

Gas Transportation Charges

Effective from 1 October 2003

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1. INTRODUCTION

Transco is responsible for transporting gas safely and efficiently from the coastal terminals to around 21 million gas consumers around the country. Transco's pipeline network consists of approximately 280,000 kilometres of mains plus diurnal storage, compression and control assets. Transco transports gas from six main coastal terminals and from storage facilities and small onshore gas fields to exit points from the Transco system. Exit points may be to individual supply points, storage sites or connections to other systems, such as interconnectors to other countries or pipelines operated by other Gas Transporters (GTs).

These operations are carried out to meet the needs of the companies that supply gas to domestic, commercial and industrial consumers and to power stations. In 2002 1,107 TWh of gas was transported to these customers.

This publication sets out the transportation charges which apply for the use of the Transco pipeline network from 1 October 2003. The charges are set to comply with the price control arrangements from 1 April 2002.

Details of Transco and its activities can be found on Transco's Internet site at www.transco.co.uk. An electronic version of this publication, along with other documents on transportation charges, can be found by clicking on "**Our Publications**", "**Pricing Publications**". Any enquiries regarding this service should be directed to UK Communications, either by calling **01926 655 370** or by e-mail to webmaster@transco.co.uk

2. GAS TRANSPORTATION CHARGES EFFECTIVE FROM 1 OCTOBER 2003

2.1 Introduction

This publication sets out the transportation charges which apply from 1 October 2003 for the use of Transco's pipeline network, as required by Standard Condition 4 of the Gas Transporter Licence. This document does not override or vary any of the statutory, licence or Network Code obligations upon Transco.

For more information on the charges set out below, contact Transco's Pricing team on **(01926) 655 444**.

2.1.1 Network Code

The Network Code is supported by an integrated set of computer systems called UK Link. The charges and formulae in this booklet will be used in the calculation of charges within UK Link, which are definitive for billing purposes.

There are a number of areas of the Network Code that impact upon the cost to shippers of using the transportation network, such as imbalance charges, scheduling charges, capacity over-runs and ratchets, top-up neutrality charges and contractual liability. Reference should be made to the Network Code – as modified from time to time – for details of such charges and liabilities.

2.1.2 Units

Commodity charges are expressed and billed in pence per kilowatt hour (kWh).

Capacity charges are expressed and billed in pence per peak day kilowatt hour per day.

Fixed charges are expressed and billed in pence per day.

2.1.3 Invoicing

Transco's Invoicing team produce and issue the invoices that are derived from the transportation charges shown within this publication. To clarify this link between pricing and invoicing, charge codes and invoice names are included in the tables.

For more information on invoicing, please contact Transco's Invoicing team via email at **&Box_CSS_Billing_Transco@UKTransco.com**.

2.1.4 The Transco transportation price control formulae

Transportation charges are derived in relation to price control formulae which are set by Ofgem, the gas and electricity market regulator, for the transportation of gas. These formulae dictate the maximum revenue Transco can earn from the transportation of gas. Should Transco earn more or less than the maximum permitted revenue in any formula year, then a compensating adjustment is made in the following year. Where a significant over- or under-recovery is anticipated within a year an adjustment to charges may be made during the year.

Since April 2002 there have been separate price controls for the National Transmission System (NTS) and the Local Distribution Zones (LDZs). The NTS control is further subdivided into Asset Owner (TO) and System Operator (SO) controls.

Transportation charges are now set to reflect these price control arrangements.

Within the LDZ price control revenue recovery is split between use-of-system charges and customer charges. The relative level of these charges is based on the relative level of costs allocated to these areas of activity by Transco's Transaction Model.

2.1.5 Firm transportation

Firm transportation charges comprise NTS and LDZ capacity and commodity charges plus customer charges.

2.1.6 Interruptible transportation

Interruptible transportation is available for supply points with Annual Quantities (AQs) of over 5,860 MWh per annum.

For supply points which have been nominated by a shipper as interruptible, the shipper will pay neither the NTS (TO) exit capacity charge nor the capacity element of the LDZ standard charge. The commodity element of the LDZ standard charge or, alternatively the optional LDZ charge if appropriate, will continue to apply. Where Transco nominates a supply point to be interrupted for more than 15 days in a particular year (measured from 1 April to 31 March) there is a transportation charge credit. For each day of interruption over 15 days, a transportation charge credit, equivalent to 1/15 of the annual NTS exit capacity and LDZ standard capacity charges avoided by having interruptible rather than firm transportation is payable to the shipper. Transco has the right to

interrupt these supply points for up to 45 days each year. Appendix 2B details the business rules for interruptible supply points.

To help Transco run the network safely and securely the Network Code defines two special types of interruptible supply points. These are Network Sensitive Load (NSL) and Transco Nominated Interruptible (TNI).

NSLs are supply points where specific interruption may be required to maintain the supply of gas to firm supply points in the same area.

TNIs are supply points where Transco reserves the right to interrupt for more than 45 days each year.

Transco offers a number of services related to interruptible supply points:

- Allocation arrangements allow more than one shipper / supplier to supply interruptible gas to sites with AQs in excess of 58,600 MWh per annum. This flexibility of supplier enables the end user to make greater use of the competitive market and allows for alternative provision of gas during commercial interruption. Further details of this service are given in Section 2.5.2.

- The Partial Interruption service is designed to allow shippers to reduce offtake rates at supply points (to predetermined levels agreed between the shipper and the end user) where capacity exists, so that the site remains on a part-load, where otherwise it would have been fully interrupted.

- The Interruptible Supply Point Firm Allowance (IFA) is available to all interruptible supply points. It allows a guaranteed supply of 14,600 kWh per day (this figure can be higher if the capacity is available), where this allowance is subject to normal firm transportation charges. This enables end users to maintain their critical processes when their supply is interrupted.

- Transfer of Firm Offtake Capability. This allows a shipper to release capacity allocated to a firm supply point in order to meet the requirements of an interruptible supply point during an interruption notice. This is subject to system constraints and other eligibility criteria.

Details of all the above interruption services are available from gas suppliers / shippers or from Transco System Operation on **(01455) 893 147**.

2.1.7 Theft of gas

The licensing regime places incentives on transporters, shippers and suppliers to take

action in respect of suspected theft of gas. Certain costs associated with individual cases of theft are recovered through transportation charges. Transco's charges reflect these requirements, with Transco remaining cash neutral in the process.

2.2 National Transmission System

The National Transmission System (NTS) is a network of pipelines presently operated at pressures of up to 85 bar which transports gas from entry points to Transco's local transmission and distribution systems, other connected systems, storage sites and directly to some large volume consumers.

Charges for the use of the NTS are split into entry and exit capacity (TO) charges and commodity charges (SO). Charges for entry capacity are not fixed but are determined by auctions which apply to all system entry points. For system entry capacity from 1 October 2003, the reserve prices for the auctions are based on the Unit Cost Allowance (UCA) for each existing entry point as set out in Transco's Gas Transporters (GT) Licence.

The target for NTS (TO) revenue remains at 50% for entry capacity and 50% for exit capacity. However the 50 / 50 split may not be achieved in practice because of the unpredictability of auction revenue. Exit capacity charges reflect the estimated long run marginal cost (LRMC) of developing the system to meet a sustained increase in demand and are determined by the exit zone to which a particular offtake point belongs.

The standard NTS (SO) commodity charge is a uniform charge, independent of entry and exit points. A distance-related commodity tariff, the optional NTS commodity charge, is also available as an alternative.

2.2.1 System entry capacity

For each of the system entry points capacity is made available on a firm and interruptible basis. All entry capacity is offered on a pence per kWh per day basis where the quantity is measured in terms of an end of day entitlement.

Interruptible capacity is limited to being offered on a daily basis in an auction that is conducted on the day ahead of the intended day of use.

Firm Entry Capacity is offered in bundles of quarters, months and days.

2.2.1.1 Quarterly System Entry Capacity

Entry capacity can be obtained through the Quarterly System Entry Capacity (QSEC) process up to 16 years ahead of the intended year of use. Transco has an obligation to make available a core baseline quantity which is calculated in accordance with paragraph 14(5)(g) of part 2 of Special Condition 28B of

Transco's GT Licence. The baseline quantity from which Transco's obligation is derived is set out in Appendix 2C. The minimum quantities to be offered in the Annual System Entry Capacity auctions, after taking into account a GT Licence requirement to hold back some capacity for short term allocation, is detailed in Appendix 2D.

For each of the system entry points Transco has determined a baseline price and an additional 20 price steps for increments of capacity that may be demanded above the baseline quantity. The methodology for determination of the baseline price and incremental price steps is set out in Transco's Incremental Entry Capacity Release (IECR) statement. The step prices that are applicable for QSEC allocation are set out in Appendix 2E. Prices are published for each system entry point and are applicable for all periods in which QSEC is offered. Allocation of capacity will be conducted in accordance with the provisions set out in Transco's IECR statement.

2.2.1.2 Monthly System Entry Capacity

For each of the system entry points Monthly System Entry Capacity (MSEC) is allocated by auction for a period no more than two years ahead of the period of use. The maximum quantities to be offered in MSEC allocations for 2003/4 are also set out in Appendix 2D. MSEC auctions offer monthly tranches of firm capacity and are held in respect of each Aggregate System Entry Point (ASEP). Capacity is allocated in respect of each bid in descending price order starting at the highest bid until all monthly system entry capacity has been allocated or all valid bids have been considered. Successful bidders are liable to pay the bid price of each accepted or part accepted bid.

Following the final annual MSEC auction in which capacity is offered for a capacity year, any remaining quantities of entry capacity may be bought in a series of Rolling Monthly System Entry Capacity (RMSEC) auctions. RMSEC auctions can be conducted within a capacity year. The quantities to be offered will be any unsold baseline capacity that is carried over from the annual MSEC allocations. Each allocation will be conducted on one of 5 business days preceding the last business day in a calendar month and the capacity offered in that allocation will be specific to the succeeding month only. As with annual MSEC the allocation is conducted on a pay as bid basis.

The lowest price that can be accepted in an MSEC allocation is the reserve price as set out in Table 2.2.2. (See section 2.2.2).

2.2.1.3 Daily System Entry Capacity

Transco offers two daily capacity services – a firm Daily System Entry Capacity service (DSEC) and a Daily Interruptible System Entry Capacity service (DISEC). Both services are offered through a tender process and are subject to minimum reserve prices. Successful bidders are liable to pay the bid price of each accepted or part accepted bid. Capacity is allocated, in respect of each bid, in descending price order until all capacity has been allocated or all valid bids have been considered.

The allocation of DSEC is initiated before the gas day and is repeated at intervals through to 02:00 hours on the gas day. Shippers may have up to 20 bids on the system at any one time. DSEC availability is presently defined in the Network Code as the amount, determined by Transco, by which system entry capacity exceeds firm system entry capacity held by shippers.

DISEC is allocated by means of a single tender that is held on the day before the gas day. Shippers may submit up to 20 applications for this capacity in respect of each ASEP.

DISEC consists of any unutilised booked monthly capacity on a day. Transco determines the availability of capacity after consideration of the daily allocation levels at each ASEP on the day before the gas day. If on a day, nominations from primary holders of firm capacity increase so that gas flow exceeds booked levels at an entry point, any DISEC service entitlements would be scaled back.

2.2.2 Entry capacity reserve prices

To date all system entry capacity auctions have been subject to reserve prices.

The reserve prices applicable to MSEC and DSEC sold before the day from 1 October 2003 are shown in Table 2.2.2. For DSEC sold on the day the reserve price will be set to zero from 1 October 2003. Reserve prices for DISEC are set at zero. The invoice and charge codes are:

Service	Invoice	Charge Code
MSEC	NTS Capacity	LTF
DSEC	NTS Capacity	DAF
DISEC	NTS Capacity	DIC

Table 2.2.2 Entry capacity reserve prices for capacity from 1 October 2003

Entry Point	Reserve prices	
	Pence per kWh per day	
	MSEC	DSEC
Coastal terminals		
Bacton	0.0056	0.0037
Easington / Rough	0.0011	0.0007
Theddlethorpe	0.0010	0.0007
St Fergus	0.0198	0.0132
Teesside	0.0018	0.0012
Barrow	0.0004	0.0003
Onshore fields and connections		
Hatfield Moor	0.0013	0.0009
Wyth Farm	0.0000	0.0000
Caythorpe	0.0021	0.0014
Burton Point	0.0001	0.0001
Hole House Farm	0.0001	0.0001
Storage		
Hornsea	0.0047	0.0031
Glenmavis	0.0165	0.0110
Partington	0.0003	0.0002
Aldbrough	0.0018	0.0012
Constrained LNG		
Avonmouth	0.0020	0.0013
Dynevor Arms	0.0000	0.0000
Isle of Grain	0.0058	0.0039

2.2.3 Constrained LNG

Shippers that book the constrained Liquefied Natural Gas (LNG) storage service, available from the LNG storage sites at Dynevor Arms, Isle of Grain and Avonmouth, undertake an obligation to provide transmission support gas to Transco on days of very high demand. In recognition of this, shippers receive a credit in respect of minimum booked storage deliverability. Full details of associated rules are available on request from Transco's LNG business unit. The credit is deducted from the charge for the storage service.

Entry Point	Credit
	Pence per registered kWh per day
	From 1 May 2003
Avonmouth LNG	0.0042
Dynevor Arms LNG	0.0006
Isle of Grain LNG	0.0008

2.2.4 NTS (TO) exit capacity charges

NTS (TO) exit capacity charges apply to loads supplied through existing NTS offtakes into the Local Distribution Zones (LDZ) and to large loads and interconnectors supplied directly from the NTS. The exit zone for an LDZ supply point is determined by its post code.

For new loads supplied directly from the NTS, the exit zone charges provide an indication of the likely level of charges. However, in general, an individual exit zone will be created with its own charge for new NTS offtakes.

At present, Transco makes no charge for NTS exit capacity at storage points. This is on the basis that the transportation service to the storage points is interruptible. If a firm transportation service to storage were provided, an NTS (TO) exit capacity charge would be payable.

There are four small towns in Scotland where LNG needs to be transported by road tanker to supply end users on distribution systems which are not physically connected to the main Transco network. For these locations, NTS (TO) exit charges will be calculated on the basis that they are allocated to exit zone SC4, the location of the LNG storage site which supplies them.

