Transco

# Gas Transportation Charges

from 1 July 2002

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# 1. INTRODUCTION

Transco is responsible for transporting gas safely and efficiently from the coastal terminals to around 20 million gas consumers around the country. Transco's pipeline network consists of more than 274,000 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 2001 1104 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 July 2002. NTS exit capacity charges (table 2.2.4) and the NTS standard commodity charge (table 2.2.5.1) have been changed from those applying from 1 April 2002. All other transportation charges are unchanged from those published in the statement applying from 1 April 2002. The charges are set to comply with the anticipated price control arrangements from April 2002.

Details of Transco and its activities can be found on Transco's internet site at **www.transco.uk.com**. 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 Transco Communications, either by calling **(0121) 623 2425** or by e-mail to **webmaster@transco.uk.com.**

# 2. GAS TRANSPORTATION CHARGES EFFECTIVE FROM 1 JULY 2002

## 2.1 Introduction

This publication sets out the transportation charges effective from 1 July 2002. Notice of the changes from the 1 April 2002 charges was originally given on 1 May 2002. These charges apply for use of the Transco pipeline network, as required by Standard Condition 3 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 **(0121) 623 2340.**

### 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 on **(0121) 781 2118.**

### 2.1.4 The Transco 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 in respect of each unit of gas transported through its network. Should Transco earn more or less than the maximum permitted revenue in a formula year, then a compensating adjustment is made in the following year. Where a significant over-recovery is anticipated within a year an adjustment to charges may be made during the year.

Within the cap on charges set by the price control formulae, the transportation charging methodology has been developed to reflect the relative costs of constructing, maintaining and operating the different parts of the gas transmission and distribution systems.

For the purposes of setting transportation charges reflecting the anticipated price control arrangements, Transco's National Transmission System (NTS) and the Local Distribution Zones (LDZs) are considered separately. The NTS charges are further split between those activities related to the Asset Owner (TO) and System Operator (SO) while the LDZ charges are split between system and customer related activities.

The revenue to be collected from charges relating to the use of the NTS is determined by the TO and SO price controls. Total LDZ related revenue is also determined by a price control formula. However the share of LDZ revenue recovery from system charges and customer charges is based on the relative level of costs allocated to these areas 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. Transco has the right to interrupt these supply points for up to 45 days each year.

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. The additional reduction in transportation charges applying to NSLs referred to in the Network Code (G6.7.14) has been set to zero.

TNIs are supply points where Transco reserves the right to interrupt for more than 45 days each year. These supply points are not only exempt from NTS exit capacity and LDZ capacity charges but also attract discounted NTS (SO) and LDZ commodity charges.

The discount percentage is calculated as:

$$\left(\frac{N-45}{183}\right)\times 100\,percent$$

where *N* is the lower of the maximum number of days of permitted interruption or 183.

(For example, if it is specified that the supply point can be interrupted for up to 90 days, then *N* equals 90 and the NTS (SO) and LDZ commodity unit charges are reduced by 24.6%.)

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 58,600MWh 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 to date have been held every six months and apply to all system entry points. Prior to the auctions the NTS (TO) target revenue is allocated 50% to entry capacity charges and 50% to exit capacity charges and this allocation is used in the determination of the reserve prices for the auctions. However the 50 / 50 split is unlikely to 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 Monthly system entry capacity

#### 2.2.1.1 Firm entry capacity

For each of the system entry points Monthly System Entry Capacity (MSEC) is allocated by auction. 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 price 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. Unsold MSEC may be bought on a first come first served basis, after the auctions have closed, up to three days before the month of use. The charge for this capacity is the weighted average of the top 50%, by volume, of accepted bids in the relevant auction of MSEC. The lowest price that could be accepted is the reserve price, set out in Table 2.2.2.

**Table 2.2.1 Monthly System Entry Capacity**

| Entry Point | Capacity Availability from 1 April 2002 GWh per day |
|---|---|
| **Coastal Terminals** | |
| Bacton | 1,374.3 |
| Easington / Rough | 994.5 |
| Theddlethorpe | 682.2 |
| St Fergus | 1,520.1 |
| Teesside | 819.0 |
| Barrow | 730.8 |
| **Onshore Fields and Connections** | |
| Hatfield Moors | 1.1 |
| Wytch Farm | 3.6 |
| Caythorpe | 0 |
| Burton Point | 61.3 |
| Hole House Farm | 26.3 |
| **Storage** | |
| Hatfield Moors | 53.6 |
| Hornsea | 175.4 |
| Glenmavis | 99.2 |
| Partington | 215.0 |
| **Constrained LNG** | |
| Avonmouth | 148.9 |
| Dynevor Arms | 49.6 |
| Isle of Grain | 218.3 |

### 2.2.2 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.

#### 2.2.2.1 Entry Capacity Reserve Prices

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

The reserve prices for MSEC and DSEC are shown in Table 2.2.2. The 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**

| Entry Point | Reserve price | |
|---|---|---|
| | Pence per kWh per day | |
| | MSEC | DSEC |
| **Coastal terminals** | | |
| Bacton | 0.0006 | 0.0004 |
| Easington / Rough | 0.0020 | 0.0014 |
| Theddlethorpe | 0.0008 | 0.0005 |
| St Fergus | 0.0189 | 0.0126 |
| Teesside | 0.0047 | 0.0031 |
| Barrow | 0.0023 | 0.0016 |
| **Onshore fields and connections** | | |
| Hatfield Moors | 0.0026 | 0.0017 |
| Wytch Farm | 0.0000 | 0.0000 |
| Caythorpe | 0.0020 | 0.0013 |
| Burton Point | 0.0000 | 0.0000 |
| Hole House Farm | 0.0002 | 0.0002 |
| **Storage** | | |
| Hatfield Moors | 0.0026 | 0.0017 |
| Hornsea | 0.0028 | 0.0019 |
| Glenmavis | 0.0088 | 0.0059 |
| Partington | 0.0007 | 0.0005 |
| **Constrained LNG** | | |
| Avonmouth | 0.0000 | 0.0000 |
| Dynevor Arms | 0.0000 | 0.0000 |
| Isle of Grain | 0.0000 | 0.0000 |

### 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 2002 |
| Avonmouth LNG | 0.0116 |
| Dynevor Arms LNG | 0.0000 |
| Isle of Grain LNG | 0.0023 |

