WESTERN EUROPE NATURAL GAS TRADE

FINAL REPORT

International Natural Gas Trade Project
Center for Energy Policy Research
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Massachusetts Institute of Technology

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CONTENTS

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Preface

This report on Natural Gas Trade in Western Europe is the final of three units produced by the M.I.T. Center for Energy Policy Research on the subject of the international prospects for natural gas trade. The first unit on Canadian-U.S. trade was published in July 1985 (MIT-EL 85-013). The second unit on East Asia/Pacific trade was published in March 1986 (MIT-EL 86-005).

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EXECUTIVE SUMMARY

THE GENESIS OF THE REPORT

During two past two years, a group of researchers at the MIT Center for Energy Policy Research has been conducting a study of the medium term prospects for international trade in natural gas in various regions of the world. This report, focussing on Western Europe, is the third and final region study for this research project, the first two having covered trade between the U.S. and Canada and LNG trade in the Eastern Pacific. All three studies have shared a common focus and utilized a similar methodology.

Specifically, each study has explored the cost side of natural gas production and exporting, separating "real" or economic costs from taxation which is treated as a transfer payment, and differentiating between different cost reserves in various regions and countries. The common question which was asked was how rapidly would costs rise at different levels of demand growth over a 20-30 year period. On the demand side, a range of plausible future levels was derived by looking at prospects for gas capturing a greater share within specific using sectors of the different countries, considering whether or not new gas utilization technologies would play an important role in expanding gas demand, and integrating the effects of high or low oil price scenarios on total energy demand and natural gas's competitiveness. Long term contracts for the advance purchase of natural gas and LNG are an important component of producer-consumer relations and play a significant role in determining the pattern of international trade in gas. For this reason, each study has included research on contracting issues, including some modelling of how contracts might be improved to bring about greater efficiency. Finally, dynamic trade models were developed in each regional study to integrate the separate components dealing with supply costs and demand levels. The models were used to test for data consistency, to help calculate long run marginal costs, to determine the relative costs of alternative trading patterns, and to measure the economic costs of different policy distortions. At all stages, careful attention was paid to the role government polices--pricing, quantitative restrictions, bargaining--have played and what effects these have had on efficiency.

This study of the prospects for natural gas trade in Western Europe has followed this pattern, and this report has chapters dealing with each of the above elements. The purpose of this introductory chapter is to provide a brief summary and explanations of the main conclusions. In addition, short summaries are included of the separate chapters of the report.

BACKGROUND

Five years ago, the Western European energy market appeared on the verge of a second natural gas revolution. The second oil price shock, coupled with concern about security of energy supplies, appeared to provide new opportunities for market penetration by gas, while at the same time new supplies were becoming available, especially from Algeria, Norway, and the Soviet Union. All indications were that natural gas consumption would grow rapidly, mainly at the expense of oil's market share. Because of optimistic expectations about future demand and pessimistic expectations about future domestic supply and world oil prices, consumers signed import contracts for large quantities of additional natural gas, agreed to contracts with rigid take-or-pay clauses and rather high built-in prices. Producers, extrapolating long-term market trends from short-term market conditions, insisted on such contracts as a means for insuring maximization of their rents.

Instead, as world oil prices began to fall and the Western European economies continued to show weak growth, events unfolded very differently to what had been expected. The apparent cost advantages of natural gas largely evaporated. Natural gas demand stagnated, resulting in excess supply in the short run. The importers found themselves burdened with supplies that were clearly overpriced and saddled with inflexible contracts that did not allow for any adjustments to reflect the new environment. Slowly, and painfully, exporters have had to recognize that natural gas was neither as scarce nor as valuable as they had believed. The result has been that many contracts had to be adjusted or rewritten. Relations between consumers and producers became increasingly antagonistic, and until the signing of the Troll contract this spring, it appeared that no major new natural gas supplies would be developed, at least during the remainder of the 1980s.

Certainly, externalities have played a major role in the failure of the gas market to perform as expected, including the drop in oil prices (and their failure to continue rising) as well as the sluggishness of Western European economic growth. However, it has been a contention of this study that past analyses of natural gas markets relied excessively on assumptions and paid too little attention to the attendant consequences should those assumptions not prove out.

PRINCIPAL CONCLUSIONS

The main findings of this study can be briefly summarized in the following propositions:

-- Natural gas is likely to remain an under-exploited fuel from the strict perspective of economic efficiency

-- Natural gas consumption is likely to grow rather slowly, in the range of 1.5% to 2.5% annually, through the year 2010.

-- Low oil prices would reduce the potential for market share gains by natural gas, while high oil prices would hinder economic activity and demand for energy in general even if gas became more competitive with oil.

-- New utilization technologies will not have a major impact on demand without significant changes in prices and policies.

-- At these projected consumption levels, the long run marginal costs of producing and exporting natural gas to Western Europe will rise very little, and be in the range of $1.00 to $1.50 per thousand cubic foot.

-- Existing capacity can be operated economically even at extremely low oil prices (e.g. $7-$10 per barrel) and gas supplies can still be expanded at low oil prices (e.g., $10-$15 per barrel).

-- Little, if any, new large-diameter pipeline capacity will be required through 2000, beyond the Troll project.

-- Lower oil prices and slow energy demand growth will contribute to some reduction in government interference and policy obstacles to gas use, but not to a degree necessary to create fully competitive markets.

-- The relative importance of spot sales is likely to increase due to the current surplus and the ability of some producers to add small increments to supply without undertaking major investments.

-- Any large new natural gas export projects will require long-term contracts, although these (like Troll) are likely have greater flexibility than those signed in the early 1980s.

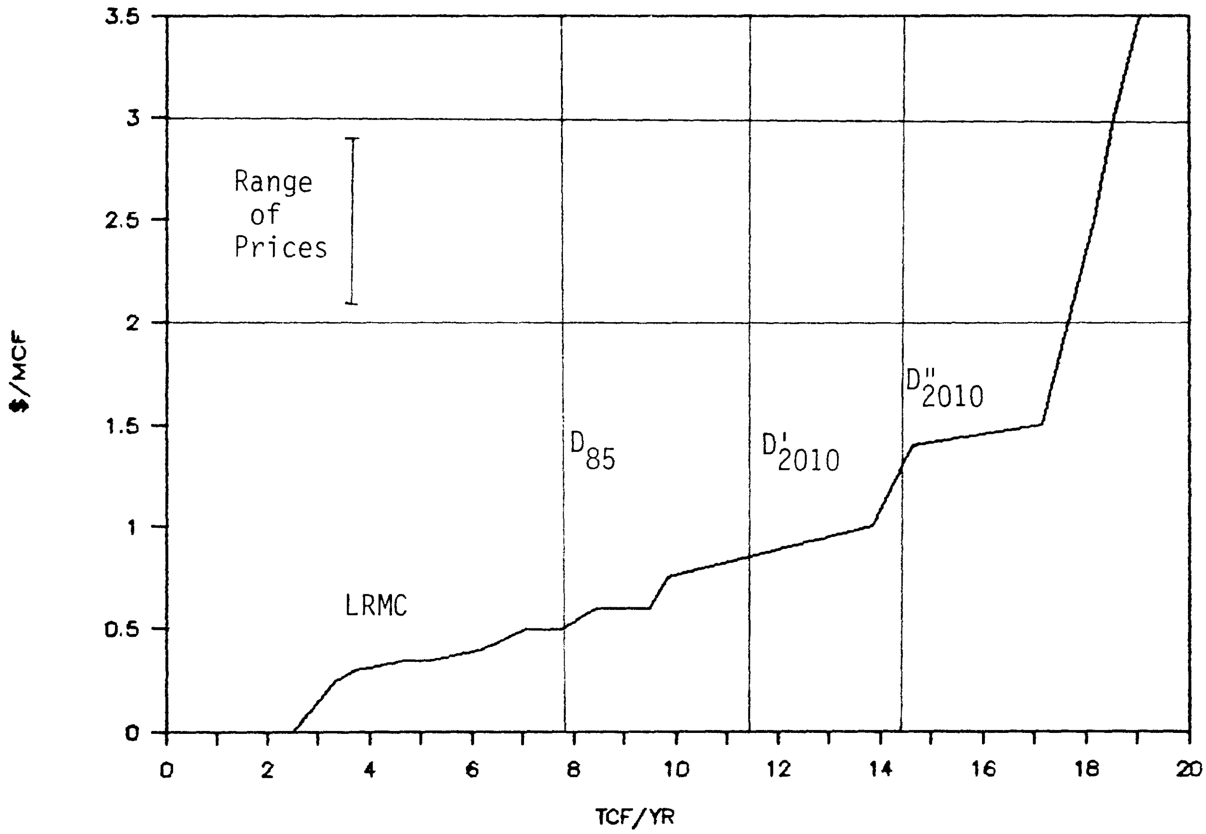
Of course these rather pessimistic conclusions would be altered either by greater movement by consuming or importing countries to encourage more competitive natural gas pricing more in line with long run marginal costs, increased emphasis on pollution control which would see a move to increase gas use in boilers, especially at the expense of coal, or a stronger desire on the part of consumers to increase the use of natural gas for security reasons.

The analytical underpinning of some of these conclusions can be easily explained using Figure 1 as simple illustration. The estimated long run marginal cost curve of supplies to Western Europe (aggregated over all suppliers) is shown as a continuous line beginning at a very low level, rising slowly and then reaching a level of $3.50 per thousand cubic feet when supply reaches about 19 TCF per year. The "flatness" of the curve at intermediate demand levels comes in part from plentiful low cost reserves and in part from excess capacity in the present (and committed) pipeline network. The sharp rise in the right-hand portion reflect both new pipeline costs and more costly reserves.

The horizontal symbols are meant to bracket the estimated range of future gas prices. The floor of $2.00 per thousand cubic feet corresponds to oil prices at $11.60 per barrel if gas and oil were priced equally in terms of heat content and a oil price of $17.40 per barrel if the gas-to-oil price ratio were at the historical average of about two-thirds. The corresponding oil prices for the ceiling of $3.00 per thousand cubic feet are $17.40 and $26.10 per barrel.

The vertical lines represent consumption levels. The left-most level corresponds to current natural gas use in Western Europe, while the two vertical lines on the right bracket the range of demand which the study concluded is likely by about 2010. These illustrate the two major conclusions regarding demand projections: (1) that the growth rate

FIGURE 1



LRMC = Long Range Marginal Cost Supply Curve
D_{85} = Demand in 1985
D'_{2010} = Low end demand estimate for 2010
D''_{2010} = High end demand estimate for 2010

of consumption will be low, and (2) that the range between faster and slower gas consumption growth likely will be narrow. The upper bound on gas consumption is meant to correspond with the lower price for gas and the lower level of consumption with the higher price level for gas.

Putting these pieces together, Figure 1 implies that at likely demand levels in the future, gas prices will remain significantly above long run marginal costs. This is what is meant by the conclusion that the market will remain inefficient and natural gas under-exploited in Western Europe. Another way of saying this is that there are likely to be further opportunities for some combination of higher demand and lower prices.

Figure 1 is, of course, an oversimplification in the sense that dynamic factors such as reserve depletion effects and the importance of existing contracts are neglected in the long run marginal cost curve. These and other complications which cannot be included readily in a two-dimensional graph are accounted for in the dynamic model of Western European gas trade.

IMPLICATIONS FOR THE FUTURE OF GAS CONTRACTING

The project analyzed contracting practices with special emphasis upon the changing pressures and motivations for traditional and new forms of gas contracting. Results on the two key aspects of contracting practices, price and quantity provisions, are summarized here.

Table 1 presents a concise summary of key changes in the Western European natural gas market and the associated changes in contracting practices that have occurred over the past 15-20 years.

As displayed column 4 of Table 1, pricing practices have undergone rather dramatic changes over the past history. Pricing practices in long term contracts had been quite rigid prior to the 1970's and the initial oil price increase. During the 1970's new contracts and some renegotiation of old contracts established the practice of indexing the price for contracted gas deliveries to the price of oil. This practice continued and spread. In recent years the development has been in the direction of more sophisticated formulas, but with the impact being a greater degree of flexibility in the price and continued attempts to write contract price clauses which make the price terms of the agreed upon sale more responsive to market conditions for gas and competitive fuels.

As described more fully in the chapter covering the analysis of contracts, there is an inherent contradiction between the use of long-term contracts and the need for price terms which reflect the current market alternatives. The objective of a contract is to establish clearly ahead of time the intention to purchase gas and some certainty as to the profitability of the sale to the producer. This inevitably requires establishing some set of price terms and it is impossible to foresee all of the future developments which might arise and to write a set of price provisions which will correspond to the anticipated future market conditions. In the past, when oil prices were relatively stable, the cost of rigidity in the price formula was relatively low. The price of oil was unlikely to deviate far enough and fast enough to make the unilateral cancellation of a contract by one party a viable alternative to fulfillment of the agreed upon obligation.

Table 1

Evolution of Western European Natural Gas Market

Period	Buyers	Producers	Price	Quantity	Risk Allocation
Pre-'70s	Small, Growing; Gas is essentially a specialty fuel	Few; Emergence of The Netherlands is most important development	Fixed	Relatively low minimum takes	Sellers take development cost risk
1970s	Growing; adding industrial and electrical customers	Growing; adding Norway, U.K., Soviet Union, Algeria with significant production	Indexed to oil	High minimum takes	Buyers
1980s	Level	Increasing	More complex indexing	Range of takes required	Buyers typically; sellers in rare cases, Netherlands
Prospects	Level	Level	More flexible to reflect market realities	Continued variability in takes: field by field	Field dependent: buyers typically, sellers for competitive advantage when feasible

Subsequently, however, a long-term fixed price came to be viewed as too rigid. Parties to a long-term agreement with a fixed or very inflexible set of price terms would very likely discover in some period of time that one party or the other had an incentive to demand a renegotiation under threat of unilateral abrogation. Extreme variability in the markets and price terms for competing fuels forced flexibility upon the price terms for the long-term contracted gas market. This flexibility is noted in the table as the key characteristic of pricing terms in the 1980's.

The increased sophistication of price indexes in gas contracts is an extension of this process.

This trend to increased flexibility in price indexes in long-term contracts will undoubtedly continue. It is a response to the increased flexibility of the markets on which gas competes, and the increased flexibility in these markets is likely to persist for the foreseeable future. While, the particular form of widely used indexes will perhaps be developed further, the basic principle of a relationship between gas and oil and of increased flexibility in the contracted gas price will remain.

Historical developments in the quantity provisions of long-term contracts do not lead us to similar conclusions regarding future developments. These developments are summarized in column 5 of Table 1. While early gas contracts in western Europe were not characterized by high take provisions, this was largely due to the fact that the inexpensive Netherlands supply dominated the market. As capital intensive fields with large liquifaction or pipeline expenses became a large factor in the supply during the 1970's, high takes also came to characterize the market as we note in the table. Recent years, however, have seen a large amount of renegotiation and therefore de facto flexibility in quantity provision as well as reports of new contracts with a larger degree of flexibility in the takes--Troll for example. There is a widespread belief that the current time is characterized by greater flexibility in quantity terms. We note in the table, however, that this increased flexibility is not a general feature, but associated with particular fields or with marginal quantities from developed fields.

It is tempting to conclude from the trend towards greater flexibility in the take provisions of gas contracts that the old-style, high take, low flexibility contracts are a creature of the past, and that a producer seeking to sell their gas in today's or tomorrow's market must forgo the security of rigid long-term contracts. The analysis of contracts presented in the accompanying study provides one with an understanding of why such a prognosis would be unfounded. A prediction of unending flexibility in gas contract quantity provisions would be a blind extrapolation of history, baseless in its understanding for the past historical developments, and confused regarding the underlying purpose which rigid quantity provisions serve.

Long-term contracts in gas are designed to provide the producer with sufficient certainty of the intentions of the buyer to warrant the large dedicated capital expenditures necessary to deliver the quantities of gas needed by the buyer. The importance of this depends critically upon the nature of the field being developed and the structure market to which the gas is to be delivered. If the capital expenditures necessary for developing the field and the associated delivery system are relatively small, then the long-term contract is not as critical as when the capital expenditures are large. In terms of the European market this is the obvious reason why the Dutch Groningen fields are sold on a flexible basis while Soviet gas has typically been sold under relatively stiff quantity terms. When the delivery system is already extensive and there exist a large number of buyers, then the long-term contract is not as critical as when the delivery system is dedicated to a single market. In terms of the North American market this is a principle variable affecting the degree of flexibility which is possible in the contracting of Albertan gas to the Midwest and Western US markets in contrast with the relatively inflexible terms that must be negotiated to bring on line the production from the Venture field to the East Coast market.

Unlike the historical developments in price indexes, the increased flexibility in the quantity terms of gas contracts have not been a response to a permanent change in the gas or competing fuels markets. The increased flexibility in observed quantity provisions for gas in the European market have been driven primarily by a change in the composition of those fields supplying gas to the market and the associated change in the optimal contract structure. What is important to keep in mind is that the flexibility that any given producer should find acceptable depends not upon the general trend of the market, but rather the nature of the field which that producer is developing and the range of alternative buyers to which the gas can be sold once the capacity is installed. A producer like the Soviet Union can accept flexible quantity provisions only under penalty of accepting the significant risk of being subject to opportunistic bargaining in the future in which the actual price of gas delivered above and beyond the bare minimum take occurs at extremely unfavorable prices. The mere fact that there exist competing producers willing to offer flexible quantity terms does not eliminate this risk nor change the calculated advantages of long-term contracts. Of course, it may imply that the Soviet Union will face difficulty finding a buyer willing to accept the inflexible provisions, but this would then be a signal that Soviet gas is "expensive."

Our prognosis therefore for future developments in quantity provisions of contracts is flexibility for particular fields, but continued reliance upon high take requirements for other fields. The material in the contracts section of the report makes clear how this differentiation will develop across the potential suppliers.

ANALYSIS OF WESTERN EUROPEAN GAS TRADE

A dynamic linear programming model was constructed in order to integrate the supply and demand components of this study. The model was used to check the feasibility and consistency over time of the various demand forecasts and supply constraints developed elsewhere in this study, and where necessary revise any inconsistencies or identify potential bottlenecks. The supply constraints include reserve levels, installed pipeline capacities linking various countries, and minimum or maximum export/import flows associated with either contracts or exogenous policies.

Given these inputs, the model calculates least-cost production and trade patterns to meet alternative projected gas demand levels in the different countries of Western Europe. This provides a method for estimating the opportunity cost of following a trade pattern which might be sub-optimal from the point of view of real costs of production and transportation. By varying the demand growth rates, the model can calculate the opportunity cost associated with increasing deliveries to particular countries.

Numerous model runs were conducted to perform a variety of sensitivity tests of specific scenarios. Among the variables used in developing a specific scenario are: the time pattern of gas demand growth by individual countries; country-specific gas reserve levels and production costs; different pipeline capacity availabilities and additions; minimum delivery requirements under existing and foreseen contracts, and various policy constraints that can be imposed by specific importing or exporting countries. By having the model calculate the least-cost solution for each scenario, it is possible to estimate optimal build-up and depletion profiles, export patterns, and the real costs (in terms of production and transportation costs) of policies such as supply diversification strategies.

In Tables 2 to 4, some results of the model runs are presented. Perhaps most striking are the calculations of the opportunity cost of producing and delivering additional quantities of gas to the consuming countries. Although there are minor differences between the importing countries, related mainly to transportation cost differentials, the model estimates that the marginal costs remain below $1 per Mcf for the next twenty years (1986-2000). This holds for all demand levels that were considered to be even remotely likely and whether minimum contract takes are imposed or not and reflects the availability of large amounts of low-cost supplies.

Table 2

Summary Results: Case 1

Demand Scenario --medium
Export Constraints--none
New Pipelines --none

Discounted Cost ($ bils.) = 13.88

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	3.6	4.2	5.1	6.1	7.3
Belgium from Algeria	1.5	0.0	0.0	0.0	0.0	0.0
Belgium from Netherlands	5.8	12.1	14.5	17.0	11.3	6.7
Belgium from Norway	1.7	0.0	0.0	0.0	8.6	16.6
France from Algeria	9.0	0.0	15.0	22.4	31.0	31.0
France from Netherlands	7.3	33.6	26.5	27.3	0.0	0.0
France from Norway	2.3	0.0	0.0	0.0	0.0	0.0
France from USSR	4.9	0.0	0.0	0.0	28.4	39.6
Netherlands from Norway	2.8	0.0	0.0	0.0	0.0	0.0
Italy from Algeria	6.7	0.0	18.0	18.0	18.0	18.0
Italy from Netherlands	5.2	27.4	14.4	19.7	17.8	27.7
Italy from USSR	8.2	0.0	0.0	0.0	8.9	7.7
United Kingdom from Norway	12.1	0.0	11.9	20.0	0.0	16.7
W. Germany from Netherlands	15.0	45.1	51.1	0.0	0.0	0.0
W. Germany from Norway	7.0	0.0	0.0	2.9	22.9	49.3
W. Germany from USSR	13.5	0.0	1.9	60.1	52.6	41.4
Total Gas Trade Flow	105.8	121.7	157.6	192.4	205.6	262.0
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.45	0.49	0.76	1.11
Belgium from Algeria		NA	NA	NA	NA	NA
Belgium from Netherlands		0.15	0.42	0.46	0.75	1.10
Belgium from Norway		NA	NA	NA	0.75	1.10
France from Algeria		NA	0.44	0.48	0.76	1.12
France from Netherlands		0.17	0.44	0.48	NA	NA
France from Norway		NA	NA	NA	NA	NA
France from USSR		NA	NA	NA	0.76	1.12
Netherlands from Norway		NA	NA	NA	NA	NA
Italy from Algeria		NA	0.48	0.52	0.81	1.16
Italy from Netherlands		0.21	0.48	0.52	0.81	1.16
Italy from USSR		NA	NA	NA	0.81	1.16
United Kingdom from Norway		NA	0.33	0.36	NA	0.71
W. Germany from Netherlands		0.14	0.40	NA	NA	NA
W. Germany from Norway		NA	NA	0.44	0.71	1.07
W. Germany from USSR		NA	0.40	0.44	0.71	1.07

Table 3

Summary Results: Case 2

Demand Scenario --medium
Export Constraints--minimum contracts imposed
New Pipelines --none

Discounted Cost ($ bils.) = 17.71

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	3.6	4.2	5.1	6.1	7.3
Belgium from Algeria	1.5	1.5	1.5	1.5	0.0	0.0
Belgium from Netherlands	5.8	7.6	8.9	12.9	18.3	8.3
Belgium from Norway	1.7	3.0	4.1	2.6	1.6	15.1
France from Algeria	9.0	6.7	5.8	4.0	24.5	31.0
France from Netherlands	7.3	13.9	20.8	29.9	13.5	0.0
France from Norway	2.3	3.4	6.7	7.8	6.4	6.4
France from USSR	4.9	9.6	8.3	8.0	15.0	33.2
Netherlands from Norway	2.8	3.0	4.1	2.6	1.6	1.6
Italy from Algeria	6.7	7.8	9.6	18.0	18.0	18.0
Italy from Netherlands	5.2	9.7	16.4	13.3	20.3	27.7
Italy from USSR	8.2	9.8	6.4	6.4	6.4	7.7
United Kingdom from Norway	12.1	7.6	7.6	0.0	0.0	20.0
W. Germany from Netherlands	15.0	21.6	31.1	45.6	12.9	0.0
W. Germany from Norway	7.0	8.5	13.5	9.0	10.8	42.9
W. Germany from USSR	13.5	14.9	8.4	8.4	51.9	47.8
Total Gas Trade Flow	105.8	132.3	157.3	175.0	207.2	267.0
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.45	0.45	0.64	1.11
Belgium from Algeria		0.32	0.32	0.32	NA	NA
Belgium from Netherlands		0.10	0.15	0.27	0.62	1.10
Belgium from Norway		0.46	1.10	0.52	0.62	1.10
France from Algeria		0.30	0.30	0.30	0.64	1.12
France from Netherlands		0.12	0.17	0.29	0.64	NA
France from Norway		0.48	1.12	0.54	0.64	1.12
France from USSR		0.45	0.45	0.45	0.64	1.12
Netherlands from Norway		0.43	1.08	0.49	0.60	1.08
Italy from Algeria		0.30	0.30	0.33	0.68	1.16
Italy from Netherlands		0.16	0.21	0.33	0.68	1.16
Italy from USSR		0.50	0.50	0.50	0.69	1.16
United Kingdom from Norway		0.33	0.98	NA	NA	0.74
W. Germany from Netherlands		0.08	0.13	0.26	0.60	NA
W. Germany from Norway		0.42	1.07	0.48	0.59	1.07
W. Germany from USSR		0.40	0.40	0.40	0.59	1.07

Table 4

Summary Results: Case 3

Demand Scenario --"super"
Export Constraints--none
New Pipelines --1996: Algeria-Italy +12 Bcm
2002: Norway-UK +20 Bcm, USSR-W. Germany +40 Bcm
2005: Algeria-Italy +18 Bcm, USSR-Austria +20 Bcm
2008: Norway-UK +20 Bcm
2011: USSR-Austria +30 Bcm, USSR-W. Germany +40 Bcm
2014: Norway-W. Germany +30 Bcm, Algeria-Italy +18 Bcm
2017: USSR-W. Germany +40 Bcm

Discounted Cost ($ bils.) = 26.39

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	4.8	6.3	8.2	10.7	13.8
Belgium from Algeria	1.5	0.0	0.0	0.0	0.0	0.0
Belgium from Netherlands	5.8	15.0	19.7	24.8	31.6	40.0
Belgium from Norway	1.7	0.0	0.0	0.0	0.0	0.0
France from Algeria	9.0	12.0	15.0	31.0	31.0	31.0
France from Netherlands	7.3	31.3	43.5	8.8	11.4	17.7
France from Norway	2.3	0.0	0.0	0.0	0.0	0.0
France from USSR	4.9	0.0	0.0	35.5	55.3	76.5
Netherlands from Norway	2.8	0.0	0.0	0.0	0.0	0.0
Italy from Algeria	6.7	18.0	30.0	30.0	30.0	66.0
Italy from Netherlands	5.2	18.3	18.7	25.5	26.4	0.0
Italy from USSR	8.2	0.0	0.0	6.9	24.3	38.2
United Kingdom from Norway	12.1	0.8	20.0	22.6	58.1	35.1
W. Germany from Netherlands	15.0	59.4	18.6	0.0	0.0	0.0
W. Germany from Norway	7.0	0.0	1.0	15.5	66.0	86.0
W. Germany from USSR	13.5	0.0	58.8	85.5	65.7	84.5
Total Gas Trade Flow	105.8	159.6	231.6	294.3	410.6	488.9
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.55	0.95	2.18	0.45
Belgium from Algeria		NA	NA	NA	NA	NA
Belgium from Netherlands		0.28	0.51	0.94	2.17	3.24
Belgium from Norway		NA	NA	NA	NA	NA
France from Algeria		0.30	0.53	0.96	2.19	3.26
France from Netherlands		0.30	0.53	0.96	2.19	3.26
France from Norway		NA	NA	NA	NA	NA
France from USSR		NA	NA	0.96	2.19	3.26
Netherlands from Norway		NA	NA	NA	NA	NA
Italy from Algeria		0.34	0.57	1.00	2.23	0.50
Italy from Netherlands		0.34	0.57	1.00	2.23	NA
Italy from USSR		NA	NA	1.00	2.23	0.50
United Kingdom from Norway		0.36	0.41	0.82	1.03	1.14
W. Germany from Netherlands		0.27	0.50	NA	NA	NA
W. Germany from Norway		NA	0.50	0.91	2.14	3.21
W. Germany from USSR		NA	0.50	0.91	2.14	3.21

The more crucial factor in calculating marginal costs are pipeline constraints. So long as import demand levels fall within the capacity of the existing network, the marginal costs of expanding deliveries are low. Because the demand scenarios imply that, at best, demand will grow only modestly, the model is able to operate in most scenarios within present capacity and in future capacity expansions for which commitments have already been made. Again, note that the marginal costs calculated by the model ignore all taxes, royalties, rents, and other transfer payments. By inference, however, we conclude that the bulk of the present prices importers are paying for gas are for rents and taxes rather than merely to cover opportunity costs.