Table 2.2.4 NTS (TO) Exit Capacity Charges

Invoice	Charge Codes	
NTS Capacity	NDX (DM) / NNX (NDM)	
Network	LDZ Exit Zone	Pence per peak day kWh per day
East of England	EA1	0.0024
	EA2	0.0086
	EA3	0.0031
	EA4	0.0093
	EM1	0.0026
	EM2	0.0006
	EM3	0.0066
	EM4	0.0053
North of England	NE1	0.0001
	NE2	0.0017
	NE3	0.0008
	NO1	0.0001
	NO2	0.0007
London	NT1	0.0175
	NT2	0.0114
	NT3	0.0126
North West	NW1	0.0071
	NW2	0.0063
Scotland	SC1	0.0001
	SC2	0.0009
	SC4	0.0001
South of England	SE1	0.0093
	SE2	0.0175
	SO1	0.0121
	SO2	0.0166
Wales & the West	SW1	0.0068
	SW2	0.0130
	SW3	0.0257
	WA1	0.0091
	WA2	0.0156
West Midlands	WM1	0.0055
	WM2	0.0060
	WM3	0.0066

**Table 2.2.4 NTS (TO) Exit Capacity Charges
(continued)**

Invoice	Charge Code
NTS Capacity	NDX (DM)

	Pence per peak day kWh per day
NTS Sites	
AM Paper	0.0029
Baglan Bay PG	0.0177
Barking PG	0.0095
BASF Teesside	0.0001
BP Grangemouth	0.0001
BP Saltend (HP)	0.0008
Bridgewater Paper	0.0083
Brigg PG	0.0005
Brimsdown PG	0.0102
Brunner Mond	0.0029
Connahs Quay PG	0.0083
Corby PG	0.0038
Croyton PG	0.0072
Cottam PG	0.0005
Deeside PG	0.0083
Didcot PG	0.0131
Goole Glass	0.0001
Great Yarmouth PG	0.0024
Hays Chemicals	0.0029
ICI Runcorn	0.0085
Immingham CHP	0.0005
Keadby PG	0.0001
Kemira Ince	0.0085
Kings Lynn PG	0.0023
Kingsnorth PG	0.0075
Little Barford PG	0.0047
Longannet PG	0.0001
Medway PG	0.0075
Peterborough PG	0.0023
Peterhead PG	0.0001
Phillips Seal Sands	0.0001
Rocksavage PG	0.0085
Roosecote PG	0.0019
Rye House PG	0.0102
Saltend PG	0.0008
Sappi Paper Mill	0.0071
Seabank PG	0.0120
Sellafield PG	0.0019
Shotton Paper	0.0083
Stallingborough PG	0.0008
Staythorpe PG	0.0023
Sutton Bridge PG	0.0016
Teesside Hydrogen	0.0001
Teesside PG	0.0001
Terra Billingham	0.0001
Terra Severnside	0.0124
Thornton Curtis PG	0.0005
Zeneca	0.0001

Invoice	Charge Code
NTS Capacity	NDX (DM)

	Pence per peak day kWh per day
Interconnectors	
Bacton I/C	0.0024
Moffat I/C	0.0001
Storage Sites	
Avonmouth	0.0120
Dynevor Arms	0.0156
Glenmavis	0.0001
Hatfield Moor	0.0001
Hole House Farm	0.0029
Hornsea	0.0008
Isle of Grain	0.0075
Partington	0.0029
Rough	0.0008

2.2.5 NTS (SO) commodity charges

2.2.5.1 Standard charge

Invoice	Charge Code
Commodity	NCO
Pence per kWh	
Standard	0.0177

The standard NTS (SO) commodity charge is a uniform charge, independent of entry and exit points. The charge is payable on exit flows until October 2004 when the appropriate rate will be payable on both entry and exit flows.

2.2.5.2 Optional charge

The optional NTS commodity tariff is available as an alternative to the standard commodity charge and may be attractive for large daily metered sites located near to entry terminals, since the standard commodity tariff is not distance-related and can result in a relatively high charge for short distance transportation. This could give perverse economic incentives to build dedicated pipelines bypassing the NTS, resulting in an inefficient outcome for all system users.

The optional tariff applies in respect of gas delivered from the local specified terminal. The charge is site specific and is calculated by the function shown below.

Invoice	Charge Code
ADU	880
Pence per kWh	
$1203 \times [(SOQ)^{\wedge-0.834}] \times D + 363 \times (SOQ)^{\wedge-0.654}$	

where **D** is the direct distance from the site or non-Transco pipeline to the elected terminal in km and **SOQ** is the registered supply point capacity in kWh. Note that \wedge means "to the power of ..."

Further information on the optional NTS tariff can be obtained from our Pricing team on (01926) 656 317.

2.2.6 Compression charge

An additional charge is payable where gas is delivered into the Transco system at a lower pressure than that required, reflecting the need for additional compression. For gas delivered at the Total Oil Marine sub-terminal at St. Fergus, a compression charge of 0.0046 pence per kWh is payable.

2.2.7 System balancing charge

A system balancing commodity charge will be payable to reflect the costs of ensuring a balance between gas entering the system and gas offtaken.

For shippers operating wholly under Network Code arrangements, the system balancing charge is zero.

The system balancing commodity charge is calculated as: The sum of energy balancing charges which are or would be payable under the Network Code less energy balancing charges paid by or to the Shipper pursuant to the Network Code or any other arrangement divided by the total quantity offtaken.

Energy balancing charges are defined in the Network Code and include imbalance charges, scheduling charges and any additional charges payable by or to the Shipper for the purpose of enabling Transco to balance system inputs and offtakes.

The system balancing charges will be determined following each calendar month by monitoring gas inputs and offtakes on a daily basis.

2.3 Local Distribution Zones

Local Distribution Zones (LDZs) contain the local transmission system, a network of pipelines operating generally at pressures up to 38 bar, and the distribution system, a network of mains operating in three pressure tiers: intermediate (2 to 7 bar), medium (75 mbar to 2 bar) and low (below 75 mbar).

Where LDZ charges are based on functions, these functions use Supply point Offtake Quantity (SOQ) in the determination of the charges. At daily metered (DM) firm supply points the SOQ is the registered supply point capacity. For non-daily metered (NDM) supply points, the SOQ is calculated using the supply point End User Category (EUC) and the appropriate load factor. Details of EUCs and load factors are shown in Appendix 2A of this document and are also available on Transco's web site under "Pricing Publications".

For interruptible supply points the rule set out in Section B 4.6.5 (Bottom-stop supply point capacity) of Transco's Network Code applies in the determination of the LDZ charges.

The term PL (Peak Load) was used previously in the functions but this has been replaced with the term SOQ as this is the standard terminology.

2.3.1 Standard LDZ System charges

The standard LDZ system charges comprise capacity and commodity charges, with separate functions for directly connected supply points and for Connected System Exit Points (CSEPs).

2.3.1.1 Directly Connected Supply Points

The unit charges and charging functions used to calculate charges to directly connected supply points are set out in Table 2.3.1.1 below.

Table 2.3.1.1 Directly connected supply points

Invoice	Charge Code
LDZ Capacity	ZCA
LDZ Commodity	ZCO

	Capacity	Commodity
	pence per peak day kWh per day	pence per kWh
Up to 73,200 kWh per annum	0.0498	0.1331
73,200 to 732,000 kWh per annum	0.0462	0.1231
732,000 kWh per annum and above	$0.2192 \times \text{SOQ}^{-0.1806}$	$0.7636 \times \text{SOQ}^{-0.2121}$
Subject to a minimum rate of	0.0050	0.0116
Minimum reached at SOQ of	1,181,616,389 kWh	382,022,999 kWh

2.3.1.2 Connected Systems

A separate charging function for transportation to Connected System Exit Points (CSEPs) was introduced from 1 October 2000. This function reflects the view that transportation to CSEP loads typically makes less use of the LDZ system than to other similar-sized loads. In the calculation of LDZ charges payable, the unit commodity and capacity charges are based on the supply point capacity equal to the CSEP peak day load for the completed development irrespective of the actual stage of development. The SOQ used is therefore the estimated SOQ for the completed development as provided in the appropriate Network Exit Agreement (NExA). For any particular CSEP, each shipper will pay identical LDZ unit charges regardless of the proportion of gas shipped. Reference needs to be made to the relevant NExA or CSEP ancillary agreement to determine the completed supply point capacity.

Table 2.3.1.2 Connected Systems

Invoice	Charge Code
ADC	ZCA
ADC	ZCO

	Capacity	Commodity
	pence per peak day kWh per	pence per kWh
Up to 73,200 kWh per annum	0.0498	0.1331
73,200 to 732,000 kWh per annum	0.0462	0.1231
732,000 kWh per annum and above	$0.2318 \times \text{SOQ}^{-0.1939}$	$0.7287 \times \text{SOQ}^{-0.2131}$
Subject to a minimum rate of	0.0050	0.0116
Minimum reached at SOQ of	376,129,100 kWh	279,629,352 kWh

2.3.2 Optional LDZ Charge

The optional LDZ tariff is available, as a single charge, as an alternative to the standard LDZ system charges. This tariff may be attractive to large loads located close to the NTS. The rationale for the optional tariff is that, for large LDZ loads located close to the NTS or for potential new LDZ loads in a similar situation, the standard tariff can appear to give perverse economic incentives for the construction of new pipelines when LDZ connections are already available. This could result in an inefficient outcome for all system users.

where: (SOQ) is the Registered Supply Point Capacity, or other appropriate measure, in kWh per day and D is the direct distance, in km, from the site boundary to the nearest point on the NTS. Note that ^ means “to the power of ...”

Further information on the optional LDZ tariff can be obtained from Transco’s LDZ Pricing team on **(01926) 655 444**.

The charge is calculated using the function below :

Invoice	Charge Code
ADU	881

Pence per peak day kWh per day
$902 \times [(\text{SOQ})^{-0.834}] \times D + 772 \times (\text{SOQ})^{-0.717}$

2.4 Customer Charges

For supply points with an AQ of less than 73,200 kWh per annum, the customer charge is a commodity charge.

For supply points with an AQ between 73,200 and 732,000 kWh per annum, the customer charge is made up of a fixed charge which depends on the frequency of meter reading, plus a capacity charge based on the registered supply point capacity (SOQ).

For supply points with an AQ of over 732,000 kWh per annum, the customer charge is based on a function related to the registered supply point capacity (SOQ).

2.4.1 Pre-Network Code contracts

In relation to pre-Network Code contracts, in addition to the customer charges set out in the table there will be an administration charge of 171.5068 pence per day (£626 per annum) per supply point.

Table 2.4 Customer charges

Up to 73,200 kWh per annum

Invoice	Charge Code
Commodity	CCO
	pence per kWh
Commodity charge	0.1482

73,200 kWh up to 732,000 kWh per annum

Invoice	Charge Code
LDZ capacity	CFI
Fixed charge	pence per day
Non-monthly read supply points	15.6179
Monthly read supply points	16.6296

Invoice	Charge Code
LDZ Capacity	CCA
	Pence per peak day kWh per day
Capacity charge	0.0018

732,000 kWh per annum and above

Invoice	Charge Code
LDZ Capacity	CCA
	Pence per peak day kWh per day
Charging function	$0.0379 \times \text{SOQ}^{-0.2100}$

2.5 Other Charges

Other Charges include administration charges at Connected System Exit Points, Shared Supply Meter Points and Interconnectors.

2.5.1 Connected System Exit Points

A CSEP is a system point comprising one or more individual exit points which are not supply meter points. This includes connections to a pipeline system operated by a Gas Transporter other than Transco. NTS capacity and commodity unit rates are calculated for each shipper transporting to the CSEP as though the gas were being shipped to a single supply point.

The calculation of LDZ charges payable for shipping to CSEPs is explained in section 2.3.1.2.

There is no customer charge payable for connected systems, however separate administration processes are required to manage the daily operations and invoicing associated with CSEPs, including interconnectors, for which an administration charge is made.

The administration charge which applies to CSEPs containing NDM and DM sites is:

CSEP administration charge

Charge per supply point	0.3288 pence per day (£1.20 per annum)
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The invoice and charge codes are:

	Invoice	Charge Code
DM CSEP	ADU	879
NDM CSEP	ADC	894

2.5.2 Shared supply meter point allocation arrangements

Transco offers an allocation service for daily metered supply points with AQs of more than 58,600 MWh per annum. This allows up to four (six for VLDMCs) shippers / suppliers to supply gas through a shared supply meter point.

The allocation of daily gas flows between the shippers / suppliers can be done either by an appointed agent or by Transco.

The administration charges which relate to these arrangements are shown below. Individual charges depend on the type of allocation service nominated and whether the site is telemetered or non-telemetered.

The charges are (expressed as £ per shipper per supply point) :

Invoice	Charge Code
ADU	879

Agent Service

	Telemetered	Non-telemetered
Set-up charge	£107.00	£183.00
Shipper-shipper transfer charge	£126.00	£210.00
Daily charge	£2.55	£2.96

Transco Service

	Telemetered	Non-telemetered
Set-up charge	£107.00	£202.00
Shipper-shipper transfer charge	£126.00	£210.00
Daily charge	£2.55	£3.05

2.5.3 Interconnectors

- Allocation arrangements at Interconnectors:

The following allocation charges apply at interconnectors (GB-Ireland and UK-Continent) and apply for each supply point. Allocating daily gas flows between shippers / suppliers can be done either by an appointed agent or by Transco. The same set up charge applies in either case. The daily charge depends on whether the service is provided through an agent or not:

Invoice	Charge Code
ADU	879

	Set up charge per shipper	Daily Charge per shipper
Agent service	£141.70	£1.62
Transco service	£141.70	£2.46

- Administration charges at Moffat:

The following administration charges apply only to the GB-Ireland interconnector at Moffat. The charges, which vary if the service is provided via an agent or Transco, are detailed below:

Invoice	Charge Code
ADU	879

	Daily Charge per shipper
Agent service	£15.08
Transco service	£30.16

The charges with or without an agent cover the operation of the flow control valve. In addition the Transco service provides the Exit Flow Profile Notice (EPN).