### 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) |

| | Pence per peak day kWh per day |
|---|---|
| **LDZ Exit Zone** | |
| EA1 | 0.0024 |
| EA2 | 0.0084 |
| EA3 | 0.0030 |
| EA4 | 0.0091 |
| EM1 | 0.0025 |
| EM2 | 0.0006 |
| EM3 | 0.0065 |
| EM4 | 0.0052 |
| NE1 | 0.0001 |
| NE2 | 0.0017 |
| NE3 | 0.0008 |
| NO1 | 0.0001 |
| NO2 | 0.0007 |
| NT1 | 0.0172 |
| NT2 | 0.0112 |
| NT3 | 0.0124 |
| NW1 | 0.0070 |
| NW2 | 0.0062 |
| SC1 | 0.0001 |
| SC2 | 0.0009 |
| SC4 | 0.0001 |
| SE1 | 0.0091 |
| SE2 | 0.0172 |
| SO1 | 0.0119 |
| SO2 | 0.0163 |
| SW1 | 0.0067 |
| SW2 | 0.0127 |
| SW3 | 0.0252 |
| WA1 | 0.0089 |
| WA2 | 0.0153 |
| WM1 | 0.0054 |
| WM2 | 0.0059 |
| WM3 | 0.0065 |

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

| Invoice | Charge Code |
|---|---|
| NTS Capacity | NDX (DM) |

| | Pence per peak day kWh per day |
|---|---|
| **NTS Sites** | |
| AM Paper | 0.0028 |
| Baglan Bay PG | 0.0174 |
| Barking PG | 0.0093 |
| BASF Teesside | 0.0001 |
| BP Grangemouth | 0.0001 |
| BP Saltend (HP) | 0.0008 |
| Bridgewater Paper | 0.0081 |
| Brigg PG | 0.0005 |
| Brimsdown PG | 0.0100 |
| Brunner Mond | 0.0028 |
| Connahs Quay PG | 0.0081 |
| Corby PG | 0.0037 |
| Coryton PG | 0.0071 |
| Cottam PG | 0.0005 |
| Deeside PG | 0.0081 |
| Didcot PG | 0.0128 |
| Great Yarmouth PG | 0.0024 |
| Hays Chemicals | 0.0028 |
| ICI Runcorn | 0.0083 |
| Keadby PG | 0.0001 |
| Kemira Ince | 0.0083 |
| Kings Lynn PG | 0.0023 |
| Kingsnorth PG | 0.0074 |
| Little Barford PG | 0.0046 |
| Longannet PG | 0.0001 |
| Medway PG | 0.0074 |
| Peterborough PG | 0.0023 |
| Peterhead PG | 0.0001 |
| Phillips Seal Sands | 0.0001 |
| Rocksavage PG | 0.0083 |
| Roosecote PG | 0.0019 |
| Rye House PG | 0.0100 |
| Saltend PG | 0.0008 |
| Sappi Paper Mill | 0.0070 |
| Seabank PG | 0.0118 |
| Sellafield PG | 0.0019 |
| Shotton Paper | 0.0081 |
| 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 | 0.0122 |
| Thornton Curtis PG | 0.0005 |
| Zeneca | 0.0001 |

| Invoice | Charge Code |
|---|---|
| NTS Capacity | NDX (DM) |

| | Pence per peak day kWh per day |
|---|---|
| **Interconnector** | |
| Bacton I/C | 0.0024 |
| Moffat I/C | 0.0001 |
| **Storage Sites** | |
| Avonmouth | 0.0118 |
| Dynevor Arms | 0.0153 |
| Glenmavis | 0.0001 |
| Hatfield Moors | 0.0001 |
| Hole House Farm | 0.0028 |
| Hornsea | 0.0008 |
| Isle of Grain | 0.0074 |
| Partington | 0.0028 |
| 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 | 0.0150 |

The standard NTS (SO) commodity charge is a uniform charge, independent of entry and exit points.

#### 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 |
|---|
| $1203 \times [(PL)^{\wedge -0.834}] \times D + 363 \times (PL)^{\wedge -0.654}$ |

where **D** is the direct distance from the site or non-Transco pipeline to the elected terminal in km and **PL** is the registered supply point capacity in kWh. Note that ^ means “to the power of …”

Further information on the optional NTS tariff can be obtained from Transco’s Customer Portfolio Management (CPM) team on **(0121) 713 5446.**

### 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 0.0052 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).

The LDZ charging functions – capacity, commodity and customer – use Supply point Offtake Quantity (SOQ) in the determination of charges for firm supply points.

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.

### 2.3.1 Standard LDZ charges

The functions used to calculate the LDZ capacity and commodity charges are shown in the following tables. Note that PL, in kWh, means the registered supply point capacity (a Network Code term) which is capacity sufficient for the peak daily load of a supply point.

**Table 2.3.1 Directly connected supply points**

| Invoice | Charge Code |
|---|---|
| LDZ Capacity | ZCA |
| LDZ Commodity | ZCO |

| Capacity | pence per peak day kWh per day |
|---|---|
| Up to 73,200 kWh per annum | 0.0474 |
| 73,200 to 732,000 kWh per annum | 0.0440 |
| 732,000 kWh per annum and above | $0.2088 \times PL^{-0.1806}$ |
| Subject to a minimum rate of | 0.0048 |
| Minimum reached at PL of | 1,181,616,389 kWh |

| Commodity | pence per kWh |
|---|---|
| Up to 73,200 kWh per annum | 0.1268 |
| 73,200 to 732,000 kWh per annum | 0.1172 |
| 732,000 kWh per annum and above | $0.7272 \times PL^{-0.2121}$ |
| Subject to a minimum rate of | 0.0110 |
| Minimum reached at PL of | 382,022,999 kWh |

### 2.3.2 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 peak load (PL) 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 2.3.2 Connected Systems**

| Invoice | Charge Code |
|---|---|
| ADC | ZCA |
| ADC | ZCO |

| Capacity | pence per peak day kWh per day |
|---|---|
| Up to 73,200 kWh per annum | 0.0474 |
| 73,200 to 732,000 kWh per annum | 0.0440 |
| 732,000 kWh per annum and above | 0.2208 x PL ^ -0.1939 |
| Subject to a minimum rate of | 0.0048 |
| Minimum reached at PL of | 376,129,100 kWh |

| Commodity | pence per kWh |
|---|---|
| Up to 73,200 kWh per annum | 0.1268 |
| 73,200 to 732,000 kWh per annum | 0.1172 |
| 732,000 kWh per annum and above | 0.6940 x PL ^ -0.2131 |
| Subject to a minimum rate of | 0.0110 |
| Minimum reached at PL of | 279,629,352 kWh |

### 2.3.3 Optional LDZ Charge

The optional LDZ tariff is available, as a single charge, as an alternative to both the standard LDZ capacity and commodity 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.

