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The Statement of the Gas Transmission Transportation Charging Methodology

Effective from 1 October 2007

nationalgrid

Document Revision History

Version/ Revision Number	Date of Issue	Notes
1.0	April 2007	
2.0	October 2007	Updated for GCM01. Updated for new Licence. Minor descriptive and formatting changes.

About this Document

This document describes the methodology that National Grid Gas NTS ("National Grid") employs to levy charges for use of the Gas Transmission System in Great Britain. This document is one of a suite of documents that describe the charges levied by National Grid and the methodologies behind them. The other documents that are available are:

- **Statement of Gas Transmission Transportation Charges**
- **Incremental Entry Capacity Release Methodology Statement**
- **Metering Charging Statement**
- **Connection Charging Statement**

These are available on our Charging website at:

http://www.nationalgrid.com/uk/Gas/Charges/statements/

This statement is effective from 1 October 2007.

This document has been published by National Grid in accordance with Standard Special Conditions A4 and A5 of its Gas Licence in respect of the NTS and is approved by the Gas and Electricity Markets Authority (the Authority).

If you require further details about any of the information contained within this document or have comments on how this document might be improved please contact our UK Transmission Charging team on **01926 656022 or 01926 656317.**

Or at:

National Grid House
UKT Commercial
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA

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GENERAL INTRODUCTION

Background

National Grid is the owner and the operator of the gas National Transmission System (NTS) in Great Britain.

The NTS is a network of pipelines, presently operated at pressures of up to 85 bar, which transports gas safely and efficiently from coastal terminals and storage facilities to exit points from the system. Exit points are predominantly connections to Distribution Networks (DNs) and large consumers but also include storage sites, and direct connections to other systems, such as interconnectors to other countries.

These operations are carried out to meet the needs of the companies that supply gas to domestic (located within DNs), commercial and industrial consumers and to power stations. In 2006/07 1,042 TWh of gas was transported to these consumers.

This publication sets out the transportation charging methodology that applies for the use of the NTS pipeline network from 1 October 2007. NTS transportation charges can be found in the "Notice of Gas Transmission Transportation Charges".

Details of National Grid and its activities can be found on its internet site at www.nationalgrid.com . An electronic version of this publication, along with the "**Notice of Gas Transmission Transportation Charges**" can be found at the following web address:
http://www.nationalgrid.com/uk/Gas/Charges/statements/site:

National Grid's Licence Objectives

Standard Special Condition A4 of National Grid's Gas Transporter Licence in respect of the NTS (the "Licence") requires National Grid to establish a methodology showing the methods and principles on which transportation charges are based. National Grid's present charging methodology was introduced in 1994 and has been modified from time to time in accordance with Standard Special Condition A5 of the Licence. This document does not override or vary any of the statutory, Licence or UNC (Uniform Network Code) obligations upon National Grid.

National Grid's Licence Obligations relevant to the Charging Methodology

The transportation charging methodology has to comply with objectives set out in the Licence under Standard Special Condition A5. These are to:

- reflect the costs incurred by National Grid where charges are not determined by auctions; and, subject to this principal consideration;
- facilitate competition between gas shippers and between gas suppliers; and
- take account of developments in the transportation business;

- where prices are established by auction and where reserve prices are applied that these are set at a level best calculated:
  i) to promote efficiency and avoid undue preference in the supply of transportation services; and
  ii) to promote competition between gas suppliers and between gas shippers.

In addition to these Licence objectives National Grid needs to comply with EC Regulation 1775/2005 on conditions for access to the natural gas transmission networks (binding from 1 July 2006). A summary of the principles for network access tariffs or the methodologies used to calculate them follows. The principles or methodologies shall:

- Be transparent
- Take into account the need for system integrity and its improvement
- Reflect actual costs incurred for an efficient and structurally comparable network operator
- Be applied in a non-discriminatory manner
- Facilitate efficient gas trade and competition
- Avoid cross-subsidies between network users
- Provide incentives for investment and maintaining or creating interoperability for transmission networks
- Not restrict market liquidity
- Not distort trade across borders of different transmission systems.

Before National Grid makes any changes to the methodology, it consults with the industry in accordance with Standard Special Condition A5 of the Licence. Ofgem has the right to veto any proposed changes to the methodology.