In the event that the appointed agent fails to provide an EPN to Transco, the following additional charge will apply:

EPN Default Charge per shipper per event **£0.63**.

2.5.4 Must Reads

If a shipper is unable to provide meter readings in compliance with the Network Code, Transco may initiate processes to obtain a meter read, referred to as a 'must read'. A charge will be made for each must read and will depend on the number of meters at a supply point requiring a must read at the same time. If there is one meter at the supply point, the charge will be £40, for two meters the charge will be £60 and for three or more meters the charge will be £80. These charges are based on the typical cost of such reads which may include multiple visits to the site and obtaining and executing a warrant of entry.

2.5.5 Opening read estimates

Incoming shippers are required by the Network Code to provide an actual opening meter read to Transco within a window around the date that the supply point transfers. If no read is provided within the period, Transco is required to provide an estimated reading. In respect of supply points with an annual consumption of up to 73,200 kWh, a charge of **£1.13** applies for each estimate provided, where an individual shipper's opening read performance has fallen below 90% in any month.

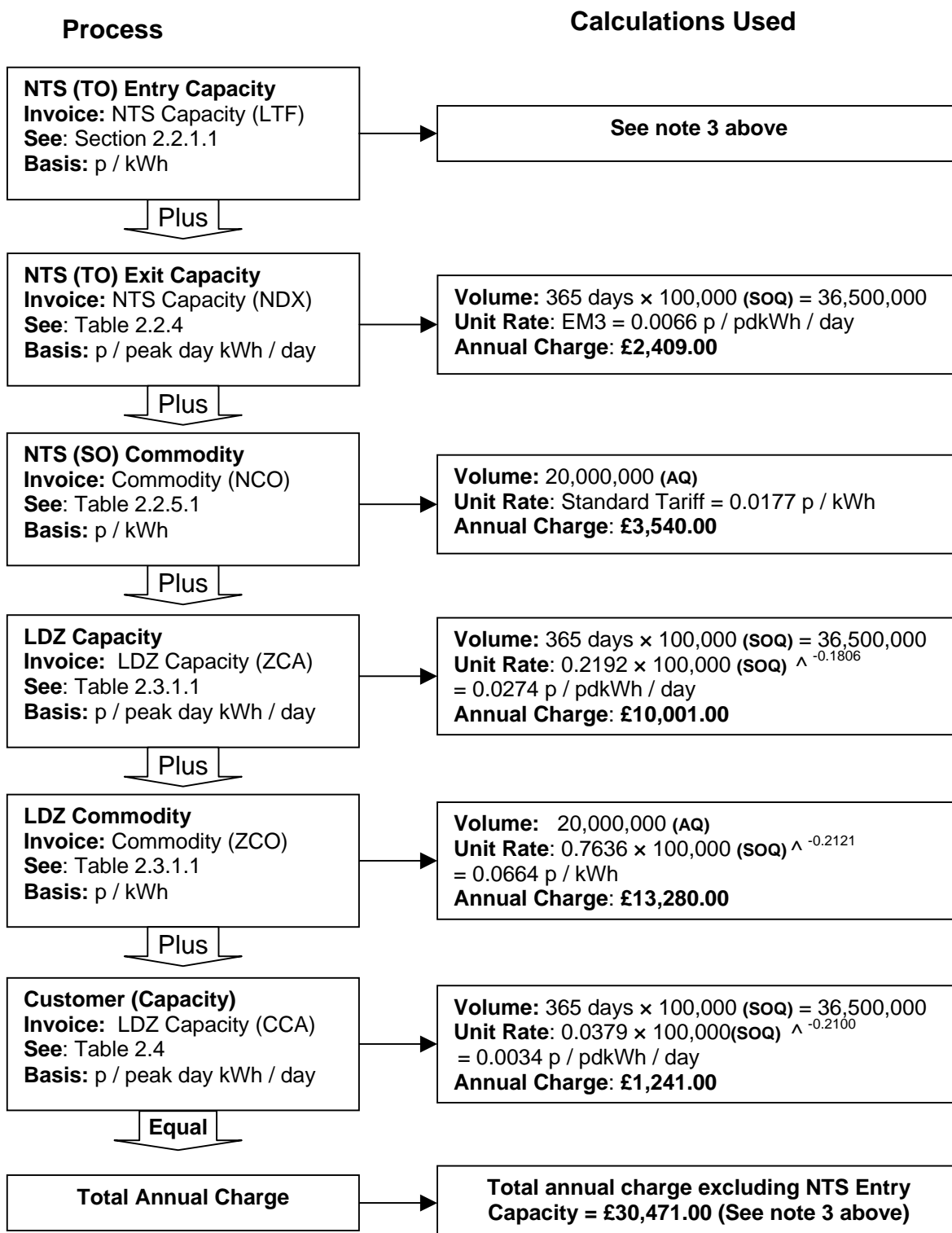
2.6 Examples

Notes

1. Charges produced by UK Link are definitive for charging purposes. Calculations below are subject to rounding and should be regarded as purely illustrative.
2. Under the Network Code, NTS exit capacity is booked separately from system entry capacity. At daily-metered supply points the supply point capacity is booked independently of NTS capacity. For simplicity the examples below assume that the NTS exit capacity booked is mirrored by the bookings of system entry capacity, and equals the supply point capacity.
3. The NTS entry capacity charge at each terminal is now set by an auction process rather than by means of an administered charge, it would therefore be inappropriate to include entry capacity charges in these worked examples. Users however may wish to apply their own charges.

Example 1

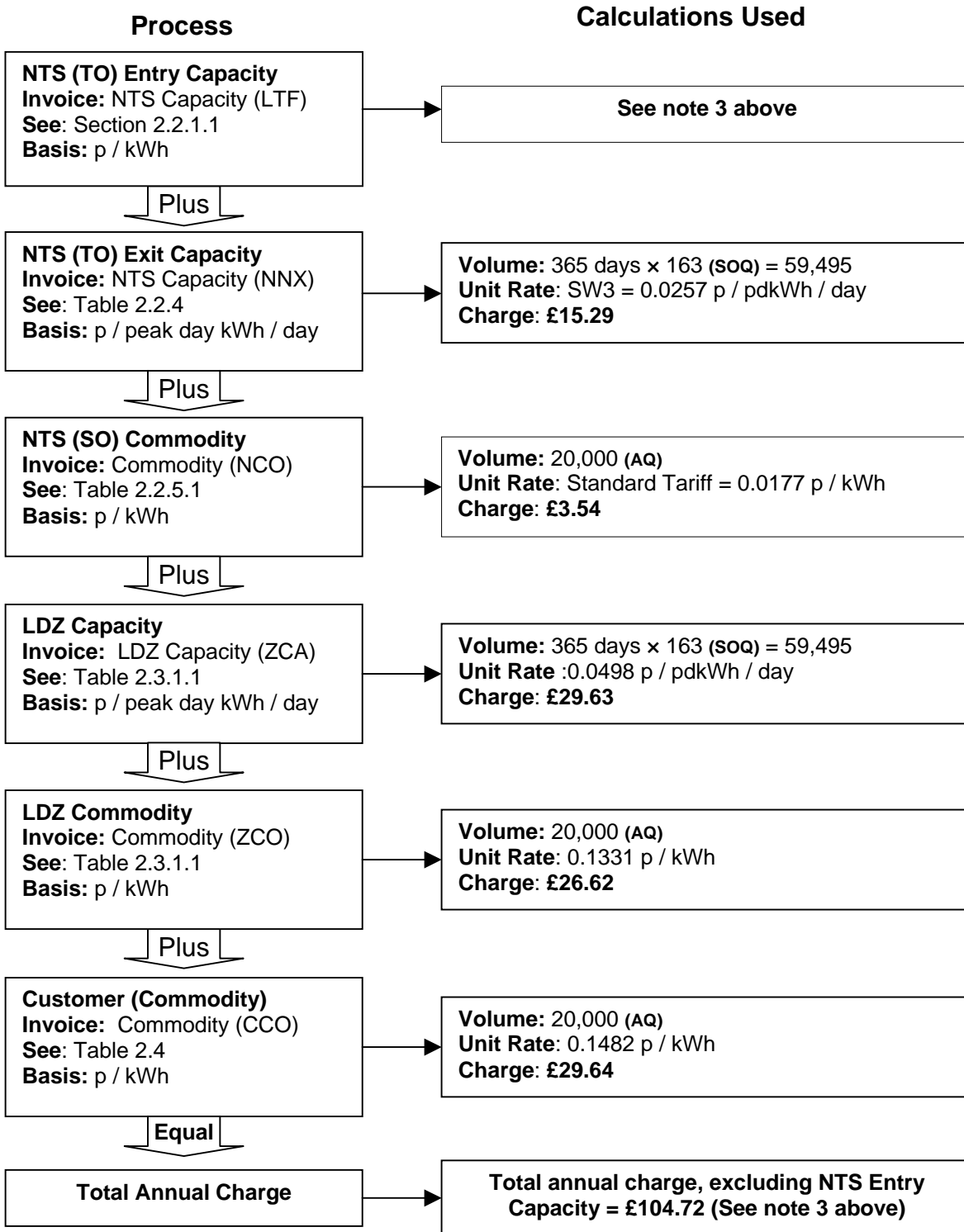
A shipper has a daily metered customer in Leicester (**EM3**) with an annual consumption (**AQ**) of **20,000,000 kWh** and a registered supply point capacity (**SOQ**), booked directly by the shipper of **100,000 kWh** per day.



Unit Charge : Dividing by the annual load of 20,000,000 kWh gives a unit charge (excluding NTS entry capacity) of 0.1524 pence per kWh. If the above example was an interruptible load, the NTS exit and LDZ capacity charges would not be levied. This would reduce the total charge for a shipper nominated interruptible load by £2409.00 and £10,001.00 respectively to a new total of £18,061.00. For each additional day of interruption over 15 days, the Transportation Charge Credit would be £827.33 per day.

Example 2

A shipper has a domestic customer in Plymouth (**SW3**). Suppose the load has an **AQ** of **20,000** kWh per annum. Using the definition of end user categories table in Appendix 2A, this annual load places the end user in category E0301. Using the appropriate small NDM supply points table of load factors, it can be seen that the load factor for such a site in the SW LDZ is 33.7%. The peak daily load (**SOQ**) is therefore $20,000 \div (365 \times 0.337) = 163$ kWh.



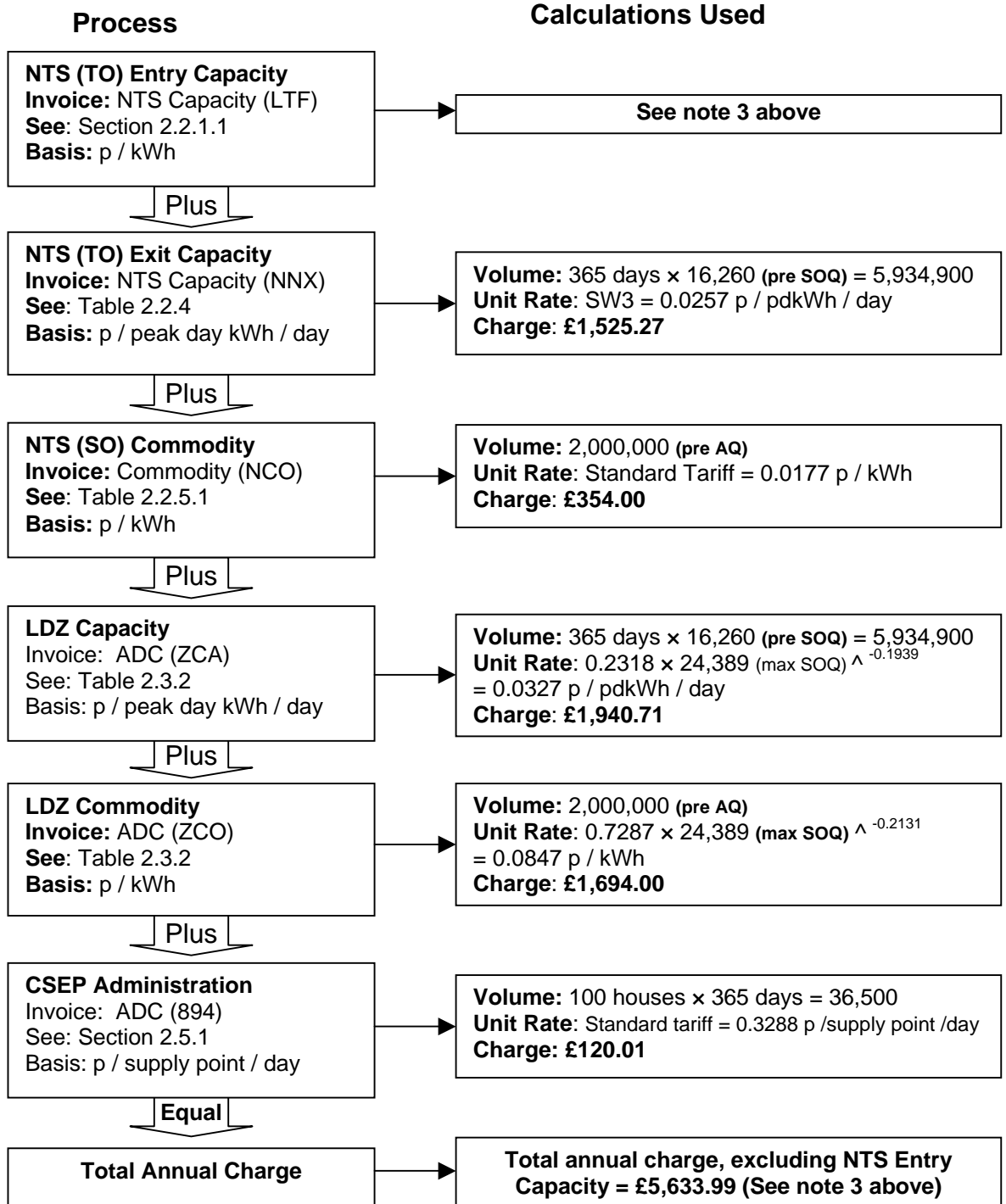
Unit Charge : Dividing by the annual load of 20,000 kWh gives a unit charge (excluding NTS entry capacity) of 0.5237 pence per kWh.

