27th February 2007 - The following draft NTS Charging Methodology capacity charging section has been produced to seek to provide further clarity regarding Charging Methodology proposal GCM01. This document represents a draft of the text that would replace sections 2.2 & 2.3 in the prevailing methodology. In the event that the proposal is not vetoed

Derivation of NTS Capacity Charges

The NTS Capacity Charging Model comprises:

- **The Transport Model** that calculates the Long Run Marginal Costs (LRMCs) of transporting gas from each entry point (for the purposes of setting NTS Entry Capacity Prices) to a "reference node" and from the "reference node" to each relevant offtake point.
- **The Tariff Model** that adjusts the LRMCs to either maintain an equal split of revenue between Entry and Exit users (where prices are used to set auction reserve prices) or to recover a target level of revenue (where prices are set as administered rates).

Prices for each Gas Year are calculated using the relevant year's 1-in-20 peak base case supply and demand data and network model (e.g. if setting exit capacity prices for Gas Year 2006/7, the base case supply/demand forecast for 2006/7 and the base network model are used).

For determining Entry Capacity Prices, NTS Entry Capacity Baseline Reserve Prices are set by adjusting supply flows in the base case data to reflect the obligated flow at each NTS Entry Point.

The Transport Model

Model Input Data

The transport model calculates the marginal costs of investment in the transmission system that would be required as a consequence of an increase in demand or supply at each connection point or node on the transmission system, based on analysis of peak conditions on the transmission system. The measure of the investment costs is in terms of £/GWhkm, a concept used to calculate marginal costs, hence marginal changes in flow distances based on increases at entry and exit points are estimated initially in terms of increases or decreases in units of kilometres of the transmission system for a small energy injection to the system.

The transport model requires a set of inputs representative of peak 1-in-20 conditions on the transmission system:

- Nodal forecast 1-in-20 peak day supply and demand data (GWh)
    - DN and DC offtake demands
    - ASEP supplies
- Transmission pipelines between each node (km)
    - Existing pipelines
    - New pipelines expected to be operational at the beginning of the gas year under analysis
- Identification of a reference node

Model Inputs

The nodal supply data for the transport model will be derived from the supply/demand match set out in the Ten Year Statement. The supply figures at Storage and Interconnector entry points will be set at a level less than or equal to the expected entry point capability. The aggregate storage and Interconnector flows will be adjusted such that a supply and demand balance is achieved.

Nodal demand data for the transport model will be based on demand that DN Users have forecast to occur at the National 1-in-20 peak day demand level and the booked capacity for directly connected consumers.

National Transmission System network data for the charging year will be based on data taken from National Grid's most recent Ten Year Statement.

The use of the reference node enables the marginal costs to be considered as those supply costs generated from a notional change in flow *from* any node *to* the reference node. The costs generated from a notional change in flow from the reference node to any node are the negative of these supply costs.

It may be demonstrated that the choice of the reference node does not affect the final tariffs, after they have been adjusted to recover revenue (for exit charges) or to maintain a defined entry-exit split of revenue (for entry prices) i.e. it determines the magnitude of the marginal costs but not the relativity. For example, if the reference point were put in the North of Scotland, all nodal supply marginal costs would likely be negative. Conversely, if the reference point were defined at Land's End, all nodal supply marginal costs would most likely be positive. However, the relativity of costs between nodes would stay the same. For information, the reference node has been set at Peterborough.

The model calculates the marginal costs of investment by determining flow gradients (or shadow prices) at each node. This type of model does not require a parameter to be entered to determine the size of flow increment that should be injected to generate incremental costs of investment.

Model Outputs

The transport model is an optimisation model that calculates the minimum total network flow distance (in GWhkm) given a set of supply and demand flows i.e. it takes the inputs described above and uses a transport algorithm to derive the pattern of balanced network flows that minimises distances travelled by these flows from a supply node or to a demand node, assuming every network section has sufficient capacity.

The marginal cost values are expressed solely in km as they are flow gradients i.e. they represent the sensitivity of the total network flow distance value to a change in supply or demand at any node (Total Flow Distance ÷ Change in Nodal Flow implies units of GWhkm ÷ GWh = km).

The model computes a marginal cost for supply at each node (which may be positive or negative in relation to the reference node). The marginal cost for demand at each node is then the equal and opposite of the nodal marginal cost for supply. A negative marginal cost represents a marginal benefit or avoided cost at that point.

