Appendix 2

Network Code Operations

A2.1 Energy Balancing
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Appendix 2: Network Code Operations

The Network Code is the contractual document that defines the commercial and operational framework for all users of the Transco network. It defines a daily balancing regime where shippers are commercially responsible for balancing their own supply and demand, with Transco ensuring the safety and security of the system.

It introduced daily balancing for the winter of 1996/97. Most of the industry was encouraged by the operation of the energy balancing regime during the first winter, however there were concerns:

- Transco could not be confident in using gas input information to make balancing decisions;
- shippers faced uncertainty in respect of both gas inputs and demands;
- balancing actions late in the day gave rise to extreme flexibility and imbalance prices which had a disproportionate impact on balancing costs on a few days; and
- some shippers took imbalance positions which increased overall balancing costs and misallocation of costs between days.

The industry spent a substantial proportion of the summer of 1997 considering changes to the regime for the 1997/98 winter and the final changes were not as comprehensive as those envisaged originally. Changes were made to both the Network Code and the Operational Guidelines. The Operational Guidelines define the principles and processes associated with system balancing decisions and the hierarchies for the use of balancing tools (i.e. the flexibility mechanism, interruption, operating margins and constrained LNG).

The impact of these changes is discussed below, however it should be noted that the winter 1997/98 was extremely warm and consequently the regime was not really tested.

A2.1 Energy Balancing

The energy balancing debate during the summer of 1997 gave rise to changes in the operation of the regime during winter 1997/8. From an operational perspective the key changes were:

- the taking of balancing actions to the edge of the linepack bandwidth;
- the removal of the requirement to take balancing actions within day after midnight unless operationally essential;
- the implementation of a fixed +/- 3MCM bandwidth;
- the taking of prompt balancing actions rather than waiting to see if the system imbalance will be resolved without Transco intervention; and
- the greater provision of information indicating the extent of system imbalance.

These changes were designed to achieve:

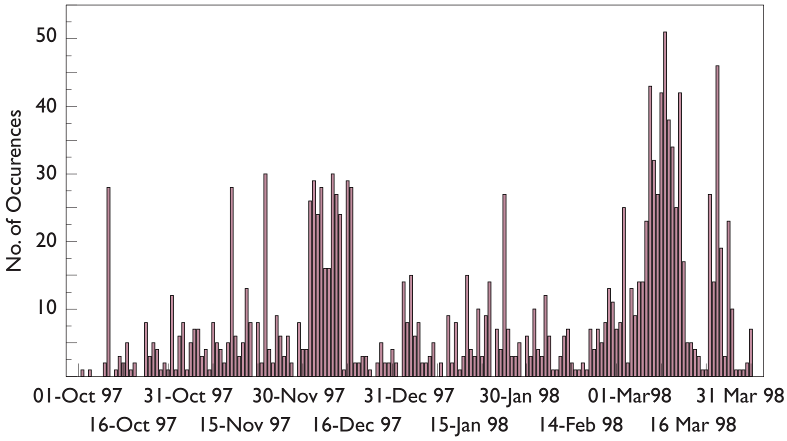
- more frequent but smaller actions in the direction of target linepack;
- increased transparency in respect of the likelihood and size of balancing actions;
- much greater information provision to shippers;
- clearing prices more closely related to market conditions; and
- greater liquidity in the flexibility mechanism.

Transco uses best available information in respect of both gas deliveries into and offtakes from the system to determine the requirement for, and size of, balancing actions.

Estimates of gas deliveries are obtained using either Daily Flow Notifications (DFNs) received from Terminal Operators or AT-Link input nominations or a combination of the two.

Analysis of DFNs indicates that they generally provide a very good basis for assessing short term gas flows. However there are occasions when significant gas flow shortfalls occur.

Figure A2.1 - Shortfalls In Expected Hourly Rates - DFNs vs Actual Flows



Most balancing actions are made taking account of the best estimate of the full day's flow, the end of day flow. The differences between the end of day flows implied by the DFNs within day and the actual end of day flow are often significant.

Estimates of gas offtakes are made taking account of models developed by Transco on behalf of the industry which place primary importance on temperature forecasts from the Meteorological Office. The accuracy of the temperature forecast is critical to the Local Distribution Zone (LDZ) gas demand forecasting process given that, for every 1˚C decrease in temperature, demand increases by approximately 6%. This is much greater sensitivity than in other gas sectors or in the electricity market. Additionally demand projections from shippers in respect of large load play a significant role in determining aggregate gas offtake projections.