The charge is calculated using the function below :

| Invoice | Charge Code |
|---|---|
| ADU | 881 |

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

Where PL 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 CPM team on **(0121) 713 5446**.

## 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 supply point capacity.

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, PL (in kWh).

**Table 2.4 Customer charges**

**Up to 73,200 kWh per annum**

| Invoice | Charge Code |
|---|---|
| Commodity | CCO |

| | pence per kWh |
|---|---|
| Commodity charge | 0.1411 |

**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 | 14.8742 |
| Monthly read supply points | 15.8377 |

| Invoice | Charge Code |
|---|---|
| LDZ Capacity | CCA |

| | Pence per peak day kWh per day |
|---|---|
| Capacity charge | 0.0017 |

**732,000 kWh per annum and above**

| Invoice | Charge Code |
|---|---|
| LDZ Capacity | CCA |

| | Pence per peak day kWh per day |
|---|---|
| Charging function | $0.0361 \times PL^{-0.2100}$ |

### 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.

## 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 | **0.3836 pence per day (£1.40 per annum)** |

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 | **61.00** | **122.00** |
| Shipper-shipper transfer charge | **76.00** | **144.00** |
| Daily charge | **1.62** | **2.07** |

**Transco Service**

| | Telemetered | Non-telemetered |
|---|---|---|
| Set-up charge | **61.00** | **135.00** |
| Shipper-shipper transfer charge | **76.00** | **144.00** |
| Daily charge | **1.89** | **2.18** |

### 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 | £86.00 | £1.07 |
| Transco service | £86.00 | £1.69 |

**- 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 | £11.72 |
| Transco service | £23.44 |

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 £0.49

### 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.

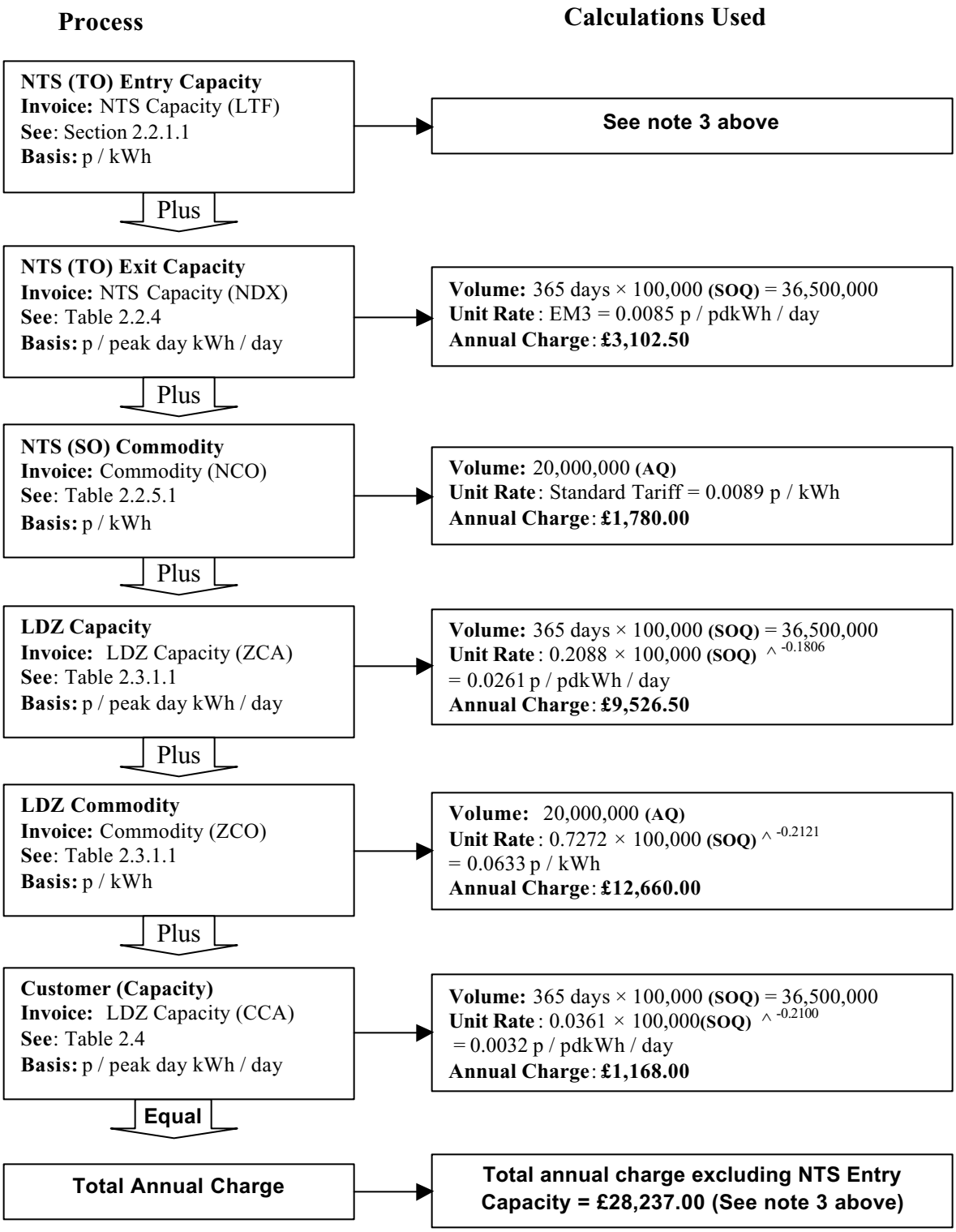
## 2.6 Examples

**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 (see note 4 below) 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.
4. **As the examples are purely illustrative, the NTS exit capacity and NTS commodity rates used are those which applied from 1 April 2002, rather than the new rates applicable from 1 July 2002.**

