WORKING GROUP REPORT

CUSC Amendment Proposal CAP148

Deemed Access Rights to the GB Transmission System for Renewable Generators

Prepared by the CAP 148 Working Group for submission to the Amendments Panel

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1. SUMMARY AND RECOMMENDATIONS

Executive Summary

1.1 CAP 148 Deemed Access Rights to the GB Transmission System for Renewable Generators: CAP 148 seeks to prioritise use of the GB Transmission System by new renewable generators in accordance with the Renewables Directive 2001/77, Article 7. CAP 148 original contains two main components:

- Provisions to ensure a renewable generator gains access to the GB Transmission System on the earlier of (1) the date by which National Grid can deliver Transmission Entry Capacity ("TEC"); or (2) three years after the later of: (i) the date on which the generator obtains its project planning consents; or (ii) the date on which it accepts a Connection Offer from National Grid, subject in both cases (1) and (2) to a local connection having been consented and commissioned, and
- Provisions to enable administered constraint payments to be made to generators that have to be constrained down/off as a consequence of the GB Transmission System being unable to meet the usage requirements of generators with TEC and DTEC. Such administered Interruption Payments would be charged out via the TNUoS Charging methodology.

1.2 After assessment of the original and Working Group Alternatives, it was decided by the working Group (WG) that legal text would be developed to cover the most supported of the Working Group Alternative Amendments (WGAA). This text would be capable of easy alteration to work for any of the other WGAAs. The WG decided not to develop legal text to cover the administered constraint arrangements and the Interruption Payments of the CAP 148 original.

1.3 Implementation of any of the WGAAs and particularly CAP 148 original would require consequential changes to other industry documents. The WG has indicated in this report where it thinks change is probably needed. The details of such changes, particularly any changes to charging arrangements will be the subject of separate assessment. National Grid is currently considering options for charging arrangements, further detail of which can be found at:

http://www.nationalgrid.com/NR/rdonlyres/3DFD600D-C03C-47D8-89E0-8A4854F37BAA/19109/TCMFCap148initialthoughtsfinal.pdf

Working Group Recommendation

1.4 The Working Group believes its Terms of Reference have been completed and CAP 148 has been fully considered.

1.5 Three attributes of the WGAA candidates were focused on to create the WGAAs that some members of the WG supported in the voting stage. These were:

Eligibility: The WG considered the eligibility criteria at length and from their consideration four candidates (1-4) were further considered. Of the four 1) all REGOs and 2) Intermittent REGOs only were considered but not supported. The supported candidates were: 3) Low carbon generation defined as (tonnes carbon emitted per MWh generated ≤ 0.2) minus Proportionally Qualifying Plant and 4) All REGO generation minus Proportionally Qualifying Plant.

Risk Allocation for delays in Wider Works: Three approaches to risk allocation were considered. Please note that under all three risk allocations the DTEC Generator would automatically gain transmission system access after completion of the Directly Consequential Works (subject to the generator being commissioned). The differences in risk allocation are with regard to delays in the completion of the wider infrastructural reinforcement works. Three candidates (A-C) were supported: A) delays affecting the Wider Works were treated as now; B delays affecting the Wider Works were treated as now except those arising from planning for which there would be no relief for National Grid; and C) there would be no relief for National Grid for delays affecting Wider Works (including normal force majeure e.g. war etc.).

Lead Time: The lead time is the earliest time the eligible generator can receive access to the transmission system, subject to completion of the Directly Consequential Works and the commissioning of the generator. (It should be noted that in the event that the wider works, the Directly Consequential Works and the generator commissioning could all be completed in less than the lead time, then the generator could receive access even earlier.) Two candidates were supported: X) 36 months, the time proposed in CAP 148 original, and Y) 48 months arising from the discussions surrounding assessment of CAP 131.

Eligibility	1 *All REGOs*	2 *Intermittent REGOs only*	3 *Low carbon Generation*	4 *All REGOs minus proportionally qualifying*
Risk Allocation	A *As now*	B *No relief for planning*	C *No Relief*	
Lead Time	X *48 months*	Y *36 months*		

The candidate combinations are set out above. Therefore a combination would combine 3 parameters: (1,2,3,4) plus (A,B,C) plus (X,Y). From amongst the possible combinations 13 WG members (Chair did not vote) were asked to consider which of the original and WGAAs were better than the current CUSC baseline. All of the WG members could vote on each of these. Then, those WG members who had supported any of the original or the WGAA were asked to vote once more to determine which of the WGAAs or original was the preferred alternative. It should be noted that some (5) of the WG members believed that none of the WGAAs or the original was better than the current CUSC baseline. Therefore these members did not express a preference for a preferred alternative amongst the WGAAs and the original.

	Compared to Current CUSC			
	Better	**Worse**	**Abstain**	
Current Baseline	5			**Preferred alternative**
4CX	2	10	1	0
4BX	6	7	0	6
4CY	2	10	1	1
3BX	2	10	1	1
4AX	0	10	3	0
CAP 148 Original	2	11	0	0

As a result of the final voting by Working Group Members none of the WGAAs or the original CAP 148 have majority support from the WG Members compared with the current baseline. A majority of WG members considered that some variant of the proposal was better than the original; Option 4BX gained the most support from WG Members relative to the current baseline and the most votes in favour of it as the preferred alternative.

In voting on the alternatives, WG members were aware that CAP 148 is premised on discrimination in favour of eligible renewable generation and against non-eligible generation technologies. They were in receipt of advice from Ofgem (DTI) to the CUSC Panel[1] which made the point that 'due discrimination' under the CUSC applicable objectives may be permissible now if objectively justified. WG members were also aware of the difference between the basis on which they made a recommendation: the Applicable Objectives, and the basis on which Ofgem may make a decision: having regard additionally to its wider licence obligations. Some WG members who had voted against the WGAAs on the basis of consideration against the Applicable Objectives suggested that options 4AX and 3BX might be supportable against the wider objectives.

Therefore the working group recommends to the CUSC Panel that:

- A consultation report containing the above options should proceed to wider industry consultation as soon as possible.
- The Working Group Report is accepted by the CUSC Panel and the Working Group is disbanded.

2. PURPOSE AND INTRODUCTION

2.1 This Report summarises the deliberations of the Working Group and describes the Original CAP148 Amendment Proposal as well as the Working Group Alternatives.

2.2 CAP148 was proposed by Wind Energy (Forse) Ltd. and submitted to the Amendments Panel for their consideration on 27th April 2007. The substance of the amendment had previously been submitted to the February meeting of the Amendments Panel as CAP147. Following preliminary discussion at this panel meeting the amendment (CAP 147) had been withdrawn by the proposer whilst concerns raised by the Panel were communicated to Ofgem and DTI and their advice sought. The response from Ofgem (and DTI) (see footnote 1) and CAP 148 were then considered together in April. A number of concerns were raised at the CUSC Panel concerning both the legality of the amendment proposal and the legality of it being assessed by a CUSC Working Group[2]. Following this discussion the Amendments Panel determined that it would seek its own advice as to the legality of the assessment process and determined that the proposal should be considered by a Working Group and that the Working Group should report back to the panel meeting within 3 months[3] (subsequently extended to 4 months). There was further discussion

[1] The Ofgem/DTI letter in response is filed with the CAP147 documents on the National Grid web site http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

[2] CUSC Panel April 2007 minutes 1044-1080 describe the issues raised and the discussion http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/Panel/current/270407pmp/

[3] CUSC Panel April 2007 minute 1081 http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/Panel/current/270407pmp/

of the legal advice and the legality of CAP 148 and its assessment at the July CUSC Panel[4].

2.3 The Working Group met on 21st May and the members amended and agreed the Terms of Reference for CAP148. A copy of the Terms of Reference is provided in Annex 3. The Internal Working Group Procedure is set out in Annex 4. The Working Group considered the issues raised by the Amendment Proposal and considered whether the amendment proposal and the Working Group Alternative Alternatives better facilitated the Applicable CUSC Objectives as compared with the current version of the CUSC. The Working Group met 9 times and attendance is recorded in Annex 5.

2.4 This Working Group Report has been prepared in accordance with the Terms of the CUSC. An electronic copy can be found on the National Grid Website, www.nationalgrid.com/uk/Electricity/Codes/, along with the Amendment Proposal Form.

3. PROPOSED AMENDMENT

3.1 The full text of the amendment is set out in Annex 6. This CAP 148 amendment proposal seeks to prioritise connection to and use of the GB Transmission System, in accordance with the EU Renewables Directive 2001/77, Article 7, such that new eligible renewable generators are given commercially firm access to the Transmission System by a fixed date.

3.2 Such new eligible renewable generators will have a different access product known as Deemed Transmission Entry Capacity (DTEC) which will confer commercial firmness on the generator regardless of the commissioning or not of any associated wider system reinforcement.

3.3 In the event of constraints on the GB Transmission System, National Grid (Great Britain System Operator GBSO) will be obliged to constrain conventional generators (and existing renewable generators) before post-CAP148 eligible renewable generators.

3.4 The amendment would also lead to a system of administered Interruption Payments being paid in the event of constraints involving CAP 148 eligible renewable generators. These payments would be collected through the Transmission Use of System (TNUoS) charging system and would cover the 'associated losses' of the constrained generators

3.5 The proposer of CAP 148 recognised that a number of consequential changes would be required in other industry codes and documents beyond the CUSC in order fully to implement the changes proposed in CAP 148.

4. SUMMARY OF WORKING GROUP DISCUSSIONS

4.1 Recognising that the role of the Working Group (WG) was to assess the amendment proposal against the CUSC Applicable Objectives, the WG looked at the regulatory and legislative context because of the fundamental nature of the proposal and the direct link drawn to government policy and EU Directives. The WG also drew help from the Ofgem/CUSC Panel correspondence about the nature of discrimination. The WG then went on to define the characteristics of the DTEC product and the operational issues and processes associated with using DTEC. It considered the impact on system security, the

[4] CUSC Panel July 2007 minutes 1172-1173

maintenance of the reliability & safety of the grid, longer term planning and investment, as well as SQSS. En route the WG sketched the impact on other industry codes and documents and operating and IT systems. The WG went on to consider a number of candidates for Working Group Alternative Amendments (WGAA), and finally the WG considered the original proposal and such candidate WGAAs against the Applicable Objectives and the Implementation Date.

4.2 National Grid Licence, Markets Directive, Renewable Directive & Environmental Directive

4.2.1 Legal Opinions: The WG had the benefit of legal advice sought for the CUSC Panel covering a number of issues related to the assessment and decision process for the proposed amendment, as well as correspondence between the CUSC Panel and Ofgem and discussions at the CUSC Panel referenced in section 2.2 above. In line with its terms of reference agreed by the CUSC Panel the WG completed the assessment phase, noting the further opportunities for interested parties to raise legal issues during consultation and during the decision phase when the assessment report is with Ofgem.

4.3 Deemed TEC (DTEC) Product Definition

4.3.1 TEC and DTEC Attributes: In the event of implementation of the amendment proposal, there will be two broad categories of generating plant created: those eligible for DTEC and those not. These will be termed DTEC generators and TEC (Transmission Entry Capacity) generators respectively for the purpose of this discussion. DTEC is in most respects very similar to TEC and so the WG focused on defining those attributes that were different from TEC. This section emphasizes some of the attributes that would be the same between TEC and DTEC. Nevertheless, readers should be aware that a lack of explicit mention of an attribute here does not mean that TEC and DTEC are different in this respect.

4.3.2 Eligibility: The WG considered and clarified which generators, under which circumstances would qualify for DTEC. Eligibility would be determined by satisfying conditions regarding timing of connection agreement and conditions regarding renewable status.

4.3.2.1 Timing of Eligibility: DTEC would only routinely become available to generators who were not connected directly or indirectly (via a BEGA) prior to the implementation of CAP148. As well as new projects this would mean that existing plant that made a Modification Application for revisions to its connection (to increase its export capacity after the implementation of CAP148 might be able to gain DTEC (for such additional output) subject to its renewable status being eligible. This example is considered further below.

4.3.2.2 Renewable Status: CAP 148 defines the types of generation that would be eligible to apply for DTEC by reference to the Electricity (Guarantees of Origin of Electricity Produced from Renewable Sources) Regulations 2003 DTI (see Annex 7). Under these regulations Users receive certificates, known as REGOs, where their output has been generated from renewable sources. Note that the definition of renewable energy sources under these regulations makes the operational attributes of the generation technology, such as the ‘intermittency’ of wind generation, irrelevant to the eligibility for DTEC. Within the group of qualifying technologies there are basically three groups: i) technologies that can only produce eligible electricity such as wind or hydro-generation, ii) technologies that can produce a proportion (up to 100%) of qualifying output such as co-fired generation and iii) pumped hydroelectric plant. These are considered in turn below. For the avoidance of doubt it should be noted that chp generation is not REGO qualifying.

4.3.2.3 <u>Wholly Eligible Plant</u>: For plant of this type the principle and volume of eligibility should be easy to demonstrate as 100% of their output is clearly REGO qualifying.

4.3.2.4 <u>Proportionally Qualifying Plant</u>: Demonstration of qualification is more problematic for these plants. For example, co-fired generation is eligible for REGOs but only on the portion of output that has been produced from energy crops. It can therefore be assumed that co-fired generation would be eligible to apply for an amount of DTEC capacity proportionate to its use of renewable fuels. However the proportion of use of renewable fuels will be determined by the relative costs of qualifying and non-qualifying fuels (which varies over time). This poses challenges for initial connection and subsequent operation. In extremis, an eligible generator could sign a 'DTEC' connection agreement with the early access this would promise and then find on commissioning that it is uneconomic to produce this proportion of qualifying output.

After further analysis WG Members concluded that it would be rare for a connection to be an issue for proportionally qualifying plant. In general, if the plant required both TEC and DTEC, then the connection date would be determined by the time taken to achieve TEC; DTEC would confer no connection time benefit. If the plant to be connected could be specified separately as TEC or DTEC plant (e.g. the plant had 4 generating units of which 1 only would be REGO qualifying and this one generating unit could be connected and commissioned prior to the other 3) then the developer could sign two connection agreements: one for DTEC and one for TEC, and hence gain the connection advantage for the DTEC plant. Therefore, WG members concluded that with regard to the connection time benefits of DTEC, an appropriate due discrimination on pragmatic grounds would be to exclude proportionally qualifying plant from the eligible set of REGO generators that could benefit from the connection advantages conferred by being able to sign a connection agreement for DTEC generation.

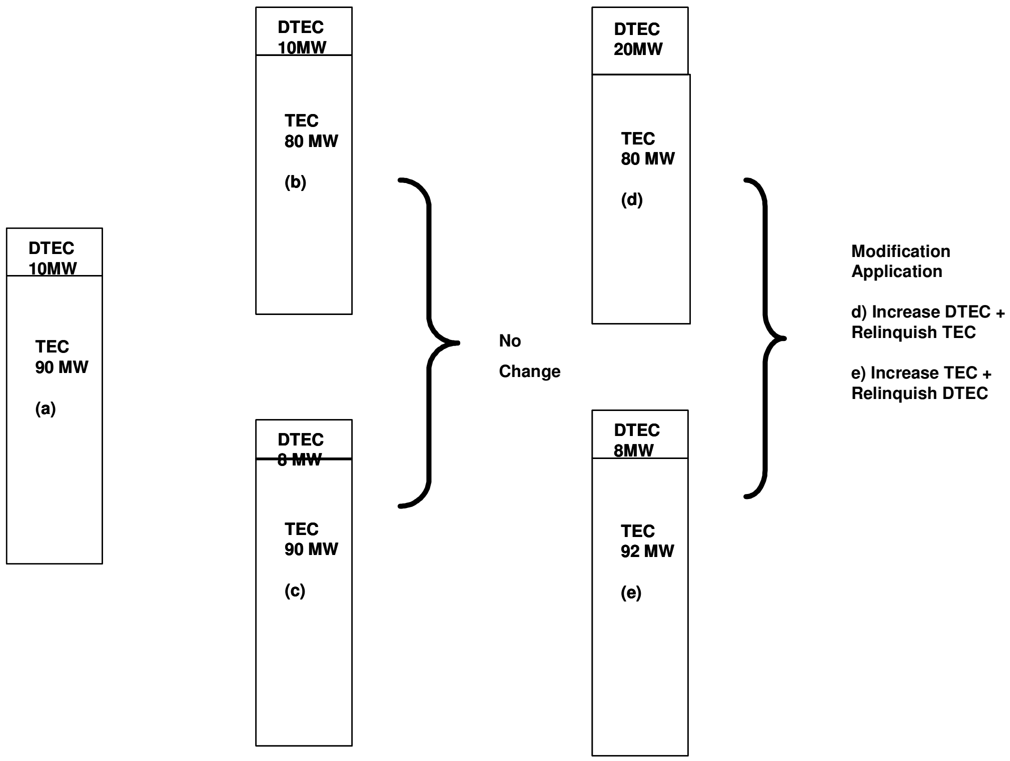
Once the plant is connected, during normal operation the number of REGOs produced over the course of the year will vary, but the DTEC is an annual stripe of access capacity. If the amount of eligible generation is less than the DTEC, but the total amount of generation remains the same, the generator would have to relinquish DTEC and apply for TEC, a process lasting approximately 3 months, assuming that TEC is available in that location. This would introduce an operational inflexibility as the plant operator tries to optimise output against a varying availability and price of eligible and non-eligible fuels. A number of WG members believed that the process would be so operationally inflexible for co-fired generation as to be practically unusable; all WG members believed it would be difficult to make work.

