CAP171: Detailed Principles

This attachment to the CUSC Amendment Proposal form for CAP171 is intended to give a broader and more detailed overview of the package of the proposal. Due to the interactions between the access and charging arrangements this attachment inevitably describes charging proposals that will be taken forward under charging governance. Where this attachment describes charging proposals these reflect the Proposer's initially favoured view, however all such proposals will be the subject of further review and consultation.

Contents

Overview

CAP171 is based substantially around the Working Group Alternative Proposal (WGAP2) initially developed by Transmission Access Working Group 2 during its assessment of CAP166.

It envisages a dual system for the pricing of transmission access rights to be effective from 1st April 2011. Users will be able to opt for one or both of the following high level methods of gaining access rights:

Option 1. Users may apply for the LCN product which will be provided in their aspirational timescales (subject to the completion of the necessary local works). Such Users will then be subject to a marginal over-run charge which will be calculated by reference to the half-hourly locational marginal costs of resolving any constraints in that half-hour; or,

Option 2. Users may then apply[1] for an access product which will be provided within their aspirational timescales (subject to the completion of the necessary local works); however User's will be required to submit contractually to binding operational parameters. Users will be given a fixed price of access reflecting the forecast asset and operational costs of providing such access and providing the User does not then exceed its contractual operational parameters, it will not be subject to the locational marginal overrun charge. The fixed set of prices for access for each Power Station will be calculated through an iterative "Capacity Pricing Mechanism (CPM)" which will be held annually.

Of the two options described above only the second option would result in a firm investment signal being sent to National Grid to invest in the transmission system. The corollary of this is that when calculating capacity prices under option 2, Users who operate under option 1 will be assumed not to be using the system and so their output will be ignored for the purposes of setting the short term price in the CPM. This may then result in Users who are willing to commit to giving National Grid a firm signal about their intended use of the GB Transmission System a lower charge for using the transmission system.

Users of the overrun product should expect to see variations in over-run charges in future years should additional volumes of generation connect to or disconnect from the GB Transmission System in the same area as they are (assuming a constrained transmission system). Overrun charges will also vary depending on the output of other generators in the same constrained zone and the capability of the circuits out of any constrained areas of the network that the generator is located within.

Should a User opt to participate in the CPM (option 2) that User will be required to submit the following parameters:

- Capacity of Access required (MW) and duration Access required for (identified years)
- Buy-Back collar information (£/MWh), per year of access requested
- Load Duration curve information, per year of access requested

National Grid will use these parameters within the CPM to determine the price of allocating parties their requested volume of rights in the timescales they have requested. Transmission access rights will continue to be defined at a Power Station level.

The CPM will be run once a year between 1st September and 31st October[2]. In this period the mechanism will be iterated a number of times (rounds), on each successive iteration (or round), Users will be able to vary their submitted parameters either increasing them or decreasing them. The CPM may close upon certain closure rules being met or by the mechanism timing out on the last business day on or prior to the 31st October. Once the CPM has closed then National Grid shall prepare a revised appendix C to the agreements within 1 month of the close of the CPM and shall send this in the form of a Modification Notice to each User who has been allocated TEC under his mechanism.

Both mechanisms will be available to both existing and new Users. Users who initially opt for option 1 may at any time decide to enter an annual CPM, however once they

[1] Either at the same time as their application for LCN or at a later date following signature of an LCN Agreement
[2] Business Days only

have done so and have a fixed price for a fixed term they will not be able to revert back to option 1 until the end of that fixed term.

Other Related Amendments

This CUSC Amendment Proposal aims to introduce the necessary changes to the CUSC to facilitate this access regime. Other amendment proposals or modifications to other codes and or methodologies will be necessary to fully implement this proposal.

The introduction of a simple overrun pricing methodology is put forward in the Charging Consultation GB ECM-14[3]. It is likely that this proposal would require a different overrun charging methodology to that proposed by GB ECM-14 to be developed and it would be National Grid's intention to progress this such that a fully locational marginal overrun pricing methodology would be in place by April 2011 to accompany the CPM.

The charging consultation GB ECM-18[4] is currently consulting upon arrangements that would introduce:

- a locationally varying component of BSUoS charges that would seek to target the costs of constraints caused by an over-pricing of TEC behind a constraint boundary to Users behind that boundary, and also
- a residual BSUoS charge that would allocate the remainder of BSUoS to all Users in line with the existing BSUoS charging methodology.

Similarly the recent open letter published by Ofgem relating to the over-pricing of TEC behind constraint boundaries[5] means that the granting of GBSQSS derogations that facilitate the allocation of TEC over and above the existing baseline may become more common, subject to the appropriate targeting of costs and also the expected successful future implementation of enduring access arrangements.

It is National Grid's intention that the locational BSUoS methodology would no longer be required as a consequence of the combined introduction of a locational marginal overrun pricing methodology and the CPM. The recent Ofgem letter regarding GB SQSS derogations would complement any allocation of access rights behind a boundary that would be subject to the CPM or locational marginal overrun.