CHAPTER 1: PRINCIPLES

1.1 Price Control Formulae

With effect from 1 April 2002 the transportation price control has treated the NTS Transportation Owner (TO) and the NTS System Operator (SO) separately. The separate price controls and incentives determine the maximum revenue that National Grid may derive from each in a formula year, 1 April to 31 March.

The Maximum Allowed Revenue under the transportation controls and incentives is determined by a number of factors including:

- the volume of NTS entry and exit capacity made available;
- National Grid's performance under the various SO incentive schemes, covering a range of activities;
- the indexation factor - under the TO formula allowed revenue is adjusted each year by a factor equal to the rate of inflation, measured on a prescribed historical basis by reference to the Retail Price Index (RPI); and
- any under- or over-recovery brought forward under each control from the previous formula year (expressed by means of a separate "K" factor within each control).

The "K" correction factors are necessary because the level of charges set under each control depends on forecasts of some of the above elements together with a view on target auction revenues[1]. Outturn will inevitably differ from forecast, thus giving rise to variances between the amount of revenue generated (on an accruals basis) and that allowed under each control. The K factors enable correction for these variances by adjusting either upwards or downwards the maximum level of revenue allowed in the following formula year (taking interest into account).

During earlier price control periods, charges were normally revised on 1 October and only changed at other times when necessary, for example to avoid significant over-recovery following auctions of entry capacity. Under the new price control regime effective from 1 April 2007, charges will ordinarily be revised on 1 April and 1 October, and only adjusted at other times of the year in exceptional circumstances and with the agreement of the Authority to ensure compliance with the Licence.

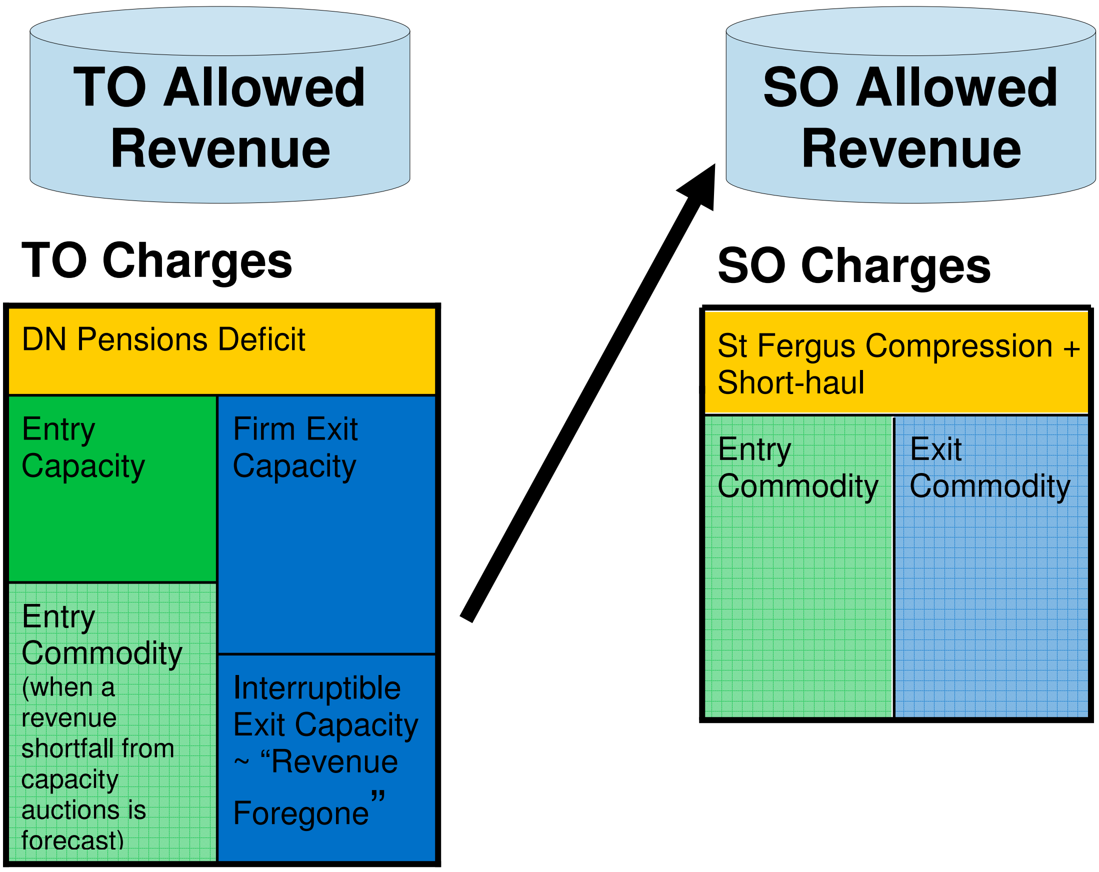
1.2 Structure of NTS Transportation Charges

