analysis	[redacted]
Consultants & Support	Employ specialist environmental /planning consultants. routing study Hinkley-Seabank	[redacted]
Commercial		
	Total	535-685

Work 2009

Sector: London: Waltham Cross-Hackney

Scope:	New 400kV substation, Waltham Cross Circuit Changes to connect to new 400kV Waltham Cross substation Modify existing Waltham Cross- Tottenham- Hackney overhead line to 400kV operation. Reconductor with xxxxx Modify Tottenham substation Brimsdown substation, install two 400/132kv SGT's to uprate to 400kv operation Hackney substation – xx new SGT's, modify to 400kV operation.	
Involvement		Budget £k
System Design	Optimise design as generation pattern develops, determine stability limits and undertake a full QoS issues, liaise with DNO to develop a co-ordinated reinforcement strategy	[redacted]
Contractors		
Land & Development	Work on substation extension options	[redacted] [redacted]
Engineering	Outline design and support consents . Outline substation designs, programme and line revisions designs / option selection	[redacted]
Consultants & Support	Employ specialist environmental /planning consultants.	[redacted]
Commercial		
	Total	425-700

Sector: Mid- Wales

Scope:	400kV substation extension for DC converter connection – location to be confirmed (Carnedd Wen). DC converters ~0.8GW capacity New DC circuit(s) between Mid Wales terminal location and substation approx. 60km.	
Involvement		Budget £k
Program Manager		[redacted]
System Design	Optimise design as generation pattern develops, determine stability limits and undertake a full QoS issues	[redacted]
Contractors	Engage with suppliers to investigate study and compare alternative design options, and issues regarding multi-terminal operation, construction and operational aspects. Costs for specialist service.	[redacted]
Land & Development	Design options review. Initiate routeing study and high level environmental constraints identification. Initiate high level stakeholder engagement on options [as required under IPC]. Design options review. Site selection and high level environmental constraints identification for works at substation and converter station	[redacted] [redacted]
Engineering	Explore high level design/programme/budget alternative design options. Investigate alternative costs, designs, and high level impacts of different Cable or Overhead line DC connection options. Design outline site installations and overhead line access arrangements Iterative design solution in consultation with consents process and requirements, programme and budget. Draft specifications and tender documents for DC Systems, respond to technical questions, and evaluate responses. High level design of new DC route and consideration of design options. Determine preferred options.	[redacted] [redacted]
Consultants & Support	Employ specialist environmental /planning consultants. routing study siting studies – converter stations Communications	[redacted]
Commercial	Develop procurement strategy and issue EU PIN notices for technical support and purchase process for DC links.	[redacted]
	Total	470-630

2009 Works

Summary

	Shared cost	SP Cost	NG cost
Incremental	1000-1500		980 -1195
West Coast DC	2960-3310	800-1050	990-1240

North Wales			705-955
Humberside			735-885
Anglia			775-1030
East Coast DC			160
Hinkley- Seabank			535-685
Waltham Cross-Hackney			425-700
Mid Wales			470-630
SUB -TOTAL	3960-4810	800-1050	5925-7800
Total with 50-50 split of shared costs		2780-3455	7905-10205
TOTAL		10685-13660	

NGET Project Rationale

1.0 *Overview*

1.1 This annex provides a summary justification for the National Grid project nominations for the proposed TO incentive arrangements. At the highest level the nominations have been identified going through the following process:

1.1.1 Identifying a range of generation and demand scenarios which meet the EU target for 15% of the UK's energy from renewable sources by 2020. These scenarios have been endorsed by the ENSG.

1.1.2 Using the scenarios it has been possible to assess the required power transfers against the existing and committed system.

1.1.3 The investments identified are based on meeting the current GB Security and Quality of Supply Standard (GB SQSS). The investments, however, have also been subject to a cost benefit analysis to assess the economical requirements for the proposed investment.

1.1.4 Having identified the need for the investment a delivery timescale has been developed to assess when the pre-construction work needs to commence to deliver the investment in a timely manner. The pre-construction requirements for 2009/10 were identified in the submission on 30 January 2009.

1.1.5 The submission only includes those projects that are robust against a credible range of scenarios for meeting the 2020 targets and require some pre-construction work to commence in 2009/10 to keep the option of delivering the transmission investment in a timely manner. Other projects which do not meet the criteria have been included in the work undertaken for ENSG but have not been included in this submission.

1.1.6 The detailed information in the sections below identifies the range of scenarios and sensitivities considered in relation to the proposed regional investments. The potential location of onshore and offshore wind and the opening and closing of nuclear plants were the key sensitivities (although where appropriate sensitivities around the connection of new conventional plant and interconnectors were taken into account). In developing scenarios, factors such as the Scottish Government's targets (which is likely to influence the amount of wind in Scotland)

and the offshore cost information from the Crown Estates report (which provides an indication of the most likely offshore sites for development) have been taken into account.

