COMMISSION
OF THE EUROPEAN
COMMUNITIES

DIRECTORATE-GENERAL FOR ENERGY

NATURAL GAS COMMON CARRIAGE :
FOLLOW-UP STUDY

Final report

May 1989

our reference

Mr R De Bauw
Director
Oil and Natural Gas Directorate
Directorate General for Energy
Commission of the European Communities
Rue de la Loi 200
B-1049 Brussels
Belgium

25 May 1989

Dear Robert,
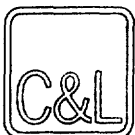

Follow-up study on natural gas common carriage

In response to your letter of 24 February 1989 setting out terms of
reference for a follow-up study to our earlier report on natural gas common
carriage, I have pleasure in enclosing our final follow-up report. This
takes into account the comments on our draft received from the Gas Division
of your Directorate.

We very much appreciated the opportunity of working with DG XVII again on
this issue and hope that, despite the limitations which we both recognise
attend an exercise of this sort, this further analysis will be of value to
you in your global evaluation of the common carriage option.

Yours sincerely

W I M Goskirk
Director, Oil and Gas.

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OF THE EUROPEAN
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NATURAL GAS COMMON CARRIAGE: FOLLOW-UP STUDY

Final Report

May 1989   Coopers & Lybrand

NATURAL GAS COMMON CARRIAGE : FOLLOW-UP STUDY

Contents:-

SUMMARY AND CONCLUSIONS

Introduction

1.   In January 1989, we presented to the European Commission (DG XVII)
our Final Report on a study entitled "Advantages and drawbacks for the
European Community of the introduction of a system of 'common carrier' for
the transportation of natural gas". The terms of reference for the study
required us to spell out the key advantages and drawbacks of common
carriage for consumers, the gas industry and the Community as a whole.

2.   In the light of our conclusions, we were then asked to carry out a
short piece of follow-up work which would provide some elements of
quantification not included in the terms of reference for the main study
referred to above. The quantitative assessment is set out in this
follow-up report and concerns:-

   (a)   the level of border prices for imports into the Community;
   (b)   efficiency in transmission and distribution;
   (c)   redistribution of income (between gas companies and consumers, or
         between different classes of consumers); and
   (d)   macro-economic effects.

3.   It must be stressed at the outset that these are not areas in which
precise and purely objective quantitative assessments can be made. This
reflects both the limited availability of commercially sensitive
information and the nature of the issues involved. We have therefore had
to rely on a combination of best estimates and informed subjective
judgements in a number of areas. Our overall conclusions are, in our view,
reasonable, but should not be interpreted as anything other than "order of
magnitude" indications.

Extent of Common Carriage

4.   The most important effects of common carriage are likely to be
indirect and may well be out of all proportion to the extent of direct
marketing which actually takes place. The mere threat of increased

competition, underlined by a limited amount of actual competition between
gas suppliers, is likely to erode monopoly profits and encourage
efficiency, as existing gas suppliers respond to increased pressures in the
market place. In this sense, the actual extent of direct marketing via
common carriage is a secondary issue. Nevertheless, quantitative assessment
of the direct effects (loss of market by existing suppliers) requires a
view of the likely use of common carriage rights.

5.   In our view, the number of consumers both willing and able to
conclude direct purchases is likely to be small - mainly large industrial
users and power plants. Moreover, the major gas producing countries are
unlikely to embark on an aggressive price-cutting battle for market share,
while gas transmission companies faced with the threat of direct sales
competition may make pre-emptive reductions in their own selling prices to
some large users.

6.   For these reasons, we do not consider that direct sales via common
carriage would account for more than about 4% of the total Community gas
market in 2000, even if such a system were introduced by the end of 1992.
We expect the use of common carriage to be higher than average in the UK
(perhaps 7% of the market) and somewhat lower (around 3%) elsewhere in the
Community.

Border Gas Prices

7.   The view has sometimes been advanced that common carriage will
unleash increased competition between gas producers, considerably reducing
the level of prices for gas imported into the Community. In its simple
form, we do not consider this argument to be very credible; common carriage
may introduce new gas buyers into the market, but it does not of itself
change the number of sellers. Intensified competition may take place to
some extent where large new markets are available (gas-fired power
generation, for example), but widespread price cutting seems most unlikely
in the oligopolistic conditions of the European gas market. Nevertheless,
there would be some increased competitive pressure on existing gas buyers
to negotiate the best possible import deals.

8.   We would therefore expect a fairly modest reduction in the average
cost of gas imported into the Community; this is difficult to quantify, but
we would regard 2-3% as a reasonable overall estimate (see paragraphs
3.20-3.26 below). This is equivalent to perhaps ECU 175 million p.a. by
2000 for the Community as a whole, excluding the UK where a right to common
carriage already exists. There is also likely to be some reduction in the
costs of new gas production within the Community, as a result of increased
competitive pressure. Taking this into account, the total 'gas cost'
benefit attributable to common carriage might be ECU 250 million p.a.
However, these benefits are only likely to be achieved if the current
'buyer's market' conditions persist. In a 'seller's market', which seems
unlikely to recur for a considerable period, the increased number of bulk
gas purchasers resulting from common carriage rights might even exacerbate
the tendency to 'bid up' the level of prices when gas is perceived to be in
short supply.

Gas Industry Efficiency

9.   The competitive threat of direct marketing via common carriage will
also bring some additional pressure to bear on gas utilities to operate
more efficiently and reduce their non-gas costs, especially at the level of
transmission. The relationship between competition and efficiency seems
intuitively plausible, but the evidence does not point to a very strong
link, at least in the short to medium term. Nevertheless, some benefit
seems likely over a longer period. For example, a 5% reduction in
transmission and storage costs across the Community could yield an
efficiency benefit of about ECU 300 million p.a. by 2000, or some ECU 250
million if the UK is excluded on the grounds that common carriage
legislation is already in place (see paragraphs 4.11-4.12).

Income Distribution Effects

10.   Concern has been expressed that common carriage might benefit large
consumers at the expense of smaller consumers, or gas utilities, or both.
While it is true that much of the immediate benefit of gas common carriage
would go to large industrial or power plant consumers, competition in
manufactured goods markets and cost-plus pricing of electricity may well

ensure that a large portion of these gains is passed on to final consumers. To the extent that these benefits arise from lower border gas prices or improved efficiency in transmission and distribution, they will not give rise to a commensurate disadvantage for smaller gas consumers or gas utilities.

11.   Where existing sales to large users incorporate an element of . monopoly profit, however, common carriage is likely to have a negative impact on the financial position of transmission companies. Of the major utilities examined, British Gas, Ruhrgas and SNAM appeared to make more than a 'normal' return on capital in 1987 (table 5.7 below) and common carriage might to some degree erode 'above normal' margins in these cases, to the extent that such high profits persist in future years. Elsewhere, utility returns tend to be below a 'normal' level and any adverse financial effect on transmission companies might be passed on to smaller customers. In general, we would expect this effect to be small (table 5.8), except perhaps in Member States at an early stage of gas industry development (such as Spain) where unit costs are high and industrial use still dominates the gas market.

Macro-Economic Effects

12.   To the extent that gas common carriage leads to lower industrial gas prices, it might be expected to contribute to an improved Community trade performance in world markets for manufactured goods and thus to an increased level of economic activity in the longer term. Although some manufactures (such as nitrogenous fertilisers) are very gas-intensive, the cost of gas accounts for only around 0.5% of output value for EC industrial production as a whole. For this reason, the external trade effect is likely to be relatively modest; we estimate an annual benefit of around ECU 125 million per year (paragraph 6.14). In individual gas-intensive sectors (such as some steel and chemical products), however, the 'local' impact may be proportionately greater.

Overview

13.   Focusing on the net benefits of a common carriage system to the Community as a whole, our best estimates for the year 2000 are as follows:-

(a) border prices and Community gas production costs - around ECU 250
     million p.a, provided that 'buyer's market' conditions persist;

(b) gas industry efficiency - around ECU 250 million p.a; and

(c) macro-economic (trade) benefit - about ECU 125 million p.a.

The combined benefit of some ECU 625 million p.a. is equivalent to around
2% of the Community's projected total annual gas supply costs in 2000.
These figures exclude the UK, on the grounds that common carriage
legislation already exists and a decision to introduce a Community-wide
common carriage system would have little additional effect.

14.   We should perhaps emphasise once again the 'order of magnitude'
nature of these results and the dangers of reading too much precision into
our estimates. Nevertheless, we consider that our analysis provides a
reasonable guide to the broad magnitude of the benefits which might be
forthcoming.

I   INTRODUCTION

Background to the study

1.1   In January 1989, we submitted to the Directorate-General for Energy
(DG XVII) of the European Commission a report on the advantages and
drawbacks for the European Community of the introduction of a system of
"common carrier" for the transport of natural gas. The principal potential
advantages and drawbacks identified were as follows:-

Advantages	Drawbacks
(a) the possibility of lower gas purchase prices, if direct marketing opportunities lead gas producers to compete more aggressively for market share;	(a) the possibility, in a tighter gas market than exists today, that competition between new and existing bulk gas buyers could lead to a "bidding up" of gas purchase prices;
(b) the erosion (through common carriage arrangements) of monopoly profits on certain high-margin gas sales to industrial customers;	(b) possible increases in selling prices to small consumers, to compensate gas utilities for any loss of industrial market profits;
(c) some increased competitive pressure on gas utilities to reduce overheads and operate more efficiently;	(c) increased market uncertainty which might put at risk the necessary long-term investments in gas supply capacity, both within and outside the Community;
(d) wider gas purchase options (and therefore, possibly, lower prices) for new gas-fired power stations;	(d) adverse consequences of market uncertainty for the development of "new" or infant gas industries.

(e) increased options for UK gas
    producers to sell into the rest
    of the Community, increasing the
    likelihood of a cross-channel
    link and a further integration of
    the European gas grid.

1.2   In accordance with the terms of reference for the original study, the
conclusions set out above were presented in a largely qualitative manner.
In a letter dated 24 February 1989 (reproduced for reference in Appendix
C), DG XVII subsequently asked us to carry out some elements of
quantification on our key conclusions which are susceptible to quantitative
analysis. The four effects of the possible introduction of a common
carriage system for natural gas on which we were asked to focus are the
following:-

> (i)   possible reductions in the border price of gas imported into
>   the Community;
>
> (ii)   possible increased efficiency in gas transmission and
>   distribution operations;
>
> (iii)   possible redistribution of income between gas companies and
>   consumers, or between different classes of consumers; and
>
> (iv)   an indication of the macro-economic benefit of possible
>   reduced industrial gas prices.

Quantitative analysis of these issues will then form part of the European
Commission's global evaluation of the desirability of introducing a common
carriage system at Community level.

1.3   The terms of reference for this study cover not only the key areas in
which a common carriage system might lead to an overall improvement in the
welfare of the Community, but also the possibility of welfare
redistribution from one group to another. Of particular importance in the
latter case are:-

(a) an erosion of monopoly profits through increased competition (which also has resource allocation benefits for total welfare), redistributing income from gas utilities to large consumers; and

(b) possible adverse consequences for smaller gas users, offsetting benefits to large consumers.

The most important of the possible effects of common carriage not covered by this follow-up study is its impact on gas supply security. This does not mean that this effect is neglected, merely that it is not readily quantifiable.

1.4 As agreed with DG XVII, the detailed analysis in this follow-up study relates to the six main gas-consuming Member States which do not already have significant common carriage rights enshrined in national legislation - Belgium, France, Italy, the Netherlands, Spain and West Germany. The United Kingdom, which established a legal right to common carriage in 1982 and substantially reinforced the legislative and regulatory framework in 1986, is also included as a reference point. Having carried out our detailed analysis, we then extrapolate the results to cover the other Member States (Denmark, Ireland and Luxembourg) which already have a natural gas industry and those (Greece and Portugal) which plan to develop such an industry in the 1990s.

Approach to quantification

1.5 Our approach to quantification in the four areas identified by DG XVII for attention is first to set up a framework for analysis. This framework comprises an assessment of gas selling prices, the various elements of non-gas costs and bulk gas purchase prices in the Member States concerned. Some of the elements in this assessment can be obtained or calculated from published sources; others require a degree of informed subjective judgement, since gas utilities' cost structures are rarely published in the form required for our analysis. Once established, the framework then allows us to trace the impact of common carriage on efficiency and the distribution of incomes (issues (ii) and (iii) of the four selected by DG XVII) through to changes in cost levels, selling prices and gas utility profit levels.

1.6   Our analysis of all four areas to be covered is set out in detail
below.   Briefly, the approach we have taken to each area is as follows:-

(i)   border prices - a review of the limited available evidence on
        this question and an informed judgement as to the range of
        probable outcomes;

(ii)   efficiency in transmission and distribution - analysis of the
        relationship between competitive sales market pressures faced
        by gas utilities and their level of efficiency;

(iii)   redistributional effects - analysis based on utilities'
        current gross trading margins, reasonable levels of carriage
        charges and gas industry profitability; and

(iv)   macro-economic benefits - a review of the literature on the
        Community's trading performance in world markets for
        manufactures (to assess the likely impact of any reduction in
        manufacturing industry's gas costs), together with a case
        study of the iron and steel sector.

Structure of the report

1.7   The analytical framework referred to above is set out in Section II
below for each of the seven Member States considered in detail.   Sections
III, IV, V and VI respectively then deal with border gas prices, gas
industry efficiency, income distribution effects and macro-economic
benefits.   Our summary and conclusions are presented at the beginning of
the report document for ease of reference.

1.8   Further details of our cost analysis are set out in Appendix A.
Appendix B contains an assessment of the likely level of direct marketing
via common carriage in each Member State.   In Appendix C, we present some
evidence on the impact of open access transportation in the U.S. gas
industry and Appendix D contains the study Terms of Reference.

II   ANALYTICAL FRAMEWORK

2.1   As outlined in the introduction, we have carried out an analysis of revenues, costs and netbacks for each of the seven Member States examined. In this Section, we set out briefly our approach and the results obtained. Further details of our analysis are set out in Appendix A.

Methodology

2.2   In each country, we have adopted a simplified analysis of revenues, costs and netbacks by market sector, using two classes of consumer as follows:-

(a)   smaller residential and commercial customers, who are almost exclusively supplied from the local distribution grid; and

(b)   large industrial and power station users, who are frequently supplied direct from the transmission grid, although significant numbers of industrial users are located on distribution grids in Member States such as Denmark, France, the United Kingdom and West Germany. This category includes both firm and interruptible gas sales.

2.3   We have taken the year 1987 as the basis for our analysis, since this is the most recent period for which comprehensive data is available. (In interpreting our results, it should therefore be noted that a single year's figures may not necessarily be representative of longer term trends). For each consumer category in each of the seven Member States examined in detail, we identified or estimated the average revenue obtained from gas sales to final users, excluding taxes. We then:-

(a)   calculated a netback at the point of bulk gas delivery (border, beach, wellhead, etc) for each of the two market sectors, by deducting the estimated average non-gas costs of supply to the sector from the sector's average sales revenue; and

(b)   calculated a net transmission company trading margin for each market sector and hence an average net trading margin for natural gas sales overall, by deducting average gas purchase costs from the netback.

The overall net margin is defined as equal to operating profit before interest, extraordinary items and taxation.

2.4   We have categorised the costs of gas supply into five basic cost elements as follows:-

(a)   the average cost of <u>gas purchases</u> made in bulk by transmission companies. In some cases, such as Belgium, this is simply the average border price of imported gas. In other instances, it is a weighted average of border prices for gas imports and the prices of indigenous gas supplied from producers to the transmission company;

(b)   the average unit cost of <u>storage</u>, which we define to include the costs of underground storage (acquifers, salt caverns, partially depleted gas fields etc) and overground LNG storage for peak-shaving, together with any LPG/air peak-shaving facilities and seasonal production facilities owned by transmission companies (the British Gas Morecambe field, for example). Diurnal and other local storage facilities owned by distribution companies are included separately as part of distribution costs;

(c)   long distance gas <u>transmission</u> costs;

(d)   the costs of local <u>distribution</u> (which may be zero in the case of transmission companies' direct sales); and

(e)   customer-specific costs, including the unit cost of <u>connection</u>, meter reading, billing and other specific services. These are significant for small domestic and commercial customers, but negligible (in unit cost terms) for large consumers in the industrial and power station markets.

The full detail of our cost estimates is set out in Appendix A. For the purposes of the summary presented in this Section, categories (b) and (c) are combined as transmission level non-gas-costs, while (d) and (e) are combined as distribution level non-gas costs.

2.5   It should be stressed at this stage that the cost data needed for this exercise are not readily available in the form required and the amount of information published also varies considerably from one Member State to another. In most cases, published data provide a reasonably good guide to

selling prices, profit margins, total expenses and (sometimes) the breakdown between gas purchase costs and non-gas costs. Non-gas costs are rarely if ever categorised into customer-related costs, distribution, transmission and storage. In some cases, therefore, we have had to rely on our own estimates, based on limited published data and other information available to us. The results obtained should not be regarded as precise, but we consider that they still provide a broadly reasonable reflection of the true picture and a helpful framework for analysis.

2.6   The non-gas cost information presented in this report is based largely on the company accounts set out in gas utilities' Annual Reports for 1987. With few exceptions (such as British Gas), these accounts are based solely on historical cost accounting (HCA) conventions under which depreciation allowances are typically related to the original cost of capital and equipment, although in some cases assets are revalued from time to time. Current cost accounting (CCA) uses the full replacement cost of assets as the basis of depreciation and can produce significantly higher cost figures. For example, the British Gas accounts for 1987/88 show average non-gas operating costs for the company's gas supply business of 12.2 p/therm (ECU $0.059/m^3$) on an HCA basis. On a CCA basis, the equivalent figure is 13.5 p/therm (ECU $0.066/m^3$), some 11% higher. In proportionate terms, the difference between HCA and CCA unit costs would probably be greater for a pure transmission company than for a vertically integrated utility such as British Gas, since transmission is more capital-intensive than distribution. This should be borne in mind when we discuss the question of 'fair' carriage charges in Section VI, in particular, since there is a reasonably strong argument that a 'fair' charge should cover the unit replacement cost of assets used, such as pipelines or storage facilities.

2.7   Where the natural gas supply industry is vertically stratified into separate transmission and distribution companies, we have identified or estimated the average price at which gas is sold from transmission companies to local distributors. In such cases, the distributors' own profit margins are treated as part of gas supply costs at the distribution level. The split between transmission level (transmission and storage) and distribution level (distribution and connection) non-gas costs is therefore

reasonably clear in Belgium, Italy, the Netherlands, Spain and West Germany, since different organisations are involved. For vertically integrated utilities such as British Gas and Gaz de France, we have had to rely on our own estimates, supported in the former case by information from the 1988 MMC report.

2.8   Some remarks may be appropriate at this stage regarding the estimated breakdown of joint non-gas costs (for transmission, storage and, in some cases, local distribution) between domestic/commercial and industry/power station markets. In simple terms, industry/power station consumers impose lower costs on the supplier because of their higher consumption load factors and, in many instances, the higher grid pressures at which they are supplied. The higher load factors mean lower unit transportation capacity costs and/or a significantly lower requirement for storage to meet the seasonal peak in demand.

2.9   Particular cost allocation problems are raised by interruptible sales contracts with large users. In certain circumstances, it can be argued that interruptible sales do not impose any capacity costs. Moreover, the ability to interrupt may have a positive value in terms of reduced storage costs, since the utility would otherwise have had to construct additional storage to meet the peak in firm gas demand. There is, in fact, no internationally agreed approach to this cost allocation question, although some utilities do put these principles into practice. Our approach is to distinguish several types of supply situation and to adopt different cost allocations in each case, as follows:-

(a)   Member States where storage is relatively limited (Belgium, Spain, West Germany and the UK) and interruption is used in severe winters for seasonal supply/demand balancing. In such cases, the system is sized to meet peak firm gas demand and we have therefore assumed that interruptible sales do not bear capacity costs and also provide a benefit in terms of reduced storage requirements;

(b)   Member States (France and Italy) where substantial underground storage exists, for strategic as well as load-balancing reasons, and interruption is rarely if ever used for seasonal load balancing. Effectively, the system is sized to meet the combined peak in firm

and interruptible demand and interruption would normally be used only in the event of a major disruption to supplies. We have therefore assumed that interruptible sales should bear some of the capacity costs of pipeline and storage facilities; and

(c)   the Netherlands, where the Groningen field provides seasonal flexibility and there is (as yet) no underground storage. There are some interruptible contracts (with power stations) but interruption is rarely used and we have assumed that interruptible sales should bear a proportion of transmission capacity costs.

Results

2.10 As mentioned above, a detailed presentation of our analysis and the results obtained is set out in Appendix A. In this Section, we set out our conclusions in a simplified form for each of the two defined market sectors and for total natural gas sales in each Member State considered. This simplified presentation shows average gas purchase costs, distribution level non-gas costs and transmission level non-gas costs, with transmission companies' profit margins separately identified. The results of our analysis are set out on this basis in Table 2.1 below and illustrated in Figures 2.1 to 2.3 respectively for the residential and commercial sector, industry/power sector and total gas sales to all sectors combined.

Table 2.1   Netback Analysis Results for 1987
(in ECU/m^3 x 100)

(a) Domestic/Commercial Sector

	B	F	I	NL	SP	FRG	UK*
Average Selling Price	20.3	22.1	26.5	15.4	41.1	20.9	19.6
Distribution Level	8.5	4.8	12.0	4.0	28.5	8.1	4.5
Transmission Level	1.8	2.7	4.7	0.5	8.0	4.6	3.0
Gas Purchase Costs	9.2	10.1	6.8	8.2	7.3	7.1	8.3
Transmission Co.Margin	0.7	4.5	2.9	2.6	(2.7)	1.0	3.7

Figure 2.1: Netback Analysis 1987
Domestic/Commercial Sector

Figure 2.2: Netback Analysis 1987

Industry/Power Sector

Costs,'Revenues ECU/m3 (*100)