The structure of National Grid's transportation charges reflects the revised price control arrangements that came into effect from 1 April 2007. Charges are set separately for those activities related to the Transportation Owner (TO) and to the System Operator (SO).

[1] Auctions presently relate only to NTS entry capacity revenues, for which mechanisms exist whereby a proportion of any forecast <u>excess</u> auction revenue may be returned to shippers within the formula year by the use of the entry buy-back offset mechanism or any <u>under recovery</u> of auction revenue charged to shippers through a TO commodity charge levied on entry flows.

The maximum revenue to be collected from the NTS TO and NTS SO charges is determined by the TO and SO price controls, as described in Section 1.1 above. The NTS TO allowed revenue is collected by entry and exit capacity charges, with a TO commodity charge levied on entry flows where entry auction revenue is forecast to be under recovered. The NTS SO allowed revenue is collected largely by means of a commodity charge levied on entry and exit flows. The levels of NTS capacity and commodity revenue are therefore now determined by the separate TO and SO price controls and not, as prior to April 2002, by a 65:35 capacity: commodity ratio. Figure 1 below shows the relationship between the TO and SO allowed revenue and NTS charges.

Figure 1 NTS charges to collect TO and SO revenue



Of the NTS TO target revenue, 50% is assumed to be derived from non incremental obligated entry capacity sales, determined through auctions subject to reserve prices. Exit capacity charges are applied on an administered peak day basis, and are set so as to recover the other 50% of the TO target revenue level when they are applied to the Baseline firm and interruptible exit capacity levels. Both auction reserve prices and exit charges reflect National Grid' long run marginal cost (LRMC) methodology. The unpredictability of revenue from auctions means that the target 50:50 entry exit split may not be achieved in practice. A TO commodity charge may be levied on entry flows where entry capacity auction revenue is forecast to be below the entry target level.

Commodity charges are payable on gas allocated. Capacity charges are payable when a right to flow gas is purchased, with payment due irrespective of whether or not the right is exercised. However, although the obligation to pay for capacity remains with the primary purchaser, all types of entry capacity can be traded between Shippers, such as Monthly System Entry Capacity (MSEC).

Having established by the above methods the target revenue to be derived from each main category of charge, the next stage is to set the charges within each of these charge categories. The methodologies used to do this are described in the appropriate sections below.

CHAPTER 2: CAPACITY CHARGES

NTS capacity charges consist of charges for exit, entry and credits payable for constrained LNG.

Following the approval of GCM01 in April 2007 the NTS Transportation Model has replaced Transcost in deriving the NTS capacity charges. The details of the Transport model and the Tariff Model which make up the charging model are available in section 2.5 below.

2.1 System Exit Firm Capacity

The terms on which exit firm capacity is sold are set out in the UNC; Section B. Charges reflect the estimated long run marginal cost (LRMC) of reinforcing the system to transport additional gas between entry and exit points. The calculations are described in more detail below. At present, exit charges are applied only in respect of firm loads.

2.2 System Exit Interruptible Capacity

In accordance the UNC, NTS Interruptible Supply Points avoid the NTS (TO) Exit Capacity charge and are eligible for transportation credits where the number of days interruption for any Gas Year exceeds 15. The business rules for these arrangements are set out in Appendix 1.

2.3 System Entry Capacity

System Entry Capacity is presently[2] allocated by means of five related auction mechanisms.