1.2 The sections below provided further detail on:

1.2.1 The **approach** in developing the scenarios.
1.2.2 The high level **findings** in terms of power flows
1.2.3 The basis upon which **system analysis** has been undertaken
1.2.4 The National Grid **project nominations**

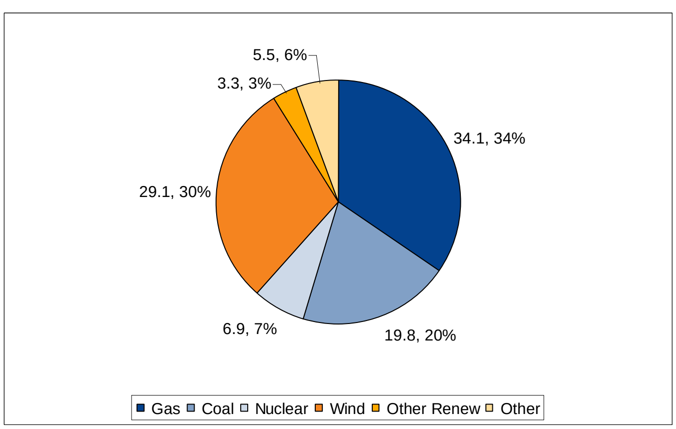
2.0 *Approach*

2.1 The reinforcements put forward are based on a range of scenarios that take into account the significant changes anticipated in the generation mix between now and 2020. In particular, the scenarios examine the potential transmission investments associated with the connection of large volumes of onshore and offshore wind generation that are required to meet the 2020 renewables target and new nuclear generation. The electricity generation and demand scenarios are consistent with the EU target for 15% of the UK's energy to be produced from renewable sources by 2020.

2.2 A number of electricity generation and demand backgrounds have been developed. In their development, numerous factors have been taken into account; particularly in relation to ensuring that the UK and Scottish Executive 2020 targets for renewable energy and the UK target for Greenhouse Gas emissions would be met. Such factors included the analysis of:

- closures of existing plants due to various legislation and age profile;
- contracted new connections for all types of plant;
- the potential for, and location of onshore and offshore wind generation; and
- the potential build rates for wind and new nuclear generating plant.

2.3 In developing a detailed background, issues such as: security of supply; the ability of the supply chain to deliver; and technological advances have been taken into consideration. The fuel mix in the scenario for 2020 (known as the Gone Green scenario) was endorsed by the ENSG and on which the study is based, is set out below:



Generation connected to Transmission

2.4 The resulting generation background scenarios, upon which the studies are based, vary the capacity of renewable generation in Scotland from a minimum of 6.6 GW (this is the minimum required to meet the Scottish Executive target assuming that the existing hydro generation contributes to the target), a second scenario with 8 GW and a final scenario with a maximum of 11.4 GW by 2020. All scenarios considered achieve a total UK renewable energy contribution of 147 TWh by 2020, to achieve this, the volume of offshore windfarm generation in England and Wales was increased to compensate for any volumes less than 11.4 GW in Scotland.

2.5 The total offshore windfarm capacity in England and Wales is assumed to be in the region of 21 GW-25 GW by 2020. In considering how this offshore capacity could be achieved, it is assumed that some 8 GW of Round 1 and 2 wind generation projects will proceed to completion, with the remainder being made up from the proposed Round 3 development sites. In determining the timing and location of the potential projects in England and Wales the report produced by Crown Estate (Round 3 Offshore Wind Farm Connection Study) and the report recently published by DECC (National Grid input into DECC Offshore Energy Strategic Environmental Assessment) were used as basis of the future analysis, together with appropriate sensitivity studies.

2.6 The generation scenarios assume two new nuclear installations with a combined capacity of 3.3 GW by 2020. The existing signed agreements identified in the 2008 GB Seven year Statement (SYS) and subsequent Quarterly Updates, was used as a basis for determining possible future nuclear sites.

2.7 The generation assumptions are entirely independent from and in no way pre-supposes the outcome of individual planning decisions about projects on particular sites and, in the case of nuclear, the Strategic Siting Assessment (SSA) process.

3.0 *Findings*

3.1 The predominant power flow on the GB transmission system is from the North towards the South. In the North of Scotland, local demand is, for the most part, adequately met by the portfolio of hydro generation, Peterhead power station and an increasing number of windfarm developments. Accordingly, there is a predominant net export of energy from the region to the Central Belt of Scotland. Additional power flows in the Central Belt of Scotland, within the SP Transmission (SPT) network, place a severe strain on the 275 kV elements of the network and, in particular, the north to south and east to west power corridors.

3.2 The circuits between Scotland and England are already operating at their maximum capability. Under all the generation scenarios considered, the transfers from Scotland to England increase significantly. Reinforcements identified to relieve the boundary restrictions across these circuits result in power transfers on the Upper North network of the England and Wales transmission system exceeding network capability. South of the Upper North boundary the increased power flows south from Scotland and North West of England progressively diminish as they are offset by the closure and displacement of existing conventional generation along the way. Accordingly, while there are transmission overloads in northern England the effects are greatly muted as the flows travel towards the Midlands.

