STANDING GROUP REPORT

Transmission Access Standing Group 2007

Issue	V1.0
Date of Issue	23 August 2007
Prepared by	National Grid

I DOCUMENT CONTROL

National Grid Document Control

Version	Date	Author	Change Reference
V1.0_	23 August June 2007	PH	

Distribution

Name	Organisation
Panel Members	Various
TASG 2007 Members	
National Grid Industry Information Website	

II CONTENTS TABLE

SUMMARY AND RECOMMENDATIONS

Executive Summary

The objective of TASG was to discuss the further development of entry access arrangements that would facilitate use of the system in a more flexible manner than that currently available today i.e. more flexible trading solutions and / or flexible access in the short term. The standing group was also charged with considering how any revised arrangements could better facilitate the efficient and non-discriminatory integration of renewable generation.

The standing group reviewed eight high-level access concepts, ranging from developments of the existing arrangements to more fundamental reforms. Three of these models were presented initially by National Grid (TEC trading, Extra TEC and Overrun) and four were put forward by other group members (Connect and Manage, Moderated sharing of capacity, Connect and Manage Plus and NovTEC). A further model (Shared TEC) was developed jointly in the group.

The principles, eligibility criteria and proposed process for each model was initially discussed and established. Following this the group sought to establish the pros and cons of each model. In a number of areas there were clearly opposing views as to whether a particular feature was a pro or con. The group then assessed the models against the applicable CUSC objectives, based on the pros and cons.

The group also discussed the potential implications of each of the models on other industry documents and processes to gain an appreciation of the associated implementation issues.

Recommendations and next steps

The standing group agreed that the Connect and Manage models, which socialise the additional cost of connecting generation prior to the completion of the necessary transmission reinforcements, provide the most effective means of connecting renewable generation earlier than currently planned. The standing group agreed that the models which target this additional cost at the generators which cause it are less likely to be usable by these generators due to the associated risk, although their use by existing generation may release transmission capacity which could then be used by new generators. The concept of sharing entry capacity may also provide additional access to new generators where there are technically and commercially complimentary technologies that are seeking to use the transmission system in the same area (subject to resolving competition issues).

Individual CUSC members are invited to consider the issues discussed in this report when formulating new access arrangements.

National Grid is happy to discuss the potential changes to the access regime highlighted in this report prior to a formal amendment being received. Any party who wish to discuss the issues contained in this report in more detail should contact Hêdd Roberts at hedd.roberts@uk.ngrid.com

The Standing Group believes its Terms of Reference have been completed, the issues associated with the entry arrangements have been fully considered, and recommends the TASG be disbanded.

INTRODUCTION

This Report summarises the discussions of the Transmission Access Standing Group (TASG). The re-establishment of the TASG was agreed at the May 2007 CUSC panel in response to a paper presented by National Grid[1].

The objective of the TASG was to discuss the further development of entry access arrangements that would facilitate use of the system in a more flexible manner than that currently available today i.e. more flexible trading solutions and / or flexible access in the short term. The standing group was also charged with considering how any revised arrangements could better facilitate the efficient and non-discriminatory integration of renewables.

A primary objective of the standing group and this report is to bring industry expertise together to understand the benefits and pitfalls of suggested arrangements, and also the potential impact of differing access arrangements on all industry parties. The standing group has not sought to replicate the assessment process carried out by CUSC amendment working groups in examining the models. The models described in this report have been submitted by members and developed by the group to explore the principles of varying access regimes, rather than to develop specific proposals for implementation.

It is intended that this report will inform CUSC parties who wish to develop CUSC amendment proposals along the lines of the described models, ensuring that future CUSC working groups are familiar with the issues and that working group proposals are sufficiently described.

In order to fully asses the wider impact of the models the standing group have discussed areas of the Industry framework, e.g. Licences and charging methodologies, which are not part of the CUSC. The group acknowledge that some models would require changes to the CUSC and other industry documents.

All notes and presentation from the standing group meetings are available on the National Grid Industry information website.

Standing group process

Following the May 2007 panel meeting parties were invited to nominate members. National Grid received 20 nominations for membership, with a number of alternates attending in place of members. BERR and Ofgem also each nominated observers. At a number of meetings, additional Industry experts and academics also attended and made presentations.

The standing group met 7 times, with the first meeting being on 15th May. At the first meeting the standing group discussed and agreed a number of minor changes to the originally proposed terms of reference. Along with the proposed membership[2] the revised terms of reference[3] were reported by the Chair at July CUSC panel meeting and subsequently agreed.

[1] Panel paper available on the National Grid Industry website – CUSC/Panel Info/ may 2007
[2] Appendix 2 - Membership and attendance of TASG
[3] Appendix 1 Agreed Terms of Reference and standing group procedures

Summary of standing group discussion

The bulk of discussion at the standing group focused around a number of high-level conceptual models.

National Grid initially presented three conceptual models for discussion. Other standing group members provided four further models for consideration. The standing group also developed a further model. The models discussed are summarised below:

TEC Transfer	Arrangements to further facilitate the transfer of previously allocated transmission access rights between power stations.
Extra TEC, ETEC	Identification by the System Operator of additional transmission access available in operational timescales, purchased before real time, priced ex ante and cost reflectively.
Overrun, (with expost pricing)	Arrangements to allow power stations to generate above their Transmission Entry Capacity, charged on usage, priced ex post and cost reflectively.
Connect and manage	Provision of transmission access rights prior to reinforcements under the SQSS being competed. Charged at TNUoS
Connect and Manage Plus model	Provision of transmission access rights prior to reinforcements under the SQSS being competed. Postage stamp charging. Despatch at administered bid price.
Moderated sharing of capacity	Capacity is shared by Users that can elect to have their physical export rights (transmission capacity) reallocated to a new User(s). The User losing its physical export rights will face no TNUoS charges and can remain in the Balancing Mechanism. The new User with physical export rights allocated to it will have to pay TNUoS and cannot access the BM. All existing Users, remaining with physical export rights, would pay TNUoS and use the BM until there are new Users with which it can pass on the physical transmission capacity allocated to it.
Shared TEC	Access shared between two nodes, Sum of output must not exceed Shared TEC (STEC). STEC and parties defined in new CUSC bilateral agreement. Local export limited by individual CEC. Charges calculated cost reflectively as a multiple of TEC.
NovTEC	Facilitate earlier connection of generation from novel renewable sources by allowing parties with current or future access (through a signed offer) to transfer access to them.

The models themselves have not been formally put forward as future CUSC amendments, but have been presented to allow the standing group to consider and understand the impact of different principles. This process drew out the main issues and implications of changing the current arrangements, as perceived from different industry participants.

For each model in turn the standing group agreed a high-level description and noted the assumptions behind the model. The group then discussed the pros and cons of each model. Based on the understanding gained from these discussions the group then sought to identify at a high level how each model would impact on other industry documents and also the potential impact on Industry systems. In discussing these issues the group noted the potential charging and revenue implications for the Transmission Licensees. Following this, the group assessed each of the models against the applicable CUSC objectives.

The standing group discussed the appropriate assessment criteria for the models and agreed that the applicable CUSC objectives were appropriate:

- o The efficient discharge of the obligations imposed upon National Grid through the Act and by the licence; and
- o Facilitating effective competition in the generation and supply of electricity.

The standing group considered Security of Supply as a fundamental cornerstone of any proposal. Security of supply is facilitated through access and charging arrangements by providing the correct long-term signals for generation to invest in new plant and for transmission licensees to provide for a robust, secure and efficient transmission system in the future. Equally important to the longer term investment signal is that the framework as a whole must facilitate the efficient discharge of the licensee's duties of balancing the system in real time.

Failure to provide the effective signals could lead to either over or under investment in the transmission system, transferring inefficient costs through to end users. In the case of the latter this is protected by the deterministic arrangements in the SQSS. In terms of short-term access it was recognised by the group that more flexible access arrangements could deliver benefits by ensuring the system is used more efficiently. National Grid noted that whilst flexibility with available access could be beneficial, over allocation of access would lead to increased in short term costs that would not necessarily be efficient unless the additional access was priced appropriately. In any event increased use of the transmission system would most likely increase operational cost; however this had to be viewed alongside efficiency gains. Cost reflective pricing of the increased operational costs demonstrates they are efficient i.e. if a generator is willing to bear the price of short term access, it is efficient to sell it.

Common issues

<u>Definition of “local” infrastructure works</u>
The standing Group discussed a number of models in which a distinction between “local” and “wider” reinforcements was required. These models assume that there is a subset of reinforcement works (“local”) which are always required to be complete prior to a power station connection.

In all of the models discussed it was assumed that the Connection Entry Capacity (CEC) of a power station could **not** be exceeded. CEC currently represents the maximum amount that can be safely exported from an individual generating unit or power station.

The Standing Group agreed that for a number of the models, the apportionment of the TNUoS residual charge and the need for a charge for “local” infrastructure would need to be reviewed. As CEC reflects the connection asset capability and TEC the wider system capability, a new limit reflecting the capability of the “local” infrastructure may be required. An alternative may be to extend the use of CEC, although this may be inefficient to the extent that CEC is very focused on the capability local connection assets.

<u>Short and long-term products</u>
Whilst the majority of the discussion at the group was in terms of short-term products and exchange of these, it was recognised that this interacts strongly with the attributes of the long-term product, currently TEC. Failure to provide the appropriate balance between long-term (generally products that signal new investment) and short term (acquiring access on installed assets or using ‘spare’ capacity) could lead to a collapse in the long term signal. It was recognised this was part of the cyclic balancing of the market i.e. once the investment signal disappeared parties would eventually be exposed to

increasing short-term costs and then signal investment. Over a period of time, this might be expected to stabilise however, should an amendment be put forward, this would need to be assessed against the SQSS which is principally a demand security standard.

<u>Implementation costs</u>
The standing group also agreed that the costs of implementation and enduring operation of any revised arrangements must be outweighed by the benefits provided through such changes i.e. have a positive cost benefit. It was noted that this must be Industry wide and not just National Grid costs, i.e. a minor change to National Grid systems may require all industry parties to make significant changes their systems. However such an assessment is not possible with the level of detail of the models contained in this report. A cost benefit analysis would need to be performed at the Standing Group assessment stage.

<u>Transmission incentive arrangements</u>
In a number of the models the incentives placed on the National Grid (as an SO and TO) and the other Transmission Owners through the licences is a key issue in facilitating more efficient used of the system. The incentive arrangements should recognise that most of the products increased the costs of system operation and also made the system 'work harder'. In some cases the potential for increased operation costs could be significant e.g. with over-allocation without direct pass through to those directly benefiting from the over-allocation.

<u>Definition of TEC and access rights</u>
Although the access rights associated with TEC are not explicitly defined in the CUSC, the standing group suggested that TEC represents an evergreen right to use the transmission system subject meeting the requirements of the CUSC i.e. paying the charges. TEC is only effective (i.e. parties are liable for charges) once the transmission connection works have been completed. The standing group did not consider alternative arrangements other than TEC for the definition of access rights or use of the transmission system. It was recognised that more fundamental changes to TEC and its associated transmission access rights could require a wider reforms that were outside the scope of the TASG terms of reference. However it was also noted, but not agreed by all, that introduction of short term access would require the commitment associated with TEC to be reviewed.