- Quarterly (firm) System Entry Capacity (QSEC)
- Monthly (firm) System Entry Capacity (MSEC)
- Rolling Monthly (firm) System Entry Capacity (RMSEC)
- Daily (firm) System Entry Capacity (DSEC)
- Daily Interruptible System Entry Capacity (DISEC)

The reserve prices applicable to each type of auction are set out in section 2.3.1 below. Under its NTS SO incentive schemes, National Grid is obliged to make available for sale in the Entry Capacity "Long Term" auctions, Quarterly System Entry Capacity (QSEC) calculated in accordance with Special Condition C8D Part C Paragraph 9 of National Grid's GT Licence. QSEC can be obtained in respect of each of Capacity Year + 2 to Capacity Year + 16 inclusive (where 'Capacity Year + n' is a reference to the Capacity Year commencing on the n^{th} anniversary of the first day of the Capacity Year in which the applications are invited to be made). The methodology for determination of the obligated capacity price and incremental price

[2] In addition a trade and transfer auction will be held for the months of November 07 to March 08.

steps is set out in National Grid's Incremental Entry Capacity Release (IECR) methodology statement.

MSEC is allocated by auction for a period no more than two years ahead of the period of use and is also calculated in accordance with Special Condition C8D Part C Paragraph 9 of National Grid's GT Licence. National Grid is obliged to make available for sale in the MSEC auctions capacity at the level of the NTS initial baseline entry capacity level, as set out in the NTS Gas Transporter Licence, plus any funded obligated incremental entry capacity previously released less any NTS initial baseline entry capacity already sold in previous auctions[3]. Any remaining capacity for the succeeding month that has not been sold in the MSEC allocations is offered for sale in a series of Rolling Monthly System Entry Capacity (RMSEC) auctions. The MSEC and RMSEC allocation is on a pay as bid basis.

Any unsold remaining capacity, will be offered for sale ahead of the gas day and during the gas day as DSEC. Bids for DSEC can be made from seven days before the gas day. Also on the day before the gas day, National Grid will establish, on the basis of a rolling 30 day average, the difference between firm capacity held by shippers and their actual nominations (i.e. any unutilised booked firm capacity) at each ASEP. This volume is then made available in the single DISEC auction held on the day before the gas day. National Grid retains a right to scale back previously released interruptible capacity for the purposes of system management and to release discretionary interruptible capacity.

Above baseline (which can include obligated and non obligated) capacity can be released by National Grid in accordance with its entry capacity investment incentive or entry capacity buy back incentive as set out in its GT Licence. QSEC is the vehicle for releasing additional capacity in accordance with the Incremental Entry Capacity Release (IECR) statement.

A situation may arise, on any day, in which National Grid is unable to meet all of its entry capacity obligations. In this case it may buy-back sold entry capacity rights through a tender mechanism, tenders being accepted in ascending price order until the required level of buy-back has been achieved.

[3] For the first 18 months auctioned, 100% of initial baseline and for the last 6 months auctioned, 90% of the initial baseline.

Figure 2.3 below shows schematically how system entry capacity might actually be allocated on a day.

Figure 2.3 System Entry Capacity Auctions

QSEC Capacity available = 90%(Initial Baseline entry capacity) plus any unsold incremental	
QSEC Sold	QSEC Unsold

MSEC Capacity available = (Initial[4] Baseline entry capacity plus incremental – QSEC sold)	
MSEC Sold	MSEC Unsold

RMSEC Capacity available = (Initial Baseline entry capacity + incremental – QSEC sold – MSEC sold[5])	
MSEC Sold	MSEC Unsold

Daily System Entry Capacity		
MSEC Nominations	DISEC	DSEC

2.3.1: Reserve Prices in System Entry Capacity Auctions

System entry capacity is allocated by means of auctions as described in the UNC and outlined in Section 2.3 above. This approach includes various reserve prices below which bids will not be accepted.

QSEC reserve prices for obligated entry capacity are calculated each year through using the NTS Transportation Model as described in 2.5 below. QSEC step prices for release of additional (incremental) capacity are calculated with reference to the applicable reserve price and in accordance with the methodology for the determination of incremental step prices as set out in National Grid's Incremental Entry Capacity Release (IECR) methodology statement.

MSEC reserve prices are equal to the baseline price for capacity offered in the auction of QSEC capacity.