Another interesting result is that, unless demand growth accelerates substantially, there are significant additional costs incurred by adhering to the minimum takes in existing contracts. (Compare Tables 2 and 3.) For the medium-demand scenario, the present value of the additional opportunity costs are estimated to be $3.8 billion, a 28 percent increase over the least-cost production and trade scenario. Of course, compared to the unit prices importers are paying at present, the increase may not seem substantial, and could be considered the cost of diversification. However, it does indicate that significant bargaining room exists both among exporters and between exporters and importers. Indeed, the change in the total discounted cost of moving from the contract-constrained to the unconstrained cases is greater than the additional cost of moving from the low demand to the high demand scenarios.

SUPPLY AND PRODUCTION COSTS

The past decade has seen most market actors confuse high-priced gas with high-cost gas, with producers taking advantage of the sellers' market to maximize markup rather than market share. However, this should not be allowed to obscure the fact that most natural gas supplies now available cost very little to produce and transport. The result has been a surplus of supplies and competition between sources, which drove gas prices down even before the recent drop in oil prices.

In the Supply Chapter, we employ publicly available information to analyze natural gas development and production costs for major fields in Algeria, the Netherlands, Norway, the United Kingdom, and the USSR. Figure 1 includes the aggregate marginal cost curve derived from our analysis. This curve should be considered conservative, inasmuch as it concentrates on the larger increments to supply, e.g., Groningen, Troll, Algeria, and the Soviet Union, with supply from small domestic fields limited to the United Kingdom and the Netherlands. Inclusion of domestic natural gas in France, West Germany, and Italy would extend the curve further. Even allowing for this conservative interpretation, it is clear that potential supply of natural gas to Western Europe is far in excess of current demand at current, or likely, prices.

In North America, lower prices should result in an end to the gas surplus, but in Western Europe, the situation is not so clear-cut. In the first place, taxes and royalties, as well as other forms of rent, have been much higher in Western Europe, and can be reduced to allow sales to continue. In fact, the need for revenue should encourage some producers to seek higher sales volumes to offset lower prices. The price break has certainly undermined the belief future prices can only increase such that withholding supplies will inevitably be profitable.

While low oil prices will reduce drilling to some degree, and therefore discoveries of natural gas, the reduction in demand for drilling, offshore construction, and similar investments should act to create short-term surpluses in the oil service, drilling and construction industries, keeping costs down and improving the economics of many projects. However, lower prices should not curtail natural gas availability in Western Europe because current supplies are so abundant that new discoveries are unneeded until well into the next century.

Costs are low enough, in fact, that producers have the capability to expand their sales in the low-margin markets, including spot sales and the smaller, immature markets, such as Spain. This is seen especially in the Norwegians' attempt to market Troll gas in the smaller markets.

DEMAND PROSPECTS

In the Demand Chapter, we first analyze the historical development of natural gas markets, especially in France, Italy, the United Kingdom, and West Germany. This analysis is then combined with a review of recent Western European economic growth forecasts to specify three possible scenarios of Western European natural gas demand. A simple economic model of the relation between fuel use, and relative oil and natural gas prices and economic growth is used to generate these natural gas demand scenarios which are used as input to the Western European natural gas trade analysis discussed above.

Natural gas demand is influenced by several factors, most importantly:

-- Its price relative to those of close substitutes, especially oil products but also coal and electricity;

-- The level of economic growth, and its composition (e.g., growth in heavy industry relative to services and light industry);

-- Expectations about both future prices and reliability of supplies;

-- Technology developments affecting the delivered service cost of natural gas and closely competing fuels;

-- Government policies, especially fuel choice and environmental policies.

The most important differences in assumptions underlying the three Western European natural gas demand scenarios relate to (i) natural gas prices relative to prices of closely competing oil products, and (ii) the effect of overall energy prices -- in particular, oil prices -- on economic growth. Regarding oil price expectations, we postulate three possibilities for future oil prices (constant 1986 Dollars) including,

-- Re-emergence of a strong oil producer's cartel, resulting in oil prices returning to the $26-30 range in the near future, and continuing into the next century;

-- Emergence of a competitive world oil market, resulting in oil prices in the $7-9 range; and,

-- A relatively weak oil producer cartel, resulting in considerable volatility in oil prices in the $10-20 range.

Economic growth rates and future natural gas demand depend upon these oil prices scenarios in the following way. High oil prices permit increased scope for natural gas to increase market share. However, higher overall energy prices will retard economic growth, and especially growth of energy intensive industries and activities. The effects of slower growth on natural gas demand will depend importantly on gas pricing policy relative to oil. Low oil prices would have the opposite effect in that economic growth rates are stimulated; but now natural gas must compete against cheap oil. Finally, volatile oil prices will likely have a neutral effect upon economic growth, but will increase the premium for investing in flexible, fuel-switching capability -- especially for industries where energy accounts for a significant share of total costs. Investments in such flexible fuel systems will depend importantly on natural gas pricing policy; for example, natural gas prices that are rigidly locked to oil prices will reduce the flexibility premium, and limit the possibility for natural gas demand to benefit from volatile oil prices.

We employ a simple economic model to analyze the combined effects of alternative oil prices, economic growth, and efficiency of natural gas technologies, on future Western European natural gas demand. The results are presented in Table 5. Most importantly, the analysis indicates that future Western European natural gas demand to fall within a fairly narrow range. Overall for the three oil price scenarios outlined above, the average growth rate for gas demand in the period through 2010 ranges from 1.88% to 2.05% per year; adjusting further for various contingencies suggests the plausible range is perhaps 1.5% to 2.5% per year, still a very narrow range.

These small difference are due primarily to the off-setting effects between oil prices, economic growth, and interfuel substitution possibilities for natural gas. While high oil prices provide opportunity for natural gas substitution, they reduce overall economic growth, especially in the energy-intensive industries, thereby reducing overall growth in energy demand. Conversely, low oil prices have a

Table 5

Natural Gas Consumption and Average Annual Growth Rates

Countries	1984 consumption (Bcm)	Demand Scenarios low	medium	high	"super"
France	29.50	2.94%	3.19%	3.43%	5.00%
West Germany	50.20	2.33%	2.52%	2.70%	4.41%
Italy	33.20	2.21%	2.35%	2.49%	4.25%
United Kingdom	47.50	0.87%	0.53%	0.18%	3.28%
Netherlands	38.60	0.50%	0.45%	0.40%	1.00%
Belgium	9.00	2.94%	3.19%	3.43%	5.00%
Austria	4.10	2.33%	2.52%	2.70%	4.41%
Norway	3.70	1.20%	1.00%	0.80%	3.00%
Total/Average	215.80	1.88%	1.96%	2.05%	3.85%

positive impact on economic growth, but reduce opportunities for natural gas substitution for oil.

Table 5 also includes a much higher set of exogenously specified growth estimates ("super"); these estimates are not related to any particular oil price or economic growth scenario, but, as discussed above, are used only to explore possible Western European natural gas trade patterns under very extreme demand growth conditions.

Our analysis of the three oil price scenarios reflects the assumption that government policy changes will have a small overall positive impact on natural gas demand. We expect only slow, and small, changes in the protection of market share for coal and nuclear in the generation of electricity; however, the abundance of natural gas supplies, and the likely aggressive pricing policies of natural gas producers, should encourage penetration in, for example, boiler fuel markets.

Government environmental policies might have some effect on future natural gas demand since low pollutant characteristics are an important attribute of natural gas. Although the value of this quality is impossible to quantify, the growing concern worldwide with environmental, health, and safety (specifically acid rain, chemically-induced mutagenity, radiation, and CO_2 and SO_2 emissions) could conceivably stimulate demand for natural gas well beyond present levels. This socially-driven, potential impact on demand is noted, but it is very difficult to project any significant effect with current information.

NEW TECHNOLOGIES

As noted above, technology developments are potentially important in analyzing future natural gas demands. We have continued the analysis of natural gas related technologies begun in our previous two studies and found that there are still economic possibilities of increasing efficiency of natural gas use for all three of the oil price scenarios considered in this study. These gains have not yet reached their upper limit, and should continue, in combination with the lower gas prices that have accompanied the fall in oil prices, to augment natural gas's competitive position against other energy sources.

Specific technology developments in the major consuming sectors--industry, residential and commercial, electric power generation, and transportation--are also examined with an eye to determining the potential scope of their commercial application in the future. The major technologies assessed are: industrial cogeneration; heat pump and air conditioning systems in residential and commercial applications; gas turbine and steam turbine cycles and methane gas via fuel cells in electric generation; and, in the transportation sector, compressed natural gas- and liquid methanol-fueled vehicles, methanol-derived gasoline, and methane derived middle distillate fuel.

Of these technologies, only methane-gas turbine, combined-cycle systems provide a potentially excellent opportunity for increased natural gas demand in electric power applications. In the residential and commercial sectors, no outstanding technology development is evident on the horizon that would affect demand, although cogeneration systems in commercial applications may present opportunities in the future. There is some evidence that utilities will help stimulate this potential market. In the transportation sector, potential demand gains are hampered by the vast alterations in vehicle engines and the development of a dedicated delivery system needed before liquified petroleum gas, compressed methane, or methanol could make any inroads into gasoline and diesel markets.

A FINAL FOOTNOTE: THE TROLL PROJECT

The development of a set of contracts that will apparently allow the Troll project to move forward was quite fortuitous for this project, inasmuch as it validates many of the conclusions reached in the analysis. On the supply side, the Troll project, often described as "ultra-high cost", is able to proceed even at oil prices in the $15 per barrel range, once the tax regime was altered. Our analysis of the physical economics suggest that, exclusive of government rent, gas can be landed in Western Europe for $1.50 per Mcf with the project as now constituted. The willingness of the government to reduce its take in order to bolster the project shows the attitudinal change wherein lower prices have encouraged supply increases.

On the demand side, the difficulty that the Norwegians have had in finding buyers for first Sleipner, then Troll, illustrates the basic weak nature of the market. The success achieved by discounting gas prices relative to oil prices shows the importance of relative pricing strategies in increasing sales, and the decision to add a new entry point to the Western European market in Belgium is a move towards more competitive markets.

The Troll contracts, which are so flexible that they have been described as the equivalent of letters of intent, confirm the findings of the contract section that the lower the cost of gas, the less guarantees the producer requires against risk. Certainly, the size of the Troll project makes it stand out from other gas deals, but at the same time, we feel that the manner of its marketing and the price and policy trends inherent in the deal, are indicative of the changes occurring in the Western European gas market rather than an aberration.

WESTERN EUROPEAN NATURAL GAS POLICY: MANAGEMENT OR MARKETS?

by

Loren C. Cox[1]

INTRODUCTION

The Western European natural gas market currently occupies an uneasy middle position between a true economic market and one constrained by the policies of many different governments. Its interconnected pipeline system, relatively short distances for transportation, diversity of supply sources, and environmental concerns all suggest that an economic market would be easy to implement. However, the inescapable fact remains that national boundaries and national policies have had and continue to have enormous impact on the Western European natural gas market.

Thus, any analysis of this market must deal with the reality of policy interventions by both consuming and producing countries. Indeed, there is considerable risk of becoming so transfixed by the enormously complex set of policies that analysis yields only a reiteration of the reasons why such complexity evolved. To do so makes little contribution, since participants know the situation well. At the other extreme, only extolling a true economic market is overly simplistic, and thus irrelevant.

The aim of this chapter therefore will be to identify those policies that are the most constraining on an expanded Western European natural gas market, and to reflect on what gains might be found to mutual advantage by implementing changed policies.

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[1] The author owes a special debt of gratidude for the considerable efforts of the project's Technical Editor, Mr. Peter Heron.

To put the discussion into context, it is first necessary to review briefly the history of gas use in Western Europe. However, rather than touch on each country, this chapter will concentrate on four specific consuming countries: West Germany, Italy, France, and the United Kingdom. This list may be somewhat surprising both for what it includes and what it omits. The United Kingdom is included because it is a potential importer, thus competing with continental importers; it also is a potential exporter of gas to the continental market, either of its own production or of resold Norwegian gas that might pass through its pipeline system. Because the United Kingdom's future as either importer or exporter is uncertain, it is worth examining with some care.

The omission of the Netherlands also may seem curious, since in this country gas occupies the highest percentage of total primary use of any Western European country. It is that fact that drops it from the list, for there are almost no imaginable circumstances whereby the Dutch would expand gas use domestically. Instead this chapter will examine the role that the Netherlands historically played in Western European gas market development and speculate on its future role as a natural gas broker.

The chapters elsewhere in this study provide considerable detail on supply cost questions and on the competitive forces shaping demand for natural gas in the four countries noted above. However, producing countries' policies also have influenced the development of the current market in Western Europe. Supplier strategies both have encouraged the gas market to grow, then have put limits on its growth. The timing of policy shifts has had a profound impact, and this chapter will pay considerable attention to those actions, and reactions to them by consuming countries.

HISTORICAL DEVELOPMENT: PRE-1973

As noted in our previous studies of North American and East Asian natural gas trade,[2] the first extensive use of gas in Western Europe also was in the form of manufactured gas. Town gas companies were established in most countries in the early 19th century, with manufactured gas used primarily for lighting. Later, town gas expanded to home heating markets and to industrial use, and continued in all countries at least into the 1950s. By this time, oil was becoming a significant competitor for direct use under boilers and in space heating, and town gas companies switched to oil as a feedstock for manufacturing gas.

Natural gas transmission and use was well established in North America by the late 1950s, but Western Europe had no apparent access to substantial supply sources until the 1960s and beyond. Discovery and appraisal of the Netherland's Groningen field between 1959 and 1962[3] resulted in the first significant prospect for transborder trade of natural gas in continental Western Europe. With successive upward revisions of Groningen reserves in the 1960s, it became clear that Dutch gas would become a significant export product. Because of the length of time the Netherlands needed to switch its domestic distribution from manufactured to natural gas, the majority of early production from this new, large field was available for export. The central

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[2] International Natural Gas Trade Study Group, Final Report: Canadian-U.S. Natural Gas Trade, MIT Energy Laboratory Report No. MIT-EL 85-013, Cambridge, Massachusetts, October, 1985; and Final Report: East Asia/Pacific Natural Gas Trade, MIT Energy Laboratory Report No. MIT-EL 86-005, March, 1986.

[3] Malcolm W.H. Peebles, Evolution of the Gas Industry, New York University Press, New York, New York, 1962.

location of the Netherlands made its gas easily available to West Germany, France and Italy. Despite its relatively lower calorific value, the Groningen gas was easily sold, especially when priced to compete with oil products. Thus, by the late 1960s, Dutch gas was flowing to West Germany, Italy, France, and Belgium.

At about the same time that the Groningen field was discovered, LNG imports by the United Kingdom began in 1959 on an experimental basis (ironically, from Lake Charles, Louisiana). With this supplemental supply proving a technological success, the United Kingdom contracted with Algeria for LNG deliveries to begin in 1964.[4] Introduction of this gas required construction of high-pressure trunk lines, and thus put into place a large piece of the basic infrastructure that later would be used to transport North Sea natural gas. With the discovery of North Sea gas in 1965, the U.K. system was positioned to distribute this high-caloric gas to a large portion of the country.

Thus, by the late 1960s, natural gas use by a combination of domestic production and imports was well established in all four countries. This use was impelled by differing motivations in each country; in all cases natural gas initially was seen as a very limited option in the fuel mix. For the United Kingdom, LNG was an alternative to increasingly high-cost manufactured gas, and a welcome relief to serious air pollution problems.

For France in the 1950s, natural gas was produced principally from the large southwestern Lacq fields (discovered in 1951),[5] but these were located

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[4] ibid., p. 28.

[5] J.D. Davis, Blue Gold: The Political Economy of Natural Gas, George Allen & Unwin, London, England, 1984, p. 173.

at a considerable distance from major industrial centers. Thus, manufactured gas retained a significant role in French gas use until the 1960s. By 1966, Dutch gas was available for French industrial use, first in the north and soon after in Paris and its environs. Thus, Dutch imports allowed France to solve an internal distribution problem at an attractive price.

Italy demonstrates similar early experience. Discoveries of significant deposits in the Po Valley in 1949[6] were reasonably close to industrial centers. A problem arose fairly quickly as demand claimed amounts in excess of domestic production. Although basic market economics would suggest that increased prices would have affected that demand, price controls on natural gas foreclosed such a prospect. Thus, Dutch imports became an attractive supplement.

West Germany also had early experience with natural gas available only in limited quantities. The Ruhr coal and steel industries were prodigious producers of manufactured gas, and coal itself was a major fuel. Also, coal interests have exerted major influence on West German federal policy, including a policy that the electric utility industry use domestically produced coal in specified amounts. In 1935, the Reichstag enacted a law that gave the Laender (states) broad authority over natural gas pricing, and broad discretionary powers to plan for its transmission and distribution.[7] The result was to segment the gas industry, concentrating use in Laender close to or involved with production. Introduction of Dutch gas thus first occurred in areas adjacent to the Dutch border, and tended to be used for electricity

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[6] ibid., p. 167.

[7] ibid.

generation--which did not compete with manufactured gas sales. In this sense, the Dutch supply was incremental, and closely tied to the electricity sector.

In summary, the use of natural gas in Western Europe throughout the 1960s was as a specialty fuel, primarily of interest to areas close to domestic production or to import points. The introduction of natural gas through trade was incremental both to manufactured gas and to constrained domestic natural gas supplies. Interfuel competition was not a significant issue, as natural gas occupied only a minority position in total fuel use. Crude oil and its products were plentiful and their prices stable, and coal use was still well established.

In this review of the introduction of natural gas into major Western European markets, little specific reference has been made to price. One reason for this omission was that manufactured gas was quite expensive, so natural gas could be priced at market-penetrating levels, pay for new, high-pressure transport and distribution systems, and still provide an attractive rate of return to producers (whether private or public). The other reason is that producing, contracting, and transmission costs and prices are considered to be private information. Thus, the only price fairly readily observed is the price of final sale to end users; that price includes taxes plus all other costs and margins along the production/transmission/distribution chain.

As a result of this price non-transparency convention, analysis of the sort undertaken here suffers from a handicap. The author's general perspective is that price has a significant impact on interfuel competition, and thus on policy alternatives considered by both producing and consuming countries. Because price data have not been published in a consistent series over time and across consumption sectors, we have had to rely on episodic and anecdotal evidence. Also, because such information often has been reported in English language publications, and because most natural gas trade contracts have been denominated in U.S. $, our references in turn are in U.S. $. Exchange rates have fluctuated considerably over the period covered in our analysis, so most mention of price in this chapter are to the then current U.S. $ equivalent.

The reason for this short digression on price data limitations is that the next stage of European natural gas trade is the 1970s: the decade of the first OPEC oil price shock (see Table 2-1). When oil prices rose as a result of crude oil price increases, the role of natural gas changed dramatically. Not only did the interfuel competitive environment change, but policy actions in both consuming and producing countries also sharply shifted. As shall be seen, the fundamental changes were in the perception of oil price trajectories and of the availability of oil (whether affected by global depletion--a popular notion then--or by boycott). In these contexts, policies about natural gas were based on securing access to supplies, and price was considered a secondary concern.

As indicated below, this view turned out to be not only inaccurate but even pernicious. Policies to encourage natural gas use in large consuming countries led producing countries to institute fiscal regimes, development policies, and contract terms that led to serious rigidities when later responding to competition both from falling oil prices and from new gas exporters.

We now turn to the evolution of natural gas markets in the 1970s.

Table 2-1

Nominal Crude Oil Prices

Year	(Persian Gulf/Saudi Light)	MMBtu*
1965	1.17	21
66	1.27	23
67	2.54	47
68	1.83	34
69	1.27	23
70	2.01	37
71	2.27	42
72	2.53	46
73	2.80	51
74	10.84	199
75	11.51	211
76	12.85**	235
77	13.90**	255
78	14.00**	257
79	23.20**	425
80	36.25**	664
81	35.00**	641
82	33.50**	614
83	29.90**	548
84	29.90**	548

* Calculated on a thermal equivalent basis.
** BP/BNOC prices.

SOURCES:

1960-70: M.A. Adelman, *The World Petroleum Market*, Baltimore: The Johns Hopkins University Press, 1972. (Derived Persian Gulf prices)

1973-83: BP Statistical Review of World Energy, London, August, 1985. (Official Saudi Light Prices and U.K. Forties/BNOC Prices)

THE OPEC OIL PRICE SHOCKS OF 1973-1974: A NEW ERA FOR GAS

The 1973-74 agreement by OPEC to limit production of crude oil and to capture price increases created a very new environment for natural gas. As noted in our previous studies, these oil price increases were seen as heralding an end to available liquid and gaseous hydrocarbons. Oil use had been increasing since the mid-1960s, and both industrial and electric utilities had built substantial fractions of boiler capacity to use fuel oil. Until 1973-74, oil prices had been remarkably stable, so such investment decisions made good sense. However, with the OPEC shock, coupled with threats of boycott or similar barriers to access, the notion of oil scarcity gained credibility with remarkable speed.

With a producer's cartel operating with apparent effectiveness, consuming countries formed the International Energy Agency (IEA), on the presumption that international cooperation by consuming countries would be more effective in coping with shortages in oil markets than would individualized actions. Despite the IEA's apparent helplessness in the face of the second oil price jump in 1979-80, it continued to seek common, effective counters to cartel actions.

Based on ministerial agreements made during the 1970s, the IEA evolved the view that reducing oil use would be the most effective action against OPEC threats. Thus, IEA member countries pledged targets for reducing oil use in individual countries, with methods for such reductions left to individual country policies. The use of market forces generally was politically unpopular--and potentially damaging to local economies. Indeed, some countries having substantial domestic oil production (notably the United States and Canada) retained or implemented price controls on crude oil and oil products. These price controls on domestic oil production had the effects of subsidizing oil imports and lowering the total cost of oil use inside that country, an outcome that was seen by countries without significant domestic production as unfairly uncompetitive. Whatever the competitive effects, it is now nearly universally acknowledged that, by any rational measure, these were misguided policies. However meritorious or wrong-headed various policies may have been, they all were directed away from oil consumption. A principal beneficiary of this set of actions was natural gas. Oil was strongly identified with Middle Eastern production and governments. Energy sources from any other location were seen as vastly preferable, perhaps because it was felt cooperation with non-Arab Gulf countries was much easier. However erroneous this perspective turned out to be, at the time it provided major impetus to the import and use of both coal and natural gas from anywhere other than an OPEC country, insofar as that was practically feasible.

In the earlier description of the historic development of the Western European natural gas market, it was seen that Groningen exports in the 1960s fit well into certain market niches in West Germany, France, and Italy. These exports also allowed the Netherlands time to build a domestic distribution system for its own major utilization of that resource, while simultaneously generating significant revenues for the Dutch economy. Because the Netherlands could not use its own gas quickly, they priced their gas exports in such a way as to develop markets in the countries described above. With the first oil price shock, the world changed very dramatically.

As Table 2-2 indicates, the price of gas (which had been set to win markets) no longer needed to stay low to ensure Groningen a place in export markets.

Table 2-2

Groningen Export Prices
(US$/MMBtu)

Contract Date	Country	Initial Price	1976	1981
1966	West Germany	N.A.	1.1	4.1
1966	Belgium	0.33	1.1	4.1
1967	France	0.36	1.1	4.1
1970	West Germany	0.38	1.1	4.1
1969 - 70	Italy	0.44	1.1	4.1

SOURCE: Davis, *ibid*., p. 161.

This Table is not designed to show any particular characteristic of Dutch export behavior, but rather to illustrate the movement over time of natural gas prices in relation to oil price increases. As shall be seen, it is only an example of a general rule about gas pricing in the 1970s.

Before turning to gas prices in consuming countries, it first would be helpful to look at the exporter situation entering the 1970s. The Netherlands dominated circumstances at this point, with their contracts backed by the massive Groningen reserves. As of 1970, Dutch gas exports accounted for essentially 100 percent of all natural gas trade in Western Europe, and by 1974 they still represented nearly 75 percent.

In the United Kingdom, the 1960 non-associated gas discoveries in the southern North Sea had reduced reliance on Algerian LNG imports. Although the contract remained in effect, Algerian LNG increasingly was used in the United Kingdom for peak-shaving purposes until the contract term expired in 1979. Because U.K. producers were required to sell their gas production to the British Gas Corporation (BGC), prices were at low levels (see Table 2-3).