Annual CPM: Pre-Qualification

Each party wishing to enter into a CPM in a given year will need to have the following:

1. The User must have in place a signed agreement for LCN as of 15th July in the year of the annual CPM,
2. Parties that do not have a signed LCN Offer in place by 1st March in the year of the CPM but intend to participate within it should have completed a "notice of intention to participate" by 1st March. This enables National Grid to assess the likely candidate transmission network reinforcements that will be part of the inputs into the CPM.
3. The User must have notified National Grid of its intention to participate in the CPM by completing a "confirmation of CPM participation" either alongside the

[3] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/
[4] http://www.nationalgrid.com/uk/Electricity/Charges/modifications/uscmc/
[5] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=122&refer=Networks/Trans/ElecTransPolicy/tar

acceptance of its original LCN Offer, or by submitting it at another time, in either case prior to 15th July in the year of the annual CPM, and;

4. The User must have paid the appropriate Pricing Mechanism Participation Fee[6].

National Grid will confirm in writing during August to all Users that are eligible to participate in that year's CPM. Such confirmation will also include details regarding how to practically take part in that year's mechanism including for instance details on how to access any electronic systems that may be used to submit bids for access rights for that User's Power Station(s).

LCN

The concept of LCN as established by Transmission Access Working Group 3 will also be applicable to CAP171. That is the concept of LCN will be introduced that has the following features:

- LCN is the term used by a generator to notify National Grid of its desired maximum local capacity holding in a transmission charging year;
- LCN represents the physical (and contractual) cap on the total generators' transmission access (MW) derived from a combination of access rights procured through the CPM, overrun and any other applicable short term access products;
- LCN will not exceed a generator's CEC;
- LCN is defined on a Power Station basis;
- LCN will be allocated on a first-come-first-served basis;
- LCN will be the basis upon which the local asset charge will be calculated and levied;
- LCN is shareable between generators, when multiple generators agree to share. Any sharing arrangement would be managed with a clause which, in the case of two generators sharing, would restrict one generator if the other generator is using the local connection capacity and vice versa. This approach is similar to that currently adopted to deal with design variation connections.
- LCN will be a right only terminated in accordance with terms to be expressly defined within the CUSC;
- Works to facilitate LCN will be calculated by reference to the assets required to connect a Power Station to its nearest Main Interconnected Transmission System (MITS) substation. A MITS Substation will be defined as a substation with more than 4 transmission circuits connected to it or a Grid Supply Point with 2 or more transmission circuits connected to it at the substation.

LCN Application Process:

Users who apply for a LCN will be given an offer within the usual 3 months timeframe. This offer will be for a "local only" connection to the GB Transmission System and the timescales for the delivery of this will be reflective of the resource and network access constraints for these works only (i.e. any wider reinforcements beyond the first MITS substation will not be factored into the offer). Users will be given the option in the offer to either:

(a) sign up to the offer and National Grid will immediately commence the construction programme set out in the LCN Construction Agreement, or

[6] The CPM Fee will reflect the administrative costs of operating the CPM and include an appropriate fee for the preparation of the Modification Notice sent to all successful Users at the conclusion of the CPM. It shall be more precisely defined within the Use of System Charging Methodology.

(b) the User may indicate that it wishes National Grid to delay commencement (and connection date) until after the next available annual CPM has been completed.

Should the User decide to proceed immediately with the LCN Construction Programme then it will become immediately liable for the LCN securities (detailed below). It will also be contractually liable for local TNUoS payments once the local connection has been delivered.

Should the User choose to delay the LCN construction programme commencement date until after the next annual CPM for the avoidance of doubt National Grid will make no further progress with the construction programme until such time as the results of the CPM are known. Following the release of the CPM results and the issue of agreements to vary to Users who have successfully procured access, any User's who have delayed their construction programme will be faced with one of the following three options:

1. Continue with the scheduled LCN programme, recommencing from the date of signature of the Agreement to Vary

2. Align the delivery of LCN with the start date for the transmission access rights procured through the CPM

3. Terminate their existing Bilateral Agreement (but only where the User did not procure access rights in that year's CPM).

Should the User progress down either option 1 or option 2 then LCN securities will become due at the appropriate point (see below) and the user will also become liable for local TNUoS charges once the LCN works have been delivered.

Capacity Pricing Mechanism (CPM):

The CPM will be run annually to allocate capacity to those Users that require GB transmission system access rights that are to be charged at a fixed rate[7]. The CPM will commence on the first business day on or after 1st September in a given year, closing on the last business day on or after 31st October in the same year, or earlier if the mechanism closure rules have been met. Users will have the opportunity to procure access at a fixed locational price (while still being subject to the residual elements of the BSUoS and TNUoS charges) for any financial year from that commencing on 1st April in the following year (Y+1) to that beginning on 1st April 20 years following it (Y+21). E.g. a CPM commencing on 1st September 2011 will potentially allocate access for the period 1st April 2012 – 31st March 2033.

In order to participate in a CPM, Users will be required to have in place a signed agreement for LCN by no later than the last business day on or before 15th July in a given year.

Users participating in a CPM round will be required to submit the following data items:

"**Capacity**"	The required maximum MW capacity that a User requires at a Power Station in a given year. This figure may not exceed the Power Station LCN figure in that year.

[7] Only the charge representing the locational elements of TNUoS and BSUoS charges will be fixed for Users that participate in the CPM. They will still be required to pay the variable residual BSUoS and TNUoS charges.

"**Duration**"	The number of years that the User requires capacity for.
"**Buyback Collar Information**"	The Buyback collar information would represent the price at which the User was willing to reduce its output due to a constraint. It will effectively act as a "contract for difference" around Bid prices that a User submits into the Balancing Mechanism. It will be comprised of up to 4 prices valid for different seasons and times of day.
"**Load Duration Curve**"	The load duration curve would show the cumulative number of hours a year that the generator plans to utilise its Power Station at or above a certain MW output. Up to 4 different load duration curves may be submitted reflecting different seasons and times of day.