The Tariff Model

The Initial Nodal Marginal Distances

The key inputs to the Tariff Model are the marginal costs of supply and the marginal costs of demand calculated from the transport model. These are used to set the Initial Nodal marginal Distances (InitialNMkm):

$$InitialNMkm_{Si} = LRMC_{Si} \quad \text{and} \quad InitialNMkm_{Dj} = -LRMC_{Dj}$$

Where

$InitialNMkm_{Si}$	=	*Initial nodal marginal distance for supply i (km)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
$LRMC_{Si}$	=	*Long run marginal cost of flow to reference node from supply i (km)*
$LRMC_{Dji}$	=	*Long run marginal cost of flow to reference node from demand j (km)*

The Initial Nodal Marginal Distances are adjusted to either maintain an equal split of revenue between Entry and Exit users where prices are used to set auction reserve prices, or to recover a target level of revenue, where prices are set as administered rates. The adjustments made for entry and exit capacity charges are described in detail later in this document.

The adjusted marginal distances are converted into unit costs (£/GWh) by multiplying by the Expansion Constant. These unit costs can then be converted into daily tariffs by applying the anuitisation factor contained within the NTS Gas Transporter Licence.

The Expansion Constant

The expansion constant, expressed in £/GWhkm, represents the capital cost of the transmission infrastructure investment required to transport 1 GWh over 1 km. Its magnitude is derived from the projected cost of an 85bar pipeline and compression for a 100km NTS network section. The 100km distance was selected as this represents the typical compressor spacing on the NTS.

Calculated from first principles, the steps taken to derive the expansion constant are as follows:

a) National Grid NTS determines the projected £/GWhkm cost of expansion of 85bar gauge pressure pipelines and compression facilities, based on manufacturers' budgetary prices and historical costs inflated to present values.

b) An average expansion constant is calculated from the largest three pipeline diameter/compressor sections (network sections *n = 1, 2, and 3*). The selection of expansion constants calculated from these three network sections is based on recent and expected future projects on the transmission system. The pipe diameters used are:

D_1 = 900 mm

D_2 = 1050 mm

D_3 = 1200 mm

c) The maximum daily flow that can be facilitated through each of the three network sections is calculated. This is based on assumptions of an 85bar_g inlet pressure and a minimum outlet pressure of 38bar_g and is calculated from the Panhandle A pipe flow equation (a standard flow equation used within the gas industry).

$$Q_n = K_{flow} \times \left(\frac{T_{std}}{P_{std}}\right) \times D_n^{2.6182} \times \left(\frac{P_1^2 - P_{2,n}^2}{G^{0.8538} \times T_{av} \times L \times Z_{av}}\right)^{0.5394}$$

Where

Q_n	=	*Flow for network section n (mscmd)*
K_{flow}	=	*Constant (0.0045965)*
T_{std}	=	*Standard temperature (291.4°K)*
P_{std}	=	*Standard pressure (1.01325 bar_a)*
D_n	=	*Diameter for network section n (mm)*
P_1	=	*Pipe absolute inlet pressure (86.01325 bar_a ~ 85 bar_g)*
$P_{2,n}$	=	*Pipe absolute outlet pressure for network section n (bar_a)*
G	=	*Gas specific gravity (0.6)*
T_{av}	=	*Pipeline average temperature (285.4°K)*
L	=	*Pipe length (100 km)*
Z_{av}	=	*Average gas compressibility (0.85)*

d) The maximum daily energy flow is calculated from the volumetric flow using a standard planning CV of 39 MJ/m3 and the planning flow margin of 5%.

$$Capacity_n = \frac{Q_n \times CV}{((1 + FM) \times 3.6)}$$

Where

$Capacity_n$	=	*Daily capacity for network section n (GWh)*
Q_n	=	*Flow for network section n (mscmd)*
CV	=	*Calorific Value (39 MJ/m3)*
FM	=	*Flow margin (5%)*
3.6	=	*Converts 10^6 MJ to GWh*

e) The compressor power requirement to recompress back to 85 bar_g is calculated from the flow and the inlet and outlet pressures. The inlet pressure for the compressor is the outlet pressure of the pipe section for each pipe diameter D.

$$Power_n = \left(\frac{\gamma}{\gamma - 1}\right)\frac{K_{power} \times Z_{av} \times T_{av} \times Q_n}{\eta}\left[\left(\frac{P_{out}}{P_{in,n}}\right)^{\frac{\gamma-1}{\gamma}} - 1\right](1 + FM)$$