These issues are illustrated diagrammatically below: The plant originally has 90MW of TEC and 10 MW DTEC (a). For so long as its eligible output does not exceed its DTEC holding and its non-eligible output does not exceed its TEC holding ((b) or (c)) no action is required. If either the generator wants to produce more eligible or non-eligible output than it has DTEC or TEC capacity respectively ((d) or (e)), then it would need to go through the Modification Application process. It should be noted that in the examples below ((d) or (e)) the total output does not exceed the sum of TEC+DTEC.

WG Members also noted that National Grid would have the obligation to treat the DTEC and TEC elements of the output of the same proportionally qualifying plant differently with regard to constraint management and National

Grid would need to know operationally what the relative volumes were. Even if the generator were able to generate an approximately constant volume of REGO eligible electricity, there would still be the problem of demonstrating, in an auditable way, that the average generation over the year was equal to the DTEC volume. This obligation would rest on the generator, but National Grid would have to develop an administrative system to deal with this.

In view of the complexities identified above some WG members suggested that mixed TEC/DTEC generators should not be eligible for DTEC, although the original amendment would define Proportionally Qualifying Plant as proportionally eligible for DTEC.



4.3.2.5 Mixed Holding Plant: As well as arising from co-fired plant, the WG discussed more generally whether or not a generator could hold both TEC and DTEC on the same Connection Site. The thrust of the amendment proposal is that new renewable generation will be eligible for DTEC. For existing sites, members anticipated that DTEC would be available for new additional capacity qualifying as REGO renewable generation. Therefore members could envisage a two-stage wind development, for which the currently operational stage I would have and maintain TEC, whilst the new stage II would have DTEC. If an existing wind development were to re-plant its turbines so that the total number of turbines remained the same, but the capacity increased, under the terms of the amendment as proposed, only the increase in capacity above the original TEC value would be eligible for DTEC. The WG also considered that, within the terms of the original amendment, such an existing renewable TEC generator could terminate its existing connection agreement and seek a new connection agreement for only DTEC. However, this is not without risk. At the point of termination the generator would surrender its TEC (into the pool of TEC) and it would not be guaranteed to gain its DTEC until 3 years' time. As an alternative, such a generator might consider giving three years' notice of surrender of its TEC and seek a new connection agreement with only DTEC, although possible the WG did not pursue this line of argument any further, but noted there were further complexities associated with replanting by existing renewable TEC generators. National Grid expressed concern about managing the constraints aspects of the amendment with mixed-holding sites.

4.3.2.6 Pumped Hydroelectric Plant: For pumped hydroelectric plant, REGOs are issued for any electricity from a renewable source that is used to fill a storage system but not for the electricity generated from opening that storage system. Therefore the WG interpreted this as meaning that electricity exported from the pumped hydroelectric scheme would not be qualifying and such a generator could not apply for DTEC. However, the WG noted that some pumped hydro-electric schemes have run-of-river run-off generation as well as the pumped water. This type of scheme would be classified as 'Proportionally Qualifying Plant' mixed holding and would face the issues outlined above.

4.3.2.7 Intermittency: A WG member suggested that a sub-set of the REGO qualification should be adopted (instead of the definition proposed in the original amendment proposal). The variant is that eligible generators would be REGO producing, but limited to intermittent generation technologies and excluding proportionally qualifying such as co-fired. Intermittent generation would be defined as generation technologies for which the fuel source is variable with time and over which the generator can only have limited or no control. Practical examples of 'intermittent generation' would be wind, hydro-electric, tidal and marine, and solar PV. The WG member proposed that limitation to this sub-set of REGO generators would maximise the use of zero operational carbon emission generation, in pursuit of the Government's renewable target. The exclusion of proportionally qualifying plant was on the additional grounds of practicality.

4.3.2.8 Low Carbon Generation: A WG member suggested a different approach to eligibility (instead of the definition proposed for the original amendment), namely that low carbon generation would be eligible for DTEC. Low carbon would be defined as having an operational value for carbon dioxide emitted to the atmosphere per MWh generated that is lower than a cap value:

[CO_2 emitted (tonnes)/MWh generated] $\leq$ X, where X takes a value of 0.2

In principle this approach would lead to technologies such as REGO generating, coal or gas with carbon capture and storage, nuclear, good quality chp, all being eligible for DTEC, depending on their operational carbon emissions per MWh generated being lower that a cap. As the cap value 'X' is the criterion, in principle specific examples of the above technologies may or may not qualify for DTEC, depending on their carbon emission performance. Additionally, the WG member proposed that Proportionally Qualifying Plant technologies should be excluded from qualifying for 'low carbon' defined DTEC) as a matter of practicality. The value for 'X' of 0.2 arises from the clean coal qualifying criteria set out in the Energy White Paper, 2007. Most if not all clean coal projects with CCS will have to capture 85%-90% of CO_2 to qualify for HMG's subsidy "competition" as per Energy White Paper p.176 (Para 5.4.21). Consequently, conventional coal has a carbon intensity (CI) of 0.9t/MWh, so 10%-15% gives a CI of 0.1t/MWh to 0.14t/MWh. Therefore a cap of 0.2 is a useful value to separate current from future carbon-based technologies.

4.3.2.9 Optionality: The proposer of CAP 148 clarified and WG members agreed that in order to achieve the goal of the proposal DTEC would have to be mandatory for all eligible generators. Because of the issues facing

Proportionally Qualifying Plant sites outlined above, a WG member suggested that for such sites, it should be possible for the User to elect to only have TEC for both its non-eligible and eligible capacity.

4.3.2.10 Capping: WG Members agreed that in line with all existing access products DTEC access would be capped at the level of CEC such that over a Connection Site:

$$\Sigma \text{ (TEC + STTEC + LDTEC +DTEC)} \leq \text{CEC}$$

4.3.2.11 Trading DTEC: This amendment proposal does not include provisions for DTEC trading between qualifying sites. Therefore if the amendment were to be implemented, there would be no means by which DTEC could be traded; obviously, a further amendment proposal could be made in the future to introduce such trading. Similarly there would be no means by which DTEC and TEC could be cross-traded. WG members briefly considered trading of DTEC and noted that although, in principle, generator/developers must be capable of trading DTEC nevertheless the attributes of DTEC would make it unlikely that this would happen frequently. Any eligible candidate for DTEC must (according to the amendment proposal) receive it 3 years after the later of signing a connection agreement or receiving planning approval for the power station, anyway (subject to other conditionality mentioned in the proposal). Additionally, it was not clear how National Grid could calculate an exchange rate higher than zero, unless exchanges would be allowed that exacerbated constraints (this is explicitly disallowed for TEC trades and exchanges). Nevertheless, in the longer term the WG believed that the volume of DTEC on the system would be likely to increase and hence the possibility of trading would be more likely to arise.

4.3.2.12 Eligibility Summary: Four candidate eligibility criteria were identified by the WG and carried forward to the WGAA section: i) All REGO generation, ii) REGO generation excluding Proportionally Qualifying Plant , iii) Only Intermittent REGO generation (excluding Proportionally Qualifying Plant), and iv) Low Carbon generation (excluding Proportionally Qualifying Plant).

4.4 DTEC Connection

4.4.1 Applications Process: The WG agreed that the applications process for DTEC would be a normal 'box-ticking' part of an application for a connection. In order to complete the process a number of conditions would have to be fulfilled by the generator. These conditions would be specified in the CUSC Bilateral Connection Agreement (BCA). WG members agreed with the National Grid preference that the obligation would be placed on the generator/developer under the CUSC BCA to be self-certifying, noting that breach of the obligation would lead ultimately to DTEC being removed. This was agreed to be an appropriate incentive.

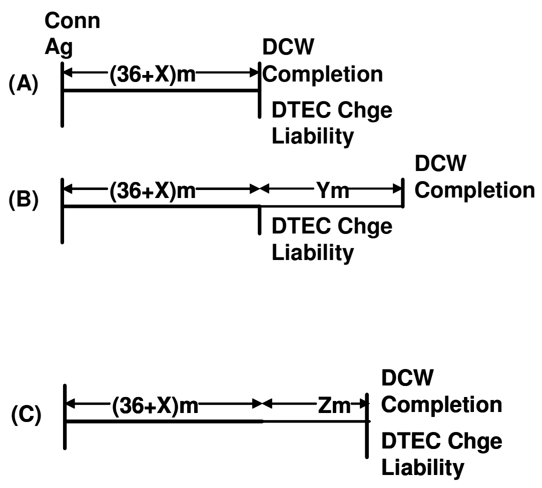
4.4.2 Schedule of Works: WG members noted that the current CUSC arrangements involve clustering with an opportunity for volunteering into an arrangement similar to that being considered by CAP 131. They therefore discussed what would be in the schedule of works and what would carry final sums liability (FSL) for DTEC generators in such a way that it would deal with the current circumstances but hopefully be robust to an implementation of CAP 131 type arrangements (were they to be approved by the Authority). CAP 148 holds out the prospect of early connection. However, it does not suggest that DTEC Generators should have an additional financial benefit during the construction process. Therefore WG members agreed that consistent with the thrust of the amendment proposal, the Construction Agreement would need to include both the Directly Consequential Works (DCW) and the wider works for the purpose of final sums liability. These liabilities would finish at the DTEC Charges Liability Date, subject to the power station having been commissioned. Members noted that DTEC Generators would benefit from knowledge of the progress of wider works, particularly where these wider works were expected to be completed within 3 years. Provision of such information between DTEC generator and National Grid would form a normal part of the regular contract management dialogue.

4.4.3 Local (DCW) and Wider Works: The definition of DCW separate from wider works is a cornerstone of the amendment proposal. WG members discussed how to define DCW in an unambiguous way. A top-down approach would be those works required to allow the connecting plant to export CEC under n-1 (<1320MW connecting plant) or n-2 (>1320MW connecting plant) conditions with minimum demand and disregarding any other non-eligible generation. Annex 8 shows a very simple illustration of a hub being used to connect a variety of new generation (some DTEC and some TEC) to the existing Main Interconnected Transmission System (MITS). The illustration in Annex 8 shows the final form of the hub and generators after all have been connected. In the illustration DTEC generator (A) signs a construction agreement before any of the other prospective generators and the generators are connected in the order A, E, B, C and D.

4.4.3.1 DTEC Generator A: When the DTEC generator (A) is the only party connecting to a new remote substation which requires a new line to connect it to the remainder of the transmission system, the DCW needs to include the construction of the remote substation and the new line as a minimum. In the Illustration DTEC generator (A) is the first to sign a connection agreement .For this generator the DCW will be the i) the local connection assets at the power station A, ii) the connection from the power station to the hub (A-H), iii) the portion of the assets at the hub H necessary to export up to the CEC of the power station, and iv) the portion of the line and other assets from the hub to the MITS M necessary to export up to the CEC of the power station. Clearly National Grid may decide to size the hub and the line H-M to accommodate other foreseen export requirements. However, Transmission Licensees do not build assets speculatively; they will only build when they have a firm signal that is supported through the regulatory regime. If further reinforcements of the MITS are required in order to accommodate the export from power station A, they would form part of the wider works.

4.4.3.2 DTEC Generator E: WG members noted that when the next DTEC generator (E) wished to connect, the DCW for E should be such that both generator A and E could export to the MITS simultaneously; otherwise the connection of E could cause A to be constrained down/off and hence undermine the purpose of the amendment proposal. Unless there is spare capacity arising from the unit size of the DCW for generator A, this will mean that DTEC generator E will require a DCW that will provide i) the local connection assets at the power station E, ii) the connection from the power station to the hub (E-H), iii) the portion of the assets at the hub necessary to export up to the CEC of the power station at the same time as A is exporting, and iv) the portion of the line and other assets from the hub to the MITS necessary to export up to the CEC of the power station E at the same time as A is exporting.

4.4.4 Back-Stop Dates and Delays: WG members discussed the implications of delays. Under the CAP148 amendment proposal an eligible generator will agree a Completion Date and a DTEC Charges Liability Date. They will normally be coincident. These dates will occur on completion of the conditions precedent. This is illustrated in the diagram below, in which it has initially been agreed that the DCW works will take 36+X months to complete illustration A). If there is a delay that causes the generator/developer to seek a Modification Application (Illustration (B)), then the completion date will be pushed back to 36+X+Y months. However, the generator/developer's obligation for liability for DTEC Charges still begins after 36+X months. (It should be noted that this date-firm obligation on the generator/developer is not explicit in the original amendment proposal; an alternative could be considered in which delays to the generator/developer could precipitate the ability to move both the completion date and the DTEC Charges Liability Date backwards. However, the majority of the WG members including the proposer of CAP 148 believed that a date-certain for DTEC Charges Liability reflected an element of balance to the date-certain obligations placed on National Grid). If there is a delay that affects completion of the Directly Consequential Works (DCW) by National Grid, (Illustration (C)) then both the completion and DTEC Charge liability date are pushed back to 36+X+Z months. Finally, if there is a delay that affects National Grid's programme for wider works, neither the completion, nor the DTEC Charge liability date is affected. The consequence of the date-certain by which DTEC is available to the DTEC generator is that National Grid can have no protection under Force Majeure for wider works. If there is a delay affecting the User and the User does not make a Modification Application to defer the Completion Date National Grid may complete its works so far as possible, subject to Independent Engineer certification (noting that the connection may not be completed). As a consequence the DTEC Charges Liability Date will occur and the User will become liable to commence payment of TNUoS (or whatever charge NG deems appropriate to make for DTEC, with the agreement of Ofgem, pursuant to the charging regime) up to the level of DTEC in the agreement (even if the connection is incomplete). However, the User would have to agree changes to the construction programme to deliver a revised completion date for the connection. If the generator/developer does not believe that any proposed delay to the DCW is justified, then it can begin the normal dispute process that is available under the CUSC. WG Members noted that this date-certain approach placed an additional financial risk on the DTEC generator in the event that they did not successfully manage their own construction and commissioning programme within the times prescribed by CAP148.



Generator	NG
(A) Routine CAP148 DTEC from (36+X)m DTEC Charge liability from (36+X)m	(A) Routine CAP148 DCW completed by (36+X)m DTEC charges received from (36+X)m
(B) Generator ModApps delay of +Ym DTEC from (36+X+Y)m DTEC Charge liability from (36+X)m	(B) Generator ModApps delay of +Ym DCW completed by (36+X+Y)m DTEC charges received from (36+X)m
(C) Delay of +Zm to NG DC Works DTEC from (36+X+Z)m DTEC Charge liability from (36+X+Z)m	(C) Delay of +Zm to NG DC Works DCW completed by (36+X+Z)m DTEC charges received from (36+X+Z)m
NB Delays to NG wider works have no affect on DTEC availability date or charges liability date	
NB Original ConnAg specifies 36+Xm for NG DC works	

4.4.5 Delays and Risk Allocation: The WG discussed this allocation of risk and possible variants of the allocation. In the original amendment proposal National Grid has relief from external events that cause a delay to the DC Works, but no relief from external events causing delays to the wider works. One WG member suggested that National Grid should have the same relief as exists currently: relief from delays arising from external events causing delays to DCW and to wider works. His argument is that National Grid is already incentivised to build wider works and DCW as soon as possible because only once these assets are built can National Grid gain income from them. National Grid would neither cause nor exacerbate external delays, nor could it manage them, apart from the normal obligation to minimise their effect. Therefore, National Grid should not have to bear the risk of delays arising from external events. Some Members of the WG believed that this variant would be no different from the current TEC product however. It should be noted that such external delays would increase the time period between the DTEC generator having access and the date on which wider works are completed and hence may exacerbate constraints, the costs of which are ultimately borne by generators and suppliers and hence the end customer.