Users will be contractually tied to the applicable submitted parameters following a successful allocation of access rights through the CPM. That is to say they will take on liabilities to pay charges based upon their Capacity and Duration submissions, they will be tied to their Buy-back price information for restrictions on access or energy throughout the Duration and they will also only be able to output energy in excess of that stated in their load duration curve subject to paying an appropriate marginal overrun charge.

The CPM will then be made up of a number of rounds. In each round, National Grid will take the submitted parameters from all generators in that pricing round and together with any background of previously allocated rights[8] seek to calculate the least cost of providing access to Users through either investment or operational actions in the years that access has been requested. This cost will be calculated through a probabilistic cost forecasting algorithm. For a given transmission network topology this algorithm will forecast an unconstrained running order, based upon the all Users' submitted Capacity, Duration and Load Duration parameters (and also any access rights already allocated in previous year's CPMs).

From these expected individual power station generation and the national demand positions the "unconstrained schedule" is calculated. The next stage is to overlay the transmission network limitations (if any) and revise the output positions of the Power Stations in the model to achieve the "constrained schedule". The forecast cost of moving between the unconstrained and constrained schedules is the forecast constraint cost for that snapshot.

The model then repeats the forecast a number ~10,000 of times to achieve a probabilistic forecast of constraint costs and this then forms the basis of the £/MW charge levied on generators in certain areas of the GB Transmission System.

The CPM will be run for each year with the expected system topology based upon the contracted position of existing generators and the submissions of generators participating in the CPM.

For each iteration (round) of the CPM, this central forecast cost in terms of operational actions forms the basis of the £/MW tariff that is charged to each generator. At the end of each round, subject to the CPM not closing due to the Closure Rules being met (see below for details on the Closure Rules) each participating User has the opportunity to amend its submitted parameters. Then the next iteration (round) of the CPM will calculate (potentially) revised tariffs for access for each of the participating Users

[8] This background of rights will include access rights held by Users as of the 31st July in each year which will include access rights awarded via previous CPMs.

based upon both its (re-)submitted parameters and the (re-)submitted parameters of the other participating Users.

After the final round of the CPM, all Users will be contractually bound to the tariffs that have emerged from the mechanism for the duration contained within their submitted bid. National Grid will within 1 month of the CPM close, issue revised Appendix Cs to each successful User through a Modification Notice.

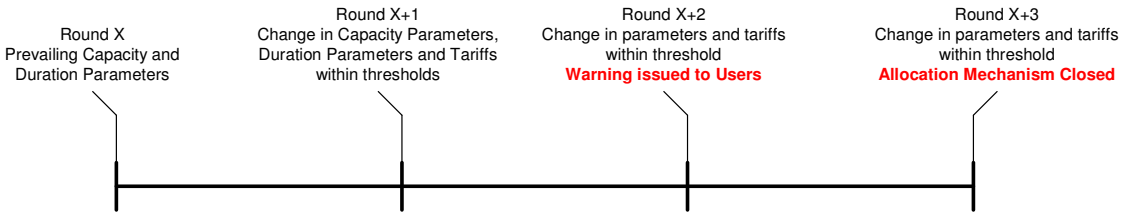
Any access right allocated through the CPM will be an annually defined product valid for the period 1st April – 31st March inclusive. For the avoidance of doubt a User who seeks access for a new Power Station that commissions mid-year will still be required to seek access rights through the CPM for the entirety of that commissioning year.

Mechanism Closure Rules

The output of each round of the CPM will be a Capacity and a £/MW access tariff for each User, for each year of the Duration it has bid for. A set of rules will be established to determine when the CPM shall close in each year and will be set according to the following principles:

- If in three successive rounds the Tariffs offered to each User in each Year do not both differ by more that a threshold of max (£1/kW, +/-2.5%) when compared to those in the previous round
- The capacities tendered by each User do not differ by +/- 5% in three successive rounds
- The final round is held on the last business day on or following 31st October in a given year.

A warning will be issued to Users once two successive rounds have passed in which the thresholds have not been broken.



Buyback Price

The manner in which the buyback price functions is a key aspect of the CPM.

The manner in which the CPM is designed will mean that both the buyback collar and the load duration curve submitted by Users will have a key influence over the number of MWh an individual power station is expected to generate over a year and thus the forecast volume of constraints. The cost of these constraints will then form potentially all of a User's charge for transmission where it is based upon the SRMC[9].

Financial Incentives on Generators

[9] Subject to the complementary Charging Consultations the tariff emerging from the CPM may be collared at a LRMC tariff.

The basis of the transmission charge is a fixed charge. Thus once the model has calculated a price and the generator is locked into that price for its Power Station(s) then it cannot influence its charges but it could influence its actual running regime in real time. Thus the only way in which it may seek to reduce its charge is through trying to optimise its output in the pricing model through careful selection of its input parameters.

The model initially ranks the Power Stations in a merit order according to the submitted applicable ***buyback price***. Once this merit order has been established the model will probabilistically simulate an output for each power station based upon its submitted applicable ***load duration curve***. Then each power station will be "scheduled" to run in the model based upon that scenario's forecast demand level.

The most obvious way to influence the resultant charge is to reduce the hours in its submitted load duration curve at which it is operating at higher output levels; however as this curve is a contractually binding parameter any actual output above this submitted load duration would be charged as over-run.

This then leaves the remaining option to vary the submitted buy-back price. As proposed the model will place a generator in a merit order ranked according to the submitted buy-back price. Therefore the forecast of Power Station output in a constrained area of the network and hence the forecast costs of resolving the constraints and therefore the access price will in some part be driven by the Buy-back price.