Model description and pros and cons

Temporary TEC Transfer, TTECT

Principles

- Facilitate the transfer of physical system capacity between generators for a period of 2 years
- Since the transfer is short term, exchange rates calculated against the SQSS operational criteria and set to achieve cost neutrality. This is an assessment against the SQSS operational criteria and must be performed against a base-case. However, significant changes to the generation background would still require an SQSS licence derogation.
- TEC donors retain rights and obligations for access in the longer term (i.e. liability for TNUoS charges, still in SQSS planning criteria study background, gets full access back at end of trade)
- No assets will be installed to facilitate usable exchange rates
- Transfer rate takes no account of plant type or historic loading

Eligibility

- Anyone that holds current (rather than future) TEC can donate all or part of it.
- Anyone that either has sufficient CEC or will have sufficient CEC at the start of the transfer period can accept a TEC transfer
- Donor must maintain CEC, (this does not prevent the generator from being unavailable, e.g. major outage, during that period).
- Restrict transfers to nodes that are electrically proximate (i.e within a similar areas of the system i.e. north east of Scotland or north west England)

Process

- In September, TEC holders indicate MW they are prepared to surrender and associated price (£/MW) in Y+1 and Y+2
- In October, National Grid publish capacity available in each zone as a result of the surrendered capacity together with a reserve price (for each tranche of capacity in each zone) for Y+1 and Y+2
- In November, National Grid host pay-as-bid auction for surrendered capacity
- In December, National Grid assess bids, identify users that have successfully surrendered and acquired capacity and notify
- From January to March, National Grid make the necessary changes to users' bilateral agreements – may be include in a separate side agreement
- Excess revenues would be circulated back though TNUoS and used to fund any transmission charges / incentives

Attribute	Pros	Cons
Ease of use for new entrants	Concept fairly simple;	Shortage of sellers; Lack of transparency, certainty and stability of exchange rates; Uncertainty associated with an auction for surrendered capacity; More difficult for new entrants because they also need to establish a connection

Attribute	Pros	Cons
Ease of use for existing parties	Does not increase the amount of capacity available	Gives additional value to a current parties' TEC; Allows existing users to extract SRMC from access for which they pay LRMC, which may be problematic when capacity is scarce (i.e. may encourage capacity 'hoarding'); Multi-year trades allow existing generators to transfer something they haven't paid for.
Flexibility of usage within-year	Not applicable for proposal outlined above – Cap 142 permits it.	
Level of charge for participants	Existing generator with an outage could be considered to be a 'distressed seller'	Seller may be in a strong position when capacity is scarce; Likely to be a thin market; Transaction cost may be significant due to level of SO study work required.
Level of Risk for participants	Secure for the period obtained - suits advancement of mature projects, but not early stage projects	High; Uncertainty associated with an auction for surrendered capacity; Unlikely to provide bankability required to finance new projects
Level of cost for all transmission customers	Near-zero (provided exchange rates can avoid increase in constraints)	
Level of risk for all transmission customers	Low or Moderate (if existing low load factor generator trades to higher load factor generator)	Effectively creates stranded "local" assets for the duration of the trade.
Degree of discrimination	Minimal	Arguably discriminates in favour of existing TEC holders Existing generators less likely to close -barrier to entry
Signal for TO Investment	May strengthen the investment signal associated with an application for TEC, since this has been made despite the ability to bid for transferred TEC	Barely. (Only to the extent that existing TEC is slightly heavier used)
Overhead for GBSO		Complex systems (access exchange) may be required to calculate exchange rates and track capacity holding

Group discussion on Temporary TEC Transfer

If the auction takes place before the charging setting process is completed for the next year excess revenues from the auction process could be taken account of in the appropriate charging year. From a revenue collection perspective it is important to know the outcome and revenue flows before final tariff setting occurs to avoid significant revenue recovery errors.

National Grid believe that in an ideal world the maximum period a party should be able to indicate its willingness to give up capacity should at least match up to the period which they have committed to pay charges for. Generation as a whole only contributes to 27% of the overall cost of transmission and in terms of the TNUoS tariff they are only committed to pay it for the current year. Therefore a model with maximum of two years forward trading should be balanced by at least two years of forward commitment. To have the ability to sell capacity without the approparite financial commitment would lead to hoarding and not encourage parties to freely release access that they were never intending to use.

The group discussed the commitment required to trade. It was noted that in the model as presented the ability to trade is linked to having active CEC on the donor side, therefore if the donor releases CEC the trade would no longer be valid.

The standing group agreed that in this model, in order to sell capacity in Y+1 and Y+2, the donor must have bought access in Y+1 and Y+2. Some standing group members believed that the property rights associated with TEC meant that existing TEC holders had effectively bought access in Y+1 and Y+2. Other standing group members did not agree. The standing group recognised that there was an interaction with CAP142 (Temporary TEC Transfer) and CAP131 (User Commitment) which would require further consideration if a CUSC amendment was brought forward.

Restrictions to trading on parts of the system that are non-compliant with the SQSS planning criteria were discussed. The current understanding is that if the system is non-compliant then the exchange rate calculated by National Grid would be zero. National Grid confirmed that if non-compliance is exacerbated by a significant change to the background then it would expect the exchange rate to be zero. However, if the level of non compliance was not made worse, taking account of year round system conditions, then it may be possible to accommodate a non-zero exchange rate providing it had a net benefit.

It was also important to note that if the trade was between plant with different load factors, e.g. low merit conventional thermal to intermittent renewable, there would be a potential increase in constraint costs at certain times of the year (when the low merit plant was not forecast to run). If these costs were mitigated through reducing the sharing factor then the granularity of the trading product would be critical. In any event National Grid indicated that it would be practically impossible to establish a non-zero exchange rate that did not have the potential to increase constraint costs. National Grid presented the example in appendix 5 where a generator with a different load factor may reduce the level of non-compliance in the winter but increase the costs to maintain compliance in the summer. National Grid indicted that in order to have a non zero exchange rate the forecast benefit in the summer must at least be balanced out the saving in the winter.

The group discussed the scenarios whereby a generator is willing to donate capacity whilst it has an outage, however the outage may be extended indefinitely. Under these circumstance some members of the group believed there would be merit in limiting the length of time that a trade could take place when the donor was unavailable. It was noted if the donor would have actually closed the recipient could benefit from taking up the TEC without any additional trade charge or opt for a short term product which would have a relatively low risk (until the TEC was reallocated). Trading would allow existing plant to mothball whilst freeing up access for other parties such as renewables hoping to advance connection prior to firm TEC being available, maximising the efficient use of the transmission system.

The group discussed the potential for trading future TEC, where capacity was being held up elsewhere on the system. National Grid indicated TEC was a nodal product, if there was spare capacity on the system National Grid could release this through other products e.g. LDTEC, STTEC or ETEC. The group noted National Grid was best placed to optimise the release of short term capacity created through delays in the queue. National Grid indicted that it does not support a trading solution to the current access issues in Scotland as this would disincentivise parties from releasing future capacity in circumstances where it is very unlikely the project is viable.

It was indicated that the limited firmness of trading or the other short term products discussed at TASG may not be suitable for new entrants e.g. the time period for building new plant does not align with the length of time the products are available. It was noted that there are other amendments going forward that are seeking to deal with releasing parties from existing bilateral agreements where projects were not proceeding, allowing viable projects to advance. It was suggested that the short term products, trading / ETEC / overrun etc., may be more suitable for older plant considering closure and seeking to avoid long term commitment.

The group discussed the auction terminology and it was noted that the process was more akin to National Grid acting as a broker. The reserve price described in principles would most likely be the cost that the donor was prepared to give it up for.

Variants

TEC Sharing

The Standing Group subsequently agreed that TEC Sharing should be developed as a separate model in its own right.

A further model where National Grid facilitates TEC transfer in the short term was also discussed. Whilst this is not presented as a model itself in this report the basic principles are described after the TEC sharing model.

TEC trading beyond Y+2

The group also discussed a variant that allowed trading beyond 2 years. National Grid indicated that estimates of constraints at such a timescale were extremely uncertain, because of uncertainties in generator running patterns; hence it would be challenging to implement any criterion approaching 'Constraint neutrality'.

Zonal TEC Trading

Trading limited to preset zones (TNUoS + a further two) to avoid the need for exchange rates i.e. all trades would be on a 1:1 factor. However this additional flexibility would not result in a cost neutral approach, initial estimates are that for this will increase constraints by about £10m per GW /annum. The additional cost could be passed through BSUoS or if it could be identified in advance with sufficient confidence treated as a charge to trade i.e. £10/kW. Restricting trading to a zone has a negative effect in limiting the market for trades. The group discussed that this variant could be considered in a number of timescales and varying granularity of product, possibly very much closer to real time. National Grid noted that as trading takes place closer to real time, there is an increased need to automate systems for notification, although this could be post event in some circumstances however this would require a relatively complex settlement process.

The standing group also discussed the option that parties could donate TEC they were not using to National Grid, within year (possibly very close to real time and for small blocks), National Grid would then reallocate that access and refund a portion of TEC to the donor on a commoditised basis. This variant was also discussed as a variant to TEC sharing (Facilitated Sharing).

Extra TEC, ETEC

Principles

- Extra TEC (MW band by zone and boundary) is identified by National Grid
- Extra TEC bands are allocated in either an annual or three monthly pay as bid auction with a reserve price set by National Grid to equal the forecast constraint costs the Extra TEC would cause
- Extra TEC provides the user with the same rights as TEC for the time period purchase
- Extra TEC price corrected depending on forecast load factor of generation (e.g. 100% price for conventional generation, 40% price for wind generation)
- Extra TEC priced at forecast constraint cost
- The revenue from the release of Extra TEC is fed back into BSUoS as a negative term
- ETEC holders will have bid prices collared at £0/MWh
- No primary assets will be installed to facilitate the release of ETEC (the group noted that certain secondary assets e.g. inter-trip schemes could be installed and used to provide short-term access)
- ETEC Users exposed to 'normal' BSUoS
- National Grid is not obliged to offer ETEC

Eligibility

- All parties are eligible for ETEC up their CEC, subject to technical requirements under the Grid Code

Process

For yearly product:

- In November, NGET release info on:
    - MW bands of ETEC on offer, by Zone <u>and</u> Boundary
    - ETEC price that will be charged for Y+1 / Y+2
- Users apply in January for Y+1 or for Y+2 or both
    - User applies for a MW level, up to a tendered price
- Allocation of ETEC is now automatic:
    - If MW applied for < MW band, then User pays the ETEC price
    - If MW applied for > MW band, then we allocate up to MW band in price

Within year product

- <u>Every Three Months:</u>
- At W-6, NGET release info on:
- MW bands of ETEC on offer, by Zone
- ETEC price that will be charged for M+1 / M+2 / M+3
- At W-2,Users apply for M+1 /+2 /+3 (any combination)
- User applies for a MW level, up to a tendered price
- Allocation of ETEC is now automatic:
- If MW applied for < MW band, then User pays the ETEC price
- If MW applied for > MW band, then we allocate up to MW band in price order, and User pays their tendered price
- order, and User pays their tendered price

- ETEC can be for three periods:
    - 'base-load' = 168hrs per week

- ‘peak’ 0700-1900 Mon-Fri = 60hrs per week
- ‘off-peak’ 1900-0700 Mon-Fri +Sat+Sun = 108hrs /week

Attribute	Pros	Cons
Ease of use for new entrants	Concept fairly simple	Timescales of 1-2 years ahead may not fit with project development timescales; Volumes at acceptable prices may be too small to be used by potential buyers; Only likely to be useful to new project developers if there is a right to convert to TEC in a fixed time period. Availability to larger parties?
Ease of use for existing parties	Concept fairly simple	Existing parties buying in the same zone where they hold the majority of TEC may pose significant risk to the system operator
Flexibility of usage within-year	Good. Down to month-ahead	
Level of charge for participants		Set by NGET; relatively high ; May be too high to be used by potential buyers
Level of risk for participants	Low, once signed	High, until signed up to a ETEC tariff; Uncertainty beyond defined period; Collared bid-price not appropriate. Non cost reflective bid-prices are a competition issue and should be referred to the relevant authorities
Level of cost for all transmission customers	Depends on γ	Depends on γ; $\gamma < 1$ represents cross-subsidy from all transmission customers; Charges based on SRMC ignore the cost of “local” infrastructure works and would represent a further cross-subsidy from all transmission customers
Level of risk for all transmission customers	Some opportunity, if NGET over-prices constraints or auction bid > reserve price; Limited by ETEC collared bid-price	High risk, when NGET under-prices constraints; The practicality of accurately forecasting constraint costs 2 or 3 years ahead of time is

Attribute	Pros	Cons
		questionable; Could undermine TEC and the signals this provides to the market through the its usage of the transport model
Degree of discrimination	TEC is cost reflective and ETEC is cost reflective	Possible discrimination between parties who have TEC and those who don't have it but required to have ETEC at a higher cost (SRMC as apposed to LRMC).
Signal for TO Investment	A charge for "local" infrastructure works would signal that they are required.	Low; No signal for "wider" infrastructure works. For new entrant would inform on certainty for future TEC.
Overhead for GBSO		Fairly high – need to identify constraint prices ex ante

Group discussion on ETEC

The standing group recognised that charges for ETEC would be in relation to the potential for wider system constraints. This indicated that there may need to be a separate local charge relating to the capacity of assets to facilitate connection to the wider system.

The group noted that the original suggestion was that no assets would be installed. The group noted that it may be commercially viable for National Grid to fund secondary assets, e.g. commercial intertrip schemes. It was queried why primary assets would not be built to facilitate ETEC. National Grid indicated that TEC was considered as the signal for investment. It was noted the ETEC is distinct to TEC in that it was primarily a fill in product for new generator prior to TEC being available or a hedging tool against overrun costs for an existing generator wishing to avoid TNUoS liability and possibly future commitment.

National Grid confirmed that the limitation beyond two years was due to the inherent uncertainties of predicting constraints beyond two years. This was similar to the TEC trading timescales for the same reason. The cost of the product beyond three years would have to be so extreme to cover all uncertainties that National Grid do not believe it would be efficient to calculate and offer. It was noted that the determination of future constraints and risk is a lengthy and detailed process, particularly when exposed to the financial consequences of getting it wrong

The group noted that the cost of ETEC was related to the forecast constraint cost. If more parties applied then the cost would increase. National Grid indicated that this would be dealt with through allocation of blocks of volume at various prices. The group noted that there was a strong interaction with the transmission incentivisation. If National Grid was not incentivised strongly on BSUoS, but was on release of MW capacity under ETEC BSUoS could increase. The reverse would lead to National Grid not releasing ETEC in an attempt to capture value by reducing BSUoS. National Grid indicated it did have a wider objective for efficiency but indicated that proportionate aligned incentives would be beneficial to the extent that they had the correct focus.