Categories: Margin, Gas, Trans, Dist

Countries: Belgium, France, Italy, N'lands, Spain, W Germany, UK
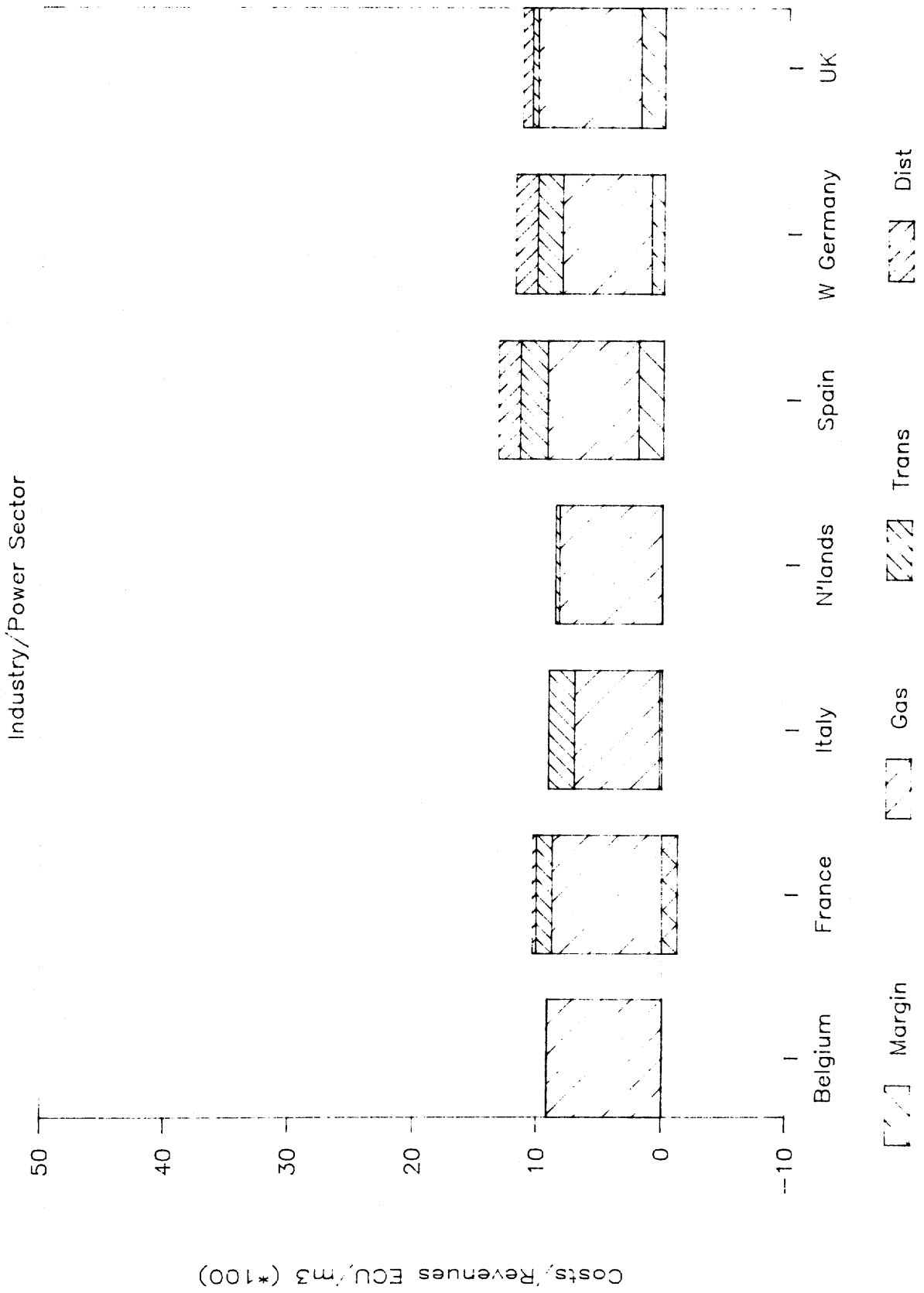
Figure 2.3: Netback Analysis 1987
Total Sales
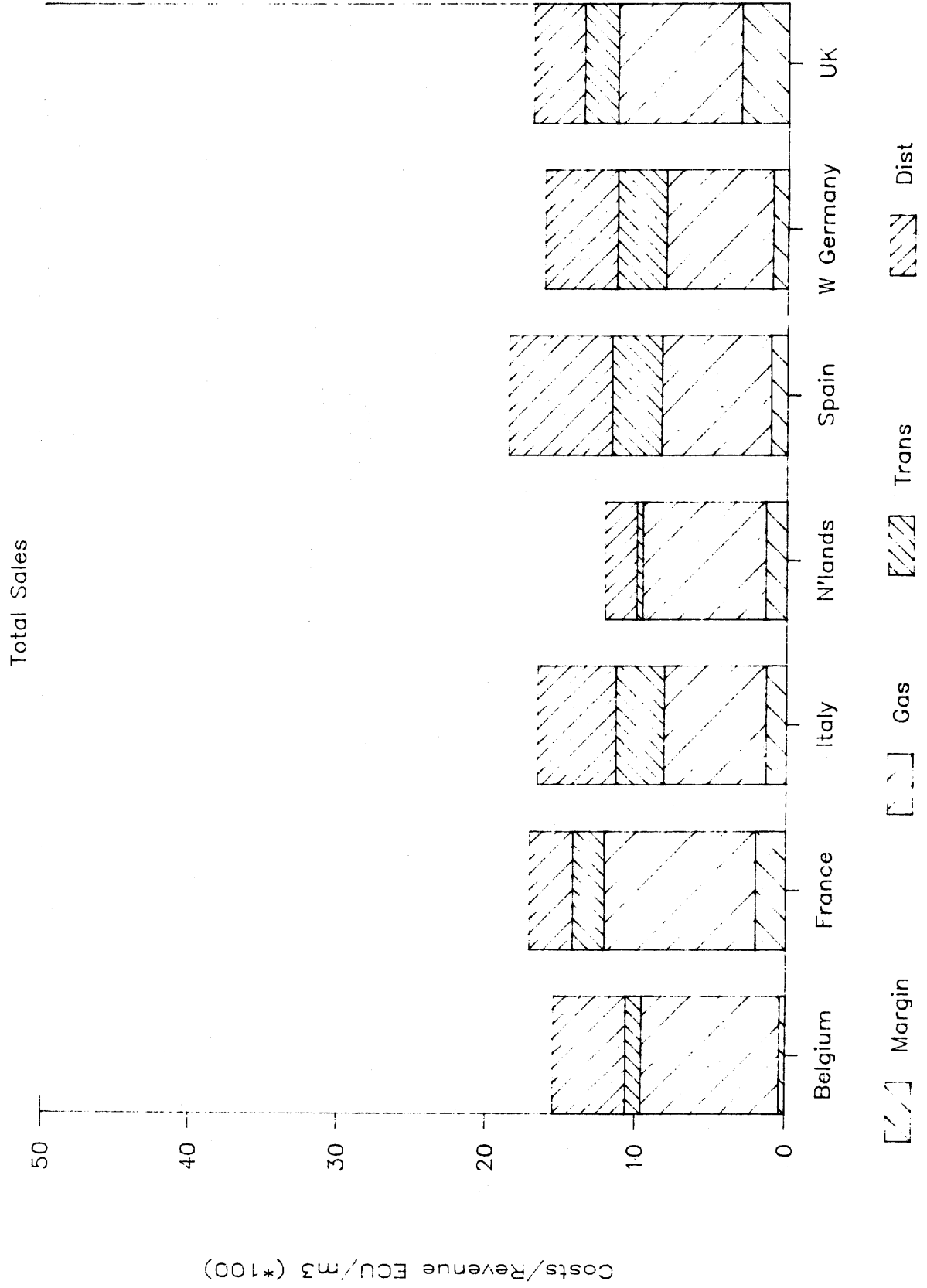
(b) <u>Industry/Power Sector</u>

	B	F	I	NL	SP	FRG	UK
Average Selling Price	9.2	10.4	9.1	8.6	13.3	12.0	11.4
Distribution Level	-	0.3	-	-	1.8	1.8	0.8
Transmission Level	-	1.3	2.0	0.3	2.2	2.0	0.5
Gas Purchase Costs	<u>9.2</u>	<u>10.1</u>	<u>6.8</u>	<u>8.2</u>	<u>7.3</u>	<u>7.1</u>	<u>8.3</u>
Transmission Co.Margin	-	(1.3)	0.2	-	2.0	1.0	1.9

(c) <u>Total Home Market Sales**</u>

	B	F	I	NL	SP	FRG	UK
Average Selling Price	15.5	17.1	16.6	12.1	18.6	16.3	17.1
Distribution Level	4.8	2.9	5.2	2.1	6.9	5.1	3.4
Transmission Level	1.0	2.1	3.2	0.4	3.3	3.0	2.2
Gas Purchase Costs	<u>9.2</u>	<u>10.1</u>	<u>6.8</u>	<u>8.2</u>	<u>7.3</u>	<u>7.1</u>	<u>8.3</u>
Transmission Co.Margin***	0.4	2.0	1.4	1.4	1.1	1.0	3.2

   * 1987/88 financial year throughout

  ** excludes exports, where relevant (especially important in the Netherlands)

 *** derived from Annual Reports; net operating profit before interest, extraordinary items and tax

2.11 Although some of the estimates set out above should be regarded as indicative rather than precise, a number of features do emerge which are salient to the impact of gas common carriage:-

(a)   the level and structure of gas supply costs varies considerably as between Member States, depending on factors such as the source and load factor of gas supplies, the geographical size of the country, the grid location of different customers, the type of storage facilities and their capacity, the manner in which seasonal storage and interruptible contracts are used to balance supply and demand, the penetration of gas into domestic markets and the size and structure of the utilities responsible for gas distribution. High

non-gas costs in Spain, for example, appear to reflect low levels of grid utilisation and considerable up-front costs in the early stages of gas industry development;

(b)   on average, gas purchase costs account for a very large proportion of the price at which gas is sold to final consumers - typically around 50%, with variations from about 40% in Spain to as much as two-thirds in the Netherlands, where the cost of providing seasonal supply flexibility is effectively part of the price at which Gasunie purchases gas from NAM;

(c)   the majority of non-gas costs of supply is generally incurred at the distribution level, for the gas market considered as a whole. This is especially true of residential and commercial sales; in most cases, the non-gas costs of supply to large industrial and power station customers are mainly or entirely incurred at the level of transmission and storage;

(d)   the unit net trading margin (operating profit before interest, extraordinary items and taxation) earned by transmission companies on their total sales in 1987 was typically around ECU $0.01/m^3$ or a little higher. Margins were lower than average in Belgium (Distrigaz), in particular. In the Netherlands, the reported margin of ECU $0.014/m^3$ for total home market sales considerably exceeds the overall Gasunie operating profit for 1987. This is because we estimate a much lower margin on export sales, which are excluded from Table 2.1. The figures for the UK and France cannot be directly compared with those of other Member States, since the British Gas and Gaz de France operating margins reflect the vertically integrated nature of their gas supply businesses. If the overall BG and GdF margins were compared with total operating profit in other Member States (with transmission and local distribution company margins combined), then they would not appear unduly high; and

(e)   in all Member States examined except Spain, domestic and commercial sales appear to provide a netback (to beach, border or other point of bulk gas purchase) which at least equals the average gas purchase price. In the large users' market sector, netbacks in France appear to be below the average cost of gas purchases. Sales to large users seem to be most profitable in Spain, West Germany and the UK.

2.12 It should be recalled that these results are based for simplicity on a single year's data. Nevertheless, they may provide some useful pointers to the likely attractiveness of direct marketing via common carriage, both for gas consumers in the Member States concerned and for producers who might wish to sell their gas direct. They also provide a framework within which the possible quantitative impact of a gas common carriage system can be assessed.

III   BORDER GAS PRICES

Introduction

3.1   One of the arguments advanced for gas common carriage is that it would encourage more competitive marketing by gas producers and lead to a general reduction in the level of imported (or wellhead) gas prices. It is suggested that gas buyers, adhering to a broad 'netback' principle for setting gas purchase prices, have paid too high a price for imported gas. Since a number of gas producing countries currently have very substantial unexploited reserves and (in some cases) excess deliverability into the Community, it is suggested that a competitive market price would be below the netback level set in relation to the value of gas marketed against alternative fuels.

3.2   On the other hand, a counter-argument is sometimes made that the introduction of new gas buyers via common carriage (with the number of producers unchanged) would simply lead to a "bidding up" of gas purchase prices, especially in a tighter gas market than prevails today.

3.3   Although the level of bulk gas purchase prices is a key issue, there is very little in the way of quantitative evidence to be produced for either view. Thus a substantial degree of subjective judgement is necessarily required when assessing the likely outcome. It is nevertheless important to consider the limited evidence which is available. This Section of the report therefore outlines the available evidence from U.S. and European experience, together with our own assessment of the impact which common carriage might have on the general level of prices for gas imported into the Community.

U.S. Experience

3.4   Although the U.S. gas supply situation is very different from that prevailing in the Community, we nevertheless consider it helpful to assess the quantitative impact of open access transportation since around 1984. The impact of common carriage on imported gas prices in Europe is most unlikely to be as great as that of open access transportation on U.S.

wholesale (wellhead, border or producer sales) prices. U.S. experience may therefore provide some pointers to the maximum possible effect of common carriage in Europe, if it were to lead to much intensified price competition between gas producers.

3.5 The impact of open access transportation in the U.S. is considered in Appendix C. Direct comparisons with European experience during 1982-88 are rendered more difficult by the extent of U.S. wellhead price controls, especially in the period through to the end of 1984. Around 1982-3, average wholesale prices for U.S. gas were well below European import prices, although U.S. import prices were actually higher than those of imports into Europe. In 1983, for example, average U.S. wellhead prices were around $2.90/mmBtu and average import prices about $5.35/mmBtu. By 1987, the average wellhead price had fallen to a little under $1.90/mmBtu and the average U.S. import price to $2.40/mmBtu, although some "spot" gas was changing hands at prices much lower than the wellhead average. For comparison, typical European gas import prices in 1987 were around $2.50/mmBtu. There is therefore some evidence that gas-gas competition in the U.S. brought about lower wholesale prices than would otherwise have prevailed. It must, however, be recalled that this took place in a situation of substantial shut-in production, many small producers striving to market their output and a high degree of competition for business between long-distance pipelines. Thus conditions are very different from those prevailing or likely to prevail in Europe.

3.6 A number of other points from U.S. experience are worth noting:-

(a) pipeline companies' trading margins on traditional merchanting (purchase and sale) activities were squeezed somewhat over the period 1984-88;

(b) distribution companies' margins, on the other hand, appear to have been maintained and even increased towards the end of the period, as City Gate prices fell faster than retail gas prices to final consumers;

(c) among final consumers, large industrial and (especially) electric utility users were the main beneficiaries of falling wholesale gas

prices, while retail prices to smaller residential and commercial customers fell much less than wholesale prices;

(d) notwithstanding gas-gas competition in the U.S., small user gas prices fell by much less than competing gas oil prices over 1984-86, while gas prices to larger consumers fell no faster than the price of residual fuel oil;

(e) average U.S. gas prices to industrial and power station users in 1987 were around $2.90/mmBtu, somewhat below the average level of large user prices in most but not all Member States; and

(f) average U.S. gas prices for smaller residential and commercial customers were $5.17/mmBtu, below the average price level for such consumers in all Member States except Luxembourg and well below the average for the European Community as a whole (about $7.00/mmBtu, net of tax).

3.7 Thus there is evidence to suggest that gas-gas competition in open access transportation allowed large consumers in the US to obtain supplies on more favourable terms than they would otherwise have done. There is, however, little to support the view that gas-gas competition allowed retail gas prices to fall relative to the price of alternative (oil) fuels.

Current European Situation

3.8 A reduction in border gas prices as a result of common carriage is only likely to come about if the introduction of such a system leads to more intense price competition between gas producers. The current situation of very considerable unsold gas reserves internationally and under-utilised production and export facilities in some of the countries which supply the European Community with gas have led some observers to suggest that this would take place in Europe, as it did with open access transportation in the United States. Algeria and the Soviet Union, in particular, could probably export much more gas than they currently do without major investment in production or export facilities, provided the facilities are installed to take delivery in Western Europe. The additional export potential may currently be as much as 10 bcm/a from the USSR and perhaps 20 bcm/a from Algeria, equivalent to over 10% of total Community consumption. With investment in new export pipelines, it is

clear that the USSR, in particular, could deliver far more additional gas than this. Current excess export capacity (which is not the same thing as excess deliverability to customers in the Community) has led some observers to conclude that common carriage would unleash new and powerful forces of competition between gas producers which have not hitherto arisen. In its simple form, this sort of argument does not appear to us to be credible. We can consider it in two parts - first, the current European situation and, second, the likely impact of common carriage.

3.9   The key differences between the European supply situation and that which enabled gas-to-gas competition to emerge in the US were outlined in our previous report to the European Commission. Briefly, the European market is characterised by:-

(a)   many fewer gas producers/suppliers, even in the gas producing Member States such as the United Kingdom and the Netherlands and especially in those Member States with little or no indigenous production, where exports from four producing countries (Netherlands, Norway, Algeria and the USSR) account for a very large share of total gas supplies;

(b)   little or no competition between pipeline companies for long distance transportation to particular markets; and

(c)   little excess deliverability (to customers) in the short term, which contrasts with considerable spare pipeline capacity in the US which enabled direct marketing of the 'gas bubble' to develop.

3.10   Between the four main gas producing countries which supply continental Western Europe, there is a form of limited oligopolistic competition, by which none can afford to sell gas at a price considerably out of line with the others for very long. In general, the USSR pitches its export prices towards the bottom of the range for the other suppliers, in order to offset any suspicions of unreliability in supply for political reasons. The Netherlands has the advantages of reliability, flexibility and proximity, while Norway is a fairly high cost producer in a favourable geo-political position. Each has typically been able to command a small premium above Soviet prices. Algeria has traditionally pursued a hawkish line on prices, relying on political and wider trade considerations to

maintain interest in the importing countries. Its export prices are currently well above those of the Netherlands, for example. Of the four main producers:-

(a) the Netherlands' export sales volume is subject to a restrained depletion policy and the country can export all the gas it wants to under existing arrangements;

(b) Norway is facing a substantial decline in exports to the UK over the next few years and is keen to increase sales elsewhere. Recent marketing efforts have involved sales agreements with Austria, Spain and SEP of the Netherlands, but high production and transportation costs would make it difficult for Norway to compete against more aggressive price cutting by other producers;

(c) Algeria is in desperate need of increased foreign exchange earnings and is known to be interested in LNG sales to the US or Japan, in addition to agreements reached with new European importers such as Greece and Turkey. It has recently shown some flexibility in export deals such as the relatively small peak-shaving LNG agreement concluded with British Gas, which is reported to involve no take-or-pay commitment; and

(d) the USSR is also seeking to expand energy export earnings to boost a flagging economy and has been looking for new markets in Sweden, Greece, Turkey and elsewhere. In some existing markets, the USSR may face an informal ceiling on its market share, although the practical significance of this remains unclear.

3.11 Although each producer is clearly keen to maximise export earnings, the fact that each already has a significant market share is a key difference from the US situation, where even the largest producing oil company supplies no more than 5% of the market. No major exporting country would wish to make modest incremental sales to the Community if the cost of doing so were a substantial reduction in the general level of market realisations.

3.12 It should perhaps be noted that the present gas supply situation does not preclude export discussions or agreements with buyers other than the

traditional gas transmission company buyers. Among these are the following examples:-

(a) long-standing import contracts between Gasunie and electricity companies RWE, VEW and EWE of West Germany;

(b) purchase of Norwegian Statfjord gas by BP's West German subsidiary Gelsenberg in the early 1980s, at a price reportedly higher than that agreed by the continental buying consortium (a base price of $5.50/mmBtu, subsequently renegotiated). Gelsenberg eventually found they were without a market for this gas and resold it to Ruhrgas;

(c) purchase of Norwegian Statfjord gas by Mobil AG of West Germany as part of the continental buying consortium;

(d) an attempt by Elf Aquitaine to purchase Troll/Sleipner gas from Norway for CeFeM, at an offer price reportedly above that agreed by the continental buying consortium in 1986. This attempt was ultimately abandoned in favour of GdF on-selling Troll/Sleipner gas to Elf;

(e) the recent agreement for a 2 bcm/a direct supply from Norway to SEP of the Netherlands for use in new gas-fired power stations from around 1995-6;

(f) a sales contract signed in 1988 for direct supplies from the BP-operated Miller field in the UK North Sea to the North of Scotland Hydro Electric Board's (NSHEB's) Peterhead Power Station, from around 1993; and

(g) a number of relatively small scale direct sales arrangements from offshore gas producers in Italy (other than AGIP), mainly to their own downstream chemical plants.

3.13 Most of the arrangements referred to above do not involve any transportation of third party gas in pipeline companies' grids, but they may offer limited evidence as regards the price which new gas buyers might pay for gas sold direct from producers via common carriage. In fact, the examples quoted above illustrate the whole range of possible outcomes:-

(a) both Gelsenberg and Elf appear to have been prepared to pay more than the established buyers in order to obtain supplies for themselves, although neither arrangement came to fruition;

(b) SEP agreed to a significantly higher initial price with the Norwegians than the level of "E" tariff at that time for sales to power stations by Gasunie, but secured indexation to coal (rather than oil) prices which was not then on offer from Gasunie. This provides the possibility of lower prices than 'E' tariff in the long term if oil prices rise faster than coal prices, as many observers expect; and

(c) NSHEB paid a price reported in October 1988 to be around 8.5 pence/therm (ECU $0.04/m^3$) for very sour gas. This allowed the producers to avoid the costs of processing required to sweeten the gas sufficiently for British Gas to be able to accept it into its grid for public distribution. Even allowing for these costs, the NSHEB price appears to be somewhat lower than recent British Gas' purchase prices for comparable high load factor associated gas supplies. It may be that British Gas was reluctant to accept this gas on the timescale required to ensure timely development of the Miller oil field. However, there is also a suggestion that some producers may be prepared to offer keen prices to allow gas to break into new markets.

3.14 Also in the UK, it is reported that Associated Gas Supplies (AGAS), an independent gas marketing company, has concluded the first carriage deal with British Gas. AGAS will buy gas from UK producers and is seeking to sell it on to high load factor industrial users (via common carriage) at a price below that on offer from British Gas. Recent press reports suggest an average AGAS selling price of around 26.5p/therm (ECU $0.14/m^3$), which is below current BG firm gas prices for all except very large firm industrial customers. Any AGAS price advantage over BG is likely to arise mainly from a lower trading margin rather than a lower gas purchase price, although UK producers might be prepared to offer somewhat lower prices for a high load factor supply to AGAS which would avoid the offshore capital costs necessary for a lower load factor supply required by BG.

3.15 This evidence is clearly limited and inconclusive but there may be
some tentative general conclusions which can be drawn from it:-

(a) new buyers are unlikely to conclude arrangements with significantly
     higher prices than those obtained by existing transmission companies
     except in times of perceived gas supply shortage (which seem unlikely
     to arise for the foreseeable future) or in return for other
     advantages, such as favourable indexation terms; while

(b) producers are unlikely to offer new buyers discounted prices unless
     the direct sale offers opportunities to break into a new market (such
     as power station use in Member States where this does not currently
     exist) or significantly increase gas penetration in existing markets.

We now turn to the likely impact of a common carriage system in the
Community.

Impact of Common Carriage

3.16 Even after the event, comparisons between individual direct sales
agreements and transmission companies' existing purchase terms would be
rendered difficult by the fact that transmission companies buy for a
mixture of different markets (including higher value domestic and
commercial sales) and not for a specific industrial or power station use of
relatively low value. Fluctuating prices of alternative fuels and
different price indexation terms would also make it difficult to isolate
the impact of common carriage from general movements in the gas market
which would have occurred in any event. It is particularly difficult to
make a precise quantitative assessment in advance regarding the likely
effect of common carriage on the general level of gas import prices. We
outline below some of the key factors involved, in a qualitative fashion,
and illustrate our conclusions with what we consider to be a reasonable
quantitative example.

3.17 There are a number of factors which suggest a favourable net impact
of common carriage. Large, energy-intensive industrial users and power
utilities will be looking to cut costs and are unlikely to pay a premium
for direct purchases, unless there are other offsetting advantages such as

more favourable indexation or a considerable saving in cost from border to delivery point. Where major new markets for gas emerge (such as efficient combined cycle gas-fired plant for power generation), the direct purchase option will enhance buyers' choices, promote competition between suppliers and help ensure that supplies are available on favourable terms. The common carriage option will also allow end users to communicate more directly to producers the opportunities for selective price reductions to induce load switching to gas from other fuels, although transmission companies should generally be aware of these in the normal course of events. A threat of direct sales via common carriage may also place some additional competitive pressure on transmission companies to ensure that their own purchases are made on the best possible terms.

3.18 The main counter-weight to this potential for increased competition is the structure of the European gas market and the attitude of the major producers. Gas common carriage is likely to add new (potential) buyers to an oligopolistic market. This will scarcely make it perfectly competitive, although it may enhance sellers' access to some market sectors. The major gas producing countries are unlikely to begin competing much more fiercely for market share, without regard to the effect of competitive price cutting on market realisations, simply because there are a small number of large industrial consumers seeking a gas supply alongside their traditional utility customers. They might be prepared to make some limited price concessions where there are opportunities to enter a new market (such as power generation in the UK) or where a large industrial user would then be willing to switch or convert a substantial load (eg for auto-generation) from another fuel to natural gas. Nevertheless, producers would still be conscious that substantially lower prices to direct buyers could have a "knock-on" effect on their next price renegotiation with existing purchasers. Of all the gas producing countries, the USSR (with its massive reserves and low production costs) is perhaps best placed to reduce prices and common carriage may offer the opportunity to circumvent any informal ceilings on market share observed by purchasing transmission companies. Yet the Soviet Union has already demonstrated its skill in pitching prices just slightly below those of other producers in order to protect its position, without triggering off a competitive price cutting response.

3.19 On balance, we would expect the impact of gas common carriage on the border price of imported gas to be favourable. It is also likely to have some beneficial effect on the costs of gas production within the Community, in the longer term. In quantitative terms, however, we conclude that some observers have exaggerated the likely benefits, often by misplaced analogy with recent U.S. experience. The market and regulatory conditions which precipitated intense gas-to-gas competition in the U.S. simply do not exist in the European situation. We therefore take the view that the beneficial impact of gas common carriage on the general level of bulk gas purchase prices in the Community (as opposed to the price level in particular direct marketing deals) is likely to be fairly modest.

3.20 A modest percentage reduction in gas purchase costs nevertheless equates to a substantial sum of money. DG XVII's current projections show around 230 mtoe (some 270 bcm/a) of gas consumed in the Community at the turn of the century. At average 1987 gas purchase prices of around ECU $0.08/m^3$ (some \$2.75/mmBtu), for example, this implies a total annual gas purchase bill of around ECU 22 billion (about \$27 billion). Of this, 39% is projected to be incurred as gas imports from outside the Community, with the other 61% going in payments to indigenous gas producers, especially in the Netherlands and the UK.

3.21 In commercial terms, Community gas producers would probably have to respond to any general reduction in imported gas prices, in order to maintain their competitive position. From an economic welfare viewpoint, however, it is principally the resource cost of producing gas within the Community which is relevant and not the level of purchase prices from Community producers. In respect of gas fields currently in production, the bulk of the resource costs have already been incurred during construction. Reduced selling prices from such fields would benefit consumers, but may not improve overall Community welfare significantly unless capital or operating costs are actually reduced as well. Nevertheless, lower gas prices from producing fields could have some overall Community welfare benefits if upstream monopoly profits are eroded or the level of funds repatriated to non-EC parent oil companies is reduced.