The Buy-back price itself will be used to place a "contract for difference" around the Bid prices[10] a generator submits for its BM Units. That is to say that Users will be free to set their BM prices for their BM Units at levels they deem appropriate for unconstrained operation. However should an export constraint boundary become active then a post event mechanism will act to amend cashflows from settled Bid prices at BM to the pre-contracted level as defined by the Buyback price. These restrictions will be tailored to allow for a number of different pricing sensitivities to be built into the Buyback price to more accurately allow short-term incentives to be placed upon Users. These are as follows.

Buy-Back: Short-Term Incentives

Seasonality will also be built into the Buyback price in order to refine the short term incentives on Users. Assessing seasonally and by time of day allows Users to profile their load duration and buyback parameters more accurately, and so a thermal power station that would aim to two shift and run predominantly during the day could reflect this by submitting a very low load duration for overnight periods. Likewise a generator may wish to indicate a lower load duration during the summer where it expects to take its maintenance outages.

The initial proposal is therefore to structure the Buyback price as follows:

		Buyback Prices
Season 1 (GMT)	0600 – 2200	
	2200 – 0600	**Buy Back**
Season 2 (BST)	0600 – 2200	**Submissions**

[10] The term "Bid Prices" in this note refers to Bid prices submitted for negative bid-offer pairs only.

	2200 – 0600	

Load duration parameters will be submitted according to the same matrix

The above matrix is the initial proposal and it is anticipated that this may be further developed following feedback from Users in any Working Group or consultation on this amendment proposal. In the absence of any consensus emerging however the above matrix would form the basis of the buyback price in this proposed amendment.

Securities for Transmission Access Rights

Secured Amounts will all be set with reference to a generic methodology. No options for Final Sums will remain.

LCN Securities

Prior to the date at which the transmission works to deliver a Power station's local access rights have been delivered – the "LCN Completion Date" – Users will be required to put in place sufficient financial security to guard against the potential for stranded asset costs should the User terminate its Bilateral Agreement. The required securities ramp up as the LCN connection date approaches, reflecting the increased committed costs National Grid incurs on local transmission infrastructure. The multiplier 8 is used based upon the analysis presented during the assessment of CAP165, namely that a value of 8 × the relevant transmission access tariff represents a 50% share of the mean cost of constructing transmission assets to give effect to a User's transmission access rights.

Time Period	***Secured Amount***
In the period more than 48 months prior to the LCN Completion Date	*Nil*
In the period commencing 48 months prior to the LCN Completion Date until 36 months prior to the LCN Completion Date	$TNUoS_{Local} \times 2$
In the period commencing 36 months prior to the LCN Completion Date until 24 months prior to the LCN Completion Date	$TNUoS_{Local} \times 4$
In the period commencing 24 months prior to the LCN Completion Date until 12 months prior to the LCN Completion Date	$TNUoS_{Local} \times 6$
In the 12 months prior to the LCN Completion Date	$TNUoS_{Local} \times 8$

Pricing Mechanism Securities:

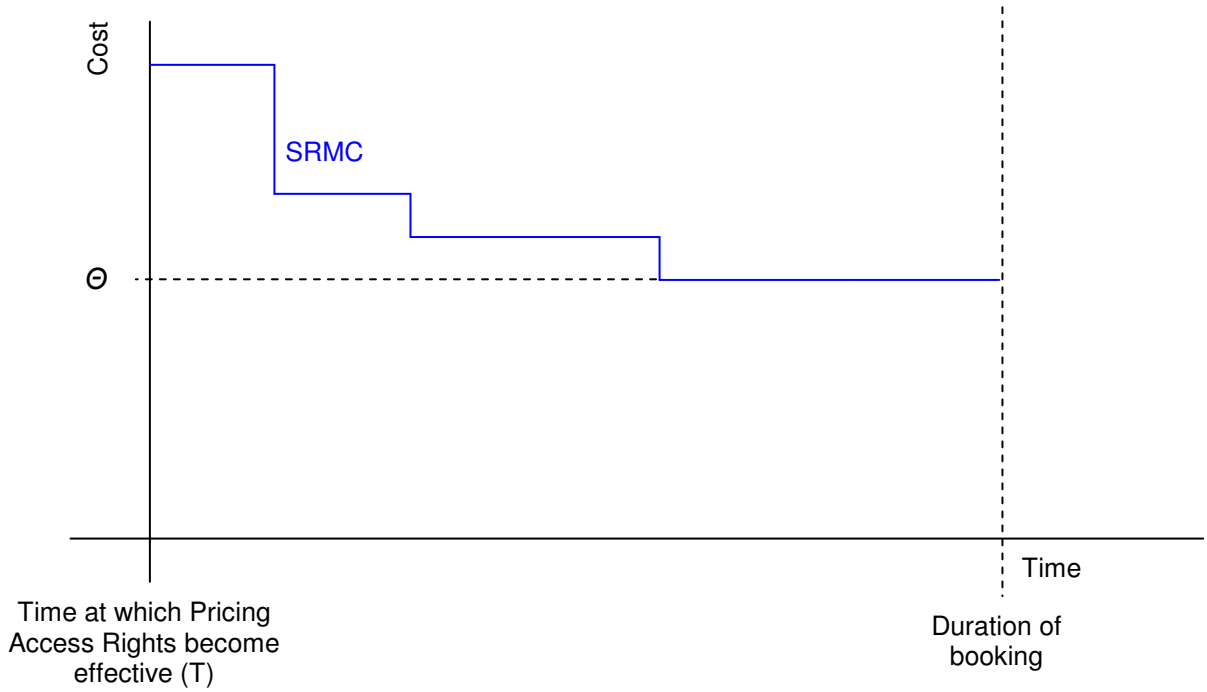
In addition to the above LCN securities, Users who have successfully procured access rights through the annual CPM will also have to provide financial security to National Grid. The aim of pre-use securities for any access secured through a CPM is to ensure that any committed spend by National Grid to deliver wider reinforcements is not stranded should the User terminate its agreement prior to use.

