CAP131 Working Group
18 December 2006

Aim

For each of the areas of working group discussion, agree the following:

- Working group agreement reached
- Working group agreement possible (further analysis work required)
- Working group agreement unlikely (high probability of working group alternatives)

Principles

- Replace the current arrangements for fully cost-reflective final sums liabilities with generic liabilities;
- Generic liabilities for new generators should be fixed to provide certainty;
- Generic liability is staged (i.e. pre and post trigger);
- In the case of a project termination, there would be no refund of securities [In the circumstances where the connection date is delayed by National Grid, the termination amount payable should be based on the revised generic profile];
- Risk of inefficient investment shared between generators that introduce risk and all users;
- Additional information required from existing generators;
- Arrangements for new generators to be applied to all (including those that currently have signed agreements);
- An orderly transition from the existing arrangements will be required with the earliest practicable implementation date;
- Level of commitment required from generators to be updated at Price Control.

Further work:

- The mechanism by which generators terminate following National Grid delaying the connection date requires clarification. The working group agreed that the provision of a 'notice period' would be useful in these circumstances;

1.0 Applicability

In addition to the areas outlined below, the working group also discussed:

- Whether a threshold should be applied to the arrangements for incremental and decremental TEC. The current threshold for TEC (i.e. 1MW) was suggested and agreed;
- That under any circumstances, an existing generator could avoid the requirement to provide securities if incremental TEC became active on signature of the agreement.

Further work:

- The impact of any changes to the arrangements for 'Third Party Works' require consideration.

1.1 No transmission reinforcement works required

Option	Pros	Cons
[Original] CAP131 arrangements applied in their entirety to all incremental TEC (regardless of whether transmission reinforcements are required)	• Consistent treatment for all applications; • Discourage speculative applications for capacity; • Prevents existing generators reserving TEC in the future without facing a cost.	• Not cost reflective; • More difficult to implement since it is inconsistent with the current treatment of pre (construction agreement) and post (BCA) commissioning agreements..
£1/kW, £2/kW or £3/kW liability applied to incremental TEC that does not require transmission reinforcements	• Commitment of some kind required from all applicants;	• Not cost reflective; • More difficult to implement since commitment will be required from users that do not have a construction agreement; • Inconsistent treatment for different generators could be seen as discriminatory.
CAP131 arrangements only applied where transmission system reinforcements required	• More cost reflective; • Facilitates straightforward implementation with requirement to provide security covered in the construction agreement.	• Existing generators are able to reserve TEC in the future without facing a cost; • Inconsistent treatment for different generators could be seen as discriminatory.

Further work:

- Explain the problem!

1.2 TEC Reduction Arrangements

Option	Pros	Cons
[Original] Arrangements for TEC reduction only apply to projects that have passed the 'TEC effective date'	• More flexibility for new generation projects.	• Inconsistent treatment for different generators could be seen as discriminatory.
Arrangements for TEC reduction apply to all	• Consistent treatment for all; • Removes opportunity to book future TEC without facing a cost; • Easier to implement in existing agreements (than applying arrangements for incremental TEC to those generators that do not trigger reinforcement works).	• Reduced flexibility for new generators.

Further work:

- Confirm the definition of the 'TEC effective date';
- Consideration of the treatment of staged connection offers (e.g. 200MW of TEC in 2008 and a further 500MW of TEC in 2010).

1.3 Changes to Connection Entry Capacity

The working group has discussed:

- CEC changes at existing power stations;
- Asset replacement of transmission assets at existing power station sites;
- Other changes (no change to CEC or TEC) that lead to a requirement for transmission asset works at existing power station sites (e.g. generator transformer replacement);
- New generators requesting a connection to the main interconnected transmission system prior to the date at which TEC is made available.

Option	Pros	Cons
[Original] Generic final sums arrangements are applied to higher of incremental CEC or incremental TEC	• Simplistic single set of arrangements for generator securities.	• Unlike TEC, CEC is not a commercial product and was never intended to be used in this way; • Generic arrangements are complicated by the use of CEC and TEC.
[Preferred] No change to the final sums liabilities arrangements for non-TEC changes [e.g. CEC change, asset replacement, etc.]	• No interaction with other parties, therefore consistent to address with fully cost reflective final sums liabilities arrangements; • Complexity associated with two processes is limited since the arrangements for CEC will be consistent with those for demand	• Inconsistent with arrangements for TEC; • Complexity and lack of transparency associated with two processes for generator securities

Further work:

- Since CEC is defined on a station and a unit basis, the usage of the term CEC needs to be clarified.