Overall, the Meteorological Office temperature forecast accuracy and bias have not improved compared with the previous winter. Despite this, Transco's forecasting error and bias have improved significantly.

The 16:00 hrs within day forecast is of particular significance to shippers. Despite the fact that the Meteorological Office forecasts have not improved and the day on day demand volatility has increased, Transco's average accuracy of under and over forecasts at 16:00 hrs has improved from 1.82% to 1.19%.

The variability in the best estimate of gas deliveries is greater than that associated with demand projections.

Balancing actions are assessed based on the differences between estimated inputs and outputs. Whilst DFNs provide good information of short term gas flows there is significant difference between final end of day flows and that implied by prevailing DFNs. In practice the best estimates of input quantities generally exhibit far more variability from end of day flows than demand forecasts.

The regime delivered safety and security of supply with balancing actions taking place on 91% of days, compared to 53% for the winter of 1996/97. Balancing gas equivalent to 2.5% of throughput was used to achieve system balance.

Of this, 91% was used for national supply/demand balancing with 9% used to resolve local requirements.

The system balancing tool usage was as follows:

Flexibility Mechanism	99.8%
Constrained LNG	0.0%
Operating Margins	0.2%
Top Up	0.0%

The flexibility mechanism successfully addressed all balancing requirements during the winter.

Operating margins gas was used twice. On one occasion, it was used to address a supply shortfall; on the other occasion it was used to support system pressures whilst awaiting interruption to take effect following an NTS capacity constraint.

Most local actions were required because of supply / demand constraints. These arise from the interaction of gas inputs at particular locations and levels of demand. To ensure system safety and security, system reconfiguration and ultimately local system sells may be necessary. Most of the local constraints have been resolved by the turn down of gas flows at Barrow.

Demand levels were exceptionally low during the winter so recourse to constrained LNG and Top Up was unnecessary.

A2.1.2 Flexibility Mechanism

Approximately 30 players continue to participate in the flexibility mechanism regularly. A dramatic increase in the number of bids reposted onto the mechanism was seen. This was a result of better AT-Link functionality and the presence of more transparent information concerning the likelihood of flexibility actions.

During the winter 1997/8, Transco has provided more information to shippers regarding the Projected Closing Linepack (PCLP) estimate - the key determinant of balancing actions. From the 15th January Transco made hourly estimates of the PCLP available via the AT-Link commercial computer system. Should this published data indicate a balancing requirement, then, subject to operational circumstances, Transco endeavours to take action approximately 15 minutes later.

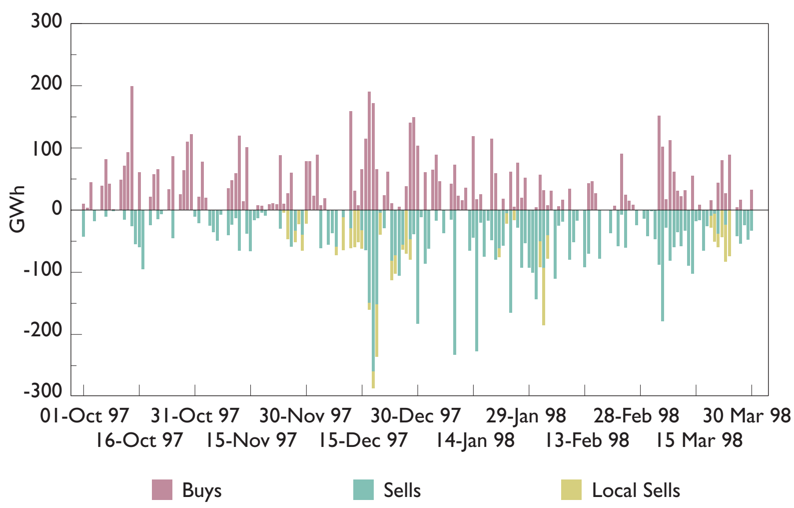
Publication of this information has generated more price competition to secure flexibility bid acceptance. This is reflected in the dramatically increased number of reposted bids.

On several occasions more than 100 bids were reposted during the short window between linepack publication and the flexibility action. Most of this activity has created more favourable flexibility prices. This has benefited the community by approximately £400,000.

The flexibility mechanism has provided sufficient gas to ensure effective balancing actions, although on occasions, specifically the 16th & 17th December, this involved the acceptance of very highly priced bids.