**Example 1**

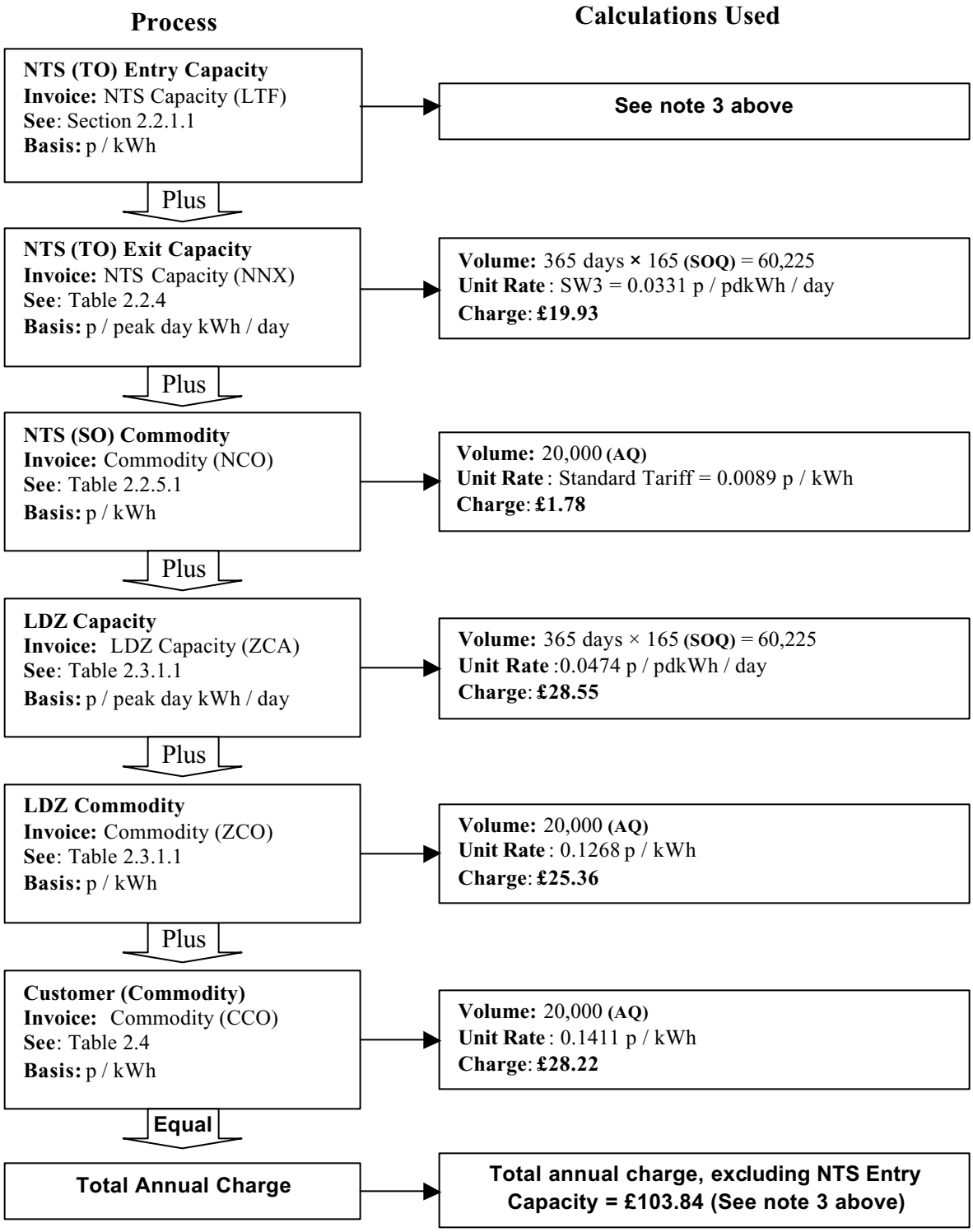
A shipper has a daily metered customer in Leicester **(EM3)** with an annual consumption **(AQ)** of **20,000,000** kWh and a registered supply point capacity **(SOQ)**, booked directly by the shipper of **100,000** kWh per day.




Unit Charge : Dividing by the annual load of 20,000,000 kWh gives a unit charge (excluding NTS entry capacity) of 0.1412 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 £3,102.50 and £9,526.50 respectively to a new total of £15,731.50.

**Example 2**

A shipper has a domestic customer in Plymouth. 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 E0101. 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 33.2%. The peak daily load **(SOQ)** is therefore 20,000 ÷ (365 × 0.332) = 165 kWh.