These low prices allowed Algerian LNG to be rolled-in to U.K. supply, so the price to consumers remained at levels that continued to penetrate the

Table 2-3

Initial Prices for North Sea Gas

SOUTHERN FIELDS	PRICE/THERM (105 Btu)	
	UK pence	US cents
West Sole		
1967-70	2.08	5.01
1971-	1.12	2.39
Hewett		
Base Price	1.195	2.83
Valley Gas	0.844	1.997
Leman		
First 600 million ft3/day	1.196	2.83
Second 600 million ft3/day	1.1875	2.81
Remainder	1.792	2.79
Indefatigable		
All gas to be 1983	1.208	2.89
Viking (1972)	1.5	3.5
Rough (1974)	3.4	7.87

NORTHERN FIELDS	(PRICE IN UK PENCE/THERM)	
	Initial	1982 (est)
Frigg (Norwegian) 1974	8.8	11.5
Brent	6.5	12.5
Beryl	---	16.0
North Alwyn	---	22.0 - 23.0
Asking for New Fields	---	20.0

SOURCE: Derived from Davis, pp. 106, 114.

market (especially for residential use). With the 1973-74 oil price hikes, gas contracts from North Sea production also increased in price, though less than at the rate of oil prices.

The 1972 discovery of the Frigg field introduced Norwegian gas into the U.K. system. This field was bisected by the U.K./Norwegian boundary, and U.K. intentions to build its own gas line to the shore made purchase of Norwegian zone gas an obvious solution. However, Western European buyers also competed for these supplies, so for the first time the price paid by the BGC was bid up.[8] As noted in Table 2-3, the price for Frigg gas in 1974 was the only sale made at a price higher than that paid for the initial West Sole purchase in 1967 (which subsequently decreased after the three-year initial contract period). The competitive force of Western European buyers is a useful way to take a brief look at Norway.

Norway might be considered a lucky country: it was in the right place at the right time. Exploration in its North Sea sector began in the late 1960s, and it began to log discoveries of oil and gas soon afterward. Frigg, Ekofisk, Albuskiell, Tor, and the giant Statfjord fields were all identified, defined, and made available for buyer bidding in the 1970s. Although Norway long has had a reputation for engineering prowess, it also has a relatively small population, which is widely scattered across a rugged and vast landscape. These conditions made domestic use of natural an expensive proposition, and its small population gave rise to concern about the economy's ability to absorb a too-rapid development of oil and gas resources. The Norwegians thus adopted a carefully phased development strategy, designed to

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[8] Peebles, op. cit., pp. 31, 44.

dampen inflationary impacts, provide full and geographically distributed employment (without labor imports), and secure long-term export income to the Norwegian economy. Concerns also were expressed about internalizing future expected income into current national budgets.

These very sensible steps all were laudable. Of course, the oil price shocks were pleasant surprises for Norway, at least at first. Most of its discoveries in the 1970s were predominantly of oil, and gas development was oriented toward capturing associated streams and pulling in non-associated smaller gas fields (Frigg was the early exception). In this early strategy, the task was to dispose of gas safely, at a profit, and to ensure that oil development was not impeded. Norwegian supplies from Frigg had been negotiated before the first oil price hike, and from Ekofisk not long afterward. The prices in these contracts were relatively modest, with purchasers apparently willing to pay somewhat more for Norwegian gas than for alternative supplies, to encourage further development of gas in Norway.

Norway in the 1970s may be viewed as having gained valuable experience in exploiting its oil/gas reserves, and in establishing itself in Western European markets as a reliable supplier. The carefully designed phasing of developments likely was considered as a strength, which also fostered intermittent auctions of the (expected-to-be modest) gas resources. Potential buyers would bid for the expected output of the field, and the resulting contracts provided the financial means to proceed with actual development of the field. Later the unforeseen risks embedded in the Norwegian strategy will be examined.

Algeria has been a player in the Western European natural gas market since 1964, when it first made an LNG delivery to the United Kingdom (although the contract was signed in 1961).[9] Exports of Algerian LNG to France commenced in the mid-1960s and to Belgium, Spain, and Italy in later years. However, it might be argued that at the time, Algerian/U.S. LNG negotiations had more impact on Algerian exports than did any other factor.

In the 1970s, the U.S. gas market was subject to price controls. This induced a shortage of U.S.-produced gas and caused pipelines to turn to imported supplies of gas to satisfy the need for incremental supplies. These supplies (from Canada, Mexico, and Algeria) were priced higher than U.S.-controlled prices, but those higher prices could be "rolled in" to the lower-cost U.S. production. Because Algeria had developed substantial liquefaction capacity (both to capture flared gas and to utilize non-associated fields), by the early 1970s it had greater productive capacity than sales contracted for in the late 1960s. In 1971, a U.S. consortium led by El Paso concluded a contract with Algeria for 10 Bcm of annual LNG deliveries to several U.S. terminals. The initial price was negotiated at about $0.40/MMBtu f.o.b. (As can be seen from Table 2-1, this was approximately f.o.b. oil price parity.)

U.S. regulatory and Algerian construction delays prevented timely delivery, and as a result of the oil price increases of 1973-74 and 1979-80, Algeria argued for an increase in the delivered price of its LNG. Because U.S. gas markets still were subject to price controls, El Paso agreed to a second contract as a mechanism to increase the price. This second contract apparently included an index linking the price of Algerian LNG to oil prices, a condition that caused the Federal Power Commission to balk--fearing this would encourage Canada and Mexico to do the same. Deliveries on the first

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[9] _ibid._, pp. 28-9.

contract began in 1978, but due to continuing disputes over the price, shipments were suspended the following year. The later Trunkline project also agreed to increases between the pre-1973 negotiation and the late 1970s' planned delivery. Partial Algerian successes with U.S. contract price revisions in the mid-1970s undoubtedly encouraged its view that gas should be linked to f.o.b. oil prices.

However, Algerian attempts to escalate prices to Western European customers have had mixed success. The 1971-72 project to France at Fos-sur-Mer fit well into existing distribution from the Lacq fields, and the mid-1970s' price escalation was absorbable for peak-shaving purposes--and to offset decline in Lacq production. Another outcome resulted in negotiations with the SAGAPE consortium of five Western European nations (Austria, Belgium, France, Switzerland, and West Germany). SAGAPE signed letters of intent to buy 15.5 billion Bcm annually for 20 years from Algeria beginning in the mid-1970s.[10] The Algerian demand in the mid-1970s for a tripling of the previously negotiated price likely was encouraged by the apparent success of similar moves in the United States, but here the outcome was different. The Austrian and West German participants dropped out of the consortium, which then collapsed. As will be noted later, the French and Belgian groups later accepted higher (and f.o.b. oil-indexed) prices.

An interesting hypothesis can be constructed from this discussion. Because Algeria was so hawkish about f.o.b. oil price equivalents--and was encouraged in that strategy by peculiarities in U.S. price-controlled environment--conditions were created in Western Europe that made Soviet

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[10] Oil and Gas Journal, November 8, 1976, p. 145.

supplies enormously attractive. Indeed, had Algeria taken the Dutch strategy of setting prices with an eye to achieving market penetration, there well may have been little interest in or actual need for Soviet supplies. Current Algeria LNG capacity stands at approximately 31.3 Bcm, for which 20.4 Bcm is either currently contracted or under negotiation. This leaves 10.9 Bcm, or 1.05 Mcf/day, that could have been supplied to Western Europe.

By comparison, since 1975 the Soviet Union has developed capacity to export 30 Bcm to Western Europe. While it is only speculation that Soviet gas exports would not have expanded had the Algerians been more aggressive in marketing, it is an intriguing question, to which we shall return momentarily.

The Soviet Union has exported oil and natural gas for decades. Recent western (especially U.S.) interest in these exports has tended to focus on the geopolitical consequences of planning decisions about exports versus domestic use. There also has been an inclination to view these decisions as being based on non-economic criteria, most usually attributing anti-western motives to decisions. This in part is due to cold war suspicions, but also in part to uncertainty about the capacity of Soviet planners to understand the consequences of their actions on market economies. Of course, both views cannot be simultaneously correct. Western European perspectives seem to be more benign (although occasionally bemused). In general, this view holds that the Soviet Union knows how to participate in markets (both import and export), though bureaucratic inefficiency may result in delays on schedules, poor quality, and so forth. Fluctuating oil exports in recent years were seen by the U.S. government as deliberately destabilizing; Western Europeans appeared to attribute the variance to technical field problems, poor equipment, excessive production, and so forth. This difference in perspectives and experience also was at the heart of the dispute over the Urengoi gas export project in the early 1980s. The U.S. government's view was portrayed as concerned with technology transfer, easy credit when tightening financial flows would have hurt military expansion, and especially with creating resource dependency that could be used as leverage to divide Allied interests on controversial matters. This chapter will speculate below on this conundrum and examine alternatives for mitigating the controversy.

Soviet gas supply prospects are examined in detail in the supply chapter (see Chapter 3), but the basic facts are straightforward. The Soviet reserve base is huge, and exploration/delineation still is underway. Domestic use has first priority, especially to meet the fuel requirements of industrialization. The second stage of development was export to Eastern European countries, which expanded rapidly (see Table 2-4). With major transmission lines in place to this region, further expansion to Western Europe was only a modest incremental step (though in this case, building new lines to reserves were necessary). However, deliveries to Western European countries are not a recent event, as sales to Austria began in 1968 (and expanded in 1974), to West Germany in 1973, to Italy in 1974, and to France in 1976. Because transportation costs to Western European delivery points were only incremental, the prices offered at that time were quite attractive (see Table 2-5). Also recall that by the mid-1970s the SAGAPE consortium was faced with Algerian demands for a tripling of price. In such circumstances, it is not surprising that Western Europeans were interested in purchasing natural gas from the Soviet Union.

As this review indicates, the 1970s largely saw a continuation of producing/exporting country actions initiated in the 1960s. The Netherlands

Table 2-4

Exports of Soviet Natural Gas to Eastern Europe: 1967-77

Year	Poland	Czechoslovakia	E. Germany	Bulgaria	Hungary	Total
1967	1.12	0.17	--	--	--	1.29
1968	1.00	0.59	--	--	--	1.59
1969	0.99	0.89	--	--	--	1.88
1970	0.76	1.08	--	--	--	1.84
1971	1.13	1.25	--	--	--	2.38
1972	1.14	1.47	--	--	--	2.61
1973	1.30	1.80	0.60	--	--	3.70
1974	1.61	2.53	2.20	0.23	--	6.57
1975	1.91	2.81	2.51	0.90	0.46	8.59
1976	1.93	3.50	2.56	1.69	0.76	10.44
1977	2.09	3.86	2.74	2.19	0.76	11.64
TOTAL	14.98	19.95	10.61	5.01	1.98	52.53

Exports of Soviet Natural Gas to Western Europe: 1968-77

Year	Austria	W. Germany	Finland	Italy	France	Total
1968	0.14	--	--	--	--	0.14
1969	0.78	--	--	--		0.78
1970	0.73	--	--	--	--	0.73
1971	1.08	--	--	--	--	1.08
1972	1.24	--	--	--	--	1.24
1973	1.23	0.27	--	--	--	1.50
1974	1.60	1.62	0.34	0.60	--	4.16
1975	1.43	2.43	0.55	1.78	--	6.19
1976	2.11	3.01	0.66	2.83	0.75	9.36
1977	1.89	3.84	0.68	3.82	1.46	11.69
TOTAL	12.23	11.17	2.23	9.03	2.21	36.87

SOURCE: Peebles, *op.cit.*, pp. 31, 44.

Table 2-5

Average Apparent Soviet Export Border Prices of Natural Gas
(U.S.$ per 1000 cubic feet)

COUNTRY	1970	1974	1975	1976
Exports to:				
Austria	40	51	119	125
Finland	--	179	184	177
France	--	--	--	96
Italy	--	29	64	62
West Germany	--	53	70	85
Bulgaria	--	57	115	125
Czechoslovakia	46	57	100	133
East Germany	--	56	59	104
Hungary	--	--	117	127
Poland	43	52	110	120
AVERAGE FOR ALL EXPORTS	44	57	91	106

SOURCE: Peebles, _op.cit._, p. 181.

already was exporting its North Sea gas, Algerian LNG projects were underway or under negotiation/dispute, Norwegian North Sea oil development was proceeding, and the Soviets already were transporting gas to Eastern Europe and beyond. There appears to be no indication that natural gas trade was initiated because of market opportunities created by the 1973-74 oil price increase, or even that there was a significant expansion of existing trade to capture opportunities presented by that price increase.

What did appear to happen was: (1) producing/exporting countries did increase the price of natural gas (although not at the same magnitude of oil price changes); and (2) consuming/importing countries did make policies to shift fuel use away from oil and toward other fuels, including natural gas. It was this second factor that had the greatest impact on Western European natural gas markets in the mid- to late-1970s. The IEA and the European Economic Community (EEC) both were strongly exhortatory in their attempts to move member nations away from oil use. This period was characterized by annual reckonings on barrels of oil saved over previous years (usually using 1973 consumption as the base of comparison). These savings were the result of a number of factors, including: taxes levied on oil products; the installation of new, energy-efficient equipment; the impacts of a recession (which reduced demand for all primary energy forms); requirements and/or subsidies for insulation; and use of alternative fuels.

It is not possible to affix accurate shares to each of the above actions, but the generally favorable environment for expansion of natural gas use is obvious. From 1970 to 1979 natural gas use in the EEC grew from 56 to nearly 200 Bcm.[11] As will be recalled from Table 2-1, the price of gas was very

[11] European Economic Community, "Communication from the Commission to the Council Concerning Natural Gas," Brussels, Belgium, April 9, 1984, pp. 2, 18.

competitive, and the policy climate for its use was most favorable.

During the 1970s, the countries most closely studied here were leaders in Western European natural gas use. From 1970 to 1979, West German consumption grew from about 15 to over 50 Bcm.[12] During this period, residential and commercial use steadily increased (from 2.25 to 17 Bcm) and that trend likely will continue. Industrial use also increased from nearly 7 to over 15 Bcm; this sector appears to have plateaued. Electric utility use expanded from about 3.5 to nearly 16 Bcm, but has shown sharp and continued declines since 1979.

In the United Kingdom, natural gas use always has been heavily oriented toward the residential/commercial sector and toward the feedstock and specialty industrial markets. By the time of the introduction of Algerian LNG and later North Sea gas, the distribution system already was well established. With capital costs already sunk, the infrastructure in place, and an integrated monopoly (BGC) transporting and distributing the gas, it is no wonder that use grew--especially considering the prices that were offered. In examining BGC pricing practices, the Price Commission in 1979 noted that gas was priced far below alternative fuels in residential markets, as Table 2-6 indicates.

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[12] Burckhard Bergmann, "The European Market for Natural Gas," Ruhrgas Report Presented to European Gas Conference 1985, Oslo, Norway, 1985.

Table 2-6

Natural Gas Prices (=100) versus Alternative Fuels

Use	Electricity	Coal	Oil
Central Heating	140-170	130-150	125-140
Cooking	160-200		
Space Heating	170-200	125-140	

SOURCE: The Price Commission, British Gas Corporation: Gas Prices and AlliedChanges, HMSO, London, England, 1979, p. 116.

Recalling the contract prices for North Sea gas, such prices were possible, although how long BGC could hold customers if alternative fuel prices continued to edge upward is a relevant question, addressed later.

In a response to the 1973-74 prices increase, French policy during the 1970s was strongly oriented toward promoting nuclear power. However, natural gas also became increasingly important to France. By 1975 gross domestic consumption of gas was 19.3 Bcm, and by 1980 it had grown to 26.4 Bcm.[13] This period saw deliveries from the Netherlands, Norway, Algeria, and the Soviet Union (plus increases in their own domestic production). Because of the focus on nuclear-generated electricity, French natural gas policy was somewhat neglected, or at least unclear. During the 1970s, residential use of gas expanded rapidly, and the industrial sector saw strong growth as well; however, with the nuclear push, consumption in the electric utility sector declined sharply.

During the 1970s, Italy had substantial domestic natural gas production, and most use was concentrated in the industrial sector. Deliveries from the

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[13] CEDIGAZ, "Natural Gas in the World," Paris, France, 1985, p. 57.

Netherlands and the Soviet Union also began during this period, although both contracts were negotiated in the late 1960s; this also was the start-up period for LNG trade from Libya. These additional supplies allowed a significant expansion of natural gas use in the Italian residential sector, which was able to absorb these relatively higher-priced imports. Because domestic production was not increasing, imported natural gas became increasingly important. Since Italy imports nearly all its oil, substituting natural gas for oil must have appeared to be a supply diversification strategy of sorts.

From this review it is clear that the 1973-74 oil price jump, to some extent, did affect both natural gas consumers and exporters. However, because increases in gas prices lagged behind increases in oil prices, expansion of gas markets was substantial. Further, other national and international policies were directed to attractive alternative fuels, which gave gas use additional impetus.

Thus, it is reasonable to attribute the growth in natural gas use in Western European in the 1970s to two factors. First, the increasing availability of gas from domestic production and imports from reasonably proximate sources (via both pipelines and LNG shipments) allowed distribution grids to expand without serious manpower or material bottlenecks. Second, the policy overlays from the mid-1970s onward gave considerable encouragement to use natural gas as a replacement for current imports of oil--or at least to reduce future oil import requirements.

TIMES OF TURMOIL: THE 1980s

From the vantage point of 1986, the 1970s was a comparatively a quiet and orderly period in Western European natural gas trade, a period during which policy guided the evolution of natural gas use, and imports/exports were viewed as serving common, if not mutual, interests. However, the second oil price shock of 1979-80 brought that relatively placid period to an abrupt and dramatic halt. This event heralded the end of natural gas market growth in Western Europe, with the first three years of the decade witnessing falling levels of demand. This occurred despite strong perceptions of the need to move away from oil. Because, beginning in late 1979, oil prices rose for three years running, it became an article of faith that they would continue to increase well into the forseeable future. The push toward reducing dependency on oil imports became even stronger, and the IEA and EEC became even more prescriptive in their advice to member nations.

Gas supplier actions added to this atmosphere of confusion and contention. Algeria suspended LNG exports to France when the French resisted demands for a major price increase. Dutch demands for price increases had been underway for some years, and in 1980 the Dutch reached quick agreement with buyers. This latter action was especially noteworthy, because Groningen still represented a substantial fraction of total Western European gas trade. Because Dutch export prices were low, the volume was large, and contract terms permitted relatively low offtakes, Western European buyers were able to pay relatively high prices and accede to high take requirements from other suppliers (especially from Algeria, Norway, and to some degree from the Soviet Union). Dutch impatience was understandable, as was buyer resistance to the Dutch price increase.

In many ways, the Groningen renegotiation marks a watershed event in Western European gas markets. Its large impact was not only due to the factors just described, but also due to timing. In the 1979-80 period, Dutch exports comprised a significant percentage of imports to Italy, France, and Germany (see Table 2-7).

Table 2-7

Imports from the Netherlands as a Percentage of Total Natural Gas Imports (average of 1979-80)

Importing Country	Total Imports (Bcm)	Imports from Netherlands	Percent
Italy	14.6	5.5	37.7
France	19.8	11.4	57.6
W. Germany	45.4	24.9	54.9

SOURCE: OECD, Annual Oil and Gas Statistics, Paris, France, 1979/80.

The significance of these relatively high percentages is obvious in light of the earlier discussion about new contracts, contracts that exploited the relatively low-cost and very flexible take terms embodied in the Dutch contracts. In effect, the price renegotiation sharply reduced or entirely removed opportunities to "roll in" new, high-cost supplies.

Simultaneously, the jump in oil prices contributed to a serious slump in the world economy, a slump that was especially severe in Western Europe. The concommitant drop-off in economic activity reduced demand for all fuels, and for the first time there was a notable drop in the demand for natural gas. Gas markets were caught in a significant whipsaw effect. First, Western European countries' base supply contract prices (with the Netherlands) rose just as expensive new supplies from other sources were either under negotiation or under development. Simultaneously, although not apparent at the time, in 1979 gas demand peaked, then began a four-year decline. Finally, the increase in Dutch prices, in addition to new and expensive supplies, raised prices to a level that forced the use of gas in the electric generation sector to decrease, a fact that (together with the overall decline in industrial activity) resulted in a shift in load factor toward a more seasonally varied one. This in turn made high take requirements from new suppliers such as Norway and the Soviet Union (plus Algerian LNG) especially onerous.

For all these reasons, the Dutch price change appears to have had a significant impact on Western European gas markets, although it is not clear that this impact has been thoroughly appreciated. What is clear is that existing contracts and domestic production can meet virtually all annual demand for natural gas in Western Europe throughout the remainder of this century. If the oil price collapse proves durable, gas contracts likely will be renegotiated to stretch out deliveries beyond 2000, perhaps bringing significant price reductions as well.

Contract terms increasingly have tied gas price indices to competing fuels, especially low-sulfur fuel oil, gas oil, and distillate. Thus, the price of gas is less likely to be significantly out of line over a long period (although this in turn depends on the time frame for automatic adjustments, which typically have been shortening). What have not changed greatly are take requirements (although Dutch contracts still are the most flexible). With load factors in Western European consuming countries trending strongly toward seasonal residential patterns, load balancing considerations will become increasingly important.

With residential/commercial markets being the only sectors experiencing continued growth (or remaining stable), this move toward a seasonal heating pattern is general to the Western European market. In West Germany, the shift of load toward the residential sector is especially striking; between 1980 and 1983, gas use in the electricity generation sector declined by 60 percent; since then it has declined another 30 percent. Electricity generation still represents nearly 20 percent of total West German consumption, so gas continues to be subjected to very severe interfuel competition. During the 1980-83 period, the West German residential sector grew approximately by 10 percent, but that increase accounted for less than 3 percent of the total volume of gas used in total energy consumption.[14] Although more recent data suggest that the industrial sector is recovering somewhat, the real growth continues to be in the residential/commercial sector. The implications for West Germany are obvious: there will be slow or no growth in the total volume of gas used and increased seasonal variability of demand for it.

France, in part because of its relatively early, policy-driven commitment to nuclear power, has chosen not to rely on the use of natural gas in electric power generation. Its use of gas in the industrial sector was strong and growing in the 1970s, but levelled off in the early 1980s. Because French natural gas prices have been high and electricity prices low, expansion in the residential sector has been less rapid than in, say, West Germany. It is likely that the cost of electric appliances also will remain low, so longer-term prospects for increases in residential sector demand for gas are not likely to improve. France also has the problem of carrying contracts with very high gas prices. Following the Algerian LNG supply interruption of 1980, France agreed to a price increase that seemed to have a premium attached for

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[14] *ibid.*, p. 57; also British Gas Corporation official's speech, 1985, not for record.

non-energy purposes. Although deliveries of LNG resumed, natural gas has been--and still is--at a competitive disadvantage compared to other fuels in France.

Italy entered the 1980s particularly dependent on imports of all fuels. Natural gas has been and remains today the only fuel in substantial domestic production. Therefore, it is not surprising that one of Italy's major objectives is diversification of imports of all fuels, and especially of natural gas. In 1981, Italy passed a national energy program designed to decrease oil dependency. Although the plan was ambitious in scope, by most accounts it has fallen short of its goals (as did most other national energy programs of its kind). The following IEA review of Italy underscores those difficulties.

> While most of those policy developments [Italy's national energy program and subsequent laws] have been positive, actual results of implementing these policies has been mixed . . . There are also areas where the government has failed to define policy measures . . . Clearly the effect of not holding to the targets in the 1971 NEP is to shift the schedule of implementation back, implying a continued high level of dependence on oil imports for several years more . . .[15]

Irrespective of its national energy program, Italy has been very active in contracting for natural gas supplies from a very diverse set of exporters, more so than any other European country. It received Groningen gas, Norwegian gas, Soviet supplies, LNG from Libya, and pipeline supply from Algeria. Despite this diversity of suppliers, Italy for a long time has been unable to reduce supply prices through contract negotiation. While not so obvious as in

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15 International Energy Agency, "Energy Policies and Programmes of IEA Countries," 1984 Review OECD, Paris, France, 1984.

the French experience, Italy has been inclined (or pushed by the government) to accept an Algerian price settlement that must have non-price benefits (which one commentator suggested was in construction benefits for Italy in North Africa and other Arab countries).[16] The value of such a trade-off is open to question, but another policy decision gave natural gas imports a strong push--the decision to expand gas transmission to the Mezzogiorno region in the south of Italy.

The majority of Italian industry is located in the north of the country, and the perceived imbalance of economic development between the north and south has been a long-standing, contentious issue. The TransMed pipeline landing point in the south gave further access to supply in that area, and provided the basis to link north and south with a common pipeline system. Hookups have increased dramatically, but the bulk of users in the south are in the residential/commercial sectors. Since most industry is in the north and already has access to gas, growth in the south is potentially large in terms of the number of customers but relatively small in volume. In order to use contracted supply volumes, there has been a temporary shift to gas use in electric power generation. Between 1983 and 1984 the amount in this sector rose from 3.14 to 5.73 Bcm,[17] and recent reports suggest that the trend continued into 1985 as well.

Because new coal and nuclear plants are scheduled to come on-line in the 1990s, Italy appears destined to follow other Western European countries

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[16] Jann Haaland Matlary, Political Factors in Western Europe Gas Trade, Oslo, Norway, 1985, pp. 49-50.

[17] Financial Times, "International Gas Report," London, England, January 17, 1986, p. 8.

toward a gas market concentrated in the residential/commercial sector. Thus, the load factor problem likely will become more troublesome here as well. Indeed, if gas used in the electric generation sector declines in the 1990s, Italy could well face difficulties in using supplies for which it already has contracted.

Finally, as noted, natural gas in the United Kingdom long has been focused on the residential/commercial and light industrial sectors, and that condition has not changed in the 1980s. The most notable development in the early 1980s was growing concern about future supplies. BGC lost out in bidding on the very large Norwegian Statfjord and Ekofisk fields (although it was successful on the Frigg field). The Sleipner field was its next target, but although BGC was successful in concluding a contract, that contract did not receive U.K. government approval. Western European interest in this field appeared desultory but that may be open to question; certainly Western European buyers did not step in after the U.K. government's failure to approve the contract. The reasons for failure to approve the contract still are hotly debated, but clearly it has partial origins in the U.K. price structure controversy discussed earlier.