A further variant of risk allocation examined by the WG was planning risk. A WG member proposed that National Grid should have no relief for external events arising from planning issues such as planning inquiry delays and leading to delays in construction of the wider works. However, they would have relief for other Force Majeure type events such as flood, famine, war and terrorism, etc.

4.4.6 Risk Allocation Summary: In summary WG members agreed that three candidate risk allocation criteria should be carried forward to the WGAA section: i) National Grid has no relief from external delays to the wider works, ii) National Grid has no relief from external delays to the wider works arising solely from obtaining planning permissions, and iii) National Grid has the current CUSC relief from external delays to wider works.

4.4.7 First Availability: The eligible generator will gain access to DTEC via signing either a Bilateral Connection Agreement (BCA) if it is transmission connected or a BEGA if it is distribution connected. (Generators with BELLAs are not directly affected by DTEC, just as they do not currently have TEC). Under the original proposal the eligible Generator will have DTEC from the earlier of (1) the date by which National Grid can deliver Transmission Entry Capacity (“TEC”); or (2) three years after the later of: (i) the date on which the generator obtains its project planning consents; or (ii) the date on which it accepts a Connection Offer from National Grid, subject in both cases (1) and (2) to a local connection having been consented and commissioned: such date being the “DTEC Completion Date’’. The proposer of CAP 148 clarified that although not stated explicitly in the original amendment proposal, an additional condition precedent to the receipt of DTEC is the commissioning of the generating plant itself.

The CUSC agreement provides for access in the future, conditional on completion of specified work. The access allows a User to export power up to a specified MW figure. The specified MW figure is the MW given by TEC (or DTEC if CAP 148 is implemented) in the BCA. Therefore the access product (TEC or DTEC) is available to Users when the specified works are complete and any other conditions precedent are satisfied or waived; before this point the User has no access (i.e. it does **not** mean the user has access at TEC or DTEC of 0).

4.4.8 Implementation & Existing Applications: Those applicants in the current connection queue already have signed connection agreements that promise them TEC. In order for this amendment proposal to apply to them, it must be possible to change these agreements prior to commissioning. The construction agreement and the BCA (clauses 15 and 10 respectively on standard form) provide National Grid with the right amend the contents of the CONSAG or BCA respectively following approval of an amendment by Ofgem. Therefore the amendment must include a provision for National Grid to amend the CONSAG or BCA of those eligible renewable generators who have not yet been connected so that they enjoy the benefits of DTEC. The cut-off date would be the Completion Date as defined in the Construction Agreement; if it occurred after the CAP 148 Implementation Date; eligible generators would receive DTEC; if it occurred before the CAP148 Implementation Date eligible and non-eligible generators would receive TEC. As DTEC is mandatory for all eligible generators, the change would be automatic. However, a process will be required to enable eligible generators to indicate their eligibility for DTEC. WG members envisaged that on implementation of CAP148, National Grid would contact all generators to confirm eligibility and status, then to conform all existing eligible but unfinished BCAs to DTEC and all existing non-eligible and unfinished BCAs would remain with TEC. For those DTEC generators with planning permission, the completion date would be set; for those without, the completion date would be indeterminate. As generator developers came forward with planning permission, the completion date would be agreed in their BCA.

4.4.9 Lead Time Variants: The original proposal has a period of 36 months after grant of planning approval for a project before the connection date occurs (unless TEC can be provided earlier). The rationale for choosing this period was that it matched the implementation period for planning consents in Scotland. In order to hold consents, parties must commence substantial construction works within 36 months. Some WG members considered this time period to be too short for National Grid to build infrastructure and suggested a WG alternative amendment candidate of a longer fixed duration period of 48 months in line with the discussions of CAP 131. The WG agreed to carry forward these two lead time candidates (the original amendment proposal of 36 months or the variant of 48 months) to the WGAA section.

4.5 DTEC Operation

4.5.1 Constraint Management: The proposer envisaged that CAP 148 would deal with the situation in which connection of new eligible plant before the completion of wider works would lead to local, easily identifiable constraints that would apply until the wider reinforcement works were completed, at which point the transmission system would become unconstrained. However, constraints are by their nature impermanent and the location of constraint boundaries will change in response to a variety of factors. Constraints could in principle affect only DTEC generators, only TEC generators, or a mix of DTEC and TEC generators. The constraint management system needs to deal with all three scenarios. The amendment proposal does not propose any change to the current constraint management arrangements when only TEC generators are affected by the constraint. It should be noted that although CAP148 expects TEC generators to be constrained down/off before DTEC generators, in the event of constraints, National Grid have a licence obligation with regard to Security of System and so with due regard for System Security, balancing actions may need to be taken on plant with DTEC prior to all other feasible balancing actions having been exhausted.

4.5.2 Constraint Identification: The proposer's expectation of how constraints arising from CAP 148 would be dealt with is illustrated simplistically in Annex 8. As a result of the connection of the DTEC generators (A), (B) and (E) prior to the completion of wider infrastructural reinforcement, a constraint would arise between the hub (H) and the MITS (M) requiring National Grid to constrain down/off TEC generators (C) and (D), prior to constraining down DTEC generators (A), (B), & (E). Generators (C) and (D) would receive an Interruption Payment to cover their 'associated losses'. Also, in the event that (A), (B), or (E) was constrained they would receive Interruption Payments. (This is further illustrated in Annex 9a). This type of constraint was anticipated to be identifiable and distinct from other constraints on the system and likely to be temporary until the wider infrastructural reinforcement is completed. (The proposer noted that National Grid, in applying the SQSS, might decide under certain circumstances not to undertake wider infrastructural reinforcement as the more cost-effective alternative was for the market to bear the constraint costs, rather than the higher TNUoS charges arising from additional infrastructural assets.) In discussion the WG considered that it might be possible, in certain circumstances, to identify a situation as simple and clear-cut as that portrayed in annex 8 and 9a. However, in practice less localized constraints would arise and their cause was likely to be more ambiguous than anticipated in the simple example. In this more usual example (see Annex 9b), preferential dispatch would have to be applicable to all TEC and DTEC generators. For the avoidance of doubt, any generator that was constrained on/up in the unconstrained or constrained part of the system would receive its BM Offer value.

4.5.2.1 Choice of Constrained Plant: The amendment proposal is clear that in the event of a constraint there will be a hierarchy of plant to be constrained down/off: TEC generators will be constrained first, followed by DTEC generators. There will also be Proportionally Qualifying Plant TEC/DTEC individual generating stations. WG members discussed where they would be placed in the hierarchy for constraint. A pragmatic approach was to place them in a position between TEC generators and DTEC generators. WG members recognised that this would tend to over-value them relative to all TEC generators and under-value them relative to all DTEC generators. It would also raise the gaming opportunity for some conventional generators to apply for a nominal (say 1MW) of DTEC for a trivial amount of co-fired energy crop fuel. However, this approach would at least have the over-riding value of relative simplicity for National Grid as constraint manager. Also, it should be noted that in managing constraints, National Grid may need to constrain DTEC generation before exhaustion of all other TEC or Proportionally Qualifying Plant options for reasons of system security, for example.

4.5.2.2 Constraint management approach - Long-Term: WG members noted that in the management of constraints National Grid takes actions over a number of timescales ranging from up to a year ahead to operational timescales. Where National Grid has prior knowledge of a long/medium term constraint, their first option is to negotiate with all the affected generators with a view to agreeing a commercial arrangement that will minimize the overall cost of the constraint to the system. Similarly, in the shorter term National Grid may seek to deal with impending constraints ahead of real time via other arrangements. National Grid would have knowledge of likely constraint costs in negotiating these commercial services agreements. Depending on the nature and duration of the constraint National Grid would seek to achieve differing mixes of short and long-term constraint management tools. All of this exists now and would continue to be available to National Grid under CAP 148.

4.5.2.3 Constraint management approach - Operational Timescales: WG Members discussed the provision of a new constraint management system and the proposer of CAP 148 explained that part of their reasoning for the new system was the interaction of the ROC system and the current constraint management approach. If a TEC or DTEC renewable generator were to be constrained off they would not receive ROCs (ROCs are determined on the basis of the metered output) and hence their marginal cost of being constrained down would include the cost of the ROC not received. The proposer wished to avoid TEC generators in known constraint areas using locational power to bid at levels which would result in them receiving a loss-of-profit that included the ROC cost. Therefore rather than using BM Bids and Offers, as now, there would Interruption Payments for constraints leading to the need to constrain down/off generation (TEC or DTEC) where there is either DTEC only plant affected or a mix of TEC and DTEC plant. These Interruption Payments would be administered payments. The following outline scenarios deals with the three types of export constraint. It should be noted that in all cases, the price paid to the generators constrained on/up is their BM Offer value. The rationale for this is that the constrained on/up generator will be in the majority part of the market where locational market power considerations will not apply.

4.5.2.3.1 <u>DTEC Only Plant Affected</u>: Where only DTEC plant is affected by the constraint, the choice of which plant is to be constrained down/off will be made by National Grid on the basis cost efficiency (as now) and taking into account the administered estimate of the associated losses of reduction of output for each eligible DTEC generator (Interruption Payment).

4.5.2.3.2 <u>TEC Only Plant Affected:</u> Where only TEC plant is affected by the constraint, the choice of which plant is to be constrained down/off will be made by National Grid on the basis of cost efficiency (as now) and taking into account the Bid prices submitted by the affected generators, exactly as now.

4.5.2.3.3 <u>DTEC & TEC Plant Affected:</u> Where a mix of plant is affected by the constraint, the choice of which plant is constrained down/off will be made by National Grid on the basis of cost efficiency (as now) and firstly choosing TEC generators in order of increasing Interruption Payment and then, once all the TEC generators were exhausted, any mixed TEC/DTEC generators and finally, the DTEC generators would be chosen in order of increasing Interruption Payment.

4.5.2.4 <u>Constraint Payment arrangements</u>: In the event of a constraint, the two differing types of payments: CAP 148 Interruption Payments and BM Bids & Offers would flow down different paths through the industry. TEC generators would need to have systems in place to deal with their being constrained and then receiving their Bid/Offer or receiving an Interruption Payment. In order to illustrate these payments and paths the WG constructed a number of scenarios and money-flow diagrams. (See Annex 10).

4.5.2.4.1 <u>Scenario 1</u> Shows a Long Market under the current baseline.

4.5.2.4.2 <u>Scenario 2</u> Shows a long market with a 20MWh constraint under the current baseline

4.5.2.4.3 <u>Scenario 3</u> shows the same as scenario 2, but with the constraint requiring TEC generators to be constrained down/off. For the purposes of this scenario it is assumed that the Interruption Payment for the affected TEC generators is the same as their Bid values: £24/MWh. The blue arrows indicate those cash flows arising from Interruption Payments that must now flow through the TNUoS system.

4.5.2.4.4 <u>Scenario 4</u> shows a long market in which there is an export constraint affecting a DTEC wind generator under the current baseline.

4.5.2.4.5 <u>Scenario 5</u> shows the same as scenario 4. The constrained wind generator is a DTEC generator. Therefore the Interruption Payment includes the value of the ROC The sequence of events/payments would be:

- ROC Eligible TEC generator (ROCETG) is constrained off at ROC-price reflective bid price - i.e. receives ROC payment through BM
- No ROCs are produced so Supplier will be short and liable for ROC buyout price
- ROCETG needs to compensate Supplier for lost ROCs (presumably at the ROC market price less any shared amount between ROCETG Gen and Supplier)
- No payment is required from Settlements to the Supplier for lost ROCs.

The ROC and constrained off (disregarding energy payments) money flows would be:

Assumptions:

i) RO buyout price is £33/MWh
ii) ROC market price is £43/MWh
iii) ROCETG Gen and Supplier share ROC Benefit 50:50 i.e. £5/MWh each

Now:	**Receives**	**Pays**	**"Profit"**
	£/MWh	**£/MWh**	**£/MWh**
ROCETG	38 (in contract)	0	38
Supplier	43 (through ROC stir back	38 (in contract)	5
Under CAP 148			
ROCETG	38 (through –ve bid) (plus £38 from contract with Supplier)	38 (back to Supplier)	38
Supplier	38 (from ROCETG)	33 (RO obligation)*	5
* No ROC 'recycle' payment			

In summary both parties end up in the same position as now through the –ve bid and bilateral contract.

4.5.2.5 <u>'Associated Losses':</u>

4.5.2.5.1 <u>Principle of 'Associated Losses':</u> CAP 148 anticipates that the administered Interruption Payment, payable to those generators constrained down in constraints involving TEC and DTEC, or just DTEC generators, would cover 'associated losses'. Some WG Members expressed their strong aversion to administered payments (in a competitive market) being used during the management of constraints, which, in their view, should be managed in as nearly a market-based way as possible. The existence of administered payments would always be a second-best to the provision of BM Bid (& Offer) prices by generators that were their own best estimate of their losses. They also believed that the complexity associated with the co-existence of administered payments and BM Bids (& Offers) would increase the complexity and systems required by National Grid to carry out it GBSO role, without any benefit. Finally, they were concerned that the imposition of any administered price would have competition law implications for the TEC generators who would be forced to accept CAP 148 Interruption Payments (which may well not cover all their actual costs/losses).

Other members of the WG responded that in a constrained part of the market, individual participants may have locational market power and may provide a BM Bid price reflecting that locational market power and so gain inappropriate commercial advantage. They were not confident that the normal operation of the market would always lead to a cost-efficient outcome. They noted that the likely outcome of implementing CAP148 would be to increase the volume, duration and frequency of constraints and hence increase the risk that more participants could game the locational power arising from the constraint more frequently. They were concerned that self-regulation may fail under such increased pressure. It was noted that the market was subject to continuing surveillance by the Regulator and that the remedies available to the Regulator for anti-competitive behaviour could be up to 10% of global turnover.

4.5.2.5.2 <u>Elements of 'Associated Losses':</u> WG members discussed the elements of such an administered Interruption Payment. The administered Interruption Payment is intended to hold the affected generator harmless against their net lost income, whilst at the same time avoiding opportunities for gaming by conventional plant with regard to the value of ROCs. For differing types of generation technology, the elements of associated losses can vary tremendously. Below the WG discussed a few illustrative examples.

For a thermal plant, the bid price will generally reflect the avoided fuel costs as the generator is earning its contract price and effectively rebating the cost of the fuel not burned. The bid price may be less than this due to fuel handling and other associated charges. If the generator has a take-or-pay fuel contract then the bid price could be zero or even negative. If a generator had a technical restriction on operation with its plant it could put in an extremely negative bid.

For a nuclear plant, constraining it down or off could result in a period of forced unavailability outside of the accepted bid and so the associated imbalance costs at SBP may be reflected in the bid price which could be highly negative.

For a renewable generator, the contract with the supplier will incorporate an energy price (this would include a value for the intermittent energy produced and any other costs incurred by the generator i.e. financing costs, TNUoS, losses, operation and maintenance) and a "green" price (this would be the £38/MWh listed above i.e. the RO buyout price plus shared ROC value). If the ROC-eligible generator was constrained down/off then its bid price should only reflect the green price element as the other (energy price) costs should be covered in the contract price received from the supplier.

For CHP plant with a significant heat load the decision to dispatch-off plant that is used to provide steam for processors (paper, chemicals refinery etc) in favour of renewable plant will have a number of consequences:

- The process will either have to stop or auxiliary boilers will have to be run at huge inefficiencies. The auxiliary boilers have emissions limits and this may force the process to be shut down if these are exceeded.
- The cost of interrupting the process can be high with damage to catalysts running in to millions of pounds as well as lost production
- The return of the plant may take hours to achieve as steam conditions for the process will need to be established prior to generation being available.

A WG member suggested that the calculation of associated loss would need to include consequential loss and not just the loss due to failure to supply generation. His preferred approach would therefore be to use the current BM Bid price mechanism so that plant can indicate its costs to National Grid prior to it being despatched off.

A further issue with defining the elements of associated losses was the frequency and duration of the constraints. If CAP 148 led to long duration and frequent constraints, albeit until the wider reinforcement is built, the affected generators will be at risk of not recovering their ongoing fixed costs.