Example 3

Suppose that instead of supplying just one domestic customer in Plymouth (as in Example 2) the shipper actually supplies a connected system presently comprising 100 domestic customers and the completed connected system will comprise 150 domestic premises. Suppose that each of these premises has the same (AQ) of 20,000 kWh per annum.

Prevailing AQ (pre AQ)	100 houses × 20,000 (AQ) = 2,000,000
Maximum AQ (max AQ)	150 houses × 20,000 (AQ) = 3,000,000
Prevailing SOQ (pre SOQ)	2,000,000 ÷ (365 × 0.337) = 16,260 kWh
Maximum SOQ (max SOQ)	3,000,000 ÷ (365 × 0.337) = 24,389 kWh

Note that the prevailing annual and peak day loads of the connected system in effect would change over the year however, for simplicity, these have been assumed as constant in this example.



Unit Charge : Dividing by the annual load of 2,000,000 kWh gives a unit charge (excluding NTS entry capacity) of 0.2817 pence per kWh.

Appendix 2A

Estimation of peak daily load for non-daily metered supply points

For non-daily metered (NDM) supply points, the peak daily load is estimated using a set of End User Categories (EUCs). Each NDM supply point is allocated to an EUC. In each LDZ each EUC has an associated load factor, as listed in Tables 2A.2 and 2A.3. The data in these tables applies for the gas year 1 October 2003 to 30 September 2004.

In the tables 'XX' refers to the LDZ Code (e.g. WS).

These EUCs depend upon the annual quantity (AQ) of the supply point and, in the case of monthly read sites, the ratio of winter to annual consumption where available.

Monthly read sites

It is mandatory for supply points with an annual consumption greater than 293 MWh to be monthly read, however, at the shipper's request, sites below this consumption may also be classified as monthly read.

For monthly read sites where the relevant meter reading history is available, the winter: annual ratio is the consumption from December to March divided by the annual quantity. If the required meter reading information is not available, the supply point is allocated to an EUC simply on the basis of its annual quantity.

The peak load for an NDM supply point may then be calculated as:

$$\frac{AQ \times 100}{365 \times LoadFactor}$$

Example

For a supply point in Wales South LDZ with an annual consumption of 1,000 MWh per annum.

Assume consumption December to March inclusive is 500 MWh.

$$\text{Winter: annual ratio} = 500 \div 1000 = 0.5$$

For a site with an annual consumption of 1,000 MWh, a ratio of 0.5 falls within winter: annual ratio band WO3 and the site is thus within End User Category WS:E0304W03.

For a site in this category, the load factor is 30.9% and the peak daily load is therefore

$$\frac{1000 \times 100}{365 \times 30.9} = 8.87 \text{ MWh}$$

If the required meter reading information is not available to calculate the winter: annual ratio, the supply point is allocated to an EUC simply on the basis of its annual quantity, in this case WS:E0304B.

For a site in this category, the load factor is 33.9% and the peak daily load is therefore

$$\frac{1000 \times 100}{365 \times 33.9} = 8.08 \text{ MWh}$$

Six monthly read sites

In the case of six monthly read sites, the supply point is allocated to an EUC simply on the basis of its annual quantity.

Example

For a supply point in Scotland LDZ with an annual consumption of 200 MWh per annum, the EUC will be SC:E0302B.

For a site in this category, the load factor is 38.2% and the peak daily load is therefore

$$\frac{200 \times 100}{365 \times 38.2} = 1.43 \text{ MWh}$$

Notes

The term LDZ is applied in the context of its usage with reference to the Network Code daily balancing regime. This is not precisely the same as the term LDZ when it is used in the context of Transco's organisation structure.

For supply points whose consumption is over 73,200 kWh and which include one or more NDM supply meter points, an end user category code can be found in the supply point offer generated by UK Link. This code may be correlated with the end user category code shown opposite by means of a lookup table issued separately to shippers. Copies are available from Transco's CPM team on **(0121) 713 5569**.

For additional information regarding the demand estimation process, please contact Transco's Demand Estimation Team on **(01926) 656 149**.

Daily metered supply points

The SOQ of daily metered sites is known and hence no load factor is required.

Supply points with annual consumptions greater than 58,600 MWh should be daily metered. However, a handful of sites remain as non-daily metered as a result of difficulties installing the daily read equipment. In such cases the end user category code XX:E0309B is used.

Firm supply points with an AQ above 73.2 MWh pa may, at the shipper's request, be classified as daily metered. All interruptible supply points are daily metered.

Consultation on end user categories

Section H of the Network Code requires Transco to publish, * by the end of June each year, its demand estimation proposals for the forthcoming supply year. These proposals comprise end user category definitions, NDM profiling parameters (ALPs and DAFs), and capacity estimation parameters (EUC load factors). Transco presents its analysis to users and consults with the Demand Estimation Sub-Committee (a sub-committee of the Network Code Committee) before publication of its proposals. Transco submits its final proposal not later than 15 August. On this occasion the final figures were unchanged from those published in June.

* NDM Profiling and Capacity Estimation Algorithms for 2003 / 04, June 2003.

Table 2A.1 Definition of end user categories

The following tables define the end user category for particular LDZs by reference to annual consumption and winter: annual ratio, applicable from 1 October 2003 to 30 September 2004.

EUC Code	Annual Load (MWh)	Winter Annual Ratios (WAR)			
		W01	W02	W03	W04
xx:E0301B	0 to 73.2	-	-	-	-
xx:E0302B	73.2 to 293	-	-	-	-
xx:E0303B	293 to 732	0.00 - 0.41	0.41 - 0.49	0.49 - 0.57	0.57 - 1.00
xx:E0304B	732 to 2,196	0.00 - 0.41	0.41 - 0.49	0.49 - 0.57	0.57 - 1.00
xx:E0305B	2,196 to 5,860	0.00 - 0.40	0.40 - 0.46	0.46 - 0.54	0.54 - 1.00
xx:E0306B	5,860 to 14,650	0.00 - 0.35	0.35 - 0.43	0.43 - 0.51	0.51 - 1.00
xx:E0307B	14,650 to 29,300	0.00 - 0.34	0.34 - 0.39	0.39 - 0.47	0.47 - 1.00
xx:E0308B	29,300 to 58,600	0.00 - 0.32	0.32 - 0.35	0.35 - 0.42	0.42 - 1.00
xx:E0309B	> 58,600	-	-	-	-

Table 2A.2 Small NDM Supply Points (Up to 2,196 MWh per annum)

xx: = LDZ =	SC	NO	NW	NE	EM	WM	WN	WS	EA	NT	SE	SO	SW
xx:E0301B	39.8%	36.1%	39.1%	38.8%	38.8%	34.9%	39.1%	35.9%	37.1%	36.2%	35.5%	32.1%	33.7%
xx:E0302B	38.2%	32.0%	34.4%	29.9%	32.0%	30.3%	34.4%	28.6%	34.5%	35.8%	34.7%	29.8%	27.6%
xx:E0303B	40.8%	31.6%	36.2%	34.4%	35.4%	30.8%	36.2%	31.1%	35.5%	35.1%	34.5%	30.7%	30.9%
xx:E0303W01	59.8%	56.1%	55.9%	55.6%	57.1%	51.5%	55.9%	54.5%	54.8%	58.6%	57.6%	52.0%	57.8%
xx:E0303W02	47.0%	40.4%	43.7%	44.5%	45.7%	39.2%	43.7%	43.1%	42.7%	43.3%	43.4%	38.3%	43.0%
xx:E0303W03	35.2%	27.8%	30.7%	31.9%	33.0%	28.8%	30.7%	30.9%	30.7%	31.0%	30.9%	27.6%	30.0%
xx:E0303W04	28.2%	23.4%	25.3%	25.5%	26.1%	23.6%	25.3%	23.8%	25.7%	24.9%	25.4%	21.5%	23.5%
xx:E0304B	41.2%	33.0%	36.4%	36.8%	35.8%	32.7%	36.4%	33.9%	35.8%	37.7%	36.6%	32.4%	35.2%
xx:E0304W01	59.8%	56.1%	55.9%	55.6%	57.1%	51.5%	55.9%	54.5%	54.8%	58.6%	57.6%	52.0%	57.8%
xx:E0304W02	47.0%	40.4%	43.7%	44.5%	45.7%	39.2%	43.7%	43.1%	42.7%	43.3%	43.4%	38.3%	43.0%
xx:E0304W03	35.2%	27.8%	30.7%	31.9%	33.0%	28.8%	30.7%	30.9%	30.7%	31.0%	30.9%	27.6%	30.0%
xx:E0304W04	28.2%	23.4%	25.3%	25.5%	26.1%	23.6%	25.3%	23.8%	25.7%	24.9%	25.4%	21.5%	23.5%

Table 2A.3 Large NDM Supply Points (2,196 and above MWh per annum)

xx: = LDZ =	SC	NO	NW	NE	EM	WM	WN	WS	EA	NT	SE	SO	SW
xx:E0305B	43.2%	36.8%	40.8%	39.2%	41.5%	36.9%	40.6%	38.7%	40.0%	42.0%	39.9%	36.4%	38.3%
xx:E0305W01	63.5%	60.0%	63.0%	61.5%	64.7%	58.4%	62.9%	63.7%	61.6%	62.8%	58.9%	58.3%	62.2%
xx:E0305W02	50.0%	44.8%	47.1%	47.7%	49.0%	43.8%	46.9%	47.3%	47.4%	48.6%	48.5%	43.7%	45.6%
xx:E0305W03	38.1%	32.8%	36.2%	36.4%	38.4%	33.6%	36.0%	36.2%	36.0%	37.0%	36.2%	32.7%	35.7%
xx:E0305W04	30.3%	25.1%	27.5%	26.7%	28.3%	25.6%	27.3%	25.9%	27.3%	28.4%	28.0%	24.6%	26.3%
xx:E0306B	47.3%	40.8%	45.4%	45.1%	46.8%	42.0%	45.2%	44.7%	43.5%	46.6%	46.3%	40.2%	44.4%
xx:E0306W01	71.6%	70.2%	71.3%	71.1%	71.2%	70.3%	71.2%	71.3%	76.8%	76.6%	76.4%	70.6%	71.2%
xx:E0306W02	55.3%	51.2%	54.5%	53.1%	53.3%	51.1%	54.3%	52.7%	54.7%	54.0%	53.3%	50.4%	52.5%
xx:E0306W03	42.6%	39.2%	42.9%	40.5%	40.7%	38.2%	42.7%	38.5%	42.6%	42.1%	41.7%	37.9%	39.6%
xx:E0306W04	30.5%	27.5%	31.1%	29.3%	29.9%	28.0%	30.9%	28.1%	30.6%	30.5%	30.1%	27.8%	29.0%
xx:E0307B	50.1%	49.7%	53.0%	52.5%	52.7%	50.3%	52.8%	43.6%	49.7%	49.0%	48.3%	41.3%	43.4%
xx:E0307W01	76.8%	76.0%	76.5%	76.8%	76.9%	76.6%	76.5%	79.4%	79.6%	79.4%	79.2%	78.7%	79.2%
xx:E0307W02	63.2%	59.8%	62.4%	60.9%	61.1%	59.1%	62.3%	58.9%	60.1%	59.5%	58.9%	56.6%	58.7%
xx:E0307W03	49.4%	45.1%	48.6%	46.9%	47.1%	44.5%	48.4%	45.1%	46.9%	46.1%	45.4%	42.6%	44.9%
xx:E0307W04	33.9%	30.1%	34.1%	31.7%	32.3%	30.4%	33.9%	30.6%	33.2%	32.8%	32.4%	29.9%	31.3%
xx:E0308B	68.5%	65.1%	67.8%	58.4%	58.6%	56.3%	67.6%	56.1%	57.6%	56.9%	56.3%	53.6%	56.0%
xx:E0308W01	83.8%	82.3%	82.9%	83.6%	83.6%	83.2%	82.8%	82.2%	83.3%	83.2%	83.2%	82.9%	82.3%
xx:E0308W02	72.2%	69.6%	71.6%	71.7%	71.9%	70.3%	71.5%	70.2%	71.0%	70.6%	70.3%	68.6%	70.1%
xx:E0308W03	59.0%	55.0%	58.0%	58.1%	58.3%	55.9%	57.8%	55.7%	57.1%	56.4%	55.8%	53.4%	55.5%
xx:E0308W04	39.2%	35.2%	39.2%	38.5%	39.2%	36.9%	39.0%	36.3%	38.9%	38.5%	38.1%	35.5%	37.0%
xx:E0309B	70.7%	67.2%	69.8%	69.9%	70.1%	68.0%	69.6%	67.8%	69.0%	68.4%	67.9%	65.7%	67.6%

Appendix 2B

Business rules for interruptible supply points

1. Introduction

- 1.1. Contracted interruptible exit capacity remains unchanged at 45-day standard. Sites nominated by Transco 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. Transco 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.

2. Calculation of Payment

- 2.1. The credit will be calculated in accordance with Transco'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 3 and 4 of this Appendix but subject to:
 - 2.2.1. 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 Transco for interruption.
 - 2.2.2. Subject to 2.2.1 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.

- 2.2.3. The charge quantity of any 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.
- 2.2.4. 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 Transco for interruption.
- 2.2.5. Subject to 2.2.4 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.
- 2.3. For the avoidance of doubt, a shared user's interruptible supply point capacity (SOQ), or such tranche under 2.2.1 above, will be used for charge quantity purposes, and not the shared supply point aggregate interruptible capacity (SSP SOQ).
- 2.4. User proposed ratios as alternatives to mechanisms described under 2.2.2 and 2.2.5 above will not be allowed.
- 2.5. Supply point data at the point of interruption will be used for charge calculation purposes.
- 2.6. 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.
- 2.7. The registered shipper at the point of interruption will be the qualifying shipper for receipt of any payment.

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 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.