Prices to U.K. end users remain the lowest in all of Western Europe, and the average price paid to producers also is very low.[18] There is little incentive to add to reserves, with no one permitted to bid against the BGC and with gas exports forbidden by law. During and following the Sleipner events, the prices that the BGC offered to U.K. producers began to move upward, but it

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[18] L. Cox and M. Lynch, "European Gas Prices: Limits to Growth," MIT Energy Laboratory Working Paper No. MIT-EL 83-021WP, Cambridge, Massachusetts, 1983.

will take some time to determine if this incentive is sufficient to produce U.K. reserves--and to see if the reserves indeed exist. In the meantime, it is curious that U.K. consumer prices continue to lag so far behind those on the Continent.

This brief review of Western European consuming country developments in the early 1980s includes: continued "off-oil" strategies (except for the United Kingdom, a major oil exporter); a sharp fall in gas demand, especially in the electric utility and industrial sectors; and continued growth in the residential and commercial sectors. All these factors have combined in the mid-1980s to produce a glut of contracted gas and a load curve that is becoming increasing seasonal.

Turning to exporter country actions following the 1979-80 oil price shock, we find that a very mixed set of circumstances prevails. Algeria consolidated its reputation as an unreliable supplier by suspending LNG shipments to France, and by threatening similar actions to Belgium and Italy. After these three countries all capitulated on price terms, deliveries resumed, although the ill-will generated is likely to be long-lasting. Certainly it is true that gas priced at levels of the renegotiated contracts contributed to the fall in gas markets seen in the early 1980s. Clearly, Algeria's behavior in the 1970s and early 1980s created an aversion by many countries to relying on it, which in turn likely created a significant opportunity for Soviet supplies to make in-roads into the effected markets.

The Soviet Union has not suffered from a similar poor reputation, but nonetheless it was at the center of a major dispute about future reliability. The controversy surrounding the Soviet Union's negotiations with Western European buyers in 1981-82 has been chronicled and interpreted elsewhere.

Stated at its simplest, Soviet gas was (as was true of Norway in the 1970s) in the right place at the right time. During the protracted renegotiation of Dutch contracts in the late 1970s, the Netherlands suggested that it might not renew contracts when they expired in the 1990s. The collapse of the SAGAPE consortium over Algerian demands for price increases, together with the Dutch negotiating threat, left Western European purchasers facing an apparently significant shortfall in future supply. All this occurred in the atmosphere generated by the oil supply crisis, and there was great pressure to move away from what were thought to be either politically inaccessible or physically depleting global oil resources. In addition, there was a firm belief that oil prices would rise rapidly and forever. Of course, oil prices in Western Europe continued to rise into 1985 because of appreciation of the U.S. dollar, thus prolonging this perception in Western Europe.

Under this set of circumstances, the Soviet offer to supply 40 Bcm of gas at attractive prices and other favorable trade terms was of enormous importance to Western European buyers. Their commercial experience with the Soviet Union had been without serious problems, and there seemed little reason to believe this would change.

In addition, the loss of 15.5 Bcm/year by SAGAPE made the Soviet offer of 20 Bcm/year almost irresistible. If the Algerian sale to SAGAPE had been consummated, the interest in Soviet supplies may have been small, and likely only for spot or peaking purposes. What was different in this instance was U.S. objections to the Western European/Soviet transaction. Outraged over Soviet actions in Afghanistan and Poland, U.S. foreign policy under President Carter was focused on a search for effective sanctions to punish such adventurism. Lacking any realistic military options, the United States instead sought Allied cooperation in leveling economic actions against the Soviet Union. In light of this, the Soviet gas contract was seen as manifesting Western European indifference to Soviet expansionism, and an implicit repudiation of the best opportunity available to deny the Soviet Union commercial benefits. Additionally, U.S. policymakers suspected that reliance on Soviet gas would give the Soviets leverage over the Alliance in the future.[19]

After the conclusion of negotiations, the Soviet Union proceeded with a major expansion in its exploitation of the Yamal/Urengoi reserves. As the new deliveries fell due, technical problems arose, threatening their timely execution. Nevertheless, the Soviets met all initial requirements, and thus allayed Western European concerns about their commercial performance. Indeed, in sifting through the role of exporters in the 1970s and 1980s, the Soviets' conduct appears exemplary. In fact, it was one of the few exporters that did not exploit external market opportunities by threatening to stop deliveries or increase prices beyond the terms of its contracts. It has shown flexibility equal to the Dutch (who have set the Western European standard) on both matters.

In the mid-1980s, Norway's luck apparently ran out. After its successes with Frigg, Ekofisk, and Statfjord, failure to secure the Sleipner sale could not have come at a worse time. The Norwegian policy was one of phased development (bringing oil and gas projects forward in a sequential way), and

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[19] As is not infrequent in such policy matters, the lack of available alternatives was persuasive in favor of proceeding with the contracts. U.S. policy toward the Soviets is not less belligerent now, but currently the United States has no objection to Allied trade with the Soviets in other than high-tech matters.

during the time that oil and gas prices were increasing, the approach worked wonderfully. Yet Statoil either seemed unaware or unwilling to admit that the Western European gas market, by the early 1980s, was decreasing just as new supplies (including its own) were coming on stream. Holding out for price and development terms geared to a previous era helped doom the Sleipner negotiation to failure. At the same time, it was becoming clear that Norwegian hydrocarbon prospects increasingly favored gas, and its oil options were increasingly limited. Discovery of the giant Troll gas field, with Sleipner still in the inventory, presented Norway with a formidable challenge.

In negotiations with both U.K. and Western European buyers, Norway became increasingly aggressive about price and volume terms. Perceiving what it thought to be a seller's market, Norway sought to shift both price and reserve risks downstream, arguing that it had assumed exploration risks. Norway did not contract to sell a specified volume of gas, but instead sold production from a specific field; buyers assumed the risk of what the field would produce. Statoil negotiators also were very aggressive about prices, arguing for a "security premium" based on their Western Europeanness.

Unfortunately, with Sleipner unsold, Ekofisk operating at reduced output (because of platform subsidence), and the Troll field too large to sell as a whole field, Norway entered the mid-1980s facing some serious problems.

Mention of the Netherlands has been interwoven throughout the discussions of the 1970s and 1980s. The Dutch initiated natural gas trade in Western Europe, remain prominent today, and will continue to be a major influence for the foreseeable future. For 15 years it has been a load-balancer, both due to the nature of the Groningen field and its willingness to contract to fulfill such a role. Its export prices for four years (1976-80) provided the cheapest supply in Western Europe, even while delivery requirements were pushed into future years (by France, for example, to accommodate expensive Algerian supplies). With requests for renegotiation receiving no response, the Dutch then suggested that if the contracts were not be renegotiated, they might not be renewed upon expiration. Even then, at the height of Dutch irritation, there was no verifiable suggestion that it would abrogate the contracts. However, in the panicky policy atmosphere of the early 1980s, renegotiation of Dutch export contracts did occur--presumably to ensure renewal (and supply) prospects in the 1990s.

This renegotiation of Dutch contracts also saw indexation of natural gas with oil products, satisfying the major concern of the Dutch. However, the flexible take provisions remained, thus keeping the Netherland's exports exposed to being backed out by other high take export requirements during times of weak gas markets. This was viewed as a problem, but it may turn out to be a significant strength in the future.

NEW PROBLEMS AND NEW PROSPECTS: THE FUTURE

This review of Western European natural gas markets has attempted to identify the key factors in both importing and exporting countries that shaped the evolution of those markets. The markets originally developed as economic markets, in the sense that normal commercial transactions determined their essential character. These markets were small and specialized, and received little significant policy attention by consuming governments. This was true despite the fact that most of the exporters and importers are government-controlled or government-directed organizations.

By the 1970s, natural gas began to play a more prominent role in energy markets, and this trend accelerated after the first oil price shock of 1973-

74. It was at this juncture that policy assumed a more prominent role, particularly in importing countries. The "off-oil" push had begun, and much more active attention was given to expanding the role of natural gas. Exporter behavior still remained largely commercially-oriented in nature, and there appeared to be no gas brought to market that was not already in prospect. While gas prices did increase, they lagged behind the startling jump in oil prices.

The second oil price hike of 1979-80 had more dramatic consequences. The Western European transportation infrastructure was well-developed, and most major industrial countries enjoyed relatively easy access to gas supplies from a variety of exporters. Importing countries became even more anxious to secure alternative fuels to decrease oil imports, and policies by both individual countries and international agencies were established to speed this process. At this point, exporters' policies also became more aggressive, usually reflected in their demands for higher prices. Contract abrogation was not a factor; Algeria was the only supplier to suspend shipments and then restart them (Libya's export shutdown appears permanent).

* * *

At present (early 1986), the major change that faces both importers and exporters in the Western European market is the sharp drop in oil prices. Although the policy frameworks to reduce oil imports still remain in place, interfuel competition at the burner tip will be savage and the outcome is uncertain. Gas prices will come under increasing pressure, especially as contract indexing provisions fall due. Although the residential sectors of Western European countries likely will not switch if gas prices are only somewhat higher than those of light oil products, new hookups certainly will slow or even halt altogether. Electric generation from gas certainly will decline if gas prices are not competitive with alternatives and if industrial users have increasing access to fuel-switching capability.

The implications of this new end-use price competition are striking. With the demand load curve becoming increasingly seasonal, pressure will increase to stretch out contracted quantities over even longer periods of time, with importers seeking greater flexibility in annual takes. With consumption by base-load users declining, opportunities for large volume sales are decreasing for all but the lowest cost exporters. Failure to respond to these competitive circumstances has another possible consequence for exporters. That problem is the evolution of the view that natural gas is an expensive fuel that offers no real flexibility in price or delivery terms, and therefore in the longer run it is fundamentally not reliable. If that perception takes hold, then gas will carry a discount rather than a premium.

The Western European gas industry (both importers and exporters) frequently views natural gas as being in a long-range market situation, and responses to this cannot be distracted or panicked by short-run fluctuations. While this is a true statement, it is not a complete statement--or necessarily relevant. Underlying this view is a belief that contractual relationships will be enduring. But this outlook is challenged by the fact that falling prices are no more predictable than rising prices. Rising fuel prices bring contracting parties together to sort out division of rents, a task that may result in argument, but nonetheless this is a process in which both parties gain. A falling market (both price and volume) requires allocation of risk, and this always is a less pleasant task.

The uncertainties that face future Western European gas markets suggest that new importance should be placed on achieving greater flexibility. With high volatility in fuel prices, end users have a strong incentive to invest in fuel-switching capacity to ensure minimum disruption. End-use flexibility carries with it opportunities for collecting substantial premia if expected price variations are great. Installation of fuel-switching capacity will add to demand uncertainties, increasing the potential for even greater price volatility.

Natural gas markets have inherent rigidities for several reasons: Storage of very large amounts is expensive or prohibitive; transportation systems may stretch over long distances, and the longer the more expensive; distribution systems (especially for new residential customers) often lie within urban areas and thus are expensive to construct; new residential customers must buy new appliances, adding to conversion costs; producers (especially of offshore wells) need assurance of future sales to make investments to develop the project--all this, and yet the price of natural gas to end users may vary with changing relative fuel price competition. These are all difficult matters, matters moreover that must be dealt with simultaneously.

In other fuel markets, temporary imbalances are moderated through spot markets. During unexpected circumstances these spot markets act as clearing agents, and their greatest impact is felt during shorter-term imbalances. However, if spot markets are well established as a market clearing function, they also may serve as a reference point that allows contracts to adjust quite quickly. This helps stabilize markets by ensuring that the price of a fuel adjusts rapidly to competitive price changes, whether up or down.

The United States has experienced some success with a gas spot market, at least until new regulatory rules brought new difficulties. The Western

European natural gas market appears capable of enjoying substantial benefits from the institution of a spot market as well, and that potential is likely to increase with time. The growing seasonality of load, sharp competition from oil products, and the apparent over-contracting of imported gas supplies are all disturbances with which spot markets can deal efficiently. Spot markets could move gas at high prices during periods of unexpected peaks in demand, and at low prices during all periods to large users, which would help clear excess inventory.

Unfortunately, the prospects for a spot market emerging in Western Europe are bleak. There are two major impediments: national policies favoring supply security, and the absence of a common carriage pipeline system. A few words on each are in order.

There is a strong tendency in Western Europe for purchases to be made on a bilateral basis, despite the "continental consortium" buying group negotiations. In effect, each importing country decides what volume of gas it wants to take from an exporter's current offer. These individual importer volumes are collected together, and a lead organization (Ruhrgas, for example) then acts as initial negotiator. The negotiation from that point forward then is concerned not with volumes, but with price and with minimum/maximum annual takes.

In short, the volume for each country already has been determined, implying that demand also has been determined--and therefore supply sufficient to meet that demand has been secured. This perspective seems firmly entrenched, and dates from the era of concern over supply shortages.

The second impediment to the development of a spot market in Western Europe is the lack of common carriage transportation. The pipeline system in

Western Europe has become highly interconnected. Thus, the physical capability to move natural gas through the various countries of the region is not a problem for spot markets. The constraint rather appears to be some combination of unfamiliarity with such markets, and the unwillingness of certain sectors of the pipeline system to permit such carriage arrangements. Ruhrgas, for example, has been characterized as reluctant to engage in common carriage/spot market transportation arrangements. Ruhrgas is especially important for several reasons: Its system is the major access point for both Norwegian and Soviet supplies; the West German market is relatively open and regulatory interference is slight; and the large fraction of Dutch gas taken by West Germany gives it considerable potential for flexibility. There are, however, no indications of any change in Ruhrgas's reluctance to become a major common carrier in Western Europe.

Absent the use of such mechanisms as spot markets, the Western European gas market is likely to experience increasing volatility. This probability arises from rigidities in policy and practice reviewed above, and from the potential of increasingly unbalanced load factors in the future. The alternatives for dealing with this volatility are limited, but increasing the flexibility of the system certainly would help. Such actions as a pipeline between the United Kingdom and the Netherlands would open the possibility for two-way flows, including trans-shipment of Norwegian gas via the U.K. system, and/or United Kingdom access to Soviet supplies. If the Norwegian underseas pipeline now landing at Emden also had a spur landing in the Netherlands or elsewhere outside Germany, flexibility would be increased without disturbing Ruhrgas' capacity.

In certain ways, the Netherlands occupies a potentially pivotal position. Just as its location was important earlier in establishing markets for

Groningen gas, its location now could be important for brokering supplies in an oscillating market. The Groningen reserve/production characteristics have unique qualities, and if linked with other supply sources could serve another producing country (e.g., Norway) and several consuming countries' interests very well.

The future for gas markets in Western Europe is highly uncertain. Policy management will be less effective when competitive pressures are high, which they are now and will become increasingly in the future. Although Western European governments seem mistrustful of economic markets, their influence may be unavoidable, and attempts to avoid them may carry a very high cost, which someone will have to pay.

* * *

A TROLL POSTSCRIPT

A contract for the sale of Troll (and perhaps Sleipner) gas to continental buyers was announced after this chapter was completed. As of mid-June 1986, details about price and contract terms still remain unclear. Rather than recasting the analysis of this chapter in light of the Troll sale, we reflect upon the impact this sale might have on future gas use patterns in Western Europe. Indeed, the Troll sale would not change the foregoing analysis in any significant way--except to note that, once again, Norway has become a "lucky country." The trenchant question is: To what use will the reported buyers put Troll gas? Oversupply under existing contracts presently appears substantial. The previously-suggested need for spot markets likely will increase, as will the necessity to find some way to deal with seasonal load factor growth.

Three other issues are intriguing. First, the United Kingdom is the only country of the four studied that is not a party to this new Troll contract. Second, the three major producers (other than Norway)--Algeria, Netherlands, and the Soviet Union--are facing quite different competitive circumstances. Finally, the new pipeline from the Norwegian North Sea has opened prospects for additional pipeline interconnections, especially in view of the substantial remaining Norwegian reserves.

These three issues are not unrelated, and the United Kingdom is the first obvious point of intersection. Having previously failed to secure the Sleipner sale, the United Kingdom now potentially faces a "sold out" sign in Norway. It thus is faced with the prospect of relying upon domestic production or some incremental import arrangement. This chapter earlier speculated on a pipeline link from the Netherlands, and this remains a viable prospect--but only if the Dutch are able and willing to act as a broker for other imports from Norway, and/or the Soviet Union, "mixed" with its own Groningen production. Additionally, Belgium--with the new Zeebrugge link from Norway at the same point as its LNG terminal from Algeria--now also has the opportunity to link up with the United Kingdom, even though it lacks a Groningen-type supply base.

Further, the United Kingdom has had a stable contractual relationship with Algeria. Having overpriced its gas for over a decade, Algeria finds nearly half its liquefaction capacity lying idle, and is facing contract renegotiations with France, Italy, Spain, and Belgium under very unfavorable circumstances. The Troll contract leaves Algeria squeezed, and mutual interests between it and the United Kingdom now may be very strong.

The new contract may make life the most difficult of all for the Soviet Union. As noted earlier, the Soviet Union has its largest pipeline capacity directed into West Germany. Thus, it is heavily dependent upon the West German pipeline system to deliver gas beyond West Germany itself--especially to the United Kingdom (the one major market not connected to the continental system). Of course, the southern route to/through Austria to Italy (and potentially to France/Switzerland) offers some growth prospects--but not of such large volumes, and with potentially stiff competition from Algeria via an expanded TransMed Pipeline.

Soviet gas could move west as well as south, if Ruhrgas offers access and reasonable tariffs. Under this prospect, through its excess pipeline capacity, the Soviet Union might become a swing and/or spot supplier. Indeed, it may have to function like the Dutch in balancing loads, including balancing its own previously contracted volumes. This is not likely a preferred path for Soviet gas sales, but it may be the only path open to it. Otherwise, the Soviet Union will be competing head-on with Algeria for the smaller but growing Southern European markets. In view of its need for hard currency earnings, it is likely the Soviet Union will opt for the largest volume sales, under whatever conditions it must operate.

The Troll arrangement appears to bring the Western European market to greater "maturity" in terms of interconnection, and thus the market increasingly will resemble the North American situation than it ever has before. And this condition includes the prospect for a "gas bubble" of sustained oversupply conditions, especially if oil prices remain soft through the next several years. Thus, Western Europe has succeeded in securing gas as an alternative to imported oil--just as oil is becoming a relative bargain.

It will be interesting to see if Western European countries' policies, including those of the IEA and EEC, now relax pressures to reduce oil use. If so, there may be a real prospect that economic gas markets will begin to emerge in Western Europe.

ABBREVIATIONS

UNITS

Mcf = thousand cubic feet
MMcf = million cubic feet
Bcf = billion (thousand million) cubic feet
Tcf = trillion (million million) cubic feet
Bcm = billion (thousand million) cubic meters
MMBtu = million British thermal units
bbl = barrel

1 cubic meter = 35.3 cubic feet
1 cubic foot = 1000 Btus

fob = freight on board (i.e., price of good loaded on ship at point of export)
cif = cost-insurance-freight (i.e., fob price of good, plus shipping and insurance costs, or cost at point of import)

SOURCES

FT = Financial Times, daily, London
FTEE = Financial Times Energy Economist, monthly, London
IGR = International Gas Report, bimonthly, London
IPE = International Petroleum Encyclopedia, annual, Tulsa
MEES = Middle East Economic Survey, weekly, Cyprus
NYT = New York Times, daily, New York
OGJ = Oil and Gas Journal, weekly, Tulsa, Oklahoma
PE = Petroleum Economist, monthly, London
PIW = Petroleum Intelligence Weekly, weekly, New York
PPS = Petroleum Press Service, monthly, London (succeeded by PE in 1974)
WO = World Oil, monthly
WSJ = Wall Street Journal, daily, New York

NATURAL GAS SUPPLY IN WESTERN EUROPE

by
M.A. Adelman and Michael C. Lynch
assisted by Jeffrey A. Stewart

SUMMARY AND CONCLUSIONS

While natural gas is "surplus" in both North America and Western Europe, supply prospects are very different for the two regions.

In North America, the capacity to produce and deliver natural gas at prices prevailing in fall 1986, greatly exceeds what consumers are willing to take. The new but broad-based spot market price for gas has been falling for the past two years, well before the 1986 oil price drop. Spot prices in producing regions are now in the neighborhood of $1.50/Mcf. But this surplus is deceptive in two senses. First, consumer prices are only moderately affected by wellhead prices; hence, the demand response is slow. Second, from the supply perspective, few term contracts are being signed at anything near the levels of spot prices. The consensus, with which we concur, is that these prices will not support investment sufficient to maintain the current level of producing capacity. And as capacity shrinks, prices will rise.

On the other hand, in Western Europe, the price relevant to supply is hard to discern, in part because natural gas is sold to distributors and large end-users at prices that are considered proprietary, and in part because there is no short-term market by which to gain reliable information. And suppliers are willing to offer much more natural gas for long-term sales than buyers are willing to take.

Thus, the long-run disequilibrium in Western Europe appears to be the opposite of the short-run imbalance in North America. To determine whether this impression is correct requires a detailed examination of cost and supply, which this chapter undertakes.

Our conclusion is that a landed or border Western European price of even $2.50 per thousand cubic feet (Mcf)--compatible with an oil price of $12 to $15 per barrel-- rules out West Africa, the Persian Gulf, and the Pacific. But this price is enough to make profitable the investment needed to supply 10 to 15 trillion cubic feet (Tcf) annually from non-Soviet Western European sources alone, and perhaps much more from the Soviet Union. This is several times the amount of gas being sold today and more than anyone expects to be sold even in the next century. Even some egregious errors in our calculations --which are admittedly imprecise--would not affect these conclusions.

So what prevents these large volumes of gas from being developed, when that would benefit both producers and consumers? The basic explanation lies with the existence of many barriers to competition. A competitive market is a method of spreading and using information; the lack of competition has obscured basic facts on supply. The slow growth of understanding explains why natural gas prices were under downward pressure even before the oil price break.

Moreover, as will be shown, lower oil prices have drastically <u>increased</u> gas supply, an impossible result under competitive market conditions, but logical enough given current conditions in the Western European natural gas market.

The Supply Curve of Natural Gas in Western Europe

In the Western European market natural gas supply is currently overabundant as a result of the oil crises of the 1970s and the price increases that resulted. Increased drilling for oil created large additions to gas reserves. Consumers' desire to reduce oil imports, coupled with a willingness to sign natural gas contracts at high prices, led producers to develop production capacity in excess of demand.

The oil price decline of early 1986 doubtlessly will have an impact on supply. However, there will be no short-term reduction in capacity. And most of the price paid for natural gas represents not cost but economic rents, mostly to producing governments. Hence, there is room for increased supplies over the longer term, even with low oil prices.

Current installed capacity is very inexpensive to operate, since operating costs are far below current price levels. In the short term, the surplus of capacity could mean an increase in supplies from countries seeking to maintain their revenues.

As to new projects, the analysis of this chapter suggests that at the equivalent of $10/bbl of oil landed or delivered to the point of import, many gas projects become economically questionable, even excluding rents. However, with prices slightly higher, and with favorable tax regimes, substantial new supplies will be available.

Given the very large role transport costs play in producing and delivering natural gas, long-run delivered cost trends should be relatively flat. This is especially true in both Algeria, where the vast bulk of costs are for pipelines, and/or liquefaction and shipping, rather than for production, and in the Soviet Union, where pipeline costs constitute about 80 percent of total delivered costs. In the United Kingdom and the Netherlands field development costs play a much larger role.

Future supply trends are heavily dependent on government policies, but the connection between the two is complex and many-sided. In the United Kingdom, the British Gas Corporation agreed to pay higher prices for gas from the southern North Sea and thus greatly increased drilling and additions to reserves. In Algeria, the government has priced itself out of most of the markets. The recent trend for producing governments to reduce their rents has increased supply potential, and a move away from crude oil price parity would do the same, at least in the short term. Over the longer term, low oil prices would tend to increase supply from Norway and the Soviet Union.

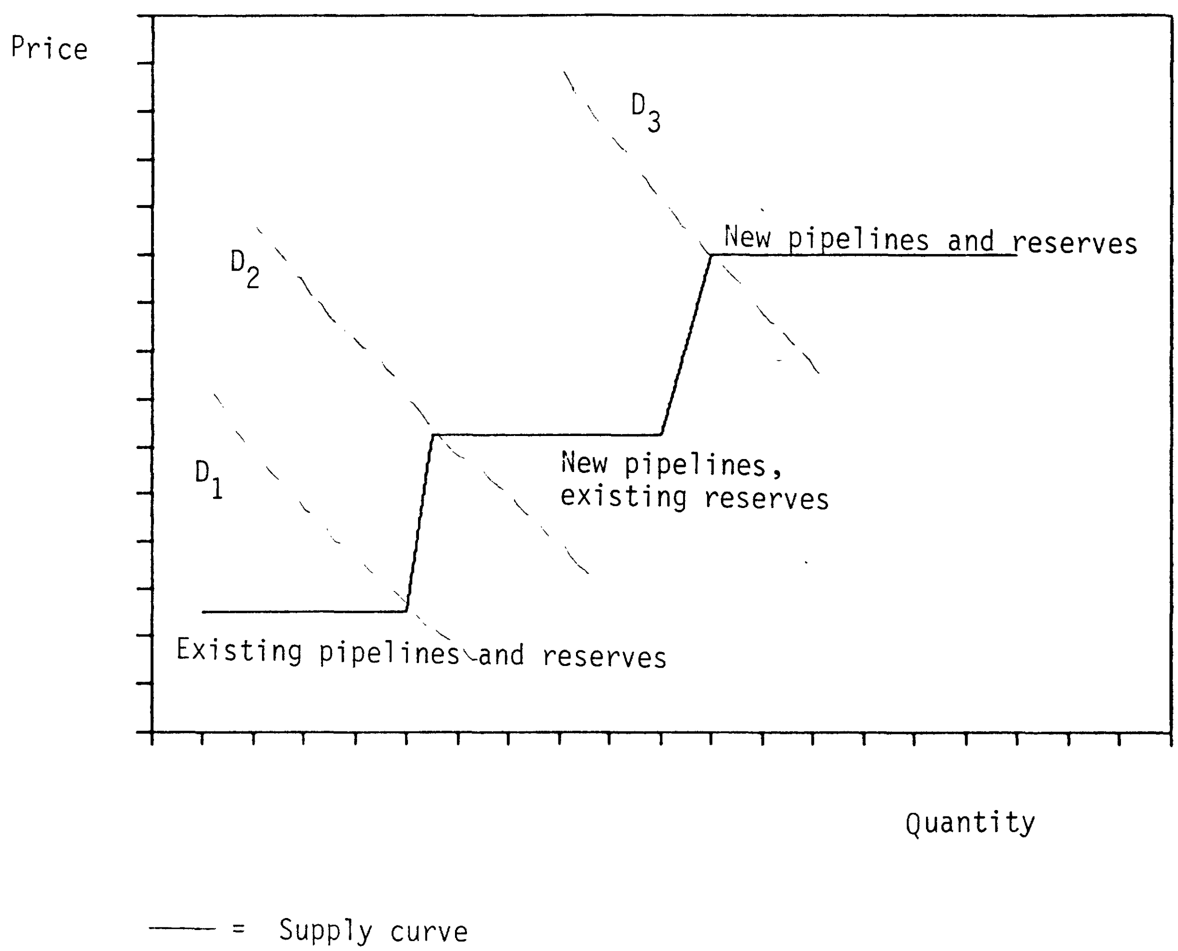
The simplest way to represent these results is to aggregate them into a supply curve. First, the shape of the theoretical supply curve of natural gas supplies is shown in Figure 1. It consists of three levels:

(1) Current capacity to deliver gas, (shown by the lowest level), will contine to operate even at extremely low prices, since variable costs for both production and transportation are quite low. Oil cannot recapture the market at any price. But much of this capacity is Algerian and Soviet, however, and may be unavailable for policy reasons, either on the producer or consumer side.