3.22 In order to provide an "order of magnitude" impression of the impact which common carriage might have, we can consider an illustrative example with three different elements. Our example assumes:

(a) direct buying by large users via common carriage (on the scale set out in Appendix B) at a border price which is on average 5% below that at which transmission companies would otherwise have bought for re-sale, mainly reflecting competition between suppliers for new or expanding markets such as combined cycle power generation;

(b) a "knock-on" effect on the general level of imported gas purchase prices of 2%. This reflects transmission companies' response to the direct sales threat in large user markets (which are only part of their total sales), reducing some selling prices and at the same time seeking concomitant improvements in their gas purchase terms; and

(c) a reduction in the resource cost of producing gas in the Community of 1%, mainly reflecting lower capital and operating costs for new fields.

3.23 The UK is excluded from the estimated benefits of a Community-wide carriage system, since there is already a common carriage principle enshrined in the national legislation (1986 Gas Act) and reinforced by subsequent measures taken in response to the MMC report of 1988. A Community-wide move to introduce common carriage would therefore have little additional impact as far as the UK is concerned.

3.24 The three effects outlined above can be quantified for the year 2000, as follows:-

(a) 6 bcm (3% of the Community gas market, excluding the UK) supplied from non-Member States via common carriage at a reduction of 5% on an average price of ECU $0.08/m^3$ would cut the Community's gas import bill by around ECU 25 million per annum (providing that it does not put existing importers into irrecoverable take-or-pay penalties);

(b) a general 2% reduction in the price of other gas imports (95 bcm) would reduce the annual import bill by ECU 150 million; and

(c)   a 1% reduction in the resource cost of non-UK Community gas
      production (98 bcm) would provide a benefit of approximately ECU 80
      million per year.

3.25 It should be emphasised that this is merely an illustrative example,
but in our view a not unreasonable one. The economic cost of natural gas
to the Community would, on this basis, be reduced by around ECU 250 million
per annum, equivalent to about 1.2% of the current Community gas purchase
bill. Even allowing for a fairly wide margin of error in our assumptions,
it seems plausible to conclude that the benefit is most likely to lie
within a range of perhaps ECU 150-350 million p.a.

3.26 This result assumes that current 'buyer's market' conditions continue
to prevail in the European gas industry. In a 'seller's market' of
perceived gas supply shortage (which we consider unlikely to recur for the
foreseeable future), the introduction of additional buyers via common
carriage might exacerbate a tendency to 'bid up' gas purchase prices. This
tendency was evident, for example, in the early 1980's when the original
Norwegian Statfjord deal was concluded.

IV   GAS INDUSTRY EFFICIENCY

Introduction

4.1   The second effect of gas common carriage which we have been asked to consider in this report is its impact on the efficiency of gas transmission and distribution operations within the Community. Recent reductions in the level of gas purchase costs since 1986 mean that non-gas costs have assumed an increasing importance in proportionate terms. As shown in Section II, they typically account for around 50% of total gas supply costs for domestic and commercial users, but a much lower proportion (typically, 10-20%) for large industrial and electric utility consumers. Over and above this, transmission costs outside the borders of the importing country account for a significant proportion of the border price in some cases, such as Soviet exports to France or future Norwegian exports to Spain, for example. The impact of common carriage on non-gas costs should not, therefore, be ignored.

4.2   Even if common carriage were to have no beneficial effect on border prices (which we consider unlikely), it could allow some large users to undercut the gross trading margins of existing transmission company suppliers, where those trading margins currently reflect an element of monopoly profit. If this occurs, there could be three main effects:-

(a)   a distributional impact (welfare transfer to large gas consumers from gas utilities or, possibly, from other consumers) discussed in Section V below;

(b)   a resource allocation benefit, from bringing industrial gas prices closer to an 'economic' level free of monopolistic distortions; and

(c)   an economic benefit, to the extent that gas utilities respond to competitive pressure on their margins by cutting the resource cost (capital and operating costs) of transmission and distribution within the Community.

It is the last of these three effects on which we focus in this section of the report.

4.3   Again, it must be recalled that a large part of the cost of transmission and distribution comprises sunk capital costs, in existing pipeline and storage facilities. The efficiency effect of common carriage on non-gas costs therefore depends on:-

(a)   reducing the operating costs of existing facilities where, for example, monopoly positions may have allowed labour costs to increase above a market level;

(b)   reducing the capital and operating costs of new facilities through more cost-effective design, improved construction methods and the elimination of "gold-plating"; or

(c)   reducing unit costs through the more effective utilisation of existing facilities.

4.4   The quantitative importance of these effects depends on a relationship between increased competition (via common carriage) and efficiency. One way of assessing whether increased competition (via common carriage) would lead to greater efficiency in transmission and distribution is to consider whether there is any relationship between the degree of competition which various gas utilities already face, from other fuels, and the level of their non-gas costs. There are two ways in which this might be considered, as follows:-

(a)   cross-sectional comparisons between gas utilities at a point in time; or

(b)   time series analysis of a given utility's costs over a period of time.

Each of these is addressed in turn below.

Cost Comparisons

4.5   As shown in Section II, the level and structure of non-gas costs varies considerably as between Member States. Non-gas costs tend to be lowest in the Netherlands and highest in countries such as Spain and Italy, especially at the distribution level. This does not necessarily mean that

the former is much more efficient than the latter. In providing a distribution grid to serve smaller consumers, there is a large cost element which is essentially fixed, regardless of the density of connections on that grid. Moreover, the costs of providing a network with higher capacity rise much less than in proportion to increasing average consumption per customer. There is therefore a strong tendency for unit distribution costs to fall with increasing penetration of domestic and commercial networks by natural gas and increasing use of gas for central heating, in particular, since this brings with it a significant increase in average consumption.

4.6   There are also a number of reasons why non-gas costs may vary between countries at the level of transmission and storage, such as geographical size and the availability of relatively low cost underground storage. For these reasons, we consider that it is not meaningful to equate relative non-gas cost levels among gas utilities with differences in efficiency, nor to try and relate these costs differences to the degree of competition faced in the gas market by each utility.

Competition and Efficiency

4.7   Having examined and rejected the possibility of meaningful comparisons of non-gas costs between utilities, we now turn to trends in individual utilities' costs over time. With the fall in oil product prices from late 1985 (in the case of heavy fuel oil) and early 1986 (in the case of heating oil), gas companies across Europe have faced increasing competitive pressure from oil in most markets, especially as regards sales to industrial users. If competitive pressure from the threat of common carriage would bring efficiency benefits, then we would expect to see some evidence of improved efficiency in the light of increased competition from oil. Unfortunately, the information available (for the years 1982-87) is rather limited for a full and fair test of this hypothesis. In particular, any efficiency improvements are likely to take place gradually over a period of years. The limited available evidence may nevertheless cast some light on the efficiency question and we have therefore examined trends in non-gas costs for a number of major European gas utilities, compared with trends in the competitive position of natural gas versus oil.

4.8   Table 4.1 summarises the results obtained from an examination of real
unit non-gas costs and their relationship (if any) to relative gas and oil
prices. The gas/oil relative price index was constructed by using
industrial gas and heavy fuel oil prices (in ECU/GJ), then converting the
ratio into an index using 1985 as the base year. The non-gas cost index
was constructed using data derived from annual reports; these costs were
then deflated and turned into an index.

4.9   As can be seen in Table 4.1, the rapid fall in oil prices over
1985/86 made gas appear uncompetitive in all of the seven countries
considered. However, as the index of non-gas costs shows, this did not
necessarily produce a reduction in utility costs to improve the competitive
position. In Italy, West Germany and the UK, unit non-gas costs increased,
which may reflect the volume effect of losing interruptible gas consumers
to oil. By 1987 as gas prices fell to a more competitive level, only the
Dutch and Spanish utilities managed to continue to reduce their non-gas
costs. In Belgium and Italy, for example, utility non-gas costs rose
considerably.

4.10 Figure 4.1 shows the actual observations for all of the Member States
considered, together with a line of best fit. The regression line suggests
that there is a general tendency for real non-gas costs to be lower in
years when gas prices are high relative to those of oil, and gas utilities
come under increasing competitive pressure. However, as Figure 4.1 clearly
highlights, the relationship is not a very strong or consistent one. The
most likely reason for this is that efficiency can only be improved in
response to increased competition over a period of years; we do not yet
have sufficient data to capture the full response to falling oil prices
from 1985-86.

Impact of Common Carriage

4.11 Having reviewed the evidence for a general link between the extent of
competition and efficiency, we now turn to the impact of common carriage,
in particular. In our view, a common carriage system would provide a much
more considerable competitive threat at the level of transmission than at

Table 4.1 Competitive Position & Non-Gas Costs

(Indices, 1985=100)

Belgium

Year	Gas/Oil Index	Non-Gas Cost Index*
1982	96.99	-
1983	99.25	-
1984	87.97	89.80
1985	100.00	100.00
1986	227.07	102.02
1987	115.04	102.00

France

Year	Gas/Oil Index	Non-Gas Cost Index
1982	91.15	-
1983	91.15	107.60
1984	78.76	111.90
1985	100.00	100.00
1986	170.80	91.90
1987	103.54	92.80

Italy

Year	Gas/Oil Index	Non-Gas Cost Index
1982	100.83	-
1983	101.67	-
1984	88.33	-
1985	100.00	100.00
1986	201.67	100.20
1987	85.00	123.60

Netherlands

Year	Gas/Oil Index	Non-Gas Cost Index
1982	98.26	99.20
1983	93.04	106.90
1984	85.22	98.80
1985	100.00	100.00
1986	174.78	74.90
1987	70.43	71.30

Spain

Year	Gas/Oil Index	Non-Gas Cost Index
1982	119.75	174.50
1983	96.30	147.00
1984	102.47	133.60
1985	100.00	100.00
1986	192.59	85.10
1987	135.80	81.20

West Germany

Year	Gas/Oil Index	Non-Gas Cost Index
1982	122.48	-
1983	-	-
1984	98.45	109.20
1985	100.00	100.00
1986	227.13	107.80
1987	156.59	106.60

UK

Year	Gas/Oil Index	Non-Gas Cost Index
1982	165.00	109.00
1983	155.00	102.90
1984	128.33	100.80
1985	100.00	100.00
1986	271.67	102.20
1987	213.80	98.00

* Index of real (inflation-adjusted) non-gas costs throughout
- denotes unavailable
Source: OECD/IEA (energy prices) and company Annual Reports (non-gas costs)

Fig. 4.1

Actual & Predicted Non-Gas Costs
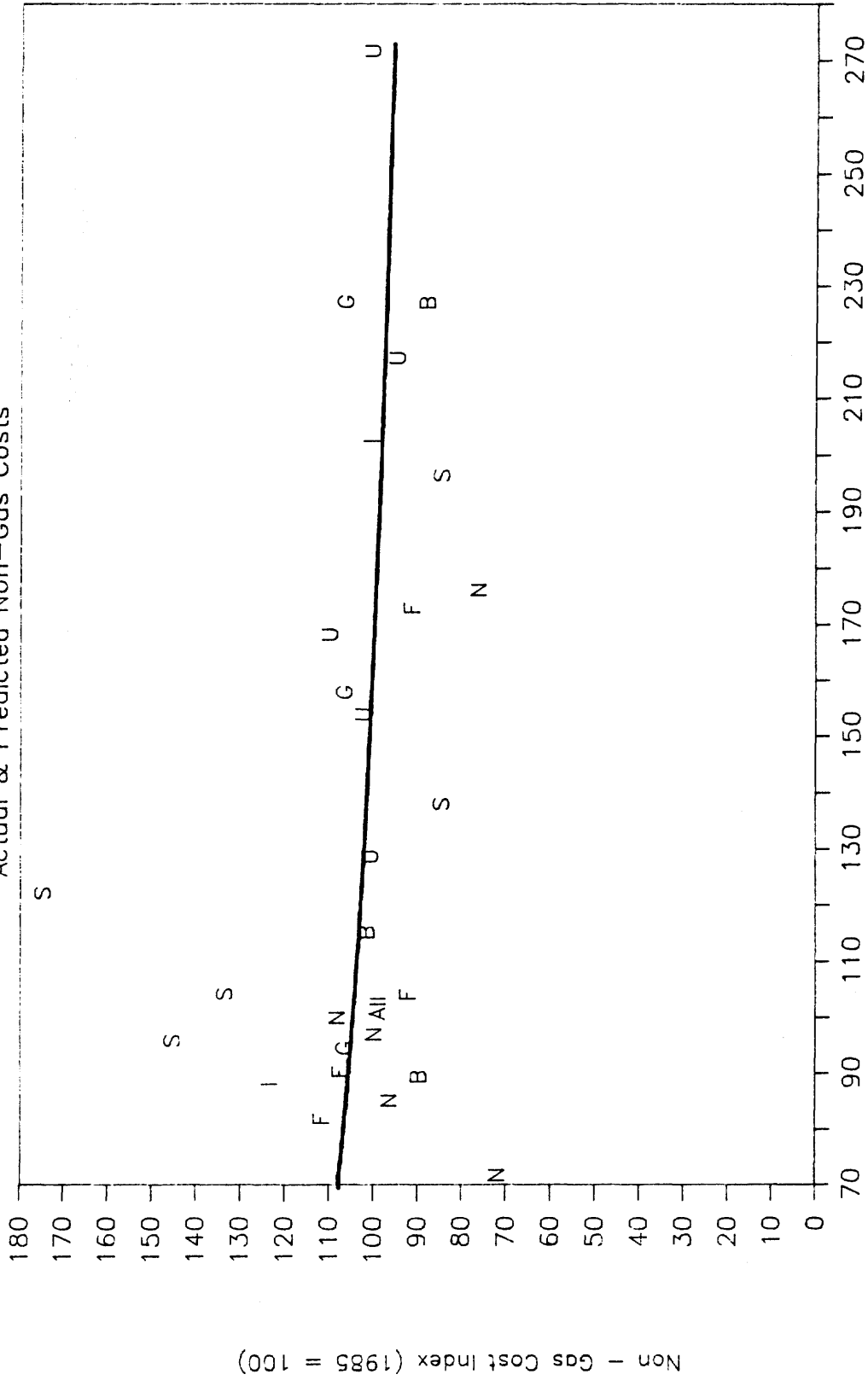
the level of distribution. Only in Member States where there are significant industrial customers supplied by local distributors (such as Denmark and West Germany) is there a possibility that transmission companies might "cherry pick" attractive loads by direct sales through the distribution grid, using common carriage. In general, local distributors who supply only smaller domestic and commercial customers are unlikely to be subject to any significant increase in the degree of competition they face. It therefore seems to us that the major part of any efficiency benefits will be felt at the level of transmission and storage, rather than local distribution.

4.12 In 1987, the (weighted) average level of transmission and storage costs across the Member States examined in Section II (excluding for this purpose the UK, which already has common carriage legislation) was around ECU $0.022/m^3$ (some $0.80/mmBtu). Assuming that the 1987 cost structure is broadly maintained (in real terms) to the year 2000 and that cost levels are or will be comparable for the Member States not examined in detail (Denmark, Greece, Ireland, Luxembourg and Portugal), the total gas transmission and storage gas cost incurred within the Community (again excluding the UK) would be around ECU 5 billion in that year. In practice, the total cost might be somewhat greater than this, since unit storage costs, in particular, will tend to increase over time as average consumption load factors fall and the seasonal flexibility available from old fields (such as Groningen) diminishes over time. Efficiency improvements appear to be feasible and common carriage seems likely to provide a greater competitive spur to achieve them, since it will put pressure on transmission company margins on firm industrial sales which face relatively limited inter-fuel competition. On the other hand, the most significant non-gas cost reductions are to be had from increased sales volumes and greater market penetration. Common carriage per se is likely to make only a modest contribution in this regard. Nevertheless, if the competitive threat implicit in a common carriage system induces only a 5% improvement in transmission level efficiency by 2000, then an economic benefit to the Community of some ECU 250 p.a. would result.

V   INCOME DISTRIBUTION EFFECTS

Introduction

5.1   The third element of the common carriage effects which we have been asked to consider in this report is the possible redistribution of income between gas companies and consumers, or between different classes of consumers. If a large gas consumer decides to purchase gas direct from a producer via common carriage, then the impact on its existing transmission company supplier could consist of three main elements:-

(a)   a direct loss of sales and sales revenue if existing customers are 'captured' by direct sales competition, together with a gain in income from carriage charges which may or may not offset the loss of sales revenues;

(b)   an indirect loss of revenue, if the threat of competition via common carriage leads gas companies to offer their large existing customers more favourable price terms; and

(c)   a possible take-or-pay cost incurred under gas purchase contracts, if the loss of sales causes a transmission company to take less than the contracted 'minimum bill' purchase quantities.

5.2   If a transmission company is worse off as a result of the three factors outlined above, then it may seek to pass the additional cost on to its distribution company buyers or (in the case of British Gas or GdF) its own domestic and commercial customers. Its ability to do so will depend on a number of factors, including:-

(a)   the regulatory regime (if any) in place at the national level, governing transmission company sales to distribution companies or sales to smaller domestic and commercial consumers; and

(b)   where sales terms from transmission companies to distributors are not directly regulated (West Germany), the relative negotiating strengths of the two parties and the attitude of the competition authorities.

5.3   For the purposes of our analysis, we assume that regulators and competition authorities will not, in the long run, wish to see transmission

companies driven into a loss-making position as a result of common carriage. We therefore make the presumption that:-

(a) transmission companies making 'above-normal' profits will themselves have to absorb any loss of profitability arising from common carriage; while

(b) those already earning less than a 'normal' profit would be allowed to pass on extra costs to their remaining customers.

5.4 The definition of 'normal' profit is discussed in more detail below. First, we consider what might constitute a 'fair' carriage charge and the impact which common carriage at 'fair' rates would have on the financial position of the main transmission companies concerned. We make the assumption that carriage charges would, in the first instance, be negotiated between the grid owner and the third party shipper, but that there would be a system of appeal to the responsible authorities in the event of alleged abuse of a dominant position by the grid owner. In such instances, we assume that the authorities would have the power to arbitrate and set a 'fair' carriage charge, which we define as:-

(a) one which yields a 'normal' return on capital employed for the grid owner; and

(b) one which charges the third party no more than a proportionate share of the costs which the grid owning company notionally 'charges' itself for its own sales to comparable customers.

'Fair' Carriage Charges

5.5 For simplicity, we assume that the use of common carriage which takes place by 2000 (as outlined in Section III) involves high load factor transportation, without any significant need for storage services from the grid owner. In practice, we believe that most direct sales would involve high load factor consumers, although some firm gas buyers with no installed capacity to burn alternative fuels might require a 'back-up' service which might call on the grid owner's storage capacity in the event of disruption

to the direct supply. While storage costs do vary considerably between Member States, the costs of long distance transportation (in ECU/m^3/km, for example) will tend to be much more comparable from one location to another, subject to differences in terrain, pipeline capacity and other grid operating conditions. There would in practice be variations in 'fair' carriage charges from case to case; for the purposes of illustration, however, we consider typical average figures. We first discuss the question of rates for firm carriage; interruptible transportation is also conceivable and we return to this possibility below.

5.6 There are a number of clues as to what might constitute a typical 'fair' carriage charge for firm transportation. In its 1986 statement of guidance for those seeking common carriage transportation, British Gas quoted figures of 3.5 p/therm and 4.0 p/therm (around ECU 0.018/m^3 and ECU 0.021/m^3 respectively) for conveyance at 60% and 90% load factors over distances of around 300 km. The lower of these figures represents ECU 0.00006 per m^3 per kilometre. These quotes cover transportation through the British Gas regional transmission system (at medium pressure) as well as through the national high pressure transmission grid. From the 1988 MMC report, it appears that regional and national transmission each account for about half of the proposed total charge. The figures also include a profit element and it must be recalled that actual carriage charges can be (and have been) appealed to the regulatory body OFGAS for a decision. This means that the charges actually paid by third parties might be somewhat below the levels quoted by BG.

5.7 Further evidence is provided by the cost of the MEGAL pipeline, which carries Soviet gas from the Austrian/West German border across West Germany and into France. The line is reported to have carried 800 million kWh (some 75 million m^3) of natural gas per day in 1985, over an average distance of 400 km. Its capital cost is said to have been DM 2.1 billion (around ECU 1 billion), which might equate to some ECU 1.3 billion at today's (1989) costs and prices. If this capital cost is amortised over a 30 year pipeline life at 5% (real return on capital), it is equivalent to around ECU 85 million per year. Assuming that gas used for compression amounts to 2% of the total volume carried, this element of operating costs could be as much as ECU 40 million per year. Other operating costs are

likely to be relatively minor, perhaps ECU 20 million per year to cover maintenance, equipment and labour costs. These costs suggest a total transmission cost of ECU 145 million per annum, equivalent to ECU $0.005/m^3$ ($0.16/mmBtu) transported at 1985 volumes. This corresponds to just ECU $0.000013/m^3$/km, which is only just over 20% of the British Gas rate on an equivalent ECU/m^3/km basis. This reflects the purely high-pressure trunkline nature of MEGAL, with a large capacity and limited inter-connections, as compared with the higher unit cost of operating a complex grid with many offtake points. It is also worth noting that BG's publicly quoted figure may be "regulated downwards" in cases referred to OFGAS. Even if direct purchases via common carriage are limited to large, high load factor customers taking gas at high pressure, the total unit cost of transmission from border to plant gate is likely to be substantially greater than the cost of transportation in a trunkline such as MEGAL.

5.8   A further indication of a 'fair' transmission charge can be obtained from Gasunie's accounts, since the company does not seek to make anything more than a normal profit and its unit non-gas costs of ECU $0.004/m^3$ are very close to a pure transmission cost. Assuming that the average distance over which natural gas is transported by Gasunie is 100 kilometres, this equates to ECU $0.00004/m^3$/km. This is somewhat below the BG quote but well above the estimated MEGAL transportation cost. Gas is transported within the Netherlands at relatively low load factors (only around 40%) and the unit transmission cost would be significantly lower at a high pipeline load factor. On the other hand, replacement cost accounting and a full commercial profit element would considerably increase transmission costs, as compared with the figure obtained directly from Gasunie's Annual Report.

5.9   We have also examined the transportation rate schedules of U.S. pipeline companies for a firm transportation service. Given the fact that a number of inter-state trunklines do not have many offtake points along their length, transportation charges in the U.S. are typically "postage stamp" rates which are fixed irrespective of distance. We have, however, found three examples of distance-related charges, as follows:-

Table 5.1: Illustrative U.S. Firm Transportation Rates, 1989

	US $/mmBtu/mile*4	US $/mmBtu	ECU/m^3/km
ANR Pipeline Co*1	0.00181	0.54	0.000036
Natural Gas Pipeline Co of America *2	0.00065	0.19	0.000013
Northern Natural Gas Company *3	0.00150	0.45	0.000030

*1 Maximum Rate, Mainline Access plus Mainline Mileage charges

*2 Southern Zone, Maximum Peak Rate, Reservation Charge plus Commodity Charge

*3 Field-Market, Reservation Fee plus Commodity Rate plus Mileage (Maximum Charges)

*4 Based on a distance of 300 miles

We have taken maximum transportation rates in each case, which are typically based on full average cost; in practice, competition between pipelines is such that lower rates are often negotiated. Rates clearly vary from pipeline to pipeline, but it is interesting that two out of the three companies examined have maximum firm transportation rates which are similar to the cost of ECU 0.00004/m^3/km estimated from the Gasunie accounts. It should also be recalled that long distance pipeline construction costs may be lower in parts of the U.S. than in Europe, due to lower population densities.

5.10 The total length of the transmission network varies considerably between Member States and this would tend to produce different transmission costs per m^3, even if the cost per m^3/km were uniform across the Community. As of 1986, the position was as shown in Table 5.2 below:-

Table 5.2: Total Length of Transmission Pipelines, 1986

Country	km	Consumption (mtoe)*
Belgium	3,387	7.5
France	27,392	25.3
Italy	20,156	33.0
Netherlands	5,750	33.6
Spain	1,581*	2.8
West Germany	51,500	44.8
United Kingdom	17,702	48.9

*1987

It can be seen from this table that there is a broad correlation between length of system and consumption, with the notable exceptions of the Netherlands and the UK, which both have short transmission grids in relation to market size. In the UK, in particular, this reflects the very extensive distribution grid and the fact that even quite large consumers are often supplied at the distribution level. Table 5.2 does not take into account the average capacity of transmission lines in each Member State, but this information taken together with country size and the physical configuration of the grid provides some clues as to the average distance over which gas is transported in each case.