The group discussed the possible discrimination and the difference between new and existing parties. The arguments for and against the benefits for various parties are captured in the pro and cons table.

As noted above there are a number of significant issues in relation to incentivisation. It was suggested that if National Grid was incentivised on ETEC, it would prefer to sell ETEC than LDTEC / STTEC. It was noted that this and similar issues would need to be addressed through changes to the transmission licence and incentive arrangements.

Also discussed further under overrun below is the issue of fair distribution of the generation TNUoS residual contribution. For all of the short-term models, there are issues about charges for 'local' infrastructure and distribution of the TNUoS residual. National Grid indicated if such a model was put forward it would discuss the issue of commoditisation of the TNUoS residual and possibly local asset charges in the Charging forums to understand industry views. Within TASG, the general consensus was that there would be merit in further discussion if short products were to compete equally with TEC.

The question was raised about the eligibility of embedded generators. National Grid indicated that it assumed that, subject to the DNO system, embedded generators should have equal access to ETEC (and other short term products).

It was recognised that the following issues would have to be explored during the development of an ETEC product:

- BSUoS is being used to provide transmission access;
- ETEC Pricing Methodology required;
- How much would National Grid be prepared to release? (e.g. base case is National Grid 'reasonable' forecast – ETEC volume added and incremental constraint cost above base case identified – ETEC price calculated to recover incremental constraint cost over ETEC capacity).

Potential System and process changes for implementation

The systems generally exist to calculate the potential risk however these are manual and very subjective. It would also be difficult under the current mechanism in a transparent manner as they are based on commercially sensitive data or data provided to National Grid on a confidential basis e.g. National Grids internal view of individual generator bidding strategies. Whilst the methodology employed in producing ETEC prices could be made transparent it is unlikely that all the data could be.

Variants

Applicability of a users sharing factor, y

Infrastructure costs are shared on a 27:73 ratio, although a generator sees the full differential for locational assets, it is for further discussion as to whether some of the short term costs should also be divided in a similar way to ensure a completely level playing filed e.g. the generator should receive a discount of 73 % of the residual commoditised on additional constraints. In general the group did not agree on the reasoning behind the use of a sharing (or cross subsidy factor)

National Grid providing ETEC much closer to real time

Whilst this is possible it was indicated that the proposed timescales reflect a largely manual process for quantifying the risks. A process close to real time would involve automation of currently manual processes and therefore increase implementation costs and timescales. It was suggested that this may be a future step.

Overrun

Principles

- Generation above TEC (+STTEC+LDTEC) will be charged ex post at the short run cost caused
- Prices are calculated and posted 1 or 2 days after real time
- Prices are calculated for predefined zones using an agreed process, which will involve a degree of engineering judgement
- The revenue from overrun charges are fed back into BSUoS as a negative term
- If users are required by the System Operator to overrun, then an access charge will not be levied [and an offer will be paid] (implicit access)
  (Concern that this meant a free access option over peak - Likely to mean that reserve MW released!)
- No assets will be installed to manage overrun charges

Eligibility

- Overrun permitted up to CEC, subject to technical requirements under the Grid Code

Process

- Parties who have TEC are freely allowed to generated up CEC
- Any self despatch above TEC classed as overrun *(to confirm implicit access)*
- Overrun calculated and posted D+2
- Billing and settlement process similar timescales to BSUoS

Attribute	Pros	Cons
Ease of use for new entrants		Unknown liability; Only likely to be useful to new project developers if charges could be hedged or capped to a multiple of TNUoS; Possible hedges include TEC, transfer TEC and ETEC but, TEC may not be available in the required timescales and transferred TEC and ETEC each have different durations (i.e. not half hourly); Lack of transparency associated with price calculation; Generation developer must treat transmission charges as variable rather than fixed costs.
Ease of use for existing parties	May be suitable for last few MW of low load factor station	Unknown liability; Lack of transparency associated with price calculation.
Flexibility of usage within-year	Very flexible	
Level of charge for participants	Set ex-post by NGET; Very low (zero?), for the	Set ex-post by NGET; Relatively high, for the

Attribute	Pros	Cons
	periods when you use it in parts of the transmission system with spare capacity	periods when you use it in capacity restricted parts of the system.
Level of risk for participants		Very high
Level of cost for all transmission customers	Low?	TNUoS is not just LRMC, but includes element of revenue recovery (residual element)
Level of risk for all transmission customers	Low?	TEC could be undermined; Market could be distorted by incentive to reduce TEC holding where LRMC>SRMC (over time) and by lack of access product for demand side; May make constraints more volatile and therefore make BSUoS more volatile
Degree of discrimination	None	
Signal for TO Investment	A charge for "local" infrastructure works would signal that they are required. Establishing a short term market support the concept of TEC as an investment product i.e. user has a choice.	No signal for "wider" infrastructure works; If existing TEC users migrate to overrun, sunk investments may be stranded.
Overhead for GBSO		High / Very High (depending on degree of accuracy, and if priced ahead)

Group discussion on Overrun

National Grid presented how and why the current internal process for calculating constraint volumes and costs is carried out. This is performed each working day by day support staff. Actions from the previous day (3 days if on a Monday) taken in the control room, along with any forward trades made ahead of time and system planning studies are used to identify the causes of constraints and allocate costs.

This process provides feedback in to planning and real time control allowing National Grid to optimise system configuration close to real time. For example, release of a particular circuit for outage would be sanctioned on the basis of forecast costs, if in real time costs exceed forecast then alternative actions such 24hr working, forward contracting with generation or even recalling and rescheduling outages can be assessed as options against a known costs.

National Grid stressed that whilst the process is fixed and the methodology could be set out, it is a manual process that involves a high degree of judgement drawn from many groups within Operations. Therefore the process and methodology could be made auditable, but was there would always be an element of subjectivity in the allocation of actions.

National Grid confirmed that nested constraints costs are allocated to local areas on the first pass as these will always have to be solved. Following this the wider constraints would be resolved. Costs are allocated first to the local constraint until this is satisfied and then additional actions beyond those needed for the local constraint's resolution are allocated to the wider constraint. National Grid also confirmed that the costs of 'sterilised headroom' and margin replacement (see presentation) were also allocated to particular boundaries. Sterilised headroom occurs where a constraint exists behind which an amount of generation not running but declaring available MWs cannot be accessed in practise due to a biting constraint limit precluding it being run in practise.

It was noted that a constraint based pricing methodology would not provide a signal if there is not a constraint. Whilst this may be correct when there is spare capacity on the system, it does not necessarily provide the correct signal for local assets which are generally designed to allow full export up to and including the N-1 outage condition. In these circumstances there may need to be an alternative charge that ensured that the investment signal was maintained for the local assets.

This local asset issue above is in relation to assets where the costs vary by distance. In addition to this there is also the issue of the residual charge that is levied on all parties on a flat basis (based purely on capacity) to ensure correct cost recovery. This is generally perceived to recover the non locational cost of assets and fixed transmission cost, e.g. substation costs and National Grid overheads. In order to avoid any cross subsidy between parties with TEC and those utilising overrun it may be appropriate to distribute the residual charge in a different manner. One possible alternative would be to commoditise the residual element and charge it to all parties on a usage (MWh) basis. Whilst this potentially means that high load factor plant would pay a higher proportion this would be offset by the contribution of parties who choose to overrun. As noted above with ETEC this same issue arises whenever parties have the potential to avoid the TNUoS tariff that currently includes the residual element.

Access to market information ahead of time to allow generators to manage their risk was highlighted as an important issue. It was recognised that parties would be able to predict better with experience and also that more information may need to be provided.

A member of the group noted the recently release TADG report and indicated that if embedded generation overruns but does not cause an export for a GSP, that it would be difficult to manage. National reiterated the main point in favour of a gross model in TADG i.e. that reductions on demand affects the flow and therefore the costs on the transmission system in the same way a directly connected unit. National Grid indicated that it did not see any significant barriers to extending access overrun to embedded generation, if this was the model developed in light of the TADG report.

The group discussed the scenario of large amounts of existing TEC holders releasing TEC and converting to overrun, thus avoiding TNUoS. Such a move it was argued would undermine investment signals, however it may be transitory to the extent that new parties requesting TEC appeared in the future. There was also concern that overrun would interact with the energy market, the strength of such an influence was not quantified but would need to be considered in an amendment.

Some of the pros and cons for a generator to switch are captured below:

Drivers for existing generators to switch from TEC to overrun

Pro	***Con***
Avoid TNUoS	Still subject to a new Local asset charge and the residual
Increased flexibility	More generation zones become negative – need TEC to gain benefit
Allows mothballing, generators can react efficient to wider market issues	No firm access price
Pay on basis of actual usage	Payment is at a short run marginal cost, SRMC, calculated from constraint costs that are uncertain and could be large
In areas where there are historically low constraints expect SRMC to be low	Charge calculation is ex post
Not willing to make TNUoS commitment	Low SRMC would increase on connection of new plant (without wider infrastructure reinforcement)
	Restricted and more volatile pricing in the energy market to cover SRMC risk
	Transparency of constraint costing and exposure to length of market

Overall the group believed that some parties may choose to opt for overrun, however the majority of generators that wished to trade in the market in the medium term would see TEC as a beneficial economic hedge. Generators that were intending to close shortly or intended to operate in a reserve mode (replacing baseload intermittent generation) may find overrun to be a viable alternative to TEC.

There was a discussion about whether TEC overrun could introduce a security of supply issue. The logic was that overrun generation would declare itself unavailable if SRMC is high and this could cause a margin issue. The Standing Group concluded that, generally, high SRMC would be associated with too much generation available behind a boundary and therefore this scenario is unlikely. In particular it was noted that in areas that were already constrained (e.g. northern Scotland), the cost of overrun could be particularly high, significantly reducing the potential benefit of the product, when compared to a firm access right. The overrun cost would tend to deter new projects connecting without TEC in constrained areas.

It was recognised that an overrun product may increases constraints and, consequently the number and frequency of short term actions taken by the system operator in the balancing mechanism. Under the current arrangements under the BSC such actions could impact on cash out prices, particularly in a long system where the marginal cost of constraining renewable generators was low or potentially negative (reflecting the lost opportunity cost of ROCs). The impact of constraints on cash out prices has already been noted (cf the cash out review or BSC Modification Proposal P211). It is possible that if constraints increase as a consequence of overrun then further changes to the rules governing the derivation of cash out prices are required.

With regard to BSUoS and TNUoS the creation of an overrun product suggests that there should be an explicit recognition of the trade off between increased costs of managing constraints and the avoided cost of investment in transmission assets. This could require that some elements of costs currently charged in BSUoS are recovered separately on a cost-reflective basis and that these costs are recognised in the current price control arrangements (i.e. the TO has not made an investment in assets but rather has enabled use of the system by efficiently managing constraints).

Potential System and process changes for implementation

Developing and agreeing an auditable methodology for determining the locational constant costs.

Possibility of automating the current process for determining constraints (as far as possible). It is noted that there would also be an increased enduring cost in terms of proving staff to facilitate the production of these costs robustly on a daily basis. Staff training issue.

Therefore would also need to be a billing and settlement system developed to charge for any overrun.

Variants

<u>Implicit access</u>

As described but with implicit access in the BM. The idea behind implicit access with accepted offers is to avoid offers being inflated by the potential risk of overrun payments.

For example, a generator may have additional generation available but this is currently sterilised because of the lack of access. In the overrun scenario the generator could make this available, but would have to include a risk premium associated with overrun. The risk premium would be driven by the system operator actions and not the generator actions. The overrun price behind an export constraint is driven by the constrained off and on costs. If the system operator constrained off a very high cost plant and replaced it with a generator overrunning, the local cost would be the difference in the bid and offer prices.

The major drawback of this option appears to be that the generator without firm access would be at a commercial advantage over the generator who had committed to TEC. The standing group noted that parties who run exclusively for BM operation would avoid any TNUoS charge. This could be redressed by charging a commoditised locational TNUoS for overrun when required through the BM. However this adds additional complexity and still leaves the overrun generator with less commitment.

Such an issue may be very relevant when considering the potential for intermittent generation to fall away in real time and thermal generation required as replacement. Prior to gate closure parties may be able to trade or share (to varying degrees depending on the exact products developed), however after gate closure National Grid, with the responsibility of balancing the system and ensuring system security, is the only counter party. Under this scenario National Grid would be forced to regularly take bids that include a premium driven by the generators requirement to avoid expensive overrun charges.