Floor prices are calculated by applying the following discounts to the baseline prices for capacity offered in the auction of QSEC capacity:

- Monthly System Entry Capacity (MSEC) and Rolling MSEC (RMSEC); 0%
- Daily System Entry Capacity (DSEC); 33.3%

Note that from October 2003 the discount for DSEC sold on the day has been 100%. The discount for DSEC sold ahead of the day remains at 33.3%.

- Daily Interruptible System Entry Capacity (DISEC); 100%

[4] For the first 18 months auctioned, 100% of initial baseline and for the last 6 months auctioned, 90% of the initial baseline.

[5] RMSEC capacity available is also adjusted to incorporate the Transfer and Trade of System Entry Capacity (TTSEC) for the months of Nov 07 to Mar08 inclusive

2.3.2: Entry Capacity Buy-Back Mechanism

Following an assessment of entry capacity auction revenue for any forthcoming financial year, if auction implied revenue for that year is anticipated to be more than 10% above the target TO allowable revenue, the level of this excess revenue is divided into monthly amounts and is used to offset the costs of entry capacity buy-back that would otherwise be borne by shippers through the capacity neutrality mechanism,. This is achieved by way of a credit in their entry capacity charges for each month (by the lower of the monthly excess and monthly buy-back cost). Any excess amount (of over-recovery) remaining for any month is carried forward to the next month. This methodology was implemented in October 2001 following approval of PC65.

2.4 Constrained LNG (CLNG)

Shippers booking the constrained LNG storage service agree to ensure the continuing availability of transmission support gas throughout the winter period on behalf of National Grid. During 2007/08 the storage sites providing these services are Avonmouth, Dynevor Arms and Isle of Grain. All constrained LNG sites provide a transmission benefit that is effectively in lieu of further investment on the pipeline system. It is therefore appropriate that a credit is offered to reflect the benefit obtained. The credit is based upon the exit capacity charge of the exit zone or zones supported by the CLNG site and the volume of deliverability required.

Full details of associated rules are available on request from National Grid's LNG Storage business unit.

2.5 Derivation of NTS Capacity Charges

The NTS Transportation 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 entry prices are used to set auction reserve prices) or to recover a target level of revenue (where exit 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 2007/8, the base case supply/demand forecast for 2007/8 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.

2.5.1: 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)
    - Distribution Network (DN) and Direct Connection (DC) offtake demands
    - Aggregate System Entry Point (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 data set out in the most recent Ten Year Statement for each year for which prices are being set. The aggregate storage and Interconnector flows will be adjusted such that a supply and demand balance is achieved. This initial supply and demand match is achieved by reducing supplies in a merit order to match the forecast demand. Supplies are reduced, until a match is achieved, using the following sequence; short range storage facilities (LNG), mid range storage facilities, long range storage facilities, Interconnectors, LNG Importation Facilities, and Beach Terminals. The supply figures at Storage and Interconnector entry points therefore may be set at a level less than or equal to the expected entry point capability.

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 represent 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. the relativity of the marginal costs is maintained. 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
Sum of flow times distance (GWh x km) divided by Change in Nodal flow (GWh) equals marginal cost (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.

2.5.2: 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 at 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 (see below). These unit costs can then be converted into daily prices by applying the annuitisation factor contained within the Licence. For entry prices, an adjustment to reflect the calorific value at the ASEP is also applied.

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 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 D_1, D_2, D_3 (network sections $n = 1, 2, \text{and } 3$). 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 greater than or = 38 bar_g)*
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 $85bar_g$ 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.

$$Specific\_Expansion\_Constant_n = 10^6 \text{ x } Unit\_Cost_n/L$$

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)*

2.5.3: 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 (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 2007/8, the base case supply/demand forecast for 2007/8 and the base network model for 2007/8 are used).

Revenue Recovery Adjustment

The total revenue to be recovered through Exit Capacity Charges is determined each year with reference to the Price Control formulae stated in the Licence. Hence in any given year t, a target revenue figure for Firm Exit Capacity Charges ($TOExRF_t$) is set. An adjustment is made to compensate for any under or over recovery from the previous year. For further information, please refer to Special Condition C8B and C8E of the Licence.