Where

$Power_n$	=	*Compressor power for network section n (MW)*
$P_{in,n}$	=	*Compressor absolute inlet pressure for network section n(bar_a)*
P_{out}	=	*Compressor absolute outlet pressure (86.10325 bar_a)*
K_{power}	=	*Constant (0.0040639)*
Z_{av}	=	*Compressibility (0.85)*
T_{av}	=	*Average gas temperature (285.4°K)*
Q_n	=	*Flow for network section n (mscmd)*
γ	=	*Isentropic index (1.363)*
η	=	*Compressor adiabatic efficiency (80%)*
FM	=	*Flow margin (5%)*

f) The capital cost of the pipe for each network section is calculated from the pipe cost equation, the pipe diameter and the pipe length of 100km.

$$Pipe\_Cost_n = L \times (D_n \times Pipecost\_diameter\_factor + Pipecost\_constant\_factor)$$

Where

$Pipe\_Cost_n$	=	*Capital cost for pipe in network section n (£m)*
L	=	*Length (100 km)*
D_n	=	*Diameter for network section n (mm)*
Pipecost_diameter_factor	=	*Capital cost factor (£m/km/mm)*
Pipecost_constant_factor	=	*Capital cost factor (£m/km)*

g) The capital cost of recompression from the minimum pressure up to 85barg is calculated from the compressor power requirements

$$Compressor\_Cost_n = Power_n \times Power\_Unit\_Cost$$

Where

$Compressor\_Cost_n$	=	*Capital cost for compression in network section n (£m)*

$Power_n$	=	*Compression power for network section n (MW)*
Power_Unit_Cost	=	*Unit cost for additional power at existing stations (£m/MW)*

h) An allowance for engineering and project planning costs is included at 15%. Project management costs are variable costs that are dependent upon many factors including location, timing, type and size of investment, however, size of investment is the main indicator of the scale of expected project management costs.

$$Project\_Cost_n = Project\_Factor * (Pipe\_Cost_n + Compressor\_Cost_n)$$

Where

$Project\_Cost_n$	=	*Project costs for network section n (£m)*
Project_Factor	=	*15%*
$Pipe\_Cost_n$	=	*Capital cost for pipe in network section n (£m)*
$Compressor\_Cost_n$	=	*Capital cost for compression in network section n (£m)*

i) The total cost is the pipe cost plus the compressor cost plus the project costs (£)

$$Total\_Cost_n = Pipe\_Cost_n + Compressor\_Cost_n + Project\_Cost_n$$

Where

$Total\_Cost_n$	=	*Total cost for network section n (£m)*
$Pipe\_Cost_n$	=	*Capital cost for pipe in network section n (£m)*
$Compressor\_Cost_n$	=	*Capital cost for compression in network section n (£m)*

j) The unit cost is the total cost divided by the maximum energy flow (£m/GWh)

$$Unit\_Cost_n = Total\_Cost_n / Capacity_n$$

Where

$Unit\_Cost_n$	=	*Total unit cost for network section n (£m/GWh)*
$Total\_Cost_n$	=	*Total cost for network section n (£m)*
$Capacity_n$	=	*Daily capacity for network section n (GWh)*

k) The expansion constant is calculated by dividing the unit cost by the pipe section length of 100km (£/GWhkm). The expansion constant for each pipe diameter section is dependent on the minimum pressure. A higher pressure will reduce the compressor power requirement and hence will reduce the compression cost but will also reduce the maximum pipe flow. An optimum minimum pressure is calculated for each pipe diameter such that the pipe diameter specific expansion constants are minimised.

$$Specific\_Expansion\_Constant_n = 10^6 \times Unit\_Cost_n / L$$

Where

$Specific\_Expansion\_Constant_n$	=	*Expansion constant for network section n (£/GWhkm)*
L	=	*Length (100 km)*
10^6	=	*Conversion factor from £m to £*
$Unit\_Cost_n$	=	*Total unit cost for network section n (£/GWh)*

l) The final expansion constant is a simple average of the individual pipeline expansion constants

$$EC = \frac{\sum_{n=1}^{3} Specific\_Expansion\_Constant_n}{3}$$

Where

EC	=	*Expansion constant (£/GWhkm)*
$Specific\_Expansion\_Constant_n$	=	*Expansion constant for network section n (£/GWhkm)*

The Tariff Model for Determination of NTS Exit Capacity Charges

NTS Exit Capacity Charges are administered rates designed to recover 50% allowed TO revenue when they are applied to the firm and interruptible exit capacity levels (with the remaining 50% TO allowed revenue being recovered through Entry charges). The process for calculating NTS Exit Capacity Charges is described below.