Connect and Manage

Principles

- Connect and manage parties has the same rights and obligations as any other party generator once connected
- Allocation of transmission access guaranteed within [3] years provided "local" connection is in place
- Access is quantified as TEC with no further restriction (other than customers choice local design variation agreed with user)
- Firm commitment to pay TNUoS charges for [2-6] years from firm start date (No avoidance due to consent issues)
- Charged TNUoS
- Liable for BSUoS
- Additional constraint costs are passed through BSUoS to all users

Eligibility
All new generation would be eligible

Process
- In terms of the CUSC no new process were identified

Attribute	Pros	Cons
Ease of use for new entrants	Attractive package for new entrants	
Ease of use for parties already connected	Not applicable	
Flexibility of usage within-year	Not applicable; Does not offer within-year flexibility	
Level of charge for participants	As per current TNUoS (based on LRMC), with commitment to pay [6] years TNUoS charges;	If transmission reinforcements cannot be completed in time, participants are causing short term costs but are being charged at long run marginal cost
Level of risk for participants	Moderate risk of project commitment	
Level of cost for all transmission customers	Extra constraint costs may be limited by the effects of a marketplace with a very high plant margin further explanation required.	High if transmission reinforcements cannot be completed in time; Extra constraint costs left for NGET to manage and pass on; If transmission reinforcements cannot be completed in time, the difference between SRMC and LRMC will be picked up by all transmission customers
Level of risk for all transmission customers		High risk?, particularly if subject to planning; All transmission customers pick up risk of further constraint costs; Difficult for suppliers to pass volatile BSUoS costs through to customers

Attribute	Pros	Cons
Degree of discrimination	The group was split, some suggesting that it put new entrants on par so reduced discrimination, others felt this unduly favoured new entrants and through socialisation of costs was effectively subsidised entry	
Signal for TO Investment	Large. (To the extent that firm commitment is made)	Possibly later signal if a generator knows it will get connection in a specified period, some members felt that the possible misalignment was overstated and would not occur in practice
Overhead for GBSO		Fairly high – need to manage large constraint exposures; SQSS change may be required.

Group discussion on connect and manage

The standing group discussed the financial impact of connect and manage at length. Most parties agreed that the volume of constraints would increase under a connect and manage scenario. National Grid indicated that allocation of firm rights prior to the necessary wider reinforcement being completed would most likely give rise to a significant increase in constraint costs. However, some members of the group believed that there would be a net positive effect if the impact of increased volumes in the energy market were also considered.

National Grid indicated that such an effect would be difficult to quantify if indeed it existed. However National Grid did note that given the new plant was renewables with a very low capacity factor then the market would need to support a very much larger fixed cost. Whilst the marginal prices may go down in some periods, in others periods marginal prices would go up as generators sought to recover fixed cost over a smaller period. The periods when the prices increased are likely to be at higher demand periods when greater volume would be affected.

If National Grid were to receive an earlier signal it would be able to proceed with planning. It was noted that investing only when a firm contract for TEC has been signed delays investments, however it was recognised that this was mainly a regulatory and stranded asset risk issue. A particular case was described where the Forestry Commission was auctioning land for renewable development and that National Grid could conceivably be progressing consent in advance of application through discussion with the Forestry Commission. It was noted this was a form of advanced service and this was not precluded under the existing arrangements, however it was unclear which party would apply and when for the Advanced Services Agreement. How the current process of planning could delay a connection and how implementation of connect and manage transfers this risk from developers in the costs of delays to users in the costs of constraints is shown in appendix 4.

The proposed model assumed the additional costs driven by the earlier connection date are passed through TNUoS. Deconstructed this would be similar to connection with TEC at 0 (generator will always be limited by local works) and being exposed to a cost reflective overrun charge (the current arrangements+ overrun). The main difference is the generator would not be exposed to full TNUoS, but only the residual and possibly local locational charge reflecting the ‘distance’ to the MITS.

National Grid also presented some analysis in Cap148 on the potential costs of a connect and manage approach. There were a number of high level assumptions to this work and therefore it should not be regarded as a forecast. Although it indicates the potential magnitude of cost, there are a number of variables that could make a significant difference, for example, the cost of construction outage has not been factored in, these will be significantly more expensive if the plant they are intended to facilitate is already connected. Additionally, the analysis assumed a 15% incidence of constraints, further analysis shows that with a moderate increase in connected volume this can increase up to 35% very quickly. An overview of the presentation is included in Appendix 6, the main presentation is on the CUSC web site under Cap148 standing group material.

Operationally the increased volume of constraints (under any of the models) may require the further development of existing operational processes and systems, or even new processes for management of constraints to be developed i.e. more forward contracting or new contractual forms developed.

Connect and Manage Plus, CaMP

Principles

- Allocation of transmission access guaranteed within 3 years
- Administered bid prices for all generation
- Constraint management taking account of economics, technology factors and carbon emission levels
- Transmission investment based on short run marginal costs (level of constraints)
- Postage stamp MWh charging with an exposure to transmission loss factors (move from capacity to commodity)

Eligibility

- All generators, new and existing

Process

- No CUSC process changes would be required
- Note comment above on operational processes for accommodating increased volume of constraints under a C&M model

Attribute	Pros	Cons
Ease of use for new entrants	Attractive package for new entrants	
Ease of use for existing parties		Administered bid price is a significant change from current balancing arrangements; This requires National Grid to make estimate of the costs of the generator concerned, which may change dynamically
Flexibility of usage within-year	Not applicable; Does not offer within-year flexibility	
Level of charge for participants		Significant change from the current arrangements
Level of risk for participants	None	
Level of cost for all transmission customers	Extra constraint costs may be limited by the effects of a marketplace with a very	High?; Extra constraint costs left for NGET to manage and

Attribute	Pros	Cons
	high plant margin	pass on, although they would be limited by the administered bid price arrangements;
Level of risk for all transmission customers		High risk; All transmission customers pick up risk of further constraint costs, although these are limited by the administered bid price arrangements; All transmission customers pick up the cost of transmission investments, the efficiency of which is not supported by a users willingness to pay a cost reflective charge
Degree of discrimination	The group was split, some suggesting that it put new entrants on par so reduced discrimination, others felt this unduly favoured new entrants and through socialisation of costs was effectively subsidised entry	
Signal for TO Investment		None Not clear how Transmission Licensees would be able to justify investments if users not exposed to the long run costs they cause
Overhead for GBSO		Fairly high – need to manage large Constraint exposures

Group discussion on CaMP

The group discussed the impact on the SQSS. It was noted that the SQSS has two parts, a minimum deterministic standard and an economic assessment. The minimum is being assessed elsewhere.

The group discussed the economics and agreed that connect and manage will increase the constraint cost. However, the group could not agree on the wider benefits purported by the proposer, mainly an improvement in competition in the energy market and thus reduction in energy prices. Other members of the group recognised that whilst in some periods the spot price may be lower, it would be higher at other times. These higher costs would be at higher demand periods where the marginal generation seeks to cover fixed costs over a shorter period.

Whilst it was discussed that bringing new generation to the market would increase competition in the energy market, this would increase the operational costs and these are socialised under BSUoS. It is debateable whether and at what point these cost cross from being beneficial.

The group noted further analysis of this competition issue and interaction with the energy market would be useful. However given the nature of the analysis this could not be done at TASG.

The group noted that the current arrangement appeared to restrict the ability to optimise between short term and longer term costs because the significant risk of high costs in the short term. If this risk could be mitigated through limiting the right to compensation, such as restricting access for a percentage of time or limiting the bid prices, then investment may be more efficient.

It was noted that any reduction in the firmness of the access products reduces the bankability.

Variants

Local asset charge

The local assets could be charged on a capacity basis. This element is common to all of the shorter term access models, along with reviewing the residual charging arrangements.

The commodity charge discussed above could include a locational element. The group felt that complete removal of a locational element would not encourage efficient behaviour and increase the risk of stranded assets.

Moderated sharing of capacity

Reallocation of capacity if an existing generator accepts sharing the network

Principles

- Capacity is shared by Users that can elect to have their physical export rights (transmission capacity) reallocated to a new User(s).
- The User losing its physical export rights will face no TNUoS charges and can remain in the Balancing Mechanism.
- The new User with physical export rights allocated to it will have to pay TNUoS and cannot access the BM.
- All existing Users, remaining with physical export rights, would pay TNUoS and use the BM until there are new Users with which it can pass on the physical transmission capacity allocated to it.

Eligibility

- Access is not available to new generators in queue; this model does not propose over-allocation of capacity, only sharing of capacity
- All existing generators can choose to donate

Process

- Donor and recipient agree to share
- Recipient or donor requests a sharing factor from National Grid
- National Grid agrees a sharing factor
- Recipient also applies for local connection.
- Recipient and Donor agree bilateral contract and inform National Grid.

Further assumptions:

- If some existing Users give up access, it can be reallocated, but the next firm applicant will need capacity built for it, so this is not a “connect and manage” model
- There would be increase in constraints (or SRMC) through sharing
- It aims to prevent some generators from accessing the BM, thus reducing the cost/risk of constraints (or SRMC)
- Contracted positions exist for all generators.
- Increased capacity margin will not linearly increase constraints as: Contracted energy = (demand +/- imbalance) and new plant is higher merit

- Generators will not give up firm rights if they are exposed to the cost of constraints, especially if constraints could involve ROC subsidised generators

Worked process example for moderated sharing of capacity was provided by the proposer and discussed by the standing group. This is includes in appendix 3.

Attribute	Pros	Cons
Ease of use for new entrants	Existing users would be incentivised to release capacity and new Users have "bankable" access	New User can only access BM if it waits for transmission capacity to be built for it
Ease of use for existing parties	Those located close to other generation have option to "share" capacity.	Those not located where new generation wants to connect remain with capacity allocated and must also pay TNUoS to use the BM
Flexibility of usage within-year	Not applicable	
Level of charge for participants	Those with physical export rights pay TNUoS and BSUoS Those without physical capacity allocated to it pay BSUoS	
Level of risk for participants	None	
Level of cost for all transmission customers	Implicit BSUoS cross-subsidy in this model, by allowing an increase in constraints in sharing. However it attempts to control this through: 1. Not over-allocating capacity without sharing; 2. Removing some generators from the BM.	High Giving all Users that are supposed to be sharing capacity full access rights (Users with capacity allocated not in BM can't be constrained, User in BM can submit bid) will increase constraint costs; Would increase the cost of energy balancing.
Level of risk for all transmission customers		High? As above.
Degree of discrimination	Existing users that are located away from other generators may argue that they are being discriminated against since they do not get the chance to avoid TNUoS charges, but are exposed to the additional balancing costs associated with it.	
Signal for TO Investment	If some existing Users give up access, it can be reallocated, but <u>the next applicant will need capacity built for it</u>, signalling investment	
Overhead for GBSO		Fairly high – need to manage large constraint exposures

Group discussion on Moderated sharing
National Grid noted that participation in the BM was a requirement in the Grid Code for all parties and is the primary mechanism for managing the system in real time. The Moderated sharing of capacity model implies that users who have firm access will not be required to participate in the BM. Such a principle would increase constraint costs by

limiting competition for services in the BM, and under certain circumstances leave the system operator with no option other than emergency actions for local constraint resolution. This restricted participation in the BM would be at the same time the risk of increased constraint volumes increased.

The group considered that the existing generator retaining rights suggested this model was another form of connect and manage. It was recognised that by not restricting the existing generator that BSUoS charges would increase. Additional BSUoS charges are dealt with under current rules thus creating a cross subsidy.

Shared TEC, STEC

Principle

- Generators at different points on the system agree to share access in real time.
- An agreement exists that allocates STEC to generators (possibly more than two), combined as STEC.
- Each station can generate individually up to STEC but their combined output cannot exceed STEC.
- Boundary compliance is based on STEC.
- STEC agreement is enduring as other bilateral agreements.
- STEC between parties is limited to preset zones, largely based on TNUoS zones with a few alterations.
- Sharing within the zone is at 1:1 sharing factor.
- Charged at TNUoS plus a multiple to capture additional local assets.
- Combined output in excess of STEC is breach of the CUSC. Therefore explicit sharing arrangements are required in the generator agreement. This could include nomination arrangements between generators (e.g. today the STEC is for generator A, tomorrow generator B) or even be more dynamic (this is entirely up to the generators involved).

Eligibility

- Generators must be in electrically proximate zones
- At each site CEC must not be exceed
- Agreement is invalidated if either party breaches the CUSC

Process

- New applicants could be existing party and a new party or two new parties.
- On application same connection process applies to establish compliance.
- New form of bilateral agreement completed, generators are joint signatories
- Arrangements splitting the agreement in the future are included in the Bilateral – i.e. the amount of TEC each has a claim on if they wish to terminate the joint agreement.
- Services in the Balancing Mechanism can only be offered up to the STEC for both parties
- STEC parties comply with the Balancing Codes as now individually i.e. it is not shared PN. It is the generators responsibility to ensure sum of MELs does not exceed STEC

Attribute	Pros	Cons
Ease of use for new entrants	New parties can share with existing users and connect as soon as CEC / local works are complete A firm bilateral agreement provides bankability.	Existing users retain access for own new developments i.e. have priority access

Ease of use for existing parties	Existing users can sell can align operating regime with new parties to maximise value	Would need to limit output a certain times as per bilaterally agreed sharing rights
Flexibility of usage within-year	Between the two parties subject to local CEC no restriction	
Level of charge for participants	Possibly slightly higher than TEC to take account of increased local assets (twice as many). Overall charge would be less than individual TECs because wider assets are being shared	
Level of risk for participants	Still subject to local works force majeure. Additional risk mitigated through bilateral contract with counter party	
Level of cost for all transmission customers	More efficient use of system infrastructure	Increase in constraint costs, but limited
Level of risk for all transmission customers		Not all generation with capacity is able to generate – plant margin issues (probably exist with intermittent in any event)
Degree of discrimination	Existing parties retain priority access	
Signal for TO Investment	Additional information available for planning – expected mode of operation	
Overhead for GBSO	Limited.	Increased BSUoS

Group discussion on Shared TEC
Based on existing TNUoS zone plus North, North Midlands and South Midlands split East West. Limiting the zones allows a 1:1 sharing factor the estimated cost would be £10m additional constraints per GW per annum. This represents the increase in local constraints and the higher load factor on wider system constraints. Cost is inversely proportional to size of zones.