The WG discussed the merits of differing approaches to defining the elements of associated losses and hence the Interruption Payment. The majority (but not all) of WG members believed that using BM Bid Prices (i.e. no administered Interruption Payment) was superior to any administered approach. It allowed for the variety of technologies commercial positions as identified above without undermining competition. The other extreme would be to establish a claims process with an open-book accounting approach under the administration of the CUSC Panel. This highly administered approach would have the risk of undermining the operation of the competitive electricity market. A further approach considered by the WG as a second best administered approach consistent with the principle of Interruption Payments, but without the complex administrative arrangements otherwise required would be to use the market price for the relevant Settlement Period(s). This is a public domain datum with safeguards to avoid any gaming. For affected generators that are ROC producing, the Interruption Price would be the market price plus ROC value. This approach would be similar to that adopted for unplanned outage under CAP48. However, this would only represent a recent market price for electricity, not the intention of the proposer of CAP 148 to hold the affected generator harmless. CHP and Nuclear plant, as illustrated above, would be particularly affected by this approach.

In summary the WG could identify an administratively complex method that would deliver a more accurate Interruption Payments after the event and a less administratively complex method that would be less accurate and more arbitrary. The majority of the WG remained concerned that either of these two methods would have unpredictable and damaging effects on the operation of the competitive electricity market. The remainder of the WG remained concerned that the administrative approach would have to be very complex in order to be accurate and hence unlikely to be easily practicable. For these reasons the WG agreed not to pursue Interruption Payments and Associated Losses as part of the candidates in the WGAA section. Nevertheless, the WG did recognise that a reliance on the BM Bids and Offers in a post CAP 148 environment would place self regulation and the regulatory oversight function under greater pressure.

4.5.2.6 <u>Impact on Cash-out Prices</u>: In the event of a constraint, it is usually the case that the volumes of constrained off and constrained on plant are 'tagged out' under the BM so that there is no net impact on cash-out price. However, there can be a case where the price can impact cash-out price. Under the current circumstances, where the system as a whole is long and the constrained-down plant has a Bid (which may be negative) accepted, that bid will influence the cash-out price. Under the CAP148 arrangements, the WG agreed that the volumes of TEC or DTEC generation that was constrained should be tagged out as now. If the same approach is applied to the Interruption Payment as to Bids/Offers, then the Interruption Payment will contribute to the cash-out price. This potentially exacerbates this existing problem by mixing competitive market and administered prices in the inputs into cash-out price when the whole system is long.

4.5.2.7 Impact on Constraint Costs – Longer Term: WG members tried to develop a rough estimate of the impact of implementation of CAP 148 on constraint costs. As with any such estimate, it is almost impossible to be clear about the impact of a change on participants' behaviour later. Also, the WG did not have the wherewithal to try to ascertain the impact on each of the connectees currently in the queue and those already connected. Therefore the estimate contains a number of 'heroic assumptions'. Nevertheless, the connection queue data is in the public domain and other parties can use the same data to try the impact of their favoured assumptions. In summary, the WG took the current connection queue till 2016 and assumed that varying percentages of the generators in the queue with connection dates beyond 2010 (25%, 50%, and 100%) all had their connection dates brought forward by three years. At the same time the wider works required for the queue were still being built by National Grid, albeit at the rate consistent with the current queue timetable. Then by making assumptions for the cost of each constrained MWh and the percentage of time each boundary in the transmission system was constrained, the WG was able to come up with a rough range of constraint costs arising, year by year. The basis of calculation is set out in Annex 11. If 25% of the current projects are advanced then the minimum additional constraint cost between 2011 and 2019 is approximately £135m; this rises to £542m if 100% of the projects are advanced. This cost is over and above ongoing constraint costs arising from the pre-CAP 148 situation and constraints associated with the outages needed to reinforce the wider transmission system. These numbers have been derived using an assumption that all projects currently in the queue can potentially proceed to be built and hence the percentages mentioned relate to the percentage of the total that are accelerated. The WG were satisfied that to obtain a more accurate set of figures would require access to information that they could only guess. A WG member asked about the price track for 'normal' constraints over this period. National Grid currently have a annual System operator Incentive Scheme and hence produce a public domain estimate of constraint costs up to a year in advance, not further.

4.5.3 Longer Term System Issues

4.5.3.1 Planning assumptions TEC & DTEC Transmission Licensees currently undertake the planning and scheduling of both wider and local works across the whole system on the basis of one long-term access product: TEC. The introduction of another superior product (DTEC) will provide eligible renewable generators with access to the GB Transmission System, notwithstanding that wider works which would have been required for the equivalent TEC generator had not been completed. Transmission Licensees may have to decide between preferentially facilitating the Directly Consequential Works (DCW) for DTEC generators or wider works and be confident they have the regulatory framework that allows them to justify such an action. However explicit prioritisation of asset build would be a transmission licence issue not covered in this amendment proposal. This runs the risk of producing a sub-optimal, longer and/or more costly overall connection process for TEC generation in the "queue" due to the less efficient integration of local and wider works compared to the status quo.

4.5.3.2 Impact on Security of Supply: Post implementation of CAP 148, Transmission Licensees would, as now, manage the longer-term investment in infrastructure so as to deliver local and wider works as quickly and cost efficiently as possible. Implicit in CAP 148 is the expectation that the network will be more constrained more frequently. Whilst this is likely to lead to higher constraint costs until the wider works are complete (not least because of the increasingly unpredictable running pattern of TEC generation), it is not expected that operational security of supply will be compromised because National Grid retains the over-riding power to take actions to maintain security of supply. However, as noted above TEC generators are likely to find that their running patterns may become increasingly uncertain and erratic as constraints dictate that they are "constrained down/off" in order to accommodate DTEC generators.

4.5.3.3 Maintenance of the Reliability and Safety of the Grid: The WG noted that Article 7 of the EU Renewables Directive 2001/77 refers to 'without prejudice to the maintenance of the reliability and safety of the grid'. The WG agreed that it would be for National Grid to advise Ofgem if, in their opinion, either the original amendment proposal or any Working Group Alternative Amendments or any Consultation Alternative Amendments would be prejudicial to 'maintenance of the reliability and safety of the grid'.

4.5.3.4 Impact on SQSS: WG members noted that CAP 148 proposes no changes to SQSS. As now, National Grid would form an assessment of which assets to build (or not build if the costs of constraints are economically preferable) and then build them. What could change is the frequency with which National Grid have to approach Ofgem for a derogation for the period between the date upon which the DTEC generator receives its DTEC (maximum 3 years from connection agreement, subject to some conditions precedent outlined above) and the date when the wider system reinforcements are in place to bring the whole system back into compliance with the SQSS. These are currently rare events. National Grid representatives at the WG indicated National Grid's unease at the implication of CAP 148, that National Grid would begin a connection agreement knowing that it could be in breach of its licence if derogation was not automatically granted. This issue might be resolved by a separate agreement between National Grid and Ofgem, or more likely by a change to the SQSS so as to deal with this situation for DTEC generators. Such changes would be consequential changes to other documents, if this amendment were to be implemented.

4.5.3.5 Connection Queue Management: Currently, the Transmission Licensees undertake their system planning and reinforcement on the basis of a sole access product – TEC. If CAP 148 were introduced there exists the possibility that the revised system could become unduly discriminatory against those prospective new users seeking TEC, noting that some new connectees only have the option to seek TEC (rather than DTEC).

The process may delay the connection of new or expanded TEC generation, due to the allocation of resources onto the DTEC local connection works, in preference to "TEC" generator local connection works. It could also delay the connection of TEC generation further, if there is a consequential delay in the progressing wider system reinforcement which is required to allow TEC generation to connect (finite resources/outages etc., will have been reallocated to local DTEC connection work). Whilst there is currently no explicit obligation to advance DCW the WG understood that once DCW and wider works became separate, advancement of DCW may occur subject to other licence obligations (and possible changes in licence obligations (see section 4.5.3.1 above)). There is also the possibility that TEC generation might have to wait not only for those wider infrastructure works for which it is "responsible", but also the wider works which have been triggered by DTEC generators due to the system being rendered non-SQSS compliant, so no more TEC until it is compliant. Finally, the discrimination in favour of the DTEC generator will mean that at all points in the connection process for a

TEC generator it is subjected to greater risk than at the moment that its programme will be shifted because of DTEC later comers.

4.5.3.6 Risk Perceptions and Realities for all generators: If CAP148 were to be implemented and successfully brought forward more renewable generation more quickly, there would be impacts on the risks faced by TEC generators. Running patterns for TEC generators are likely to become more uncertain and volatile pending the construction of wider reinforcements. The likely increase in constraint during this interim period, but more importantly the increase in uncertainty of when it might arise and for how long, will result in greater uncertainty for the users in creating cost-reflective BM Bids. Ultimately the effects of such uncertainties in costs are likely to be borne by the customer.

At present operational market access risk is small, as evidenced by the current annual costs of constraints compared with the value of energy traded per annum. If in a post-CAP 148 implementation market the operational access risk is enhanced and hence the costs of constraints increased, the point may be reached at which the continuing appropriateness of the current mutual self-insurance provided via the BM may need to be reviewed.

4.5.4 Industry Documents and Systems requiring change to implement CAP 148: National Grid provided a list of probable other industry document changes that would be required. This is based on the original amendment proposal. In the event that Interruption Payments based on Associated Losses are not part of the implemented amendment, the number of other industry document changes is substantially reduced.

Balancing Principles Statement, BPS	***Necessary for CAP 148 original but not WGAAs***
	Changes to indicate the 'must run' nature of DTEC generators identified in CAP148
	Clarification of the circumstances and when National Grid would use market based services or the administered services This might better placed in a separate licence document.
Procurement Guidelines, PGs	***Necessary for CAP 148 original but not WGAAs***
	National Grid to consider if the use of market based tools for the provision of services from renewables was appropriate
	Additional services may be required that deal with providing services explicitly in the context of DTEC constraint.
	Some changes required to the Balancing Services Adjustment Data, following on from PGS
Grid Code, GC	***Necessary for CAP 148 original but not WGAAs***
	Number of new obligations on the National Grid or the DTEC generator and exemptions from existing obligations Focusing on Balancing Codes
	Mixed holding will require changes for clarity
	Form of and procedure for accepting administered bids to underpin CUSC mechanism
	Possible changes to frequency control services Balancing Code 3
	Any changes to despatch systems EDL Interface specification Data Validation Consistency

	Defaulting Rules
BSC	***Necessary for CAP 148 original but not WGAAs***
	Depends on how DTEC interacts with BSC
Charging Methodology	***Changes probably required with WGAAs (or original)***
	Method for charging late connectees
	Possible differential charging between TEC & DTEC
SQSS	***Changes probably required with WGAAs (or original)***
	Possible change to avoid multiple derogations
STC	***Changes probably required with WGAAs (or original)***
	Identification of DCW
	Planning prioritisation framework for DCW versus wider works
Transmission licences	***Changes probably required with WGAAs (or original)***
	Aligning the incentives for National Grid and the TOs with the DTEC principle
	Comparison of costs against due discrimination
	Additional cash flow requirements
DCUSC	***Changes probably required with WGAAs (or original)***
	Amendments to recognise difference between TEC and DTEC generators when embedded
Distribution Code	***Changes probably required with WGAAs (or original)***
	Amendments to recognise difference between TEC and DTEC generators when embedded

4.5.4.1 <u>Balancing and 'despatch' IT and other Systems:</u> National Grid noted that in order to run the constraint management system so as to allow for TEC and DTEC generators to be dealt with separately, there would be a need for new IT systems to support National Grid analysis and decision making. Operational planning would need to be expanded to allow differentiation between TEC and DTEC generators. There would need to changes to the TNUoS calculation systems to allow for differences in treatment of TEC and DTEC as well as the TNUoS payment arrangements to allow the inclusion of Interruption Payments.

4.5.5 <u>Discrimination and Wider Policy Issues</u>:
The WG agreed that the CAP148 proposals would introduce a degree of discrimination under the CUSC in favour of new (DTEC) renewable generation projects which would be offered different and more advantageous connection arrangements when compared with other TEC generation projects (i.e. existing conventional and renewable plus new conventional). The key issue for the WG was whether this comprised "due" or "undue" discrimination. In the Ofgem/DTI (now BERR) letter to the CUSC Panel referenced earlier (see section 2.2) help is provided with the concept of 'due discrimination'. '… *no discrimination arises where like situations are treated differently provided that the difference in treatment can be objectively justified.*' Additionally '…*in relation to the question of economic and efficient operation, we consider it would be possible to make an argument that it is more economic and efficient for generators that do not emit carbon to have grid access than for carbon emitting generators to have access when you consider the environmental costs associated with higher carbon emissions. It is of course open to those carbon emitting generators to make an argument for no change on the basis that the EU ETS is designed to internalise the costs of carbon into their decision making. We believe that the CUSC process should facilitate this discussion and debate*.' A consensus was not achieved amongst the WG as

to whether or not implementation of CAP 148 would lead to 'due discrimination'.

It was recognised that the CAP 148 proposal could help to facilitate Government and EU targets for renewable generation (see for example Ch. 5, Para 5.3.75 of UK Govt Energy White Paper, May 2007, 'Meeting the Energy Challenge.') and help to meet wider UK Government and EU objectives in relation to reducing CO_2 emissions (see for example p14 Executive Summary of UK Govt Energy White Paper which makes reference to taking into account the implementation of the European Council agreement to a binding renewable energy target for 2020. However, it was noted that such considerations were not explicitly part of the CUSC applicable objectives. Other governmental energy policy goals such as security of supply and minimisation of costs of energy via the use of competitive markets are easier to trace to the CUSC applicable objectives and they are considered explicitly below in the context of the WGAAs.

5. WORKING GROUP ALTERNATIVE AMENDMENTS

5.1 Following the assessment discussion summarized above, members considered possible Working Group Alternative Amendments (WGAA). The discussion focussed on two areas: connection and operation.

5.2 <u>Connection Alternatives:</u>

5.2.1 <u>Definition of Eligible Generation</u>: The WG considered the eligibility criteria at length and from their consideration four candidates (1-4) were further considered. Of the four 1) all REGOs and 2) Intermittent REGOs were considered but not supported. The supported candidates were: 3) Low carbon generation defined as (tonnes carbon emitted per MWh generated ≤ 0.2) minus Proportionally Qualifying Plant and 4) All REGO generation minus Proportionally Qualifying Plant.

1	All REGOs: any generator including Proportionally Qualifying Plant
2	Intermittent REGOs only minus Proportionally Qualifying Plant
3	Low Carbon Generation minus Proportionally Qualifying Plant
4	REGOs minus Proportionally Qualifying Plant

5.2.2 <u>Delays and Risk allocation:</u> <u>Risk Allocation for delays in Wider Works:</u> Please note that under all three risk allocations the DTEC Generator would automatically gain transmission system access after completion of the Directly Consequential Works (subject to the generator being commissioned). The differences in risk allocation are with regard to delays in the completion of the wider infrastructural reinforcement works. Three candidates (A-C) were supported: A) delays affecting the Wider Works were treated as now; B) delays affecting the Wider Works were treated as now except those arising from planning for which there would be no relief for National Grid; and C) there would be no relief for National Grid for delays affecting Wider Works.

A	National Grid have all current external event delay relief (subject to lead time below)
B	National Grid have no relief for delays arising from obtaining Planning permissions for wider works (non DCW works)
C	National Grid have no relief for delays however arising

5.2.3 Different lead times: The lead time is the earliest time the eligible generator can receive access to the transmission system, subject to completion of the Directly Consequential Works and the commissioning of the generator. (It should be noted that in the event that the wider works, the Directly Consequential works and the generator commissioning could all be completed in less than the lead time, then the generator could receive access even earlier.) Two candidates were supported: X) 36 months, the time proposed in CAP 148 original, and Y) 48 months arising from the discussions surrounding assessment of CAP 131.

X	48 months plus any additional time for DCW
Y	36 months plus any additional time for DCW

5.3 Operational Alternatives

5.3.1 No Special Constraint Management: Although the WG members as a whole decided to abandon the special arrangements for Interruption Payments, some did so because they believed it was deleterious to the competitive energy market and overly costly and complex with nugatory benefit if any, whilst others only accepted the complexity and cost argument. WG members agreed to rely for all the Working Group Alternative Amendments on the current constraint management processes, noting that eligible renewable generators would routinely set BM Bid prices that would make them the least attractive to constrain down/off. All WG members noted that the likely increase in frequency and duration of constraints under CAP 148 is likely to impose more of a regulatory burden for Ofgem's market oversight function. WG members further noted that the CAP 148 original Interruption Payment scheme would have led to the additional constraint costs being recovered via the TNUoS route compared with the BSUoS route. The TNUoS route allows constraint costs recovery to be smoothed over 12m, subject to National Grid being able to charge the costs of carrying these costs. The twelve-monthly cycle of TNUoS aligns more closely with domestic tariff cycles. The BSUoS route for constraint cost recovery associated with all the Working Group Alternative Arrangements is more rapid and therefore more volatile than TNUoS. Nevertheless, the other administrative complexity of having to run both a TNUoS and BSUoS approach to CAP 148 constraints was agreed to be an overwhelming factor against it.