(2) The middle level shows where additional supplies can be obtained cheaply, where fields are known and partly or fully developed but where transportation constraints prevent their full exploitation. Supergiant

Figure 3-1

THEORETICAL SUPPLY CURVE



fields like Groningen, Hassi R'Mel, and Urengoi (in ascending order of costs) could increase production if pipeline or liquefaction capacity were added. (Some additional field capacity might be necessary, but the costs would be small relative to those of transportation.) This gas could be delivered at prices competitive with very cheap oil, perhaps as low as $10/bbl.

(3) Finally, large increments in supply could be obtained at higher price levels, as shown by the top level of the supply curve. This includes the costs for new fields and pipelines (or liquefaction capacity) necessary to expand greatly the amount of gas supplied to Western Europe. For a landed price ranging between $1.50 and $3.00/Mcf, most of this supply is economic, with the Troll project being in the middle and small offshore fields, which require (relatively) substantial pipeline investment, being at the high end.

At the high end of this price range, gas deliveries from more distant provinces--like Askeladden, Qatar, and possibly Nigeria--begins to become economic. However, these supplies have been analyzed only cursorily due to the fact that cheaper, closer supplies are so abundant.

It is, of course, not possible to create an exact, complete long-term supply curve based on empirical results: Many fields have not been discovered yet, and/or development costs have not been aggregated. However, because so much of the gas that is available to Western Europe over the long run comes from a relatively small number of large fields, it is possible to develop an empirical supply curve that encompasses a large portion of the supply that will be available. In addition, using the obseràtions on smaller fields that are shown in the producing country sections below, costs from areas like offshore Netherlands and United Kingdom can be estimated. Table 1 shows the numerical data used to create the supply curve for Western Europe which is presented in Figure 2.

Before analyzing the curve, some caveats are in order. While costs for fields like Troll or supplies flowing over gas gathering systems like Statpipe are reasonably well estimated, a fraction of the curve represents costs aggregations or interpolations of data, often subjectively interpretated. Further, some supplies are not included at all due to a lack of data, such as domestic production in France, Italy, and West Germany, which accounts for 20 percent of Western European consumption. However, their inclusion would not notably change the results of the curve.

The implications of the supply curve are clear: Natural gas supplies can be abundant in Western Europe for many years to come, even with very low prices, so long as policies do not inhibit them. Neither the economics of production and delivery nor the size of the physical resource will be a constraint.

Plan of the Report

This chapter is divided into three sections and two appendices. The first section provides some historical background on the development of the natural gas industry in Western Europe, then gives an overview on natural gas economics, including a brief discussion of the methodology used in this chapter. Appendix A includes a more thorough explanation of the methods and rationales underlying the critical assumptions.

Figure 3-2

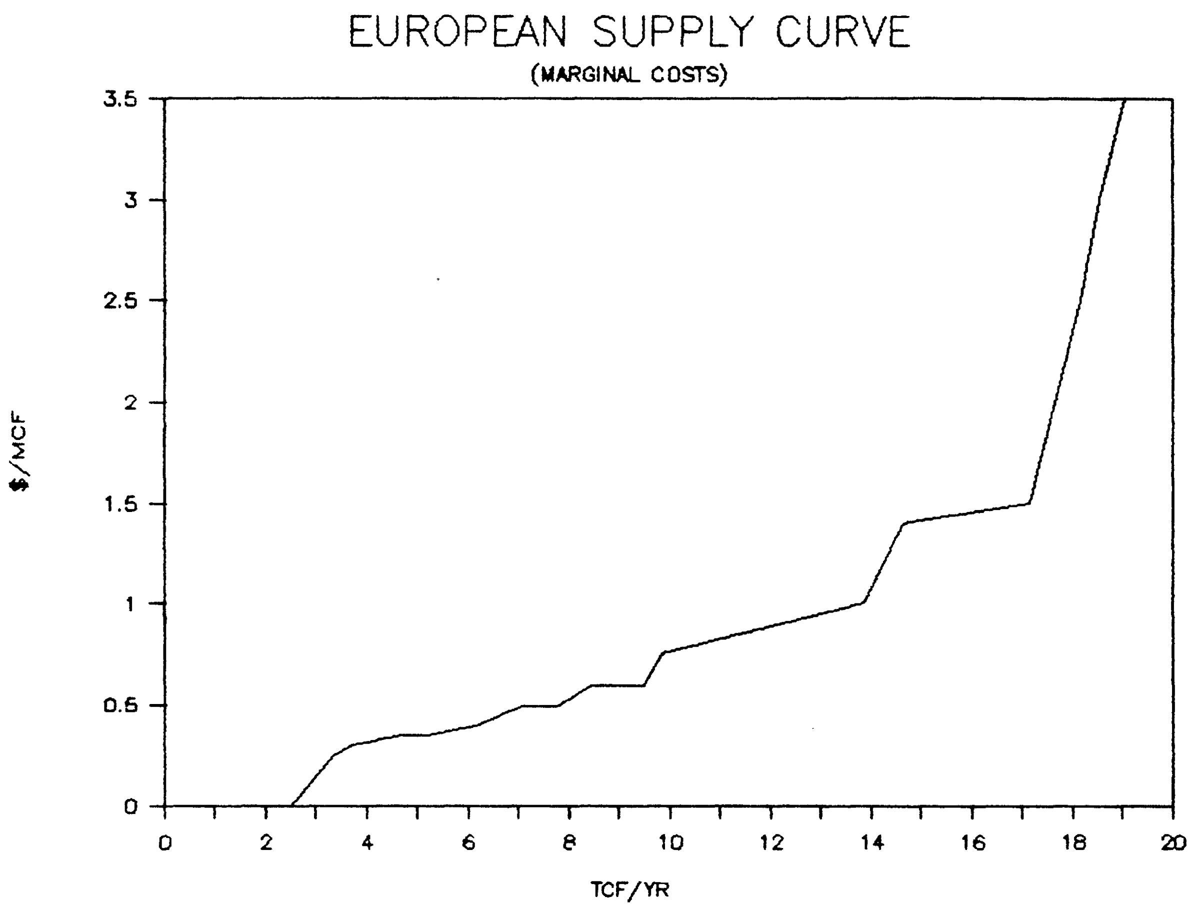

EUROPEAN SUPPLY CURVE
(MARGINAL COSTS)
$/MCF
3.5
3
2.5
2
1.5
1
0.5
0
0
2
4
6
8
10
12
14
16
18
20
TCF/YR

TABLE 3-1

WESTERN EUROPE SUPPLY CURVE

A. EXISTING PRODUCTION AND TRANSPORT CAPACITY

Country	CAPACITY Production (Bcf/yr)	Transport	MARGINAL COSTS Variable ($/Mcf)	Total
Netherlands				
Groningen	2500	2500	0.05	0.05
Other	950	1000	0.4	0.4
Norway				
Statpipe/Norpipe		700	0.5	0.5
Frigg (incl. UK share)		700	0.6	0.6
UK				
Existing southern field	850	850	0.25	0.25
FLAGS		360	0.3	0.3
Algeria				
LNG		1000	0.35	0.35
Transmed Pipeline		460	0.35	0.35
USSR				
		882.5	0.5	0.5
Urengoi pipeline		1059	0.6	0.6

B. EXISTING FIELDS AND NEW TRANSPORT CAPACITY

Algeria				
Hassi R'Mel	4000	4000		1
Rhourde Nousse	800	800		1.4
USSR				
Additional compression on Urengoi		350		0.75

C. NEW FIELD DEVELOPMENT AND TRANSPORT

Norway				
Troll	2500	2500		1.5
Sleipner	500	500		3.5
Askaladden	400	400		3
USSR				
Yamburg	1000	1000		2.5

The next section examines the main producing nations, to wit, the Netherlands, Norway, the United Kingdom, Algeria and the Soviet Union, in some detail. A brief history and some discussion of producer policies is provided for each country, but the main emphasis is on the cost structure of their respective supplies. The section concludes by unifying the analysis of the economics of the individual supplies to offer an overview of the economics of natural gas supply for Western Europe.

The final section discusses future developments, beginning with an overview of forecasts performed by other organizations. Our own expectations are discussed, including observations on marginal cost trends in both the short- and long-term, and on the impact of changed perceptions toward energy resources on the development of future supply.

Appendix B presents data on existing Western European natural gas contracts.

INTRODUCTION

The oil price spike of 1979-80 provided not only economic but political impetus for Western European consumers to sign large, long-term contracts to import natural gas. However, by agreeing to large price increases for volumes covered in old contracts as well as for new volumes, they not only rendered large amounts of gas economic to develop but also set into motion events that would drastically reduce demand. The end result has been a severe glut of supply for the past several years.

Although recent contract renegotiations have led to reductions in deliveries, Western Europe still will have to cope with this glut for years to come, including supplies still under contract, the surplus production and delivery capacity that now exists, plus that from large, undeveloped reserves. This should produce downward pressure on prices, even if oil prices recover to previous levels.

The question then is: What will the impact of lower gas prices be on supply? What resources still can be developed, and where will there be an impetus to increase sales, to add capacity rather than just to use existing capacity?

Historical Background of Natural Gas Supply in Western Europe

With its abundant coal reserves, Western Europe produced manufactured town gas for many years. The natural gas discoveries that did occur before the 1960s (mainly the Lacq field in France in 1951 and the Po Valley fields in Italy in the 1950s), were uneconomic to transport long distances and so were utilized locally. This reflected in part the low price of oil, which was gas's major competitor, plus the lack of an existing pipeline distribution system. Only the availability of substantial volumes would provide the assurances necessary to encourage the development of an infrastructure to transport gas any great distance, and so development of national gas markets did not occur.

The 1959 discovery of the supergiant Groningen field in the Netherlands changed the situation dramatically. Within five years, the Dutch realized that their gas reserves were so huge that they dwarfed potential domestic consumption. (Even now, after a quarter century of exploitation, Groningen could satisfy domestic consumption for 40 years into the future.) Because the field was so large and the costs of production so low, it was profitable for the Dutch to price the gas low enough to ensure the development of a pipeline transmission system throughout Western Europe to utilize it.[1]

The Groningen discovery also encouraged oil companies to begin drilling in the British sector of the southern North Sea, an extension of the same geological formation. There, in 1965, the first of many natural gas discoveries was made, leading to the development of a nationwide natural gas grid in the United Kingdom, which to this day is independent of the continent.

At the same time, the commercialization of LNG technology led to the signing of small-scale contracts between Algeria and the United Kingdom and France. Although the early contracts were not particularly profitable, they did prove the feasibility of the technology. By the time of the 1973 Arab Oil Embargo, LNG trade had grown several-fold, with several new contracts between the North African producers of Libya and Algeria and southern Mediterranean consumers of Spain, Italy, and France.

When the 1973 Arab Oil Embargo occurred, gas had reached only a 10 percent penetration into the continental market, and new supplies still were being discovered. The oil price increases of that time provided a spur to more extensive LNG projects in North Africa, Soviet pipeline expansion, and increased drilling in the northern North Sea. Although predominantly oil was discovered, large quantities of associated gas

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[1] This condition also was seen in the United States, where the wellhead price of gas in Texas and Louisiana was far less than the wellhead price of oil because the gas had to be shipped great distances. Algeria was able to approach f.o.b. parity for gas as a result of the panic generated by the oil crises in the 1970s, consumer government perceptions of resource scarcity, and their zeal to obtain supply at any price.

were found as well. In 1976, the British began planning the FLAGS system to utilize their associated natural gas, while the Norwegians built the 15 Bcm/yr (530 Bcf/yr) Norpipe system to tap the 170 Bcm (6 Tcf) of associated gas in the Ekofisk field and land it in continental Europe, as well as the 20 Bcm/yr (730 Bcf/yr) Frigg pipelines to deliver gas from the Frigg field to the United Kingdom.

As a result, Western European gas consumption grew from 10 percent of the total fuels market in 1973 to 14 percent in 1978; and while domestic production grew 19 percent, imports more than doubled, providing 60 percent of gas supplies.[2] After the second oil price shock, consumers frantically sought to contract for new gas supplies, while the Dutch revised their export policy to take advantage of the new atmosphere of perceived scarcity. In essence, they refused to extend their existing contracts, allowing exports to decline as contracts expired, thus "preserving" the remaining Groningen reserves for domestic consumption. To make matters worse, the new Iranian government tightened the market by cancelling the IGAT-2 project, which was to have transferred 10 Bcm/yr (350 Bcf/yr) to Western Europe over the Soviet pipeline network.

Thus, Western European demand for natural gas from Algeria, Norway, and the Soviet Union increased substantially. In response, these countries increased their price expectations. Algeria, in particular, demanded parity with f.o.b. crude oil prices, which would have made delivered LNG more expensive than equivalent delivered oil products. While importers resisted that pricing concept, they did agree to pay much

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[2] OECD Energy Balances. In this instance, Norwegian gas is considered an import.

higher prices on both new and existing contracts. As a result large amounts of production and transportation capacity were added.

However, the combination of recession and higher gas prices resulted in much lower levels of demand. Initially, consumers responded by underlifting on contracts that had either no or weak take-or-pay clauses, mainly the Dutch contracts, then renegotiating lower and more flexible take levels on other contracts. Only recently have customers demanded price reductions, and they have received some.

Yet gas frequently is being delivered for more than the equivalent crude oil price. Low oil prices can be expected to worsen further the outlook for gas prices further, and the viability of some new gas supply projects now may be in doubt. The recent signing of the Troll contract, for example, envisaged a 1995 oil price of $28/bbl, and some participants are concerned that the project will not be viable at lower levels.[3] This will be discussed in greater detail below.

Western European Natural Gas Resources

As mentioned in our previous studies of international natural gas supply, neither reserves nor resources are a fixed stock. Both are increased by investment in facilities and in knowledge. Thus, the fact that Western European natural gas "proved reserves" are equal to 34 years of production or 27 years of consumption says little about future gas availability. The rapid growth in reserves in the last two decades (seen in Figure 3) is a much more important indicator of supply trends,

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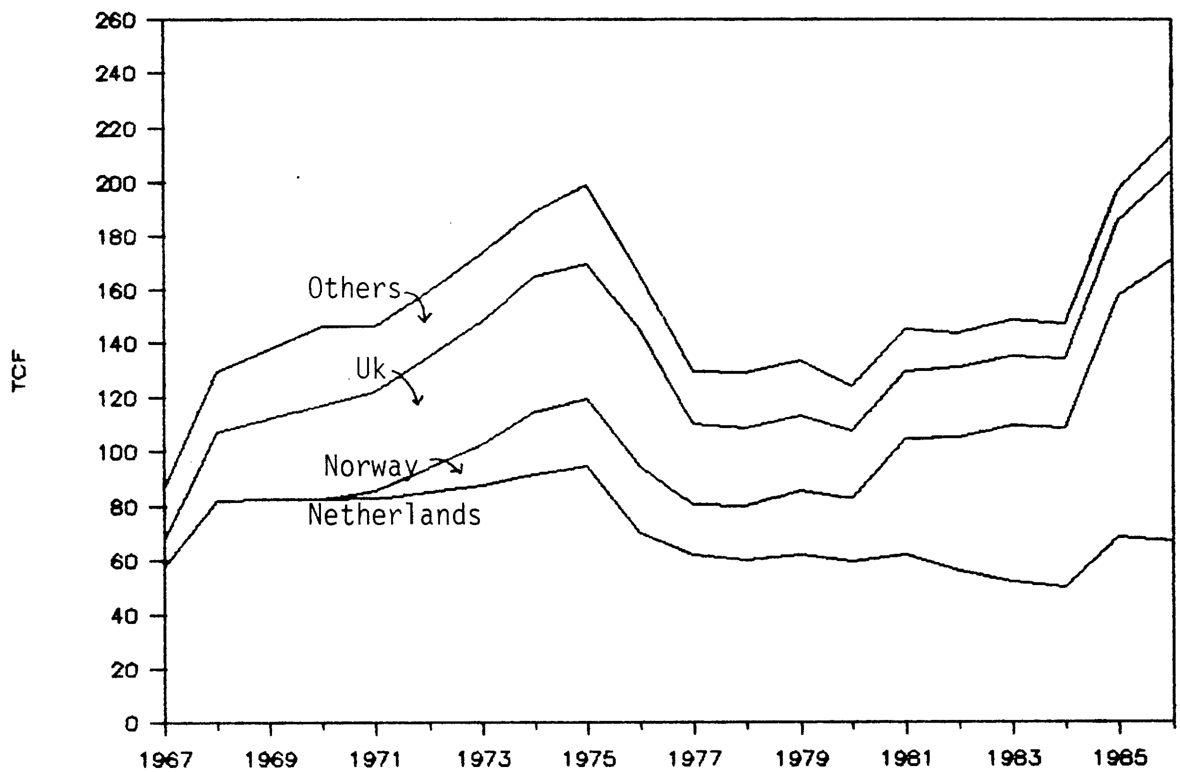
[3] See WSJ, 8/12/86, p. 32.

Figure 3-3

EUROPEAN GAS RESERVES



Source: <u>Oil & Gas Journal</u>

as is the level of drilling (shown in Figure 4) and the market price for natural gas (in Figure 5).

In assessing the natural gas resources available to Western Europe in the long-term future, estimates of undiscovered gas are indicative at best. (See Table 2 for estimates made by the U.S. Geological Survey.) These estimates define undiscovered reserves as gas that would be economic to produce given current prices, technology, and operating conditions, including tax regime. Since these factors all change over time, the amount of undiscovered producible gas will change as well.

The reserves north of 62° N off the Norwegian coast provide a perfect example of how changing conditions impact the definition of undiscovered reserves. At present, any but the largest undiscovered gas field that might exist in the Askeladden area probably would be considered uneconomic and thus not be included in the resource estimate shown in Table 2. With the development of the Haltenbanken area further south, and the construction of a pipeline from there to the Continent, the incremental cost of hooking up the Askeladden field would fall, forcing a reassessment of the viability of those resources, possibly allowing a number of large potential deposits to be added to the "undiscovered reserves" category.

Further, if the pipeline were extended northward to exploit the large, existing gas fields at Askeladden, then smaller fields would only have to bear the incremental cost of being attached to the trunkline. This would allow much smaller gas fields to be defined as economic, assuming a constant landed price for the gas, and the resource base would be greatly increased.

Table 3-2

Undiscovered Reserves - Northwest Europe

	Undiscovered Reserves Assessment (Tcf)		
	Low	High	Mean
Volume South of 62° N (Areas I and II)			
United Kingdom	7.6	27.8	16.4
Norway	32.2	118.3	69.6
Denmark	0.9	3.5	2.0
Germany	0.5	1.8	1.0
The Netherlands	5.2	19.1	11.4
Ireland	0.9	3.5	2.0
Total	47.3	174.0	102.4
Volume North of 62° N			
Norway	17.9	127.6	65.0
Total	65.2	301.6	167.4
Volume in Total Northwest Europe Assessment Area	92.0	258.0	167.0

Total Assessment Area:

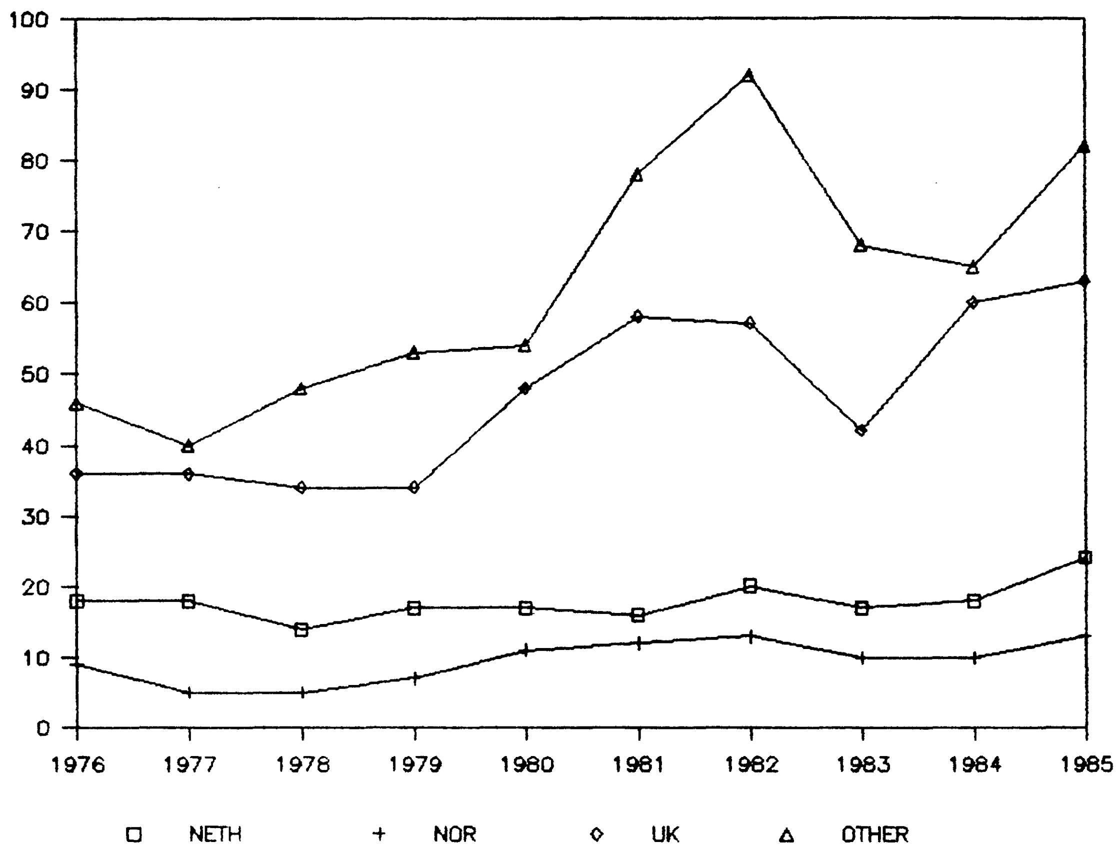
Demonstrated Reserves:	222 Tcf
Inferred Reserves:	n.a.
Cumulative Production (1/1/82)	40 Tcf

Notes: Area I consists of Viking and Central Grabens, Morray Firth basin, and partial Ireland area. Area II consists of Southern North Seas basin and partial Ireland area. Total assessment area includes all of the North Sea, as well as parts of onshore Netherlands, Belgium, and France.

Source: H. D. Klemme and Charles Masters, "Assessment of Undiscovered Conventionally Recoverable Petroleum Resources of the Northwest European Assessment Area," USGS Open File Report 84-094, USGS, Washington D.C., 1984.