3.3 Offshore wind generation in England and Wales, together with the potential connection of new nuclear power stations raises a number of regional connection issues; particularly in Wales (North & Central), and the South West and along the English East Coast between the Humber and East Anglia. The increased power transfers across the North to Midlands boundary and/or the increased generation off the East Coast and/or Thames Estuary results in severe overloading of the northern transmission circuits securing London.

4.0 *Analysis to determine transmission reinforcement requirements*.

4.1 In identifying the potential transmission reinforcements, the opportunity was taken to, first, maximise the utilisation of the existing assets. Where the need for significant reinforcements has been identified, consideration has been given to employing the latest technology, especially where additional economic and/or additional environmental benefits can be expected. In such cases, due account has been taken of the lead time required to develop robust engineering solutions and the need to obtain the necessary planning consents for each reinforcement.

4.2 The range of potential power flows on the GB transmission system have been determined on the basis of the currently authorised GB transmission system (i.e. the existing GB transmission system together with all the approved transmission system reinforcements assumed to be in place for the years 2015 and 2020). Such authorised transmission reinforcements include:

- the proposed Beauly – Denny 400 kV line,
- the uprating of the transmission capacity between Scotland & England (TIRG); and,
- the additional transmission capacity around the North West and North East of England.

4.3 Application of the current GB Security and Quality of Supply Standard (GB SQSS) was used in determining the reinforcements necessary under the ‘Gone Green’ generation scenarios. In determining wider infrastructure requirements we have assumed a high level of network sharing. By applying the GB SQSS against the agreed ’Gone Green’ scenarios and appropriate sensitivity studies, a range of potential power transfers can be determined at winter peak. These transfers are not necessarily the maximum transfers and may be significantly higher at off-peak times; particularly in areas where there are significant volumes of wind generation. The impact of our sharing assumptions and the potential for increased transfers is considered in more detail in the Cost Benefit Analysis (CBA) described below.

4.4 When considering local generation connections, in areas which predominately contain wind and/or nuclear generation, given the high value associated with low carbon generation, developing a transmission network is generally more economic and efficient than curtailing low carbon production. If the local network was designed to accommodate only 90% of the output of a wind farm generator, the cost of constraints would be in the region £5-7M per annum per GW of installed wind generation. This level of constraint cost is generally higher than the marginal cost of providing transmission capacity, nevertheless, the opportunity will taken to optimise the level of renewable generation which can be accommodated to ensure economic and efficient level of investment into transmission is undertaken.

4.5 Even with a high level of assumed sharing, there is concern that due to the relative low utilisation of renewable intermittent generation together with the increased margin between installed generation capacity and demand, there may be opportunities for greater sharing of existing transmission capacity. A Fundamental Review of the GB SQSS and a Transmission Access Review (TAR) are currently being conducted. Whilst this report did not undertake analysis against all variants under consideration by these two reviews, a CBA was undertaken in respect of proposals to reinforce major system boundaries. The level of transmission capacity identified by the CBA should be consistent with the conclusion of both the review of the GB SQSS and the TAR, since it ensures that the GB transmission system is designed to give the most economic and efficient solution. Nevertheless, the proposals presented within this report will be subject to further examination in light of the conclusions of the two reviews. These reviews are due to be completed this year, and this re-examination will not impact on delivery of required network capacity.

4.6 The CBA has been fully developed for all reinforcements from the central zone of the Scottish Hydro Electric Transmission Ltd (SHETL) system through the SP Transmission (SPT) system to the North of England. In undertaking a CBA the generation has been ranked as described in Annex A of this report. That is generation has been grouped according to fuel type (e.g. nuclear, wind, large coal, modern gas etc.) and ranked in accordance with perceived likelihood of operation based on historic information covering the last few years. The generation constraint prices (i.e. bid on/off) are based on the average price seen over the last few years. Data in respect of the current year is atypical and is influenced by unusual conditions which are not believed to be representative of the long term outlook, which would result in higher constraint cost if utilised in future constraint analysis over a long period. The cost of carbon is assumed to be included within the energy cost used in the study. Whilst this assumption is unlikely to have a material impact on the future constraint cost, it is recognised that it is likely to lead to an underestimation of the cost of losses in future years and, as a consequence, underestimate benefits of future transmission upgrades, but these underestimations are not considered to be material.

4.7 A generic wind output distribution curve has been developed which reflects the intermittent nature of wind generation output. The model ensures that the different generation output over seasons is calculated (average utilisation of 38% and 30% respectively for winter and summer has been used) along with an appropriate diversity factor for wind farm generation across the GB system. The wind generation output at any given time is determined by Monte Carlo sampling. The CBA model then seeks to dispatch the most economic generation, whilst not violating transmission capacity limits. A series of sensitivity studies have then been undertaken to ensure that proposals arising are robust against a wide range of sensitivities which are discussed in the main report.