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 annuitisation 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 annuitisation factor specified in the 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 , multiplying by 100 and dividing by 10^6. 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 annuitisation 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.

2.5.4: 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. (i.e. the obligated entry capacity level when setting the obligated entry reserve price) Demand flows remain unadjusted.

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

To determine the entry reserve price at the obligated entry 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 25 entry points, a maximum of 25 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 annuitisation factor specified in the 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, multiplying by 100 and dividing by 10^6. 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 annuitisation 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_{Si}	=	*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 the 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).

CHAPTER 3: COMMODITY CHARGES

3.1 NTS TO Commodity Charge

This is a charge per unit of gas allocated to shippers at entry terminals but not storage facilities. The charge is levied where National Grid forecasts that the entry capacity auction revenue will be below the target revenue.

The charge will be set to zero where entry capacity auction revenue is at, or above, the entry capacity target level. National Grid will assess its forecast entry capacity auction revenue following the AMSEC auction and, if necessary, determine a 12 month schedule of TO commodity charges to apply from the following October. National Grid would only depart from this schedule under exceptional circumstances.

3.2 NTS SO Commodity Charge

This is a charge per unit of gas transported by the NTS and is applied uniformly on both entry and exit flows at all NTS system points. The target revenue to be raised by the charge is the NTS SO allowed revenue, including any incentive additions or deductions, less any revenue to be obtained from the St. Fergus compression charge and the Optional NTS commodity tariff.

At present, National Grid does not levy the charge on gas flows at NTS Storage facilities, however, an amount of gas is utilised as part of the operation of any NTS Storage facility, known as storage “own use” gas. This is effectively the difference between the quantity that is injected into storage and the quantity that is available for withdrawal back into the system. For the purposes of charging, the “own use” gas is treated as leaving the NTS at that exit point, and hence attracts the standard NTS SO commodity charge. The quantity of storage own use gas attributed to Users is notified by the Storage Manager to National Grid in accordance with the terms of the Storage Connection Agreement in respect of the NTS Storage Facility.

3.3 NTS Optional Commodity Charge

In June 1998 National Grid introduced an optional NTS commodity tariff to reflect more accurately the costs of gas transportation from a terminal to a nearby large supply point. Shippers can elect to pay the optional tariff as an alternative to both the entry / exit NTS SO commodity charge and the NTS TO commodity charge. The tariff is derived from the estimated cost of laying and operating a dedicated pipeline of NTS specification. A charging function has been calculated based on a range of flow rates and pipeline distances. Although the tariff is available to all daily-metered supply points, in practice it is only attractive for large supply points situated close to terminals.

3.4 Compression Charge

An additional charge is payable where gas is delivered into the NTS at a lower pressure than that required, giving rise to a need for additional compression. The compression charge is derived from an analysis of costs at the compressor site and the annual throughput at that site.

CHAPTER 4: OTHER CHARGES

4.1 Other Shipper Services Charges

There are other charges applied to services which are required by some shippers but not by all, for example special allocation arrangements. It is more equitable to levy specific cost reflective charges for these services on those shippers that require them. Income from these charges is included in the regulated transportation income. These charges include:-

- charges for the administration processes required to manage the daily operations and invoicing associated with CSEPs;
- charges for the administration of allocation arrangements at shared supply meter points and Interconnectors; and
- charges for specific services at Interconnectors.

The methodology used to calculate the appropriate level of these charges is based on an assessment of the direct costs of the ongoing activities involved in providing the services. The costs are forward looking and take into account anticipated enhancements to the methods and systems used. A percentage uplift based on the methodology described in National Grid's background paper "Charging for Specific Services - Cost Assignment Methodology" (May 1999) is added to the direct costs to cover support and sustaining costs. The latest level of the uplift was published in PD16, Section 5, (November 2002)

4.2 DN Pensions Deficit Charge

A specific annual cost allowance for the part-funding of the deficit in the NGUK Pension Scheme has been included in National Grid's TO price control formula. In respect of the share of this allowance that arises from pension deficit costs associated with former employees of the DNs, the allowed cost is recovered via the application of a DN Pensions Deficit Charge which is levied on each of the DNOs on a monthly basis. The actual monthly pension charges for each DN are given in National Grid's Statement of Charges and are in accordance with the annual allowances set out in Special Standard Condition C8B[6] of the Licence.