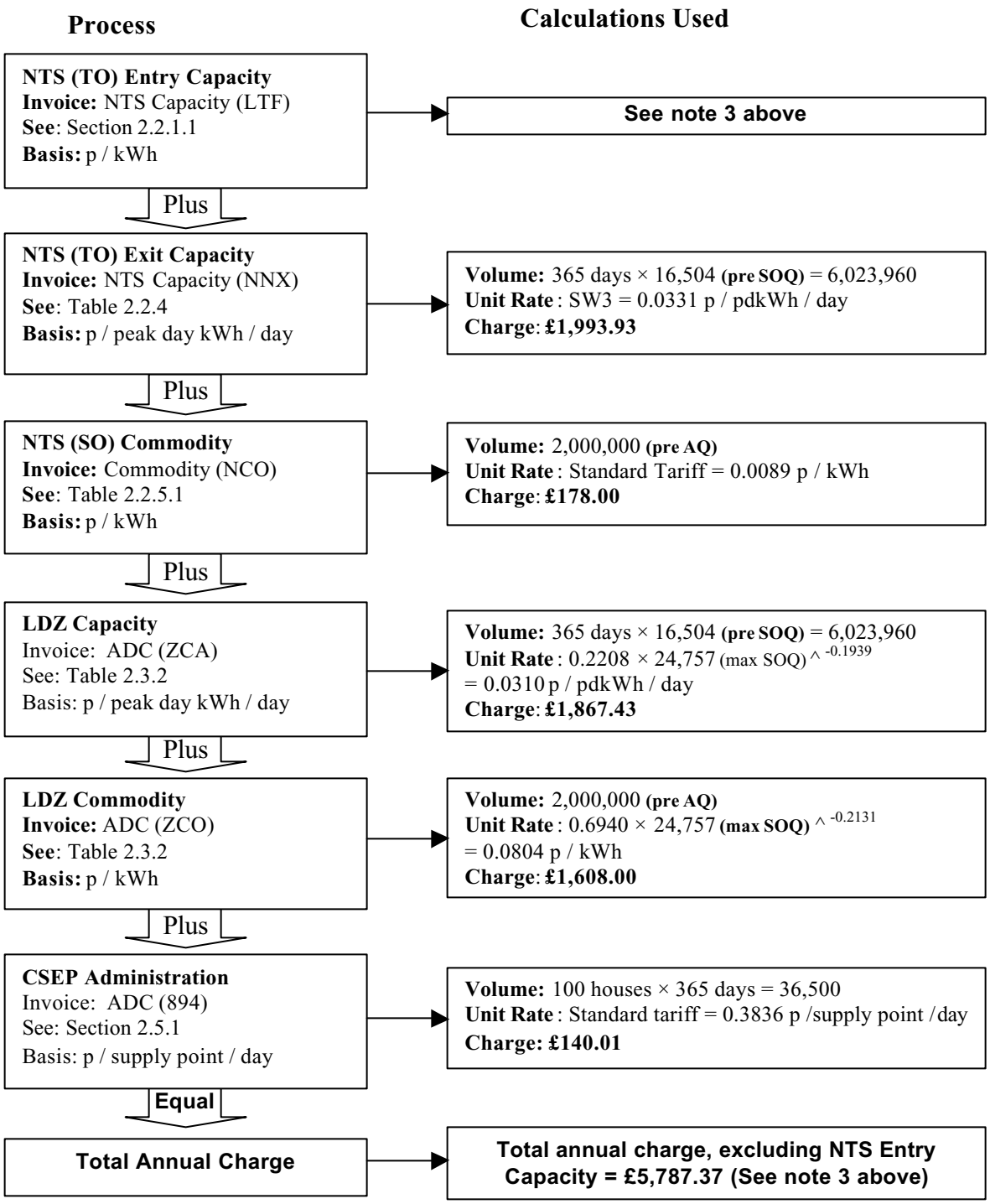

Unit Charge : Dividing by the annual load of 20,000 kWh gives a unit charge (excluding NTS entry capacity) of 0.5192 pence per kWh.

**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 kWh |
| Maximum AQ (max AQ) | 150 houses × 20,000 (AQ) = 3,000,000 kWh |
| Prevailing SOQ (pre SOQ) | 2,000,000 ÷ (365 × 0.332) = 16,504 kWh |
| Maximum SOQ (max SOQ) | 3,000,000 ÷ (365 × 0.332) = 24,757 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 0.2894 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 2001 to 30 September 2002.

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.

Winter: annual ratio = 500 ÷ 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 WO2 and the site is thus within End User Category WS:E0104W02.

For a site in this category, the load factor is 44.0% and the peak daily load is therefore

$$\frac{1000 \times 100}{365 \times 44.0} = 6.23 \text{ MWh}$$

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:E0104B.

For a site in this category, the load factor is 34.6% and the peak daily load is therefore

$$\frac{1000 \times 100}{365 \times 34.6} = 7.92 \text{ MWh}$$

### 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:E0102B.

For a site in this category, the load factor is 39.8% and the peak daily load is therefore

$$\frac{200 \times 100}{365 \times 39.8} = 1.38 \text{ MWh}$$

### 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 5000.**

For additional information regarding the demand estimation process, please contact Transco's Demand Estimation Team on **(0121) 623 2672**.

### 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:E0109B 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 2001 / 02, June 2001.

**Table 2A.1 Definition of end user categories**

The following table defines the end user category for particular LDZ's by reference to annual consumption and winter: annual ratio.

| EUC Code | Annual Load (MWh) | Winter Annual Ratios (WAR) | | | |
|---|---|---|---|---|---|
| | | W01 | W02 | W03 | W04 |
| E0101 | 0 to 73.2 | - | - | - | - |
| E0102 | 73.2 to 293 | - | - | - | - |
| E0103 | 293 to 732 | 0.00-0.43 | 0.43-0.51 | 0.51-0.59 | 0.59-1.00 |
| E0104 | 732 to 2,196 | 0.00-0.43 | 0.43-0.51 | 0.51-0.59 | 0.59-1.00 |
| E0105 | 2,196 to 5,860 | 0.00-0.40 | 0.40-0.47 | 0.47-0.55 | 0.55-1.00 |
| E0106 | 5,860 to 14,650 | 0.00-0.35 | 0.35-0.43 | 0.43-0.51 | 0.51-1.00 |
| E0107 | 14,650 to 29,300 | 0.00-0.34 | 0.34-0.39 | 0.39-0.47 | 0.47-1.00 |
| E0108 | 29,300 to 58,600 | 0.00-0.33 | 0.33-0.36 | 0.36-0.43 | 0.43-1.00 |
| E0109 | > 58,600 | - | - | - | - |

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

| EUC Code | SC | NO | NW | NE | EM | WM | WN | WS | EA | NT | SE | SO | SW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| XX:E0101B | 39.7% | 35.9% | 38.4% | 38.9% | 37.9% | 34.7% | 38.4% | 35.8% | 35.9% | 36.8% | 35.1% | 31.5% | 33.2% |
| XX:E0102B | 39.8% | 30.2% | 34.3% | 29.1% | 32.8% | 30.1% | 34.3% | 27.5% | 35.0% | 36.3% | 35.1% | 28.3% | 29.4% |
| XX:E0103B | 41.6% | 33.4% | 37.4% | 36.9% | 36.0% | 33.0% | 37.4% | 34.6% | 35.7% | 37.7% | 36.8% | 32.7% | 36.1% |
| XX:E0103W01 | 59.9% | 54.6% | 57.3% | 57.0% | 58.0% | 51.4% | 57.3% | 56.9% | 56.0% | 56.0% | 57.7% | 52.5% | 60.9% |
| XX:E0103W02 | 47.9% | 41.0% | 45.5% | 45.2% | 45.8% | 39.9% | 45.5% | 44.0% | 43.2% | 43.1% | 44.1% | 37.5% | 43.3% |
| XX:E0103W03 | 35.4% | 28.5% | 31.3% | 32.1% | 32.9% | 29.0% | 31.3% | 30.8% | 30.7% | 31.0% | 31.4% | 27.6% | 30.5% |
| XX:E0103W04 | 28.4% | 24.2% | 25.9% | 25.9% | 26.6% | 24.2% | 25.9% | 23.9% | 25.6% | 26.2% | 25.9% | 22.4% | 23.9% |
| XX:E0104B | 41.6% | 33.4% | 37.4% | 36.9% | 36.0% | 33.0% | 37.4% | 34.6% | 35.7% | 37.7% | 36.8% | 32.7% | 36.1% |
| XX:E0104W01 | 59.9% | 54.6% | 57.3% | 57.0% | 58.0% | 51.4% | 57.3% | 56.9% | 56.0% | 56.0% | 57.7% | 52.5% | 60.9% |
| XX:E0104W02 | 47.9% | 41.0% | 45.5% | 45.2% | 45.8% | 39.9% | 45.5% | 44.0% | 43.2% | 43.1% | 44.1% | 37.5% | 43.3% |
| XX:E0104W03 | 35.4% | 28.5% | 31.3% | 32.1% | 32.9% | 29.0% | 31.3% | 30.8% | 30.7% | 31.0% | 31.4% | 27.6% | 30.5% |
| XX:E0104W04 | 28.4% | 24.2% | 25.9% | 25.9% | 26.6% | 24.2% | 25.9% | 23.9% | 25.6% | 26.2% | 25.9% | 22.4% | 23.9% |