A further consequence of this choice was that, at least in principle, once the wider works are complete the DTEC generator could revert to TEC.

5.4 Candidates for WGAA:

Eligibility	1 *All REGOs*	2 *Intermittent REGOs only*	3 *Low carbon Generation*	4 *All REGOs minus proportionally qualifying*
Force Majeure Risk	A *As now*	B *No relief for planning*	C *No Relief*	
Lead Time	X *48 months*	Y *36 months*		

The candidate combinations are set out above. Therefore a combination would combine 3 parameters: (1,2,3,4) plus (A,B,C) plus (X,Y). From amongst the possible combinations 13 WG members (Chair did not vote) were asked to consider which of the original and WGAAs were better than the current CUSC baseline. All of the WG members could vote on each of these. Then, those WG members who had supported any of the original or the WGAA were asked to vote once more to determine which of the WGAAs or original was the preferred alternative. It should be noted that some (5) of the WG members believed that none of the WGAAs or the original was better than the current CUSC baseline. Therefore these members did not express a preference for a preferred alternative amongst the WGAAs and the original.

	Compared to Current CUSC			
	Better	**Worse**	**Abstain**	
Current Baseline	5			**Preferred alternative**
4CX	2	10	1	0
4BX	6	7	0	6
4CY	2	10	1	1
3BX	2	10	1	1
4AX	0	10	3	0
CAP 148 Original	2	11	0	0

As a result of the final voting by Working Group Members none of the WGAAs or the original CAP 148 have majority support from the WG Members compared with the current baseline. A majority of WG members considered that some variant of the proposal was better than the original; Option 4BX gained the most support from WG Members relative to the current baseline and the most votes in favour of it as the preferred alternative.

In voting on the alternatives, WG members were aware that CAP 148 is premised on discrimination in favour of eligible renewable generation and against non-eligible generation technologies. They were in receipt of advice from Ofgem (DTI) to the CUSC Panel[5] which made the point that 'due discrimination' under the CUSC applicable objectives may be permissible now if objectively justified. WG members were also aware of the difference between the basis on which they made a recommendation: the Applicable Objectives, and the basis on which Ofgem may make a decision: having regard additionally to its wider licence obligations. Some WG members who had voted against the WGAAs on the basis of consideration against the Applicable Objectives suggested that options 4AX and 3BX might be supportable against the wider objectives.

5.4.1 Option 4BX: In order to ensure clarity for the reader this option is more fully laid out here. This WGAA combines the following features:

- Eligibility would be determined by the core definition of REGO production minus any Proportionally Qualifying Plant (option 4). This is seen as consistent with the general governmental goal of advancing renewable generation whilst pragmatically allowing that inclusion of co-fired generation is unlikely to significantly advance these types of projects and would be very difficult to administer correctly.
- National Grid would have full normal relief against external events delaying the Directly Consequential Works (DCW), but would have no relief against delays to the wider works arising from the planning process (option B). This allocates the planning delay risk from wider

[5] The Ofgem/DTI letter in response is filed with the CAP147 documents on the National Grid web site http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/amendments/currentamendmentproposals/

works to National Grid and thence through the rest of the market to the end customers. The rationale is that end customers (through government) can affect the wider planning risk.

- The minimum period after which the DTEC generator must receive access is 48 months, subject to completion of the Directly Consequential Works (DCW) (Option X). The rationale for this choice is that during the CAP 131 assessment it appeared to most that 48 months should be sufficient time for National Grid to build the necessary local and wider works to allow new generation to connect, subject to planning consents being obtained. New generators would potentially be able to commence construction work at the end of their three year planning validity period and would then have a year to construct – an appropriate time in the context of new wind generation which is the type of generation most likely to benefit from DTEC in the near term.
- On completion of the wider reinforcement works the DTEC would revert to TEC.
- There would be no special constraint management arrangements for DTEC generators and there would be no Interruption Payments for 'associated losses'; the normal constraint market-based approach (i.e. BM Bids and Offers) would apply.

6. ASSESSMENT AGAINST APPLICABLE CUSC OBJECTIVES

6.1 The Assessment against Applicable CUSC Objectives is summarised below:

6.2 <u>Efficient Discharge of Licence Obligations:</u>

6.2.1 <u>Efficient use of the network because of additional generation connected:</u> WG members acknowledged that an impact arising from implementation of any of the WGAAs would be to increase the volume of access used at any time. This would increase the volume efficiency of the use of the network. WGAAs with the Low Carbon eligibility option (3) are likely to result in even more new projects benefiting than REGOs (4) and hence have greater volume efficiency.

However members further noted that depending on the local state of infrastructure and other developments, the next connection may make better use of existing infrastructure or cause further constraints until further new infrastructure is built. Therefore, it would be difficult to know if any given project would enhance or decrease the cost efficiency of running the transmission system.

Members also acknowledged that a result of connecting more generation to an un-reinforced system would be that constraints would be more frequent and of longer duration: and hence the costs of constraints would increase.

Additionally, National Grid had raised concerns about the efficiency of their investment programme if it had to be rearranged to allow connection before the completion of wider works; if his were the possible outcome of implementing CAP 148, Transmission Licensees would need to consider the Licence implications with Ofgem. In developing the WGAAs, the working group assumed that the additional time (48 months) provided for in option X, would increase National Grid's ability to deliver an investment programme and a lower constraint system, than the 36 month option. However, this would inevitably delay the achievement of the primary goal of CAP 148 – additional eligible renewable generation connected sooner.

WG members were divided as to the effect of risk allocation for delays: some believed that the greater risk allocation to National Grid would act as a further incentive to build transmission assets sooner, whilst others believed that the assumption that National Grid could continue with its scheduled investment programme, whilst possibly speeding up its programme to build assets related to DTEC connections in parallel, was unfounded and perhaps optimistic.

Overall, the essential issue in favour of implementing one of the WGAAs is that it would allow more renewable generation to connect to the transmission system sooner, providing greater diversity in the sources of generation to the benefit of the government's environmental agenda. Some WG members further believed that this would improve longer-term security of supply.

In contrast, some members provided a qualifying argument to the consideration of these benefits. Namely that while all parties want to see more renewable generation, putting greater volumes onto an unready system, only to have to constrain greater volumes off again than at present, is inefficient and potentially a wasteful expense to consumers and the wider industry.

6.3 Facilitation of Competition:

6.3.1 In support of the implementation of one of the WGAAs, WG members recognised that more connected generation would result in more competition in the volume of generation and also in the variety of generation types. Additionally, for smaller Suppliers, members thought it reasonable to expect that the availability of more renewable generation should make it easier and cheaper for them to fulfil their renewable supply obligations. This would enable them better to compete with larger players with their own renewable assets.

Furthermore, some members questioned whether the industry should be too concerned with the likely increase in constraint costs, noting that NG has a variety of both short-term and long-term means for minimizing the costs of constraints.

6.3.2 One member pointed out that additional generation appearing more quickly might upset the current commercial balance of renewable generation in which additional income arising from recycle payments enhances the commercial viability of renewable generation.

More generally, in opposition to implementation of one of the WGAAs, WG members expected that CAP 148 would lead to greater constraints and hence greater constraint costs. As the WGAAs propose that the current system of constraint cost allocation via BSUoS continues, this would lead to those additional constraint costs being shared amongst all generation and supply. At present, NG ensures that the system is able to accommodate new generation, meaning that the commercial opportunity available to a new generator when they get a connection is not provided for at the expense of other parties. The WGAAs therefore raise the concern that the competition created by connecting new entrants to the generation market sooner, would be achieved through subsidisation of that competition by the wider industry and consumers.

7. PROPOSED IMPLEMENTATION

7.1 The Working Group proposes that if approved by Ofgem CAP148 Original or the WGAAs should be implemented as soon as practicable after an Authority decision subject to the timescales for implementation of any consequential changes to the Grid Code, SQSS and any other documents. It is envisaged that the use of system charging changes could be progressed after implementation (application fees would need to be agreed prior to application, National Grid indicated these would default to a TEC application fee if no action was taken).

7.2 The provisions would not be implemented retrospectively. Existing eligible generators having a signed agreement but not connected at time of implementation would be permitted to switch from TEC to DTEC, with the new provisions being applied from the date they sign an amended connection agreement. All new applications for eligible generation from the implementation date would be under the new provisions.

8. IMPACT ON THE CUSC

8.1 The WG agreed that no drafting would be supplied for CAP 148 original

8.2 The text required to give effect to the WGAA 4BX is contained as three separate documents attached with this report:

- Drafting for CAP 148 v6
- 3389 Consag amends (CAP 148 4BX) V2
- 3389 BEGA amends (CAP 148) v2.

8.3 The WG agreed that no drafting would be supplied for the other WGAAs, noting that such drafting could be created by amendment to the drafting created for Option 4BX

9. IMPACT ON INDUSTRY DOCUMENTS

Impact on Core Industry Documents

9.1 Grid Code: CAP 148 original will require amendment to the balancing codes of the Grid Code. The alternatives remove this requirement however there may need to be some future housekeeping changes.

9.2 STC: Cap 148 original or WGAAs will impact the STC. National Grid would need to agree a process from converting existing agreements and assessing future applications with the TOs. This would include separately identifying works and providing explicit competition dates for wider and DCW. It may also need to address a planning prioritisation framework for DCW versus wider works.

9.3 BSC: Cap148 original will impact the BSC, but the WGAAs would not.

9.4 SQSS: CAP 148 may impact on the SQSS: A review will be required to establish the impact of DTEC on system planning. The process for derogation application would need to be reviewed prior to the completion of any review. The review will need to be progressed with the TOs. National Grid and the TOs would need to agree an interim process with the Authority for dealing with derogations for DTEC generation **prior** to any connection agreements being revised or signed.

Impact on other Industry Documents

9.5 Charging Statements: CAP 148 original or WGAAs will require changes to the charging methodologies. National Grid has indicated that on implementation it would review the charging methodologies. Under the current licence objectives it would expect to, as far as reasonably practical and with regard to the impact on competition, explicitly reflect the costs of providing early connection to the generator(s) using this service. This would require the development a methodology and a costing tool to identify constraints caused by users of DTEC. In assessing the cost of developing a new tool and system for charging National Grid would have regard for the overall benefit.

9.6 Impact on Licences: CAP 148 original or WGAAs will probably require changes to National Grid's Licence and to the Transmission Licensees' Licences. To facilitate charges on the basis of TNUoS as per the original proposal it is expected changes would be required to the licence provisions for charging. This would not be required for any of the WGAAs. The impact on C17, transmission system security standard and quality of service, is noted above. Additionally, CAP 148 or WGAAs are likely to require review to establish a regulatory framework for the 'due discrimination' arising from CAP 148 original or WGAAs.

9.7 Balancing Principles Statement (BPS) & Procurement Guidelines (PGS): CAP 148 original will require changes to these documents to allow for the administered Interruption Payments and changes to the hierarchy of constraint management for TEC and DTEC generators.

9.8 DCUSC & Distribution Code: Changes may be required to both the DCUSC and Distribution Code for CAP 148 original or WGAAs so as to recognise difference between TEC and DTEC generators when embedded.

ANNEX 1 – GLOSSARY AND ACRONYMS

NOT USED

ANNEX 2 – PROPOSED LEGAL TEXT TO MODIFY THE CUSC

ANNEX 3 – WORKING GROUP TERMS OF REFERENCE AND MEMBERSHIP

Working Group Terms of Reference and Membership

TERMS OF REFERENCE FOR CAP148 WORKING GROUP

RESPONSIBILITIES

1. The Working Group is responsible for assisting the CUSC Amendments Panel in the evaluation of CUSC Amendment Proposal CAP148 tabled by Wind Energy (Forse) Limited at the Amendments Panel meeting on 27th April 2007.

2. The proposal must be evaluated to consider whether it better facilitates achievement of the applicable CUSC objectives. These can be summarised as follows:

   (a) the efficient discharge by the Licensee of the obligations imposed on it by the Act and the Transmission Licence; and

   (b) Facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity.

3. It should be noted that additional provisions apply where it is proposed to modify the CUSC amendment provisions, and generally reference should be made to the Transmission Licence for the full definition of the term.

SCOPE OF WORK

4. The Working Group must consider the issues raised by the Amendment Proposal and consider if the proposal identified better facilitates achievement of the Applicable CUSC Objectives.

5. In addition to the overriding requirement of paragraph 4, the Working Group shall consider the following specific issues:

   - Planning assumptions and TEC
   - Interactions between i) removal of barriers, ii) removal of discrimination, iii) facilitated entry, and iv) competition
   - Interaction between Government Policy objectives, faster market penetration by renewable energy, enhancing competition, Ofgem's Objectives, National Grid's Licence Conditions and the CUSC Applicable Objectives
   - Have regard to context of Renewables Directive, Markets Directive, Human Rights Directive, and Cogeneration Directive
   - Note CAP131 is not part of the current baseline.
   - CAP148's compatibility with competition law
   - Definitions of Renewable, low carbon generation, replacement generation, deep and local reinforcement, shallow connection,
   - Security of Supply and the potential impact of CAP148

- Impact on SQSS
- Impact on system operation, balancing systems and codes with particular reference to costs and timescales for implementation, although enduring costs to also be considered
- Have regard to work of TASG and BSSG

6. The Working Group is responsible for the formulation and evaluation of any Working Group Alternative Amendments (WGAAs) arising from Group discussions which would, as compared with the Amendment Proposal, better facilitate achieving the applicable CUSC objectives in relation to the issue or defect identified.

7. The Working Group should become conversant with the definition of Working Group Alternative Amendments which appears in Section 11 (Interpretation and Definitions) of the CUSC. The definition entitles the Group and/or an individual Member of the Working Group to put forward a Working Group Alternative Amendment if the Member(s) genuinely believes the Alternative would better facilitate the achievement of the Applicable CUSC Objectives. The extent of the support for the Amendment Proposal or any Working Group Alternative Amendment arising from the Working Group's discussions should be clearly described in the final Working Group Report to the CUSC Amendments Panel.

8. The Working Group is to submit their final report to the CUSC Panel Secretary on 20th August 2007 for circulation to Panel Members. The conclusions will be presented to the CUSC Panel meeting on 31st August 2007.

MEMBERSHIP

9. It is recommended that the Working Group has the following members:

Chair	Malcolm Taylor
National Grid	Patrick Hynes
Industry Representatives	Mike Davies (Wind Energy (Forse) Limited
	Garth Graham (Scottish & Southern)
	Ben Sheehy (E.ON)
	Richard Ford (RES)/Jeremy Sainsbury (Natural Power)
	Tony Cotton (Energy Technical)
	Bill Reed (RWE Npower)
	Bob Brown (Bizz Energy)
	Dennis Gowland (Research Relay)
	Simon Lord (International Power)
	Robert Longden (Airtricity)
	John Morris (British Energy)
	Tony Dicicco (RWE Npower)
	Graeme Cowper (BWEA)
	Dewi Ab Iorwerth (Centrica)
	Alec Morrison (Scottish & Southern)
	James Anderson (Scottish Power)
Authority Representative	Jo Witters or Hannah Cook
Technical Secretary	Richard Dunn/Bali Virk

[NB: Working Group must comprise at least 5 Members (who may be Panel Members) and will be selected by the Panel with regard to WG List held by the Secretary]

10. The membership can be amended from time to time by the CUSC Amendments Panel or the Working Group Chairperson.

RELATIONSHIP WITH AMENDMENTS PANEL

11. The Working Group shall seek the views of the Amendments Panel before taking on any significant amount of work. In this event the Working Group Chairman should contact the CUSC Panel Secretary.

12. Where the Working Group requires instruction, clarification or guidance from the Amendments Panel, particularly in relation to their Scope of Work, the Working Group Chairman should contact the CUSC Panel Secretary.

MEETINGS

13. The Working Group shall, unless determined otherwise by the Amendments Panel, develop and adopt its own internal working procedures and provide a copy to the Panel Secretary for each of its Amendment Proposals.