Figure 3-4

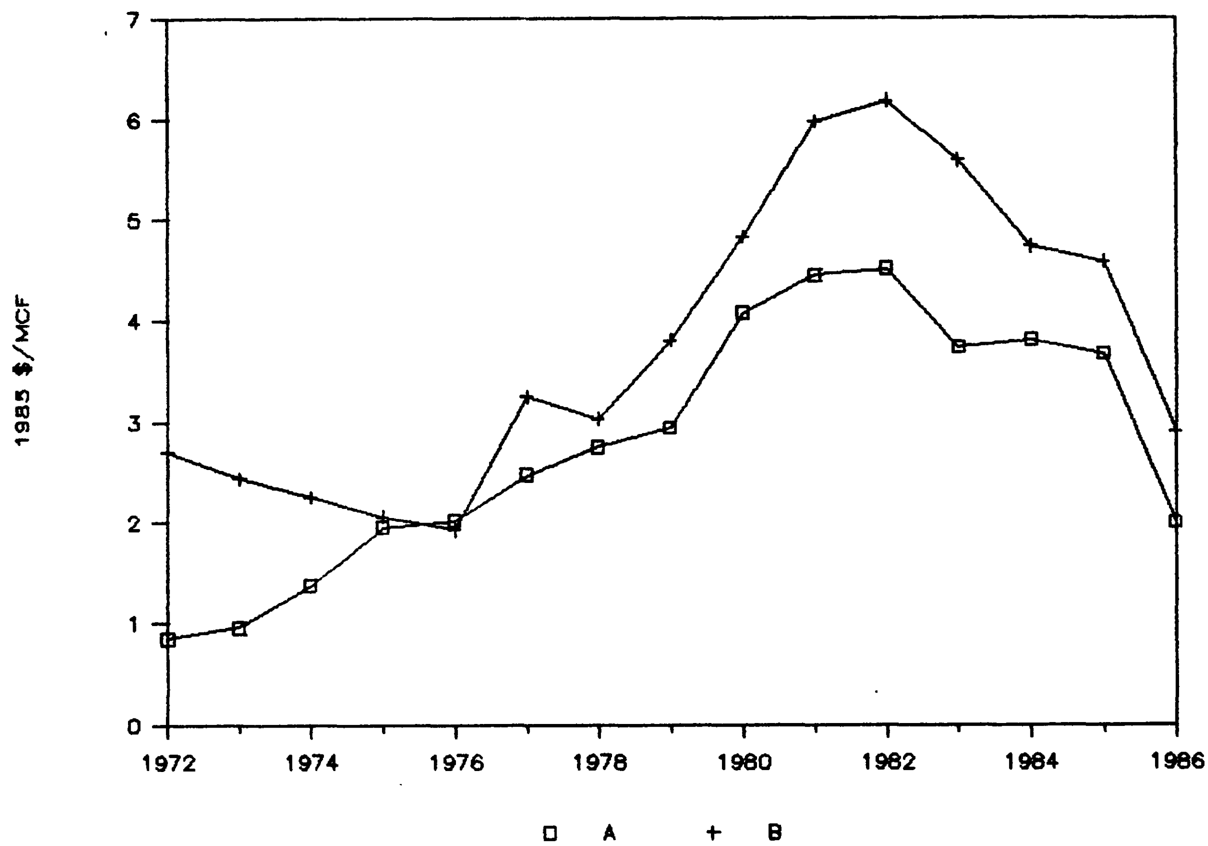
RIGS ACTIVE IN EUROPE



Source: Hughes Tool Co.

FIGURE 3-5

FRENCH NATURAL GAS IMPORT PRICES



A = Border price from Netherlands
B = Landed price for Algerian gas, regasified

Source: International Crude Oil and Product Prices, and trade press. 1986 est.

Given proved reserves of over 30 years of supply, plus undiscovered reserves that would roughly double this, natural gas supplies in Western Europe seem quite secure. Since the Soviet Union and Algeria have reserve-to-production ratios of 70 and over 100, respectively, few concerns about adequacy of supply are necessary.

Economics of North Sea Supply

In early 1986, the North Sea received considerable attention as one of two "high-cost" areas most at risk from falling oil prices. In fact, average development plus operating costs for oil in the British North Sea in 1984 were on the order of $7/bbl, with operating costs alone some $2/bbl.[4] Variable costs are naturally higher than the average for some fields, especially smaller ones, but large-scale forced shut-ins are not foreseen.[5] Even so, these costs are well below 1985 oil prices, and obviously much oil field development, at least, is quite viable economically <u>if the tax regime allows it</u>. Tax levels today are under intensive scrutiny in both Norway and the United Kingdom for precisely this reason.

However, the development of natural gas reserves is a different matter. Even with prices for oil and gas equal at the point of

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[4] M.A. Adelman, "The Competitive Floor to World Oil Prices," MIT Energy Laboratory Working Paper No. MIT-EL 86-011WP, Cambridge, Mass, 1986, forthcoming in <u>The Energy Journal</u>.

[5] Some analysts have suggested forced shut-ins will not occur in the North Sea above $5/bbl. The U.K. Energy Department has calculated production costs for older fields at $9/bbl, $15/bbl for more recent fields, and $21/bbl for fields now under development, but this obviously includes development as well as variable costs. See <u>PIW</u>, 5/5/86, p. 3.

consumption, the wellhead value of gas per unit of heat content is lower than oil because of its higher transportation and distribution costs. Moreover, at the point of consumption, gas is restricted to less valuable stationary uses, where it competes mainly with coal and residual fuel oil.

Additionally, a number of policy decisions have altered the economic environment in which gas field development takes place. The monopsony powers of the British Gas Corporation (BGC) in the British North Sea depressed wellhead prices for natural gas in the southern sector, drastically reducing incentives for finding and development. Recent steps to reverse this situation have resulted in increased drilling and discoveries.[6] Similarly, price controls in Italy have suppressed production, while West Germany at one point shut-in domestic production in favor of imports with high take-or-pay clauses.

For gas reserves associated with oil, development and operating costs are limited to the costs of processing and transporting the gas. However, as will be shown below, these are not negligible. On the other hand, associated gas and gas condensate fields contain substantial amounts of liquids, whose sales can yield substantial revenues. This can greatly enhance a project's viability.

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[6] After BGC began paying higher prices for gas from the southern North Sea, one industry journal said a "Second Boom Grips UK Gas Basin..." IGR, 4/13/84, p. 4. More recently, spending is being reduced by a number of major operators, such as BP and Britoil, and a recent report indicated that rig requirements have been cut 14 percent in the last three months. Still, a number of discoveries have been made in the southern sector that promise substantial reserve additions.

Unlike the United States, most North Sea production comes from a handful of fields. Thus, analysis of the resource economics is largely project analysis. Discerning marginal cost trends for the North Sea basin is made more difficult by the small sample size. Transportation costs cannot be generalized, given the differences in terrain which pipelines must cross. Still, past and expected development costs can be examined, as well as the role transporation costs play in delivering natural gas. The section below describes the methods applied to individual countries and projects.

Cost Assessment

There are a variety of methods by which to assess the costs of delivered natural gas: project evaluation, rate-of-return assessment, and so forth. The methods used in this chapter, which have been explained in detail in previous reports,[7] are determined by project types and the available data. This section provides a brief review of the method of calculation and assumptions used in analyzing costs; they are discussed in more detail in Appendix A.

By "cost" we mean the price that would make it barely worthwhile for a producing company to develop a given gas deposit, setting taxes equal to zero. That is, the discounted value of future revenues must exactly equal value of the capital expenditures. This yields the annualized marginal cost per unit of a project with a given time profile.

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[7] See especially the North American report, pp. 22-25, and the East Asia-Pacific report, Table 5.

This cost is the baseline for the contracting parties, i.e., the producing company and the government. They must measure this cost in order to agree on taxes and other obligations incumbent upon the producing company.

The great bulk of cost consists of the return on the necessary investment. To calculate this, need the following is needed:

- Capital expenditures for development, excluding those for exploration and bonuses, rentals, royalties, acreage acquisition, and other expenditures not needed for development. It covers field development, which includes the costs of platforms, drilling, and connecting wells and field pipelines.
- Reserves, which are total cumulative output through the facilities purchased by the capital expenditures.
- Annual output, in the initial and in subsequent years, over the lifetime of the project.
- The cost of capital, or minimum acceptable rate of return.

Given these complete data, one can write the following equation:

$$P * \frac{1-e^{-(a+i)T}}{(a+i)} = (K/R) * T$$

where P is the supply price, or cost, a is the depletion rate, i is the rate of return, or discount rate, K is the total capital expenditure, R is the amount of reserves, and T is the time of production.

The rationale underlying this equation is that a single unit produced each year over the life of the project is worth its present value, stated on the left-hand side of the equation. There will be T units delivered, each costing (K/R) up front. Given realistic values of *i*, *a*, and *T*, the left-hand side is usually simply equal to P/(a+i).

The equation can be used in either of two ways. First, we can take an appropriate rate of return i, and calculate a cost or supply price per Mcf of gas. This yields the lowest price that would make the investment barely worthwhile. Or, given a market price, the rate of return which the investor would receive (if there were no taxes) can be calculated. A government must begin with this rate, and attempt to obtain the highest possible share of it, up to the point where the company would abort the project, rather than accept anything less.

The chief problems are with obtaining the data and with using approximations to cover gaps in the data. For Algeria and the Soviet Union, there are few or no data on capital expenditures. These are estimated by using U.S. drilling and non-drilling costs for similar depth classes and geological environments. In the North Sea, expenditures are generally available by project. We think they generally tend to overstatement, perhaps for the sake of bargaining, or because of gold-plating or featherbedding. We make no corrections on this account. In some important cases, costs are so low that even an extravagant margin for error would not matter.

Reserves developed are publicly known for nearly every project or field, though the definitions used and the reliability of the data, vary widely.

Expenditures divided by reserves yield "in-ground costs" per unit. Other information is needed to derive "above-ground costs", or cost at the wellhead. An Mcf of gas in the ground is an asset, which must be held a certain length of time before it can be sold off. If each Mcf could be sold as soon as it was purchased, below-ground costs would equal wellhead costs. If it could all be sold in the first year, i.e., a decline rate of 100 percent per year, in-ground costs plus the needed return for one year, would equal the wellhead cost. In general, the higher the decline rate, the quicker the return, and hence the lower the necessary rate of return and the smaller the multiplier that transforms in-ground costs to wellhead costs.

The pattern of production and its decline rate is often unstated and we are compelled to approximate it in various ways detailed in Appendix A.

The necessary equity rate of return for companies producing oil and natural gas in the United States and Canada is about 10 percent, real. For field development in the Western European area, howeve, we use 12 percent, reflecting a somewhat higher degree of geological risk. For pipelines, which can be used by any field in the operating area, a 10 percent rate is used. The reader can easily substitute other rates.

Operating costs are assumed to be 5 percent of capital expenditures, (see Appendix A for a more detailed explanation). However, for LNG plants, 3 percent of capital expenditures is used and fuel costs are added in separately.

Pipeline capital expenditures have been reported for all major Western European projects, so transportation costs can be calculated from actual data, using the methods described in Appendix A. However, geographical diversity makes a rule-of-thumb for transportation costs impossible to develop.

Given the wildly fluctuating exchange rates of the last decade, it seems inappropriate to use actual exchange rates to convert costs from foreign currencies into U.S. dollars. Thus, we have chosen to rely on the purchasing power parity index developed by the OECD.[8] Lacking any accurate inflation index for drilling or pipeline construction costs that would be applicable to the diverse areas covered in this chapter, the implicit price deflator for the U.S. gross national product was used to convert current-year dollars into 1985 dollars.

In many cases, natural gas is not an independent product. It is frequently either associated with oil or contains liquids. In both cases, the economics are different from those of a dry gas field. For associated gas, since the costs of production must be borne by the oil being produced regardless of whether the gas is flared or piped to shore, the marginal cost of the gas is the cost of transportation. For gas fields that contain liquids, the cost of processing the liquids cannot be separated from the rest of the field development expenditures, and so the value of the liquids is subtracted from the cost of producing the gas. A $10/bbl value is assumed for the liquids, correlating to a low price for crude oil. Appendix A discusses the rationale and methods behind this in more detail.

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[8] See Michael Ward, Purchasing Power Parities and Real Expenditures in the OECD, Organization of Economic Cooperation and Development, Paris, France, 1985.

Rents to Government and Costs to Operators

In analyzing the economics of natural gas supply, taxes and other sources of rent are omitted for several reasons. First, the sheer complexity of the various systems, each bearing differently upon each individual operator and even upon each project. But even if every aspect of taxes could be accounted for, this approach would not be wise. More salient is the amount of rent attainable on the production of natural gas in any given country or region. The division of rents is a condition that the parties to a contract must negotiate. Our objective is to show both sides (and other parties) the approximate value of a project--which may be zero.

This leads to the second reason for omitting taxes and rents. The rent to the government usually acts as a cost to the operator. Therefore, a project that yields a positive pre-tax rate of return is perhaps not worth undertaking post-tax. Both parties thereby lose. The company is not a free agent, of course, and the government may not be either, depending on the circumstances. It may be constrained by public opinion to believe that "there's gold in them thar wells", and that failure to demand more rent reflects timidity or corruption by government personnel. Conversely, the operator may miscalculate or misstate costs. Thus, in the short run, rents to the government are a cost to the operator, and the short run may extend forever if both sides dig in. In the long run, both sides are better off if they negotiate on the basis of costs as they exist in reality.

Third, rents do not necessarily take the form of taxes. They may be obsolete cost factors (a particularly important factor in deep-water development, where platform costs have decreased dramatically in the last ten years). Or they may be "gold-plating" of installations, or payoffs, or overpayment of personnel, or requirements for domestic purchase of goods or services that are available more cheaply from foreign sources. Or they may be requirements to produce uneconomic oil or gas deposits, either to satisfy some local interest and produce local jobs, or to placate the fetish to preserve "precious, non-renewable resources". There are many such possibilities, and they could not possibly be measured here.

When announced investment plans are considered, and unit costs calculated from them, we do not subtract imbedded rents. Some of these rents exist to comply with government requirements. Moreover, corporations are rarely suspected of understating the costs that are submitted to governments and to public scrutiny. Nevertheless, there is usually no way of peering behind the announced numbers.

Project investments calculated by using factors drawn from the United States are relatively rent-free as far as factor inflation is concerned from 1984 onward. There were many private rents in previous years, generated by rapid expansion and resultant inefficiencies, but we consider them to be largely squeezed out now. Of course, since the U.S. numbers are averages, there is considerably more margin for error in either direction.

The next section describes the main producing countries in more detail, followed by a short section describing the small producers and potential suppliers to Western Europe, such as Qatar and Nigeria.

NATURAL GAS PRODUCING COUNTRIES

Although a large fraction of the natural gas consumed in Western Europe is produced domestically, the future of the market will depend in large part on the behavior of a handful of countries that have large gas reserves available for export. This section examines the Netherlands, Norway, the Soviet Union, and Algeria, plus the United Kingdom, which has the potential to be either an importer or exporter, depending on future prices and policies.

The Netherlands

With the 1959 discovery of the supergiant Groningen field, the Netherlands ushered in the age of natural gas into Western Europe. Like other countries, small deposits and manufactured gas had provided supplies prior to that time, covering 1 to 2 percent of Dutch energy needs,[9] with a growing natural gas industry due to a number of field discoveries. However, the Groningen field proved to be so large that it allowed a massive conversion of the Dutch economy to natural gas.

Originally estimated to contain 2 Tcf of reserves, Groningen was repeatedly upgraded so by 1963 reserves were put at nearly 40 Tcf, although today they are believed to be twice that large.[10] Although Dutch long-term planning entails a horizon distant enough to see depletion affecting the reservoir, Groningen will be a major factor in Western European gas trade for years to come.

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[9] In 1960, roughly 60 percent of gas consumed was manufactured gas. OECD Energy Balances.

[10] J. Davis, Blue Gold, p. 156.

Although the economics of Dutch gas revolve around the Groningen reserves, other, smaller fields, both onshore and offshore, have come to play an increasing part in Dutch production (see Figure 6). What stands out is the fact that Groningen is a huge reservoir, with high productivity, at medium depths, in an area having superb infrastructure, all suggesting that its gas is extremely cheap to produce. This is confirmed by the fact that, although the border price in the mid-1960s was as low as \$0.33/Mcf,[11] 72 percent of the revenues were reported to be going to the government in the form of taxes, dividends, and royalties.[12] The amount of revenue left to cover production costs and corporate return on capital could not have been large.

Our analysis of costs, discussed below, confirms this, with development and operating costs estimated to be below \$0.10/Mcf. Even assuming a large margin of error, there is little chance that the costs in this field can be significant relative to the value of the gas in the marketplace. (The costs of other Dutch fields, where known, are discussed below.)

Having gas that was far too abundant to be consumed domestically and able to compete with oil prices in the 1960s (even allowing for the costs of constructing new transmission/distribution systems) opened the door for Western Europe to enter the gas age. Contracts were signed, first with small consumers on the borders, then with the West Germans, Belgians, and French. Export prices were on the order of \$0.40/Mcf,

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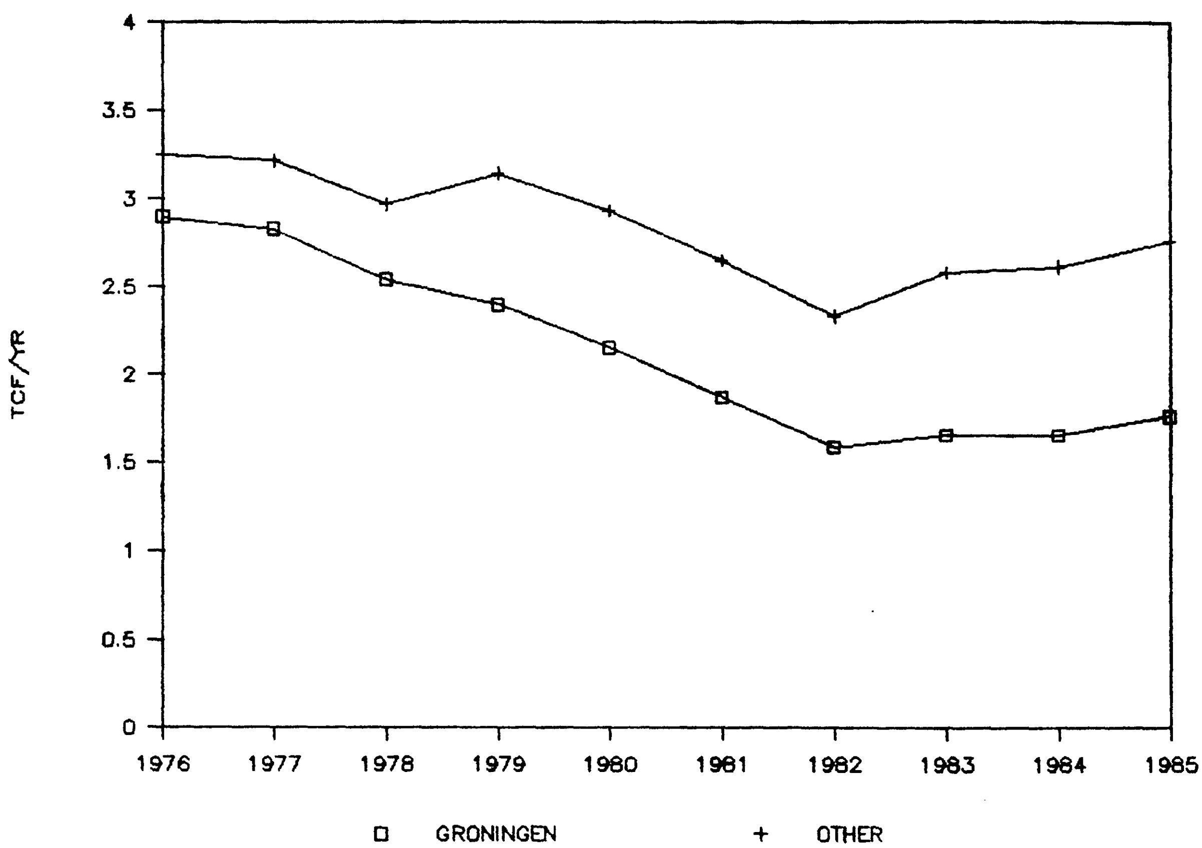
[11] Davis, op. cit., p. 161.

[12] PPS, 4/65, p. 149.

Figure 3-6

DUTCH GAS PRODUCTION



Source: Gasunie Annual Report 1985.

with links to low-sulfur fuel oil that would allow 70-75 percent of any change in oil prices to be reflected in gas prices after some delay.

Dutch policy was to allow development of the Groningen field in a measured way, so as to avoid disruption of energy markets. In other words, prices should be similar to competing fuels, which had the benefit of increasing rents to producers, and especially to the Dutch government. The other Western European countries proved to be willing buyers, and the establishment of a continental natural gas market was begun.

Within a few years, however, the spectre of competition appeared, as Soviet natural gas exports were offered in quantity. (Contracts for 25 Bcm/yr (880 Bcf/yr) were signed in the early 1970s, although the first Soviet export pipeline, to Eastern Europe, was finished in 1967. Its current capacity is 28 Bcm/yr.[13]) Concern about this development led to the first Dutch export contract signed at a fixed price, with Italy, for 6 Bcm/yr (210 Bcf/yr), in 1970.[14]

Then the oil price hikes accompanying the 1973 Arab Oil Embargo increased both the demand for and price of gas, and energy markets underwent drastic change and the suppliers' fear of competition was replaced by the consumers' fear of shortages. In addition, the added premium for more secure energy supplies meant that natural gas' value relative to oil was perceived to have increased, although perceptions differed among producers, importing governments, and actual consumers. This allowed the Dutch to ask for and receive much higher prices for

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[13] Davis, op. cit., p. 124.

[14] PE, 6/74, p. 228.

their exports, including renegotiation of the Italian contract that raised the base price and included an indexation to oil.

At the same time, the new atmosphere of perceived resource scarcity led Dutch policymakers to become concerned about the future of domestic energy resources. Gasunie felt that its gas reserves needed to be "conserved" for more valuable uses, and not "wasted" where less noble fuels would suffice. Thus, the Dutch gave priority to the distribution companies serving residential and small commercial users; ultimately, supplies for electricity generation were to be phased out. The plan was to allow export contracts to expire without renewal or extension, leaving enough reserves to supply domestic needs well into the next century. After 1973, at which time 50 percent of the then-known reserves were committed, no new contracts were signed.

This policy also was reflected in Dutch attempts to acquire gas from other sources to prolong the availability of cheaper domestic gas. Thus, The Dutch signed a contract with Norway for 1.7 Bcm/yr (60 Bcf/yr) from the Ekofisk field, and, in 1978, for 4 Bcm/yr (140 Bcf/yr) of Algerian LNG to be delivered starting in 1984, though this was subsequently cancelled.[15] Negotiations to import gas from the Soviet Union also were undertaken, but no contract was signed.

The increase in gas prices also meant a startling increase in government revenues. By 1975, half of all corporate taxes came from the gas industry, and royalties and the profits from the state's share of Gasunie were even larger. Of government revenues in 1975, 8 percent

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[15] PE, 12/78 p. 533.

came from the gas industry.[16] This increased the value of Dutch currency and made non-gas exports more difficult, leading to the coining of the term "Dutch disease" to denote the damage to non-mineral sectors of the economy that resulted from large-scale mineral exports.

With the second oil price shock in 1979, the Dutch demanded new changes in their contracts. By spring 1980, higher oil prices and the expressed willingness of consumers to pay higher prices to other exporters, led the Dutch Economics Minister to threaten to halt exports if gas price renegotiations were not satisfactory. The result was much higher prices and a change to indexation with low-sulfur fuel oil prices, readjusted monthly. At the same time, the Dutch refused Algerian demands for higher, crude oil-related prices on their LNG contract, and as a result it was cancelled.

However, the Dutch did not have the same take-or-pay protection as their competitors. When the additional supplies and the higher prices clashed with the weakening economy, commitments to take gas could not be met and the Dutch bore the brunt of the loss. For example, France cut back its cheaper Dutch supplies in 1982 by 39 percent while Algeria's market share increased by one third, despite its higher price.[17]

Overall, Dutch exports fell drastically, by 30 percent in 1982, with overall sales (i.e., including domestic) falling 12 percent. With the increased prices, revenues were slower to fall, though they were

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16 From International Financial Statistics, International Monetary Fund, and PE, 8/75, p. 295.

17 PIW, 5/2/83, p. 11.

far below those anticipated, and this discrepancy caused some economic problems.

In 1983, the reduction in sales and the addition of reserves from new discoveries led to an official reassessment: Gas supplies were no longer to be hoarded for future domestic use. The Dutch now sought new contracts (especially with the United Kingdom) and ten-year extensions of old contracts, at the same time reducing prices to defend existing market share. Price indices were changed to include gasoil, rather than just low-sulphur fuel oil, which had the effect of making them more responsive to changes in the heating market and lowering them slightly as of October 1, 1984.[18] Appendix B shows the extensions that have been signed to date.

The Dutch were, in fact, disappointed at BGC's reaction to their offer of supply. The Minister for Economic Affairs indicated that "...statements suggesting that such gas is over-priced astonish me."[19] In fact, the Dutch said they had offered to be competitive on price, flexible on supply, and to finance the pipeline.[20] Despite all this, BGC apparently felt comfortable with the cushion of supply that would be provided by the impending Sleipner deal and the existing domestic supply, and turned the Dutch away.

Dutch policy now has come full circle. At present, the Dutch rely on competitive prices to maintain export levels. Although they still

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18 <u>FT</u>, 1/21/85, "Netherlands Survey," p. IV.

19 <u>IGR</u>, 4/13/84, p. 7. Dutch gas was argued to be 10 to 20 percent more expensive than Sleipner gas. See <u>PE</u>, 5/84, pp. 188-189.

20 <u>PE</u>, 5/84, p. 189.

have gas available for export, however, major increases in exports probably will not be sought while oil prices are low.

The Resource Base

It is not possible to separate the role of Groningen gas in the Dutch resource base from that of other, smaller fields. Increasingly higher estimates of the reserves in Groningen have helped undo the Dutch perception that it is a rapidly depleting resource.[21] Beyond that, the discovery of numerous fields in the Dutch North Sea has provided a significant boost to reserves. Figure 7 shows the rate of growth in all Dutch reserves over the last two decades.

The Economics of Dutch Supply

Table 3 indicates that, given what is known about well depth and productivity, the cost of gas from Groningen appears to be lower than one cent per Mcf.[22] This would seem astonishing but for the nature of the reservoir as described above, which suggests that Groningen gas is among the world's cheapest. No field today has similar characteristics and is also located in a major consuming area.