As the "target revenue" is fixed for each of the formula years in the Price Control period 2007 - 2012, we would anticipate that this should equal the recoverable revenue for each formula year. Hence this should avoid any "carry over" of allowable revenue from one formula year to the next. For the first formula year commencing on 1 April 2007, in the event that the timing of the TPCR outcome has not allowed charges to become effective from 1 April 2007, the monthly charges may be determined from the annual allowances divided by the remaining number of months in the formula year.

[6] Subject to change as part of the new Transmission Price Control (2007 – 2012) and consequential amendments to NTS' GT Licence.

APPENDIX 1 - BUSINESS RULES FOR INTERRUPTIBLE SUPPLY POINTS

A.1: Introduction

1.1 Contracted interruptible exit capacity remains unchanged at 45-day standard. Sites nominated by National Grid as TNI can be interrupted for a greater period.

1.2 All interruptible supply points continue to avoid the NTS (TO) exit capacity charge and the capacity element of the LDZ standard charge. The optional LDZ charge, if chosen as an alternative to the standard LDZ charge, continues to be payable for interruptible supply points.

1.3 For each occurrence of nominated interruption beyond 15 days an additional credit will be offered. National Grid conducts determination of cumulative occurrences of nominated interruption on a site-specific basis.

1.4 These business rules became effective on 1 October 2002 and refer to additional interruption credits for above 15-day interruption.

A.2: Calculation of Payment

2.1 The credit will be calculated in accordance with National Grid's Pricing Methodology as established in PC74.

2.2 The charge quantity will be determined from the supply point registered interruptible exit capacity (SOQ) at the point of interruption multiplied by those qualifying occurrences of interruption in excess of 15 days as specified in sections A.3 and A.4.

2.3 The charge quantity of any Partial interruptible site, including shared supply points, being limited to that quantity (kWh rate) of exit capacity tranche(s) that was actually requested by National Grid for interruption.

2.4 Subject to 2.1 above, such shared supply point tranche(s) charge quantity will, where more than one interruptible shared user holds interruptible exit capacity at the shared supply point, be split by each user in ratio to such user's interruptible initial (D-1) gas flow nomination as a percentage of the total aggregate interruptible initial (D-1) gas flow nomination for the shared supply point.

2.5 The charge quantity of any Interruptible Firm Allowance (IFA) site being limited to that supply point registered interruptible exit capacity net of any firm exit capacity entitlement specified within each site IFA agreement.

2.6 The charge quantity of any interruptible NTS CSEP being limited to that quantity (kWh rate) of exit capacity that was actually requested on the day by National Grid for interruption.

2.7 Subject to 2.4 above, such NTS CSEP charge quantity will, where more than one interruptible user is registered at the NTS CSEP, be split by each user in ratio to such user's interruptible initial (D-1) gas flow nomination as a percentage of the total aggregate interruptible initial (D-1) gas flow nomination for the NTS CSEP.

2.8 For the avoidance of doubt, a shared user's interruptible supply point capacity (SOQ), or such tranche under 2.1 above, will be used for charge quantity purposes, and not the shared supply point aggregate interruptible capacity (SSP SOQ).

2.9 User proposed ratios as alternatives to mechanisms described under 2.2 and 2.5 above will not be allowed.

2.10 Supply point data at the point of interruption will be used for charge calculation purposes.

2.11 Payment constructed from charge quantities determined in accordance with this section 2 will not be the subject of later reconciliation should any component capacity subsequently change prospectively within the formula year.

2.12 The registered shipper at the point of interruption will be the qualifying shipper for receipt of any payment.

A.3: Count of Interruptible Days

3.1 A count of interruption occurrence will be maintained for each site within each formula year, with each day or part day of interruption representing an increment of 1.

3.2 The count will include such occurrence of qualifying interruption as defined within section A.4 below.

3.3 The count will start from zero on 1 April of each formula year beginning at April 2002.

3.4 The count will end on 31 March of each formula year.

3.5 This count will be used solely for determining the level of credit due, if any, for each site where the frequency of nominated interruption exceeds 15 days within any formula year, monitoring of transportation contract interruption will be maintained separately for each gas year.