4.8 When identifying a shortfall in network capacity, consideration has been given to traditional solutions such as reconductoring circuits, upgrading to a higher voltage and constructing new lines. However, it is recognised that traditional methods of enhancing system capacity, particularly those which involve new overhead line routes, are difficult to achieve due to planning constraints and environmental concerns. Such difficulties can result in long delays in providing the required transmission capacity and consequential delays in facilitating the connection of sufficient volumes of renewable and other forms of generation needed to meet UK targets. As a result, the Transmission Licensee’s have investigated the potential for new or previously unused technologies on the GB transmission system in order to either: enhance and maximise the use of existing assets; or to provide new infrastructure with minimal environmental impact and an acceptable level of technological risk. Discussions have been taking place with equipment manufacturers regarding the use of series compensation, HVDC technologies and developments in sub-sea cables.

5.0 *Proposed National Grid Reinforcements*

5.1 In respect of upgrading the main interconnected Scottish system from the North of Scotland to the Central Belt, and onto the North of England there are three main elements.

5.1.1 The ‘Incremental’ upgrade project nominations for National Grid relating to Scottish transfers are:

- SPT/NGET Series compensation on the circuits connecting the Scottish and English Networks - £160M
- NGET Reconductor Harker – Quernmore- £100M

5.1.2 The Western subsea High Voltage Direct Current (HVDC) Link, a 1.8 GW HVDC link between Hunterston and Deeside. This provides additional capacity across the ‘interconnector’ circuits and additional capacity across the upper North of England The total cost of the reinforcement is £760M and the major elements of the reinforcements are summarised below:

- SPT - Western HVDC Link and associated works - £400M
- NGET – Substation Works at Deeside and HVDC Link - £360M

5.1.3 The Eastern subsea HVDC Link, a 1.8 GW HVDC between Peterhead and Hawthorne Pit. This provides additional capacity across B4, B5, B6 and limited additional capacity across the upper North of England. The total cost of the reinforcements is £700M and the major elements of the reinforcements are summarised below:

- SHETL onshore Substation works & Eastern HVDC Link - £340M
- NGET onshore Substation Works & Eastern HVDC Link - £360M

5.1.4 Whilst all three reinforcements identified above are required by 2020 in the 11.4 GW scenario (based on the deterministic requirements of the GB SQSS and supported by the CBA), only two of the reinforcements would be required to meet the 8 GW scenario in Scotland. In determining which of the two reinforcements should be taken forward first, the CBA did not demonstrate conclusively that any particular two reinforcements offered significant benefit over any other combination against the scenarios under consideration. When considering the generation sensitivities, particularly extending the life of the Hartlepool and Heysham 1 Nuclear power stations (scenario assumes they close around 2017/18), then the western HVDC link reinforcement, along with the 'Incremental' provides the most robust solution.

5.1.5 If the Scottish renewable generation contribution is limited to the 6.6 GW of wind generation in total (i.e the minimum required to meet the Scottish Executive target if hydro is assumed to contribute), then any single reinforcement identified above provides sufficient transmission capacity.

5.1.6 A high level analysis has indicated that there is a high probability that at least 8 GW of wind generation will connect in Scotland. It is therefore proposed to proceed with the Western HVDC Link and the incremental upgrade immediately, with a target completion date of 2015 at cost of £1385M, but develop the incremental reinforcement in such a manner as install a subset if necessary, and then proceed with the Eastern HVDC link with a target completion date of 2018 at a cost of £700M. Whilst the Eastern HVDC link is not required until 2018 it will be necessary to undertake some preliminary engineering to ensure it can be integrated into the network.

5.2 North Wales – Stage 1

5.2.1 All 3 generation scenarios assume that up to 4 GW of offshore wind in the Southern Irish Sea may connect. This is considered a robust assumption since the offshore generation in this area is expected to be among the least cost of the Round 3 sites (reference Crown Estate report). Round 3 windfarms in the area will seek to utilise the same capacity as the existing pumped storage plant, Round 2 developments, possible interconnections to Ireland and new nuclear replanting at Wylfa. When total generation, whether wind or nuclear generation, on Wylfa exceeds 1.8 GW[3] it will be necessary to construct a new circuit from Wylfa through to Pentir and establish the second circuit between Pentir and Trawsfyndd, together with some associated works further east. These works need to be undertaken in sequence and, in order to provide additional capacity by 2015, the engineering of some elements needs to commence early in 2009 if the timeline is to be retained.

5.2.2 To provide offshore networks developers with sufficient confidence that they can connect to Wylfa, it may be necessary to seek consents for the new line prior to the development of the offshore networks. Commitment to full construction can then be adjusted as the build up of generation materialises. This approach can achieve a potential saving of offshore

[3] GB SQSS Review Group, Review Request GSR007, 'Review of Infeed Loss Limits' refers. GSR007 is considering raising the threshold limits of the normal (currently 1000MW) and infrequent (currently 1320MW) in recognition of the likelihood that single units in excess of 1320MW (possibly posing a loss of power infeed risk of upto 1800MW) will connect to the GB transmission system.

network cost in the region of £500M by facilitating connections at Wylfa rather than a more remote site

5.2.3 The proposed reinforcements will cost £400M, for completion by 2017.

5.3 Central Wales- Stage 1

5.3.1 The Welsh Assembly government Technical Advice Note 8 identifies an onshore wind generation target of 800 MW. The majority of wind resource is in central Wales which has no immediate connection to the main interconnected transmission system.