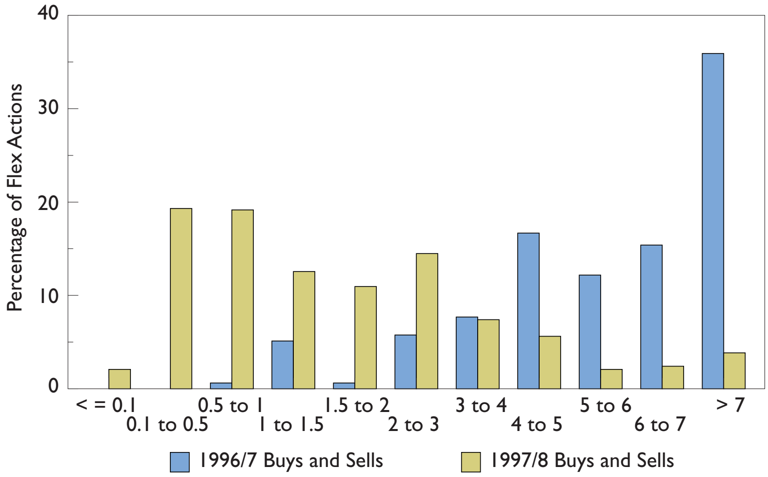
The flexibility mechanism has provided approximately 14 TWh of gas (around 30% more than last year) representing some 2.5% of throughput. The requirements for System Sells were slightly higher than System Buys, although a little over 1 TWh of the System Sells are associated with dealing with system constraints.

Figure A2.1.2a – Flexibility Mechanism Usage



A total of 622 flexibility actions were taken in winter 1997/8. This is about four times as many as the previous year. The average size of the actions (approximately 2 mcm) was much smaller than in 1996/7 as illustrated below:

Figure A2.1.2b - Distribution Of Flex Action Size For 1996/97 and 1997/98



Flexibility prices on the 16th and 17th December were significantly greater than those experienced at all other times during the winter. The inclusion of these statistics distorts overall assessment of the regime. The circumstances and effects of the events of 16th and 17th December are covered in detail in Transco's "Winter Operations Review 1998".

Flexibility bids at Barrow were taken on 34 occasions during the period 24th November and 3rd February to resolve system constraints. Additionally, flexibility bids at St Fergus were used to address system constraints on 6 further days. Background details to this are included in section A2.3.2.

Table A2.1.2 - Flexibility Mechanism Costs Oct 97 - March 98 (exc. 16th & 17th Dec)

	No Actions	No Days	Quantity (TWh)	Avg Price (p/kWh)	Cost
System Buys	263	114	5.70	0.48	27.80
System Sells	348	130	7.50	0.35	(26.40)
Net Position			1.80 (sell)		1.40

Note:

- There were 80 days with both Buys and Sells, amounting to 9,490 GWh
- The overall differential associated with the above flexibility actions represents a Buy/Sell spread of 0.13 p/kWh - much less than that demonstrated in winter 1996/7. Although the above represents a net sell, the significant differential associated with the Buy/Sell spread has given rise to a cost within the regime.
- The net flexibility cost of £1.4m can be broken down into several elements. Overall the system sold 1.80 TWh which generated revenues of £6.2m. Additionally costs arise from the buy/sell spread in the flexibility mechanism.
- The flexibility mechanism was used to satisfy both national and local balancing requirements.

Local actions were necessary to address system constraints and most of these actions were associated with sells required at Barrow to resolve supply/demand constraints. These arise as a result of the interaction of gas inputs at particular points and the level of demand. This often requires system reconfigurations and ultimately local system sells to ensure maximum system operating pressures are not exceeded and the safety and security of the system is maintained.

The costs of these local actions are assessed as approximately £2m.

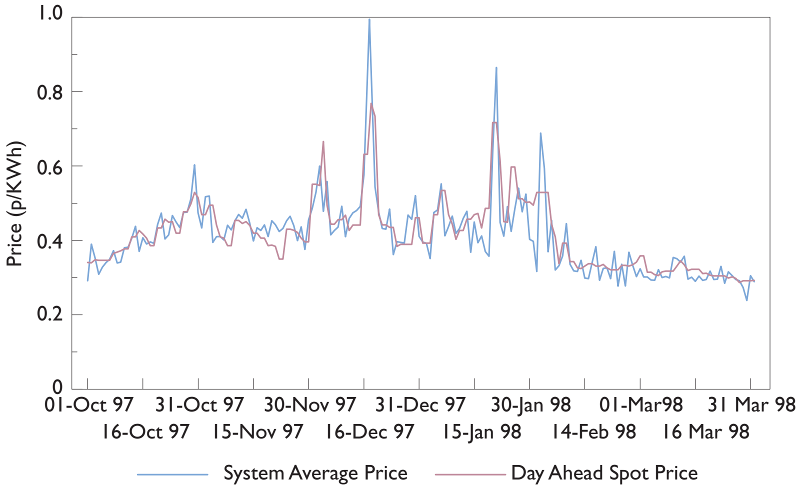
The other flexibility costs, based on the Buy/Sell spread, and associated with national balancing actions amounted to approximately £5.5m.