Analysis put forward alongside CUSC Amendment Proposal 165 (CAP165) demonstrated that on average the expenditure that National Grid incurs in connecting a User is sixteen times its long-run tariff. This was then split equitably allowing for a 50:50 share of the risk between the new entrant and the incumbent generators resulting in an eight year commitment to buy access rights and also a maximum security requirement pre-commissioning equivalent to an eight year commitment.

Another means in which to assess the level of securities is to examine the opposite sides of the security equation, on one side the cost to the User developing a new Power Station of sourcing a letter of credit (for example) for the securities it is required to hold, and on the other the cost to the wider industry or National Grid of absorbing any unsecured stranded asset cost. National Grid believes that ideally these risks should be shared between the parties with the User and the counterparty (either National Grid or the wider industry) bearing equal proportions of the stranded asset risk. Analysis included in Appendix A to this note also supports an eight year figure as the basis for security.

Given eight years of the long-run access charge is appropriate in this amendment the next question is how to identify that long-run charge.

As a result of the CPM a User will receive a profile of SRMC based tariffs for the duration of its booking, which if investment is warranted would be anticipated to reduce over time as incremental reinforcements deliver savings in operational costs in excess of their capital costs. Such a profile may look like the following:



In the above diagram the lowest SRMC value would be the closest proxy for the total value of incremental reinforcement delivered to the user. Before such point access would be delivered through operational actions freeing up capacity on the existing network and also earlier increments of the total reinforcement. Therefore the lowest SRMC value in the timeframe of a Users booking would be the basis of the Users security requirement. It is possible that in certain zones the SRMC may become zero or negative. In such zones the basis of the security requirement would be collared at a non-zero price – however the exact details of such a collar will be determined in accordance with the Charging Methodologies. Modifications to the Charging Methodologies to facilitate this treatment are being developed alongside this CUSC amendment proposal.

Securities would need to be put forward prior to the delivery of these wider reinforcements. It will be assumed that all wider works can be delivered in a period of

4 years prior to the point where the lowest SRMC tariff is achieved. This year where the lowest SRMC is achieved, is to be defined as the "Wider Reinforcement Completion Date". Assuming then that Θ denotes the lowest SRMC component (£/kW) of the Users' charges throughout their access booking, the table below indicates the Secured Amount that each User will need to have security in place for:

Time Period	***Secured Amount***
In the period more that 48 months prior to the Wider Reinforcement Completion Date	*Nil*
In the period commencing 48 months prior to the Wider Reinforcement Completion Date until 36 months prior to the Wider Reinforcement Completion Date	*Θ × 2*
In the period commencing 36 months prior to the Wider Reinforcement Completion Date until 24 months prior to the Wider Reinforcement Completion Date	*Θ × 4*
In the period commencing 24 months prior to the Wider Reinforcement Completion Date until 12 months prior to the Wider Reinforcement Completion Date	*Θ × 6*
In the 12 months prior to the Wider Reinforcement Completion Date	*Θ × 8*

Once again the secured amount increases as the Pricing Period approaches reflecting the increasing costs that National Grid is incurring in providing the physical connection assets.

Liabilities for Transmission Access Rights

LCN

The LCN right is an evergreen right, thus the associated liability for Users who hold LCN is the remainder of the current year's LCN charges. There will be no minimum booking period for LCN.

Access Rights from CPM

New Users will be required to book a minimum period of eight years[11] of access rights through any single CPM. Users will have a liability to pay for each of these eight years of access should they terminate early.

Consequences of Late Delivery

LCN

It is proposed that the existing contractual arrangements within the CUSC Construction Agreement regarding the late delivery of connections are retained for LCN Works. That is to say that any delays to the delivery of LCN will be communicated as part of the normal liaison between National Grid and the User through the construction phase. These arrangements also allow for liquidated damages provisions to be applied to certain delays and such arrangements would be retained. For the avoidance of doubt no other payments (e.g. Balancing Mechanism constrained off payments) would be made.

Should the late delivery of LCN also impact upon the commencement of access rights procured through the CPM then no charge (or payment in negative zones) will be

[11] With the exception of Users in the transition period which may book a lesser period of access rights. See "Transition" section later in this document.

made by National Grid for such rights in the period for which the LCN delay prevents energisation of the Power Station.

Access Rights through CPM

The access rights gained through the Pricing Mechanism will be financially firm. That is to say that provided a User has LCN it will be free to export up to its level of Pricing Mechanism rights from the date that they are effective. Should National Grid have failed to construct in time the wider transmission reinforcements that are required to give effect to these rights, then additional BM constraint payments may have to be made to restrict the output of generators in that locality for the amount of generation in excess of its load duration curve.

Over-run Charging

An overrun charge will be levied for all output above the specified load duration curve.

The precise definition of how the Overrun volume and price will be derived will be a matter for the Use of System Charging methodology and the complementary charging methodology modifications being progressed alongside this CUSC amendment will consult upon the detailed arrangements. However two potential methodologies for calculating the overrun volume are described below.