5.3.2 In any scenario connecting new generation in central Wales, new transmission assets including overhead line and cable sections need to be commissioned in order to connect the new generation to the transmission network. As the generation is made up of a number of small to medium wind farms the current proposal is to create a hub substation to which all wind farms connect. A single transmission route will then be used to connect to the transmission network in the Legacy-Shrewsbury-Ironbridge circuits. Exact locations of both substation and transmission connection point are being evaluated.

5.3.3 The cost of these works above is estimated to be £225M, for completion by 2015.

5.4 English East Coast Reinforcement, Humber – Stage 1

5.4.1 Previously published investigations such as The Crown Estate 'Round 3 Offshore Wind Connection Study' and National Grid's input to the DECC Offshore Energy Strategic Environmental Assessment have considered a total of up to 12 GW of Round 3 offshore wind generation from the Dogger Bank and Hornsea areas connecting into the onshore transmission network in the Humber area. However, scenarios utilised in this study assume a maximum of between 4 and 8 GW by 2020 (dependent on the level of onshore wind assumed to arise in Scotland). The conclusions from this study propose to optimise both onshore and offshore transmission networks by integrating the design of these networks in order to capture significant cost savings (potentially in the range £200-300M). This can be achieved by connecting some of the Round 3 Windfarms in this region via direct tee connections into an onshore HVDC link connecting the Humber area to East Anglia.

5.4.2 The Crown Estates report highlights that Dogger Bank is likely to be the most expensive offshore area for development and therefore the need case for these reinforcements is arguably less robust than some of the other reinforcements. That said, in order to meet the 2020 targets, it is envisaged that at least 4GW of offshore wind would need to be developed in this area and it is on that basis that it is recommended that work commences on the potential transmission reinforcements in this area.

5.4.3 In connecting these two areas affords the extra benefits of providing additional capacity for new generation connections to the north of the North to Midlands boundary as well as delaying, but not removing, the need for reinforcement in the East Anglia region. This comes as a result of the increased functionality and controllability of HVDC circuits relative to standard AC overhead lines.

5.4.4 In view of the novel nature of this development, pre-engineering works will be required to ensure that the proposed solution can be developed to required timescales. Otherwise, it may be necessary to develop an alternative solution involving new 400kV overhead lines, thus negating the potential savings.

5.4.5 The cost of the onshore works is estimated to be £510M, for completion by 2017.

5.5 English East Coast Reinforcement, East Anglia Stage 1

5.5.1 In all 3 generation scenarios, it is anticipated that between 3 and 4 GW of Round 3 offshore wind generation will be developed in waters directly east of East Anglia. This is considered robust based on the costs of offshore generation contained in the Crown Estate Report. The nearest onshore substations for connection are either Norwich Main or Sizewell, which are both located on the same 400 kV route. Therefore Round 3 offshore wind projects will interact significantly with the potential for nuclear replanting at Sizewell (of up to an additional 3.3 GW) on this part of the network. Reinforcement of the network is required for either offshore wind generation and/or nuclear replanting at Sizewell.

5.5.2 The reinforcements proposed for this area of the network include reconductoring the double circuit route from Walpole to Norwich through Bramford, a new 400 kV substation at Bramford with all circuits from Norwich Main, Sizewell, Pelham and Rayleigh turned in and a new section of 400kV double circuit overhead line, approximately 27 km in length from Bramford to the existing tee point down to Rayleigh (near Twinstead), this would then create two double circuit routes to the west out of Bramford.

5.5.3 The cost of onshore works is estimated to be £400M, for completion in 2017.

5.6 London – Stage 1

5.6.1 Historically, the network in and around London was developed to secure demand in the capital and its surroundings, when the major generation sources were the oil and coal fired plant in the Thames Estuary, or the coal-fired plant in the East and West Midlands. Additionally, it handled transfers to and from the interconnector at Sellindge.

5.6.2 However, several factors associated with the scenarios and sensivities investigated, including the introduction of new low-carbon generation and liberalisation of European energy markets, drive a need for additional transmission capacity in the London area. Specifically increased generation in East Anglia and the Thames Estuary, potential increase in interconnection with mainland Europe and the potential for future demand increases associated with the electrification of transport and/or the decarbonisation of space heat. As a consequence there will be a need for additional transmission feeding central London from the north-east, and ultimately a need to reinforce east-west ties.

5.6.3 The proposed reinforcement is to uprate a 275 kV overhead line from Waltham Cross to Hackney via Brimsdown and Tottenham to 400 kV. The cost of these works is estimated to be £190M, with a completion date of 2015.