5.11 As noted above, carriage charges would be negotiated individually and assessed on a case-by-case basis by the competent European Community authorities in the event of alleged abuse of dominant positions. There would no doubt be variations in the 'fair' level of charges from one situation to another. For the purposes of illustration, however, we have assumed an average carriage charge for high load factor firm transportation of ECU $0.00005/m^3$/km. This is equivalent to ECU $0.005/m^3$ ($0.19/mmBtu) for transportation over 100 kilometres, which we have taken to be the average transmission distance in the Netherlands. In Spain, however, the early stages of gas industry development and low grid utilisation are such that we have assumed a higher figure of ECU $0.008/m^3$. Assumptions are also required for the average distance over which gas is transported by transmission companies in other Member States. These take into account the fact that the transmission companies sometimes take delivery of imported (eg Soviet) gas at a point outside their own borders and are then responsible for transit transportation costs as well as in-country

transportation. We can then derive estimates of 'fair' average unit charges for high load factor firm transportation in each Member State. These are compared with our estimates of the transmission companies' gross trading margins on 1987 firm sales to industrial/power station consumers, in Table 5.3 below:-

Table 5.3: 'Fair' Firm Transportation Charges* and Firm Sales Margins
(in ECU/m^3, x 100)

	B	F	I	NL	SP	FRG	UK
Assumed Average Distance (km)	80	250	350	100	300	350	200
'Fair' Firm Transmission Charge	0.4	1.3	1.8	0.5	2.4	1.8	1.0
Average Distribution Charge**	-	0.4	-	-	2.0	1.3	1.2
Total 'Fair' Transportation Charge	0.4	1.7	1.8	0.5	4.4	3.1	2.2
1987 Gross Margin*** (Firm Ind/Power Sales)	0.9	1.2	3.2	0.7	9.3	6.4	7.0

*   defined as set out in paragraph 5.4 above.

**   a distribution cost element is included where a proportion of firm industrial consumers are located on the distribution grid.

***   average firm gas selling price to industrial/power station consumers minus average cost of gas purchases. Assumed selling prices are set out in Appendix A (Table A9).

5.12 In interpreting Table 5.3, it should be borne in mind that the average gross trading margins for 1987 relate to total firm industrial and power plant customers, some of whom take gas on a lower load factor and impose significant storage costs on the transmission companies concerned. There is, moreover, a substantial cost of strategic storage for the maintenance of supply security in Member States such as France and Italy. By contrast, we have assumed that the consumers seeking to buy direct via common carriage at a "fair" charge will only require transmission and not storage. It is also probable that the large, high load factor firm gas users who might consider direct purchases already buy gas at a price below the average figures on which our estimates of gross margins are based. Our estimates may therefore exaggerate the gains to be had for most large consumers in direct purchases via common carriage. Nevertheless, it appears that a 'fair' carriage charge for large, high load factor consumers might undercut current transmission company gross margins on firm sales to some large users in most Member States. This effect would be most marked in Spain, West Germany and the UK.

5.13 The foregoing analysis was based on firm carriage to high load factor consumers. A further possibility is transportation which would be interruptible at the option of the pipeline owner, particularly where the final consumer has the option of switching to alternative fuels at short notice. Interruptible transportation could be relatively cheap if the third party shipper does not bear the full capacity costs appropriate to firm transportation. It could also be valuable to the transmission grid owner, since it would release capacity and gas supplies for the owner's own firm gas sales in peak periods when carriage is interrupted. This would therefore allow the transmission company to economise on storage facilities. Interruptible transportation is common in the U.S. and generally takes place at a simple commodity rate, with no capacity charges. In general, negotiated interruptible transportation rates are significantly lower than those for a firm transportation service.

5.14 The low cost of interruptible carriage is also likely to hold true in Europe. For example, the MMC report on British Gas quotes incremental transmission and distribution costs for new interruptible users of just 0.3 p/therm (ECU 0.0015/m^3), as compared with 2.3 p/therm (ECU 0.011/m^3) for

new firm industrial sales. A number of the large consumers who might be interested in direct supplies via common carriage could switch to alternative fuels at short notice and this suggests that they might see a commercial advantage in interruptible carriage deals. To the extent that transmission companies currently get a substantial contribution to their fixed non-gas costs from interruptible sales which a 'fair' interruptible carriage charge would erode, such arrangements could also have consequences for the distribution of income between utilities, large users and smaller gas consumers.

5.15 In Table 5.4 below, we set out a similar analysis to that presented in Table 5.3, but this time for 'fair' interruptible carriage charges and gross trading margins on interruptible sales to large consumers in 1987. This assumes that 'fair' interruptible carriage charges do not include a substantial contribution to capacity costs and are set at one-third of the firm transportation charges shown in Table 5.3, to cover the cost of compression and other variable operating costs.

Table 5.4: 'Fair' Interruptible Transportation Charges and Interruptible

Sales Margins

(in ECU/m^3, x 100)

Country	'Fair' Charge (Interruptible Transportation)	Gross Margin, 1987 (Interruptible Sales)
Belgium	0.13	(1.0)
France	0.42	(1.0)
Italy	0.58	1.4
Netherlands	0.17	-**
Spain	0.80	3.2
West Germany	0.58	1.1
United Kingdom	0.50*	(0.1)

* includes a distribution cost element, as some interruptible customers are located on the distribution grid.

** power station sales only; estimated gross margin is zero.

5.16 This table suggests that a 'fair' interruptible carriage charge might undercut current gross margins on interruptible sales to large users in West Germany, Italy and Spain. In the other Member States, the transmission company's gross margin (average interruptible selling price minus average gas purchase cost) appears to have been zero or negative in 1987. This appears to reflect the more intense competition which gas faces from oil products in the interruptible market, leading to lower transmission company trading margins than those earned on sales to firm industrial consumers whose alternative fuel options are more remote.

Impact of Common Carriage

5.17 As outlined in the introduction to this Section, transmission companies could suffer a direct reduction in profit if carriage charges do not compensate them for the merchanting (purchase and re-sale) margin lost when existing customers enter into direct purchase contracts. This could arise where a reasonable carriage charge is less than the transmission company's gross merchanting margin. Direct marketing is most likely to be directed towards high margin customers and those favourably located to buy direct, with only a short distance over which the direct gas supply has to be transported.

5.18 The second effect to be considered is transmission companies' likely response to the threat of competition via common carriage, in terms of offering more favourable terms to large customers in an attempt to retain load. This effect is likely to be most apparent in Member States where current trading margins exceed the probable level of a fair carriage charge. On the basis of Table 5.3, we would expect the transmission companies in Italy, West Germany and the UK to come under most competitive pressure for sales to large users in the firm gas market. In the interruptible market, the companies in Italy and West Germany appear to face the greatest threat from direct sales competition via interruptible transportation. The utilities concerned might therefore offer improved sales terms to their customers, in an attempt to ward off this competitive threat. Our estimates also suggest that reasonable carriage charges might put ENAGAS margins under considerable pressure in Spain; in the immediate future, however, a reasonable charge may well be even higher than we have assumed, given substantial financing costs and low grid utilisation.

5.19 A significant potential problem for some transmission companies is the threat of purchase contract take-or-pay penalties. Utilities such as Gaz de France and (particularly) Distrigaz, are already at or near the 'minimum bill' level of offtakes under their purchase contracts. Demand growth prospects in Belgium and France are perhaps less promising than in some other Member States. A modest reduction in total sales might therefore be sufficient to push them into take-or-pay penalties, if they they are not able to renegotiate the relevant contract terms, nor to re-sell their contracted surplus outside their own supply areas. If, for example, the Distrigaz take-or-pay position has not improved by 2000 and 3% of the market is lost to direct marketing via common carriage, the company might then have to pay up to around ECU 23 million per annum for gas contracted but not taken under its purchase contracts.

5.20 For the purposes of assessment, we assume that most of the direct sales taking place in 2000 will require firm transportation and that relatively few direct sales are made via interruptible carriage. This assumption reflects relatively high transmission company margins on firm industrial sales, which may stimulate greater interest in direct purchases among firm gas users, as well as the greater complexity of concluding innovative interruptible transportation arrangements of a type largely unknown in Europe.

5.21 In Table 5.5 below, we present our estimates of the three redistribution effects of common carriage, as follows:

(a)   the direct effect of losing market share to direct sales competition, partially offset by income from 'fair' carriage charges;

(b)   the indirect effect on realisations from large user markets; and

(c)   the take-or-pay effect, where relevant.

The estimated magnitude of the direct and take-or-pay effects is based on the assumed level of common carriage in 2000, as set out in Appendix B. Table 5.5 shows the initial impact on transmission companies, before allowing for the fact that some of the increased costs might be passed on to other gas consumers. The table does, however, take account of the benefits to transmission companies of greater efficiency and somewhat lower gas purchase costs in a more competitive environment, as discussed earlier in the report.

Table 5.5:   Initial Impact of Common Carriage on Transmission Companies
              (Year 2000, figures in ECU million p.a.)

	B	F	I	NL	SP	FRG	UK
Firm carriage (bcm)	0.2	0.7	1.8	0.9	0.17	1.9	4.2
Interr carriage (bcm)	-	-	0.6	-	0.06	0.2	-
Direct effect * - firm	(1)	3	(25)	(2)	(8)	(63)	(204)
Direct effect - interr	-	-	(5)	-	(1)	(1)	-
Indirect effect ** - firm	-	-	(72)	-	(19)	(120)	(113)
Indirect effect - interr	-	-	(67)	-	(15)	(32)	-
Take-or-pay	(23)	(69)	-	-	-	-	-
Efficiency gain	5	33	93	8	11	80	68
Gas cost reduction	12	36	52	64	5	56	95
Total gain (+) or loss (-)	(7)	4	(23)	70	(27)	(80)	(155)

*   derived from the difference between gross margins and 'fair' carriage charges
**   assumes a 5% reduction in relevant selling prices to retained large customers of transmission
     companies 'under threat' (current gross margin significantly above 'fair' carriage charge)

5.22 As outlined earlier in this Section, the extent to which transmission companies are able to absorb any adverse financial impact of this kind would depend partly on their existing level of profitability. The financial performance of the major gas utilities in the seven Member States examined is set out in Table 5.6 below:-

Table 5.6: Profitability of European Gas Transmission Companies, 1987 [1]

	% of turnover	% of capital employed [2]
British Gas	18.0 *3	19.4 *4
Distrigaz	3.3	6.3
Enagas	8.2	6.2
Gasunie	1.6	6.7
Gaz de France	10.4	11.5
Ruhrgas *5	10.4	18.2
SNAM	12.7	32.8

*1   based on operating profit, before interest, extraordinary items and
      tax
*2   defined as shareholders' funds plus net borrowing (average of opening
      and closing balances for the year)
*3   historic cost accounts for 1987/88, gas supply business only
*4   HCA 1987/88, consolidated Group results
*5   consolidated accounts

5.23 This table shows above-average returns on capital employed for British Gas, Ruhrgas and SNAM, with an average performance by Gaz de France and significantly lower returns for Distrigaz, Enagas and Gasunie. In the latter case, it should be recalled that greater profits are earned upstream by NAM, of which a significant proportion goes in taxation to the Dutch Government. Enagas appears to have had good operating margins in 1987 (tables 5.3 and 5.4), but a fairly low return on capital employed due to low grid utilisation. In West Germany and Italy, it should be noted that a substantial portion of total profit may derive from transportation of gas for other utilities (in the case of Ruhrgas) and sales to distributors (in the case of SNAM). It should also be noted that pure transmission companies (Distrigaz, Gasunie, Ruhrgas etc) generally need to make a relatively modest margin on turnover in order to produce a satisfactory return on capital employed. Vertically integrated companies such as British Gas and Gaz de France have a much larger capital base in relation to turnover and need to earn a higher margin on their sales.

5.24 Although 1987 profits were not generally far out of line with previous (1985 and 1986) results, significant differences should be noted for particular utilities. For example, the exceptionally strong performance of SNAM in 1987 represents a substantial improvement on previous years and reflects the buoyant profitability of the whole Italian gas industry, including distributors such as Italgas as well as the transmission company SNAM. In turn, this reflects the very high level of taxation on domestic heating oil. Distrigaz, on the other hand, performed significantly worse in 1986 and 1987 than in 1985, partly as a result of very low duty-free oil prices in Belgium.

5.25 The concept of 'normal' profit depends on a number of factors, including the cost of capital and (in some cases) shareholders' expectations of a return on equity. A number of gas utilities are fairly highly geared and we have taken the cost of borrowing as an indicator of 'normal' profit in each Member State. We have assumed that relatively low risk utility borrowers would generally be able to obtain funds at 1.5% above the 1987 yield on fixed interest government securities, which represents an expected return on virtually riskless lending. A comparison

of utility returns on capital employed with this indication of 'normal' profit is set out in Table 5.7:-

Table 5.7 : Utility Returns and 'Normal' Profits, 1987(%)

Utility	1987 Return*	'Normal' profit**
British Gas	19.4	11.0
Distrigaz	6.3	9.3
Enagas	6.2	14.3
Gasunie	6.7	7.9
Gaz de France	11.5	11.7
Ruhrgas	18.2	7.3
SNAM	32.8	12.3

* return on capital employed, from table 5.6
** yield on fixed-interest government securities, plus 1.5%

5.26   From this it can be seen that 1987 transmission company returns were considerably below 'normal' in Belgium and (especially) Spain, somewhat below normal in the Netherlands, broadly in line with the cost of capital in France and well above the cost of capital in Italy, West Germany and the UK. The Gasunie result is not representative of overall gas industry profits in the Netherlands, for the reasons outlined above.

5.27   The analysis set out in Table 5.5 suggested that some transmission companies might suffer a direct loss in trading profit in the event of common carriage use of their systems. We assume that those whose profitability is currently below a 'normal' level would pass on the increased unit costs to smaller domestic and commercial customers, in order to protect an already poor financial position. A good example is the Distrigaz take-or-pay cost referred to above. In view of the competition from other (oil) fuels, Distrigaz would find it difficult to pass the additional costs on to its remaining industrial customers. It is therefore probable that the cost would ultimately be passed on via the distribution companies to domestic and commercial consumers, who have fewer alternative fuel options. The figure of ECU 23 million p.a. is equivalent to an

average unit cost increase of around ECU $0.004/m^3$ (2%) on sales to smaller Belgian gas customers in 2000.

5.28   To the extent that common carriage causes transmission companies to suffer a loss of profit (see Table 5.5), we would expect to see:-

(a)   redistribution of income from transmission companies to industrial users in Italy, West Germany and the UK; and

(b)   redistribution from small consumers to larger users in Belgium and Spain.

This reflects the pattern of profitability discussed above. Our best estimates of total redistribution effects (on the basis of 1987 profitability) are set out in Table 5.8 below:-

Table 5.8:   Summary of Redistribution Effects, 2000

(ECU million p.a.)

Effect	B	F	I	NL	SP	FRG	UK
Benefit to large users*	1	-	169	2	43	216	317
Cost to small users**	7	-	-	-	27	-	-
Cost to transmission companies***	-	-	23	-	-	80	155

*   sum of direct and indirect effects in table 5.5

**   total effect in relevant countries from table 5.5, assumed to be passed on to domestic and commercial customers

***   total effect in relevant countries from Table 5.5, assumed to be absorbed as lower profits

5.29   To put these figures in context, the British Gas current cost operating profit on its gas supply business (for example) was around ECU 1300 million in 1987/88. We are therefore suggesting that competition or the threat of competition via common carriage might erode about 12% of current profits in the longer term, primarily to the benefit of large

consumers. In Italy, SNAM made a 1987 pre-tax profit of almost ECU 350 million and, in West Germany, Ruhrgas alone made a pre-tax profit on ordinary activities of some ECU 430 million. The total increased costs projected to be passed on to small users in Belgium are equivalent to a once-and-for-all 0.5% increase in tariffs; the corresponding figure would be higher in Spain, at around 5%, due to the smaller size of the domestic and commercial market, and the greater impact of common carriage on the Spanish market.

5.30 Our assessment set out above only looks at the 'first round' effects of common carriage on the distribution of income and welfare. Especially if the internal market programme is successful in promoting a large, competitive market for manufactured goods, a substantial part of the benefit to large gas consumers may be passed through to the ultimate buyers of their manufactured products. Similarly, benefits to power utility buyers may be substantially passed on to electricity consumers. Reduced prices for gas-intensive manufactured goods may also bring macro-economic benefits in terms of improved Community trade performance, as discussed in Section VI below.

VI   MACRO-ECONOMIC BENEFITS

Introduction

6.1   In earlier Sections of this report, we considered the possibility
that some large industrial or power station users might be able to secure a
lower delivered gas cost to their plant by:-

(a)   purchasing at a lower border price than that achieved by their
       existing supplier; or

(b)   undercutting the gross trading margin of their existing supplier, via
       a 'fair' carriage charge.

Moreover, the threat of direct purchase arrangements between large
consumers and gas producers may induce existing suppliers to offer rather
more favourable prices to some of their remaining industrial and power
station customers. This therefore creates the possibility that the general
level of industrial gas prices may fall as a result of common carriage.
For simplicity in this discussion, we assume that large user prices will be
5% lower across the Community in the year 2000 than they would otherwise
have been, as a result of introducing common carriage. This represents a
combination of somewhat lower border gas prices, improved efficiency in
transmission and distribution and the erosion of any monopoly profits
currently earned by some transmission companies on sales to large
customers.

6.2   This reduction in industrial gas prices may then lead to
macro-economic benefits for the Community as a whole, as a result of
bringing down the level of manufacturing costs in gas-using industrial
sectors. The macro-economic benefits might arise from a number of areas,
including:-

(a)   improved export performance of Community manufacturers in world
       markets;

(b)   reduced penetration of Community markets by manufactured goods
       imported from third countries; and

(c)   resource allocation benefits, as a result of eroding any monopoly
       profit element in industrial gas prices.

6.3   Effect (c) above is likely to be of second-order quantitative importance; on an approximate basis, we estimate the benefit for the Community as a whole to be around ECU 5 million p.a.[1] We therefore focus principally on (a) and (b) above.   In order to indicate the likely level of benefits, we have reviewed the available evidence on the determinants of Community trade performance in general terms, in order to identify the impact of lower manufacturing costs and prices.   We have also carried out a brief case study analysis of the iron and steel sector, as agreed with DG XVII.

6.4   The section is set out as follows:-

(a)   Aggregated Evidence - findings from the literature regarding the price elasticity of demand for Community exports and imports, together with an aggregate assessment of potential macro-economic benefits; and

(b)   Iron and Steel Industry Case Study - to obtain a more detailed picture of the likely benefits in an energy-intensive industrial sector.

Aggregated Evidence

6.5   We have reviewed the literature for evidence regarding the price elasticity of demand for European manufactured exports in world markets and European manufactured imports.   A number of relevant studies have been carried out in recent years and we highlight the main results and conclusions below.

6.6   In 1984 revised price elasticity estimates from the IMF's World Trade Model (WTM) were published[2].   Price elasticities for the volume of

1   In economic terms, this is the "triangle" of additional consumer surplus obtained when demand increases as a result of eroding monopoly profit.   Our estimate is based on an assumed long-term price elasticity of demand for gas in the industry/power sector of 0.3.

2   The "World Trade Model: Revised Estimates" by G.S. Spencer in the IMF Staff Papers September 1984.

manufactured exports and imports, in both the short-run (one year) and
long-run (total response), have been calculated for fourteen industrial
countries.   Table 6.1 below summarises the major results, showing export
and import price elasticities for the European countries covered.   The
period covered is 1962 to 1979.

Table 6.1   Relative Price Elasticities for Trade in Manufactures

	Imports		Exports	
	Short-run Elasticity	Long-Run Elasticity	Short-Run Elasticity	Long-Run Elasticity
EC Countries				
Belgium	-	1.15	-0.59	-1.55
Denmark	0.75	0.67	-1.13	-1.13
France	0.52	0.52	-0.48	-1.25
West Germany	1.15	1.15	-0.09	-1.41
Italy	1.02	1.02	-0.51	-0.64
Netherlands	0.53	0.53	-0.49	-0.89
UK	0.56	0.56	-	-0.31

Source: IMF Staff Papers September 1984

6.7   Of the seven EC countries, four - Belgium, Denmark, France and West
Germany - have long-run price elasticities for exports that are
statistically significant at the 5% level.   For all but two of the export
equations, the maximum lag is less than or equal to two and a half years.
Some doubt is expressed in the article over the plausibility of the UK lag
structure, where the lag stretches to five years.   However all seven
countries' export elasticities show coefficients of the expected
(negative)[3] sign.   Overall, we can establish a band of -0.1 to -1.1 for the
short-run and a band of -0.3 to -1.6 for the long-run price elasticity of
demand for the major European economies' exports.   All the EC countries,
except for Denmark, have statistically significant long-run price
elasticities for imports.   The elasticities lie within the band of 0.52 to
1.15, giving an average of 0.8.

3 An increase in own export prices relative to competitors' prices leads
    to a decline in the demand for own exports

6.8   To assess the macro-economic benefits associated with a decline in gas prices, it is clearly desirable to use the long-run price elasticities to ensure the total price effect is captured. By using a broad long-run price elasticity figure of -1.0 for Community exports and 0.8 for imports, we can calculate the potential change in the total Community trade balance, following a reduction in industrial gas prices. For this purpose, we have assumed that the elasticities for total trade by Member States (including intra-Community trade) are appropriate to the price responsiveness of demand for trade with third countries.

6.9   The validity of the IMF WTM estimates is supported by other recent empirical studies, for example by Goldstein and Khan (1984)[4]. Comparing the total price elasticity estimates (ie the sum of export and import price elasticities for each country) of the WTM with those summarised by Goldstein and Khan, we find that the former estimates lie within the ranges quoted by the latter study for almost every country.

6.10   The fact that the average price elasticities from the IMF model are not very high and that for three of the seven countries the export price elasticity coefficients are not statistically significant is not unexpected. A study by Lachler (Weltwirtschaftliches Archiv 1985), for example, calculated the price elasticity coefficients for 23 industrial sectors in West Germany over the period 1960-1981. While the results are not directly comparable because of his use of relative demand as the dependent variable, his findings are of interest. Lachler found that the highest price elasticities were for goods in the primary goods sector, while industries with significant opportunities for product differentiation experienced, in general, lower price elasticities of demand.

6.11   Our review of the literature has provided us with estimates of the price elasticity of demand for European manufactured exports and imports

4   In "Handbook of International Economics", ed R W Jones and P B Kenen (1984)

which we use below in our "broad brush" quantitative assessment of the macro-economic benefits of a fall in gas prices. However it is clear that evidence suggests the price of a good may not always play the role assigned to it by traditional economic theory. We will reconsider this issue and the wider macro-economic implications of a fall in gas prices once the numerical exercise has been set out.

Overview of Benefits

6.12 We consider below the benefits resulting from a fall in the price of gas, firstly by calculating the possible change in the balance of trade and secondly by discussing the main linkages involved.

6.13   From Table 6.2 below, we can calculate an average gas intensity of 0.5% for the EC manufacturing industry as a whole. The assumed fall in industrial gas prices is 5%, as outlined above. The total value of EC imports and exports in trade with third countries for 1986 was ECU 242.7bn and ECU 310.9bn respectively.

Table 6.2   Manufacturing Output and Gas Intensity

1986	B	L	DK	D	GR*	E	F	IRL	I	NL	P*	UK
Man Output (ECU bn)	61.7	3.5	28.2	535.0	...	136.6	339.5	16.9	214.1	78.9	20.5	323.3
Ind Gas C ('000 TJ)	87.2	6.8	10.0	671.5	...	65.6	385.1	11.7	389.0	297.7	-	417.3
Ind Gas C (ECU mn)	327.9	30.3	37.9	3,216.5	...	229.6	1,586.6	28.7	960.8	913.9	-	1,502.3
Gas intensity (%)**	0.5	0.9	0.1	0.6	...	0.2	0.5	0.2	0.4	1.2	-	0.5

*   Greek data unavailable from Eurostat sources; no natural gas used in Portugal

**   gas costs as a proportion of output value.

6.14 From this information, together with the average price elasticities of demand of -1.0 and 0.8 for exports and imports respectively, we can calculate the change in the value of the EC trade balance. A rough estimate of the possible impact of a fall in gas prices on the EC balance of trade is shown in Table 6.3. This table draws on the data presented in Table 6.2 and analysis carried out above. Table 6.3 shows that the direct impact on the EC trade balance would be an improvement of around ECU 127mn.

Table 6.3   Impact of Gas Price Falls on the EC Trade Balance

(1)	Assumed fall in industrial gas prices	5%
(2)	Proportion of gas in total manufacturing costs	0.5%
(3)	Price elasticity of demand for EC exports	-1.0
(4)	Price elasticity of demand for EC imports	0.8
(5)	Increase in EC manufactured exports (ECU p.a.)	78m
(6)	Reduction in EC manufactured imports (ECU p.a.)	49m
(7)	Change (based on 1986 data) in the balance of Community trade (ECU)	+127m

6.15 The analysis above provides a simplified picture of the potential effect on the trade balance. Our estimate may over-state the likely benefit, because of the assumption made regarding the pass-through of cost reductions, in particular. In practice, a fall in the price of gas to industry is not likely to be fully passed through to customers and some will be retained by manufacturers in the form of higher margins. There may still be an indirect effect on trade performance, as improved profits may induce increased expenditure on improved customer service or increased advertising, for example, which in turn raises market share. These indirect effects would take longer to work through and are not easily quantifiable. Further second-order effects may occur if increased income in the Community, resulting from reduced manufactured goods prices, leads to a rise in the demand for imports.