A2.1.3 Cashout Prices

The flexibility mechanism prices are used to set cashout prices within the regime. If the 16th & 17th December are excluded it is clear that the volatility associated with the System Average Price (SAP) was much less this winter than it was during the 1996/7 winter.

Reduction in the volatility of SAP in conjunction with increased maturity in the forward gas market has given rise to a smaller variation between SAP and published day ahead spot prices than was experienced last year.

Figure A2.1.3 – Day Ahead Spot Price vs End of Day System Average Price

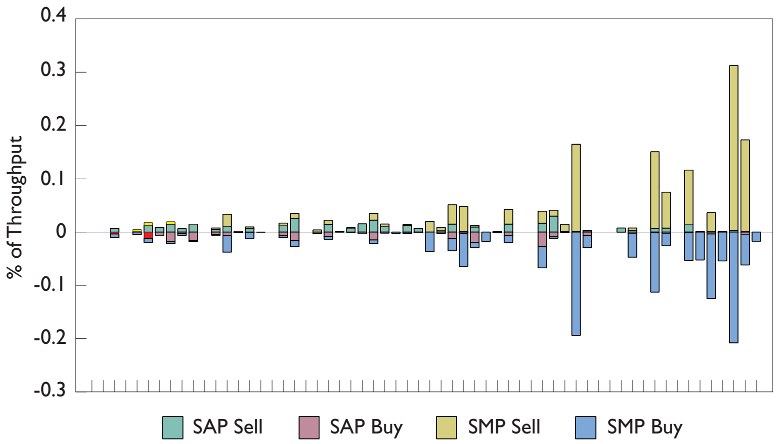


Despite this. and because of the increased incidence of flexibility activity in both directions within day, there is less certainty within day of both SAP and the System Marginal Prices (SMP) that will be used for shipper cashouts.

A2.1.4 Shipper Balancing

There was greater day on day volatility in overall demands yet the general level of shipper balancing has improved slightly over that achieved in winter 1996/7. Individual shipper balances are shown below:

Figure A2.1.4 – Shipper Imbalance Quantities As A Percentage Of Throughput



This better balancing performance may be attributable to shippers having:

- earlier opportunity to re-nominate arising from the reduction in the Non Daily Metered (NDM) trigger level from 2% to 1%;
- greater opportunity to achieve balance via the transferable re-nomination rights available as a result of the matched re-nomination rule changes implemented by Network Code Modification 169; and
- stronger pricing incentives provided by cashout prices arising from more frequent balancing actions.

Many of the shippers who had significant cashouts beyond their Imbalance Tolerance Quantity (ITQ) in 1996/7 appear to have achieved much lower levels of cashout beyond tolerance in 1997/8.

The overall imbalance revenues and costs for the winter were significantly impacted by the prices set by high priced flexibility bids accepted on the 16th and 17th December.

Excluding 16 and 17th December the average value of shipper over delivery was 0.41 p/kWh whereas the average price associated with shipper under deliveries was 0.43 p/kWh.

The overall imbalance cashouts (excluding 16 and 17th December) involved a small net buy which generated a credit to Neutrality of approximately £8.5m.

A2.2 Interruption

A2.2.1 Transco Interruption

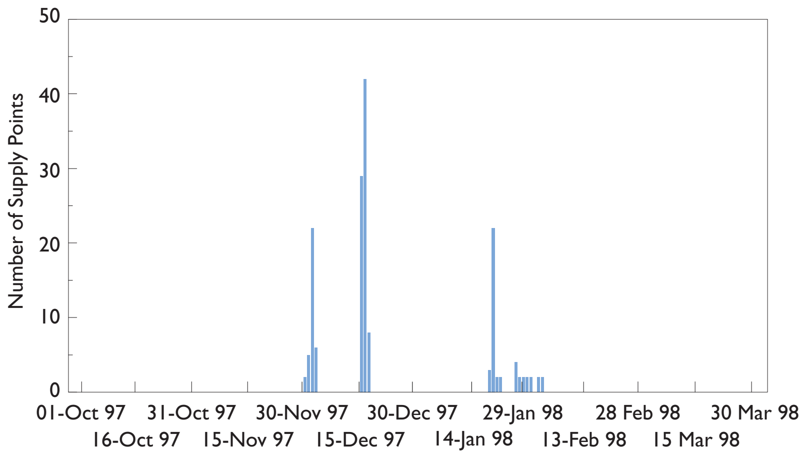
The provision of this service provides benefits to Transco, shippers and gas consumers:

- Transco can interrupt for a number of reasons including, demand exceeding available capacity on the system and forecast demand exceeding 85% of the 1 in 20 peak day demand. In return, the transportation service is provided at a discounted cost. Transco can therefore plan on the basis of interruption availability and avoid inefficient and uneconomical investment;
- shippers can choose to take normal or interruptible services enabling them to offer differential services to their customers, gas consumers; and
- gas consumers benefit from cheaper gas.

Transco provides information on the likelihood and incidence of interruption via the Internet.

Transco called interruption on 18 days affecting 66 of the 1,658 interruptible supply points. Only 7 sites were interrupted for more than 2 days by Transco.

Figure A2.2.1 – Supply Points Interrupted By Transco by Day



All interruption was triggered on the basis of full utilisation of local capacity with the exception of one day when South Wales was affected by a capacity constraint arising on the National Transmission System (NTS).

Approximately 52 GWh of demand was interrupted representing approximately 0.04% of the demand supplied under interruptible transportation arrangements.

The 159 supply point days of Transco interruption have only given rise to 2 incidents of failure to interrupt, a considerable improvement on 1996/7.

Most of the interruption was related to Network Sensitive Loads (NSL). The effective interruption of these loads is critical to the maintenance of supply to firm loads. Thus, concerted efforts were undertaken by Transco and shippers in preparing for the winter to ensure that Network Sensitive Load site obligations were fully understood.

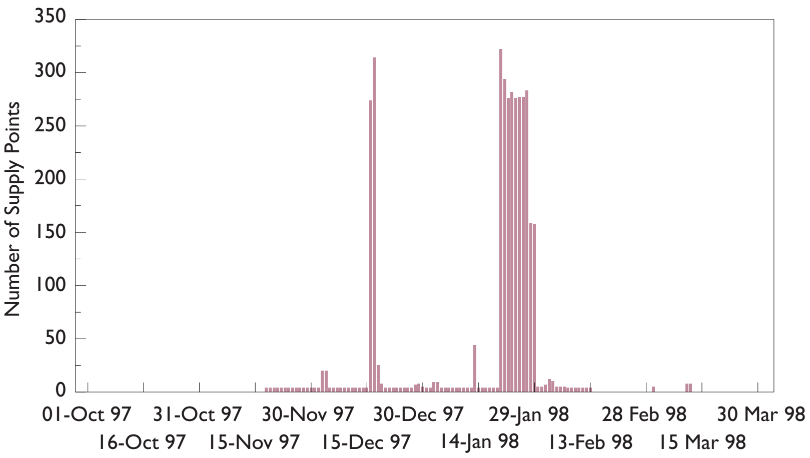
The mildness of the winter has given rise to a lower than anticipated level of interruption and therefore the effectiveness of the process to invoke widespread interruption has not been fully established.

A2.2.2 Shipper Interruption

Twenty-one shippers supply gas under interruptible transportation arrangements. During the winter, eight shippers advised Transco that they had invoked commercial interruption. The aggregate level of shipper interruption notified to Transco was approximately 1,500 GWh, about 30 times more than Transco interruption.

The shipper interruption was approximately 1,250 GWh at supply points within the LDZs and approximately 250 GWh at supply points sourced directly from the NTS.

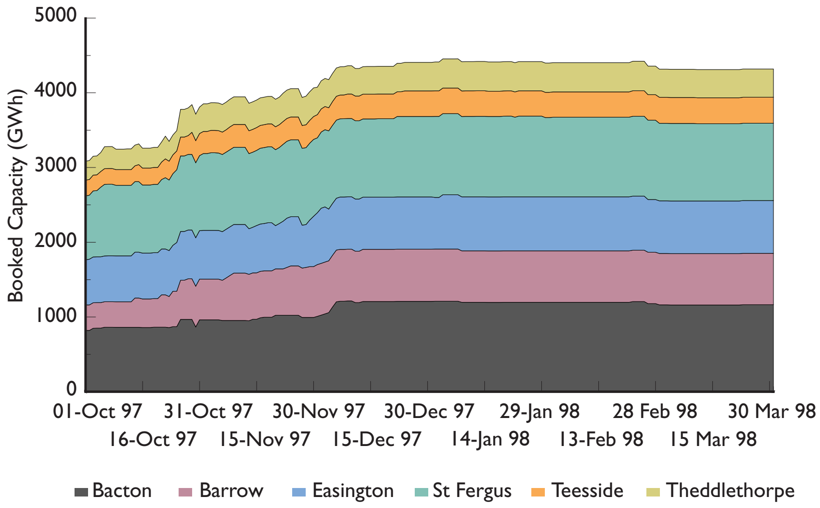
Figure A2.2.2 – Supply Points Interrupted By Shippers By Day