Overrun Volume Calculation Method 1:

For each of the (up to) 4 seasonal load durations that the user has submitted, a cumulative total volume of operation at or above each point in the submitted load duration curve will be recorded. As soon as a generator operates at a level for a number of hours in excess of that which it has specified in its load duration curve it shall be charged overrun. A complete example of this methodology can be found in Appendix B.

Overrun Volume Calculation Method 2:

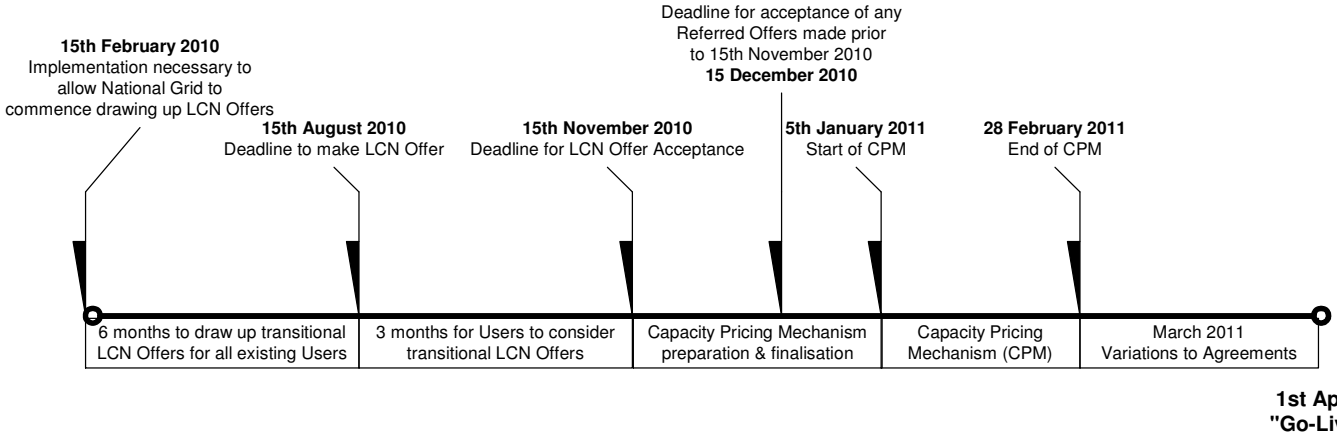
Alternatively the overrun volume could be calculated at the end of each season (currently proposed as BST and GMT) and the actual load duration curve of a Power Station will be compared with its contractual load duration. Any generation in excess of the contractual load duration curve will then be charged at a seasonal average overrun price to generate a total overrun charge for the season.

Transition

Given CAP171 will see a rescission of existing Users' access rights, a transitional process will be required in order to move from the existing access arrangements to the one based upon the CPM.

Due to the timescales involved in the preparation for the first CPM and the objective of having access rights allocated through the CPM effective from 1st April 2011 a different timetable for the first CPM is envisaged. This means that rather than the "standard" timetable which would see the CPM occur in September and October, the transitional timetable would see it occur in January and February of 2011.

The first stage in this process will be to establish LCN as the pre-qualification for the first CPM. Assuming an effective date of 1st April in 2011 for the rights allocated in the first CPM would result in the following timeline:



There will then need to be a process whereby new appendices to existing Bilateral Agreements are drawn up and agreed with Users following the first CPM such that they can come into effect for 1st April 2011. Specifically these revised appendices will need to have amended Appendix C's detailing the new access rights (and their effective dates) and potentially revised construction programmes reflecting any changes brought about by revised LCN dates or the access rights gained through the CPM.

Arrangements to transit the financial securities being posted by existing Users under the current credit arrangements to the required securities under the new arrangements will also be required.

Appendix A – Security Cover Rationale

National Grid understands that the costs to a User of procuring security range from anywhere between 2% of the principle and 15% of the principle. The "cost" of the risk that the wider industry / National Grid incurs is the risk that the User will default multiplied by the liability that it faces should the default occur.

The following table examines the number of years of long-run charges out of 16 that a User should hold as security and the corresponding perceived level of risk that the User should go bankrupt that would result in the industry / National Grid being exposed to the same level of risk. NB all costs are in £million assuming that a 1000MW generator is exposed to a £22/kW long-run charge.

User Years of Security	Lower Bound User Cost of Security (2%)	Upper Bound User Cost of Security (15%)	Socialised Cost of Default	Lower bound of Default Risk	Upper bound of Default Risk
1	0.44	3.3	330	0.13%	1.00%
2	0.88	6.6	308	0.29%	2.14%
3	1.32	9.9	286	0.46%	3.46%
4	1.76	13.2	264	0.67%	5.00%
5	2.2	16.5	242	0.91%	6.82%
6	2.64	19.8	220	1.20%	9.00%
7	3.08	23.1	198	1.56%	11.67%
8	3.52	26.4	176	2.00%	15.00%
9	3.96	29.7	154	2.57%	19.29%
10	4.4	33	132	3.33%	25.00%
11	4.84	36.3	110	4.40%	33.00%
12	5.28	39.6	88	6.00%	45.00%
13	5.72	42.9	66	8.67%	65.00%
14	6.16	46.2	44	14.00%	105.00%
15	6.6	49.5	22	30.00%	225.00%
16	7.04	52.8	0	-	-

The above table can be interpreted as saying that should a User only be compelled to hold a single years worth of security then the cost to it will be:

$$(1 \text{ year} \times £22/kW \times 1000MW \times 2\%) = £440,000$$

The equivalent cost to the industry / National Grid of this is:

$$(16\text{-}1\text{years} \times £22/kW \times 1000MW \times \text{RISK\_OF\_DEFAULT})$$

For the two sums to equal the RISK_OF_DEFAULT must be equal to 0.13%.