Introduced with overrun would limit the value an existing party could leverage, indeed overrun encourages parties to share (SIOLI). The variant to overrun that provided fir implicit access with acceded offers would allow both parties to offer additional system services in BM timescales to the System Operator.

The group discussed the benefits for incumbents over new entrants. Clearly this product would allow existing incumbents to advance new developments of complementary technologies. There may be merit on making that capacity available to third parties on an even basis, although the group recognised that was difficult. .

The group also another form of sharing that allowed TEC sharing without the need to define who is sharing with whom a long time in advance. Although this was not developed in a model in the format of the other main models it is described in detail below.

Short term TEC trading model (facilitated by National Grid)
This model was originally presented as a type of TEC sharing model (which it is). It also can be thought of as a short term TEC trading model (with the trade value in the base case being pre set as the pro rata TNUoS charge for the period traded or transferred to the shared party).

Parties with TEC that they did not wish to use for a period ahead (as far ahead as they liked but no later than 30 minutes before gate closure) could indicate this to NGC. NGC would then have a pool of available TEC that could be utilised by those without TEC. Parties wanting TEC for a particular period would signal this to NGC who would indicate to them what was available in their location. They could then take this TEC.

TEC thus taken would be transferred for the relevant periods from one party to the other. If it could be taken from more than one party it would be taken from the party that had indicated willingness to give up TEC for that period the longest in advance. The effect of the transfer would be that the party whose TEC was taken would be relieved of paying TNUoS charges, pro rata for the settlement periods for which it had been taken and the party who had taken the TEC would be obliged to pay pro rata TNUoS for those periods. There would thus be an incentive for parties who did not wish to use their TEC to indicate this as far in advance as possible as this would maximise their chances of it being taken by another party and thus saving pro rata TNUoS charges for the period.

The National Grid system for arranging these transfers would have to be automated. The system could either have exchange rates between geographical locations (the exchange rates which may be manually varied by NGC on a periodic basis) or (option) be set at 1:1 within a relatively small electrical zone, for example a generator TNUoS zone.

Whilst the system could be used for any duration of transfer including generator overhauls or breakdowns it is really aimed at more short term transfer of TEC between generators with intermittent primary power sources and generators who are needed when those primary power sources are not available. Thus whilst what is actually done is a transfer of TEC, it may also be thought of as these two types of generator sharing the same TEC.

The potential to earn revenues from TEC not expected to be used would incentivise parties to release capacity ahead of real time. This is particularly true if the recipient also has the option to spill i.e. make use of an overrun product (which if the allocated TEC was not being used would be relatively cheap) or to hedge the risks imposed by overrun by purchasing commoditised a product such as ETEC ahead of time.

When considering this as a variant to “defined in advance” TEC sharing, the main advantage is greater flexibility and a reduction in the systematic advantage that “defined in advance” TEC sharing gives to parties who have an incumbent portfolio of generators than are located so that they could share TEC. It would of course be more complex than and have IT implementation costs over and above those of “defined in advance” TEC sharing.

The group did not believe this was a bankable product by itself. However it was very suited for older low merit generation seeking to recover TNUoS when not running.

The need for a local capacity product (option to run up to short term) and a related asset charge was discussed. The group believed that this product increased the short term uncertainty, National Grid indicated that whilst this system may be more complex it did not think this was unmanageable. It was noted that in informing National Grid 30 minutes before gate closure that capacity was not going to be used may increase operational certainty.

The group noted that a 1:1 sharing factor limited by zones similar in size to the TNUoS generation zones would increase BSUoS and may need some form of fee. This approach would avoid the possibly significant burden of calculating shorter term sharing factors. Such a variation also reduces operational uncertainty.

NovTEC

Principles

- Facilitate earlier connection of generation from novel renewable sources, not currently grid connected e.g. Wave, Tidal stream – for demonstration and early commercial arrays.
- The maximum amount of NovTEC may be released at any one time is 1000MW in total and not more than 200MW in any charging zone.
- Eligible recipients would be limited to applications for a maximum of 30MW for any Bilateral Agreement (with a donor).
- NovTEC is a compliment to TEC rather than a replacement of TEC
- NovTEC allocation should be no more than 7 years after connection.
- Facilitates TEC sharing without increasing constraints.
- It expands the possible TEC donors to include both existing and future TEC holders (by virtue of a construction agreement, consag'.
- NovTEC would not return to the donor as TEC until after at least 2 years TNUoS had been paid. (For future TEC this should correspond to 6 years). After this time the NovTEC could revert to TEC for the donor or be relinquished by the donor without further charge.
- The original donor TEC party retains the rights and obligations to pay TNUoS on NovTEC.
- The recipient and donor are still subject to normal force majeure and consent delays.

Eligibility

- Eligible donors would include all parties who currently hold TEC or consag TEC provided that the potential exchange rate would be equal to or greater than 0.8 (suggested).
- Eligible recipients would be all parties who can demonstrate that they intend to connect generating devices using novel renewable energy sources.
- An eligible recipient would have to connect compliant plant.
- NovTEC donors that are existing TEC generators could give notice to GBSO at any time that they intend to enter a bilateral agreement with a party to donate NovTEC.
- If at any time the recipient failed or returned the NovTEC then it could immediately become TEC at the donor's site but 2 years TNUoS would be due in the case the donor wished then to relinquish it.
- TNUoS is due to be paid by the donor, upon energisation of their TEC plant, then TNUoS would be due for the NovTEC element. Otherwise the donor party could signal that Nov TEC had failed and that the donated TEC would be rescinded and any final sums or TEC reduction charges would be due for that part of the TEC.
- After connection of a consag TEC donor party's project, TNUoS for NovTEC would be due for a period of 6 years from the date of the connection of the donor's TEC plant if the donor wished to relinquish it.

Process

- Eligible parties could at any time refer to the TEC register and register of available NovTEC – which should show geographical location of each.
- Eligible parties would notify GBSO of their interest and GBSO would send out a notification of interest to all TEC and Consag TEC parties within the charging zone or within (suggested) 0.8 rate of exchange – whatever gives the larger choice. GBSO would send the list of these parties to the applicant. A short tender process would be carried out (facilitated by GBSO) with the applicant responsible for agreeing a Bilateral Agreement with the successful donor.
- This process of applications for NovTEC could carry on until all the agreed maximum 'pool' of NovTEC had been allocated.
- When NovTEC reverts to TEC (after being returned to the donor), GBSO would be informed, then a corresponding amount of NovTEC would be added to the available 'pool'.
- Where a recipient had used NovTEC for its full term (7 years) then it would have to apply once more for NovTEC in the normal way, if it wished to continue.

- GBSO would charge cost reflectively for services in administering the process. All application fees would be the responsibility of the would-be NovTEC recipient.

Definitions
Consag TEC: ‘The TEC is part of a party’s construction agreement (consag) and is not ‘live’ since the party is yet to connect and energise its CEC’.

Renewable Generator using Novel technology: ‘A generator using sources that qualify as REGOS where the technology has less than 1000MW grid connected at the time of application’.

Attribute	**Pros**	**Cons**
Ease of use for new entrants	Attractive package for new novel parties Allows novel generators to buy an access slot.	Limited new entrants
Ease of use for parties already connected	Not applicable	
Flexibility of usage within-year	Not applicable; Does not offer within-year flexibility	
Level of charge for participants	Recipient pays donor bilaterally agreed price.	Donor has very limited commitment, but retains responsibility for charges
Level of risk for participants	Eases investment risk for developers of novel generation	Risk for donors – may be left having to pay TNUoS of cancellation charge if their NovTEC partner fails. Both parties still subject to planning risk on TEC transferred.
Level of cost for all transmission customers	Limited as new participant is taking up a slot that already exits	If transferred on a 100 sharing factor, but established on 50% there is a additional risk – confirm sharing factor used?
Level of risk for all transmission customers	NovTEC, like other shared-TEC type models, should reduce risks to all T customers by better facilitating connection of a wider mix of generation – thus reducing the risk of stranded assets.	Other parties in the queue lose the opportunity to move forward.
Degree of discrimination	Any discrimination may be due discrimination needed to ensure that a wide mix of renewables can connect to the system.	Large, unproven renewables over proven renewables
Signal for TO Investment	Good signals from small to medium connections of new technology (facilitated by NovTEC) – which will wish to expand. Areas of	Existing parties maintain future agreements on the basis that that trading of future TEC is established.

	expansion will be clearly identified – leading to clear investment signals.	
Overhead for GBSO		Cost of managing the agreement

Group discussion on NovTEC

The group noted that this was different to C&M in that the consents and force majeure risk still exists for the donor and the recipient. The agreement would also be subject to the CEC and local works for the recipient. It was noted given the likelihood that NovTEC was on the periphery of the system that local works would be a significant factor and may take much longer that the donor's local works or the wider works. Such an impact could be assessed on a project by project basis.

It was pointed out that the works on the donor connection may or may not go ahead depending on the volume remaining at the donor. This may then require the donor to resize its project or consider alternatives such as overrun.

The group questioned the issue of how donors waiting for TEC were incentivised. The proposer indicated that the donor was still subject to final sums and therefore could not be considered as an easy get out. When the capacity is transferred back to the donor, if the donor did not build there would be final sums liability – this would need to reflect the local works that may have been built and possibly for the wider works.

It was noted that in all of the sharing models that charges may need to reflect a multiple of TNUoS covering the local works. There was an additional issue highlighted with NovTEC in that if the project is only viable for 7 years then the local assets may need to be depreciated over 7 years. The proposer noted that the resource is enduring so one could envisage that further projects would come along to use those local assets.

The group discussed the potential increase in constraint costs. The proposer indicated that as no new TEC is allocated then there should be a minimal increase. Any increase will be due to the different operational pattern and load factor. However, there may be in indirect impact on constraint payments where a party, which may have reduced TEC in an area, actually connects and uses it as NovTEC.

A TEC party connecting under 'connect and manage' may add a further burden by using the NovTEC part of its TEC in addition to its TEC. This may be mitigated if an overrun product was available to both the TEC and NovTEC users. These parties could then be exposed to real marginal costs rather than them being smeared over all users.

The two major concerns highlighted with this model are the inherent discrimination and the creation of value for perceived TEC held in a future agreement.

The group noted that there was possible merit in treating new novel technologies differently although this may be more a regulatory / Government issue. The group generally agreed if the number of projects were sufficient small and deemed to have wider long term benefits then explicit regulatory or political support would be more approparite.

In the case of trading future TEC it was noted that this could be counter productive in that parties with construction agreements would be less likely to cancel them or adjust their TEC request level in an efficient manner if they had the possibility of trading that capacity. The proposer had sought to address these issues with restricting the product and maintaining liability. However, some members did not agree that these fully mitigated the negative impact. The group noted there are a number of active proposals that are seeking to filter out non viable projects and rationalise the capacity in existing viable project (those with future TEC in excess if the expected final project).

The proposer pointed out that this approach, if unmitigated, could act to discriminate against access for new technology since any TEC (in signed construction Agreements) seen as ‘excess’ in the context of the GB queue would be allocated to presently proven technology. This allocation process would take no account of the strategic position of developments, with the end result being that peripheral areas, hoping to connect TEC for marine generation, would find that all TEC was being shifted to on-shore wind projects – often in areas unsuitable for later sharing with marine generation projects. The net effect would be that access to the grid – even for relatively modest generation – would be sterilised until later rounds of wider works had been completed around 2020 or later.

Interaction between models and existing products

The group discussed if and how the various products could work together. National Grid indicated that the original three models, trading (including the existing trading products), ETEC and overrun were all assumed to work together. These were not aimed at distinct by timescales, but seek to provide a range of products to enable generators to manage risk better, suit the nature of intermittent and low load facto plant.

The Connect and Manage Plus model was seen as having more fundamental aspects. However the basic concept of connect and manage promoted in this model and the connect and manage model itself were though to be consistent with the aims of the other models. The only area where there may be some disjoint is in charging short run costs to all users through BSUoS which appears inconsistent with the overrun concept of charging at a cost reflective short term price. The connect and manage models are more focused on getting plant connected to the system.

Appendix 7 shows a map of all the products and the timescales each is associated with.