**Table 2A.3 Large NDM Supply Points ( 2,196 – 58,600 MWh per annum)**

| EUC Code | SC | NO | NW | NE | EM | WM | WN | WS | EA | NT | SE | SO | SW |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| XX:E0105B | 43.4% | 37.4% | 40.6% | 39.2% | 40.6% | 37.5% | 39.8% | 38.2% | 39.4% | 41.4% | 39.5% | 36.1% | 40.4% |
| XX:E0105W01 | 66.8% | 61.9% | 64.7% | 62.1% | 64.0% | 61.0% | 64.2% | 66.2% | 62.7% | 61.7% | 61.0% | 62.2% | 64.6% |
| XX:E0105W02 | 52.2% | 45.3% | 48.1% | 48.5% | 49.6% | 44.0% | 47.3% | 46.2% | 46.0% | 48.3% | 48.1% | 43.8% | 46.7% |
| XX:E0105W03 | 38.8% | 33.6% | 36.1% | 36.0% | 37.4% | 34.2% | 35.3% | 35.9% | 35.7% | 37.2% | 36.5% | 32.7% | 36.4% |
| XX:E0105W04 | 30.3% | 25.3% | 27.5% | 26.4% | 27.9% | 25.6% | 26.8% | 26.4% | 27.6% | 28.3% | 27.4% | 24.4% | 26.6% |
| XX:E0106B | 47.2% | 41.1% | 45.5% | 45.0% | 45.5% | 42.8% | 44.8% | 44.4% | 42.9% | 45.9% | 44.9% | 41.1% | 43.6% |
| XX:E0106W01 | 74.8% | 73.6% | 74.7% | 73.7% | 73.8% | 73.2% | 74.6% | 74.7% | 79.4% | 79.2% | 79.1% | 74.2% | 74.8% |
| XX:E0106W02 | 56.7% | 52.6% | 55.8% | 52.8% | 52.8% | 51.0% | 55.1% | 51.8% | 54.5% | 53.6% | 53.3% | 49.5% | 51.8% |
| XX:E0106W03 | 43.1% | 38.6% | 42.3% | 40.4% | 41.1% | 39.3% | 41.5% | 38.2% | 43.0% | 42.5% | 42.4% | 37.7% | 39.6% |
| XX:E0106W04 | 31.0% | 28.0% | 31.4% | 29.2% | 29.6% | 28.2% | 30.7% | 28.6% | 30.9% | 30.6% | 30.4% | 28.2% | 29.7% |
| XX:E0107B | 49.6% | 50.4% | 53.5% | 51.1% | 51.1% | 49.2% | 52.8% | 44.0% | 50.9% | 50.5% | 50.5% | 43.0% | 45.1% |
| XX:E0107W01 | 79.1% | 78.8% | 79.1% | 80.0% | 80.0% | 80.0% | 79.0% | 80.3% | 80.6% | 80.4% | 80.4% | 79.7% | 80.3% |
| XX:E0107W02 | 62.3% | 58.9% | 61.4% | 60.8% | 60.8% | 59.2% | 60.8% | 59.4% | 60.9% | 60.2% | 59.9% | 56.7% | 59.1% |
| XX:E0107W03 | 46.6% | 42.4% | 46.1% | 45.8% | 45.9% | 43.9% | 45.3% | 45.2% | 48.6% | 48.1% | 48.1% | 44.4% | 46.6% |
| XX:E0107W04 | 32.9% | 29.6% | 33.0% | 31.8% | 32.1% | 30.8% | 32.3% | 29.9% | 33.1% | 32.6% | 32.6% | 29.3% | 30.9% |
| XX:E0108B | 64.9% | 61.2% | 64.0% | 56.9% | 56.9% | 55.0% | 63.4% | 54.3% | 56.1% | 55.3% | 55.1% | 51.5% | 54.1% |
| XX:E0108W01 | 83.5% | 83.3% | 83.5% | 83.5% | 83.5% | 83.3% | 83.5% | 83.2% | 83.4% | 83.3% | 83.4% | 83.1% | 83.2% |
| XX:E0108W02 | 70.9% | 68.2% | 70.2% | 70.3% | 70.3% | 69.0% | 69.7% | 68.6% | 69.7% | 69.3% | 69.1% | 66.7% | 68.5% |
| XX:E0108W03 | 57.0% | 53.1% | 56.3% | 56.4% | 56.4% | 54.5% | 55.6% | 54.0% | 55.6% | 55.0% | 54.7% | 51.5% | 53.8% |
| XX:E0108W04 | 38.9% | 35.6% | 38.8% | 38.5% | 38.8% | 37.7% | 38.0% | 36.1% | 39.3% | 38.8% | 38.8% | 35.5% | 37.3% |
| XX:E0109B | 71.6% | 68.2% | 70.7% | 70.8% | 70.8% | 69.2% | 70.1% | 68.7% | 70.1% | 69.6% | 69.4% | 66.5% | 68.6% |

# 3. TRANSPORTATION CHARGING METHODOLOGY

## 3.1. Introduction

Standard Condition 3 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 4 of the Licence.

### 3.1.1 Price Control Formulae

With effect from 1 April 2002 it is anticipated that the transportation price controls will treat separately the National Transmission System (NTS TO), the System Operator (NTS SO) and the Local Distribution Zones (LDZs). The separate price controls and incentives are expected to determine the maximum revenue that Transco may derive from each area of activity in a formula year, 1 April to 31 March.

The Maximum Allowed Revenue under the transportation controls and incentive schemes is expected to be 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 rely on forecasts of some of the above elements together with a view on target auction revenues [1]. Outturn will inevitably vary 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 price control period ending on 31 March 2002 charges were normally revised in 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 continued 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 total value of NTS entry capacity bought back by Transco 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 4 of the Licence. Ofgem has the right to veto any proposed changes to the methodology.