6.16 We can summarise this discussion by saying that the macro-economic benefits will primarily depend on:-

(a) the gas intensity of manufacturing production; and

(b)   the price elasticity of demand for EC exports to third countries, and
for imports into the EC.

At the aggregate level, the low gas intensity of manufacturing production
is such that the overall impact of common carriage on trade performance is
relatively limited.   However, this aggregate analysis may disguise a
significant impact on particular energy-intensive sectors, particularly as
price elasticities of demand are likely to be higher for relatively
undifferentiated energy-intensive manufactures.   We have therefore carried
out a case study of the iron and steel sector, the results of which are
reported below.

Case study evidence

6.17   This section estimates the macroeconomic benefits that may arise from
a fall in gas prices to the iron and steel industry.   The fall in gas
prices could potentially lead to macroeconomic benefits from two sources:

(a)   a fall in gas prices may lead to a fall in the price of iron and
steel products relative to those of the major competitors of the EC.
In principle this would cause an improvement in the terms of trade,
and as a result an increase in exports (or a decrease in imports);
and

(b)   a fall in the price of gas may have an impact on the allocation of
resources both between and within Member countries.   We have not
considered this point any further, however, as the benefits are
likely to be relatively small.

6.18   The size of the fall in iron and steel production costs and the
potential for increasing international competitiveness will depend on a
number of factors, including:

(a)   the processes in which gas is used and the proportion of total costs
that it accounts for; and

(b)   the competitive position of the EC in world trade for steel, its
      derived products and steel intensive manufactures.

Each of these factors is discussed in turn in the following paragraphs.

Gas use in the iron and steel industry

6.19   The iron and steel industry produces a range of products using a
large number of processes. The three main activities are:

(a)   iron production;

(b)   steel making; and

(c)   finishing operations.

Of these three activities, the production iron of takes place within an
integrated plant which would include a steel making facility and possibly a
finishing plant. Each of these activities, and the type and quantity of
fuel used, is discussed below. These activities are also shown
schematically in Figure 6.1.

6.20   The major fuel input in _iron production_ is coal. Coal is needed to
produce coke which is an essential input into the process. The coke is
produced by firing the coal in coke ovens. A by-product of this process is
coke oven gas, which can be recycled and used in the coke ovens as a source
of heat or later as a fuel in steel making. This gas tends to be fairly
low in calorific value (around 19 MJ/m^3) and can only be used economically
close to source, since unit transport costs are very high. Coke breeze is
used to produce sinter, and the coke and the sinter are then used in the
blast furnace to form iron. Fuel oil or gas can also be added to the blast
furnace to replace up to 20% of the coke; the use of fuel oil in this way
is determined by the relative prices of fuel oil and coke. In view of the
surplus gas produced in these processes, purchasing of fuel to use in this
way is not very common.   Blast furnace gases are produced in the blast
furnace and are used later in the steel making process or recycled into the
blast furnace itself. They are generally of very low calorific value,
perhaps only half that of coke oven gas.

Figure 6.1 : Iron and Steel principal manufacturing processes

By-products

Billets, blooms

Hot rolled bars and sections

Angles, sections

Universal beams and heavy plate

Rods and bars

Heavy and medium plate

Hot rolled coil and sheet

By-product plant

Secondary mills

Continuous casting machine

Soaking pits and primary mills

Ingot casting

Semi-finished and finished products (selection only shown)
Lines indicate material flows.

Coal

Coke breeze

Limestone

Iron ore concentrates

Iron ore pellets

Coke ovens

Coke

Oxygen plant

Basic oxygen steelmaking plant

Electric arc furnace

Sinter plant

Hot metal

Cold iron

Blast furnace

Scrap

Scrap handling

6.21 There are three common types of <u>steel making plant:</u>

(a) basic oxygen steel making, BOS;

(b) electric arc furnace steel making, EAF; and

(c) open hearth furnaces.

ECSC figures show that in 1986 70% of steel was produced using the BOS furnace and 30% was produced using EAF.

6.22 The BOS furnace uses molten iron as its input and therefore tends to be part of an integrated works. Iron from the blast furnace is transferred to the BOS furnace where oxygen is injected via a lance. No additional fuels are required in this process as the combination of the oxygen with the hot metal generates the required heat. Scrap iron can be added to this process to the limit of the reaction, after which additional fuel, in the form of oil or gas, is required to produce more heat.

6.23 Electric arc furnaces primarily use scrap steel with some cold scrap iron. The primary fuel used is electricity, the majority of which is used for reheating of the iron and steel. It is possible to reduce the amount of electricity used by preheating the iron and steel using LPG or natural gas; at fuel price relativities prior to 1986 this was not considered economic. Any preheating of iron and steel has tended to use by-product gases as the major fuel input.

6.24 Open hearth furnaces used to be the most common method used to produce steel. Approximately equal amounts of scrap steel and iron are used. The iron and steel is heated in the furnace, which is fired by oil and natural gas or coke oven gas. This process is now much less common. According to the data supplied by the UN Commission for Europe, no EC country currently uses open hearth furnaces. However, they are still common in Eastern Europe and developing countries, where the proportion of gas used in steel manufacture is much higher.

6.25 <u>Finishing operations</u> can be further divided into:

(a) primary finishing; and

(b) secondary finishing.

6.26 **Primary finishing** consists of converting the crude steel to slabs,
blooms or billets - 'semi-finished' steel. There are two alternative ways
of converting the crude steel to semi-finished steel:

(a) ingot casting; and

(b) continuous casting.

6.27 In an ingot casting plant liquid steel is poured into moulds to form
ingots, which are then reheated and maintained at a high temperature
(soaking) for 4-12 hours. After soaking the ingots are further processed
whilst they cool to form the semi-finished products. The fuels commonly
used include oil or natural gas, which are used to provide heat in the
soaking process. Enriched gas, which is a combination of coke oven gas or
oxygen with blast furnace gas, is also commonly used in this soaking
process.

6.28 This process is relatively inefficient and many plants have been
converted to continuous casting plants. Energy is saved in this process as
the need for soaking is removed as the liquid steel is not allowed to cool
but is instead drawn continuously through rollers and water sprays. The
energy input to this process is significantly lower. The steel waste is
also greatly reduced as the steel can be tailored to the correct size more
efficiently. A further significant advance in fuel use has been the
development of the direct connection' process, whereby instead of allowing
the slabs to cool for inspection, the slabs are inspected hot and
transferred direct to the rolling mill. This process is already in use in
Japanese and some European plants and would tend to reduce the amount of
natural gas needed for reheating metals.

6.29 In **secondary finishing** the semi-finished steel is converted into
final products, such as wire, plates etc. In all cases the steel needs to
be reheated and rolled. The major fuels used for this reheating are oil

and gas. Examples of some of the major products and their major markets are shown in Table 6.4 and ECSC production by product is shown Table 6.5:

Table 6.4 : Secondary finishing - products and uses.

Product	Principal end use
Tinplate	Canning industry
Strip mill products	Automotive industry
(eg. rolled sheets)	Construction industry
	Consumer goods (esp consumer durables)
Welded tubes	Construction, water and general pipeage.
Seamless tubes	Oil and gas industry

6.30 Table 6.6 shows the estimated fuel use for the UK in each process, based on data available in 1978:-

Table 6.6 : Energy used per tonne crude steel by fuel type (est. UK 1978)

Process	Fuel type (%)					
	Coal/ Coke	Natural gas	Other gas	Fuel oil	Electricity	Other (inc. heat)
Coke ovens	89	0	8	0	1	2
Blast furnace	82	0	12	6	0	0
Steel making	0	0	0	35	65	0
Primary finishing	0	80*	0	0	20	0
Secondary finishing	0	89*	0	0	11	0

note : * includes oil and other gases

Table 6.5   European Production in ESCS Products (1986)

PRODUCTION (m.tonnes)	Crude Steel	Continuous casting	Hot Rolled Coil	Heavy Sections	Merchant Bar & Light Sections	Wire Rod	Narrow Strip	Plate	Cold Reduced Sheet
Germany	37.1	31.4	16.6	1.8	2.9	3.4	2.0	4.3	8.5
Belgium	9.7	7.0	7.0	0.3	0.3	0.4	0.1	1.2	3.3
France	17.9	16.1	9.6	0.9	1.9	2.1	0.3	1.1	5.9
Italy	23.0	19.3	7.7	0.9	6.5	2.3	0.4	1.7	4.1
Luxembourg	3.7	1.3	-	1.3	0.7	0.5	0.3	-	0.3
Netherlands	5.3	2.3	2.8	-	0.3	0.2	0.3	0.3	1.4
United Kingdom	14.8	8.9	5.3	1.6	2.0	1.6	0.3	1.0	3.3
Denmark	0.6	0.6	-	-	0.2	-	-	0.4	-
Ireland	0.2	0.2	-	0.2	-	-	-	-	-
Greece	1.0	1.0	0.3	-	0.6	0.3	-	-	0.4
Spain	11.9	7.3	2.5	1.3	3.7	1.2	0.3	0.5	2.2
Portugal	0.7	0.3	-	-	0.3	0.3	-	-	0.1
EEC 12	125.9	95.7	51.8	8.3	19.4	12.3	4.0	10.5	29.5

Source: ECSC; excludes forging, steel tubes, wire products and ferro-alloys

Table 6.6 demonstrates that the use of natural gas is concentrated in the finishing of steel products, rather than in primary iron and steel making, and some estimates suggest that blast furnaces use 50% of total energy in the iron and steel industry. Energy use in total for each EC country is shown in Table 6.7. Natural gas accounts for 14% of total energy requirement in the iron and steel industry in the EC as a whole. There are wide variations between countries; however, the major exporting and producing countries all use similar proportions of natural gas in iron and steel manufacture.

6.31 Natural gas is more heavily used in the processing of semi-finished steel than in integrated iron and steel making. However, data on the cost of inputs to the UK general iron and steel making industry and the steel finishing sector suggest that gas costs account for around 2-4% of total costs in each case. Although gas accounts for a larger proportion of <u>fuel</u> costs in the finishing sector, other non-fuel costs are also higher; hence the proportion of gas in total costs remains broadly the same. For example, natural gas accounts for 11% of total fuel costs in the UK general iron and steel industry (when the cost of coking coal is included), and 35% of total fuel costs in the steel tube sector. In France, gas accounts for 10% of total fuel costs in the iron and steel sector. Table 6.8 shows the estimated gas cost intensity for the major EC iron and steel producing countries. The estimated 'gas intensities' are somewhat lower than those suggested by the UK and French data, probably reflecting the use of output value rather than production costs as the denominator in Table 6.8. The overall gas cost as a percentage of output value is generally in the range 1.0 - 2.5%. In conclusion, therefore, gas costs are a relatively small proportion of total costs in the iron and steel industry as a whole. Natural gas may nevertheless be an important cost element for specific products, such as those produced in non-integrated forging plants, especially as a proportion of value added (rather than total output value).

EC iron and steel trade

6.32 This final section considers the EC position in world trade, and the price responsiveness of exports to a fall in costs of the major EC producers.

Table 6.7 : Energy use in the Iron and Steel industry (%) 1986

Country	Coal (inc. brown, and coke)	Oils	Natural gas	Other gases	Electricity
EC12	46	6	14	20	14
Belgium	55	4	13	19	9
France	50	4	10	20	16
West Germany	45	7	15	21	11
Italy	37	8	19	17	19
UK	41	9	13	18	10
Luxembourg	60	5	8	20	8
Ireland	-	-	-	-	-
Denmark	-	-	-	-	-
Greece	21	33	0	0	100
Spain	45	0	9	18	27
Portugal	0	25	0	38	36
Netherlands	54	1	16	21	8

Source: OECD

Table 6.8: Iron and Steel Output and Gas Intensity

1986	B	L	DK	D	GR	E	F	IRL	I	NL	P	UK
Iron and Steel production Value (ECU bn)*	4.0	1.3	...	19.6	...	...	10.1	0	11.1	...	...	10.6
Iron and Steel Gas Cons (PJ)*	25.4	5.0	0	108.4	0	14.8	34.6	0	68.3	16.3	0	43.2
Gas Costs (ECU mn)	85.8	19.9	0	467.2	0	...	117.3	0	151.7	45.2	0	139.9
Gas Intensity (%)	2.1	1.6	0	2.4	0	...	1.2	0	1.4	-	0	1.3

notes: * estimated
... data not available

6.33 The EC is a significant net exporter of iron and steel products. In 1987 they accounted for 18% of production and 15% of consumption (see Table 6.8). However, EC steel production has fallen significantly over the past 15 years (see Table 6.9). This appears to be largely a response to the fall in both economic activity and steel intensity within the OECD. In contrast, world steel consumption rose by 9% over the period 1973 to 1986.

6.34 Through this period of general recession in the iron and steel industry, exports as a percentage of total Community production have been rising. Whilst EC consumption fell by around 18% from 1973 to 1986, production fell by just 12%; correspondingly net exports as a percentage of production have risen from around 12% in 1973 to 18% in 1986.

6.35 In 1987 the total value of iron and steel exports to countries other than member states was 13.7 billion ECU (4% of the value of total Community exports to third countries), and the total value of imports 6.1 billion ECU (2% of total imports), with a net export value of around 7.6 billion ECU. The import/export balance of the major EC iron and steel producing countries is shown in Table 6.10, and the destinations of exports in Table 6.11; the split of output by product was shown above in Table 6.5 above.

6.36 The major net exporting countries are Belgium, West Germany, and to a lesser extent France, Spain and the UK. The USA, China, N.Korea and western developing countries are the major net importers of iron and steel products; most of these countries are covered by trade restraint agreements with the EC.

6.37 Over the past five years, the financial performance of the major European iron and steel producers has been poor, although rigorous cost cutting and restructuring exercises have helped to improve the profit position of some companies, such as BSC. In the light of the significant losses that some European Steel makers have been facing until very recently and the low proportion of total costs that gas accounts for, it is possible that manufacturers will not reduce prices as a result of a fall in costs and instead seek to improve profit margins.

Table 6.9a: World Steel Production by Region

	1973 Crude steel Tonnes(m)	% of world consumption	1987 Crude steel Tonnes(m)	% of world production	% change in production 1973-87
EC 12	162	23	127	17	-22
USA	137	20	81	11	-41
Japan	119	17	98	13	-18
Other OECD	39	6	46	6	+18
OECD Total	457	66	352	47	-23
Western Developing *	28	4	85	12	+204
South Africa	6	1	9	1	+50
USSR & E Europe	178	25	224	31	+26
China & N Korea	28	4	65	9	+132
Total	697	100	735	100	+5

Source: 1987 data: IISI; 1973 data: OECD

Table 6.9b: Consumption of Crude Steel by Region

	1973 Tonnes(m)	% of world consumption	1986 Tonnes(m)	% of world consumption	% change in consumption 1973-86
EC 12	143	20	116	15	-18
USA	151	22	104	13	-31
Japan	92	13	81	11	-12
Other OECD	44	6	46	6	+ 7
OECD Total	430	61	347	45	-19
Western Developing *	59	8	107	14	+80
South Africa	6	1	6	1	-
USSR & E Europe	179	25	226	29	+26
China & N Korea	34	5	84	11	+147
Total	708	100	770	100	+9

* Latin America, Africa, Middle East and Far East, excluding Japan, China and North Korea.

Table 6.10   Exports and Imports by EEC Country, 1987

	Exports (M tonnes)	Imports (M tonnes)	Net Export Balance (M tonnes)
West Germany	21	14	7
Italy	9	9	-
UK	7	5	2
France	13	10	3
Spain	6	3	3
Belgium/Luxembourg	14	4	10
Netherlands	6	5	1
Others	2	5	(3)
Total*	78	55	23
Within EEC	42	43	-
Outside EEC	36	12	24

* includes ECSC and non-ECSC products

Source: Eurostat Iron and Steel Statistical Yearbook 1988

Table 6.11   Origin and Destination of ECSC Steel Products, 1987

	% of tonnage traded	
	Imports	Exports
Europe	57	34
Western	31	23
Eastern	26	10
Americas	*	33
North	1	26
of which USA	1	21
Asia	*	24
Other	43	9
Total	100	100

* split of imports from non-European sources not available

6.38 As a reaction to falling iron and steel demand in the late 1970s, the European Coal and Steel Community (ECSC) negotiated a series agreements and declared a state of 'manifest crisis', which led to the development of capacity, delivery quota and price controls. The main impact of these measures was to reduce EC iron and steel making capacity significantly (capacity fell by 28% from 1980 to 1987), and to restrict imports into the EC.

6.39 The EC has negotiated restraint agreements with most of the countries to which the EC exports; when they were first concluded, these accounted for around 86% of EC exports. The main features of such agreements are that:-

(a) third countries agree to restrict their quantities according to a 'triple clause', regarding non-concentration of arrivals by product, by Member State or by timing;

(b) agreements are voluntary, and there is no sanction against breaches by exporting countries;

(c) third countries are exempted from anti-dumping actions; and

(d) agreements are renegotiated annually.

6.40 The agreements are generally bilateral agreements and obviously have a significant impact on the level and value of trade. The actual restrictions placed on trade vary widely between countries; while those between EFTA and EC countries are very liberal, between EC and USA the restrictions are severe and strictly enforced. Some commentators believe that there will be increasing pressure to eliminate these agreements as they are against the spirit of GATT and may be counter to the spirit of the single internal market. In the meantime, price responsiveness in the current market conditions must be highly questionable.

6.41 A study of the elasticity of substitution of domestic for imported goods by Lachler (1985) found that the coefficient on the relative prices of domestically and imported iron and steel products was not significant. This result is not surprising, given the constraints on the market for iron and steel goods as outlined above.

Summary and conclusions

6.42 The main points which can be drawn from this analysis are:-

(a) whilst gas is a fairly significant input to some sections of the iron and steel industry, it appears that gas accounts for a relatively small percentage of total costs overall;

(b) there are some important restrictions on international trade in iron and steel, especially with the USA. This could suggest that the price responsiveness of exports will be low in some markets, although relaxation of the trade agreements may increase price competition in the future;

(c) the financial position of some EC iron and steel producers may mean that part of any reduction in gas costs is retained as improved margins, rather than being passed through to selling prices; and

(d) studies of the price elasticity of demand for the iron and steel sector in particular suggest that the price responsiveness is generally low.

On the evidence of the above, it is unlikely that in the short term there will be any significant macroeconomic benefits arising from a fall in gas prices to the iron and steel industry. In the longer term, however, as VRAs are withdrawn and iron and steel manufacturers continue to improve their financial performance, there may be some benefits, although these are difficult to quantify at the present time.

APPENDICES

Appendix A

Detailed Netback Analysis

Introduction

A1.1 As outlined in the main text (Section II), we have sought to analyse
the cost and revenue structure of gas supply in each of seven Member States
in as comprehensive and consistent a manner as the available data will
allow. We have divided total gas sales into two broad market sectors -
small domestic and commercial users, on the one hand, and large industrial
and power station consumers, on the other. For each sector, we then
identified or estimated:-

(a) average selling prices, excluding tax;

(b) customer-specific costs such as connection, metering and billing;

(c) local distribution costs and, where relevant, the average profit
    margin of the local distributors;

(d) long distance gas transmission costs;

(e) the costs of seasonal storage;

(f) the average cost of bulk gas purchases; and

(g) the transmission companies' average profit margins.

A1.2 Our detailed analysis is set out on a country-by-country basis in the
following sections of this Appendix. Figures are presented in local
currencies and gas units (volume or energy, as the case may be) and are
also converted into a common unit of ECU/m^3. The choice of a common volume
measure (rather than an energy unit) means that prices are not strictly
comparable on an energy content basis; the m^3 was chosen because it was
considered that certain costs of key importance to this study
(transmission, storage, etc.) are more likely to be related to volumes
handled than to the energy content of the gas.

A1.3 The exchange rates used to convert from local currencies are 1987
averages, as set out in Table A1 below. In interpreting the results, it
should be borne in mind that inter-country comparisons may often be
affected considerably by short term fluctuations in currency values. To
the extent that most Member States are party to the European Monetary
System, however, such problems may be less severe than is frequently the
case.

Table A1:   1987 Exchange Rates

1 ECU =

BF	42.87
DM	2.06
PTA	143.98
FF	6.88
LIT	1462.93
NFL	2.33
£	0.74

Source: Eurostat

Belgium

A2.1 The problems of data availability are less marked for Belgium than they are for many Member States, since the gas industry is well documented, both by its own association Figaz and by the tripartite Supervisory Committee (Comite de Controle) for electricity and gas. Average gas purchase costs, the average price at which Distrigaz sells to distributors and the average selling price for each market sector can all be derived from published sources.

A2.2 Our own estimates are therefore confined primarily to the split of distributors' non-gas costs into customer-related ("connection") and distribution elements and the breakdown of Distrigaz non-gas costs between transmission and storage. Here we have relied on cost levels which are typical in the European gas business, in the first case, and our understanding of the Belgian industry, in the second.

A2.3 Our analysis of the Belgian gas industry is set out in Table A.2 below, which is accompanied by brief explanatory notes, and illustrated in Figure A2 overleaf. It is perhaps worth drawing attention to the zero cost shown for storage in the industry/power sector. In 1987, some 48% of Distrigaz sales to industry and the power sector were interruptible. Interruption allowed the annual load factor of total direct sales to be

increased to around 65%, broadly in line with what we estimate to be the load factor of imported gas supplies.

Table A2: Netback Analysis for Belgium, 1987

	BF/GJ		ECU/m^3 (x100)	
	Dom/Comm	Ind/Power	Dom/Comm	Ind/Power
Average Revenue (1)	238.0	108.2	20.3	9.2
Connection etc (2)	15.0	-	1.3	-
Distribution (3)	45.0	-	3.8	-
Distributors' Profit (4)	40.0	-	3.4	-
Distrigaz/Distributor Price (5)	138.0	-	11.7	-
Transmission (6)	11.8	5.7	1.0	0.5
Storage (7)	9.5	(5.2)	0.8	(0.4)
Netback (8)	116.7	107.7	9.9	9.2
Gas Purchase Costs (9)	108.1	108.1	9.2	9.2
Distrigaz Operating Margin (10)	8.6	(0.4)	0.7	(0.03)
Average Distrigaz Operating Margin (11)	4.7		0.4	

* assuming an average calorific value of 36.5 MJ/m^3

Notes on Table A2

(1) Figaz Statistical Yearbook, 1987.

(2) Consultant's estimate based on typical industry costs.

(3) As per (2) above.

(4) Estimate based on 1986 figure from Comite du Control Annual Report.

(5) Figaz Statistical Yearbook, 1987.

(6) Consultant's estimates. Relatively low costs reflect the small geographical area of the country.