NovTEC is very similar to Shared TEC, although in the case of NovTEC the sharing is of future access. It also differs in that it envisages a wider pool of donors (i.e. includes all the parties waiting for access along with those connected) and also there is limited volume given the restriction of eligibility.

A number of amendments have been accepted that sought to introduce different element of trading in varying timescales. These are:

- Cap68 – Bilateral trading of capacity with an enduring nature. All rights and obligation associated with the transferred access rights are transferred to the buyer in perpetuity.
- Cap 94/92 – release of access within year on a cost neutral basis by National Grid. This could be considered more akin to ETEC that trading.
- Cap142 – bilateral trading of capacity within year. The seller retains the long term access right and obligation to pay TNUoS. The buyer has to pay the seller and a charge equivalent to LDTEC.

The attributes of Cap94 and Cap93, know as LDTEC and SSTEC are described in more detail in appendix 8.

In general these products have not had a significant take up, with some of them never having been used. The TEC trading in this model is very different from the Cap68 type trades particularly in respect of the seller’s future rights.

It was noted that the recently agreed CAP 142 trading mechanism imposes an LDTEC charge on capacity that is traded. The primary reason for this is not to undermine other short term products released by the system operator e.g. LDTEC. It is questionable whether LDTEC and SSTEC should be supported in such a way, or as discussed below each should be addressed on its in merits as a complement to TEC.

Therefore it does not naturally follow that trading by auction replaces some or all of the existing arrangements. However, in the longer term if more flexible arrangements were to be developed and introduced it may be efficient to review the role and need for the existing products.

There was general consensus in the group that in order for trading to deliver full benefit, short term access arrangements, such as overrun, would be a significant enabler. These set a reference value for trading and provide the buyer with an alternative, both ensuring the longer term price of trades are efficient. The group recognised that existing parties may have the opportunity to exercise market power, although it was felt that this was a regulatory matter and not a framework issue. However the making the trading process / price transparent would serve to limit the possibility of a party being able to exercise market power.

The group noted that with such a plethora of products that liquidity of the market may be a factor. Whilst many products may be useful an overabundance may be counter productive. National Grid indicated that in presenting overrun it sought to provide the lowest granularity required. This is intended to remove the need for perceived aggregated products such at LDTEC and SSTEC, also connect and manage as a product rather than as subsided early entry. However compared to connect and manage overrun does not give financial firmness (bankability) that developers have indicated is required. In the longer term there is a strong argument that if a short term product was introduced the other products could be withdrawn; however this could be done in the future if it was seen that they were no longer being used; (Although it was noted, particularly for overrun, even if a product is not actively used the fact that it exists at all influences the behaviour of parties, i.e. encourages advanced trading). Note this does not extend to a shared TEC product that has a significantly different attribute to the TEC derivate products.

Interaction with other developments

Distributed Generation

The existing electricity supply industry is based largely on the generation of electricity in large power stations connected to an actively managed high voltage transmission system which in turn feeds into largely passive lower voltage distribution networks (owned and operated by Distribution Network Operators or DNOs) for onward distribution to industrial, commercial and domestic demand customers. There has been increasing interest in recent years in the distributed (sometimes referred to as embedded) generation of electricity, with generators (often based on renewable resources) connected to the distribution system: close to the point of use and reducing the various electrical losses arising from more centralised generation.

The impact of distributed generation on the main transmission system has been examined in a number of fora including the Access Reform Options Development Group (ARODG), Transmission Access for Distributed Generation (TADG) and in various CUSC amendments. It is possible that increased distributed generation could lead to certain Grid Supply Points (GSPs) becoming net exporters. During discussion at these group National Grid has made the point that not just export, but any negative change in demand, influences investment. However the groups have discussed a number of simple net models so there is still considerable uncertainty as to how the arrangements for distributed generation will develop.

The group recognised that development any new arrangements could impact on the availability and utilisation of distributed generation and vice versa, and positively or negatively. The assessment below includes a comment in respect of distributed generation against each model; however this is focused on the current arrangements.

Cap148 Deemed TEC

The original DTEC proposal included connect and manage along with the priority redespatch and administered pricing. The standing group largely agreed that priority despatch and administered pricing would be extremely difficult to administer and therefore all the alternatives have focused on connect and manage. The main differences between the alternatives are eligibility, dealing with force majeure and the time to wait for connection 9all subject to local works). To this extent this is very similar to the connection and manage model put forward under TASG, however the fundamental difference is in the area of eligibility.

The Cap148 original and alternatives are aimed at renewables to one extend or another (or low carbon), whereas the connect and manage model in TASG is available to all forms of generator, this avoiding and argument of discrimination between technologies. However it was recognised that Cap148 did raise the issue of connect and manage as a principle and described the main benefit, early access against the main concern, the socialisation of costs of over allocation.

Cap131 User Commitment

Under the connect and manage models whilst the required wider works (under the SQSS) would yet to be built for some new plant all connected plant would all be treated the same in respect of user commitment i.e. subject to the same user commitment.

Cap149 TEC lite

This amendment seeks to codify restriction associated with design variations in the CUSC rather than in the bilateral agreements. Whilst it may impact on the detailed drafting the essential principle that users can choose a lower level of connection providing they do not impact on a third party is not envisaged to adversely impact on the objectives of the models described in this report.

Assessment against the applicable CUSC objectives

The standing group assessed the model against the Applicable CUSC Objectives. The discussion and agreements are summarised in the table below.

Model	Efficient discharge of duties		Facilitates competition	
	Promotes	Demotes	Facilitates	Frustrates
NovTEC	Note: The concept promotes wider Government policy that is not reflected in the transmission licence.	There are a number of wider issues and this form of distinct discrimination is unlikely to promote competition or meet any of National Grid's wider licence duties. The group considered that promotion of NovTEC should be at the Governmental level & would require licence changes to implement.	Possibly facilitate competition in the future.	Creating value through trading construction agreement rights may delay the efficient cancellation of agreements and therefore the release of capacity to viable projects i.e. encourage hording
Shared TEC - advanced	Allows for a more efficient use of available system. More information available in design regarding the mode of operation, this may allow more efficient design of wider works.			Two parties are agreeing not to compete. More suited for larger portfolio users. Better for existing generator to expand rather than new parties to connect earlier i.e. dominant players would become more dominant

Model	Efficient discharge of duties		Facilitates competition	
	Promotes	Demotes	Facilitates	Frustrates
Shared TEC - facilitated	Could enhance use of system. Parties inform National Grid prior to gate closure they do not intend to use system allowing more efficient operation.	Implementation and system costs need to be considered against the benefits. It may increase operational uncertainty. Existing users release access near to real time, this creates additional BSUoS costs.	Trade is not fixed in advance and facilitated by NG - parties could be competing for released access – the counter party in not known. National Grid would compete with other users for the access released in short term (additional cost passed through BSUoS).	Favours incumbents and portfolio players. Favours predictable plant.
Moderated Sharing	.	Allocation beyond capacity could be uneconomic. With socialisation of costs over allocation of capacity is not considered efficient. Removing the mandatory requirement to be in the BM restricts the system operator in managing the system. Explicit cross subsidy in BSUoS.	More parties in the market – reduced barrier to entry.	Existing parties who do not pay TNUoS can trade at a lower cost. Favours existing portfolio players.

Model	Efficient discharge of duties		Facilitates competition	
	Promotes	Demotes	Facilitates	Frustrates
Connect and Manage Plus, CaMP	Greater use of available system.	Allocation beyond capacity could be uneconomic. There is not always capacity available causing an increase in operational costs. 3 years is faster than transmission capacity can be constructed	More parties on the system would improve competition in the energy market at certain times.	Restricting the ability of parties to freely submit bids and offers.
Connect and Manage	Greater use of available system. Not building until there is a signal will avoid excess transmission capacity, but create possibly uneconomic costs.	Allocation beyond capacity could be uneconomic. There is not always capacity available causing an increase in operational costs. 3 years is faster than transmission capacity can be constructed. SoS impacted if decision to build is based solely on economic assessment.	More parties on the system would improve competition in the energy market at certain times.	Socialising the increased operation costs rather than passing on to the generator does not promote efficient decisions by the generator.
Overrun	Improves choice for generator. Facilitate more efficient investment (not agreed by all)	Undermines TEC (not agreed by all)	Facilitates competition in access. Removes a barrier to entry (but at a cost reflective price). Prevents hording and encourages existing parties to release access.	Parties are charged differently, although cost reflectively for the different service they are receiving. Not providing a bankable access product, it does not enhance competition by new renewables.
ETEC	Optimising availability on an economic basis – efficient and cost	Cost is forecast. Process for release and	Prevents hording to the extent National Grid	Limited volume at a reasonable price.

Model	Efficient discharge of duties		Facilitates competition	
	Promotes	Demotes	Facilitates	Frustrates
	reflective.	pricing, by nature will not be perfect as it is based on forecast.	can forecast and price the product.	
TTECT	Optimises use of transmission system	Improvement is limited by to need to use exchange rates.	Allows competition in access.	Incumbents have an advantage.

The table above shows the main views represented by the group. In certain areas there was considerable debate and no general consensus was found. For example, under the connect and manage model most of the group agreed that having new entrants would facilitate competition, however the group could not agree that the negative associated with a cross subsidy was justified against the stated benefit in the energy market. If the cross subsidy was removed through a more targeted charging arrangement to that proposed the benefit of competition would be muted because less developers would accept the risk. The group recognised that the impact of connect and manage on the energy market was not necessarily an area for National Grid to assess, but would need to be addresses in a regulatory impact assessment.

Impact on Industry documents

For each model, the standing group discussed the likely impact on the other industry documentation. The table below shows the groups initial thoughts. Detailed discussion in a standing group for any model may identify additional links.

Model(1)	Charging(2)	Licences and licence statements	BSC	Grid Code
NovTEC	Local assets may only be provided for short time. Clarify who pays TNUoS and when.	Discrimination issues. Impacts on moved to deal with the queue		
C&M	As proposed no changes. Charged at TNUoS and BSUoS as now.			
CaMP	Charges changed to postage stamp charging in MWh exposure to losses.	Charging objectives, Grid Code objectives, SQSS objectives	Changes associated with administered bid prices	Balancing codes to deal with administered pricing
Shared TEC advanced	Multiple of TNUoS to reflect increased local assets			BCs to deal with BM requirements. Margin / availability issues.

Model(1)	Charging(2)	Licences and licence statements	BSC	Grid Code
Shared TEC Facilitated	Multiple of TNUoS to reflect increased local assets			BCs to deal with BM requirements Margin / availability issues.
Moderated Sharing	Both parties could be using the system and should be charged.			BCs to deal with BM requirements
Overrun	SRMC caused by overrun to be charged to polluter	Methodology required for pricing	Volume correction in BSC Overrun constraint tagging	Review, may need improved transparency of forecast constraints.
ETEC	Charges for ETEC would be forecast constraint costs.			Review
TTECT	Need to ensure that trading charges were consistent with other products (e.g. LDTEC)			Review

(1) In all of the above models it was noted that a review would be required against the SQSS. This would need to look at the need for a derogation process and / or changes to the SQSS itself to deal with the changes and assumption in background plant.

(2) In all the short term models the charging for local assets and the application of the residual need top be reviewed

Summary

The report discusses the further development of access, highlighting the advantages and disadvantages of various models. The standing group believe that this high level assessment fulfils the requirements in the terms of reference. The purpose of the report is to inform users rather than develop amendments. The content of the report will provide a useful resource for users to draw upon when considering future amendment proposals.

The group have reviewed several models, the majority of which could be implemented under the current governance framework. The Connect and Manage Plus and NovTEC models as presented would most require more fundamental changes to industry framework and are unlikely succeed under the objectives alone.

The standing group agreed that there were areas of the CUSC arrangements that if developed may support the CUSC better meeting the relevant objectives. In the case of bilateral and facilitated trading, that in part currently exist, further development may be beneficial. However the short term benefit in terms of dealing with the current delays in access was debateable.

The group generally agreed the development of short term products and possibly an overrun product would be a useful compliment to longer term fixed access products, however these were not seen as products that would signal transmission investment or provide the level of ‘bankability’ required to finance new projects alone. The group also noted that development of more flexible short term products could have a significant impact on charging. In particular, the need to develop a more cost reflective short run charging methodology. Along with this review the charging arrangements for ‘local assets’ and the treatment of ‘residual’ element of charges. The impact of a more flexible short term product would require some attributes of TEC to be reviewed.

The general consensus of the group was that a product with similar attributes to shared TEC as discussed may be very useful in addressing some of the current issues of access. Such a product may also provide more efficient transmission arrangements in the longer term. However there was some significant concern about the asymmetric benefits to existing and incumbent generators over new developers. It was agreed that the short term facilitated sharing alternative seeks to address these concerns. However much more, arguably disproportionate, fundamental reform would be required if locational market power was perceived as an issue in the longer term. The group indicated that more fundamental reform would be best assessed under a more holistic high level review rather the incremental approach which the CUSC governance better supports.