4. Qualifying Interruption

- 4.1. The count of qualifying interruptible days under section 3 above will increment, but subject to 4.3 below, where curtailment of gas supply was due to:
 - 4.1.1. Interruption arising from an NTS or LDZ constraint within Transco's transportation system;
 - 4.1.2. Interruption arising for Test purposes as described within Network Code section G 6.7.3 (ii)
- 4.2. The count of qualifying interruptible days under section 3 above will not increment where curtailment of gas supply was due to:
 - 4.2.1. Emergency interruption [emergency cessation of gas supply];
 - 4.2.2. Any form of commercial interruption instigated by a shipper.
- 4.3. Transco's determination of a site for interruption will increment that site's count of interruptible days under section 3 above.
- 4.4. Where Transco 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 Network Code. In such circumstances Transco will, for the purposes of section 3 above, maintain a count based on the site Transco originally nominated for interruption.
- 4.5. Failure to interrupt of the Transco 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:

- 4.5.1. no payment will be made for the Transco proposed and shipper accepted site that subsequently fails to interrupt;
- 4.5.2. no payment will be made for the Transco proposed site where shipper substituted for a matched target volume site that subsequently fails to interrupt;
- 4.5.3. where multiple sites are substituted by a shipper, the payment(s) made to Transco 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.

5. Unit Rate

- 5.1. The unit rate will be expressed in pence per kWh of peak day capacity and will be the rate as determined by Pricing Methodology PC74.
- 5.2. NTS and LDZ unit rates will be 1/15th of the annual (daily rate × 365) NTS (TO) exit capacity rates and LDZ standard 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 LDZ standard 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.

6. Invoice

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

- 6.2. Subject to 4.5 above, Transco 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.

7. Information Provision

- 7.1. Transco will publish the count of interruptible days as specified within section 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 Transco web site updated on a weekly basis.

Appendix 2C

The table below details the Baseline Entry Capacity identified in Transco's GT Licence (Special condition 28B, Schedule 2, Table 2A) and used as the basis for determination of minimum annual quantities to be offered. All quantities identified are for a 12-month period from April to March inclusive.

Baseline Entry Capacity GWh/day

Terminal	2003/4	2004/5	2005/6	2006/7 – 2019/20
Coastal Terminals				
Bacton	1,481	1,655	1,745	1,745
Easington/Rough	887	1,027	1,062	1,062
Theddlethorpe	565	791	848	848
St Fergus	1,549	1,628	1,648	1,677
Teesside	741	751	761	761
Barrow	711	711	712	712
Onshore Fields and Connections				
Hatfield Moor	1	1	1	1
Wytch Farm	3.2	3.2	3.2	3.2
Caythorpe	0	0	0	0
Burton Point	55	55	55	55
Hole House Farm	26	26	26	26
Storage				
Hatfield Moor	54	54	54	54
Hornsea	175	175	175	175
Glenmavis	99	99	99	99
Partington	215	215	215	215
Aldbrough	233	233	233	233
Cheshire	0	107	161	214
Constrained LNG				
Avonmouth	149	149	149	149
Dynevor Arms	50	50	50	50
Isle of Grain	218	218	218	218

Appendix 2D

The following table identifies the quantities to be offered in Annual System Entry Capacity auctions (to take place in September 2003) and is determined in accordance with paragraph 14(5)(g) of part 2 of Special Condition 28B of Transco's GT Licence. For periods that are subject to a QSEC allocation, then supply can be further expanded in accordance with Transco's IECR statement. Figures shown are to nearest GWh per day with the exception of Hatfield Moor (Onshore Fields and Connections), Wytch Farm and Hole House Farm.

Entry Capacity GWh/day

Terminal	2003/04		2004/5			2005/6			
	Oct - Dec	Jan - Mar	Apr - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals									
Bacton	1,481	1,481	1,655	1,108	1,149	1,025	1,098	922	891
Easington/Rough	887	887	1,027	872	879	750	778	747	763
Theddlethorpe	565	565	791	669	674	573	589	576	589
St Fergus	1,549	1,549	1,628	326	326	0	199	0	0
Teesside	741	741	751	577	608	455	471	467	486
Milford Haven	0	0	0	0	0	0	0	0	0
Barrow	711	711	711	374	394	483	514	353	269
Onshore Fields and Connections									
Hatfield Moor	1	1	1	1	1	0.8	0.8	0.8	0.8
Wytch Farm	3.2	3.2	3.2	3.2	3.2	2.56	2.56	2.56	2.56
Burton Point	55	55	55	55	55	44	44	44	44
Hole House Farm	26	26	26	5.2	5.2	0.02	0.02	0.02	0.02
Storage									
Hatfield Moor	54	54	54	54	54	43	43	43	43
Hornsea	175	175	175	175	175	140	140	140	140
Glenmavis	99	99	99	99	99	79	79	79	79
Partington	215	215	215	215	215	172	172	172	172
Aldbrough	233	233	233	233	233	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0	0
Cheshire	0	0	107	107	107	129	129	129	129
Constrained LNG									
Avonmouth	149	149	149	149	149	119	119	119	119
Dynevor Arms	50	50	50	50	50	40	40	40	40
Isle of Grain	218	218	218	218	218	174	174	174	174

Terminal	2006/7				2007/8			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,033	1,132	927	932	1,082	1,168	1,004	1,039
Easington/Rough	797	800	793	795	823	826	811	813
Theddlethorpe	616	619	597	608	629	632	628	636
St Fergus	65	155	73	101	256	322	273	314
Teesside	499	510	496	509	538	547	543	540
Milford Haven	0	0	0	0	0	0	0	0
Barrow	429	504	384	304	444	539	410	345
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Terminal	2008/9				2009/10			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,151	1,227	1,091	1,095	1,193	1,251	1,143	1,152
Easington/Rough	830	832	825	825	836	837	841	841
Theddlethorpe	646	648	639	645	653	654	674	674
St Fergus	369	495	452	509	724	809	858	900
Teesside	540	549	534	539	552	559	572	577
Milford Haven	0	0	0	0	0	0	0	0
Barrow	465	535	435	370	480	540	450	405
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Terminal	2010/11				2011/12			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,226	1,275	1,218	1,218	1,272	1,285	1,283	1,283
Easington/Rough	850	850	843	843	850	850	845	845
Theddlethorpe	677	677	678	678	678	678	678	678
St Fergus	944	972	992	1,008	1,039	1,056	1,061	1,091
Teesside	591	591	579	582	596	596	582	584
Milford Haven	0	0	0	0	0	0	0	0
Barrow	495	545	470	430	505	545	485	450
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Terminal	2012/13				2013/14			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,339	1,346	1,337	1,334	1,345	1,353	1,346	1,339
Easington/Rough	850	850	846	846	850	850	850	850
Theddlethorpe	678	678	678	678	678	678	678	678
St Fergus	1,114	1,136	1,119	1,148	1,178	1,198	1,177	1,176
Teesside	598	598	584	585	599	599	602	603
Milford Haven	0	0	0	0	0	0	0	0
Barrow	515	545	500	470	525	550	510	485
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Terminal	2014/15				2015/16			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,352	1,358	1,383	1,378	1,388	1,391	1,386	1,381
Easington/Rough	850	850	850	850	850	850	850	850
Theddlethorpe	678	678	678	678	678	678	678	678
St Fergus	1,214	1,221	1,216	1,216	1,249	1,261	1,239	1,234
Teesside	603	603	603	603	603	603	603	604
Milford Haven	0	0	0	0	0	0	0	0
Barrow	530	550	525	510	542	550	534	520
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Terminal	2016/17				2017/18			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,390	1,391	1,388	1,383	1,391	1,391	1,396	1,396
Easington/Rough	850	850	850	850	850	850	850	850
Theddlethorpe	678	678	678	678	678	678	678	678
St Fergus	1,266	1,273	1,247	1,248	1,297	1,294	1,342	1,342
Teesside	604	604	604	605	605	605	609	609
Milford Haven	0	0	0	0	0	0	0	0
Barrow	545	550	520	520	555	555	570	570
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	0.02	0.02	0.02	0.02	0.02	0.02	20.8	20.8
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Terminal	2018/19				2019/20			
	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar	Apr - Jun	Jul - Sep	Oct - Dec	Jan - Mar
Coastal Terminals								
Bacton	1,396	1,396	1,396	1,396	1,396	1,396	1,396	1,396
Easington/Rough	850	850	850	850	850	850	850	850
Theddlethorpe	678	678	678	678	678	678	678	678
St Fergus	1,342	1,342	1,342	1,342	1,342	1,342	1,342	1,342
Teesside	609	609	609	609	609	609	609	609
Milford Haven	0	0	0	0	0	0	0	0
Barrow	570	570	570	570	570	570	570	570
Onshore Fields and Connections								
Hatfield Moor	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Wytch Farm	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Burton Point	44	44	44	44	44	44	44	44
Hole House Farm	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Storage								
Hatfield Moor	43	43	43	43	43	43	43	43
Hornsea	140	140	140	140	140	140	140	140
Glenmavis	79	79	79	79	79	79	79	79
Partington	172	172	172	172	172	172	172	172
Aldbrough	186	186	186	186	186	186	186	186
Barton Stacey	0	0	0	0	0	0	0	0
Cheshire	171	171	171	171	171	171	171	171
Constrained LNG								
Avonmouth	119	119	119	119	119	119	119	119
Dynevor Arms	40	40	40	40	40	40	40	40
Isle of Grain	174	174	174	174	174	174	174	174

Appendix 2E

The tables below detail the step prices (p/kWh/day) for use in the auctions of Quarterly System Entry Capacity.

Step Price

(pence/kWh/day)

	Coastal terminals							
	Bacton	Easington & Rough	Theddlethorpe	St. Fergus	Teesside	Barrow	Increment (GWh)	Milford Haven
Baseline	0.0056	0.0011	0.0010	0.0198	0.0018	0.0004	Baseline	0
2.50%	0.0057	0.0012	0.0011	0.0204	0.0019	0.0005	50	0.0353
5.00%	0.0058	0.0013	0.0012	0.0212	0.0020	0.0006	100	0.0220
7.50%	0.0059	0.0014	0.0013	0.0214	0.0021	0.0007	150	0.0180
10.00%	0.0060	0.0015	0.0014	0.0222	0.0024	0.0008	200	0.0157
12.50%	0.0061	0.0016	0.0015	0.0229	0.0027	0.0009	250	0.0138
15.00%	0.0062	0.0017	0.0016	0.0236	0.0029	0.0010	300	0.0124
17.50%	0.0063	0.0018	0.0017	0.0244	0.0030	0.0011	350	0.0113
20.00%	0.0064	0.0019	0.0018	0.0252	0.0032	0.0012	400	0.0102
22.50%	0.0065	0.0020	0.0019	0.0259	0.0033	0.0013	450	0.0092
25.00%	0.0066	0.0021	0.0020	0.0267	0.0034	0.0014	500	0.0085
27.50%	0.0067	0.0022	0.0021	0.0274	0.0036	0.0015	550	0.0081
30.00%	0.0068	0.0023	0.0022	0.0281	0.0037	0.0016	600	0.0077
32.50%	0.0069	0.0024	0.0023	0.0288	0.0038	0.0017	650	0.0074
35.00%	0.0070	0.0025	0.0024	0.0296	0.0039	0.0018	700	0.0071
37.50%	0.0071	0.0026	0.0025	0.0301	0.0040	0.0019	750	0.0068
40.00%	0.0072	0.0027	0.0026	0.0306	0.0041	0.0020	800	0.0066
42.50%	0.0073	0.0028	0.0027	0.0310	0.0042	0.0021	850	0.0064
45.00%	0.0074	0.0029	0.0028	0.0315	0.0043	0.0022	900	0.0062
47.50%	0.0075	0.0030	0.0029	0.0319	0.0044	0.0023	950	0.0060
50.00%	0.0077	0.0031	0.0030	0.0324	0.0045	0.0024	1,000	0.0059
Baseline 2003/4 for determination of increment size (GWh)	1481	887	565	1549	741	711	Baseline 2003/4 for determination of increment size (GWh)	0

Step Price

(pence/kWh/day)

	Onshore Fields and Connections			
	Hatfield Moor	Wyth Farm	Burton Point	Hole House Farm
Baseline	0.0013	0.0000	0.0001	0.0001
10%	0.0014	0.0001	0.0002	0.0002
20%	0.0015	0.0002	0.0003	0.0003
30%	0.0016	0.0003	0.0004	0.0004
40%	0.0017	0.0004	0.0005	0.0005
50%	0.0018	0.0005	0.0006	0.0006
Baseline 2003/4 for determination of increment size (GWh)	55	3	55	26

Step Price

(pence/kWh/day)

Storage Sites											
Aldbrough		Cheshire		Hornsea		Glenmavis		Partington		Increment (GWh)	Barton Stacey
Baseline	0.0018	Baseline	0.0001	Baseline	0.0047	Baseline	0.0165	Baseline	0.0003	Baseline	0
3.13%	0.0019	7.14%	0.0002	4.20%	0.0049	7.10%	0.0170	3.60%	0.0004	15	0.0001
6.25%	0.0020	14.29%	0.0003	8.30%	0.0051	14.30%	0.0174	7.10%	0.0005	30	0.0002
9.38%	0.0021	21.43%	0.0004	12.50%	0.0053	21.40%	0.0180	10.70%	0.0006	45	0.0003
12.50%	0.0022	28.57%	0.0005	16.70%	0.0054	28.60%	0.0184	14.30%	0.0007	60	0.0004
15.63%	0.0023	35.71%	0.0006	20.80%	0.0056	35.70%	0.0191	17.90%	0.0008	75	0.0005
18.75%	0.0024	42.86%	0.0007	25.00%	0.0058	42.90%	0.0198	21.40%	0.0009	90	0.0006
21.88%	0.0025	50.00%	0.0008	29.20%	0.0060	50.00%	0.0205	25.00%	0.0010	105	0.0007
25.00%	0.0026			33.30%	0.0061			28.60%	0.0011	120	0.0008
28.13%	0.0027			37.50%	0.0062			32.10%	0.0012	135	0.0009
31.25%	0.0028			41.70%	0.0063			35.70%	0.0013	150	0.0010
34.38%	0.0029			45.80%	0.0064			39.30%	0.0014	165	0.0011
37.50%	0.0030			50.00%	0.0065			42.90%	0.0015	180	0.0012
40.63%	0.0031							46.40%	0.0016	195	0.0013
43.75%	0.0032							50.00%	0.0017	210	0.0014
46.88%	0.0033									225	0.0015
50.00%	0.0034									240	0.0016
										255	0.0017
										270	0.0018
										285	0.0019
										300	0.0020
Baseline 2003/4 for determination of increment size (GWh)	233		161		175		99		215	Baseline 2003/4 for determination of increment size (GWh)	0

Step Price

(pence/kWh/day)

	Constrained LNG					
	Avonmouth		Dynevor Arms		Isle of Grain	
	Baseline	0.0020	Baseline	0.0000	Baseline	0.0058
	5%	0.0021	10%	0.0001	3.3%	0.0059
	10%	0.0022	20%	0.0002	6.7%	0.0060
	15%	0.0023	30%	0.0003	10.0%	0.0061
	20%	0.0024	40%	0.0004	13.3%	0.0062
	25%	0.0025	50%	0.0005	16.7%	0.0063
	30%	0.0026			20.0%	0.0064
	35%	0.0027			23.3%	0.0065
	40%	0.0028			26.7%	0.0066
	45%	0.0029			30.0%	0.0067
	50%	0.0030			33.3%	0.0068
					36.7%	0.0069
					40.0%	0.0070
					43.3%	0.0071
					46.7%	0.0072
					50.0%	0.0073
Baseline 2003/4 for determination of increment size (GWh)		149		50		218

3. TRANSPORTATION CHARGING METHODOLOGY

3.1 Introduction

Standard Condition 4 of Transco's Gas Transporter (GT) Licence requires Transco to establish a methodology showing the methods and principles on which transportation charges are based. Transco's present charging methodology was introduced in 1994 and has been modified from time to time in accordance with Standard Condition 4A of the Licence.