(7) Calculated on the basis set out below:-

Figure A2: Netback Analysis 1987

Belgium

Costs/Revenue ECU/m3 (*100)

Margin   Gas   Trans   Dist
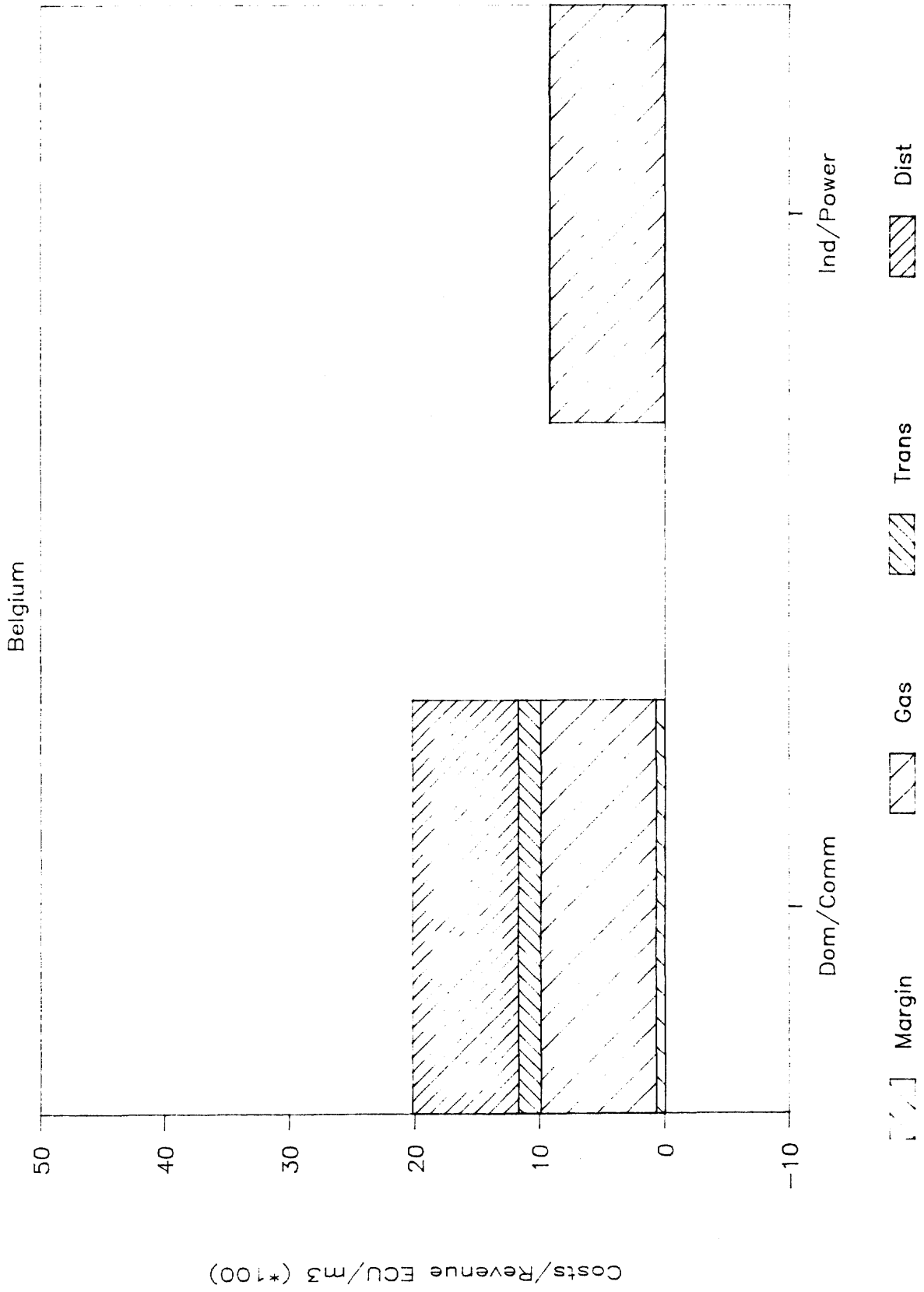
Dom/Comm   Ind/Power

	Dom/Comm	Industry/Power
Annual Sales (PJ)	192	147
Load Factor	0.3	0.65
Peak Day Sales (TJ)	1749	620
Peak Day Supplies (TJ)*	1144	876
Peak Day Storage Output (TJ)	605	(256)
Storage Cost (BF/GJ)**	9.5	(5.2)

* assumes a 46% average load factor of supply, based on the mix of Distrigaz supplies in 1987 and individual load factor assumptions for Dutch exports (30%) and for Algerian and Norwegian gas (90% each).

** assumes a Belgian storage capacity cost of BF 3,000/GJ/day. This is above the capacity charge in Dutch export contracts (reportedly DM80/m^3/hour, equivalent to BF 1,900/GJ/day), but well below the cost of expensive offshore storage in the UK, for example.

(8) Calculated by difference; weighted average netback is consistent with Distrigaz operating profit for 1987

(9) Distrigaz Annual Report for 1987

(10) Calculated by difference; weighted average is equal to Distrigaz operating margin for 1987

(11) Distrigaz Annual Report for 1987

France

A3.1   The gas industry in France is not, in fact, vertically integrated in all respects. Separate local distribution companies account for a small proportion of final sales to domestic and small commercial customers, while CeFeM and SNGSO are responsible for transmission and direct sales to large

users in their own supply areas in central and south-west France respectively. For simplicity, however, we have reported revenues and costs as if the industry were completely integrated, which we consider to be a sufficiently good approximation for the present purposes.

A3.2   The Gaz de France Annual Report for 1987 contains figures for average sales revenue (across all markets), average gas purchase costs and average non-gas costs. It also shows that GdF made very little overall operating profit in 1987. We have supplemented this published information with our own estimates of the breakdown between different categories of cost in each market sector.

A3.3   Our results are set out in Table A3 below, supplemented by explanatory notes and illustrated in Figure A3 overleaf. In respect of the large users' market sector, we have taken account of the fact that some consumers are supplied from the distribution network and others direct from the transmission grid, by showing low average unit distribution costs for that sector.

<u>Table A3:   Netback Analysis for France, 1987</u>

	FF/kWh (x100)		ECU/m^3 (x100)	
	<u>Dom/Comm</u>	<u>Industry</u>	<u>Dom/Comm</u>	<u>Industry</u>
Average Revenue (1)	13.8	6.5	22.1	10.4
Connection etc (2)	1.2	-	1.9	-
Distribution (3)	1.8	0.2	2.9	0.3
Transmission (4)	1.2	0.7	1.9	1.1
Storage (5)	<u>0.5</u>	<u>0.1</u>	<u>0.8</u>	<u>0.2</u>
Netback (6)	9.1	5.5	14.5	8.8
Gas Purchase Costs (7)	<u>6.3</u>	<u>6.3</u>	<u>10.1</u>	<u>10.1</u>
GdF Operating Margin (8)	<u>2.8</u>	<u>(0.8)</u>	<u>4.5</u>	<u>(1.3)</u>
Average GdF Operating Margin (9)	1.3		2.0	

* assumes an average calorific value of 11 kWh/m^3

Figure A3: Netback Analysis 1987

France

Costs/Revenue ECU/m3 (*100)

Dom/Comm   Ind/Power

Margin   GPC   Trans   Dist
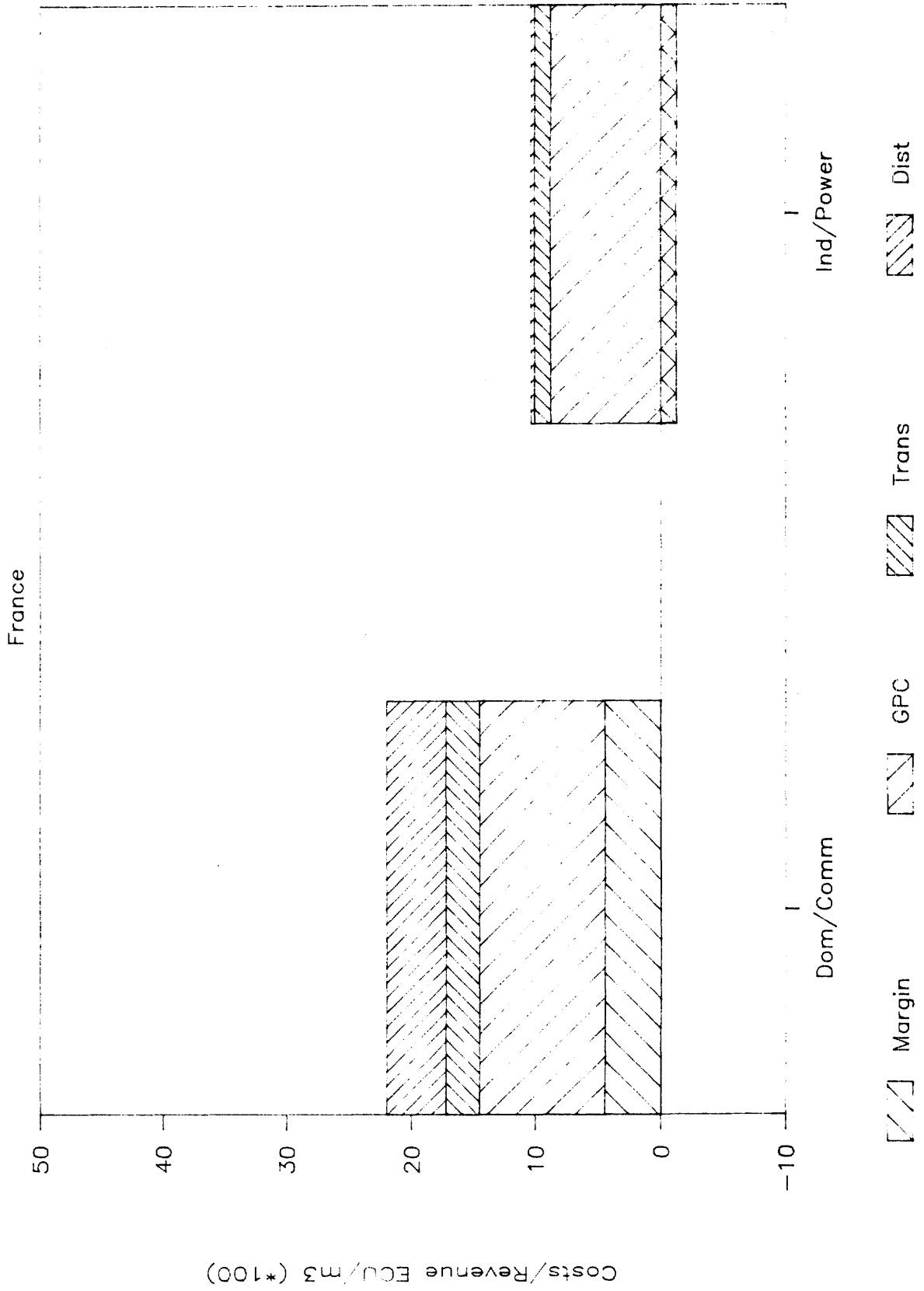
Notes on Table A3

(1) Based on data collected from Member States by DG XVII.

(2) Consultant's estimate based on typical industry costs.

(3) Consultant's estimates. Low distribution cost for industrial users reflects the fact that many large consumers are served directly from the transmission grid.

(4) Consultant's estimate.

(5) Consultant's estimates. A very large amount of storage is required to handle high load factor supplies and is used to serve industrial as well as domestic/commercial markets. Although GdF does sell gas on an interruptible basis, interruption is very rare in practice and a continuous supply is generally maintained by withdrawing gas from storage. Storage cost estimates are based on the following assumptions:-

	Dom/Comm	Industry
Annual Sales (bn kWh)	174	130
Annual Load Factor	0.4	0.7*
Peak Day Sales (bn KWh)	1.19	0.51
Peak Day Supplies**	0.60	0.45
Peak Day Storage Output	0.59	0.06
Storage Cost (c/kWh)***	0.5	0.1

* on the basis that interruption is rare, under normal circumstances
** assuming an average supply load factor of 0.8
*** at an estimated cost of FF 1.5/peak day kWh

(6) Estimates consistent with GdF Annual Report for 1987.18 c/kWh.

(7) GdF Annual Report for 1987 (quotes 6.33 c/kWh).

(8) Calculated by difference.

(9) GdF Annual Report, 1987. Consistent with (8) above when individual
     market netbacks are weighted by total French consumption of 174
     billion kWh (domestic/commercial) and 130 billion kWh (to industry).
     Reported GdF sales figures also take account of 5.3 billion kWh of gas
     exports, sold at an average price of 5.2 c/kWh.

Italy

A4.1 Italy is rather different from Belgium and France, in the sense that
direct sales by SNAM to large industrial and power station consumers are
still significantly greater than domestic and commercial sales to local
distributors. Large user gas prices also tend to be below those in most
Member States, while prices to domestic/commercial consumers are among the
highest in the Community.

A4.2 We estimate (on the basis of reported prices for imported and
indigenous sources) that gas purchase costs in Italy are the lowest of any
Member State examined, which in turn allows large consumers to be supplied
at the low prices referred to above. Unit storage costs may be quite high;
although relatively low cost capacity is available in partially depleted
onshore gas fields, a considerable amount of storage capacity is required
to handle the high load factor of gas purchased by SNAM.

A4.3 The estimated pattern of revenues and costs for Italian gas sales in
1987 is shown in Table A4 below, which is supplemented by explanatory
notes. Figure A4 illustrates the same information in diagrammatic form.

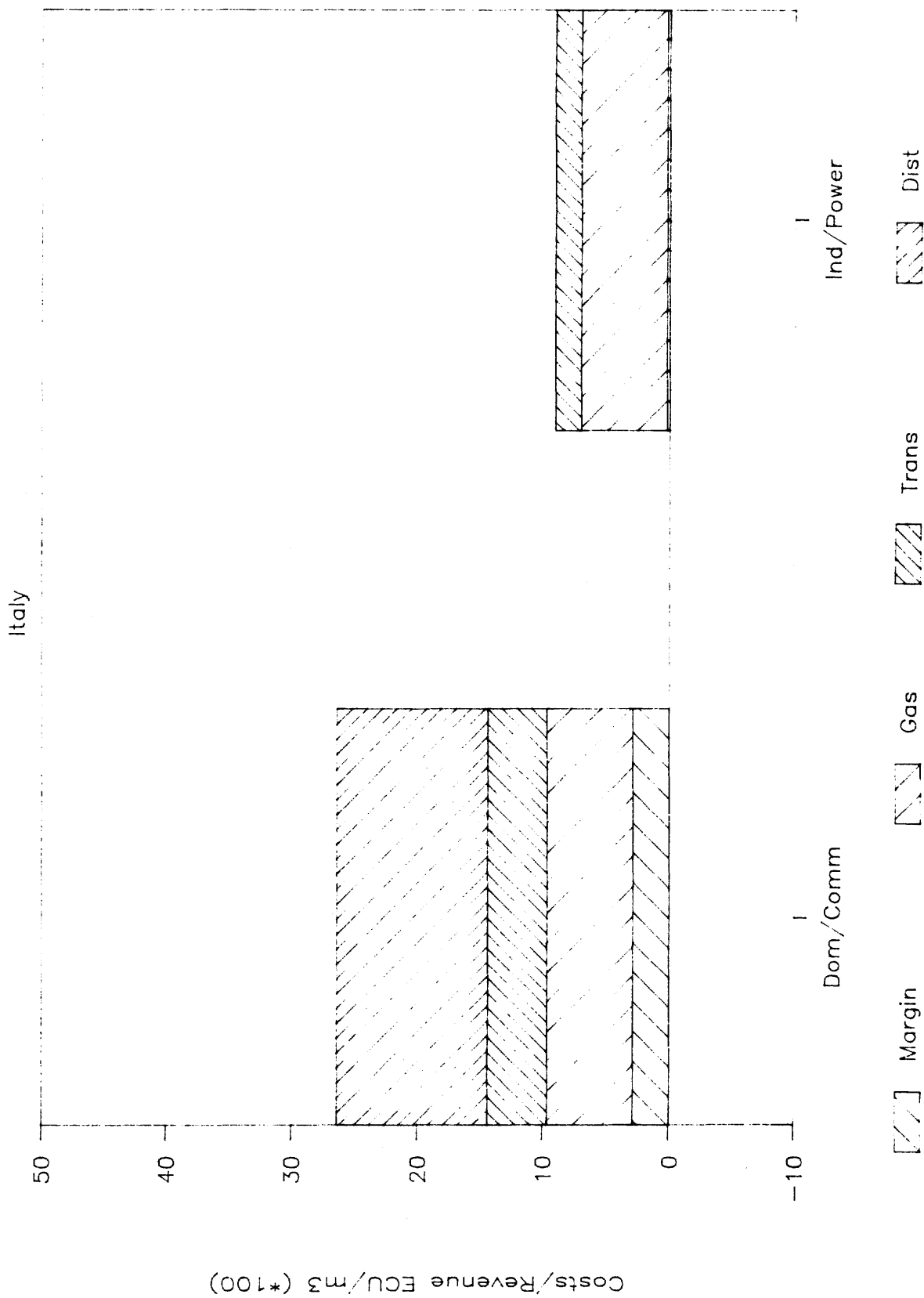Figure A4: Netback Analysis 1987

Italy

Costs/Revenue ECU/m3 (*100)

Table A4: Netback Analysis for Italy, 1987

| | L/m^3 | | ECU/m^3 (x100) | |
	Dom/Comm	Ind/Power	Dom/Comm	Ind/Power
Average Revenue (1)	387	133	26.5·	9.1
Connection etc (2)	36	-	2.5	-
Distribution (3)	110	-	7.5	-
Distributors' Profit	30	-	2.1	-
SNAM/Distributor Price (5)	211	-	14.4	-
Transmission (6)	56	28	3.8	1.9
Storage (7)	13	2	0.9	0.1
Netback (8)	142	103	9.7	7.0
Gas Purchase Costs (9)	100	100	6.8	6.8
SNAM Operating Margin (10)	42	3	2.9	0.2
Average SNAM Operating Margin (11)	20		1.4	

Notes on Table A4

(1)   Based on data collected by DG XVII.

(2)   Consultant's estimate. High figure reflects low average consumption per customer and thus high fixed costs per unit sold.

(3)   As per (2) above. Also reflects small scale of many local distribution companies.

(4)   Consultant's estimate, based on Italgas' results for 1987.

(5)   Calculated by difference using estimated SNAM average revenue ($L\ 167/m^3$), the estimated average price for direct industrial sales and the mix of SNAM sales in 1987 - 16.6 bcm for residential, commercial and automotive use, and 21.7 bcm for industry (including chemical feedstocks) and power stations.

(6)   Consultant's estimates.

(7)   Consultant's estimates; costs are based on the following assumptions:-

	Dom/Comm	Ind/Power
Annual Sales (bcm)	16.6	21.7
Annual Load Factor	0.40	0.75*
Peak Day Sales (bcm)	0.11	0.08
Peak Day Supplies**	0.05	0.07
Peak Day Storage Output	0.06	0.01
Storage Cost (L/m3)***	13	2

* on the basis that interruption is rare, under normal circumstances.

** assuming an average load factor of 85%.

*** at an assumed cost of L3,500/peak day m3.

(8)   Calculated by difference.

(9)   Estimate based on the assumption that 60% of SNAM supplies were imported at $2.30/mmBtu (cif), together with 40% from indigenous sources at a lower average price of $1.70/mmBtu.

(10) Weighted average consistent with SNAM operating profit for 1987.

(11) Derived from SNAM Annual Report, 1987.

Netherlands

A5.1 The Netherlands, with a mature gas market and a relatively small geographical area, is characterised by low selling prices and exceptionally low non-gas costs. No storage costs are incurred by Gasunie, since the seasonal flexibility of gas supplies is assured by NAM and reflected in the netback price which Gasunie pays for Groningen supplies. It should perhaps be emphasised that the NAM-Gasunie price is a transfer price, designed to produce a steady (but small) annual Gasunie profit of NFL 80 million, after tax.

A5.2 Average selling prices (from Gasunie to distribution companies and from gas utilities to final consumers) can be estimated fairly readily from information published by Gasunie or by VEGIN. The entire Gasunie non-gas cost is a cost of transmission. We have used our own estimates to split

the average gross distribution margin into its various cost and profit elements.

A5.3 Our netback analysis for the Netherlands in 1987 is set out in Table A5 and the accompanying notes; the estimated position is shown diagrammatically in Figure A5.

### Table A5: Netback Analysis for the Netherlands, 1987

	Gc/m^3		$ECU/m^3 x100$	
	Dom/Comm	Ind/Power	Dom/Comm	Ind/Power
Average Revenue (1)	35.8	20.0	15.4	8.58
Connection etc (2)	2.5	-	1.1	-
Distribution (3)	4.9	-	2.1	-
Distributors' Profit (4)	2.0	-	0.9	-
Gasunie/Distributor Price (5)	26.4	-	11.3	
Transmission (6)	1.1	0.7	0.5	0.30
Storage (7)	-	-	-	-
Netback (8)	25.3	19.3	10.9	8.28
Gas Purchase Costs (9)	19.2	19.2	8.2	8.24
Gasunie Operating Margin (10)	6.1	0.1	2.6	0.04
Average Gasunie Operating Margin (11)	0.1		0.04	

Notes on Table A5

(1) Based on data gathered by DG XVII, Gasunie Annual Report for 1987 and information published by VEGIN.

(2) Consultant's estimate. Low cost reflects high average consumption per customer and mature domestic market.

(3) Consultant's estimate. Low cost reflects small geographical area and density of gas consumers on the distribution grid.

(4) Consultants' estimate, calculated by difference from lines (1) to (3).

Figure A5: Netback Analysis 1987

Netherlands

Costs/Revenue ECU/m3 (*100)
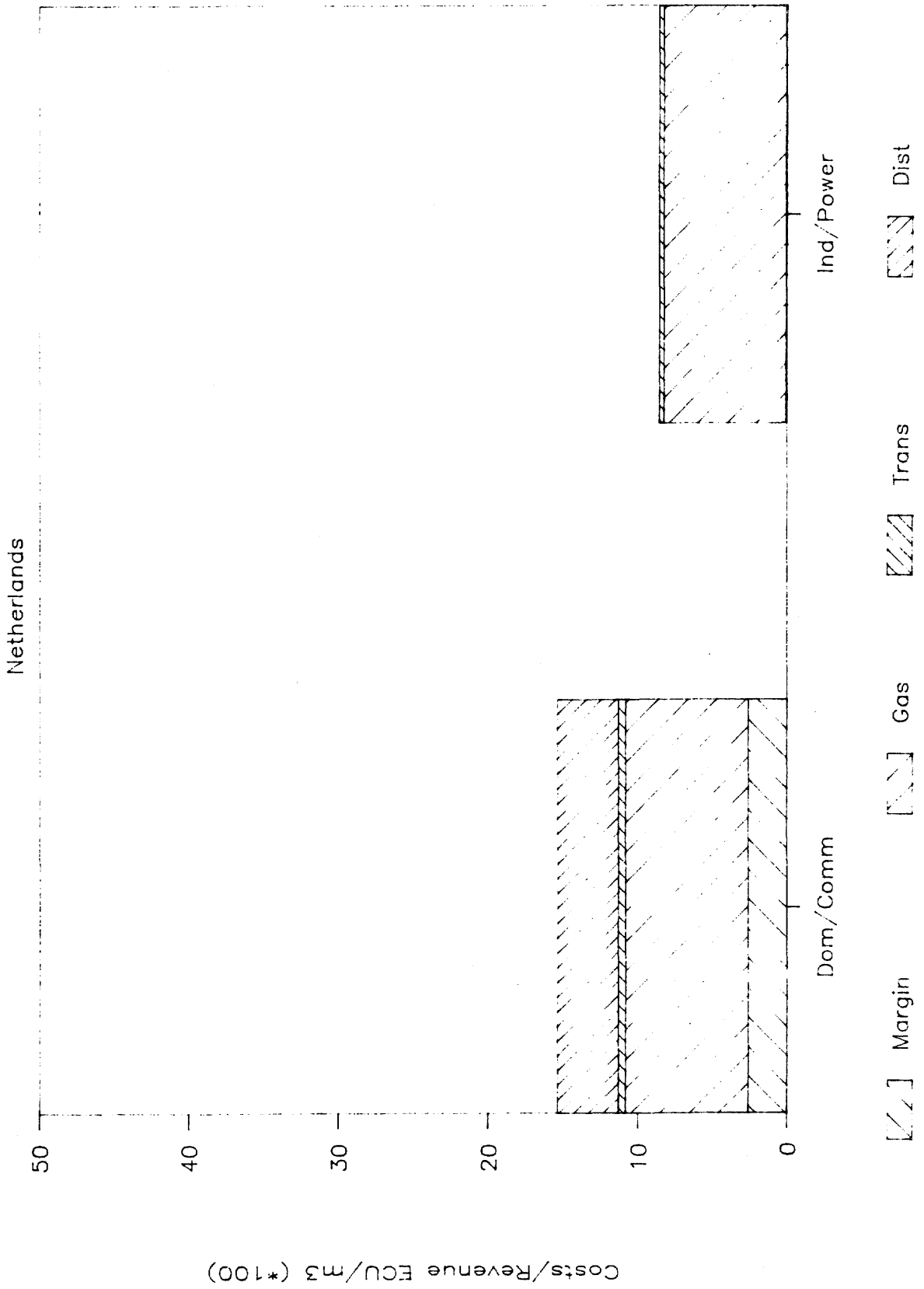
(5) Derived from Gasunie Annual Report, 1987.

(6) Consultant's estimates based on Gasunie's total costs from 1987 Annual Report.

(7) No storage cost, due to the flexibility of Groningen supplies. Effectively, the cost of providing low load factor supplies is incorporated in the purchase price paid by Gasunie to NAM.

(8) Calculated by difference and consistent with average Gasunie netback for 1987, as follows:-

Market	Sales (bcm)	Est. Netback
To Distributors	23.1	25.3
Direct Sales	21.0	19.3
Exports	30.7	14.9*
Total	74.8	19.3

        * not shown in table A5

(9) Gasunie Annual Report, 1987.

(10) Calculated by difference to be consistent with Gasunie pre-tax profit for 1987.

(11) Based on Gasunie Annual Report, 1987 (pre-tax profit).

Spain

A6.1 The Spanish gas market is unusual in that only 20% of gas sales is currently accounted for by domestic and commercial customers. Industrial and power sector consumption makes up the remainder, of which some 55% is supplied direct by ENAGAS and the rest by regional suppliers (Catalana de Gas and Gas de Euskadi) who also supply domestic and commercial users.

A6.2 This pattern of gas consumption has two main implications for non-gas costs - storage requirements are relatively low (and Spain has no underground storage at present) because the load factor of sales is high, while distribution costs are relatively high, reflecting the early stage of natural gas industry development at the distribution level.

A6.3 Our netback assessment for Spain is set out in Table A6 and illustrated in Figure A6 below.