A.4: Qualifying Interruption

4.1 The count of qualifying interruptible days under section A.3 above will increment, but subject to 4.3 below, where curtailment of gas supply was due to:

4.2 Interruption arising from an NTS or LDZ constraint within National Grid's transportation system;

4.3 Interruption arising for Test purposes as described within UNC section G 6.7.3 (ii).

4.4 The count of qualifying interruptible days under section A.3 above will not increment where curtailment of gas supply was due to:

- emergency interruption [emergency cessation of gas supply]; and
- any form of commercial interruption instigated by a shipper.

4.5 National Grid's determination of a site for interruption will increment that site's count of interruptible days under section A.3 above.

4.6 Where National Grid has called interruption, a User can request that an alternative site(s) should be interrupted as described in section G 6.8.2 of the UNC. In such circumstances National Grid will, for the purposes of section A.3 above, maintain a count based on the site National Grid originally nominated for interruption.

4.7 Failure to interrupt of the National Grid proposed site or shipper proposed alternative site(s), will result in a reduction by 1 (to a minimum of zero) of the site count of interruptible days determined under 4.3 above and such that:

- no payment will be made for the National Grid proposed and shipper accepted site that subsequently fails to interrupt;
- no payment will be made for the National Grid proposed site where shipper substituted for a matched target volume site that subsequently fails to interrupt; and
- where multiple sites are substituted by a shipper, the payment(s) made to National Grid proposed site(s) will be reduced by that shipper substituted target volume identified as failing to interrupt, with such volume reduction being applied in site highest unit charge rate ranked order.

A.5: Unit Rate

5.1 The unit rate will be expressed in pence per kWh of peak day capacity.

5.2 NTS unit rates will be 1/15th of the annual (daily rate × 365) NTS (TO) exit capacity rates valid at the point of interruption, and will be site-specific rates applied to occurrences of qualifying interruption in excess of 15 days.

5.3 Payment constructed from unit rates determined in accordance with this section 5 will not be the subject of later reconciliation should firm NTS (TO) exit capacity rates or any peak capacity component contained within such rate calculation, subsequently change within the formula year.

5.4 For the avoidance of doubt, User election of the optional LDZ tariff excludes such sites from qualification for LDZ payments in respect of interruption in excess of 15 days, such sites will still be eligible for receipt of any NTS component.

A.6: Invoice

6.1 Payment of all credits accrued in a calendar month will be made within the following month.

6.2 Subject to 4.4 above, National Grid will not issue a payment where it has reasonable grounds to believe that such payment is dependent upon the outcome of failure to interrupt investigation. Payment will be released as soon as practically possible should such failure to interrupt be disproved.

A.7: Information Provision

7.1 National Grid will publish the count of interruptible days as specified within section A.3 above where that supply point count exceeds 12 days, publication will be at an aggregate LDZ or aggregate NTS level. The information in 7.1 will be published on the National Grid web site and updated on a weekly basis.

GLOSSARY

1 in 20 Peak Day Demand	The peak day demand that, in a long series of winters, with connected load being held at the levels appropriate to the winter in question, would be exceeded in one out of 20 winters, each winter being counted only once.
Obligated Entry Capacity	The amount of System Entry Capacity which National Grid is required to make available to Users pursuant to the Licence .
Capacity Year	The period from 1 April in any year until and including 31 March in the following year.
Exit Zone	Each Local Distribution Zone (LDZ) is divided into one or more NTS exit zones for determining charges.
Formula Year	The period from 1 April in any year until and including 31 March in the following year.
IECR Statement	The statement prepared and published by National Grid in accordance with Special Condition C15 of the Licence.
Local Distribution Zone (LDZ)	Part of the system, other than the NTS, for the time being designated by National Grid as such, and described in the Ten Year Statement, or (where the context requires) the area in which such part of the system is located.
National Transmission System (NTS)	Part of the system for the time being designated by National Grid as such, and described in the Ten Year Statement.
Supply Point	A System Exit Point comprising the Supply Meter Point or Supply Meter Points for the time being registered in the name of a User pursuant to a Supply Point Registration.
Ten Year Statement	A statement (or revised statement) required to be prepared by National Grid pursuant to Special Condition C2 of the Licence.