The group also noted that in addition to the possible significant impact on charging the development of incremental access arrangements or new products would in most cases impact on the SQSS, requiring National Grid and the TOs to review certain areas, particularly the obligations associated with the generation background.

End of report

Appendix 1 Terms of reference and standing group procedures

Transmission Access Standing Group
Terms of Reference (Issue 2)

Membership of the Transmission Access Standing Group

1. All CUSC parties are invited to nominate a member for TASG. National Grid would provide members from a number of disciplines to ensure that TASG can have a full and meaningful discussion. The amendments panel would be given the opportunity to ratify TASG membership at the May panel meeting. The amendments panel would also have the right to change membership, including the Chair, from time to time.

2. The amendments panel is invited to nominate a Chair. The Chair will act impartially and as an independent chairperson.

3. Whilst it is not the intention to limit membership, in order to facilitate useful debate and a timely achievement of the objectives, it is proposed that each party, other than National Grid, limits membership to one. Any party would be free to send an alternate in place of a member. The Chair would also have the right to invite industry experts as required. A CUSC party not represented may be permitted to raise issues for discussion through formal submission to either the Chair or secretary.

4. A representative of Ofgem would be invited to attend as an observer. Other observers would be permitted at the discretion of the Chair.

5. Parties are requested to submit initial nominations for TASG membership to the CUSC amendments panel secretary by 8th May 2007.

Meeting Administration

6. The frequency of TASG meetings shall be defined as necessary by the TASG Chair to meet the Terms of Reference and timescales as defined below.

7. National Grid will provide technical secretary resource to the TASG and handle administration arrangements such as venue, agenda and minutes etc.

8. The TASG will have a dedicated page under the CUSC section of the National Grid Industry Information website. This will enable TASG information such as minutes and presentations to be available to a wider audience in a timely manner.

Timescales

9. The first meeting of TASG is proposed for 15th May 2007.

10. The TASG should aim to produce a final report covering all the issues in the terms of reference for discussion at the July 2007 amendments panel meeting. The TASG Chair may request a maximum additional month to produce the final report i.e. submission of the final report for discussion at the August amendments Panel.

Terms of Reference

1. The TASG has been established to consider the further development of the transmission access entry arrangements with the aim of providing greater

flexibility for parties to gain or exchange access in the short term; to identify and evaluate the options for change; and identify their implications for the CUSC and other industry documents.

2. The review should consider:

   - the appropriateness of existing access products to renewables and other technologies;
   - the potential for the further developing the trading of allocated rights (TEC) between Parties;
   - the potential for allocation of 'spare' capacity by the system operator in operational timescales;
   - the potential for accommodating 'spill' in excess of allocated access;
   - the inter-relationship and linkage to other industry arrangements; and
   - how any revised arrangements would be monitored and settled.

3. Any proposed arrangements or models should be considered in the context of the relevant CUSC objectives

   - the efficient discharge by National Grid of the obligations imposed upon it under the Act and the transmission licence; and
   - facilitating competition in the generation and supply of electricity, and (so far as consistent therewith).

4. TASG should also consider the cost benefit for proposed models, including the wider implications on Industry parties e.g. increase in balancing costs; and system operator and industry implementation and enduring costs.

5. In considering the issues above, the TASG should review possible interaction with existing industry developments including, but not limited to: proposed CUSC amendments, BSC modifications, offshore project, ARODG, TADG and the cashout review.

6. The TASG Chair will be responsible for providing a verbal report on progress at each Amendments Panel Meeting. Furthermore, the TASG Chair will be responsible for producing a Standing Group Report. The report should be submitted to the amendments panel Secretary by the [July / August] amendments panel for circulation to Panel Members. The report should be written with reference to Section 8.18 of the CUSC. The TASG Chair will present the summary of the report to the [July/ August] amendments panel.

7. It should be noted that, in accordance with Section 8 of the CUSC, the TASG itself, as a Standing Group under the Amendments Panel, is unable to propose an amendment to the CUSC.

Relationship with Amendments Panel

8. The TASG shall seek the views of the Amendments Panel before taking on any significant amount of work.

9. Where the TASG requires instruction, clarification or guidance from the Amendments Panel, particularly in relation to their Scope of Work, the TASG Chair should contact the CUSC Panel Secretary.

Meetings

10. The Standing Group shall develop and adopt its own internal working procedures and provide a copy to the Panel Secretary.

11. The first meeting of the TASG will be scheduled for the week commencing 14th May, provisionally booked for the 15th May.

Appendix 2 – Membership and Attendance

Attendance Record

✗ absent
✓ attended

Name		Company	15th May	5th June	15th June	26th June	13th July	1st Aug	16th Aug
Paul	Jones	E.ON	✗	✓	✗	✓	✓	✓	✓
Ben	Sheehy	E.ON	✓	✗	✗	✗	✗	✗	✗
Dennis	Gowland	Fairwind Statkraft Orkney	✓	✓	✗	✓	✓	✓	✓
Bob	Brown	Cornwall Energy Associates	✗	✓	✗	✓	✓	✓	✓
Richard	Ford	RES	✓	✓	✓	✓	✓	✗	✗
Mike	Davies	Wind Energy (Forse) Limited	✓	✗	✗	✗	✓	✓	✓
Malcolm	Taylor	AEP	✗	✓	✗	✗	✓	✓	✓
Bill	Reed	RWE	✗	✓	✓	✓	✓	✗	✓
David	Scott	EDF	✓	✓	✓	✓	✓	✓	✓
Robert	Longdon	Airtricity	✓	✗	✓	✗	✓	✓	✓
Tony	Dicicco	Npower	✓	✓	✓	✓	✓	✓	✓
John	Morris	British Energy	✓	✓	✓	✗	✓	✗	✓
Graeme	Cooper	BWEA	✓	✓	✓	✓	✓	✓	✓
David	Walker	West Coast Energy	✓	✓	✓	✓	✓	✓	✓
Charles	Williams	Faulks renewables	✓	✗	✗	✗	✗	✗	✗
Aileen	McLeod	Scottish and Southern Energy	✓	✗	✓	✗	✗	✗	✓
Dewi	Ab Iorwerth	Centrica	✓	✓	✗	✓	✓	✓	✓
Tim	Russell	Russell Power	✓	✓	✓	✓	✓	✓	✓
Jeremy	Sainsbury	Natural Power	✗	✓	✓	✗	✗	✓	✗
James	Anderson	Scottish Power	✓	✓	✓	✓	✗	✓	✓
Philip	Baker	DTI	✓	✓	✓	✗	✓	✓	✓
Karron	Baker	Ofgem	✗	✓	✓	✗	✗	✓	✓
Mark	Copley	Ofgem 1st mtg;then as alt to M Davies	✓	✓	✗	✗	✗	✗	✗
Patrick	Hynes	National Grid	✓	✗	✓	✓	✓	✓	✓
Beverley	Viney	National Grid	✓	✓	✓	✓	✓	✓	✓
Hedd	Roberts	National Grid	✗	✓	✓	✓	✗	✓	✓
Paul	Plumbtre	National Grid	✓	✓	✓	✓	✗	✗	✗
Paul	Auckland	National Grid	✗	✗	✗	✗	✓	✗	✗
Simon	Waters	National Grid	✗	✗	✗	✗	✗	✓	✗

Appendix 3 Example of Moderated Sharing model

This example was provide by the proposer of Moderated sharing to help the standing group understand the concept.

1. We have 10GW queue in Scotland, with 500MW that can connect in near timescales, but reinforcements cannot be completed, so access is unavailable.
2. Let's imagine 500MW of these new generators do not necessarily want to use the BM and would wish to use capacity allocated to existing generators, even though constraints may be increased.
3. Existing generators' TNUoS charge reflects not only the LRMC of investment in the transmission system for generation, but also has some (as a result of revised charging in this model) scarcity value associated with the demand for access from those applying for connection. (TNUoS becomes a value rather than asset based charge).
4. Existing generator, say 500MW, considers giving up access and is persuaded by avoidance of the TNUoS charge and by the consideration of its own and any new generator(s)' use of the capacity allocated to it.
5. The existing generator is now no longer considered to have transmission capacity allocated to it and this 500MW is allocated to those that can connect.
6. The new generator cannot submit prices into the BM and cannot have a BOA instruction, on the other hand, the existing generator can.
7. The new generator is liable for TNUoS charges and is committed to pay for a defined period as it is effectively taking on the investment signal from the first generator.
8. The transmission reinforcement originally considered for the new 500MW generator is allocated to those further down the queue.
9. We now have 2x500MW connected, of which 500MW is paying TNUoS (giving it "strong" physical export rights) and 500MW operating in the BM and having no transmission capacity allocated to it (User with weak physical export rights, but still firm rights in terms of receiving financial compensation at bid price when "bid off").
10. In the event that both generators have contracted to sell 500MW at the same time, the GBSO would be forced to accept a bid from the User with weak physical export rights, in the BM.
11. As the User with physical export rights has transmission capacity allocated to it, it is much less likely the GBSO should need to take it off.
12. The cost of accepting an offer on another BMU and bid on the User in the BM with weak physical export rights will increase BSUoS, where this User will be part of the SRMC.
13. BSUoS will be socialised between all Users on metered volume as now.

Alongside this:

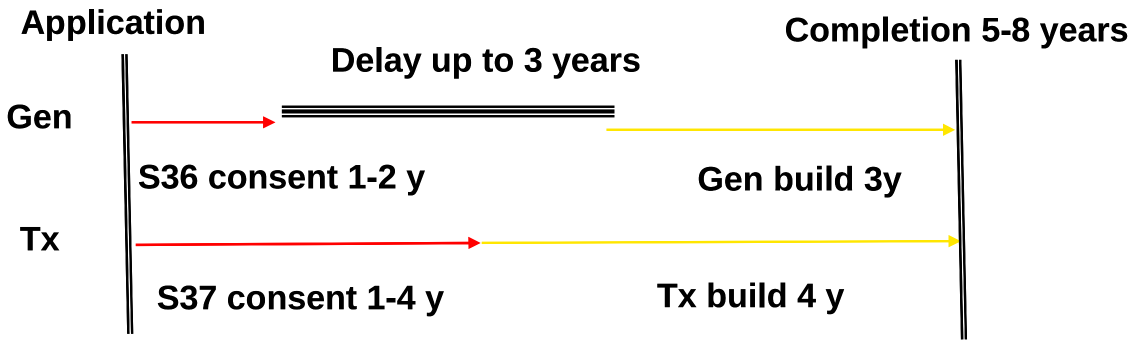
14. If a User wishes to come onto the system and immediately operate in the BM, it shall have to wait for the TOs to build the reinforcements.
15. If there are no Users allowing the reallocation of capacity, then the GBSO and TOs should invest in the system, however charges will reflect this investment in the system.
16. For existing Users, where there is no demand from new generators for the capacity, they shall see TNUoS charges reduce, as there is no demand for the Transmission capacity that supports them; these generators will remain using the BM as per normal.
17. GBSO and TOs should invest in the system to ensure that the level of constraints is not excessive.
18. GBSQSS should not reduce the availability factor A_t as this would reduce the opportunity for the capacity to be reallocated.

19. There is an explicit cross subsidy between BSUoS payers and the provision of access – the regulator would need to consider the appropriateness of this.

Appendix 4 Connect and manage implications for connection design process

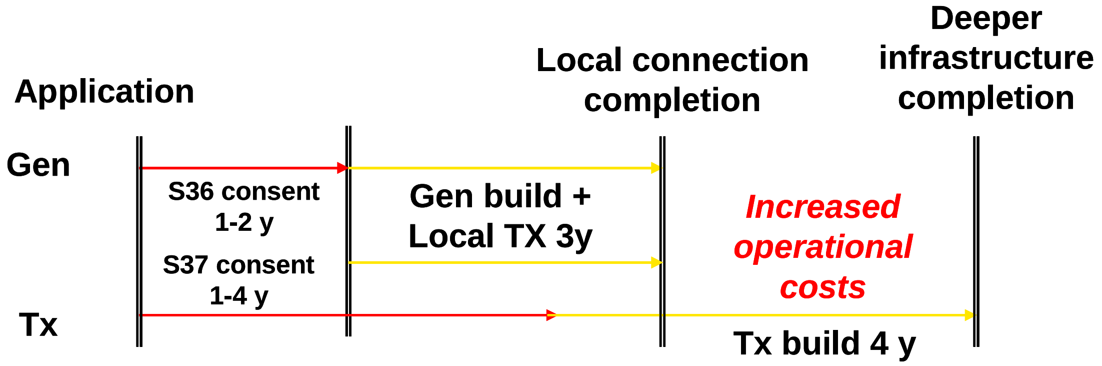
These slides were originally presented by National Grid at TASG and then further developed by RWE for a Cap148 meeting to demonstrate why increased costs can occur under connected and manage. In Cap148 further discussion took place on how the potential for increased operational costs could be limited.

Current situation:



This shows that in most cases transmission is perceived to be the critical path (in fact it is the planning consents process that dominates). The above diagram assumes that S36 and local S37 consents can be obtained before the S37 constrains for major transmission reinforcements, this will not always be the case.