5.7 South West

5.7.1 This area of the network, around the Severn Estuary, is characterised by large volumes of localised generation, high demand levels and a limited export capacity. Future changes in the generation connected in this region, including the potential for large amounts of gas fired generation and possible nuclear replanting at Hinkley Point and/or Oldbury-on-Severn drive the need for additional transmission capacity. Planned offshore wind generation through future rounds of wind leasing in this area further add to this requirement.

5.7.2 Proposed reinforcements to accommodate the agreed 2020 scenario and sensitivities investigated include a new 400 kV circuit between Hinkley Point and Seabank of approximately 50km in length. Reconductoring of existing circuits between Hinkley Point, Melksham and Bramley is also needed to provide the power generated in this area with a stronger electrical connection to the demand centre of London.

5.7.3 The cost of these works above is estimated to be £340M, with a completion date of 2017.

6.0 *Capex requirement*

6.1 The estimated capex requirement to deliver the reinforcements identified above, the amount of generation which can be accommodated and the potential reduction in cost of delivering offshore networks is shown in the table below. The estimated capex requirement to deliver the reinforcements will be subject to a rigorous review as part of the pre-construction engineering stage

Region	Reinforcement	Cost (£M)	Capacity of generation which can be accommodated (GW)			Potential saving in offshore network costs (£M)	Net Costs (£M)
			Wind	Nuclear	Total		
Scotland – Stage 1, 2015	North of Scotland Upgrade Incremental Scottish Upgrade Western HVDC Link -	180 625 760	8	0	8	NA	1565
Scotland – Stage 2, 2018	North of Scotland Upgrade Eastern HVDC Link -	450 700	4	0	0	NA	1150
Wales – Stage 1	North Wales - 2017 Central Wales – 2015	350 225	4 - 6	0 - 3.3	4 – 7.2	500	75
English East Coast – Stage 1	Humberside East Anglia	510 400	7 - 11	0 - 3.3	7 – 14.2	350	560
London	London	190	1-2	-	1 -2	-	190
South West	South West	340	2 -3	3.3 -3.3	5. 3 – 6.3	-	340
Total		4730	26 - 34	3.3 - 9.9	29.3 – 44.9	850	3880

6.2 The above costs are for the upgrades to the main interconnected system and exclude the provision of subsea links to the Scottish Islands and offshore network costs for offshore wind. The offshore network costs will be of the order of £400/KW, as indicated in the Crown Estate report on offshore connection costs.

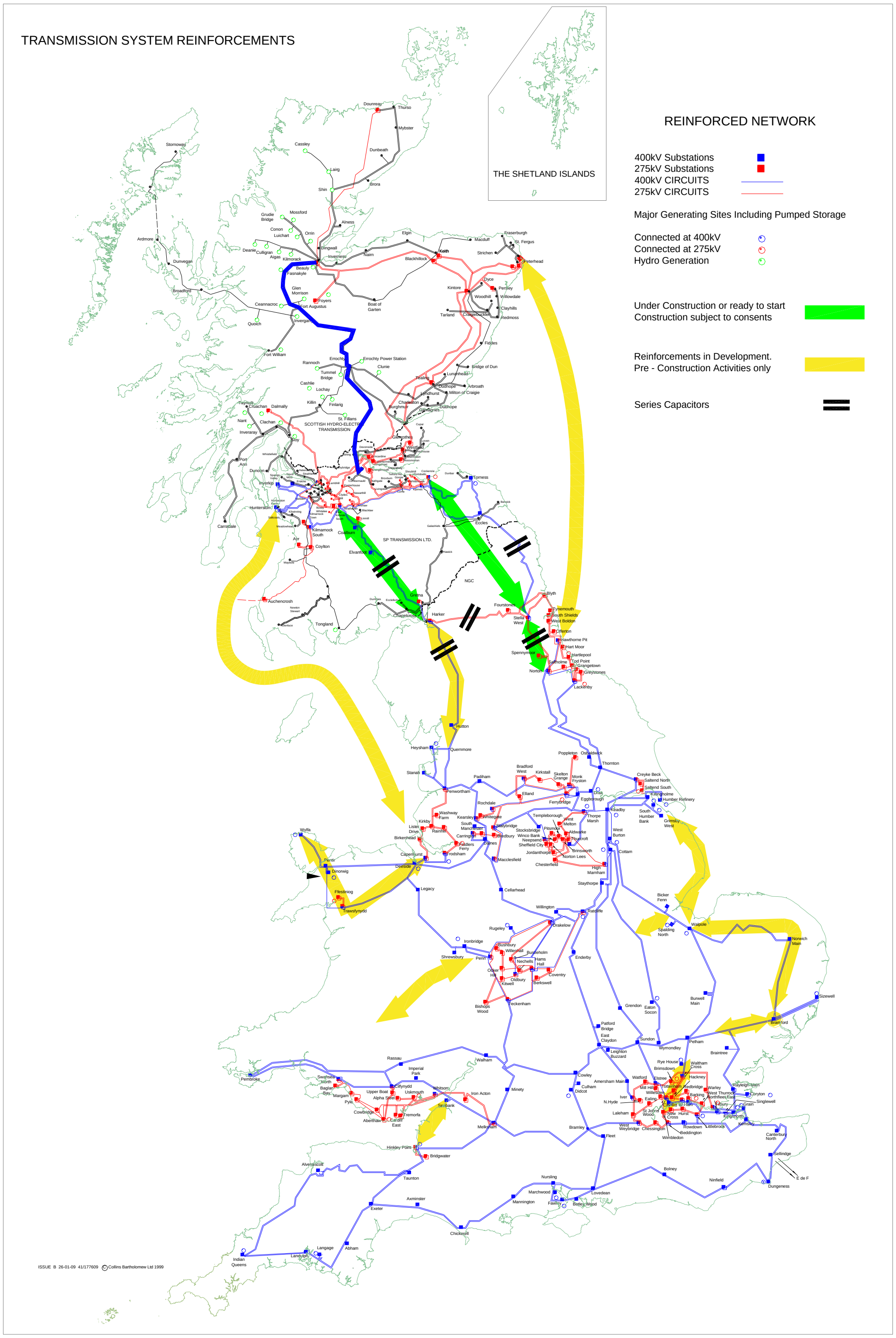
6.3 Timely investment on the onshore network can provide significant benefits in facilitating the connection of offshore networks with a potential saving of £850M. However, it should be noted that many of the proposals involve the use of new and novel solutions and the integration of these solutions into the existing transmission system needs to be carefully engineered. If the transmission network is to facilitate the connection of renewable generation in a timely manner it is essential that pre-construction work commence immediately. Recognising the use of new technology, it is difficult to determine the total cost of pre-construction engineering costs, but for schemes of this complexity it would be normal to anticipate costs in the range of 2-5% of total scheme costs, with typically 0.25-0.5% of cost occurring in year 1. For the package of schemes identified above, it is estimated that the preconstruction cost will be in the order of £150M with a cost of some £10M to £20M occurring in the first year.