3.1.1 Price Control Formulae

With effect from 1 April 2002 the transportation price control treats the National Transmission System Owner (NTS TO), the NTS System Operator (NTS SO) and the Local Distribution Zones (LDZs) separately. The separate price controls and incentives determine the maximum revenue that Transco 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 gas transported to supply points in various consumption bands within the LDZ network;
- the volume of NTS entry and exit capacity and linepack made available;
- Transco's performance under the various SO incentive schemes, covering a range of activities;
- the indexation factor - under the LDZ and NTS TO formulae allowed revenue is adjusted each year by a factor equal to two percentage points less than the rate of inflation, measured on a prescribed historical basis by reference to the Retail Price Index (RPI -2);
- 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 revenues¹. 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 the previous price control period April 1997 to March 2002 charges were normally revised on 1 October and only changed at other times when necessary, for example to avoid over-recovery following auctions of entry capacity. Under the new price control regime effective from 1 April 2002 charges will be kept under review and revised as necessary to ensure compliance with Transco's GT Licence.

3.1.2 Objectives of the Charging Methodology

The transportation charging methodology has to comply with objectives set out in the Licence. These are to:

- reflect the costs incurred by Transco 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,
 - ii) to promote competition between gas suppliers and between gas shippers.

¹ Auctions presently relate only to NTS entry capacity revenues, for which a mechanism exists whereby a proportion of any excess auction revenue may be returned to shippers within the formula year by reference to the net value of NTS entry capacity buy-back costs in each month.

In addition to these Licence objectives Transco has its own objectives for the charging regime. These are that the transportation charging methodology should:

- promote efficient use of the transportation system;
- generate stable charges;
- be easy to understand and implement.

Before Transco makes any changes to the methodology, it consults with the industry in accordance with Standard Condition 4A of the Licence. Ofgem has the right to veto any proposed changes to the methodology.

3.1.3 Structure of Charges

The structure of Transco's transportation charges reflects the revised price control arrangements which came into effect from 1 April 2002. Charges are set separately for the National Transmission System (NTS) and the Local Distribution Zones (LDZs). NTS charging is then sub-divided between those activities related to the Asset Owner (TO) and System Operator (SO). Although the LDZ control is not sub-divided, the LDZ charges are split between system related activities and customer related activities.

The maximum revenue to be collected from the NTS TO and NTS SO charges is determined by the TO and SO price controls. The NTS TO allowed revenue is collected solely by entry and exit capacity charges while the NTS SO allowed revenue is collected largely by means of a single commodity charge. The levels of NTS capacity and commodity revenue are therefore now determined by the separate TO and SO price controls and not as in previous years by a 65:35 capacity:commodity ratio.

The target level for revenue derived from Baseline entry capacity sales, determined through auctions, is set to 50% of the NTS TO target revenue level. The NTS exit capacity charges 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.

While total LDZ revenue is determined by the relevant price control, the share of this revenue to be recovered from the LDZ system charges and the LDZ customer charges respectively is based on the relative cost of each area of activity as determined by Transco's Transaction Model, including an asset-based adjustment scaled so that the final cost pools sum to the target allowed revenue.

The cost breakdown used as the basis for the October 2003 LDZ charges is set out below:

Table 3.1.3: 2002 and 2003 LDZ Cost Breakdown %

Year	LDZ System	LDZ Customer	Total LDZ
2002	70.9	29.1	100
2003	71.8	28.2	100

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.

3.1.4 Changes introduced in 2003

Reserve prices for Monthly System Entry Capacity (MSEC) from April 2003 onwards will be set equal to the baseline price for capacity offered in the auction of QSEC capacity with the relationship between MSEC and DSEC reserve prices remaining as at present, with DSEC reserve price at each entry point equal to two thirds MSEC reserve price at each entry point.

From October 2003 the reserve price for daily firm system entry capacity sales sold on the day of the capacity itself will be zero with the reserve price for DSEC sales ahead of the day remaining equal to two thirds MSEC reserve price at each entry point.

The existing balance for exit capacity charges will be maintained, rather than rebalancing exit capacity charges, until Universal Firm Registration of NTS exit capacity is introduced.

From October 2004 the SO commodity charge will apply to gas entering the gas transportation system at system entry points as well as to gas offtaken at exit points, with the same rate of commodity charge applying at both entry and exit.

The phased rebalancing of LDZ system charges to better reflect the use made of the system by loads of different sizes which was begun in 1999 was concluded last year. While the charging functions will continue to be reviewed against the latest cost and usage information as it becomes available, it is hoped that few changes in the structure of the charges will be necessary over the next few years. Ofgem has indicated that during 2003/04 it intends to undertake a review of Transco's LDZ charging objectives and methodology. Transco will participate in this review.

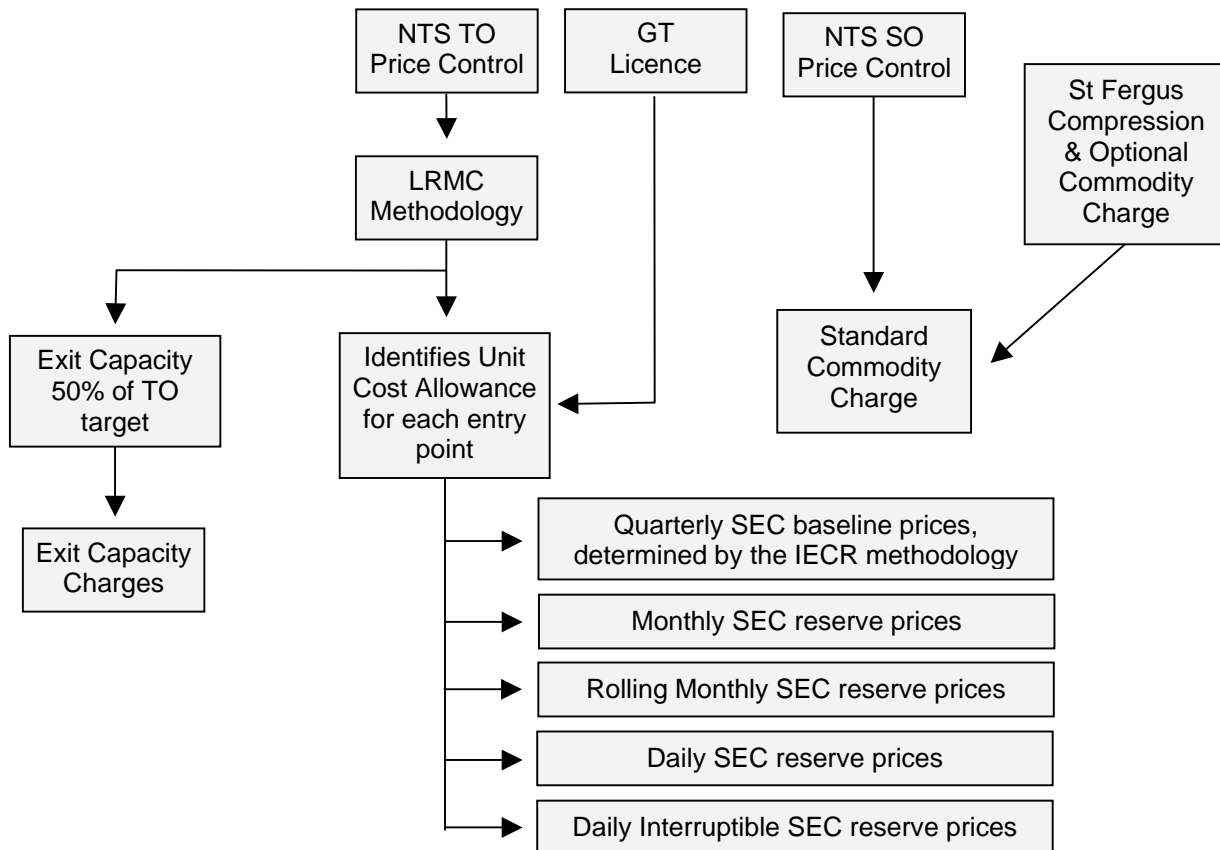
3.2 NTS Charging Methodology

3.2.1 Introduction

The maximum revenue to be recovered from NTS TO and SO charges is determined by the price controls as described in section 3.1 above. Figure 3.2.1 presents a schematic flow diagram of how the NTS capacity and commodity charges are set.

Commodity charges are payable on gas flowed. 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).

Figure 3.2.1 Setting of NTS Charges & Reserve Prices



All NTS TO charges are calculated on a capacity basis with an ex-ante assumption of a 50:50 split in revenue between that raised from entry and that raised from exit charges. Entry capacity is sold by auction subject to reserve prices whereas exit capacity charges are applied on an administered peak day basis. Both auction reserve prices and exit charges reflect Transco's 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.

3.2.2 System Entry Capacity

System Entry Capacity is presently 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 outlined in section 3.2.7 below.

Under Ofgem's final proposals for the NTS SO incentive schemes, Transco is obliged to make available for sale in the Long Term auctions, Quarterly System Entry Capacity (QSEC) calculated in accordance with paragraph 14(5)(g) of part 2 of special condition 28B of Transco's GT Licence. QSEC can be obtained from 3 to 16 years ahead of the intended year of use. The methodology for determination of the baseline price and incremental price steps is set out in Transco's Incremental Entry Capacity Release (IECR) 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 paragraph 14(5)(g) of part 2 of special condition 28B of Transco's GT Licence. Transco is obliged to make available for sale in the MSEC auctions capacity at the level of the NTS SO baseline level, as set out in the NTS TO price control, less any baseline capacity already sold in previous auctions. Any baseline 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 baseline 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, Transco 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. Transco retains a right to scale back previously released interruptible capacity for the purposes of system management.

Above baseline capacity can be released by Transco in accordance with its incremental investment or capacity buy back incentive as set out in its GT licence. QSEC is the vehicle for releasing additional capacity in accordance with the incremental investment incentive. Capacity can be released in accordance with the buy back incentive in all firm capacity release processes, although the quantities should be signalled in advance in the annual and rolling MSEC processes.

A situation may arise in which Transco is unable to meet all entry capacity nominations. In this case it may buy-back entry capacity through a tender mechanism, tenders being accepted in ascending price order until the required level of buy-back has been achieved. Transco is also developing additional tools which may be used to buy-back capacity in future.

Figure 3.2.2 below shows schematically how system entry capacity might actually be allocated on a day.

Figure 3.2.2 System Entry Capacity Auctions

QSEC Capacity available = (SO Baseline entry capacity)		
QSEC Sold	QSEC Unsold	
MSEC Capacity available = (SO Baseline entry capacity – QSEC sold)		
MSEC Sold	MSEC Unsold	
RMSEC Capacity available = (SO Baseline entry capacity – QSEC sold – MSEC sold)		
RMSEC sold	RMSEC unsold	
On the day System Entry Capacity		
MSEC Nominations	DISEC	DSEC

3.2.3 Exit Capacity Charges

The terms on which exit capacity is sold are set out in the Network Code, 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.