This exercise has been repeated for the upper and lower bounds of the Users costs of security (2% and 15%) and for a range of years of long-run costs of access forming the basis of a user's security. The corresponding risks of default are then also shown. To summarise the results if the risk is perceived to be extremely low that a User will default (and much lower than the risk premium charged for the security) then the number of years of long-run charges making up a user's security should be less than eight. Correspondingly a number of years of long-run charges in excess of eight reflects the perception that Users are more likely to go into default and indeed are more risky than their costs of security would imply.

The matter of whether a new User is likely to default prior to commissioning is a matter of great subjectivity and indicators of this risk are not readily available. However a risk

assessment will have been made by any provider of securities to the user and as such National Grid believes that it is prudent to use this assessment as a proxy for the risk of default. Thus using an eight year period provides that balance and the eight year period is chosen as the basis for the User's security charge.

Another way of looking at this is:

If n is the number of years of security posted by the User, c is the cost of that security as a percentage and r is the risk of the User defaulting as a percentage, then:

$n * c = (16 - n) * r$

which rearranges to:

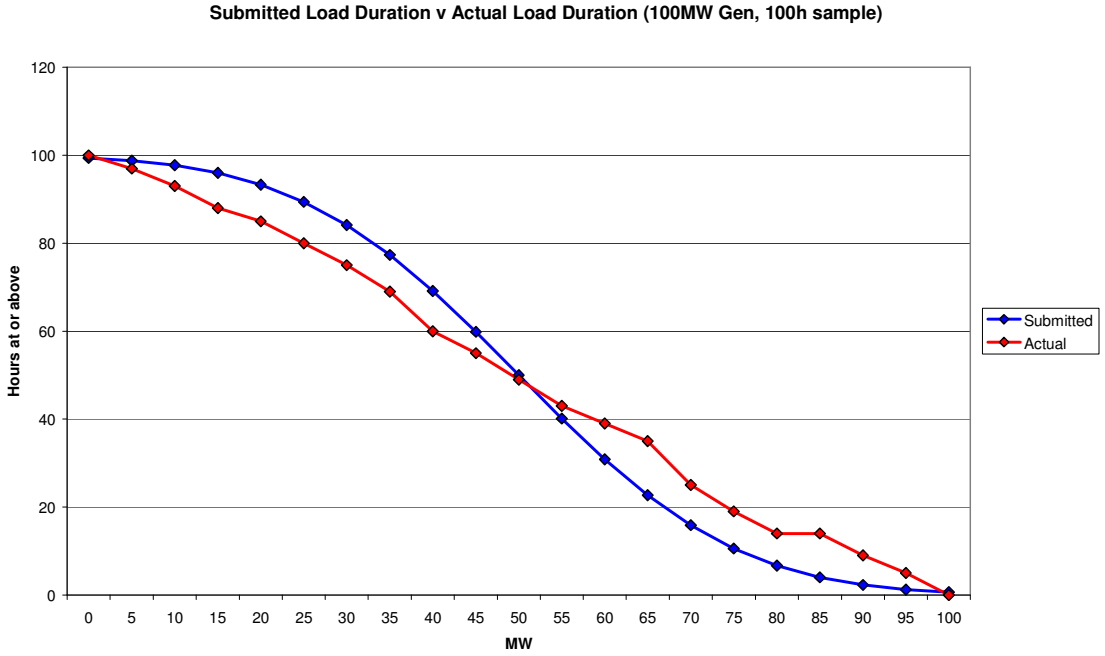
$n = (16 * r)/(r + c)$

Hence number of years depends on the balance between c and r. Assuming that they should be equal infers that n should equal 8 years.

Appendix B – Overrun Charging

The following example aims to demonstrate the overrun methodology for a sample 100MW Power Station over a 100 period season. The actual and Submitted Load Duration curves for the Power Station are as follows:

Figure B1:



It is clear from the above that the Power Station's actual load duration was in excess of that submitted as it ran at a slightly higher load factor than was indicated within its bids.

The proposal for the way in which the overrun volume will be calculated gives Users near real-time information regarding how they are being charged overrun, and is as follows:

Overrun Volume Calculation Methodology

A running tally of the hours a Power Station has operated at each point of its load duration curve is calculated. Provided that the output is within the load duration curve no action will be taken. However once the load duration curve is exceeded in a particular period an algorithm will perform the following steps:

1. Firstly it will examine the load profile in the current season to date to see if there are any unused hours of usage higher up the load duration curve – i.e. a Power station generating 82MW in a particular period may have used up all its hours of output between 80-85MW however it may yet have unused hours at 90-95MW. Therefore the 82MW would be counted against the 90-95MW range. The general rule will be to seek the lowest unused part of the load duration curve, therefore in the above example if there were unused hours in the 90-95MW part of the load duration curve and the 85-90MW part, then the period in which the 82MW was generated would be allocated to the 85-90MW section of the load duration curve.

2. Should there be no part of the load duration curve available in which a period's output maybe allocated, then an overrun volume will be calculated. Assuming that a 100MW generator has generated 82MW in a period and it has used up all of its submitted load duration profile above the 70-75MW range then it will

assume to have overrun by a level of 7MW in the period. The 82 MW is thus allocated to the 70-75MW range and also has a 7MW overrun charge allocated to it.