Table A6: Netback Analysis for Spain, 1987*

	Pta/thermie			ECU/m^3 (x100)**		
	Dom/Comm	Ind(R)	Ind/Power(E)	Dom/Comm	Ind(R)	Ind/Power(E)
Average Revenue (1)	6.2	2.5	1.6	41.1	16.6	10.6
Connection etc (2)	1.0	-	-	6.6	-	-
Distribution (3)	2.6	0.5	-	17.2	3.3	-
Distributors' Profit (4)	0.7	0.1	-	4.6	0.7	-
ENAGAS/Distributor Price (5)	1.9	1.9	-	12.6	12.6	-
Transmission (6)	0.9	0.5	0.3	6.0	3.3	2.0
Storage (7)	0.3	-	0.1	2.0	-	(0.7)
ENAGAS Netback (8)	0.7	1.4	1.4	4.6	9.3	9.3
Gas Purchase Costs (9)	1.1	1.1	1.1	7.3	7.3	7.3
ENAGAS Operating Margin (10)	(0.4)	0.3	0.3	(2.7)	2.0	2.0
Average ENAGAS Margin (11)	0.16			1.1		

* (R) denotes regional suppliers (Catalana de Gas and Gas de Euskadi);
  (E) denotes ENAGAS)

**assuming 9.55 thermies/m^3 (1 thermie = 1000 kcal)

Notes on Table A6

(1)   Estimates based on data gathered from Member States by DG XVII, together with Annual Reports for ENAGAS and Catalana de Gas.   Three broad categories of gas sales are considered, as follows:-

Distributors' sales to domestic/commercial users 5.5 bn thermies
Regional suppliers' sales to large users 10.3 bn thermies
ENAGAS direct sales to large users 12.8 bn thermies
                              Total 28.6 bn thermies

(2) & (3) Consultant's estimates. High connection and distribution costs reflect low average consumption and density of connections.

Figure A6: Netback Analysis 1987
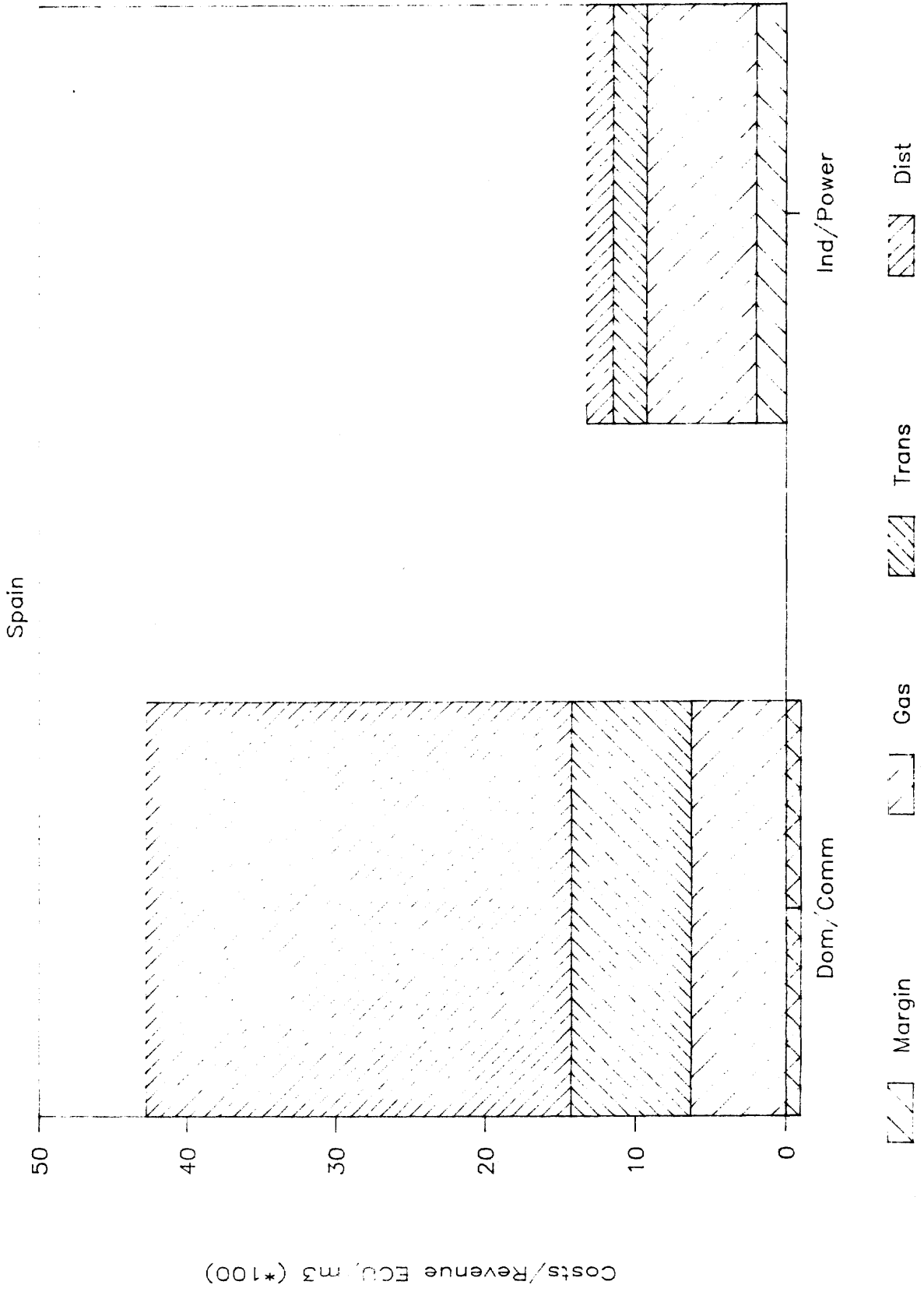
(4)   Estimates based on Catalana de Gas results for 1986.

(5)   Calculated from estimated average revenue from ENAGAS industrial
        sales, overall average revenue of Pta 1.77/thermie (derived from
        ENAGAS Annual Report, 1987) and following breakdown of ENAGAS natural
        gas sales in 1987:

                        To distribution companies   15.8 bn thermies
                        Direct to large users   12.8 bn thermies

(6)   Consultant's estimates, reflecting load factor by market.

(7)   Spain has limited LNG storage and no underground storage at present.
        Cost estimates are based on the following assumptions:-

	Dom/Comm	Ind(R)	Ind/Power(E)
Annual Sales (bn thermies)	5.5	10.3	12.8
Load Factor	0.40	0.70*	1.00*
Peak Day Sales (m thermies)	38	40	35
Peak Day Supplies**	20	38	48
Peak Day Storage Output	18	2	(13)
Storage Cost (Pta/thermie)***	0.3	-	(0.1)

*   after allowing for interruption of interruptible sales
**   at an annual average load factor of 75%
***   at a rate of Pta 80/peak day thermie, reflecting the high cost of LNG
        storage

(8)   Estimates, consistent with ENAGAS average netback for 1987 of Pta
        1.27/thermie.

(9)   Derived from ENAGAS Annual Report, 1987.

(10)   Estimates, consistent with average ENAGAS operating margin for 1987.

(11)   ENAGAS Annual Report, 1987.

West Germany

A7.1 The structure of the West German gas industry is highly complex, with three levels of gas utilities involved;-

(a) producing or importing gas utilities such as Ruhrgas, BEB and Thyssengas, who also act as regional suppliers in part of the country;

(b) regional transmission companies such as Bayerngas and GVS; and

(c) local distribution companies, for the most part wholly or partly in municipal ownership.

A7.2 This rather complex structure gives rise to a number of ways in which gas can be traded and sold, as follows:-

(i) direct from importing utilities to large consumers;

(ii) from importing utilities to regional transmission companies and thence to large consumers;

(iii) from importing utilities to local distributors in their own regional supply areas and thence to consumers, both domestic/commercial and larger users; or

(iv) from importing utilities via regional transmission companies to local distributors and thence to consumers.

A7.3 For the purposes of analysis, we have simplified this complex position and classified the industry into transmission companies (whether importers or regional suppliers) and local distributors. In terms of the sales categories above, (i) and (ii) are consolidated into transmission company sales, while (iii) and (iv) are shown as sales from the transmission level to distributors and then to final consumers. Distributors' sales are divided in turn between the domestic/commercial market and industrial/power sector consumers. Precise information on the split of industrial consumption between transmission company and distributor sales is not available, but it is understood that each accounts for about half the total. In general, transmission companies tend to sell direct to the very large users with lower gas prices and this is reflected in our estimates of average selling prices.

A7.4 The complex and fragmented structure of the industry also makes it more difficult to estimate the typical or average level and structure of non-gas costs. For example, total Ruhrgas' average non-gas costs in 1987 were around Pf 0.3/kWh, but this is only part of total transmission level non-gas costs because a considerable proportion of all gas sold also passes through the hand of a regional transmission company. A similar point relates to the average price at which gas is sold from transmission companies to distributors. Average Ruhrgas' sales revenue of some Pf 1.9/kWh mainly reflects sales to other pipeline companies and the price for sales to distributors is likely to be somewhat above this level. We have therefore reflected this in our estimates, based on our understanding that the average gross distribution margin in West Germany may be somewhat less than Pf 1.5/kWh. As transmission company sales to distributors include a capacity charge as well as a commodity charge, we have also indicated a (notionally) higher average sales price for low load factor supplies to domestic/commercial users than for higher load factor sales to larger users.

A7.5 The breakdown of gross trading (distribution or transmission) margins into their constituent cost and profit elements is not readily available from published sources. We have therefore used our own estimates, based on what is known about the West German gas industry (load factor of bulk gas supplies, type of storage facilities, etc.) and typical cost levels in the European gas sector more generally. The transmission company profit margin of Pf 0.2/kWh is based on Ruhrgas' results for 1987.

A7.6 Our analysis of costs and netbacks in West Germany is presented in Table A7 and Figure A7 below.

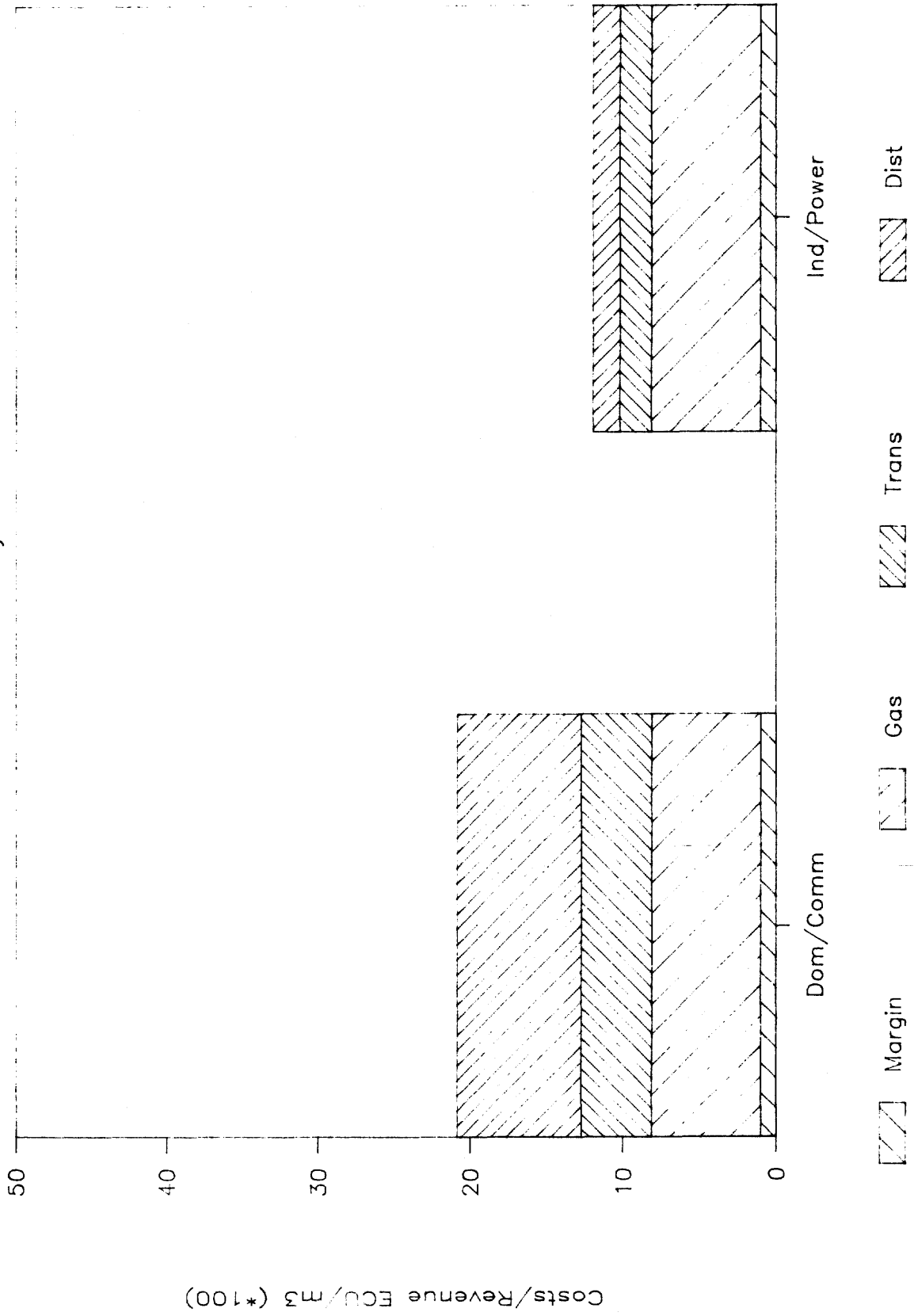Figure A7: Netback Analysis 1987
West Germany

Table A7: Netback Analysis for West Germany, 1987*

	Pf/kWh			ECU/m³(x100)**		
	Dom/ Comm	Ind/ Power(D)	Ind/ Power(T)	Dom/ Comm	Ind/ Power(D)	Ind/ Power(T)
Average Selling Price (1)	4.1	2.8	1.9	20.9	14.3	9.7
Connection etc (2)	0.3	-	-	1.5	-	-
Distribution (3)	0.8	0.5	-	4.1	2.5	-
Distributors' Profit (4)	0.5	0.2	-	2.5	1.0	-
Transmission/Distrib'n price(5)	2.5	2.1	-	12.7	10.7	-
Transmission (6)	0.8	0.5	0.4	4.1	2.5	2.0
Storage (7)	0.1	-	(0.1)	0.5	-	(0.5)
Transmission Co. Netback (8)	1.6	1.6	1.6	8.2	8.2	8.2
Gas Purchase Costs (9)	1.4	1.4	1.4	7.1	7.1	7.1
Transmission Co. Margin (10)	0.2	0.2	0.2	1.0	1.0	1.0
Average Transmission Co. Margin(11)	0.2			1.0		

* (D) denotes distributors' sales; (T) denotes direct sales from transmission companies to large consumers

** assuming 10.5 kWh/m³

Notes on Table A7

(1)   Prices based on data collected by DG XVII. Sales for 1987 estimated to be as follows:

Domestic/Commercial (distributors' sales)	270 bn kWh
Industry/Power (distributors' sales)	146 bn kWh
Industry/Power (transmission co. sales)	147 bn kWh

(2) & (3) Consultant's estimates based on typical cost levels in the industry.

(4)   Consultant's estimate.

(5)   Based on estimated average gross distribution margin of Pf 1.4/kWh; different prices to different markets reflect capacity charge element in the price.

(6) & (7) Consultant's estimates, informed by Ruhrgas' non-gas costs for 1987 (around Pf 0.3/kWh) and average revenue (from sales to other pipelines, distributors and large industrial users) of around Pf 1.9/kWh. Storage cost estimates are based on the following assumptions:-

	Dom/Comm	Ind/Power(D)	Ind/Power(T)
Annual sales (bn kWh)	270	146	147
Assumed Load Factor	0.40	0.65*	0.85*
Peak Day Sales (bn kWh)	1.85	0.62	0.47
Peak Day Supplies**	1.23	0.67	0.67
Peak Day Storage Output	0.62	(0.05)	(0.20)
Storage cost (Pf/kWh)***	0.1	-	(0.1)

   * after allowing for interruption, where applicable

  ** assumes an average supply load factor of 60%

*** at an assumed cost of DM 0.5/peak day kWh

(8)   Calculated by difference.

(9)   Assumed $2.40/mmBtu and cross-checked against Ruhrgas Annual Report for 1987.

(10) Consultant's estimates. Average margin is consistent with Ruhrgas results for 1987.

(11) Based on Ruhrgas' pre-tax operating profit for 1987.

United Kingdom

A8.1 Average revenue by market in Great Britain is published by British Gas in its Annual Report. Some information on the breakdown of non-gas costs by market is available from the recent Monopolies and Mergers Commission (MMC) report on British Gas' industrial supplies. We have, in some cases, adapted cost figures published in the MMC report to the format required for our analysis.

A8.2 The negative storage cost for industrial sales may require some
further comment. This reflects the use of interruptible contacts in severe
weather, releaving beach supplies and system capacity to meet peak time gas
demand. Effectively, the industrial market as a whole allows BG to save on
storage capacity costs, since the local factor of consumption (after
interruption) is higher than the average load factor of beach supplies.

<u>Table A8: Netback Analysis for the UK, 1987/88</u>

| | <u>Pence/Therm</u> | | <u>ECU/m^3(x100)</u>* | |
	<u>Dom/Comm</u>	<u>Ind</u>	<u>Dom/Comm</u>	<u>Ind</u>
Average Revenue (1)	40.3	23.5	19.6	11.4
Connection etc (2)	1.9	-	0.9	-
Distribution (3)	7.5	1.6	3.6	0.8
Transmission (4)	3.6	1.8	1.7	0.9
Storage (5)	<u>2.7</u>	<u>(0.9)</u>	<u>1.3</u>	<u>(0.4)</u>
Netback (6)	24.6	21.0	12.0	10.2
Gas Purchase Costs (7)	<u>17.0</u>	<u>17.0</u>	<u>8.3</u>	<u>8.3</u>
Operating Margin (8)	<u>7.6</u>	<u>4.0</u>	<u>3.7</u>	<u>1.9</u>
Average Operating Margin (9)	6.5		3.2	

* assuming 1 therm = 2.78 m^3

<u>Notes on Table A8</u>

(1)   British Gas Annual Report for 1987/88. In 1987/88,
      domestic/commercial sales were 12,896 million therms (35.9 billion
      cubic metres) and industrial sales 5,810 m.therms (16.2 bcm), making
      a total of 18,706 m.therms in total. There are currently no BG sales
      into power stations.

(2)   Consultant's estimate based on MMC Report of 1988 and BG quarterly
      standing charges.

(3)   Quoted in MMC Report is a likely average charge for common carriage
      through the BG distribution system.

Figure A8: Netback Analysis 1987/88
United Kingdom

(4) Based on MMC Report and BG's quoted charges for third party gas transmission.

(5) Storage costs (which in this case include the cost of seasonally producing gas fields) were estimated as follows:-

	Dom/Comm	Industrial
Annual Sales (m.therms)	12,896	5,810
Load Factor	0.40	0.85*
Peak Day Sales (m.therms)	88	19
Peak Day Beach Supply**	53	24
Peak Day Storage Output	35	(5)
Storage Cost (p/therm)***	2.7	(0.9)

* assumes a 60% load factor for firm sales and allows for interruption of half the contract load, under interruptible sales contracts

** assumes a 0.67 load factor of BG beach supplies, excluding seasonal fields (Sean, Morecambe) and offshore storage (the Rough field)

*** derived from an estimated storage cost of £10/peak day therm of storage requirement

(6) Derived from BG Annual Report.

(7) Includes gas levy; derived from BG Annual Report.

(8) BG Annual Report.

(9) Weighted average across both market sectors.

Industrial Selling Prices

A9.1 For the analysis (in Section V) of utilities' gross trading margins on firm and interruptible sales to large industrial and power station consumers, we have estimated the following average selling prices for 1987:-

Table A9:   Industrial/Power Sector Selling Prices, 1987

(estimated, ECU/m^3 x 100)

	Firm	Interruptible	Average
B	10.1	8.2	9.2
F	11.3	9.1	10.4
I	10.0	8.2	9.1
NL	8.9	8.2*	8.6
SP	16.6	10.5	13.3
FRG	13.5	8.2	12.0
UK	15.3	8.2	11.4

* power stations only

APPENDIX B

Extent of Common Carriage

Extent of Common Carriage

B1. Quantitative assessment of the direct effects of common carriage
(which may be much less important than its indirect effects on the gas
market in general) requires a view of the likely use of common carriage
rights, which we set out in this Appendix. Our view is that the very
extensive use of third party transportation in the United States in recent
years reflects the particular gas industry structure and market pressures
prevailing in that country. It cannot be taken as indicative of what would
be likely to happen in the Community, where pricing is more market-oriented
and the nature of competition between major gas producers/suppliers is very
different. In the UK, for example, a legal right of common carriage has
existed since 1982 and there is, as yet, no third party use of the BG
system, although this will probably begin to emerge over the next year or
two. Even if a common carriage system were introduced at the Community
level by 1992, we would not expect it to be widely used by the mid 1990s.
We therefore consider in this Section the likely situation as it may
develop by around the turn of the century.

Assessment

B2. Before considering individually the seven Member States covered in
detail by this report, it may perhaps be helpful to make some introductory
remarks regarding the prospects for use of common carriage in general:-

(a) local distribution companies, with low load factors, little storage
     of their own and often with particular gas quality requirements,
     would generally find it difficult to conclude direct gas purchase
     agreements with gas producers. They might pool their purchasing
     power to overcome the problems of size, but would still be faced with
     a complex 'package' of transportation, storage and (possibly) gas
     mixing agreements to conclude with their erstwhile transmission
     company suppliers;

(b) those large industrial or power station consumers who take
     substantial volumes on higher load factors at a single transmission
     grid location would generally be much better placed to secure a
     direct supply;

(c) interest in direct supply will tend to be greatest where current
     transmission company margins appear to be high (see section V above);
     and

(d) in some cases, common ownership between distribution and transmission
     companies is likely to militate against "by-passing" of the latter by
     the former.

B3.   The actual extent of common carriage will depend on the attitude of
producers as well as consumers. In the U.S., for example, the
determination of small, independent producers to market shut-in gas was a
major factor in the emergence of widespread third party gas transportation.
No U.S. producer is very large in relation to the total market and the
impact of individual marketing efforts on the general level of prices was a
second-order consideration, compared with the need to find a sales outlet
at all. In the European Community, the picture is very different. Leaving
aside the UK, which will supply the vast bulk of its own requirements at
the end of the century, four producing countries (Algeria, the Netherlands,
Norway and the USSR) are likely to account for over 70% of gas supplies to
the rest of the Community in 2000. Of these, the three non-Member States
will provide over 40% between them. For this reason, each producer will
consider most carefully the likely impact on general market realisations of
any attempt to gain market share or to expand the market via common
carriage. In particular:

(a) the Netherlands is able to export all the gas it wishes to under
     existing arrangements and may therefore be considered unlikely to
     pursue the direct sales option;

(b) Norway is generally a high cost producer and would have little to
     gain from an aggressive 'price war' with other producing countries;

(c) Algeria has traditionally followed a high-price strategy, although
     some recent deals (with British Gas, for example) have shown greater
     flexibility and there are economic pressures to make use of excess
     deliverability to boost export earnings; and

(d) the USSR might see common carriage as a way round any political
     'ceiling' on its market share in some importing countries, but again
     would not wish to see a round of competitive price cuts bringing down
     the general level of prices.

Producers also have existing relationships with gas transmission companies which they will not wish to impair, since these companies will continue to account for the vast majority of gas imports. This sort of caution has been shown in the UK gas market since 1982 and we would expect it to characterise the wider Community market in the 1990s, even if a common carriage system is introduced. Likely producer attitudes reinforce our view that the level of common carriage use in 2000 will be modest.

B4.   In <u>Belgium</u>, the degree of common ownership between Distrigaz and a number of joint venture local distribution companies ('intercommunales mixtes') through the Intercom/Tractebel group is a specific factor which makes direct buying by distributors less likely. Intercom/Tractebel hold some 33% of Distrigaz and Intercom is involved in around 40% of all gas distribution at a local level. Moreover, the distributors located on the 'L gas' (Groningen quality) grid in northern and central Belgium would require gas mixing facilities in order to purchase gas from other 'H' gas sources.

B5.   In 1987, power utilities accounted for some 19 TJ of gas sales, around 6% of the total Belgian market. These utilities might, in principle, seek to buy direct, but Intercom is also heavily involved in power generation (accounting for 38% of total production in 1987) and is perhaps unlikely to seek a supplier other than Distrigaz for its gas requirements. The other private generating utilities, Ebes and Unerg, are also important gas distributors and they too have established relationships with Distrigaz which they might not wish to impair. In Belgium, electricity generation planning is carried out cooperatively by the utilities, with considerable Government supervision through the Comité de Controle. The Government favours a new gas-fired plant to be commissioned in the mid 1990s and envisages that around 1 bcm/a would be supplied by Distrigaz to help utilise a contracted surplus of LNG from Algeria. For these reasons, we consider direct supplies to the power sector via common carriage to be unlikely, at least before the turn of the century.