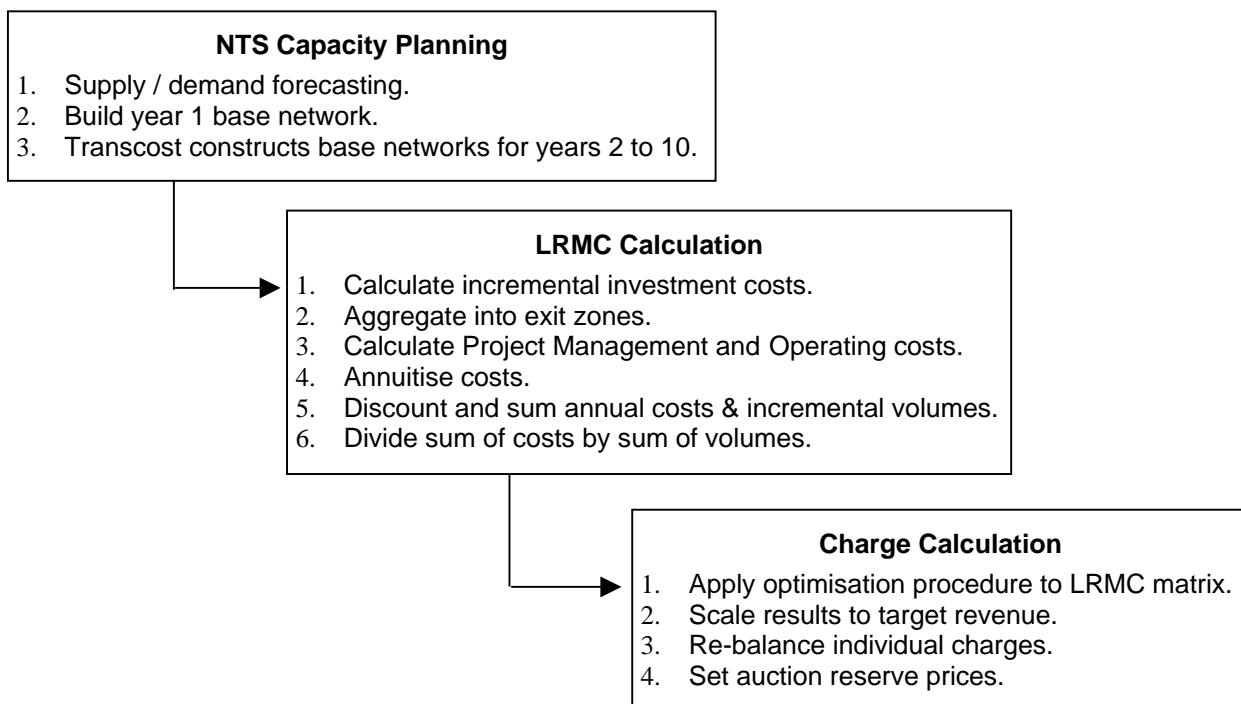
A model, known as Transcost, has been developed by Transco to estimate LRMCs to support the setting of NTS capacity charges. Transcost is also capable of estimating LRMCs for alternative supply and demand patterns relatively quickly and easily. A free copy of Transcost, supporting documentation and the data used when setting the April 2002 charges can be obtained by calling Transco on 01926-656317.

3.2.4 Calculation of Long Run Marginal Costs

The LRMC approach derives forward-looking charges, which are intended to provide economically efficient signals to system users. Figure 3.2.3 presents a schematic flow diagram of the steps involved in calculating LRMC reflective NTS TO capacity charges.

The LRMC calculation uses the supply / demand match set out in the Base Plan Assumptions and the reinforcement plans that are derived from it. Transcost first constructs a base network which is just sufficient to support the supply / demand match for year 1 of the analysis. This will equate to the present network plus any known reinforcement projects that will be completed before year 1 begins. For each subsequent year of the analysis Transcost will reinforce the modelled network from the previous year so that it is just sufficient to support the supply / demand match for that year. There are therefore ten separate but related networks to be used in the analysis.

Figure 3.2.4 LRMC Overview



The steps in this process are described in more detail below and illustrated by reference to the derivation of the LRMC for the route between Bacton entry point and SW3 exit zone.

3.2.4.1 Calculation of Incremental Investment Costs

Transcost calculates the additional investment required in new pipelines and / or compressors to support a sustained notional increase in flow along each route. Therefore, the more constrained a route is in terms of available capacity, the higher will be the level of investment necessary This analysis is carried out using the base case networks described above for all 10 years.

Size of Increment This is set such that the economic signals resulting from the LRMC process are clear: Too small an increment and the LRMCs will tend to zero, too large and they will tend to a distance related charge. The increment chosen, 2.834 mcm / d (100 mcf) represents in general, around 10% of the flow along a route. Transcost is configured such that this increment can be changed as appropriate.

Investment Costs The estimated costs of various types of investment are set out below. Transcost is configured such that these estimates can be changed as appropriate.

Table 3.2.4.1a Transcost Investment Costs

Description	Cost £s m
Pipeline	$0.0003115 \times \text{diameter} \div 0.3505652 \text{ km}$
Compressor – Greenfield	30.0 per station
Compressor – Existing site	15.0 per turbine

Transcost analysis determined that the minimum investments required to facilitate an incremental flow from Bacton to two of the exit points in SW3 (Aylesbeare and Kenn) were as follows.

Table 3.2.4.1b Bacton to SW3 Costs (£ million)

	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
Aylesbeare	32.2	34.7	32.7	35.5	30.2	33.5	35.0	39.0	34.0	41.7
	5	5	5	0	5	0	0	0	0	5
Kenn	34.2	34.7	35.2	35.5	32.2	36.0	38.0	42.0	37.0	42.2
	5	5	5	0	5	0	0	0	0	5

3.2.4.2 Aggregation into Exit Zones

NTS exit points which deliver gas into the Local Transmission System (LTS) are grouped into 33 exit zones for charging purposes. Grouping is designed to;

- Reduce the number of individual charges;
- Reflect areas with common reinforcement cost drivers; and
- Reflect actual system operation. The gas supplied to a specific area within an LDZ can often be routed through a number of different NTS exit points.

Investment costs for an exit zone are calculated by means of a flow-weighted average of all the individual exit points within that zone. Flow weighting is based upon the projected peak day delivery volumes at each exit point. It should be noted that individual supply points that are supplied directly from the NTS are excluded from this aggregation process.

Table 3.2.4.2 Costs to Exit Points in SW3 (Flow Weighted)

		Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
Investment	Aylesbeare	32.25	34.75	32.75	35.50	30.25	33.50	35.00	39.00	34.00	41.75
	Kenn	34.25	34.75	35.25	35.50	32.25	36.00	38.00	42.00	37.00	42.25
Weightings	Aylesbeare	23%	23%	23%	23%	23%	23%	23%	23%	23%	23%
	Kenn	77%	77%	77%	77%	77%	77%	77%	77%	77%	77%
Average	SW3	33.80	34.75	34.69	35.50	31.80	35.44	37.32	41.32	36.32	44.46

3.2.4.3 Project Management and Operating Costs.

Project management costs are variable costs that are dependent upon many factors including location, timing, type and size of investment. Size of investment is the main indicator of the scale of expected project management costs. In the LRMC estimation process project management costs are assumed to be 15% of the previously identified investment costs. Similarly, the change in operating costs associated with the increased throughput of the increment is assumed to be 1.5% of investment costs.

Table 3.2.4.3 Project Management & Operating Costs (£ million)

	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
Capital Cost Investment	33.80	34.75	34.69	35.50	31.80	35.44	37.32	41.32	36.32	44.46
Project Management (15%)	5.07	5.21	5.20	5.33	4.77	5.32	5.60	6.20	5.45	6.67
Total	38.87	39.96	39.89	40.83	36.57	40.75	42.92	47.52	41.77	51.13
Operating Cost (1.5%)	0.51	0.52	0.52	0.53	0.48	0.53	0.56	0.62	0.54	0.67

3.2.4.4 Calculation of Annuitised Costs

The capital cost is annuitised, that is spread evenly over the expected life of the asset taking into account the required rate of return. The annuity period considered appropriate is 20 years following the assumption of the average economic life of new NTS pipeline assets made in the BG / Ofgas Joint Consultation Document of February 1993. The annuity discount factor is 6.25% per annum, consistent with the cost of capital used to set maximum allowed revenue under the proposed price controls to apply from 1 April 2002. To obtain the annuitised present value, the capital cost is divided by 11.9433 (the sum of the discount factors over 20 years at 6.25%).

Table 3.2.4.4 Annuitised Costs (£ million)

	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
Capital Cost	38.87	39.96	39.89	40.83	36.57	40.75	42.92	47.52	41.77	51.13
Annuitised	3.25	3.35	3.34	3.42	3.06	3.41	3.59	3.98	3.50	4.28
Operating Costs	0.51	0.52	0.52	0.53	0.48	0.53	0.56	0.62	0.54	0.67
Total Annual Cost	3.76	3.87	3.86	3.95	3.54	3.94	4.15	4.60	4.04	4.95

3.2.4.5 Calculation of Discounted Annual Costs & Incremental Volumes

The LRMC for the entire period of the analysis is the weighted average of each individual year's estimate of the marginal cost, with earlier years having a greater weight than later ones. In order to provide appropriate weighting the costs and incremental volumes for future years are discounted at 6.25% per annum. Capacity charges are expressed in terms of pence per peak day kilowatt-hour per day. However incremental volumes are expressed in terms of millions of cubic metres. Therefore, at this stage in the process, the incremental volumes are converted into energy units.

Table 3.2.4.5 Discounted Annual Costs (£ million) & Incremental Volumes (GWh)

	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
Annual cost	3.76	3.87	3.86	3.95	3.54	3.94	4.15	4.60	4.04	4.95
Incremental volume	30.19	30.19	30.19	30.19	30.19	30.19	30.19	30.19	30.19	30.19
Discount Factor	1.00	0.94	0.89	0.83	0.78	0.74	0.70	0.65	0.62	0.58
Discounted cost	3.76	3.64	3.44	3.28	2.76	2.92	2.91	2.99	2.50	2.87
Discounted volume	30.19	28.38	26.87	25.06	23.55	22.34	21.33	19.62	18.72	17.51

3.2.4.6 Calculation of LRMC

The LRMC in pence per peak day kilowatt-hour per day is calculated by dividing total discounted cost by total discounted volume.

Total Discounted Cost (£s m)	31.07
Total Discounted Volume (GWhs)	233.37
LRMC (p / pdkWh / annum)	13.3136
Days in Year	365
LRMC (p / pdkWh / day)	0.0365

3.2.5 Calculation of NTS Capacity Charges

It is not practical to apply the full matrix of LRMCs for all the routes on the system directly as charges. Instead, an LRMC reflective charge is determined for each entry point and each exit point such that, when these are combined for any particular route, they replicate as closely as possible the calculated LRMC for that route.

An optimisation procedure (Microsoft Excel Solver) is used to determine the LRMC reflective entry and exit charges. For each combination of entry point and exit point, the solver uses the cost figure as the dependent variable in an equation that represents the sum of one entry charge and one exit charge. Each valid combination of entry to exit can be represented by the following equation:

$$y_{ij} = x_i + x_j + e_{ij}$$

Where:

- y_{ij} is the LRMC for the route from entry point i to exit point j;
- x_i is the entry charge at point i;
- x_j is the exit charge at point j; and,
- e_{ij} is the absolute error.

The optimisation procedure calculates the best fit by minimising the sum of the squared error terms, e_{ij} , for all entry and exit combinations. To achieve a unique solution to the procedure, it is necessary to fix at least one parameter. To achieve this the optimisation is constrained such that there is a minimum permitted charge of 0.0001 p / pdkWh / d.

Since the charges determined by this process are based on long run marginal costs, when applied to forecast peak day flows they may not be expected to generate the target revenues. They therefore need to be scaled, with separate factors for entry and exit charges, to ensure that the charges are consistent with the appropriate entry and exit target revenues.

3.2.6 Capacity Charge Re-balancing

The capacity charges actually applied do not necessarily fully reflect the latest scaled LRMCs, particularly if there have been significant year on year changes. The pricing methodology takes account of the potential impact of change on particular charges, in line with a preference for charging stability. Using the existing set of charges, scaled to achieve target entry and exit revenue, in conjunction with the latest and previous set of scaled LRMC reflective charges, the following re-balancing rules are applied:

- If both the previous and latest scaled LRMC reflective charges are higher than the existing scaled charge, then the existing charge will be increased to a level no greater than the lower of the two scaled LRMC reflective charges;
- If both the previous and latest scaled LRMC reflective charges are lower than the existing scaled charge, then the charge will be reduced to a level no lower than the higher of the two scaled LRMC reflective charges;
- Scaled charges that are already between the previous and latest scaled LRMC reflective charges will remain unchanged except for scaling; and
- Charges are not permitted to move in either direction by more than a given percentage of their existing scaled value.

Following the implementation of PC76 in December 2002, the existing balance for exit capacity charges will be maintained, rather than rebalancing exit capacity charges, until Universal Firm Registration of NTS exit capacity is introduced.

3.2.7 Reserve Prices in System Entry Capacity Auctions

System entry capacity is allocated by means of auctions as described in the Network Code and outlined in section 3.2.2 above. This approach includes various reserve prices below which bids will not be accepted. In the auctions of Long term System entry capacity, held in January 2003, the minimum price at which the baseline level of entry capacity was made available was the Unit Cost Allowance (UCA) as determined by Ofgem (assuming an annuity discount of 6.25% per annum) These UCAs have been determined from incremental cost analysis using the same basic approach as used in determining the LRMCS using the Transcost model detailed in sections 3.2.4 to 3.2.6 above. However there were a few differences which are listed below:

- the use of a 6 mcmd increment size for the UCA analysis instead of the 2.83 mcmd increment used for the standard LPMC analysis;
- the manner of determining average entry unit costs from the analysis. For the UCA analysis entry and exit unit costs were fitted to the results for each year and a simple average entry unit cost was then calculated across the ten years. For the traditional LPMC determination weighted average costs are first calculated for each route across the ten years and then entry and exit unit costs are fitted to these average costs.
- there is no scaling applied to these UCAs as in section 3.2.6 above. These UCAs represent Ofgem's view of the costs Transco could reasonably be expected to incur in undertaking additional investment in capacity.

Pricing Consultation PC76 proposed that the MSEC reserve prices should be equal to the baseline price for capacity offered in the auction of QSEC capacity . This proposal was not vetoed by Ofgem

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 of the capacity itself will be 100%. The discount for DSEC sold ahead of the day will remain at 33.3%.

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

3.2.8 Constrained LNG

Shippers that book the constrained LNG storage service agree to ensure the continuing availability of transmission support gas throughout the winter period on behalf of Transco. During 2003 / 04 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 Transco's LNG business unit.

3.2.9 Standard NTS SO Commodity Charge

This is a charge per unit of gas transported by the NTS and is applied independently of entry and exit points. The charge is payable on exit flows until October 2004 when the appropriate rate will be payable on both entry and exit flows. 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, the commodity rate is provisionally set by dividing the target revenue by forecast system throughput.

3.2.10 Optional NTS Commodity Tariff

In June 1998 Transco 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 either the standard or optional tariff. 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.

3.2.11 Compression Charge

An additional charge is payable where gas is delivered into the Transco system 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.