A2.3 Entry Capacity

Entry capacity bookings increased over the first half of the winter, reflecting increased shipper requirements for capacity. During the second half of the winter, capacity bookings were relatively flat.

Figure A2.3 - Capacity Booked Over All Beach Terminals



More capacity at Bacton had been booked than was envisaged in the 1997 Base Plan Assumptions. Capacity booked at St Fergus was much lower than expected.

Whilst entry capacity booked at St Fergus was lower than envisaged, utilisation of that capacity was very high - typically between 85-90% of the booked capacity was used. The highest capacity utilisation was 97.9% on 11th March 1998.

Conversely the utilisation at Bacton was very much lower - typically 55-75% with the highest capacity utilisation being 92.7% on 3rd December 1997.

A2.3.1 Entry Capacity Trading

Forty-six shippers participated in entry capacity trading during winter 1996/7. The number of trades during the period was 2,712, an increase of approximately 50% on the previous winter. The capacity traded represents approximately 41 TWh, which is approximately 8% of system throughput.

Some shippers sourced all of their entry capacity via the secondary capacity trading market. Other shippers were actively involved in trading capacity on most days.

A2.3.2 Network Constraints

Ofgas is undertaking an investigation into the circumstances surrounding capacity constraints and will be publishing a comprehensive report.

Currently there is no clear definition of firm capacity levels at entry. The Network Code allows Users to book capacity over and above the available capacity at an entry point.

The actual available capacity at an entry point on any day is termed the available transportation capacity, and is dependent on a number of factors including: installed pipelines/plant, the demand (particularly the demand adjacent to the terminal), and the overall supply sourcing pattern.

Assuming that the maximum transportation capacity is available at all times (as in the case of Barrow), then the actual available capacity is directly related to the demand level on the day. Therefore the 'maximum' capacity, which is based on peak day demand, is not necessarily available when demand is low.

During this winter input capacity constraints have occurred at Barrow (34 occasions) and at St. Fergus (6 occasions).

A2.3.2.1 Barrow:

Capacity constraints occurred on 34 occasions in the period from 24th November 1997 to 3rd February 1998.

The maximum transportation capacity was available throughout this period. The shipper nominations, on the constraint days, were at the maximum predicted input level. However, the system demand during this period was on average only 65% of peak day demand.
Therefore, given the relatively low level of demand, the actual available capacity was marginally less (on average 2.5 mcm), than the 'maximum' capacity, resulting in the constraints.

The total volume of system sells, to resolve the constraints, was 89 mcm, at a cost of £1.8m (cost based on the differential between SAP and the Sell price).

Of the cost, £407,000 was incurred on the 17th December when the SAP was 4.3443 p/kWh. The differential between the system sell bids taken at Barrow to resolve system constraints and system sell bids elsewhere was approximately 0.1 p/kWh. This represents about a "discount" of 25% on "normal" sell prices.

A2.3.2.2 St. Fergus:

The St. Fergus input was constrained during the period 19th to 24th March 1998.

The constraints were caused by a reduction in the transportation capacity, resulting from the requirement to isolate one of the pipelines at St. Fergus to carry out emergency repairs.

The level of constraint was identified and notified to shippers ahead of each day. Some of the reduction in nominations was achieved by removal of shrinkage (a total of 11.8 mcm) and also by some shipper response to requests for voluntary reductions in nominations (a total of 3.4 mcm). The remainder of the reduction was achieved via system sells.

The total volume of system sells was 23.2 mcm, at a cost of £275,000 (based on the differential between SAP and the system sell price).

As with Barrow, the differential between system sell bids taken to resolve system constraints at St Fergus and other system sell bids elsewhere was around 0.1 p/kWh. Given the lower system sell prices in March, this represents about a 33% "discount" on "normal" sell prices.