REPORTING

14. The Working Group Chairman shall prepare a final report to the August 2007 Amendments Panel responding to the matter set out in the Terms of Reference.

15. A draft Working Group Report must be circulated to Working Group members with not less than five business days given for comments.

16. Any unresolved comments within the Working Group must be reflected in the final Working Group Report.

17. The Chairman (or another member nominated by him) will present the Working Group report to the Amendments Panel as required.

ANNEX 4 – INTERNAL WORKING GROUP PROCEDURE

1. Very summary meeting notes of agreements reached or issues raised for further assessment, together with actions from each meeting will be produced by the Technical Secretary (provided by National Grid) and circulated to the Chairman and Working Group members for review.

2. The notes and actions will be published on the National Grid CUSC Website after they have been agreed at the next meeting or sooner on agreement by Working Group members.

2. The Chairman of the Working Group will provide an update of progress and issues to the Amendments Panel each month as appropriate.

4. Working Group meetings will be arranged for a date acceptable to the majority of members and will be held as often as required as agreed by the Working Group in order to respond to the requirements of the Terms of Reference set by the Amendments Panel.

5. If within half an hour after the time for which the Working Group meeting has been convened the Chairman of the group is not in attendance, the meeting will take place with those present.

6. A meeting of the Working Group shall not be invalidated by any member(s) of the group not being present at the meeting.

ANNEX 5 RECORD OF ATTENDANCE AT WG MEETINGS

	21/5	1/6	11/6	20/6	4/7	16/7	23/7	3/8	17/8
Malcolm Taylor -Chair (AEP)	√	√	√	√	√	√	√	√	√
Patrick Hynes (NGET)	√	√	X	√	√	√	√	√	√
Richard Dunn (Technical Secretary)	X	X	X	X	X	X	X	X	X
Jo Witters (Ofgem)	√	X	√	X	X	X	X	√	X
Mike Davies (Wind Energy (Forse) Ltd)	√	√	√	√	√	√	√	√	X
Garth Graham (Scottish & Southern)	√	√	√	√	X	√	X	√	X
Ben Sheehy (E.ON)	√	√	X	√	√	√	√	√	√
Richard Ford (RES)	√	√	X	√	X	X	X	X	X
Tony Cotton (Energy Technical)	X	√	√	X	X	X	X	X	X
Bill Reed (RWE Npower)	√	X	√	√	X	√	√	X	√
Bob Brown (Bizz Energy)	√	√	X	√	√	X	√	√	√
Dennis Gowland	√	√	√	√	X	√	√ tele	√	√
Simon Lord (First Hydro)	√	X	X	√	X	X	√	√	X
Robert Longden (Airtricity)	√	√	√	√	√	√	X	√	X
John Morris (BE)	√	√	√	√	X	X	X	X	√
Tony Dicicco (RWE-NPower)	X	√	√	√	X	X	√	√	X
Graeme Cooper (BWEA)	X	X	X	X	X	X	X	X	X
Dewi Ab Iorwerth (Centrica)	√	√	√ DW	X	√	√	√	√	√
Alec Morrison (SHTL)	X	X	X	X	X	X	X	X	X
James Anderson (SP)	√	√	√	√	X	X	X	X	√
Hannah Cook (Ofgem)	X	X	X	√	X	X	√	X	√
Tricia Wiley (Ofgem)	X	√	√	X	X	X	X	X	X
Hedd Roberts (NGET)	X	X	√	X	X	X	X	X	X
Emma Carr (NGET)	X	√	√	X	X	X	X	X	√
Tom Ireland (NGET)	X	X	X	√	X	X	√	X	X
Chris Stewart (Elexon)	X	X	X	√	X	X	X	X	X
Angela Quinn (NGET)	X	√	√	X	X	X	X	√	√

ANNEX 6 – AMENDMENT PROPOSAL FORM

CUSC Amendment Proposal Form	CAP: 148

Title of Amendment Proposal: **Deemed Access Rights to the GB Transmission System for Renewable Generators**

Description of the Proposed Amendment ***(mandatory by proposer)*:**

This Amendment Proposal will prioritise the use of the GB Transmission System by renewable generators, in accordance with the Renewables Directive 2001/77, Article 7.

Renewable generators will be given firm access to the GB Transmission System up to their CEC limit by a fixed date and be compensated to the extent they are constrained from exercising such right by the payment of a new category of Interruption Payment. This will be irrespective of whether or not any associated deep reinforcement works have been constructed and/or commissioned by such date. The Amendment Proposal achieves this by the introduction of Deemed Transmission Entry Capacity (**"DTEC"**), as described below.

DTEC will only apply to such portion of a User's output that is generated from renewable sources, as defined by the Electricity (Guarantees of Origin of Electricity Produced from Renewable Sources) Regulations 2003.

The key elements of the Amendment Proposal are as follows:

(a) under its Connection Agreement(s), a renewable generator will be deemed to have DTEC on the earlier of (1) the date by which National Grid can deliver Transmission Entry Capacity ("TEC"); or (2) three years after the later of: (i) the date on which the generator obtains its project planning consents; or (ii) the date on which it accepts a Connection Offer from National Grid, subject in both cases (1) and (2) to a local connection having been consented and commissioned: such date being the "**DTEC Completion Date**";

(b) for renewable generators, the concept of TEC will be abolished and replaced by DTEC, which will apply on a permanent basis. National Grid will not be obliged to carry out deep reinforcement works in order to guarantee firm access if it considers it to be more economic to make constrained payments but this will not override the provisions of (a)(1) above;

(c) in the event that National Grid has to constrain generators as a consequence of the GB Transmission System being unable to meet the usage requirements of generators with TEC (including STTEC and LDTEC) and DTEC then it shall be contractually obliged to pay compensation for associated losses;

(d) the additional category of Interruption Payment will be funded through National Grid's regulated income from Transmission Network Use of System Demand Charges ("**TNUoS Charges**"); and

(e) National Grid shall be obliged to constrain conventional generators off the GB Transmission System, where technically possible, rather than constrain off renewable generators.

Description of Issue or Defect that Proposed Amendment seeks to Address ***(mandatory by proposer)***:

1 Current industry regulations treat all new generation as incremental rather than replacement generation, requiring applicants for connections to wait for system upgrades to accommodate this additional power. This is not in line with Government intentions which envisage renewable generation as primarily replacement generation.

2 Many forms of renewable energy are intermittent and infrequently require use of their maximum permitted TEC. This amendment, by enabling National Grid to have a higher level of control of use of the GB Transmission System, permits a more economically efficient judgement to be made about the need for system upgrades than is possible under the current regulations.

3 This amendment will permit renewable energy to come to market faster than is possible under the current regulations, supporting the achievement of Government targets for reduction in carbon emissions and Ofgem's secondary objectives under the Electricity Act 1989 Section 3A(5)(c)[6] of (amongst other things) securing a diverse and viable long-term energy supply, and in doing so having regard to the effect on the environment of activities connected with the generation, transmission, distribution or supply of electricity.

4 This amendment will remove the timing problems of matching the obtaining and implementation of planning consents for renewable generation projects with the availability of connection dates. This problem has recently been exacerbated by the reduction in validity of planning consents in Scotland from 5 years to 3 years in the Planning etc. (Scotland) Act 2006.

5 **This amendment better promotes Government objectives for the growth in renewable generation by utilising the provisions of Article 7 of the EU Directive 2001/77/EC of 21 September 2001 which allow for Member States to provide priority access to the grid system of electricity produced from renewable energy sources.**

Impact on the CUSC

Please refer to Annex I at page 6.

Impact on Core Industry Documentation *(this should be given where possible)*:

Amendments required to the System Operator - Transmission Owner Code (the "STC")

The STC will have to be amended to reflect the Shallow Connection Works regime as set out below.

a. Section D Part Two which sets out the provisions for the development of Construction Offers and the carrying out of Construction Projects (including the information to be exchanged between a Transmission Owner and National Grid as set out in the STC), will have to be amended to include the Shallow Connection Works regime.

b. **Schedule 5 will have to be amended to include a requirement that National Grid in its Connection application provides the Transmission Owner with any details of the DTEC of the new Connection Site.**

Other Core Industry Documents

[6] As substituted by the Utilities Act 2000 Section 13.

Please refer to Annex II at page 8 for a list of other industry / regulatory documents that will need to be changed in order to implement the Amendment Proposal.

Impact on Computer Systems and Processes used by CUSC Parties *(this should be given where possible)*:

Details of any Related Modifications to Other Industry Codes *(where known)*:

Justification for Proposed Amendment with Reference to Applicable CUSC Objectives** ***(mandatory by proposer)*:**

1 The Proposer believes that the proposed amendment better facilitates Applicable CUSC Objective (a) ***(the efficient discharge by the licensee of the obligations imposed upon it under the Act and by [Transmission Licence])*** **as follows:**

(a) by introducing into the CUSC a regime whereby a Generator that generates electricity from a renewable source is granted access rights to the GB Transmission System within a guaranteed period, the Amendment Proposal would remove the inefficiencies created by the current queuing system for Connection to the GB Transmission System which presently can permit projects without planning consent to potentially have earlier connection dates to transmission than consented projects with later queue positions;

(b) by granting the GBSO the option to pay compensation to generators rather than invest to build new transmission assets which may not be economically justified, taking all issues into account, the Amendment Proposal permits a more economic investment analysis to be undertaken; and

(c) by allowing the GBSO the flexibility to more efficiently utilise transmission assets that are contractually assigned to low load fossil fuel peaking plant type generators through the present grant of TEC.

2 The Proposer believes that the proposed amendment better facilitates Applicable CUSC Objective (b) ***(facilitating effective competition in the generation and supply of electricity, and (so far as consistent therewith) facilitating such competition in the sale, distribution and purchase of electricity)*** **as follows:**

(a) by providing greater certainty for renewable generators than under the current system set out in the CUSC, as new parties seeking Connection to the GB Transmission System would be granted a firm date by which access rights can be provided (whilst at the same time, recognising the issues faced by the National Grid, for example obtaining the appropriate Consents for local connections to existing infrastructure). Furthermore, OFGEM has stated (in the context of access to the GB Transmission System in respect of all generation) that: "other things being equal, greater certainty for new parties seeking connection to the network over (a) the date by which access rights can be provided (recognising practical constraints, such as the need for consents, faced by the transmission companies)

and, (b) the level of financial commitment required to be provided, might be expected to promote competition."[7];

(b) the amendment allows supply companies to have access to greater volumes of renewable generation earlier than would otherwise be the case, permitting them to better meet their obligations for percentage supply from renewables;

(c) the amendment removes a potentially discriminatory element of the CUSC whereby intermittent generators are presently treated in the same manner as conventional generators in grants of TEC.

[7] OFGEM letter dated 9 May 2006: Access Reform in Electricity Transmission - Working Group Report and Next Steps.

Details of Proposer: Organisation's Name:	Mike Davies Wind Energy (Forse) Limited
Capacity in which the Amendment is being proposed: (i.e. CUSC Party, BSC Party or "energywatch")	CUSC Party
Details of Proposer's Representative: Name: Organisation: Telephone Number: Email Address:	
Details of Representative's Alternate: Name: Organisation: Telephone Number: Email Address:	
Attachments: YES **If Yes, Title and No. of pages of each Attachment:** Annex I - Impact on the CUSC pages 6 to 7;and Annex II - Impact on other industry / regulatory documents pages 8 to 9.	

Notes:

1. Those wishing to propose an Amendment to the CUSC should do so by filling in this "Amendment Proposal Form" that is based on the provisions contained in Section 8.15 of the CUSC. The form seeks to ascertain details about the Amendment Proposal so that the Amendments Panel can determine more clearly whether the proposal should be considered by a Working Group or go straight to wider National Grid Consultation.

2. The Panel Secretary will check that the form has been completed, in accordance with the requirements of the CUSC, prior to submitting it to the Panel. If the Panel Secretary accepts the Amendment Proposal form as complete, then he will write back to the Proposer informing him of the reference number for the Amendment Proposal and the date on which the Proposal will be considered by the Panel. If, in the opinion of the Panel Secretary, the form fails to provide the information required in the CUSC, then he may reject the Proposal. The Panel Secretary will inform the Proposer of the rejection and report the matter to the Panel at their next meeting. The Panel can reverse the Panel Secretary's decision and if this happens the Panel Secretary will inform the Proposer.

The completed form should be returned to:

Beverley Viney
Panel Secretary
Commercial Frameworks
National Grid
National Grid House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

Or via e-mail to: Beverley.Viney@uk.ngrid.com

(Participants submitting this form by email will need to send a statement to the effect that the proposer acknowledges that on acceptance of the proposal for consideration by the Amendments Panel, a proposer which is not a CUSC Party shall grant a licence in accordance with Paragraph 8.15.7 of the CUSC. A Proposer that is a CUSC Party shall be deemed to have granted this Licence).

3. Applicable CUSC Objectives** - These are defined within the National Grid Company Transmission Licence under Section C7F, paragraph 15. Reference should be made to this section when considering a proposed amendment.

ANNEX I

CUSC AMENDMENT PROPOSAL - Deemed Access Rights to the GB Transmission System for Renewable Generators

Impact on the CUSC

This Annex I sets out the impact of the Amendment Proposal on the CUSC and identifies the following:

1.1 the changes that will need to be made to the CUSC (including the underlying rationale);

1.2 the sections of the CUSC that will need to be changed in order to implement the Amendment Proposal; and

1.3 (where it has been possible to provide at this stage) the suggested legal text drafting changes required in order to implement the Amendment Proposal.

DTEC regime

Section 2 of CUSC

Section 2 of CUSC should be amended by including a new section setting out the framework for the DTEC introduced by the implementation of the Amendment Proposal. This section will provide as follows:

2.1 a User that has applied for connection to the GB Transmission System shall be granted DTEC in accordance with the terms of its Construction and Connection Agreements;

2.2 following the Commissioning of its Shallow Connection the User will be entitled to have physical access to the GB Transmission System in accordance with the terms of its Connection Agreement;

2.3 the DTEC shall cover that proportion of a User's output that is, or is expected to be, generated from renewable sources. In determining whether the electricity generated is from a renewable source, the definition for "renewable energy sources" as set out in the Electricity (Guarantees of Origin of Electricity Produced from Renewable Sources) Regulations 2003, shall apply.

3 Interruption Payments

Section 5.10 of CUSC will need to be amended to specify that Interruption Payments apply (in place of any compensation under the Balancing and Settlement Code) where the Relevant Interruption is as a result of a constraint in the system as opposed to short-term balancing actions.

4 New definitions

Section 11 of CUSC

Section 11 of CUSC would have to be amended by the addition of definitions covering the matters set out below. Where it has been possible to do so, the suggested draft new definitions have been provided. (This list is not exhaustive and it may be necessary to add more definitions when the Amendment Proposal is assessed).

4.1 "**DTEC**" means the Deemed Transmission Entry Capacity set out in Appendix [ ]. Existing renewable generators with TEC should keep it rather than switch to DTEC.

4.2 "**DTEC Completion Date**" means the date three years after the User accepts the Connection Offer or obtains its Planning Consents, whichever is the later.

4.3 "**Deemed BSUoS Charges**" means a reasonable estimate of Total BSUoS Charges that would have been incurred in respect of the BM Unit of a renewable generator had the BM Unit Metered Volume been equal to the DTEC.

4.4 "**Deemed TNUoS Charges**" means a reasonable estimate of The Company's costs in providing Transmission Network Services to the renewable generator had it been exporting the DTEC on to the GB Transmission System.

4.5 The definition of "**Interruption**" will need to be amended to apply in circumstances where The Company constrains off a generator and not solely as a result of Deenergisation.

4.6 The definition of an "**Interruption Payment**" will need to be amended to include payments:

to a renewable generator, where the renewable generator is unable to use its DTEC; and

to a conventional generator where it has been constrained off the system in favour of a renewable generator.

The methodology for payment would be based upon lost revenues (including, for renewable generators, the value of ROCs, recycle payments and LECs) less avoided costs.

4.7 "**Renewable Generator**" means [•].

Note: For the purposes of this Amendment Proposal a new definition is required for Planning Consents, which would be narrower than the current definition of Consents. The renewable generator would have a right to the grant of DTEC no later than 3 years from the date of the grant of planning permission. Note that the grant of planning permission will always be subject to the completion of the "s106[8]" Agreement.

[8] Section 106 Town and Country Planning Act 1991. In Scotland the equivalent provision is Section 75 Town and Country Planning (Scotland) Act 1997.