Supply/Demand Scenario and Network Model

Prices for each Gas Year are calculated using the relevant year's 1-in-20 peak base case supply and demand data and network model (e.g. if setting exit capacity prices for Gas Year 2006/7, the base case supply/demand forecast for 2006/7 and the base network model are used).

Revenue Recovery Adjustment

The total revenue to be recovered through Exit Capacity Charges is determined each year with reference to the Transmission Licensee's Price Control formulae. Hence in any given year t, a target revenue figure for Firm Exit Capacity Charges ($TOExRF_t$) is set after adjusting for any under or over recovery. For further information, please refer to Special Condition C8B of National Grid's Gas Transporter Licence in respect of the NTS.

A single additive constant Revenue Adjustment Factor (RAF) is calculated using Microsoft Excel Solver which, when added to the Initial Nodal Marginal Distance at each demand, gives a revised marginal distance for each demand, such that the total revenue to be recovered from exit charges equals the target revenue. The calculation simultaneously removes the negative marginal distances by collaring the revenue to that level implied by the minimum price of 0.0001 p/kWh.

$$\sum_{Dj=1}^{n_D}\left(ExitRev_{t,Dj}\right) = TOExRF_t$$

$$ExitRev_{t,Dj} = Max\left[\frac{(0.0001/100)\times ExitCap_{Dj}\times 365}{10^6}, \left(InitialNMkm_{Dj} + RAF\right)\times ExitCap_{Dj}\times AnF\times EC\right]$$

Where

$ExitRev_{t,Dj}$	=	*Exit capacity revenue from demand j (£m/year)*
$TOExRF_t$	=	*TO Exit firm allowed revenue for year t (£m)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
RAF	=	*Revenue adjustment factor (km)*
$ExitCap_{Dj}$	=	*Nodal forecast daily exit capacity for demand j (GWh)*
AnF	=	*Licence anuitisation factor (-)*
EC	=	*Expansion constant (£/GWhkm)*
0.0001	=	*Minimum price (p/kWh)*
365	=	*Conversion factor from per day to per year*
100	=	*Conversion factor from p to £*

10^6	=	*Conversion factor from £ to £m*

Nodal Exit Capacity Charges

The capital costs (£/GWh) are annuitised (using the anuitisation factor specified in National Grid's NTS Licence), which means that the cost is spread evenly over the expected life of the asset taking into account the required rate of return. The final step converts the result from £/GWh/year to p/kWh/day by dividing by 365 and multiplying by 100. Capital costs in £m/mscmd for each entry point are converted into costs in £/GWh using terminal specific calorific values.

$$ExitPrice_{Dj} = Max\left[0.0001, \left(\frac{\left(InitialNMkm_{Dj} + RAF\right) \times AnF \times EC \times 100}{10^6 \times 365}\right)_{4dp}\right]$$

Where

$ExitPrice_{Dj}$	=	*Exit price at demand j (p/kWh/day)*
$InitialNMkm_{Dj}$	=	*Initial nodal marginal distance for demand j (km)*
RAF	=	*Revenue adjustment factor (km)*
AnF	=	*Licence anuitisation factor (-)*
EC	=	*Expansion constant (£/GWhkm)*
100	=	*Conversion factor from £ to pence*
10^6	=	*Conversion factor from GWh to kWh*
365	=	*Conversion factor from annual to daily price*
4dp	=	*Rounding to 4 decimal places of precision*

Zonal Exit Capacity Charges

The nodal exit capacity prices are amalgamated into exit zones by weighting them by their relevant exit capacity. The zonal exit capacity price for each zone is calculated as:

$$ZonalExitPrice_k = \left(\frac{\sum_{Dj=1}^{n_k}\left(ExitPrice_{Dj,k} \times ExitCap_{Dj,k}\right)}{\sum_{Dj=1}^{n_k} ExitCap_{Dj,k}}\right)_{4dp}$$

Where

k	=	*Exit zone k*
Dj	=	*Demand j*
n_k	=	*Number of demands in zone k*
$ExitPrice_{Dj,k}$	=	*Nodal Exit price for demand j in zone k (p/ kWh/day)*
$ZonalExitPrice_{k}$	=	*Zonal Exit price for zone k (p/ kWh/day)*
$ExitCap_{Dj}$	=	*Nodal forecast daily exit capacity for demand j (GWh)*
4dp	=	*Rounding to 4 decimal places of precision*

The criteria used to determine the definition of the exit zones is based on DN analysis to identify the offtakes that supply a consistent subset of DN consumers.