Under a 'connect and manage' scenario the generator gains access prior to the wider reinforcements being competed, this is shown below:



This example shows that there are a number of years that users are exposed to the potential for additional costs. The Cap 148, Deemed TEC, proposal recognised this and seeks to limit the risk by proposing an administered bid regime for plant that is constrained off.

The period of exposure is driven be the time taken to gain S37 consents for wider works. In an alternative version of connect and manage the wider infrastructure reinforcement is not actually designed until after the new generation connects and the short term costs are known, this would further increase the risk of potentially uneconomic costs.

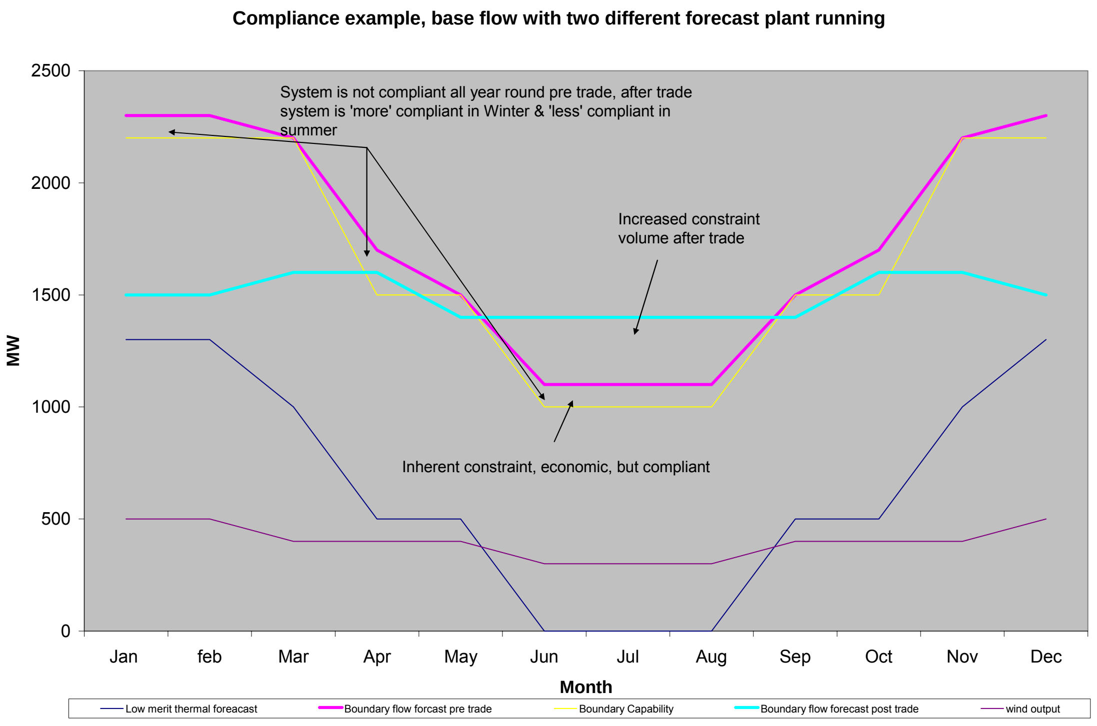
Appendix 5 Compliance and constraint cost associated with trading

In a number of working groups and TASG National Grid has indicated that the only exchange rate that can guarantee no additional constraint costs is zero. However there may also be a net benefit and any assessment must take account of this.

The chart below demonstrates that whilst trading may reduce non-compliance as assessed on winter peak, it may exacerbate the cost to maintain compliance when year round analysis is performed. If this situation occurs it would only be considered economic, and thus compliant, where the difference the overall constraint cost could be demonstrated as economic. Furthermore the type of compliance (clause for which the derogation has been granted) must also not change.

In the particular case of very low merit plant, that not forecast to run at winter peak above the 120 % plant margin, this would not be in the assessment so the non compliance would most certainly be greater.

In the example below whilst there are increased constraint volumes in the summer this is balanced with reduced volumes in the winter.

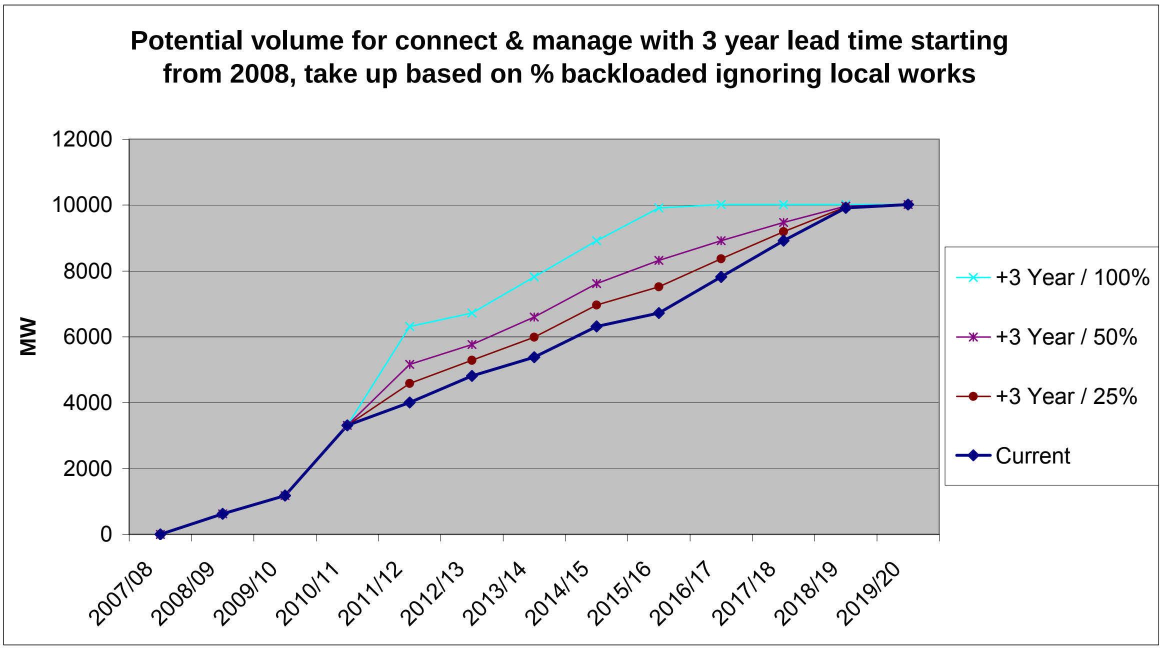


As well as the volume indicated above the bid costs are also very important. The costs for constraining the low merit plant would be far less than renewables (maybe £10/MWh to National Grid and apposed to a £40+/MWh payment to the generator). In practice under the renewable scenario the plant constrained off first would be the next lowest merit thermal unit, i.e. the bid price of renewables reflects the unwillingness to come off and so this would only be despatched when there was no other thermal plant.

National Grid assesses non-compliance jointly with the Transmission Owners; in fact it is the transmission owner who applies for a derogation. Therefore National Grid would need to discuss the methodology and actual exchange rate with the TO.

Appendix 6 Summary of slides on advancement of projects

The graph below shows the potential increase in volumes connected if 100%, 50% and 25% of project currently waiting for access were to advance by 3 years.



The assumptions used to produce the above graph were:

- Data used was from the TEC register to allow reproduction
- Post 2016 offer were assumed to connect at a rate of 1GW per annum
- Incidence of constraints was assumed to be 15% of time
- Under connect and manage (connection before reinforcement, the incidence would increase). The increase has been shown to be from 10% to 35% on individual boundaries (this will obviously depend on how near to the 'limit' the boundary is for the other 90% of the time.
- Cost of constraint £65/MWh including replacement and constrained headroom costs.
- Constrain of renewables would increase this by the cost of ROCs.
- 3 year lead time for implementation i.e. first increase is 2011.
- Analysis is on a single boundary, ignoring very local constraints.
- These constraint volume figure take no account of reductions in capacity to allow construction. In the connect and manage model construction outages would be significantly more expensive.

The volume between the current and increased capacity was converted using the formula:

Annual cost = Capacity * constraint incidence (0.15) * load factor (0.4) *8760

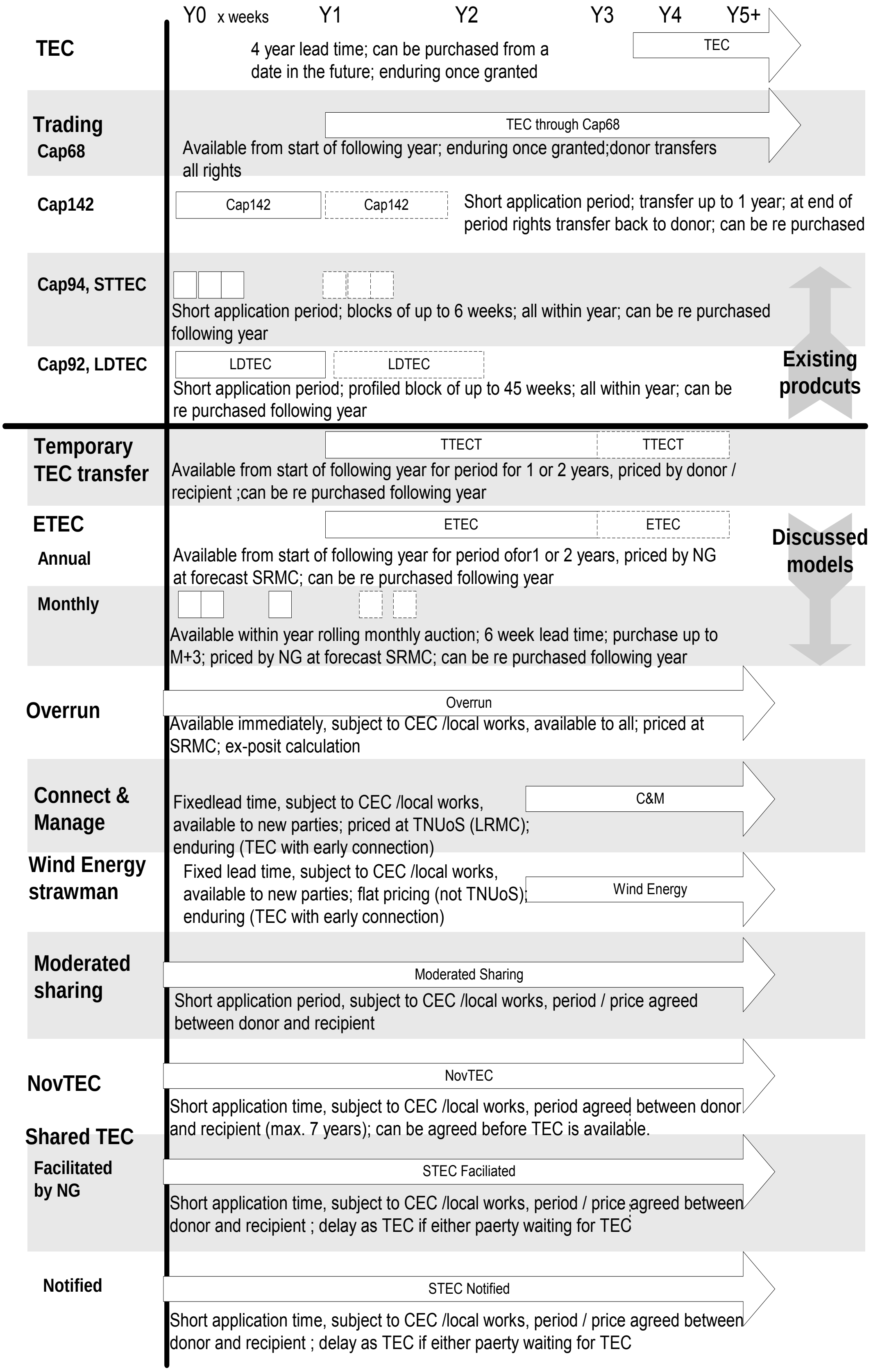
Over the eight year period this equates to:

Scenario	Volume GWh	Cost £m
100%	8337	542
50%	4169	271
25%	2084	135

Note: These figures are **not** a forecast but only serve to demonstrate the order of magnitude. As discussed above neither the cost of construction outages nor the increase in incidence of constraints have been factored in.

Appendix 7 Map of existing products along with models

Lead-time and duration of access products



* Dotted line indicates potential to purchase in the future

Appendix 8 Attributes of existing short term products

Existing short-term firm products

	STTEC	**LDTEC**
Maximum duration of rights	4, 5, or 6 weeks	45 weeks
Notice of firmness	1 or 2 weeks	7 – 45 weeks
Volume provided	Maximum MW	Profiled MW
Long-term rights (>1 year)	None	None
Compensation if withdrawn	Yes	Yes

- Limited duration, capacity and notice of availability
- Allocated on f-c-f-s bases, assuming that:
  - no increase operational costs
  - does not fetter ability to take outages for maintenance / construction

End of appendix