5 Schedule 2 Exhibit 1 (the Connection Agreement)

The standard form Connection Agreement will have to be amended reflect the principles of this Amendment Proposal.

6 Schedule 2 Exhibit 3 (the Construction Agreement)

The standard form Construction Agreement will have to be amended to reflect the principles of the Amendment Proposal.

DTEC should, ideally, be tradable per CAP 68, e.g. if one project has DTEC and another is still in its three year period of waiting for a connection.

Annex II

CUSC Amendment Proposal - Deemed Access Rights to the Transmission System for Renewable Generators

1 Impact on other industry / regulatory documents

The following documents are not Core Industry Documents and their amendment is outside the scope of this Amendment Proposal. However, if the Amendment Proposal is implemented these documents will need to be amended. Accordingly, this Annex II sets out the suggested amendments.

2 Amendments required to National Grid's transmission connection charging / use of system charging methodologies

2.1 The Statement of the Use of System Charging Methodology

2.1.1 Generators are required to pay National Grid, among other things, TNUoS Charges. TNUoS Charges are comprised of the following:

(a) the costs National Grid incurs through the Generator's use of the GB Transmission System (other than sole use assets); and

(b) an element that reflects the residual costs that National Grid incurs in respect of all Generators' use of the GB Transmission System.

2.1.2 **This does not allow for a Generator exercising DTEC to be charged for the use if would have made of the GB Transmission System. The Statement for the Use of System Charging Methodology will therefore, have to be amended to allow National Grid to charge renewable generators that are exercising DTEC (or part of such rights) Deemed TNUoS Charges and Deemed BSUoS Charges.**

2.2 The Statement of the Use of System Charges

There may be changes to the numbers set out in this as a consequence of any changes to the Statement of the Use of System Charging Methodology.

3 Amendments to Transmission Licences

3.1 Special Condition AA5 of National Grid's Transmission Licence

3.1.1 Special Condition AA5 of the Transmission Licence sets out among other

things the formula for calculating the maximum amount of transmission revenue that National Grid is allowed to recover in any year from transmission charges, and needs to be amended to include the following:

(a) a separate formula that would calculate the maximum allowable revenue that National Grid can recover from transmission charges with an adjustment for the new category of Interruption Payments that are made to renewable generators; and

(b) the information to be provided by National Grid to the Authority, for example the total number of renewable generators who have exercised their entitlement to DTEC and the total sum of Interruption Payments made in a year to those renewable generators.

(c) a separate formula that would calculate the maximum allowable revenue that National Grid can recover from transmission charges with an adjustment for the new category of Interruption Payments that are made to conventional generators together with provisions covering information provision to the Authority in relation to the Interruption Payments.

3.2 Condition C17 of the Transmission Licence and Condition D3 of the Scottish Transmission Licensees' Licences

3.2.1 The Grid Code Planning Code (PC) 6.1 requires that National Grid is to apply the Licence Standards: "relevant to planning and development in the planning and development of the Transmission System." The Licence Standards are defined in the Grid Code as Conditions C17 of the Transmission Licence and D3 of the Relevant Licensee's Transmission Licence.

3.2.2 Condition C17 of National Grid's licence and Condition D3 of the Scottish Transmission Licensees' Licences respectively, require that the (relevant) licensee is to plan develop and operate the licensee's transmission system (and, in the case of National Grid) to co-ordinate and direct the flow of electricity on to the GB Transmission System) in accordance with the following:

(a) the GB Security and Quality of Supply Standard version 1 (the "**GB SQSS**");

(b) the STC; and

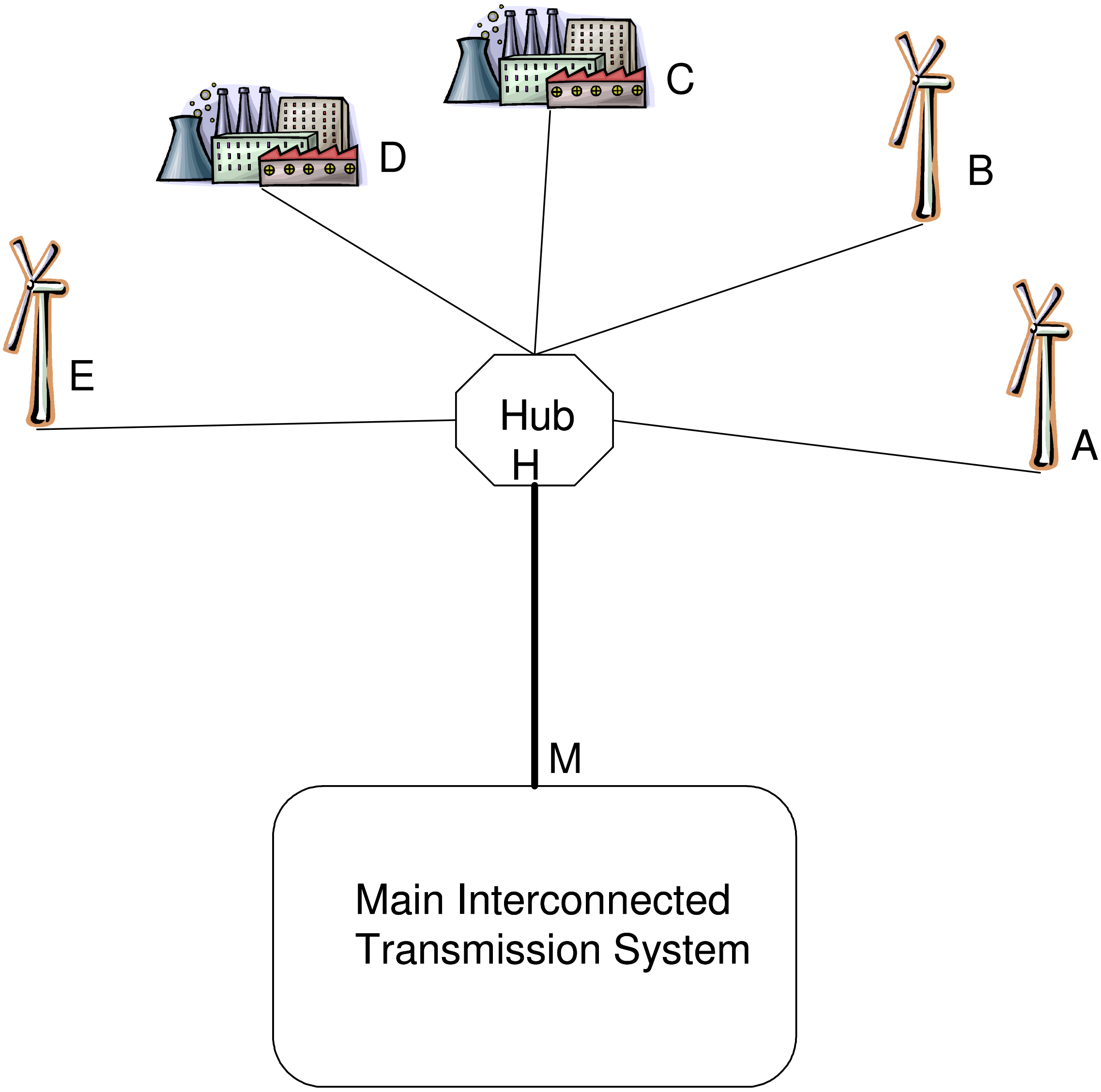
(c) any other standard of planning approved by the Authority.

3.2.3 In order to implement the Proposal, National Grid, SP and SSE would have to obtain derogations from complying with GB SQSS. National Grid would need to apply to the Authority for a derogation from its Transmission Licence requirement to comply with the Grid Code (P.C.6.1).

ANNEX 7 – Electricity (Guarantees of Origin of Electricity Produced from Renewable Sources) Regulations 2003

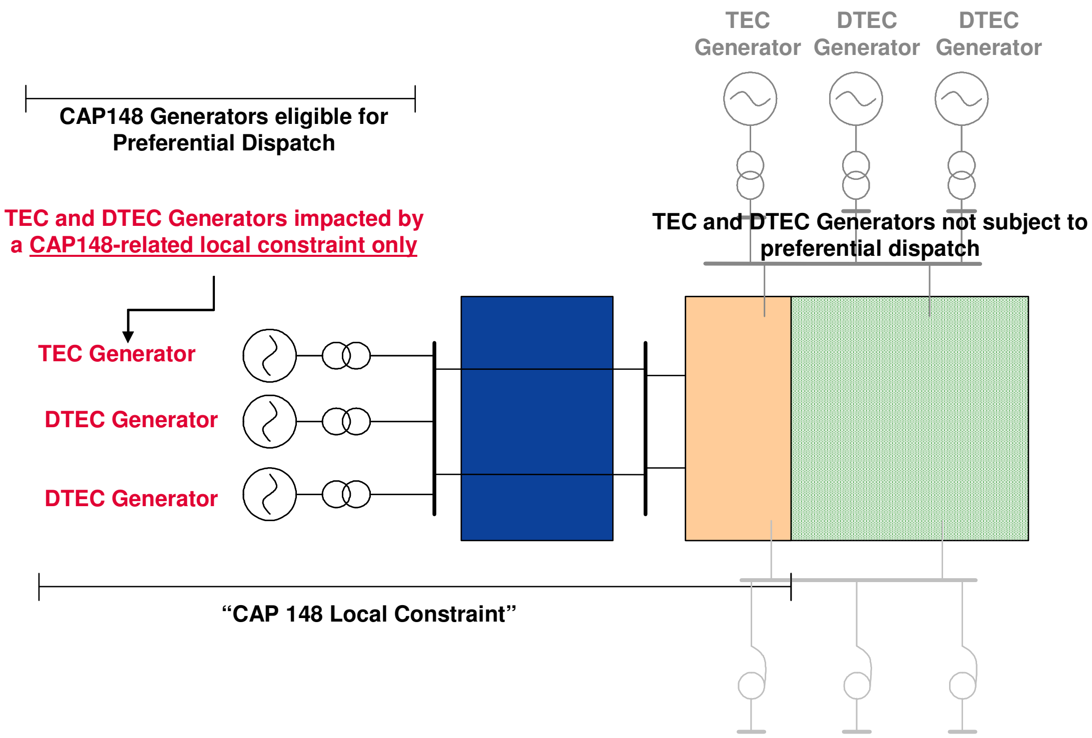
The detailed regulations that set out eligibility for Renewable Energy Guarantees of Origin REGOs can be found via the Ofgem web site. The page on REGOs http://www.ofgem.gov.uk/SUSTAINABILITY/ENVIRONMNT/REGOS/Pages/REGOs.aspx gives an introduction to the subject as well as further references to the regulations themselves at http://www.opsi.gov.uk/si/si2003/20032562.htm