The Tariff Model for Determination of NTS Entry Capacity Charges

NTS Entry Capacity Baseline Reserve Prices represent purely locational prices derived from the transport model to reflect the costs of capital investment in, and the maintenance and operation of, a transmission system to provide bulk transportation of gas from the different entry locations. The issue of residual revenue recovery is addressed via the application of the TO commodity charge.

Supply/Demand Scenario

Prices for each Gas Year are set on the basis of the relevant year's 1-in-20 peak base case supply and demand data and network model, but with adjustments to the supply flows to reflect the capacity level in question. Demand flows remain unadjusted.

NTS Entry Capacity Baseline Reserve Prices are set by adjusting supply flows in the base case data to reflect the obligated baseline capacity level at each NTS Entry Point.

Where an entry point has a zero obligated baseline capacity level (as defined in National Grid's NTS Licence), but where permanent obligated capacity has been sold at the entry point in previous auctions, the level of permanent obligated capacity released within the Gas Year in question is used as the obligated capacity level.

Where an entry point has a zero obligated baseline capacity level (as defined in National Grid's NTS Licence), but where permanent obligated capacity has been sold at the entry point in previous auctions, the level of permanent obligated capacity released within the Gas Year in question is used as the obligated capacity level.

To determine the entry price at the obligated baseline capacity level offered at an entry point, the supply scenario is adjusted for each entry point as follows:

- The supply flow is adjusted to the capacity level to be provided for the entry point in question
- All other supply flows are adjusted up or down in order of merit to balance the network back to the peak 1 in 20 demand level in the base case data

Each entry point will be analysed in this way in turn e.g. for 20 entry points, a maximum of 20 sets of analysis will be required.

Supply Merit Order

The supply merit order for each NTS Entry Point reflects the least beneficial alternate supply flow, in terms of enabling capacity provision at that entry point.

The supply merit order is determined by use of the Transport Model with the base case scenario to calculate pipeline distances from each NTS Entry Point to every other entry point.

For NTS Entry Points where flow needs to be added to the base case flow to align with the required capacity level, the remaining entry point flows are reduced in order of pipeline distance merit, starting with the furthest entry point ending with the entry point with the nearest entry point.

For NTS Entry Points where flow needs to be reduced from the base case flow to align with the required capacity level, the remaining entry point flows are increased in order of pipeline distance merit, starting with the nearest entry point and ending with the furthest entry point.

Network Model

The appropriate network model for each period of capacity allocation is used i.e. the network model that includes sanctioned projects expected to be completed by the start of the Gas Year that is being modelled. All adopted connections that are fully depreciated are included at zero length.

Entry-Exit Price Adjustment

The first step of the Tariff Model is to adjust the Initial Nodal Marginal Distances (InitialNMkm) such that the predefined 50:50 split between entry and exit is obtained and so that the negative marginal distances are removed.

An additive constant Adjustment Factor (AF) must be calculated which, when added to each Initial Nodal Marginal Distance, gives a revised marginal distance for each supply (NTS ASEP) and for each demand (NTS offtake). The calculation simultaneously removes the negative marginal distances by collaring the Initial Nodal Marginal Distances at zero.

The Adjustment Factor is calculated such that the average marginal distances (flow distances) for supply and demand are equal.

$$\sum_{Si=1}^{n_S}\left(\frac{Max\left[0, InitialNMkm_{Si}+AF\right]}{n_S}\right)=\sum_{Dj=1}^{n_D}\left(\frac{Max\left[0, InitialNMkm_{Dj}-AF\right]}{n_D}\right)$$

The Nodal Marginal Distance (NMkm) for each supply is then the Initial Nodal Marginal Distance plus the Adjustment Factor. The Nodal Marginal Distance for each demand is then the Initial Nodal Marginal Distance minus the Adjustment Factor.

$$NMkm_{x,Si}=InitalNMkm_{x,Si}+AF \quad \text{and} \quad NMkm_{x,Dj}=InitialNMkm_{x,Dj}-AF$$