1.4 Embedded Generation

Option	Pros	Cons
[Original] CAP131 arrangements apply to all generation with transmission access rights (including embedded generators with a BEGA)	• Clarity of application.	• Embedded generation that does not have access rights can still trigger transmission reinforcements. DNOs would make a modification application and the current FSL arrangements would apply (together with the issues this presents to generators); • Potentially discriminatory.
CAP131 arrangements apply to directly connected generation only	• Avoids the possibility of 'double counting' of security requirements for transmission reinforcements.	• Embedded generators with BEGAs are still exposed to the level and volatility associated with the current final sums liabilities arrangements.
CAP131 arrangements apply to all generation	• Consistent treatment for all types of generation	• Inconsistent with wider framework

Further work:

- The way in which transmission securities are passed through to an embedded generator with a BEGA is to be investigated to establish whether double counting is possible.

1.5 Long Lead-time Projects

Option	Pros	Cons
[Original] First stage commitment always applies on signature (unless connection date is not provided in the agreement)	• Equity of treatment for all. Disincentive for speculative projects.	• Not cost reflective for a number of projects; • Could be seen as discriminatory (time value of money).
First stage commitment only applies from seven years ahead of the connection date	• Cost reflective for most projects.	• With no commitment, no incentive to terminate speculative applications.

Further work:

- The impact of only applying a commitment 7 years prior to completion is to be investigated;
- Consideration to be given to whether TNUoS level at signature is appropriate if initial commitment is zero until 7 years prior to connection.

2.0 Trigger Date

The trigger date is the point at which the liability faced by a new generator increases from £1/kW, £2/kW or £3/kW to a multiple of the investment proxy.

Option	Pros	Cons
[Original] Milestone date specified by National Grid in the BCA. Maximum of 4 years prior to connection.	• When the average of all projects is considered, GBSO commits to significant expenditure 4 years prior to connection; • Minimises risk of significant costs being passed to all users; • Date specified in BCA allows the commitment required for short lead-time projects to be reflected.	• Potentially presents significant risk to developer prior to consents being granted.
Earlier of milestone date specified by National Grid in the BCA if s36 consent in place or milestone date plus one year. Maximum of 4 years prior to connection	• Commitment provided by those with increased project certainty; • Allows developer an opportunity to align the trigger date with gaining s36 consent.	• For those without s36, (milestone+12 months) provides opportunity for developers to terminate whilst GBSO is committing to significant expenditure; • The definition of a date by which s36 is in place is problematic; • s36 and s37 not required for all projects.
Later of section 36 (or equivalent) or section 37 (or equivalent) Maximum of 4 years prior to connection	• Minimises the risk presented to a developer that does not have consent.	• Presents most significant risk that costs will be passed to all users; • The definition of a date by which s36 is in place is problematic; • s36 and s37 not required for all projects.

As part of this discussion, the working group has also covered:

- The lack of a financial incentive for National Grid to deliver capacity to the agreed connection date is perceived to be a problem for developers;
- Any trigger date prior to all transmission consents required to deliver capacity being in place is perceived to be problematic for developers. This risk exists now and is outside the scope of CAP131;
- The use of a trigger date other than a milestone date specified by National Grid could be viewed as inefficient by Ofgem, exposing National Grid to a risk of inefficient investment if a project terminates prior to the trigger date.

Further work:

- The practicality of using section 36 as a trigger date and the associated mechanism (obligation on the developer to inform National Grid when s26 consent in place?) requires clarification.

3.0 Cost Reflectivity

3.1 Investment Proxy

Option	Pros	Cons
[Original] TNUoS with generic collar for negative and marginally positive zones	• Analysis shows that it provides a reasonably accurate proxy for investment when considered across main GB investment zones; • Transparent methodology to calculate; • Provides a means of handling unanticipated new generation connections; • Reflects the locational nature of investment costs.	• Locational signal from TNUoS is diluted by the inclusion of a collar for negative and marginally positive zones; • 'Smoothed' methodology not intended to be an investment proxy; • TNUoS tariff prevailing at connection agreement signature may not be fully cost reflective of costs at connection; • Zoning criteria used for transmission charges may lead to too many zones when compared with anticipated connections.
UCA	• Most accurate for new generation connections expected in next Price Control period	• Difficult to handle unexpected new generation connections; • Methodology used to calculate not transparent to users
Non-Locational (DJS)	• Simple methodology; • Provides a sharper reflection of local transmission reinforcement works.	• Data required may not be available to users; • Does not reflect the locational nature of investment; • Analysis required to establish proportion of cost that would be secured.