3.3 LDZ Charging Methodology

3.3.1 Introduction

The Local Distribution Zone (LDZ) charges effective from 1 October 2003 are based on the methodology fully described in consultation paper PC68 - Review of LDZ Transportation Charges. The LDZ networks contain a series of pipe networks split into four main pressure tiers:

Table 3.3.1a LDZ Pressure Tiers

Pressure Tier	Operating Pressure
Local Transmission System (LTS)	7 - 38 bar
Intermediate Pressure System (IPS)	2 - 7 bar
Medium Pressure System (MPS)	75 mbar - 2 bar
Low Pressure System (LPS)	Below 75 mbar

Each LDZ has a similar proportion of LTS, MPS and LPS pipelines but not all the LDZs contain IPS pipelines. The Low Pressure System itself accounts for 223,000 km out of the total 273,000 km of LDZ pipeline. In order to provide a more cost reflective basis for charging, the LPS is sub-divided on the basis of pipe diameter into six sub-tiers as shown below.

Table 3.3.1b LPS Sub Tiers

Pipe Diameter
>355mm
250- 355mm
180-250mm
125-250mm
90-125mm
<=90mm
Total

The principle underlying the LDZ charging methodology is that charges should reflect the average use of the network made by customers of a given size, rather than the actual use made by a particular customer. The latter methodology would be too complex to be a practical basis of charging. Analysis has shown that there is a good correlation between customer size and offtake tier. Large customers are typically supplied from higher-pressure tiers and small customers from lower pressure tiers. Such an approach avoids inconsistencies that may arise if neighbouring sites of similar size are actually connected to different pressure tiers.

3.3.2 Outline of Methodology

The methodology calculates the average cost of utilisation for each of the main pressure tiers of the LDZ system. Combining this with the probability of loads within a consumption band using that pressure tier generates a tier charge for an average load within that band. The summation of these tier charges gives the total charge for a load within the consumption band to use the LDZ system. The methodology uses average costs rather than marginal costs to reflect the total costs of using the system. The detail below describes the derivation of the capacity charge function and is therefore based on peak daily flows. A similar calculation, based on annual flows, is carried out to determine the commodity charge function. The data used is that from the most recent review carried out in 2001.

3.3.3 Determination of Costs

The costs related to each pressure tier were derived from the Activity Based Cost (ABC) model. These costs are split 50:50 into capacity and commodity elements.

Table 3.3.3a Determination of Tier Costs

Pressure Tier	LPS Sub Tier	% Total ABC	Cost (£M)	
			Total	Capacity (50%)
LTS		15.7%	196.3	98.1
IPS		5.4%	66.9	33.5
MPS		16.2%	201.4	100.7
LPS		62.7%	782.4	391.2
TOTAL		100.0%	1247.0	623.5

The split of LPS costs down to sub-tier level is based on year 2000 replacement cost data.

Table 3.3.3b Determination of LPS Costs

LPS Sub Tier		% Total 2000 Replacement Cost	Cost (£M)	
			Total	Capacity (50%)
LP1	>355mm	12.3%	96.2	48.1
LP2	250-355mm	12.7%	99.4	49.7
LP3	180-250mm	10.5%	82.2	41.1
LP4	125-180mm	15.8%	123.6	61.8
LP5	90-125mm	26.1%	204.2	102.1
LP6	<90mm	22.6%	176.8	88.4
TOTAL		100%	782.4	391.2

3.3.4 Probability of Pressure Tier / Sub Tier Usage

The probability of a unit of gas, supplied to a customer of given size, having passed through the various pressure tiers / sub tiers within the LDZ network is estimated. This estimation is based on the results from a survey of the pressure tier / sub tier at which individual supply points are attached to the Transco pipeline system in conjunction with the results of network analysis.

Table 3.3.4 System Usage Probability Matrix

Consumption Band (MWh)	LDZ Tiers			LPS Sub Tiers					
	LTS	IPS	MPS	LP1	LP2	LP3	LP4	LP5	LP6
0-73.2	97.8%	44.7%	94.4%	56.3%	76.7%	83.7%	77.5%	54.7%	17.1%
73.2 - 146.5	97.7%	44.6%	94.6%	55.5%	73.7%	76.7%	66.7%	42.7%	15.4%
146.5 – 293	97.8%	44.7%	94.2%	59.0%	78.2%	79.8%	67.8%	43.8%	17.2%
293 – 439	97.6%	45.0%	94.0%	52.8%	70.5%	72.8%	61.4%	40.0%	16.6%
439 – 586	97.6%	44.9%	94.1%	52.9%	70.3%	72.3%	61.4%	40.2%	16.8%
586 – 732	97.7%	44.6%	94.6%	55.0%	73.2%	73.9%	62.3%	43.1%	16.9%
732 - 2,931	97.5%	45.3%	93.7%	50.4%	66.8%	68.3%	57.2%	36.2%	13.4%
2,931 - 14,654	97.2%	44.6%	94.3%	43.1%	56.8%	54.9%	41.4%	20.9%	6.9%
14,654 - 58,614	96.7%	45.7%	91.3%	24.8%	31.8%	26.1%	15.2%	6.8%	0.0%
58,614 - 293,071	96.5%	50.0%	78.0%	10.3%	12.4%	6.5%	6.8%	4.1%	1.4%
>293,071	97.5%	49.1%	41.1%	1.2%	1.7%	1.6%	1.3%	1.0%	1.0%

Table 3.3.4 shows that for the 0-73.2MWh consumption band 97.8% (3,117 GWh from Table 3.3.5) of the total peak offtake for this consumption band (3,191 GWh) goes through the LTS, 44.7% goes through the IPS, and 94.4% through the MPS.

3.3.5 Pressure Tier / Sub Tier Usage Volumes

The application of usage probabilities to the LDZ peak day offtake volumes provides an estimate of the extent to which the different load bands make use of capacity across the pressure tiers.

Table 3.3.5 Peak Daily Capacity Utilisation (GWh)

Consumption Band (MWh)	LDZ Tiers			LPS Sub Tiers					
	LTS	IPS	MPS	LP1	LP2	LP3	LP4	LP5	LP6
0-73.2	3,117	1,425	3,010	1,794	2,446	2,668	2,472	1,745	545
73.2 - 146.5	178	81	172	101	134	140	122	78	28
146.5 - 293	159	73	153	96	127	130	110	71	28
293 - 439	82	38	79	44	59	61	52	34	14
439 - 586	64	29	62	35	46	47	40	26	11
586 - 732	53	24	51	30	40	40	34	23	9
732 - 2,931	191	89	184	99	131	134	112	71	26
2,931 - 14,654	183	84	177	81	107	103	78	39	13
14,654 - 58,614	123	58	116	32	41	33	19	9	0
58,614 - 293,071	87	45	70	9	11	6	6	4	1
>293,071	69	35	29	1	1	1	1	1	1
Total	4,306	1,981	4,104	2,322	3,143	3,364	3,046	2,101	676

3.3.6 Cost per Unit of Capacity Utilised

The cost of providing capacity utilised on the peak day within each pressure tier / sub tier per unit of capacity is calculated by the division of capacity related costs, set out in section 3.3.2, by the volume of capacity utilised. In these calculations the LPS is not treated as a single entity but rather as individual sub tiers.

Table 3.3.6 Cost per Unit of Capacity Utilised

	LDZ Tiers			LPS Sub Tiers					
	LTS	ITS	MPS	LP1	LP2	LP3	LP4	LP5	LP6
Capacity Cost (£m)	98.1	33.5	100.7	48.1	49.7	41.1	61.8	102.1	88.4
Capacity Utilised (PD GWhs)	4,306	1,981	4,104	2,322	3,143	3,364	3,046	2,101	676
Unit Cost (p / pdkWh / a)	2.28	1.69	2.45	2.07	1.58	1.22	2.03	4.86	13.08

3.3.7 Average Cost of Utilisation

The costs calculated in Table 3.3.6 represent the cost per unit of capacity utilised within each pressure tier / sub tier. Charging however is based on the average expected use made of each tier of the pipeline system. The average cost, for customers in each load band, of utilising a particular pressure tier / sub tier, is calculated by multiplying the unit cost of utilising the tier by the probability that the tier is utilised by customers in the load band. This is illustrated in Table 3.3.7a below for the MPS.

Table 3.3.7a Example - Average Cost (p / pd kWh / a) of Utilisation of MPS by Load Band

Consumption Band (MWh)	Utilisation Cost	Probability of Use %	Average Cost
0-73.2	2.45	94.4%	2.32
73.2 - 146.5	2.45	94.6%	2.32
146.5 - 293	2.45	94.2%	2.31
293 - 439	2.45	94.0%	2.31
439 - 586	2.45	94.1%	2.31
586 - 732	2.45	94.6%	2.32
732 - 2,931	2.45	93.7%	2.30
2,931 - 14,654	2.45	94.3%	2.31
14,654 - 58,614	2.45	91.3%	2.24
58,614 - 293,071	2.45	78.0%	1.91
>293,071	2.45	41.1%	1.01

Table 3.3.7b below summarises the average cost, by consumption band, of using the complete LDZ system.

Table 3.3.7b Average Cost of LDZ Utilisation by Consumption Band

Consumption Band (MWh)	Pence / peak day kWh / Annum									
	LTS	IPS	MPS	LP1	LP2	LP3	LP4	LP5	LP6	Total
0 - 73.2	2.23	0.75	2.32	1.17	1.21	1.02	1.57	2.66	2.23	15.17
73.2 - 146.5	2.23	0.75	2.32	1.15	1.17	0.94	1.35	2.08	2.01	14.00
146.5 - 293	2.23	0.76	2.31	1.22	1.24	0.98	1.38	2.13	2.25	14.49
293 - 439	2.22	0.76	2.31	1.10	1.11	0.89	1.25	1.95	2.18	13.76
439 - 586	2.22	0.76	2.31	1.10	1.11	0.88	1.25	1.95	2.20	13.79
586 - 732	2.23	0.75	2.32	1.14	1.16	0.90	1.26	2.09	2.22	14.07
732 - 2,931	2.22	0.76	2.30	1.04	1.06	0.83	1.16	1.76	1.75	12.89
2,931 - 14,654	2.22	0.75	2.31	0.89	0.90	0.67	0.84	1.02	0.90	10.50
14,654 - 58,614	2.20	0.77	2.24	0.51	0.50	0.32	0.31	0.33	0.00	7.19
58,614 - 293,071	2.20	0.85	1.91	0.21	0.20	0.08	0.14	0.20	0.18	5.96
>293,071	2.22	0.83	1.01	0.02	0.03	0.02	0.03	0.05	0.13	4.33

3.3.8 CSEPs

It has been suggested that CSEPs may use less of the LDZ system when compared with standard supply points of the same peak daily consumption, and hence separate charging functions have been generated. CSEP specific connection data is used to compile a CSEP connection probability matrix in place of Table 3.3.4.

The costs calculated earlier in Table 3.3.6 represent the cost per unit of capacity utilised within each pressure tier / sub tier of the LDZ by all loads. CSEP charging is based on the average expected cost, in each consumption band, for a CSEP utilising a particular pressure tier / sub tier. It is calculated by multiplying the unit cost of utilising each tier (Table 3.3.6) by the probability that the tier is utilised by CSEPs within a consumption band (CSEP replacement table for Table 3.3.4). The summation of each of these tier / sub-tier costs gives a total LDZ cost as in Table 3.3.7b.

3.3.9 Setting the Charging Functions

To provide a workable basis for charging individual customers of differing sizes the total average costs of utilising each tier of the LDZ network are plotted. For the capacity charges for directly connected supply points these costs are the total costs detailed in 3.3.7b above. Functions are fitted to the data points such that the error term is minimised. The functions found to best fit the underlying average cost data are in the form of a power of the peak daily load (SOQ) with straight-line elements for the domestic (<73.2 MWh / annum) consumption band and the small I&C consumption band (73.2 to 732 MWh / annum). These functions must then be scaled so that when applied to all supply points connected to the Transco network they are expected to generate the desired target revenue. For CSEPs and standard supply points less than 732 MWh / annum, the functions for capacity charges are the same as are the functions for commodity charges.

3.4 LDZ Customer and Other Charges Methodology

Customer charges reflect supply point and customer-related costs, including costs relating to service pipes and emergency work, Customer Portfolio Management, and a proportion of other shipper services costs including Billing, Account Management and Service Development.

3.4.1 Customer Charge Methodology

The customer charge methodology is based on an analysis of the extent to which service pipe and emergency service costs vary with supply point size. This analysis is used to determine the allocation of the recovery of the target revenue (based on Table 3.1.3 - LDZ Cost Breakdown) from supply points grouped in broad load bands. This is described in more detail below.

1. Using a methodology similar to that described in section 3.1.3 (operating costs plus an asset-based adjustment), the customer cost pool is sub-divided into the following cost pools:
 - i. service pipes
 - ii. emergency work
2. Each cost pool is then divided among a number of consumption bands based on weighted consumer numbers by consumption band. The consumption bands are based on the annual quantity of gas consumed. The weightings are derived from an analysis of how the costs of providing each of the services listed in 1. above vary with consumption size.
3. For each cost pool, an average cost per consumer is then calculated for each consumption band by dividing by the number of consumers in that consumption band.
4. A total average cost per consumer is then calculated for each consumption band by adding the unit costs of each service, that is service pipes, emergency work and shipper services.
5. Finally, using regression analysis, functions are developed that best fit the relationship between consumption size and total average cost per consumer.

Charges for supply points consuming below 73,200kWh (mainly domestic) consist of just a commodity-related charge. Charges for smaller I&C supply points, consuming between 73,200 and 732,000 kWh per annum, are based on a capacity-related charge and a fixed charge which varies with meter-reading frequency. Charges for larger I&C supply points are based on a function that varies with supply point capacity.

3.4.2 Charging for Connected Systems (CSEPs)

The standard customer charge is not levied in respect of supply points within CSEPs. However a CSEP administration charge is levied to reflect Transco's administration costs related to servicing these loads. The methodology for setting this charge was established in 1996 and is based on the same methodology described in 3.4.3 below for setting Other Charges.

3.4.3 Other 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 of allocation arrangements at shared supply meter points and Interconnectors;
- charges for specific services at Interconnectors;
- charges for Transco supplied meter reads (Must Reads) where a shipper has been unable to provide meter readings in compliance with the Network Code;
- charges for opening meter read estimates;
- charges connected with the Transco isolation service of removing or clamping meters; and
- charges for the administration of pre-Network Code contracts;

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 Transco'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).