### 3.1.3 Structure of Charges

For the purposes of setting transportation charges and reflecting the anticipated price control arrangements Transco's National Transmission System (NTS) and the Local Distribution Zones (LDZs) are considered separately. The NTS charging is further considered split between those activities related to the Asset Owner (TO) and System Operator (SO), while LDZ charges are split between system and customer related activities.

The maximum revenue to be collected from charges relating to the use of the NTS is determined by the TO and SO price controls. While maximum LDZ related revenue is also determined by a price control formula, the split between LDZ system and LDZ customer charges is based on the relative cost of each activity as determined by Transco's Transaction Model including an asset-based adjustment which is scaled so that the final cost pools sum to the target allowed revenue. Charges are then set to recover these target revenues.

The resulting cost pool breakdown used as the basis for the April 2002 charges is set out below:

**Table 3.1.3: 2000 and 2002 LDZ Cost Pool Breakdowns %**

| Year | LDZ System | LDZ Customer | Total LDZ |
|---|---|---|---|
| **2000** | 71.0 | 29.0 | 100 |
| **2002** | 70.9 | 29.1 | 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 Main Points for 2002

The NTS TO allowed revenue is now collected solely by entry and exit capacity charges while the NTS SO allowed revenue is collected 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.

NTS TO capacity charges and auction reserve prices are now set on the basis that, if administered charges were to apply, there would be a 50:50 split in revenue from entry and exit charges. Previously there has been no such specified division of target revenue between exit and entry.

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 is concluded this 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. One area where change may be necessary is in relation to the potential change to exit capacity arrangements, which might require the exit charging arrangements and the 50:50 capacity:commodity assumption to be reviewed. The level of the charges will be revised as necessary to ensure that collected revenue stays consistent with allowed revenue.

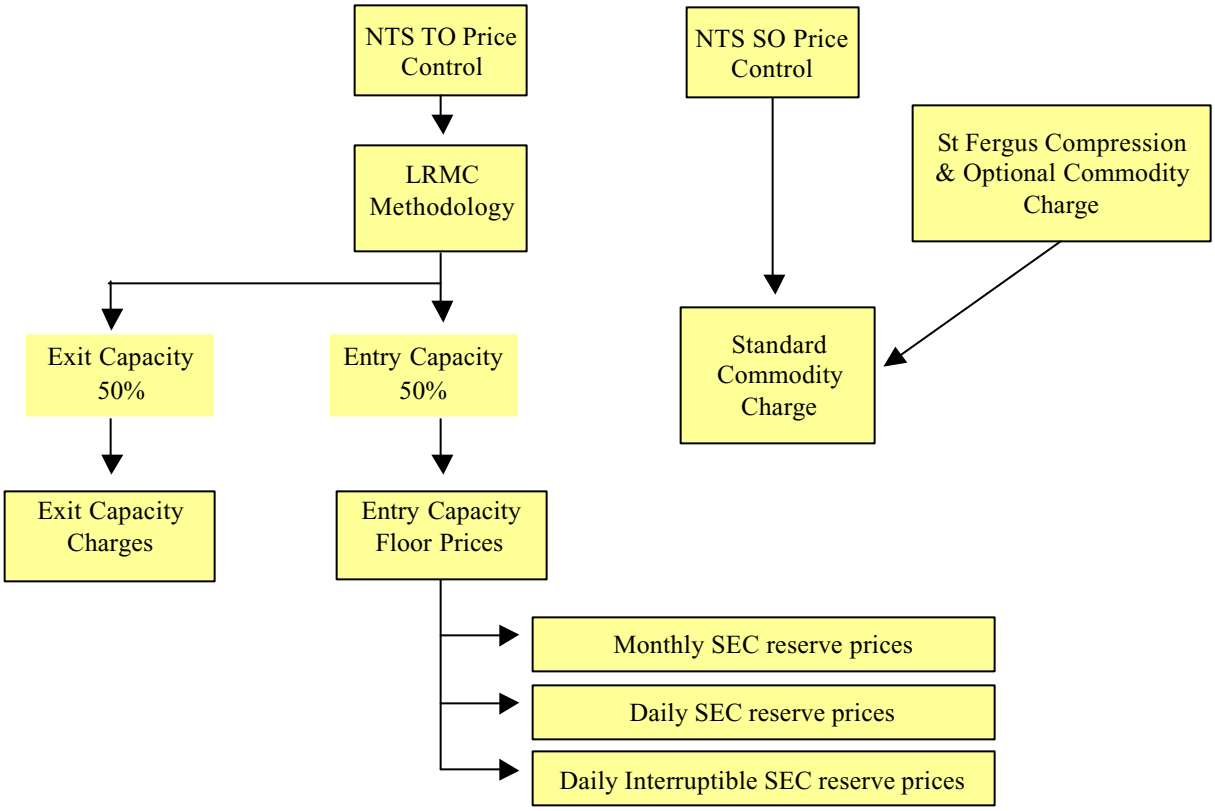
## 3.2. NTS Charging Methodology

### 3.2.1 Introduction

The maximum to be recovered from NTS TO and SO charges is determined by the anticipated 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, certain of these rights may be traded between Shippers, such as Monthly System Entry Capacity (MSEC).

**Figure 3.2.1 Setting of NTS Charges & Floor 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 three related auction mechanisms.

- Monthly (firm) System Entry Capacity (MSEC).
- 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 NTS SO incentive schemes, Transco expects to be obliged to make available for sale in the MSEC auctions a volume of capacity equivalent to 90% of the winter output measure, as set out in the NTS TO price control. Any unsold MSEC may be purchased on a first come

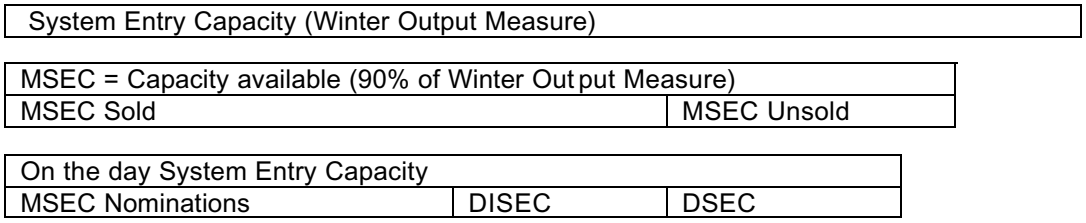
first served basis up to three days before the beginning of the relevant month. The price for such purchases is the average of the top 50%, by volume, of accepted bids in the MSEC auction.