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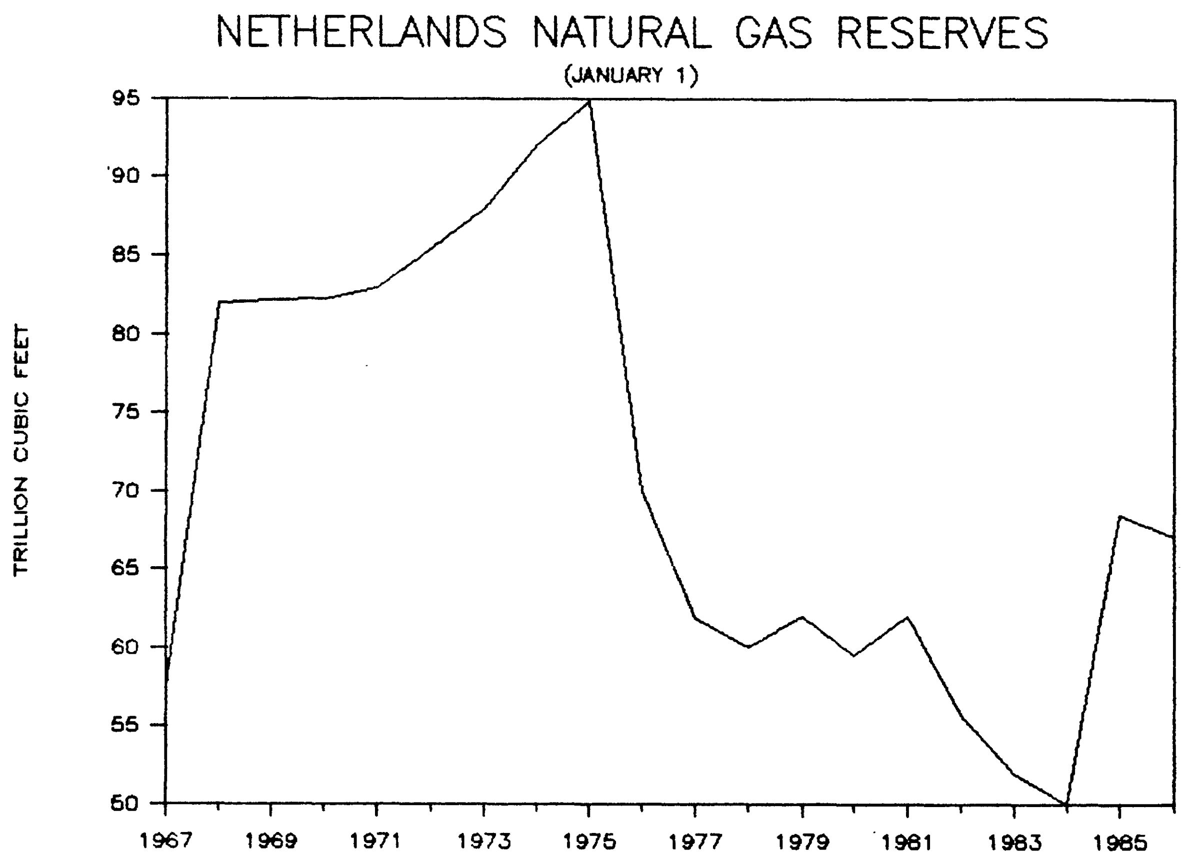
[21] IPE, 1977 puts total reserves at 58 Tcf, while Peebles, 1980, (cited in Davis, *op. cit.*, p. 156) states that industry put them at 70 Tcf.

[22] An early report suggested that well productivity for one of the initial clusters would be 26 MMcf/d, substantially lower than that reported in the 1977 IPE. Even so, this would increase costs only to the vicinity of 140/26 x \$0.006/Mcf, or \$0.03/Mcf. See PPS September 1963, p. 346. In a later report, modifications in well design were said to have increased well productivity from approximately 50 MMcf/d in the first 14 clusters of 8 to 11 wells, to as much as 110 MMcf/d in subsequent clusters. See WO, 1/73, pp. 38-39.

Figure 3-7



Source: Oil & Gas Journal.

Table 3-3

Dutch Gas Development-Operating Costs

Groningen

1	Drilling and equipping costs per well	640 ($ M)
2	Allowance for non-drilling costs per well	480 ($ M)
3	Allowance for gathering per well	340 ($ M)
4	Total development costs per well	1460 ($ M)
5	Depletion	0.04
6	Annual development-operating costs per well	307 ($ M)
7	Development-operating costs per day per well	840 ($)
8	Average production rate per well	140 (MMcfd)
9	Average development-operating costs as sold	140 (MMcfd)
10	Marginal development-operating costs as sold	0.006 ($/Mcf)
11	Development costs in ground	0.008 ($/Mcf)
		0.001 ($/Mcf)

Sources:

1. Joint Association Survey, 1984, figure for 9,500', Onshore Texas. 1984 development costs converted to $ 1985 using implicit price deflator from Economic Report of the President.
2. Assumed to be 75% of line 1.
3. Assumed to be 30% of line 1 + line 2.
5. 1984 Dutch production / Dutch reserves at year end, from Oil and Gas Journal, December 31, 1984, p. 74.
6. Line 4 * (0.12 + 0.04 +0.05), allowing 12% discount rate, 4% depletion, 5% operating costs.
7. Line 6 / 365.
8. International Petroleum Encyclopedia, 1977, p. 239.
9. Line 7 / ((line 8) * 1000).
10. (line 9) * ((line 5 + i) / i) i = 0.12.
11. Delevopment costs at wellhead = line 4 * 0.16 / 51,100 MMcf/year = $0.005/Mcf (0.16 = depletion + discount rate, 51,000 MMcf = yearly production).
    Development costs in ground = development costs at wellhead divided by (1 + (i / a)) i = 0.12, a = 0.04.

In the Netherlands, the role of Groningen is dominant, although the Dutch increasingly are turning to higher-cost supplies. The smaller offshore fields naturally are more expensive.

At present, however, there is not enough information to estimate the long-term marginal cost trend in the Netherlands. Several field development reports, shown in Tables 4 through 6, show that the offshore fields are much more expensive than Groningen. This suggests that marginal costs for the Dutch can be expected to increase, but also that future supplies will not provide rents for the government on the scale that gas Groningen has.

Norway

After the presence of hydrocarbons was found in the southern North Sea, albeit natural gas and not oil, drilling moved to the northern areas, where water depths were likely deeper and the weather worse, but where prospects for oil were thought to be good. The Ekofisk field, located in 1968, was the first of the major oil discoveries. Its large reserves of associated gas led to the development of the Norpipe pipeline system for deliveries to Emden, West Germany. The first large gas field, Frigg, with 10 Tcf of reserves, was discovered in 1972, and led to a contract with the United Kingdom for delivery of up to 15 Bcm/yr (530 Bcf/yr).[23]

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[23] Reserves, of which 40 percent are in the U.K. sector, from IPE, 1977, p. 239. Delivery volumes are geared to production, and the Norwegian exports have been about 12 Bcm/yr (425 Bcf/yr). See BP Review of World Gas.

Table 3-4

Dutch Gas Development-Operating Costs

Ameland Field

1	Drilling and equipping costs per well	3.15 ($ MM)
2	Allowance for non-drilling costs per well	2.36 ($ MM)
3	Allowance for gathering per well	1.65 ($ MM)
4	Total development costs per well	7.16 ($ MM)
5	Depletion	0.05
6	Annual development-operating costs per well	1.58 ($ MM)
7	Development-operating costs per day per well	4.33 ($ M)
8	Average production rate per well	33.300 (MMcfd)
9	Average development-operating costs as sold	0.130 ($/Mcf)
10	Marginal development-operating costs as sold	0.184 ($/Mcf)
11	Development costs in ground	0.029 ($/Mcf)

Sources:

1. Joint Association Survey, 1984, figure for 10,000', Offshore Louisiana. 1984 development costs converted to $ 1985 using implicit price deflator from Economic Report of the President.
2. Assumed to be 75% of line 1.
3. Assumed to be 30% of line 1 + line 2.
5. Assumed, 1984 Dutch production / Dutch reserves at year end = 0.04, from Oil and Gas Journal, December 31, 1984, p. 74. 0.05 used due to low Groningen depletion.
6. Line 4 * (0.12 + 0.05 + 0.05), allowing 12% discount rate 5% depletion, 5% operating costs.
7. Line 6 / 365.
8. Oil and Gas Journal, January 27, 1986, p.68.
9. Line 7 / line 8.
10. (line 9) * ((line 5 + i) / i) i = 0.12.
11. Development costs at wellhead = line 4 * 0.17 / 12.16 Bcf/ year = $0.100/Mcf (.17 = depletion + discount rate, 12.16 Bcf = yearly production).
    Development costs in ground = development costs at wellhead divided by (1 + (i / a)) i = 0.12, a = 0.05.

Table 3-5

Dutch Gas Development-Operating Costs

F/3 Project (F/2, F/3, F/6 Fields)
Oil & Gas Project

1.	Development costs	650 ($MM)
2.	Reserves	423 (Bcf)
3.	Average production rate	66 (Bcf/year)
4.	Depletion (Q/R)	0.156
5.	Development costs in ground	1.537 ($/Mcf)
6.	Development costs as sold	2.718 ($/Mcf)
7.	Operating costs	0.492 ($/Mcf)
8.	Development-operating costs as sold	3.210 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	2.546 ($/Mcf)

Sources:

1. International Petroleum Encyclopedia, 1981, p. 204. Development cost given in $ 1981, converted to $ 1985 using implicit price deflator from Economic Report of the President.

2,3. World Oil, August 15, 1985, p. 78.

5. Line 1 / line 2.

6. (line 1 / line 3) * (line 4 + i) i = 0.12.

7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

8. Line 6 + line 7.

7. Line 8 - (yearly revenue from oil sales / line 3) = line 8 - ((4,380,000 bbl) * ($10/bbl)) / (line 3 * 1000). Oil production rate from World Oil, August 15, 1985, p. 78. $10 oil price assumed.

Table 3-6

Dutch Gas Development-Operating Costs

Zuidwal Field

1.	Development costs	432 ($MM)
2.	Reserves	883 (Bcf)
3.	Peak output	53 (Bcf/year)
4.	Field life	20 (years)
5.	Depletion	0.019
6.	Development costs in ground	0.489 ($/Mcf)
7.	Development costs as sold	1.208 ($/Mcf)
8.	Operating costs	0.408 ($/Mcf)
9.	Development-operating costs as sold	1.616 ($/Mcf)

Sources:

1,2,4. International Gas Report, September 28, 1984, p. 7. Development costs given in Guilders 1984, converted to $ 1985 by dividing by the 1984 Purchasing Power Parity, from Purchasing Power Parity and Real Expenditures in the OECD, and multiplying by the ratio of 1984 / 1985 implicit price deflator from the Economic Report of the President. (Note that the costs include a 15 kilometer pipeline.)

3. Petroleum Economist, September 1983, p. 360.

5. a = 0.019 to satify the equation Q * (1 - exp (-at)) = aR
Q = 53, t = 20.

6. Line 1 / line 2.

7. c = (line 1 * (i + a)) / (line 3 * (1 - exp (-(i + a) * t)))
i = 0.12, a = 0.019, t = 20.

8. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

9. Line 7 + line 8.

The Norwegian sector of the North Sea has not proven to be as gas prone as the southern North Sea, although several smaller fields, like Cod, have been connected to the Ekofisk pipeline and sold into continental Europe. The third major gas development was the Statfjord sale, in 1981, which involved associated gas located 150 miles north of Frigg, well to the north of Ekofisk. It entailed laying the longest underwater pipeline in the world, partly to allow the wet gas to be processed at Karsto, in Norway, before transshipment to the continent.

Subsequently, however, the industry began discovering more gas than oil--specifically the Sleipner and Troll fields-- while the area north of 62° N, opened for drilling in 1979, yielded almost exclusively gas. Given transportation costs, this northerly gas is much less likely to be developed than similarly located oil fields would be. (The precise economics, insofar as they have been estimated, are discussed below.)

After the sale of Statfjord gas to a consortium of buyers in continental Europe, the Norwegians turned next to marketing the Sleipner field, located 200 miles north of Ekofisk and containing about 7 Tcf of reserves. Given the glut in natural gas supplies on the continent and the optimistic price expectations of the Norwegians, only the United Kingdom showed real interest. After protracted negotiations, an agreement with the BGC was reached in late 1984. This included a base price of $4.10/Mcf ($1.40/Mcf less than the Statfjord base price, partly reflecting the drop in oil prices), lower volumes than the Norwegians had wanted to sell, especially peak volumes, and a sharing of the tax revenues from the gas liquids pipeline, which the British wanted landed in the United

Kingdom with the gas, but which the Norwegians insisted on landing in Norway.

However, in early 1985 the U.K. government intervened and cancelled the deal for a variety of reasons (discussed below). This left the Norwegians with a "small" gas field unsold at the same time they were trying to market the much larger Troll field. This suggested to the Norwegians that Troll gas would be much harder to sell than originally thought.

The Norwegians floated several responses to the Sleipner cancellation. First, they suggested that, given unwillingness to accept the gas contracts being offered, oil field development would be accelerated to maintain the domestic offshore service industry, and further supplies of gas simply would not be forthcoming. A second tactic was a change to offering quantities of gas rather than entire fields, leaving the development decision and source of gas to by made by the Norwegians. Of course, new contracts still would have to involve large quantities if fields like Troll were to be developed, but smaller fields could provide incremental volumes. (In fact, the Tommeliten field, which contains only 750 Bcf, is slated for development to provide several years of supplies to the Ekofisk field to help with its subsidence problem.)

Thus, it came as quite a surprise to many observers in spring 1986 when not only was a contract concluded that would justify development of Troll, but that would include the Sleipner field as well. By all accounts, the buyers were seeking gas from Troll, and the Norwegian government encouraged them to increase purchases to cover Sleipner also. To date, many details of this deal are not clear, but an analysis of the economics of the development is provided below, followed by a more general analysis of Norwegian supply economics.

Troll

Except for the Soviet-Western European contract for Urengoi natural gas, the Troll contract is the largest ever signed, covering 450 Bcm (1.6 Tcf) of gas to be delivered from 1993 to 2020. At present, reports of project costs are not entirely clear, but some information is available.[24]

Originally, the planned Troll field development called for a $6 billion investment, which would have produced 1.5 Bcf/d and 70 tb/d of oil.[25] Gas would be piped over either the Frigg field pipeline or through the Statpipe system. The plan to include oil production reflected the government's insistence that oil not be left in the ground.[26] The uneconomic oil has now been excluded, and the project was revised to reduce costs and the length of time required to develop the field.

The volumes of gas to be delivered include 1.76 Tcf from Sleipner and 14.12 Tcf from Troll. The delivery period is 1993 to 2020, with gas being delivered first from Sleipner, then from Troll (which makes

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[24] The Troll development revision was announced only in April 1986, and details have been forthcoming only in the last few months. Therefore, much uncertainty lingers as we analyze the development.

[25] OGJ, 11/28/83, p. 48.

[26] The Norwegians were hardly alone in their belief that the oil must not be left behind without regard for the economics of its development. As the Nordic editor of the Financial Times put it, "...only an altruistic [sic] political decision by the Storting to abandon the oil layer would make [large-scale gas exports] possible before the next century." See FT, 9/24/82, p. 32.

up the great bulk of the project). Expenditures fall into three categories: \$1.92 billion for Sleipner development, \$3.2 billion for Troll field development, and \$2.56 billion for pipeline and the Zeebrugge shore terminal construction.[27]

It is hard to say whether the pipeline expenditures are necessary. Originally, it was expected that Troll gas would be piped the short distance to the United Kingdom, and either be sold there or piped over land a short distance, then under the Channel to the Continent. (The decline of production from Frigg in the mid1990s will also allow deliveries of increasing amounts of gas to the United Kingdom without new pipeline construction.) The current project calls for an undersea pipeline of nearly 700 miles to Belgium, although early volumes will be sent through Statpipe.[28]

In any case, the current plan is designed to cover the cost of laying a new pipeline, and it leaves three-fourths of Troll gas undeveloped. It therefore is proper to look at the capital costs of production for the Troll field. The operating conditions are extremely difficult, since the field lies under 1100 feet of water, yet is so close to the seabed that directional drilling cannot be used. Still, very high production rates bring unit costs down to low levels.

Total Troll field capital expenditures are \$3.2 billion, which indicates an in-ground cost of \$0.227 per Mcf. However, the formula $(1+(i/a))$, developed earlier, cannot be used, since the duration of the

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27 OGJ, 6/9/86, p. 19.

28 OGJ, 9/22/86, p. 26.

flow is limited and there is no indication of any decline rate. Some simplifying assumptions must therefore be made: that the delivery period is 23 years, and that there is zero decline. (The lower the decline rate for any given cumulative output, the higher the cost of holding the asset in-ground.) The formula equation [7] from Appendix A can then be used:

$$P * (1-e^{-23i})/i = \$.227 * 23$$

The rationale for the equation is that the right-hand side is the up-front outlay for 23 Mcf, to be delivered at a rate of 1 Mcf per year for 23 years; the left-hand side is their present value. If a value for i, the necessary rate of return, is assumed, P can be computed as the supply price, or cost. Conversely, if a value for the net price is assumed, the rate of return, i, can be determined.

If the needed rate of return is 12 percent, then P = \$0.669/Mcf.[29] Conversely, at a price of \$3.50, as has been reported,[30] the rate of return, before taxes, is 67 percent.

This calculation relates only to field development. Pipelines are necessary before the initial sale can be completed, and the price of the gas must cover the full cost of developing the pipeline. Subsequent sales will pay only pipeline operating and maintenance costs. Pipeline (and shore facilities) are slated to cost \$2.56 billion. While capacity is said to be planned for as much as 40 Bcm/yr (1412 Bcf/yr), we shall

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29 If a 10 percent internal rate of return were employed, as was done recently by a Statoil official in calculating costs for Askaladden, a supply price of \$0.58/Mcf results, as shown in Table 7. See PE, 1/86, pp. 8-10.

30 PIW, 6/9/86.

assume that the full costs will be borne by the sales announced to date, which total 20 Bcm/yr (706 Bcf/yr).

At that rate, transportation costs will total \$0.62/Mcf, or 8.8 cents per Mcf per 100 miles. Additional volumes, such as the 4 Bcm/yr (140 Bcf/yr) of sales now being discussed for Austria, Spain, and Italy, may cost less to transport, if only additional compression is required.[31]

Re-estimating the rate of return with these pipeline costs simply involves subtracting the transportation costs from the landed price. Thus, a \$3.50/Mcf landed price becomes a \$2.90/Mcf wellhead price. (The precise price formula is unclear at this point, though the widely-cited \$3.50/Mcf price has been said to correspond to an oil price of \$28/bbl.[32]) Operating costs for the field will be \$0.23/Mcf. Subtracting that from a \$2.90/Mcf wellhead price, yields \$2.67/Mcf to cover capital costs, which would give an internal rate of return of 51 percent. Table 7 shows sensitivity analysis for various assumed rates of returns and wellhead prices.

Calculating the rate of return at a price of \$3.50/Mcf may be counting the chicks before they hatch. "The agreement gives all the buyers the right to renegotiate prices, volumes, and length of the contract."[33] Unless the Western European gas market can be controlled and prices fixed above the market-clearing level, or unless oil prices

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[31] PIW, 7/7/86, p. 10.

[32] WSJ, 8/12/86, p. 32.

[33] OGJ, 6/9/86, p. 20.

TABLE 3-7

Troll Sensitivity Analysis

A. Initial volumes

Price of oil in $/bbl:	10	15	20	25	30
Equivalent landed price of gas in $/Mcf	1.67	2.50	3.33	4.17	5.00
Pipeline costs	0.62	0.62	0.62	0.62	0.62
Operating costs	0.23	0.23	0.23	0.23	0.23
Wellhead netback	0.82	1.65	2.48	3.32	4.15
Rate of return	15.6%	31.6%	47.6%	63.5%	79.5%

B. Subsequent Volumes (no pipeline capital costs)

Price of oil in $/bbl:	10	15	20	25	30
Equivalent landed price of gas in $/Mcf	1.67	2.50	3.33	4.17	5.00
Pipeline variable costs	0.18	0.18	0.18	0.18	0.18
Operating costs	0.23	0.23	0.23	0.23	0.23
Wellhead netback	1.26	2.09	2.92	3.76	4.59
Rate of return	24.1%	40.0%	56.0%	72.0%	87.9%

C. Supply Price if IRR is assumed

Assumed rate of return	8.0%	10.0%	12.0%	15.0%	20.0%
Capital Costs	0.50	0.58	0.67	0.81	1.05
Operating costs	0.23	0.23	0.23	0.23	0.23
Pipeline costs	0.62	0.62	0.62	0.62	0.62
Equivalent landed price of gas in $/Mcf	1.35	1.43	1.52	1.66	1.90
Equivalent price of oil in $/bbl	8.08	8.58	9.11	9.95	11.43

recover much more strongly than we expect, the chance of ever collecting such a price seems unlikely. But the project appears to be viable even at lower oil prices.

If we assume that the price of gas stays approximately equal in thermal value to the price of oil at $10/bbl, i.e., about $1.67/Mcf, then the Troll rate of return is about 24 percent (after allowing for operating costs; see Table 7). In other words, if the initial contract covers the pipeline costs, the rest of the Troll field is viable even if oil prices are below $10 when production begins.

The chief obstacle to sales at such prices lies in the chagrin of the Norwegian decision-makers. Only a few years ago, they could have pre-sold the Troll field at $6 and, allowing a $1 return to the operating company, for $5 to Norway. At present, they probably cannot obtain more than half of that net, and if the price of oil stays at current levels ($15), and the gas price stays near the thermal parity ($2.50), they will receive only about $1.50/Mcf. Moreover, pre-selling Troll would have started development several years sooner. Thus the Norwegian policy of holding out for a very high price for the so-called "ultra-expensive Troll gas" turns out to have been a great mistake, resulting in the loss of well over half the value of the asset.

This is, of course, complicated by the fact that no contract is inviolable, and no price agreement is guaranteed fixed. Although Statfjord gas was sold at a high price, changes in the market environment meant that the price was subsequently renegotiated downward.[34] Still, the overall Norwegian policy of "orderly development", to avoid the economic difficulties faced by the Dutch, and to ensure the maximum amount of Norwegian content in the offshore industry, has delayed development and reduced the benefits to the country. Many observers in the private sector have suggested that faster development with investment of the surplus rents overseas would reduce the impact of the "Dutch disease," but this policy has not been accepted by the government.[35]

The current state of the Troll field development has been substantially clarified by the recent announcement that the project partners had unanimously agreed to accept the government's tax concessions and to submit development plans to the government.[36] (The buyers must still approve the purchase contracts by October 15 in order to meet the project deadline.) According to this report, Shell estimated that, should oil prices remain at $15/bbl, the rate of return for the project would be 8 to 10 percent. Referring to Table 7, we can see that, using our calculations of the project economics, the cost of the landed gas would be between $1.35 and $1.43/Mcf, if those rates of return hold. The equivalent price of oil would be much less than $15/bbl, but this can be explained by two factors.

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[34] The willingness of the Norwegians to respond to market conditions in this manner probably helped persuade customers that they would not bear all of the market risk for the Troll contract, which would have contributed to their acceptance of the contract.

[35] See PE, 11/75, p. 429, and NYT, 3/18/85, p. D9.

[36] See PIW 9/22/86, p. 10.

First, the contract apparently calls for the landed price of the gas to be less than the equivalent crude oil price. As noted above, at $28/bbl for oil, the gas price would be $3.50/Mcf, or 75 percent of the Btu-equivalent price of oil. Assuming that this ratio is constant for all oil prices, and we have no knowledge one way or another, then a $15/bbl price for oil would mean a landed price for the gas of $1.875/Mcf, somewhat higher than the cost cited above.

This discrepancy is not serious, however, since it is expected that the government will receive some degree of rent. If all of the above calculations are correct, then the rent would be equal to between $0.445 and $0.525/Mcf. If, as reported, Shell expects to receive a 15 percent rate of return at an oil price of $20/bbl, then using the same assumptions as above yields a landed cost of $1.66/Mcf, a landed price of $2.50/Mcf, and a rent to the government of $0.84/Mcf.[37]

Given these estimates, it would appear that (a) the gas will be priced at a competitive level, and (b) the government has made sufficient concessions to allow the project to proceed even under a weak oil price environment. Thus, our earlier pessimism over this project has changed substantially.

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[37] Note that we are applying the rate of return that Shell is reported to have calculated for the "project" to Troll development costs, not to Sleipner or to the pipeline. This, and other factors concerning the precise participation by the different partners, financing, etc., which would affect the calculations, are not easily assessed given the information available to us.

Sleipner

The economics of the Sleipner development are an interesting facet of the Troll deal. Originally, the group of fields known collectively as Sleipner was slated for development with sales planned for either the continent or the United Kingdom. The high CO_2 content of the gas meant that development would be expensive. Since the original negotiations followed shortly after Statfjord was sold in July 1981 for $5.50/Mcf landed at Emden, the Norwegians argued that the higher cost associated with Sleipner meant that an even higher price was justified.

The original development plan called for expenditure of $3.5 billion[38] for the full 7 Tcf of reserves.[39] Given the planned delivery profile, the above-ground cost would have ranged from $1.10 to $1.70/Mcf (see Tables 8A and 8B), depending on the length of production. No separate estimates of the pipeline construction costs were announced, but given the distances involved, they probably would have been on the order of $0.30/Mcf. (See the section on U.K. associated gas.)

Under the revised development plan, deliveries from Sleipner are slated to be only some 27 percent of total reserves. Since Sleipner

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[38] See WSJ, 2/13/85, p. 35. For higher estimates, see PE, 12/84, p. 438, which gave $5 billion, and WO, August 15, 1984, p. 82, which put costs at $6 billion. These apparently included pipeline costs as well as field development costs.

[39] PE, April 1984, p. 137.

Table 3-8 A

Norwegian Gas Development-Operating Costs

Sleipner
Gas/Condensate Field

Case A1: Original development plan with 10-year field life

1.	Development costs	3.5 ($billion)
2.	Reserves	7.0 (Tcf)
3.	Average production rate	700 (Bcf/year)
4.	Depletion (Q/R)	0.100
5.	Development costs in ground	0.500 ($/Mcf)
6.	Development costs as sold	1.100 ($/Mcf)
7.	Operating costs	0.250 ($/Mcf)
8.	Development-operating costs as sold	1.350 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	1.084 ($/Mcf)

Sources:

1. Wall Street Journal, February 13, 1985, p. 35.
2. New York Times, June 3, 1986, p. A1, and Petroleum Economist, April 4, 1984, p. 137.
3. 7 Tcf / 10 years. 10-year project to supply 7 Tcf, from Wall Street Journal, February 12, 1985, p. 35. Other reports of project life: 15-20 years, from Financial Times Energy Economist, February 1985, p. 1.; 25 years, from Financial Times International Gas Report, February 15, 1985, p. 1. See Case A2 for costs using 20-year life.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = .12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.
9. Line 8 - revenue from condensate sales.
   = line 8 - ((condensate reserves bbl / gas reserves mcf) * $7.50 / bbl). Condensate reserves = 250 MM bbl from Petroleum Economist, April 1984, p. 84. $7.50 condensate price assumed. Note that this calculation assumes that the condensate/gas production ratio = the original condensate/gas reserve ratio.