As part of this discussion, the working group has also covered:

- Other proxys derived from the TNUoS methodology have been considered. A locational only tariff, re-zeroed at the central London zone provided a marginal improvement in cost reflectivity, but this improvement was thought to be outweighed by the associated reduction in simplicity and transparency;
- The use of TNUoS as a proxy provides a strong locational signal which may impact generator investment decisions.

Further work:

- Consideration of the Revenue Drivers work published in the Price Control Final Proposals
    - Consideration of TNUoS zones to match UCA zones
- Consideration of the appropriate TNUoS tariff in the case of:
    - Generation subject to small gens discount;

    - Generation subject to SQSS design variation discount (provided this modification is not vetoed).
- Consideration of where the appropriate TNUoS tariff will be highlighted to users.

3.2 £3/kW collar for negative and marginally positive charging zones

Option	Pros	Cons
£3/kW	• Cost reflective of transmission reinforcement works in negative and marginally positive charging zones identified in next Price Control period.	• Marginally positive charging zones thought to require significant wider reinforcements that are distorting the average.

Further work:
- Investigate impact of marginally positive charging zones.

3.3 £1, £2 or £3/kW first stage

Option	Pros	Cons
£1, £2 or £3/kW	• Cost reflective across all projects; • Significant commitment which should disincentivise speculative applications that would otherwise exacerbate a capacity queue.	• Cost reflectivity may be distorted by long lead-time reinforcement projects.

Further work:
- Investigate the impact of only getting commitment from projects seven years prior to the connection date (refer to section 1.5 above)..

3.4 Asset Reuse

Option	Pros	Cons
Reasonably foreseeable asset reuse should be discounted from generator commitment	• Cost reflective.	• Difficult to forecast asset reuse.
[Original] All users are picking up an increased risk as a result of moving to these arrangements and therefore should benefit (charges net of generic user commitment called down) from any asset reuse	• Avoids the complexity of forecasting asset reuse.	• Not cost reflective and therefore changes share of risks between generators and all users.

Further work:
- The consideration of asset reuse needs to be factored into the risk assessment work (see below);

- The forecast of asset reuse must be updated to include:
    - Investigation of the impact of the perceived assumption that all project termination happens in the final year prior to connection;
    - Advanced asset replacement works;
    - Reinforcements that could potentially be reused by other generation connections in the future;
    - Losses.

4.0 Existing generation

4.1 Implementation

Option	Pros	Cons
2 years TNUoS fee on TEC reduction if full 2 years notice is not provided	• ?	• More difficult to implement. • Reduced generator flexibility
Any TEC reduction request does not become active for at least two years. Generator continues to be liable for TNUoS charges at original TEC until the end of the 2 years.	• Straightforward implementation.	• Reduced generator flexibility

As part of this discussion, the working group has also covered the trading of a liability for two years of TNUoS charges under the CUSC arrangements introduced by CAP068. The working group discussed a generator wanting to reduce TEC finding a buyer (potentially within the same portfolio) willing to buy TEC at a minimal exchange rate (e.g. 1%) in order to remove the liability.

Further work:
- Analysis of Grid Code data;
- Investigation of alternatives.

4.2 Negative charging zones

Option	Pros	Cons
[Original] 2 years notice of any TEC reduction required. Fee for not providing notice is 2 years of the modulus of the TNUoS tariff.	• Additional notice allows National Grid to reinforce and avoid risk of reduced security of supply.	• Since no transmission charges are due, no real incentive provided.
[Preferred] No notice required in negative charging zones.	• ?	• 5 days notice does not allow National Grid time to complete any reinforcements required to avoid reduced security of supply.

5.0 Implementation date

Option	Pros	Cons
CAP131 to come into operation at least 12 months after Ofgem decision. CAP131 would come into operation in either April or October (to reflect end of 6 month security period under current arrangements)	• Sufficient time for generators to make necessary decisions in light of revised arrangements; • Straightforward.	• Advantages for generators delayed.

As part of this discussion, the working group has also covered the transitional arrangements and agreed that a voluntary move to the generic arrangements should be made available to all if practicable.

Further work:

- National Grid to consider whether 12 months are required prior to implementation of whether 6 months would be sufficient;
- The timing of the update to the level of user commitment required from generators (i.e. at Price Control) to be reviewed when the implementation date is confirmed.

6.0 Risks Assessment

Further work:

- Analysis required to reflect risk of a new project termination decreasing as the project moves towards connection;
- Scenario analysis is required investigate the impact of first stage and second stage commitments;
- Working group to consider Mike Davies' work on risks.