Where

$InitialNMkm_{x,Si}$	=	*Initial nodal marginal distance for supply i for price step x (km)*
$InitialNMkm_{x,Dj}$	=	*Initial nodal marginal distance for demand j for price step x (km)*
AF	=	*Adjustment factor (km)*
$NMkm_{Si}$	=	*Nodal marginal distance for supply i (km)*
$NMkm_{Dj}$	=	*Nodal marginal distance for demand j (km)*
n_S	=	*Number of supply charging points (-)*
n_D	=	*Number of demand charging points (-)*

Entry Capacity Reserve Prices

The Nodal Marginal Distances are converted to capital costs by multiplying by the Expansion Constant, and annuitised using the anuitisation factor specified in National Grid's NTS Licence (which means that the cost is spread evenly over the expected life of the asset taking into account the required rate of return). The final step converts the result from £/GWh/year to p/kWh/day by dividing by 365 and multiplying by 100. Prices are adjusted to recognise the different calorific values of gas entering the system using ASEP specific calorific values.

The reserve price will be calculated such that it is collared at a minimum value of 0.0001 p/kWh/day.

$$Entry\,Price_{Si} = Max\left[0.0001, \left(\frac{NMkm_{0,Si} \times AnF \times EC \times 100}{10^6 \times 365} \times \frac{39}{CV_{Si}}\right)_{4dp}\right]$$

Where

$EntryPrice_{Si}$	=	*Entry Reserve Price for supply i (p/kWh/day)*
$NMkm_{Si}$	=	*Nodal marginal distance for supply i (km)*
AnF	=	*Licence anuitisation factor (-)*
EC	=	*Expansion constant (£/GWhkm)*
10^6	=	*Conversion factor from GWh to kWh*
100	=	*Conversion factor from £ to pence*
365	=	*Conversion factor from annual to daily price*
39	=	*Standard calorific value (MJ/m^3)*
CV_i	=	*Calorific value for supply i (MJ/m^3)*
4dp	=	*Rounding to 4 decimal places of precision*

Application of Entry Prices

The relevant baseline capacity reserve price for each Gas Year is used to set prices in auctions:

- For RMSEC and DSEC Baseline Reserve Prices, published in respect of a Gas Year (Gas Year Y), this means the network model including all projects expected to be completed for the start of the Gas Year.
- For MSEC Baseline Reserve Prices, published in respect of capacity allocation across three Gas Years (Gas Years Y, Y+1, Y+2), this means the network models including all projects expected to be completed for the start of each of these Gas Years.
- For QSEC Baseline Reserve Prices, published in respect of future Gas Years (Gas Years Y+2, Y+3 to Y+16), this means the network model including all projects expected to be completed for the start of Gas Year Y+2.

Table 1 summarises the use of network and supply/demand year models for calculation of NTS Entry Capacity Baseline Reserve Prices applicable from 1 October in calendar Year N (corresponding to Gas Year Y) in chronological order of auction dates and capacity release.

Table 1: Gas Years Modelled and Capacity Allocation Periods

Auction	Date Held	Gas Day - Capacity Allocation		Gas Year Modelled
		From	To	
QSEC	September [N]	1 Apr [N+2]	30 Sep [N+2]	Y+2
		1 Oct [N+2]	30 Sep [N+16]	Y+2
		1 Oct [N+16]	31 Mar [N+17]	Y+2
RMSEC	Sep [N] to Aug [N+1]	1 Oct [N]	30 Sep [N+1]	Y
DSEC (Day Ahead)	30 Sep [N] to 29 Sep [N+1]	1 Oct [N]	30 Sep [N]	Y
DSEC (Within Day)	1 Oct [N] to 30 Sep [N+1]	1 Oct [N]	30 Sep [N]	Y
MSEC	February [N+1]	1 Apr [N+1]	30 Sep [N+1]	Y
		1 Oct [N+1]	30 Sep [N+2]	Y+1
		1 Oct [N+2]	31 Mar [N+3]	Y+2

New Entry Points

For new NTS Entry Points, where no permanent obligated entry capacity has been sold i.e. where an entry point does not have an obligated baseline entry capacity level (defined by National Grid's NTS Licence), the entry capacity baseline reserve price is set at zero.

Where permanent obligated capacity has been sold at an NTS Entry Point in previous auctions, it is treated consistently with those entry points that have a Licence-defined obligated baseline capacity level (see above).