ANNEX 8 – ILLUSTRATION OF LOCAL AND WIDER WORKS

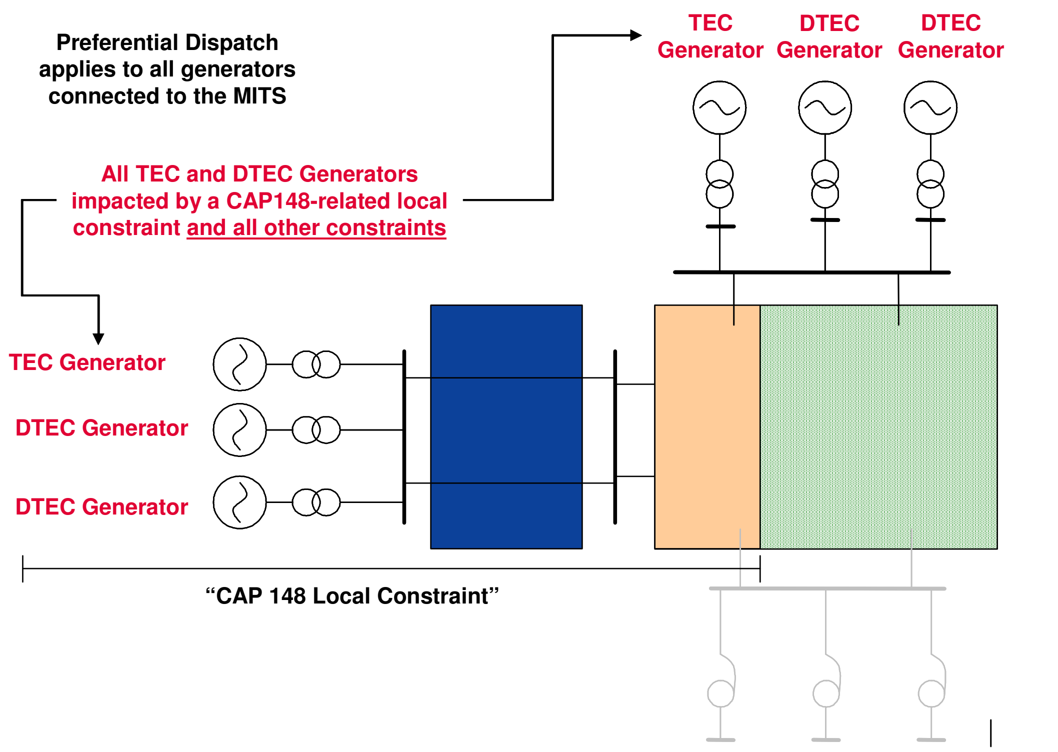


ANNEX 9 – CONSTRAINTS IDENTIFICATION AND INTERACTION

Annex 9a) Proposer's Initial Model of CAP148 – Preferential Dispatch

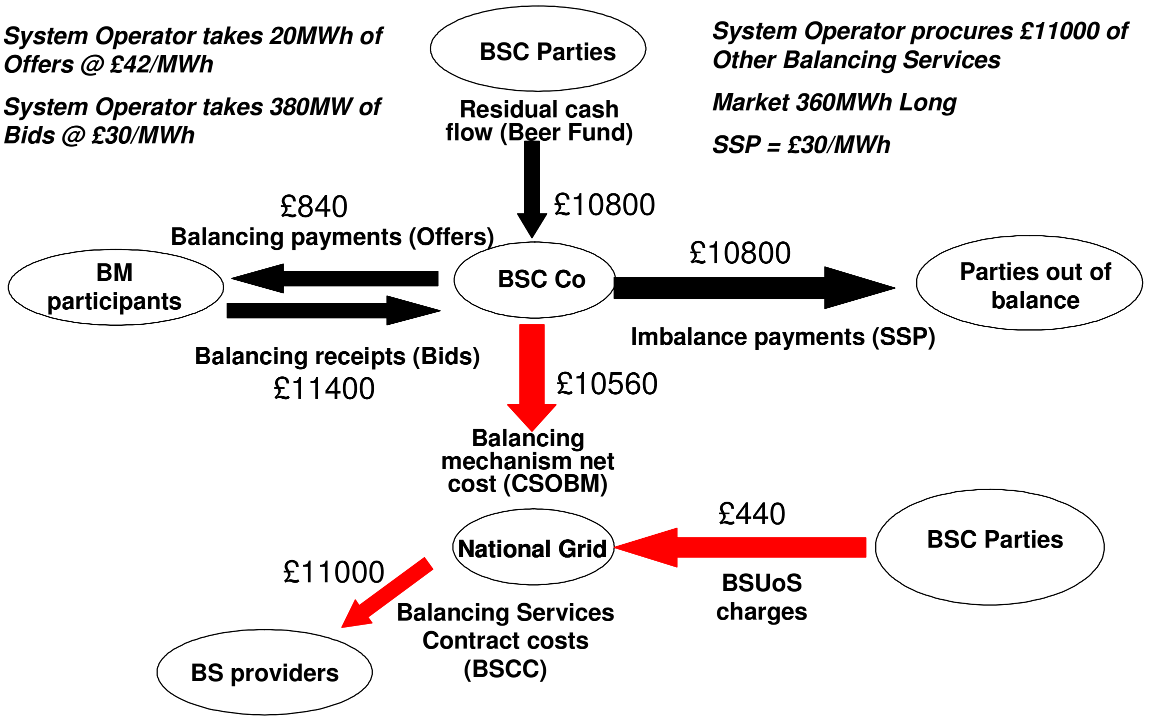


Annex 9b) Final Model of CAP148 – Preferential Dispatch

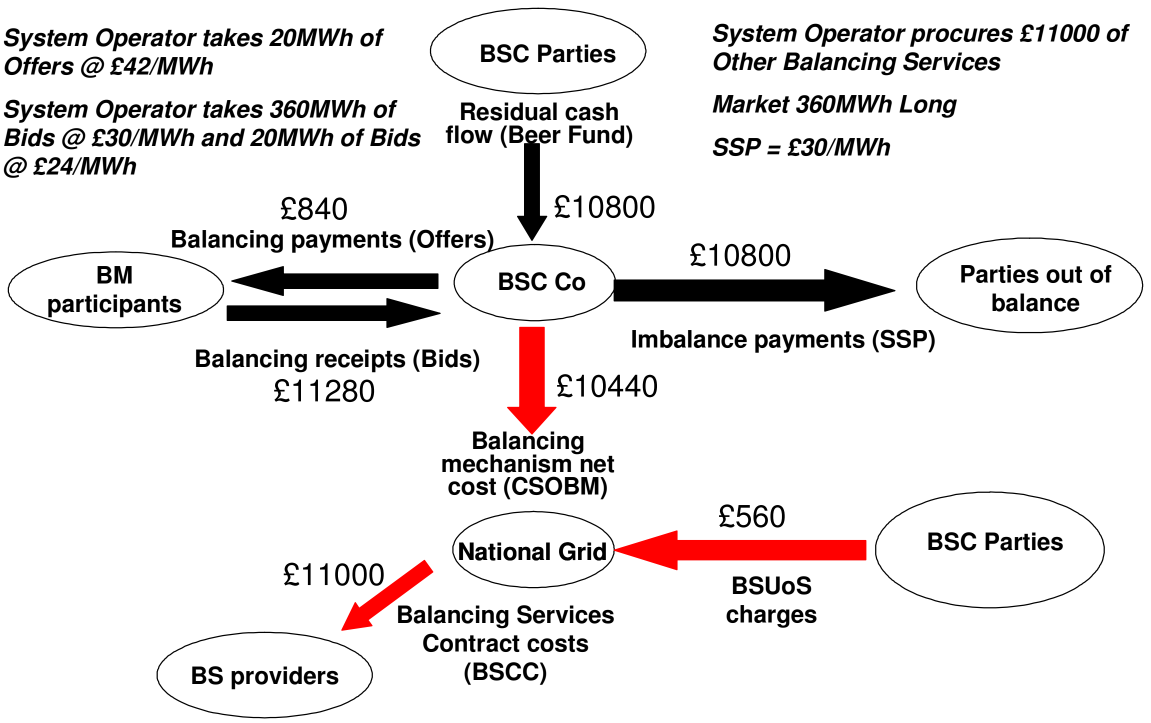


ANNEX 10 – CONSTRAINT MANAGEMENT AND MONEY FLOW

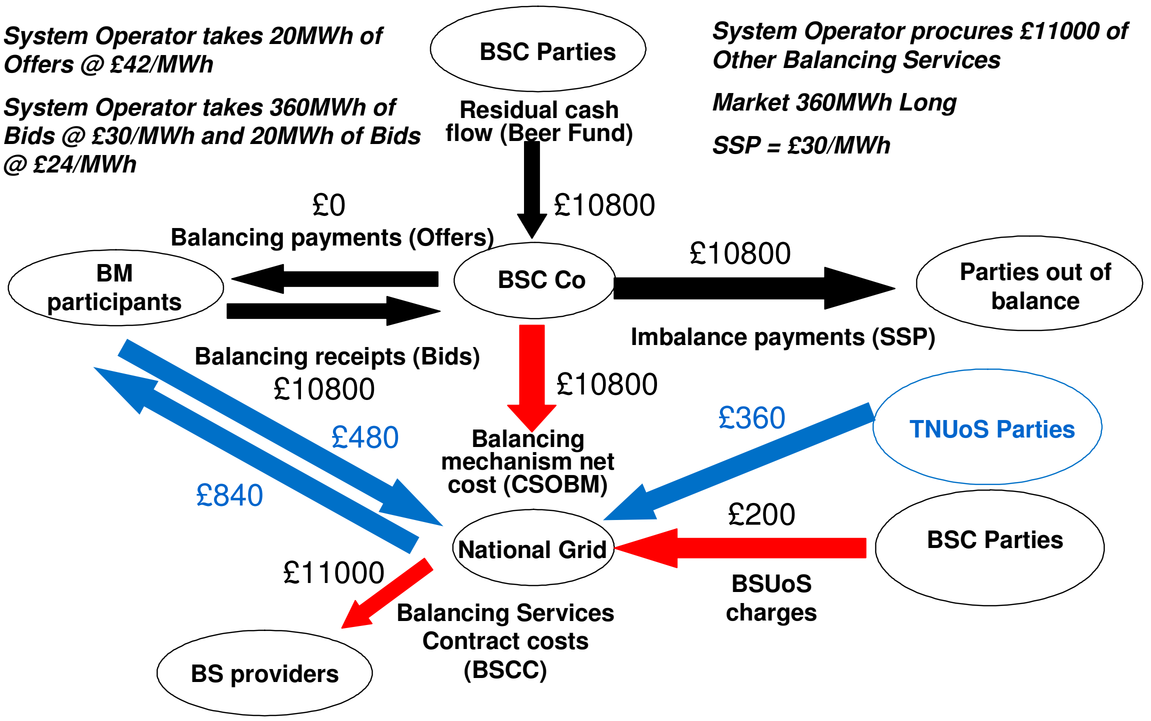
Scenario 1: BSUoS & Related Industry Cash Flows Unconstrained; Long Market



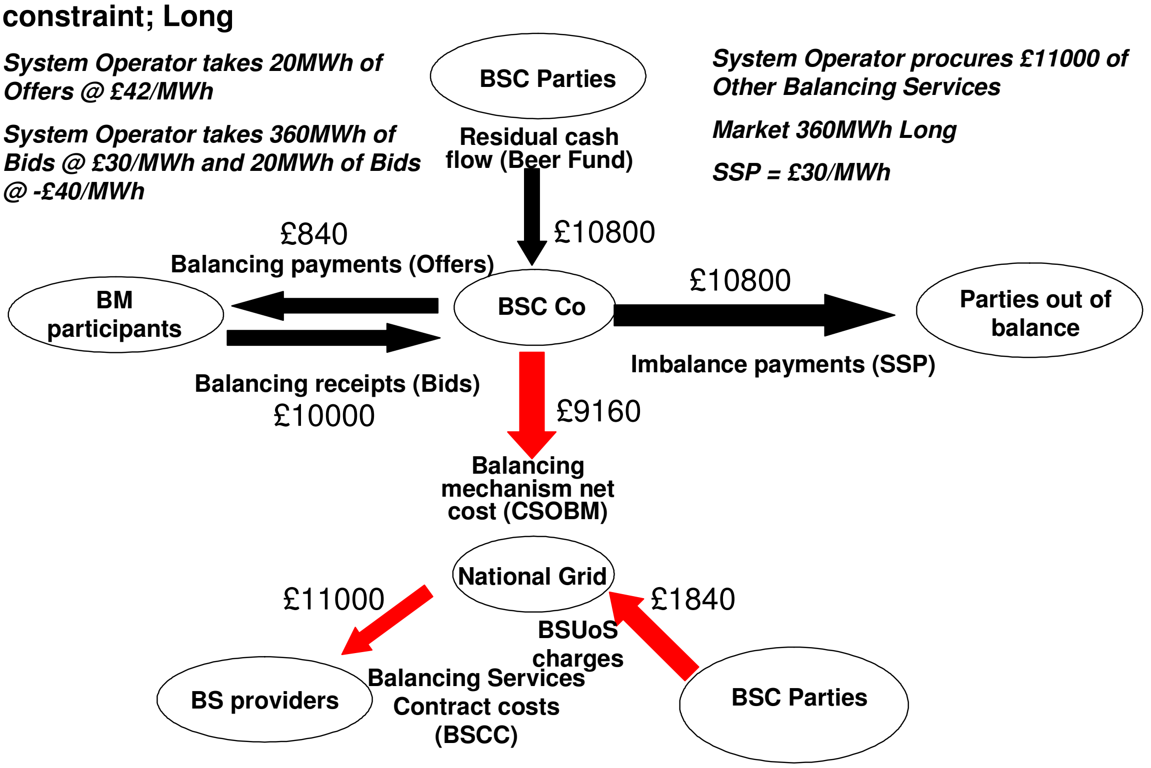
Scenario 2: BSUoS & Related Industry Cash flows: Example 1a – 20MWh constraint; Long Market



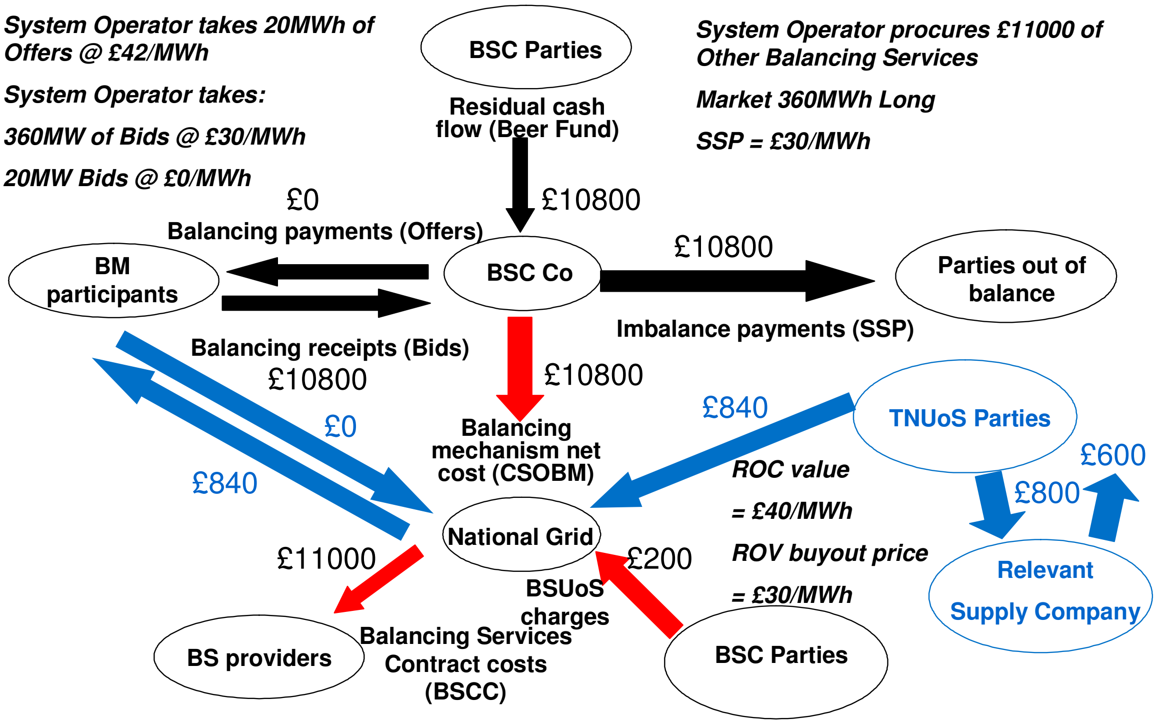
Scenario 3: BSUoS & Related Industry Cash flows: Example 1b – As example 1a with CAP148



Scenario 4: BSUoS & Related Industry Cash flows: Example 2a – 20MWh wind constraint; Long



Scenario 5: BSUoS & Related Industry Cash Flows Example 2b – As example 2a with CAP148



ANNEX 11 - ROUGH ILLUSTRATIVE CALCULATIONS OF IMPACT OF CAP 148 ON CONSTRAINT COSTS

Assumptions	
Connections	Connection Capacity and current connection date is from current TEC Register
	Beyond 2016 it is assumed that a constant connection rate is achieved
	Post Cap 148 implementation it takes 3 years before the effects start to be seen, i.e. first increase is 2011
	The range of advancements is 25%, 50%, or 100% of plant is advanced by 3 years
Constraints	Typically at the moment Scotland is modelled as two constrained zones, each active 10% of the time but out of phase with each other; therefore the combination into one zone gives a 15% minimum. The whole of Scotland is considered as one constraint zone with active constraints 15% of the time; every additional MW of DTEC would therefore be potentially fully constrained 15% of the time. Incidence of constraint increases dramatically with small increases in generation; 500 MW increase in generation increases the incidence of constraints from 10% to 35%, although not all of the additional generation would be constrained 35% of the time. No account is taken of nesting of constraints
	Cost of constraint is typically £65/MWh including constrained on costs
	Assumed load factor for new plant is 40%
	Assumed only conventional plant is constrained

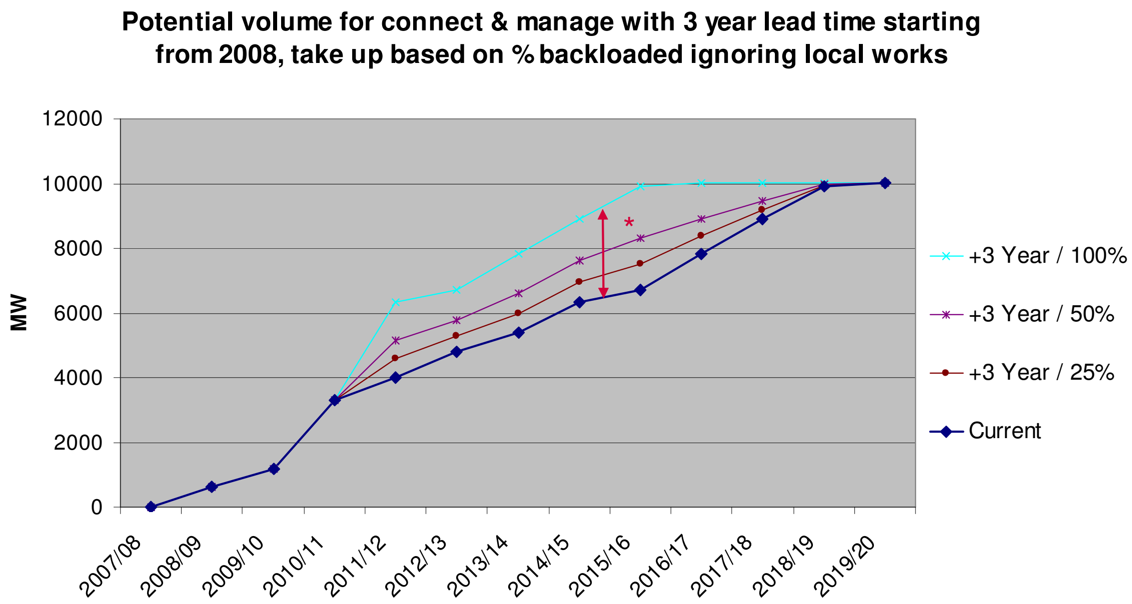
Factors likely to lead to reduction in additional constraint costs	
Development	Not all projects with connection agreements will reach operation
	Advancement of 100% of projects is unlikely because of other factors such as planning for the generation projects
	Delays in Beauly-Denny may push queue further back anyway
Constraints	National Grid will have foresight of likely constrains and will seek to manage via LT contracts

Factors likely to lead to increase in additional constraint costs	
	No account taken of additional outage costs for wider infrastructure costs
	Availability of DTEC will stimulate eligible projects to come forward
	For more frequently constrained plant, bids may not cover fixed costs

Factors that may affect costs in either direction	
	LCPD opted out plant will be using up power station hours with unknown impact on BOAs
	EU-ETS beyond 2012 has unknown impact on technology competitiveness

Volumes and Costs for 3 Year Advancement		
% Projects advanced	Volume of Constraints GWh	Cost of Constraints £m
100%	8337	542
50%	4169	271
25%	2084	135

Volumes associated with a 3 year advancement



* Volume is the increase from current connection rate

Annual costs

- The table shows the distribution costs over the connection period by percentage opting for a 3 year advancement
- 3 years is not linked to the 3 waiting period in Cap 148 original
- Figures are in £m / per annum

Projects advancing	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	Total cost £/m
100%	79	65	83	89	109	75	38	3	542
50%	39	33	42	44	55	38	19	2	271
25%	20	16	21	22	27	19	9	1	135

Assumptions

- The tables show the distribution of additional capacity and constrained volume for the 50 percent scenario
- Figures are in MW and GWh respectively

Projects advancing MW	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19
50%	1154	955	1221	1303	1600	1100	550	50

- This converts to a constraint volume using the following :

  Capacity * constraint incidence (0.15) * Load factor (0.4) *8760

Projects advancing	2011/ 12	2012/ 13	2013/ 14	2014/ 15	2015/ 16	2016/ 17	2017/ 18	2018/ 19	Total
50%	606	502	641	685	841	578	289	26	4169