B6.   This leaves the possibility of direct sales to large industrial consumers, especially the chemical industry and the steel sector. In 1987, these two sectors accounted for 16% and 7% respectively of total natural

gas consumed in Belgium. Industrial gas prices in Belgium appear to be a little above those in some neighbouring countries and the Soviet Union, in particular, might possibly consider direct sales as a way of breaking into a market where it currently has no sales presence. Nevertheless, the number of industrial users both willing and able to conclude a direct purchase deal will probably remain fairly small.

B7. It is extremely difficult to predict precisely what proportion of the market might be served by direct sales. As a working assumption, we postulate that perhaps 7-8% of industrial consumption may be met by direct purchases in 2000; this is equivalent to around 3% of the total Belgian gas market.

B8. In France, the largely vertically-integrated nature of the industry is such that the option of direct buying by local distribution companies scarcely exists. There is, however, the possibility that Elf might seek to make direct purchases for some of its SNGSO and CeFeM gas requirements as Lacq supplies continue to decline. Indeed, the company sought to buy direct from Norway at the time of the Troll negotiations but eventually reached agreement for the on-sale of gas to be imported from Norway by GdF.

B9. Natural gas is very little used in the power sector and the low load factor of peaking plant utilisation would make this market less attractive to gas producers wishing to make a direct sale than other potential sales opportunities. Moreover, state-owned electricity company EdF is perhaps unlikely to try to buy gas direct, over the head of state-owned Gaz de France.

B10. By far the largest industrial gas user in France is the chemical industry, which in 1987 consumed almost 50 TWh (some 16% of total consumption in the French gas market as a whole), of which almost half was used by the fertiliser industry. As in most other Member States with a gas-based fertiliser industry, this sector is understood to benefit from special low prices, aligned with the 'F' tariff for ammonia producers in the Netherlands. From our analysis in Section II, it appears that French gas purchase costs are above the European average and this might mean an interest from other industrialists in common carriage. However, the

apparent negative GdF margin on industrial sales offsets the relatively
high purchase costs to some extent. In practice, the interest of some
large industrial groups in direct buying may be constrained by their state
ownership. Overall, we assume that 5% of the industrial market is met by
direct sales in 2000, equivalent to around 2% of total gas consumption.

B11. In Italy, the size of most local gas distributors is small (there are
over 700 in all) and many would not be in a position to contemplate a
direct purchase. Of the distribution companies in the major cities, many
are wholly or partly owned by Italgas (40% owned and effectively controlled
by SNAM) or other SNAM distribution subsidiaries. They are thus unlikely
to by-pass the national transmission company.

B12. Italian industrial gas prices are among the lowest in the Community
and interest in direct purchases may be muted for this reason. On the
other hand, SNAM's high profit margins in recent years might lead
industrialists to consider that they could obtain more favourable terms via
common carriage. There might also be increased direct sales from
independent offshore gas producers in Italy to their own downstream
(chemicals) plants, especially if the internal European energy market
programme results in more open licensing of Italian exploration acreage in
the longer term.

B13. It is known that state-owned electricity company ENEL envisages a
very substantial increase in power station gas use over the next decade.
The power station gas burn is projected in the new National Energy Plan
(PEN) to double from 6.4 mtoe (just under 7 bcm) in 1987 to 13 mtoe in
1995. An emergency programme to boost generating capacity has been
announced, involving 1300 MW of gas turbine capacity to 're-power' existing
oil units and 1500 MW of new combined cycle plant, as well as the
conversion of the almost completed Montalto nuclear station to burn gas.
In order to ensure that it gets the most competitive gas prices from SNAM,
ENEL might be prepared to consider buying a proportion of its additional
gas requirements from another supplier.

B14. As a working assumption, we postulate that 7% of the combined industry/power sector gas market might be supplied direct via common carriage in 2000, accounting for around 4% of the total market in Italy.

B15. Gas prices in the Netherlands are relatively low and we do not believe that there would be great interest from industrial users in direct buying, via common carriage. VEGIN are known to consider the Gasunie price to them to be too high, but the distributors are not in a good position to make a direct deal and they are also contractually committed to purchase from Gasunie. It is conceivable that the electricity association SEP might wish to seek other gas suppliers, over and above its recent deal with Norwegian sellers. However, Gasunie's recently publicised acceptance of coal indexation for gas prices charged to SEP takes away some of the attraction of such arrangements from the electricity industry's point of view. By 2000, we assume for illustrative purposes that 5% of the industry/power market is supplied direct via common carriage, equivalent to 2% of the Dutch gas market overall.

B16. In Spain, the large proportion of industrial use in total consumption exposes ENAGAS to some risk of losing customers to common carriage, especially as large user gas prices appear to be somewhat above the Community average. However, few consumers are likely to have attained a scale of gas use sufficient to make them attractive to potential direct sellers. Spain is also geographically remote from those producing countries (especially the USSR) with which ENAGAS has no purchase contract and which might wish to break into the market. It would therefore be surprising if use of common carriage were to emerge on a large scale by 2000. We assume that it might amount to 5% of industry/power market consumption or about 3% of total gas sales.

B17. Local distribution companies in West Germany are generally fairly small (there are over 500 in total) and only a few large Stadtwerke would be of a sufficient size to make them credible as direct purchasers. Moreover, they tend to have a requirement for supplies on low load factor, which would render them less attractive to a direct seller. Thus they would require a storage service as well as a transportation service from transmission companies if they were to buy direct. There is, in our view,

a possibility that a regional transmission company might seek to purchase direct, as suggested at one time by Bayerngas. The regional suppliers are quite large (Bayerngas purchases as much gas as Belgium's Distrigaz, for example) and take gas on a higher load factor than most distribution companies, as they often make a proportion of direct industrial sales and, in some cases, have seasonal storage facilities of their own. EWE, for example, has a long-standing contract with Gasunie for imports of Dutch gas. However, many regional transmission companies are part-owned by the large producing or importing utilities (BEB and, especially, Ruhrgas), so this makes them less likely to purchase direct - especially if common carriage were required to effect the deal. Since the regional companies are unlikely to be able to buy on more advantageous terms than Ruhrgas (which is much larger, takes on a higher load factor and has more commercial experience), we consider that Ruhrgas and BEB will generally be able to offer sufficiently attractive terms to 'head off' by-pass proposals. This appears to have been the case with Bayerngas, for example.

B18. There is clearly some interest in direct buying via common carriage among large industrial users, especially chemical concerns who take considerable volumes on high load factor at a few sites. Such gas is often used as an ammonia feedstock or as a fuel for industrial auto-generation of electricity. West German industrial gas prices are still individually negotiated and appear, in some cases, to be above those in some neighbouring Member States. This could reinforce interest in direct purchasing by the larger high-margin customers of transmission companies. Moreover, some medium sized industrial customers currently supplied by regional transmission or local distribution companies might seek a direct supply from an importing transmission company, via common carriage.

B19. Since the Jahrhundertvertrag agreements of 1980 on the use of indigenous hard coal in West German power stations, the use of natural gas for electricity generation has declined considerably and is primarily confined to peaking load (in the case of the large DVG generating companies who are also regional suppliers) and middle merit order positions in the case of some gas-burning plant owned by Stadtwerke. While gas continues to be used on relatively low load factors (only a few hundred hours in peaking stations and perhaps 3,000-4,000 hours in mid-merit positions), the power

market is unlikely to be of great interest to most potential direct suppliers. By the turn of the century, however, it now seems likely that the Jahrhundertvertrag obligations will be significantly lower than today's level of 45 million tonnes. Indigenous coal may be substituted by coal imports or electricity purchases from abroad, but there may also be opportunities for natural gas to increase its market share again if pricing is competitive. If so, it is conceivable that some of the gas could be purchased direct by the power utilities, via common carriage, especially as producing countries would be keen to compete for a significant new market.

B20. Taking all these possibilities into account, we consider that perhaps 4% of the total West German market might be supplied via common carriage in 2000 - representing a combination of direct sales to industrial users, power companies and regional gas suppliers.

B21. In the United Kingdom, the new industrial gas pricing schedules and the obligation on British Gas to offer interruptible terms to 'premium' industrial users (with a gas oil or LPG alternative to natural gas) on a non-discriminatory basis may tend to reduce some of the interest in direct buying. Nevertheless, there will no doubt continue to be large firm gas consumers who consider that the BG trading margin is excessive. It has recently been reported that AGAS have secured a carriage agreement with British Gas for direct marketing of some 170 million therms p.a. (about 0.5 bcm/a) purchased from UK gas producers. This in itself is less than 1% of the total gas market, but AGAS plan to increase sales to 500-600 therms p.a. over the next 4-5 years and the deal also sets a precedent for other would-be competitors.

B22. There is also considerable interest in gas-fired power generation and we would expect to see around 6 GW of plant in use by the end of the century, including the Peterhead plant in Scotland which is already contracted to take Miller gas on a direct supply which does not involve common carriage. This amount of gas plant could burn over 10 bcm/a, as we expect the stations to achieve a high merit order position, below nuclear but above many older coal-fired stations. Much of this could be supplied direct and the inland gas stations are likely to require some form of carriage through the BG system. Overall, we assume that up to 7% of the

gas market in Great Britain will be supplied via common carriage in 2000. This takes into account the Government's recent decision that no more than 90% of total UK gas supplies under all new contracts may be sold to BG with effect from May 1989.

Overview

B23. It should be stressed that we have made a number of working assumptions regarding the extent of common carriage, to provide a quantitative basis for discussing its likely effects. These are hypotheses rather than precise predictions and we consider that, depending on the way gas transmission companies respond to the possibility of common carriage, the actual proportion of the market supplied direct via common carriage in 2000 may well be less than we have assumed for the purposes of illustration.

B24. Our working hypotheses regarding the extent of common carriage in 2000 are summarised in Table B1 below, using the latest (December 1988) forecasts collected by DG XVII for total gas consumption in that year:-

Table B1: Assumed Extent of Gas Common Carriage in 2000

	B	F	I	NL	SP	FRG	UK	Total(7)
% of total market	3	3	4	2	3	4	7	4
Energy (in mtoe)	0.2	0.6	2.0	0.7	0.2	1.8	3.6	9.1
Volume (in Bcm)	0.2	0.7	2.4	0.9	0.2	2.1	4.3	10.8

B25. We thus envisage an above-average level of direct sales in the UK, while the Netherlands, in particular, is projected to see a relatively low level of common carriage. The seven Member States considered together account for 96% of projected natural gas consumption across the Community in 2000; if the pattern outlined above were repeated in the other five Member States, then a total of some 9.5 mtoe (11 bcm/a) would be supplied via common carriage in the 12 Member States as a whole.

B26. It is important to emphasise at this point that the significance of common carriage is likely to be far greater than the assumed direct sales share of the total gas market would suggest. Provided at least some carriage deals are concluded, existing gas suppliers will be made aware of a new competitive threat from direct sales. This could then lead to changes in gas pricing policy and increased efficiency in transmission and distribution, as discussed in subsequent sections of this report.

B27. Gas purchases via common carriage are also likely to have a "knock-on" effect on gas in transit between Member States. Based on currently contracted gas supplies for 2000 as reported by DG XVII, Figure B1 overleaf illustrates schematically the principal inter-country flows of natural gas within the interconnected European grid. The data on which Figure B1 is based is set out in Table B2 below:

NATURAL GAS FLOWS
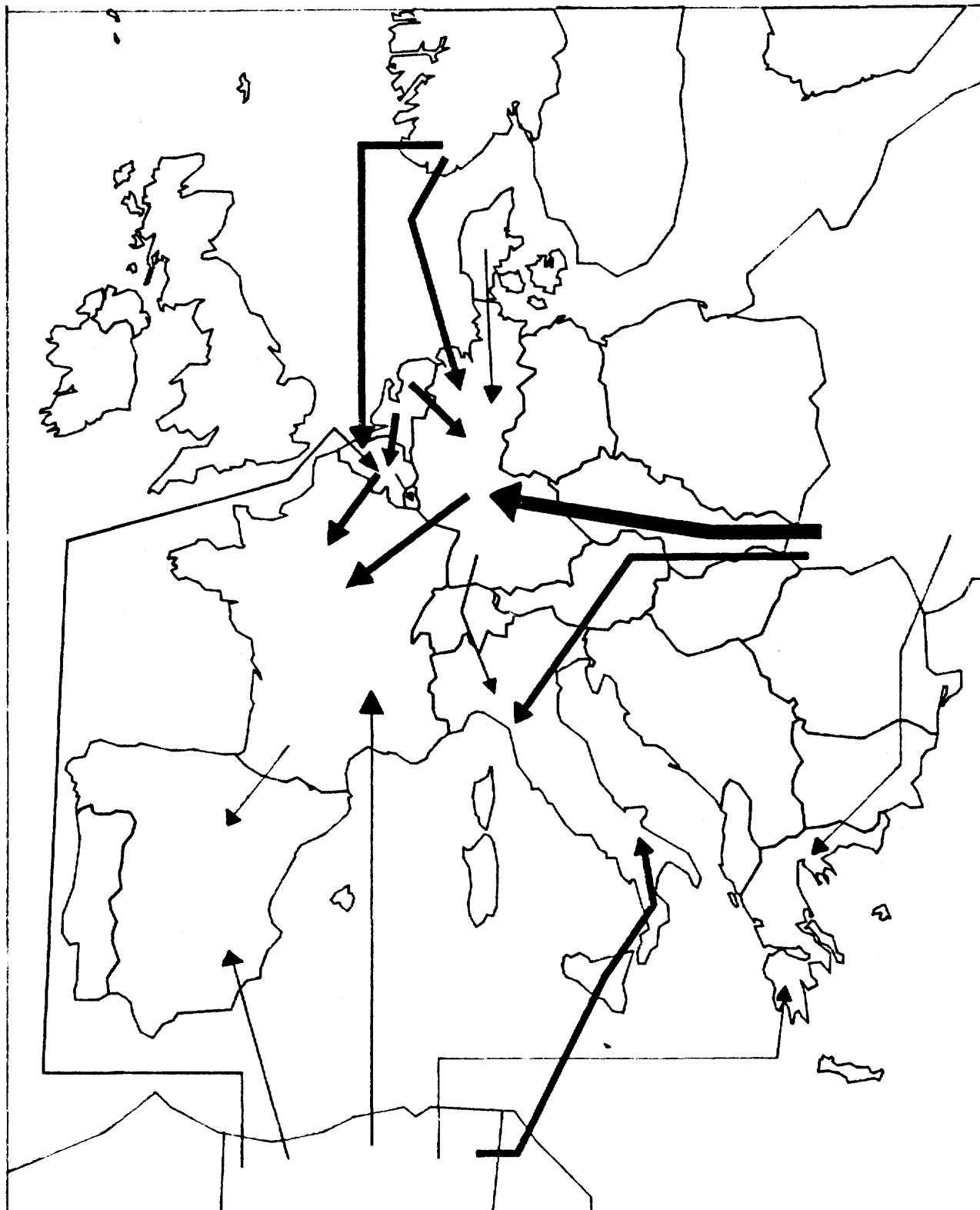IN THE INTERCONNECTED EUROPEAN GRID
Year 2000

Fig.8.1

Table B2:   Natural Gas Flows in the Interconnected European Grid[*1]

(Year 2000, in mtoe)

Norwegian Exports

To:	Belgium	France	Spain	Netherlands	West Germany	Total
Via:	Zeebrugge	Zeebrugge	Zeebrugge	Emden	Emden	-
Amount:	2.0	6.3	0.8	3.8	7.1	20.0

Algerian Exports

To:	Belgium	France	Spain	Italy	Greece	Total
Via:	LNG	LNG	LNG	Trans-med	LNG	-
Amount:	2.9	4.5	3.8	10.0	0.5	21.7

USSR Exports

To:	France	Italy	West Germany		Greece	Total
Amount	9.1	10.8	12.6		1.8	34.3

Dutch Exports

To:	Belgium	France	Italy		West Germany	Total
Amount:	3.4*2	3.8	3.3		11.9	22.4

Gas Flow, Netherlands - West Germany

Exporter:	Netherlands	Netherlands		Norway	Total
Importer:	West Germany	Italy		Netherlands	-
Flow:	11.9	3.3		(3.8)	11.4

Gas Flow, Netherlands - Belgium

Exporter:	Netherlands	Netherlands		Total
Importer:	France	Belgium		-
Flow:	3.8	3.4*2		7.2

Gas Flow, Belgium - France

Exporter:	Netherlands	Norway	Norway	Total
Importer:	France	France	Spain	-
Flow:	3.8	6.3	0.8	10.9

*1 Based on DG XVII data (from December 1988), plus new contracts from
   Norway to Spain (0.8 mtoe) and SEP of the Netherlands (1.7 mtoe).
   Table shows contracted purchases only and excludes trade involving
   non-member countries (Austria, Switzerland etc)

*2 Includes 0.4 mtoe exported from Netherlands to Belgium and sold on by
   Distrigaz to SOTEG of Luxembourg

B28. We estimate that, in 2000, around 20% of natural gas consumed in the Community will cross at least one border within the Community and some 12% will traverse one or more Member States in transit to another Member State, as set out below:-

Table B3: Contracted Gas Exports/Imports in Transit
(Year 2000, in mtoe)

Exporter	Importer	In Transit Through	Volume
Netherlands	France	Belgium	3.8
Netherlands	Italy	West Germany, Switzerland	3.3
Netherlands	Luxembourg*	Belgium	0.4
Norway	Netherlands	West Germany	3.8
Norway	France	Belgium	6.3
Norway	Spain	Belgium, France	0.8
USSR	France	West Germany	9.1
			27.5

* indirect imports, on-sold by Distrigaz to SOTEG

B29. Thus Belgium and West Germany will continue to be the main transit countries, with 11.3 mtoe and 16.2 mtoe respectively in transit to other Member States, plus (in the case of West Germany) gas destined for sale in Austria and Switzerland. Moves towards the use of direct marketing via common carriage would be likely to lead to an increased level of gas in transit, providing additional opportunities for profitable transportation business for the pipeline owners concerned. This would be the case, for example, with direct sales of Soviet gas to Belgium (increased transit through West Germany) or Algerian direct sales to West Germany.

Appendix C

U.S. Experience

U.S. Experience

C1.   In this Appendix, we set out briefly some evidence on the
quantitative impact of the shift towards open access transportation in the
United States from around 1984 onwards. As shown in Table C1 below, there
was a marked fall in average 'wholesale' gas prices (at the wellhead,
producer-pipeline delivery point, border or import terminal) over the
period 1984-87, in particular. This fall was also reflected in lower
prices for sales from pipelines to local distribution companies (LDCs) at
the City Gate. Moreover, the growing 'spot' market offered opportunities
for LDCs and large consumers to buy direct from producers at wellhead
prices well below the average cost of gas delivered to the major
inter-state pipelines.

Table C1:   Average US Wholesale Gas Prices, 1982-88
(in $/1,000 cubic feet)

Year	Wellhead	Producer*	Imports	City Gate
1982	2.46	2.72	5.03	n/a
1983	2.59	2.93	4.78	n/a
1984	2.66	2.91	4.08	3.95
1985	2.51	2.86	3.21	3.75
1986	1.94	2.39	2.44	3.22
1987	1.67	2.12	2.14	2.87
1988**	1.71	2.08	2.04	2.83

*   Average price of gas sales from producers to major inter-state
         pipelines
**   Year to September 1988

C2.   Among final consumers of natural gas, the major beneficiaries of the
decline in wholesale prices appear to have been industrial and power
station gas users. The pattern of average retail gas prices in the U.S.
over the period 1982-88 is shown in Table C2 below. This shows that
residential gas prices fell by around 9% between 1984 and 1987, while

commercial prices declined 14%, industrial prices by 26% and electric
utility prices by as much as 37%.

Table C2: Average U.S. Retail Gas Prices, 1982-88
(in $/1000 cubic feet)

Year	Residential	Commercial	Industrial	Electric Utilities	Average
1982	5.17	4.82	3.61	3.48	4.15
1983	6.06	5.59	3.94	3.58	4.64
1984	6.12	5.55	3.99	3.70	4.67
1985	6.12	5.50	3.73	3.55	4.54
1986	5.83	5.08	3.06	2.43	3.97
1987	5.56	4.76	2.94	2.32	4.06
1988*	5.90	4.57	2.90	2.32	3.89

*   Year to September 1988

C3.   An analysis of gas company trading margins over the same 1982-88
period (Table C3 below) shows that pipeline companies' margins on
merchanting activity were progressively squeezed between 1984 and 1987. On
the other hand, the margin between City Gate prices and the average price
of retail gas sales suggests that LDCs may not have passed the entire
benefit of lower wholesale prices on to their consumers.

Table C3: U.S. Gas Utilities' Average Margins, 1982-88
(in $/1000 cubic feet)

	1982	1983	1984	1985	1986	1987	1988*
Average Pipeline Purchase Price(1)	2.84	3.02	2.97	2.88	2.39	2.12	2.08
Pipeline Margin (2)	} 1.31	} 1.62	0.98	0.87	0.83	0.75	0.75
Retail Margin (3)			0.71	0.79	0.75	1.19	1.06

* first 9 months
(1)   assumes 95% U.S. gas, 5% imports

(2)   City Gate price minus average pipeline purchase price

(3)   Weighted average sales revenue minus City Gate price

C4.   There have been some suggestions, largely on the basis of U.S.
experience, that a common carriage system in Europe would unleash
gas-to-gas competition which would in turn reduce industrial gas prices
below those of the alternative fuels to which they are now linked.
Although certain U.S. consumers may have benefitted from competition
between gas producers in this way, there is little evidence that this has
generally been the case for U.S. industrial users as a whole. In Table C4
below, we compare U.S. gas and oil prices, as follows:-

(a)   average residential and commercial gas prices versus the price of No
2 fuel (gas oil), excluding taxes; and

(b)   average industrial and electric utility gas prices versus the price
of low sulphur residual fuel oil, also net of tax.

Table C4: Relative U.S. Oil and Gas Prices, 1982-87
(in $/mmBtu)

	Natural Gas		Oil Products*		Relative Price***	
Year	R/C	I/P	No 2 Fuel	Resid**	R/C	I/P
1982	4.88	4.01	5.41	4.17	90	96
1983	5.75	4.39	5.48	3.88	105	113
1984	5.79	4.35	5.48	4.02	106	108
1985	5.77	4.10	5.07	3.59	114	114
1986	5.43	3.34	3.35	2.08	162	161
1987	5.17	2.91	3.47	2.47	149	118

*   refiner sales prices to end users, excluding taxes

**   less than 1% sulphur

*** gas as % of oil

This comparison shows that small user gas prices fell much more slowly than
gas oil prices over 1984-87. Industrial and electric utility gas prices
fell somewhat more slowly than residual oil prices over the period as a
whole, and dramatically less so in 1986 when resid fell to below 60% of its
price in 1985. In spite of open access transportation, therefore, there is

little to suggest that competition led to gas prices falling faster than those of alternative oil fuels.

Appendix D

Terms of Reference

COMMISSION
OF THE EUROPEAN
COMMUNITIES

Brussels,
XVII-C-3
LB/ab

24.02.89/XVII/ 02500

DIRECTORATE-GENERAL FOR ENERGY

OIL AND NATURAL GAS DIRECTORATE

Subject: Follow-up study to C & L report on natural gas common
            carriage

Dear Mr Goskirk,

We take this opportunity to thank you for the excellent study that
C & L Belmont carried out on "The advantages and drawbacks for the
European Community of the introduction of a system of common carrier
for the transport of natural gas".

This study will be of considerable help in the framework of our current
work on the internal market for energy and gas in particular.

We think it necessary to complete your study with some elements of
quantification that we did not include, so far, in the terms of
reference of the abovementioned study.

The quantitative assessment we need concerns the following results from
the possible introduction of a common carriage system for gas:

. . .

Mr W.I.M. Goskirk
Director, Oil & Gas
Coopers & Lybrand
Plumtree Court
GB - LONDON EC4A 4HT

(i)   possible reduction in the border price of gas imported into
        the Community,

(ii)   possible increased efficiency in transmission and distri-
        bution operations;

(iii)   possible redistribution of income between gas companies and
        consumers, or between different classes of consumers;

(iv)   indication of macro-economic benefit of possible reduced
        industrial gas prices.

These elements would form part of our global evaluation of the desir-
ability of introducing at Community level a system of common carriage
for gas.

We would need to have the results of this economic evaluation by end
April 1989.

For that purpose, we would provide you with all relevant documents that
exist in the Commission and that would be of help to you.

Can you please inform us whether you accept to carry out this assess-
ment along the lines of this letter and at which price, in Ecus. We
would also appreciate an indication of the man/weeks involved.

                                        Yours sincerely,

                                        R. De Bauw