Following acceptance by Ofgem of Network Code Modification Proposal 0541 any unsold baseline capacity, will, with effect from 1 April 2002, be offered for sale ahead of the gas day as DSEC. On the gas day Transco will establish the difference between the actual system entry capacity available and the MSEC held by shippers at each ASEP. This volume is then made available in the within day DSEC auctions. Bids for DSEC can be made from seven days before the gas day. Also on the day before the gas day, Transco will establish the difference between MSEC held by shippers and their actual nominations (i.e. any unutilized booked MSEC) at each ASEP. This volume is then made available in the single DISEC auction held on the day before the gas day.

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**




### 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.

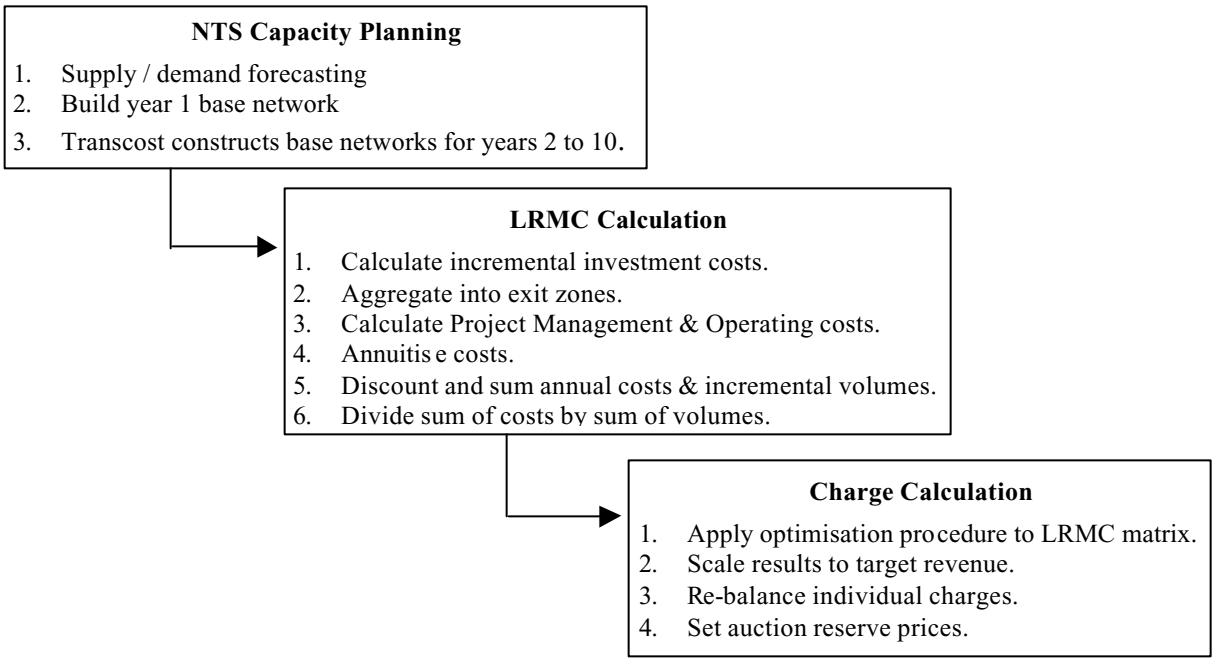
A model, known as Transcost, has been developed by Transco to estimate LRMCs to support the setting of NTS capacity charges. Transcost is also capable of estimating LRMCs for alternative supply and demand patterns relatively quickly and easily. A free copy of Transcost, supporting documentation and the data used when setting the April 2002 charges can be obtained by calling Transco on 0121 623 2340.

### 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 mcfd) 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 | 0.00043 × diameter ÷ 0.07542 / 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 | 32.25 | 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 |

### 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 optimization 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 optimization 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 optimization 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;

### 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.

LRMC reflective capacity charges on a p / pdkWh / d basis in effect apply the charge to a volume equivalent to the peak day flow multiplied by 365. However the volume of MSEC made available in the monthly auctions differs from this peak day volume. To achieve the same revenue, therefore, a common scaling factor is applied to the LRMC reflective capacity charges such that the revenue implied by the MSEC volumes times the scaled charge is equal to that implied by peak day volumes times the LRMC capacity charge. ASEPs with a Herfindahl-Hirschman index (a concentration measure whereby the market shares of individual shippers are squared and summed) of more than 8,000 are excluded from this common scaling requirement. Instead such terminals have individual scaling factors applied, in 2002 / 2003 this applies to Barrow, Wytch Farm, Hole House Farm, Burton Point, Glenmavis and Hatfield Moors.

Floor prices are calculated by applying the following discounts to the adjusted charges.

- Monthly System Entry Capacity (MSEC); 25%
- Daily System Entry Capacity (DSEC); 50%
- 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 2002 / 03 the storage sites providing these services are Avonmouth 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 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. The commodity rate is provisionally set by dividing the target revenue by forecast system throughput. It is expected that the charge will apply to all gas exiting the system, including, subject to Network Code provisions, gas exiting to storage sites.

### 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 April 2002 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 220,000 km out of the total 270,000 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. The percentage of total replacement costs for each sub-tier are also shown as they are used within the methodology to attribute the LPS costs to the sub-tiers.

**Table 3.3.1b LPS Sub Tiers**

| Pipe Diameter | Percentage of Total Replacement Costs |
|---|---|
| >355mm | 12.3% |
| 250- 355mm | 12.7% |
| 180-250mm | 10.5% |
| 125-250mm | 15.8% |
| 90-125mm | 26.1% |
| <=90mm | 22.6% |
| Total | 100% |

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 are derived from the Activity Based Costs (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 replacement cost data.

**Table 3.3.3b Determination of LPS Costs**

| LPS Sub Tier | | % Total 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)**

| | LDZ Tiers | | | LPS Sub Tiers | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Consumption Band (MWh) | 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 service pipe and emergency service costs that assesses how such costs vary with supply point size. This analysis is used to determine the allocation of the target revenue (from the customer cost pool) to groups of similarly sized supply points. Charging functions are then fitted, based on supply point capacity. 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
   iii. shipper services.
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 PD14 (November 2001).