7.0 *Taking the Investment Proposals Forward*

7.1 The transmission reinforcements identified above are required to accommodate the generation identified in the scenarios and sensitivities studies considered. Like all forecasts, there is a degree of uncertainty with regard the final outcome. In developing proposals to meet the 2020 targets there will be a varying degree of confidence of the certainty of future requirements. By undertaking the pre-construction engineering of the schemes identified in this report, it ensures that the proposed reinforcements can be engineered satisfactorily, and the lead times to deliver are maintained. This is the least regret solution, i.e retain the ability to deliver to required timescales.

7.2 Further potential reinforcements, which are detailed in the work for ENSG, (eg Combining North & Central Wales – Stage 2, Humber & East Anglia – Stage 2 and London Stage 2) are all potential future reinforcements that have **not** been included at this stage either because they are less robust to a number of scenarios and/or pre-construction work is not required to commence in 2009/10 to meet the anticipated delivery date.

Figure 1


TRANSMISSION SYSTEM REINFORCEMENTS
THE SHETLAND ISLANDS
REINFORCED NETWORK
400kV Substations
275kV Substations
400kV CIRCUITS
275kV CIRCUITS
Major Generating Sites Including Pumped Storage
Connected at 400kV
Connected at 275kV
Hydro Generation
Under Construction or ready to start
Construction subject to consents
Reinforcements in Development.
Pre - Construction Activities only
Series Capacitors

Annex 6 – SPTL Project Information

The following forecast pre-construction costs are additional costs that SP Transmission may incur for 2009/10 above those costs funded as part of TPCR4. These costs are for a HVDC link from Hunterston to Deeside.

Scheme Cost Breakdown

Categories	Forecast Expenditure 2009/10 (£m)
Western HVDC Preconstruction	
Sole Costs	
Project Management	0.10
System Design	0.30
Land and Development	0.03
Engineering	0.30
Consultants	0.08
Commercial	0.13
Shared Costs (SPT Contribution)	
Contractors	0.13
Engineering	0.14
Consultants	0.18
Commercial	0.12
Contingent Shared Costs (SPT Contribution)	
Routing Studies	0.25
Supplier Designs	0.30
Seabed Surveys	0.45
Total	**2.50**

Forecast Pre-Construction Costs for 2009 for Hunterston to Deeside HVDC Link

Scope:	**Deeside: New 400kV 21 bay GIS substation together with line entry and generator connection rationalisation. DC converter ~2GW capacity installation at Deeside (and Hunterston) DC cable connection from Deeside to Hunterston, 340km, submarine and land sections.**	**Total Shared Cost NG-SP**		**SP Cost**		**NG Cost**	
		Budget £k		**Budget £k**		**Budget £k**	
		Low	**High**	**Low**	**High**	**Low**	**High**
Program Manager				100	100	100	100