A more detailed example of this methodology for a 100MW generator generating according to the profile in Figure B1 can be seen in Table B1 below.

Table B1:

The following table shows the actual (randomly generated) period by period outputs of the generator. All periods are 1 hour long. Those highlighted in Red are those that were charged as overrun.

Period	Output	Bin	Overrun Volume	Period	Output	Bin	Overrun Volume
1	24.8	Bin 5	0	51	90.4	Overrun	5.4
2	56.7	Bin 12	0	52	65.4	Bin 14	0
3	73.7	Bin 15	0	53	70.4	Bin 15	0
4	94.6	Bin 19	0	54	94.9	Overrun	14.9
5	52.4	Bin 11	0	55	5.3	Bin 2	0
6	74.2	Bin 15	0	56	1.7	Bin 1	0
7	51.2	Bin 11	0	57	33.3	Bin 7	0
8	23.5	Bin 5	0	58	28.2	Bin 6	0
9	14.9	Bin 3	0	59	35.4	Bin 8	0
10	45.5	Bin 10	0	60	26.2	Bin 6	0
11	39.2	Bin 8	0	61	33	Bin 7	0
12	43.6	Bin 9	0	62	21.8	Bin 5	0
13	73.6	Bin 15	0	63	43.9	Bin 9	0
14	76.9	Bin 16	0	64	6.5	Bin 2	0
15	0.3	Bin 1	0	65	73.2	Bin 15	0
16	64.3	Bin 13	0	66	10.6	Bin 3	0
17	12.6	Bin 3	0	67	65.2	Bin 14	0
18	62.5	Bin 13	0	68	10	Bin 2	0
19	98	Bin 20	0	69	29.7	Bin 6	0
20	66.6	Bin 14	0	70	40.6	Bin 9	0
21	29.1	Bin 6	0	71	76.5	Bin 16	0
22	37.2	Bin 8	0	72	77.7	Overrun	7.7
23	20.1	Bin 5	0	73	12.4	Bin 3	0
24	55.4	Bin 12	0	74	0.4	Bin 1	0
25	47.7	Bin 10	0	75	15.5	Bin 4	0
26	36.9	Bin 8	0	76	87.3	Overrun	22.3
27	68	Bin 14	0	77	44.5	Bin 9	0
28	96.5	Overrun	6.5	78	65.5	Overrun	0.5
29	48.1	Bin 10	0	79	98	Overrun	33
30	66.9	Bin 14	0	80	56.5	Bin 12	0
31	65.1	Bin 14	0	81	66.1	Overrun	1.1
32	98.4	Overrun	8.4	82	85.5	Overrun	20.5
33	34.8	Bin 7	0	83	36.8	Bin 8	0
34	56.4	Bin 12	0	84	95.3	Overrun	30.3
35	46.3	Bin 10	0	85	78.7	Overrun	18.7
36	54.5	Bin 11	0	86	88.5	Overrun	28.5
37	51	Bin 11	0	87	65.2	Overrun	5.2
38	73.2	Bin 15	0	88	37.8	Bin 8	0
39	34	Bin 7	0	89	54.4	Bin 11	0
40	35	Bin 7	0	90	64.2	Overrun	4.2

Period	Output	Bin	Overrun Volume	Period	Output	Bin	Overrun Volume
41	45.9	Bin 10	0	91	66.2	Overrun	6.2
42	48.6	Bin 10	0	92	40.4	Bin 9	0
43	5.1	Bin 2	0	93	80	Overrun	25
44	11.2	Bin 3	0	94	16.7	Bin 4	0
45	27.6	Bin 6	0	95	30.3	Bin 7	0
46	89.4	Overrun	4.4	96	61.8	Overrun	6.8
47	38.5	Bin 8	0	97	86	Overrun	31
48	34.5	Bin 7	0	98	35	Bin 7	0
49	94.6	Overrun	9.6	99	17.2	Bin 4	0
50	23.1	Bin 5	0	100	52.6	Bin 11	0

Bin	Bin Range	Bin	Bin Range
Bin 1	0MW to 5MW	Bin 11	50MW to 55MW
Bin 2	5MW to 10MW	Bin 12	55MW to 60MW
Bin 3	10MW to 15MW	Bin 13	60MW to 65MW
Bin 4	15MW to 20MW	Bin 14	65MW to 70MW
Bin 5	20MW to 25MW	Bin 15	70MW to 75MW
Bin 6	25MW to 30MW	Bin 16	75MW to 80MW
Bin 7	30MW to 35MW	Bin 17	80MW to 85MW
Bin 8	35MW to 40MW	Bin 18	85MW to 90MW
Bin 9	40MW to 45MW	Bin 19	90MW to 95MW
Bin 10	45MW to 50MW	Bin 20	95MW to 100MW

The principle advantage of this methodology is that the prompt notification of overrun volumes means that in the periods where a generator is incurring significant overrun volumes (e.g. period 70 onwards in the above example) a generator could choose to restrict output if the overrun charges in those half hours are assessed as being more than they are willing to pay; alternatively the overrun charge in those periods could have been zero or close to zero meaning the generator could continue to overrun. Either way the generator will have a close to real time signal that it can respond to.

It is also proposed that for further flexibility Users can also nominate in advance which periods they wish to overrun – such periods would then not count against the running tally of actual running against load duration and the “season total” overrun volume calculation.