System Design	System modelling, network performance studies. Determine technical performance specification for DC system, in conjunction with SP. System studies to analyse and resolve system performance to enable definition of scope of DC and series compensation systems. Network modelling and studies to define control system performance and operation. Harmonic studies, DC filter design, stability and voltage studies etc. Work with suppliers to confirm detailed system models/ use supplier systems to validate designs. Additional software and training. Multiple studies of alternative network solutions to support /demonstrate validity of design proposals/ option selection. Scheme process, documentation, management of design process and records, integration of works into planned schemes. Sanction process. Purchase specialist software, and training.			250	350	250	350
	Engage contractors to support technical study work to provide detailed network modelling and performance optimisation studies. Commence on identifying filter design and connection configuration. Provide outline designs of converter installations and integrate with existing site designs. Produce policies and standards for DC systems and Series Compensation installations and systems –sub-systems. Produce policies and standards for DC systems and Series Compensation installations and systems –sub-systems. Audit and review of specifications and tender proposals.	500	700				
	Support cable route studies and identification of preferred routes. Support environmental assessment. Appointment of Preferred supplier and secure manufacturing/resources.	250	250				
Land & Development	Design options review. Initiate route and landing site selection and high level environmental constraints identification. Initiate high level stakeholder engagement on options Input to scheme team of 400kV substation design/ location.			25	25	25	25
Engineering	Develop specifications and standards for DC converter installations.	250	300	250	350	120	150
	Determine optimal layout, line entry changes and generator connection design for Deeside 400kV substation with DC converter included.					100	120

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	Detailed design of 400kV substation. Support planning permission process for DC converter. Create optimal phasing of connections/ land use to enable DC converter construction to meet required programme. Produce policies and standards for DC systems and Series Compensation installations and systems –sub-systems. Audit and review of specifications and tender proposals. DC converter tender specification, project management and tender process progress. Programme and budget management.					200	250
Consultants & Support Note 1	Appoint consultants to undertake specialist	60	60	20	20	20	20
	Cable route surveys (marine and land).Cable route studies and identification of preferred routes.	500	500				
	Appoint specialist environmental and planning aspects consultants.			40	40	40	40
	Commence environmental assessment.	200	200				
	Engage Community relations consultants and develop communications strategy.			15	15	15	15
	Engage specialist DC system designers.	100	100				
	Sea bed marine survey (if required in 2009/10). (Note 2.)	900	900				
Commercial	Develop commercial procurement strategy and EU PIN notice / procurement procedure. Embark on staged tendering and appointment process, tender evaluation, appoint preferred supplier.	200	250	100	150	100	150
	Commence negotiations with Deeside Power regarding any connection changes.(NB Excludes, external legal fees, if required)					20	20
Total		**2960**	**3260**	**800**	**1050**	**990**	**1240**

Notes:

1. The mechanism for engaging contractors will be subject to an agreed procurement and delivery strategy
2. Commitment 09/10 £0.9M the balance being in 10/11.

The Need Case for the HVDC Link from Hunterston to Deeside

The following sets out the 'need' case for the west coast High Voltage Direct Current (HVDC) link from Hunterston to Deeside[4].

The reinforcements that have been identified by the transmission licensees in the Transmission Investment Options Study are based on a range of scenarios that take into account the significant changes anticipated in the generation mix between now and 2020. The Study concludes that, provided the identified reinforcements are taken forward in a timely manner, and the planning consent process facilitates network development, then the reinforcements identified can be delivered to required timescales.

[4] The western subsea link is a 1.8GW HVDC link between Hunterston and Deeside, which will provide additional capacity across both boundaries B6 and B7(a). The total cost is estimated at £760M (£400M SPT, £360M NGET) with an assumed 50% sharing between SPT and NGET for the sub-sea element.

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The generation background scenarios vary the capacity of renewable generation penetration in Scotland by 2020 from a minimum of 6.6GW, a second scenario with 8GW, and a final scenario with a maximum of 11.4GW. Under all the generation scenarios considered, the transfers from Scotland to England increase significantly.

The range of potential power flows have been determined on the basis of the currently authorised GB transmission system and are assumed to include the Beauly – Denny 400kV line and the present TIRG upgrade on boundary B6 between Scotland and England. Reinforcements were then identified to relieve the boundary restrictions across boundaries B4, B5 and B6.

Cost benefit analyses[5] (CBA) have been undertaken on all the identified reinforcements and these have been subject to sensitivity studies to ensure that any proposals arising are robust against a wide range of sensitivities. For the 11.4GW scenario, the CBA shows that three reinforcements from Scotland are required covering the incremental upgrade and west coast HVDC link to be completed by 2015, and an eastern HVDC link to be completed by 2018. For the 8GW scenario, the incremental upgrade and west coast HVDC link provide the most robust solution when considering generation sensitivities, and in particular extending the life of northern nuclear generation. If the Scottish contribution is 6.6GW then any single reinforcement will provide sufficient transmission capacity.

A high level analysis undertaken by the licensees has indicated that there is a high probability that at least 8GW of wind generation connecting in Scotland and so it is therefore proposed to proceed with the Western HVDC Link and the incremental upgrade immediately, with a target completion date of 2015.

The transmission licensees' recommendation is therefore to proceed immediately with the incremental upgrades and the western HVDC link.

[5] Full details of the CBA approach are set out in the licensees report to the ENSG.