Table 3-8 B

Norwegian Gas Development-Operating Costs

Sleipner
Gas/Condensate Field

Case A2: Original development plan with 20-year field life

1.	Development costs	3.5 ($billion)
2.	Reserves	7.0 (Tcf)
3.	Average production rate	350 (Bcf/year)
4.	Depletion (Q/R)	0.050
5.	Development costs in ground	0.500 ($/Mcf)
6.	Development costs as sold	1.700 ($/Mcf)
7.	Operating costs	0.250 ($/Mcf)
8.	Development-operating costs as sold	1.950 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	1.684 ($/Mcf)

Sources:

1. Wall Street Journal, February 13, 1985, p. 35.
2. New York Times, June 3, 1986, p. A1, and Petroleum Economist, April 4, 1984, p. 137.
3. 7 Tcf / 20 years. 15-20 year project life, from Financial Times Energy Economist, February, 1985, p. 1. Per Financial Times International Gas Report, February 15, 1985, p. 1, 7 Tcf to be supplied over 25 years. Wall Street Journal, February 12, 1985, p. 35, reports project life as 10 years. See case A1 for costs using 10-year life.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.
9. Line 8 - revenue from condensate sales
   = line 8 - ((condensate reserves bbl / gas reserves Mcf)
   * $7.50 / bbl). Condensate reserves = 250 MM bbl, from Petroleum Economist, April 1984, p. 84. $7.5 condensate price assumed. Note that this calculation assumes that the condensate/gas production ratio = the original condensate/gas reserve ratio.

development costs are $1.10/Mcf in-ground,[40] five times those of the Troll field, it is curious that Sleipner is being developed at all, especially when Troll should easily be able to fulfill the existing contracts.[41]

These capital costs yield a development-operating cost of $3.40/Mcf, but they are dependent on certain assumptions used where gaps in the data exist. (See Table 9A.) For instance, the 1.76 Tcf reserve figure represents contracted deliveries, not developed reserves, a figure not provided in the original reports. If the ratio of production-to-reserves that was observable in the original field development project holds true for this plan (and it does not necessarily), then 2.33 Tcf are planned for development, leaving additional supplies that can be sold. If that is the case, then the development and operating costs will be less than $3/Mcf, after adjusting for condensate production (see Table 9B.)

If pipeline construction costs are charged to Troll, then Sleipner gas becomes more economical than if a new pipeline were necessary. Of

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[40] The analogy with oil from the Troll field is obvious. The original project costs would equal somewhere between $0.71 and $0.86/Mcf in-ground, notably lower. The difference might be explained by a loss of economies of scale, but it also may be due to the need for processing to remove the high levels of CO_2 found in Sleipner gas. Under the British contract, the CO_2 was not to have been removed by the project operators, but would have been blended in to the British system. Trade reports have suggested that the portion of the field with the CO_2 will not be developed for the current sale. See <u>Offshore</u>, 8/86, p. 54. The cost of processing the condensate may have grown relative to total development costs, given that liquids production has apparently grown as a part of the project. See <u>OGJ</u>, 9/22/86, p. 26.

[41] One almost gets the impression that the Norwegians believe the Sleipner field should be developed because of its place in the discovery sequence, or because it is on the route to Europe from Troll, rather than because of any particular economic rationale. One industry observer has remarked in private conversation that he believes selling Sleipner is a matter of national pride for the Norwegians, especially after the British rejection of the proposed sale.

Table 3-9 A

Norwegian Gas Development-Operating Costs

Sleipner
Gas/Condensate Field

Case B1: Troll/Sleipner sales contract development
Reserves = 1.76 Tcf

1.	Development costs	1.92 ($billion)
2.	Reserves	1.76 (Tcf)
3.	Average production rate	141 (Bcf/year)
4.	Depletion (Q/R)	0.080
5.	Development costs in ground	1.091 ($/Mcf)
6.	Development costs as sold	2.723 ($/Mcf)
7.	Operating costs	0.681 ($/Mcf)
8.	Development-operating costs as sold	3.404 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	3.138 ($/Mcf)

Sources:

1,2,3. Oil and Gas Journal, June 9, 1986, p. 19. Reserves = expected Sleipner production under the Troll/Sleipner sales contract.

5. Line 1 / line 2.

6. (line 1 / line 3) * (line 4 + i) i = .12.

7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

8. Line 6 + line 7.

9. Line 8 - revenue from condensate sales = line 8 - ((condensate reserves bbl / gas reserves Mcf) * $7.50 / bbl). Condensate reserves = 250 MM bbl from Petroleum Economist, April 1984, p. 84. $7.5 condensate price assumed. Note, this calculation assumes that the condensate / gas production ratio = original condensate / gas reserve ratio.

Table 3-9 B

Norwegian Gas Development-Operating Costs

Sleipner
Gas/Condensate Field

Case B2: Troll/Sleipner sales contract development
Reserves = 2.33 tcf

1.	Development costs	1.92 ($billion)
2.	Reserves	2.33 (Tcf)
3.	Average production rate	141 (Bcf/year)
4.	Depletion (Q/R)	0.061
5.	Development costs in ground	0.824 ($/Mcf)
6.	Development costs as sold	2.465 ($/Mcf)
7.	Operating costs	0.681 ($/Mcf)
8.	Development-operating costs as sold	3.146 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	2.880 ($/Mcf)

Sources:

1,3. Oil and Gas Journal, June 9, 1986, p. 19.

2. 1 * (7/3) 1 = # platforms currently planned to develop the field, from Oil and Gas Journal, June 9, 1986, p. 19. 7 = reserves to be developed and 3 = # of platforms to be used in original Sleipner development plan (see case A), from Petroleum Economist, April 1984, p. 138.

5. Line 1 / line 2.

6. (line 1 / line 3) * (line 4 + i) i = .12.

7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

8. Line 6 + line 7.

9. Line 8 - revenue from condensate sales = line 8 - ((condensate reserves bbl / gas reserves Mcf) * $7.50 / bbl). Condensate reserves = 250 MM bbl, from Petroleum Economist, April 1984, p. 84. $7.5 condensate price assumed. Note, this calculation assumes that the condensate / gas production ratio = original condensate / gas reserve ratio.

course, a connection to the Frigg pipeline to replace falling levels of Frigg production would mean much lower pipeline construction costs than delivery to Belgium. Or, if Troll bears the pipeline costs, Sleipner becomes more feasible.

A report recently received suggests that the development may be more economic than originally appeared.[42] First, the reserves to be developed are given as 1.9 Tcf. However, two new pieces of information were added: (1) capacity is to be 8.8 Bcm/yr (310 Bcf/yr) of natural gas and 100,000 b/d of condensate. In other words, the level of initial production reported previously and used in Tables 9A and 9B is far less than planned peak production.[43]

This information has a large impact on the cost of producing the Sleipner gas. First, the in-ground development cost drops slightly because of the higher reserve figure. Second, depletion is much higher, which reduces the development costs, as shown in Table 9C. Third, the higher production level reduces the operating costs, since we account for them as a percentage of total capital expenditures which are not increased. Finally, the level of condensate production is much higher than estimated in the previous two tables; although less than one-third of

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[42] OGJ, 9/22/86, pp. 26-27. Although there is still uncertainty, we will assume that these data are correct, and that there are no misinterpretations. For example, we assume that the report of 1.9 Tcf reserves is accurate, not a listing of contract sales instead of reserves.

[43] It is possible that capacity is higher than the level of production now planned, but full capacity utilization is appropriate for measuring per-unit costs.

Table 3-9 C

Norwegian Gas Development-Operating Costs

Sleipner
Gas/Condensate Field

Case C: Troll/Sleipner sales contract development.
Reserves = 1.9 tcf

1.	Development cost	1.92 ($bn)
2.	Reserves	1.90 (tcf)
3.	Reported capacity	310 (bcf/year)
4.	Depletion (Q/R)	0.163
5.	Development cost in ground	1.011 ($/Mcf)
6.	Development cost as sold	1.754 ($/Mcf)
7.	Operating cost	0.310 ($/Mcf)
8.	Development-operating cost as sold	2.063 ($/Mcf)
9.	Development-operating cost as sold, adjusted for condensate production	1.179 ($/Mcf)

sources: 1,2,3. Oil and Gas Journal September 22, 1986 p. 26-27
5. line1/line2
6. (line1/line3)*(line4+i) i=.12
7. 0.05*line1/line3 (annual operating expense/annual production) annual operating expense assumed 5% of development cost
8. line6+line7
9. Line 8 minus value of condensate production per Mcf of gas produced. Condensate production is 100,000 b/d, from Oil and Gas Journal 9/22/86, p. 26. Value of condensate assumed at $7.5/bbl.

the natural gas is being developed, more than two-thirds of the total condensate reserves are included in the project as it now stands.[44] The result is that the above-ground cost of the natural gas is only $2.06/Mcf, 25 percent lower than the earlier estimate, and only $1.18/Mcf when the condensate offset is taken into account. Thus, given conservative values for the condensate and even assuming full pipeline costs of $0.60/Mcf, this gas can be delivered to the continent for $1.80/Mcf, which is equivalent to less than $12/bbl of oil. If much of the gas is delivered via the Statpipe system, the delivered cost will drop substantially.

The project economics are obviously much improved, as is our assessment of its viability. If oil is only $15/bbl when deliveries begin, however, and if the price index in the contract brings the landed natural gas price to $1.875/Mcf, as discussed above, then there is little room for taxes and royalties. Certainly, the unitization of the field with Troll should allow the much better Troll economics to carry this marginal development.

Other Norwegian Gas Supplies

A number of unanswered questions about the Troll contract affects other future Norwegian supplies. By all appearances, the Troll deal is intended, in part, to provide the Norwegians with the capacity to reach easily other continental customers. By landing one pipeline in Belgium,

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[44] Unfortunately, information on the individual fields that make up the Sleipner cluster is not available to us, but it appears that the development has been planned for the field that contains the bulk of the condensate reserves and little of the CO_2. It may also be that earlier reports understated the condensate reserves of the whole group.

the Norwegians will introduce real competition between transportation systems, and Ruhrgas no longer will have monopsony powers. This is apparently a major concern of the Norwegians.[45] This should facilitate small-scale deals and even spot sales to other customers, such as Spain, Switzerland, and Italy.

Incremental pipeline costs should, if anything, be lower than they were for the original deal. Some reports suggest that the planned development includes looping of the Ekofisk-to-Emden pipeline to add 20 Bcm/yr (730 Bcf/yr) of capacity.[46] Even if this is not the case, gas could be delivered via the Frigg pipeline, or through the Statpipe system at a small incremental cost as fields now producing for them decline.

The Statfjord pipeline, built to transport associated gas from northern North Sea fields to Ekofisk and then to Emden, will allow Norway to deliver 20 Bcm/yr (706 Bcf/yr) at very low costs. The pipeline cost $3.5 billion,[47] which translates to a cost of about $0.84/Mcf. Since the gas now being used is associated gas, the incremental production costs are very small. Because the pipeline crosses such a large area, new fields can be hooked up to it relatively cheaply to replace declining

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[45] PIW, 6/9/86.

[46] Private conversations with industry officials.

[47] IEA, Natural Gas Prospects, 1986, p. 78. According to The NYT, 10/16/85, p. D5, the Statfjord pipeline cost only $2.34 billion and had a capacity of only 280 Bcf/yr. This figure probably does not include connections to the Heimdal and Gullfaks fields and similar expenses. If correct, then costs for the trunk pipeline are about $0.55/Mcf.

production in the current fields. (See Table 28 below for examples of the costs of hooking up fields to trunklines.)

New Fields South of 62° N

Development costs for a number of fields, including Odin and Northeast Frigg, which were hooked up to the Frigg pipeline to the United Kingdom, are shown in Tables 10 through 13. The costs are fairly low, even though the fields are much smaller than, for example, Sleipner and Troll. For the Tommeliten field, which is planned to produce gas initially for injection into Ekofisk, costs are over $2/Mcf, but the production of associated liquids will offset nearly half those costs, even if the liquids are worth only $10/bbl. (See Table 14.)

The development of Troll capacity for injection into the Oseberg field could be considered as a new field development, although the small size and the use of a five-well, subsea unit makes the resulting costs less typical of the Norwegian North Sea. Tax breaks given to the project and savings from the changed drive mechanism in the Oseberg field (which will reduce the number of wells necessary at Oseberg by 20) create this viability. Tables 15A and 15B show the economics of the project, with case A presenting the total development costs charged to the gas project, and case B subtracting the savings in the development of the Oseberg field from using the gas, but including the cost of injection facilities.[48]

[48] See OGJ, 6/23/86, p. 24.

Table 3-10

Norwegian Gas Development-Operating Costs

Odin Field

1.	Development costs	594 ($MM)
2.	Reserves	777 (Bcf)
3.	Peak output	135 (Bcf/year)
4.	Field life	9 (years)
5.	Depletion	0.108
6.	Development costs in ground	0.764 ($/Mcf)
7.	Development costs as sold	1.151 ($/Mcf)
8.	Operating costs	0.220 ($/Mcf)
9.	Development-operating costs as sold	1.371 ($/Mcf)

Sources:

1,4. International Petroleum Encyclopedia, 1981, p. 196. Development costs given in $ 1981, converted to $ 1985 using implicit price deflator from Economic Report of the President.

2,3. International Petroleum Encyclopedia, 1985, p. 212.

5. a = 0.108 to satify the equation Q * (1 - exp (-at)) = aR
Q = 135, t = 9, R = 777,000.

6. Line 1 / line 2.

7. c = (line 1 * (i + a)) / (line 3 * (1 - exp (-(i + a) * t)))
i =0.12, a = 0.108, t = 9.

8. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

9. Line 7 + line 8.

Table 3-11

Norwegian Gas Development-Operating Costs

North East Frigg Field

1.	Development costs	275 ($MM)
2.	Reserves	141 (Bcf)
3.	Production rate	77 (Bcf/year
4.	Depletion (Q/R)	0.546
5.	Development costs in ground	1.950 ($/Mcf)
6.	Development costs as sold	2.379 ($/Mcf)
7.	Operating costs	0.179 ($/Mcf)
8.	Development-operating costs as sold	2.558 ($/Mcf)

Sources:

1. International Petroleum Encyclopedia, 1984, p. 212. Development costs given in $ 1983, converted to $ 1985 using implicit price deflator from Economic Report of the President.
2. Petroleum Economist, April 1983, p. 127.
3. World Oil, August 15, 1984, p. 80.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.

Table 3-12

Norwegian Gas Development-Operating Costs

Heimdal
Gas/Condensate Field

1.	Development costs	1.4 ($billion)
2.	Reserves	1.2 (Tcf)
3.	Production rate	110 (Bcf/year)
4.	Depletion (Q/R)	0.092
5.	Development costs in ground	1.167 ($/Mcf)
6.	Development costs as sold	2.698 ($/Mcf)
7.	Operating costs	0.636 ($/Mcf)
8.	Development-operating costs as sold	3.334 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	3.136 ($/Mcf)

Sources:

1. International Petroleum Encyclopedia, 1981, p. 186. Development costs given in $ 1981, converted to $ 1985 using implicit price deflator from Economic Report of the President.
2. World Oil, August 1985, p.76.
3. International Petroleum Encyclopedia, 1984, p. 212.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.
9. Line 8 - (yearly revenue from condensate sales / line 3) = line 8 - ((2,920,000 bbl) * ($7.5/bbl)) / (line 3 * 1000). Condensate production rate from International Petroleum Encyclopedia, 1984, p. 76. $7.50 condensate price assumed.

Table 3-13

Norwegian Gas Development-Operating Costs

Frigg Field

1.	Development costs	1.947 ($billion)
2.	Reserves	10.981 (Tcf)
3.	Average production rate	0.250 (Tcf/year)
4.	Depletion (Q/R)	0.023
5.	Development costs in ground	0.177 ($/Mcf)
6.	Development costs as sold	1.111 ($/Mcf)
7.	Operating costs	0.389 ($/Mcf)
8.	Development-operating costs as sold	1.500 ($/Mcf)

Sources:

1. Offshore, June 5, 1976, p. 42. Note: Total cost given as 2.2 billion $ 1976 with one-half attributed to the pipelines to shore. 1.1 billion $ 1976 converted to $ 1985 using the implicit price deflator from the Economic Report of the President.
2. Reserves as of June 1985, from International Gas Report, July 5, 1985, p. 16, plus cumulative production to June 1985, from Development of the Oil and Gas Resources of the United Kingdom, 1985, p. 69. Production for the first half 1985 at average rate 1981-1984.
3. Ibid., p. 69. Average rate 1981-1984.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.

Table 3-14

Norwegian Gas Development-Operating Costs

Tommeliten
Oil & Gas Project

1.	Development costs	626 ($MM)
2.	Reserves	650 (Bcf)
3.	Depletion (assumed)	0.10 (Bcf/year)
4.	Average production rate (aR)	65 (Bcf/year)
5.	Development costs in ground	0.963 ($/Mcf)
6.	Development costs as sold	2.119 ($/Mcf)
7.	Operating costs	0.482 ($/Mcf)
8.	Development-operating costs as sold	2.601 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	1.678 ($/Mcf)

Sources:

1,2. Offshore, May 1986, p. 148.
5. Line 1 / line 2.
6. (line 1 / line 4) * (line 3 + i) i = 0.12.
7. 0.05 * line 1 / line 4 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.
9. Line 8 - (yearly revenue from oil sales / (line 4 * 1000)) = line 8 - ((600,000 bbl) * ($10/bbl)) / (line 4 * 1000). Oil production rate = aR. Oil reserves of 60 MM bbl from Offshore, May 1986, p. 148. $10 oil price assumed.

Table 3-15 A

Norwegian Gas Development-Operating Costs

Troll Field
Development for Oseberg injection

Case A: Costs of development

1.	Development costs	394 ($ MM)
2.	Reserves	255.5 (Bcf)
3.	Production rate	25.55 (Bcf/year)
4.	Depletion	0.100
5.	Development costs in ground	1.542 ($/Mcf)
6.	Development costs as sold	3.393 ($/Mcf)
7.	Operating costs	0.771 ($/Mcf)
8.	Development operating costs as sold	4.164 ($/Mcf)

Sources:

1,2,3. Oil and Gas Journal, June 23, 1986, p. 24. Costs given in $ 1986. Reserves = planned production of 70 MMcfd over 10 years.
4. Line 3 / line 2.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.

Table 3-15 B

Norwegian Gas Development-Operating Costs

Troll Field
Development for Oseberg injection

Case B: Costs of development subtracting Oseberg savings

1.	Development costs	249 ($ MM)
2.	Reserves	255.5 (Bcf)
3.	Production rate	25.55 (Bcf/year)
4.	Depletion	0.100
5.	Development costs in ground	0.975 ($/Mcf)
6.	Development costs as sold	2.144 ($/Mcf)
7.	Operating costs	0.487 ($/Mcf)
8.	Development operating costs as sold	2.631 ($/Mcf)

Sources:

1,2,3. Oil and Gas Journal, June 23, 1986 p. 24. Cost reduction from case A due to $263 MM savings at Oseberg as 20 less wells are needed, less $118 MM for conversions for gas injection. Costs given in $ 1986. Reserves = planned production of 70 MMcfd over 10 years.
4. Line 3 / line 2.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.

These examples demonstrate that Norwegian natural gas still can be developed at current low oil prices, with rents available for both the government and companies. If the tax regime is too strict, however, many new developments will not go forward. The presence of nearby pipelines with spare capacity also will be a major, if not the major, factor in influencing their development. New fields as costly as Northeast Frigg will be at risk, however, should the price of oil remain at $15/bbl or lower.

New Fields North of 62° N

"'Roll up the map of the 62nd parallel. We will not need that for 15 years.'" U.K. Department of Energy official[49]

At present, it is hard to conceive of new supplies being developed beyond Troll and Sleipner and the replacement of declining Ekofisk and Statfjord production. Large reservoirs have been discovered off Norway north of 62° N. However, the transportation distances involved ensure that the costs will be much higher, and these supplies are not under consideration for export in the near future.

To date, two areas of interest north of 62° N have been drilled: Askeladden and Tromsoeflaket, above 71° N, and the Haltenbanken area, at 65° N. The former thus far has 6 Tcf of recoverable gas and the latter about 12 Tcf,[50] although U.S. Geological Survey estimates show that total resources for both could be much higher (see Table 2). The

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49 Cited in Offshore, 8/86, p. 71.

50 See PE, 1/86, p. 8. PIW 9/29/86, p. 10, puts Haltenbanken reserves at 11 Tcf.

Askeladden area has been assessed thoroughly and is now under consideration for development.

However, the extreme distance of the Askeladden fields from markets, combined with the lack of infrastructure, apparently has made their development uneconomic. Development costs have been put at \$3.2 billion, plus either \$2.4 billion to build both a pipeline to shore and an LNG plant or \$13 billion to build a pipeline south.[51] Table 16 indicates that the wellhead cost of the gas will be \$1.50/Mcf, (slightly higher than the cost of landed Troll gas for example). However, the costs of LNG or pipeline transportation would add to this considerably, raising the landed cost of the gas on the continent to \$3.00/Mcf.[52] (This is on the low side of an estimate by Ager-Hanssen, the senior executive vice-president at Statoil, of \$1.73 to \$2.43/Mcf landed in northern Norway and \$3.21 to \$4.85/Mcf landed in Western Europe.[53] He may very well have included royalties and/or taxes.)

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[51] The pipeline cost estimate might include field development costs. Since the amount of gas reserves required for such a pipeline were put at 30 Tcf, this suggests that the pipeline would be larger than the 870 mcf/d to 1.2 Bcf/d (320-440 Bcf/yr) capacity of the LNG plant under consideration. The largest pipelines now in use can carry 1412 Bcf/yr, which would provide a depletion rate of 5 percent for 30 Tcf of reserves. See OGJ, 2/27/84, pp. 68-69.

[52] Assuming that the annual development-operating charge for both the pipeline and the LNG plant is 20 percent of the total capital cost to allow for the higher risk, and that the LNG plant capacity is 870 mcf/d (320 Bcf/yr). At 1.2 Bcf/d (440 Bcf/yr) capacity (and the same capital cost), the per-unit cost would drop by \$0.40/Mcf. The pipeline capital cost is assumed to be \$10 billion, and the capacity assumed to be 1400 Bcf/yr.

[53] Cited in PE, 1/86, p. 9. This assumes a 10 percent internal rate of return. He also estimated that the delivered cost to the United States would be from \$3.47 to \$5.02/Mcf.

Table 3-16

Norwegian Gas Development-Operating Costs

Askelladen Field		
1.	Development costs	3.31 ($billion)
2.	Reserves	6.0 (Tcf)
3.	Depletion (assumed)	0.10
4.	Production rate (aR)	600 (Bcf/year)
5.	Development costs in ground	0.552 ($/Mcf)
6.	Development costs as sold	1.214 ($/Mcf)
7.	Operating costs	0.276 ($/Mcf)
8.	Development-operating costs as sold	1.490 ($/Mcf)

Sources:

1. *Oil and Gas Journal*, February 27, 1984, p. 68. Development costs given in $ 1984, converted to $ 1985 using implicit price deflator from *Economic Report of the President*.
2. *Petroleum Intelligence Weekly*, September 10, 1984, p. 8.
5. Line 1 / line 2.
6. (line 1 / line 4) * (line 3 + i) i = 0.12.
7. 0.05 * line 1 / line 4 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.

There are desirable aspects to both transportation options. With the LNG option, the gas could be sent either to Western European or U.S. markets, and development could occur in small increments, on the order of 300 Bcf/yr. While the pipeline would require large sales volumes and would be constrained to the Western European market, the development of other, smaller offshore fields would be facilitated, especially as Askeladden declined and pipeline capacity became available.

The reality, of course, is that between the glutted Western European (and U.S.) markets and the availability of cheaper, undeveloped gas resevoirs south of 62° N, these fields are unlikely to be developed for export before the turn of the century. Developing the gas for domestic use is under consideration, especially by conversion to electricity (possibly on offshore platforms to save the cost of constructing an undersea pipeline) and transporting the electricity south. To date, none of the options has appeared sufficiently attractive to reach fruition.

The problem is that building a large-scale transportation system would necessitate large contracts, meaning either rapid growth in Western European gas demand or expiration of existing contracts. However, Troll and Sleipner, as well as the many smaller southern fields, should satisfy Western European demand for many years to come, and demand growth on a large scale seems unlikely. Thus, any large-scale development lies decades in the future. Statoil has noted that it believes there will be no buyers for this gas until after 2000, and that methanol or fertilizer plants might be appealing, but the quantities of gas that would be used are small and at present those markets are weak.[54]

Small-scale development might be more appealing, because it would allow the government to spread some of the revenues from the offshore service industry northward,[55] as well as to justify the drilling effort in those waters. Some of the natural gas from the project could be diverted for domestic use as well, providing further justification. However, any export of gas from this region would mean bypassing cheaper gas in the south.

Norwegian Policy

> The petroleum finds in the North Sea mean that as a nation we shall become richer. The Government is of the opinion that these new possibilities should be used to develop a qualitatitvely better society. A rapid and uncontrolled growth in the use of material resources should be avoided, unless the social structure is otherwise substantially changed.--Royal Norwegian Ministry of Finance, 1974[56]

Norway was very quick to recognize that the bonanza of oil and gas forthcoming from the North Sea would have potentially profound impacts on the country's economy. The 1969 discovery of Ekofisk was followed by a number of other finds, that, by the end of 1973, had boosted proved reserves to 4 billion bbl of oil and 23 Tcf of gas.[57] Concern about the

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[54] PE, 1/86, pp. 8-10, and OGJ, 4/28/86, p. 40.

[55] In Norwegian Long-Term Programme: 1986-1989, Report No. 83 to the Storting (1984-85), p. 26, the Royal Ministry of Finance stated: "A development of petroleum fields may help to give Central and North Norway a broader industrial and commercial base."

[56] Petroleum Industry in Norwegian Society, Parliamentary Report No. 25 (1973-74), Oslo, Norway, p. 6.

[57] OGJ, 12/31/73, p. 309.

possible impact of large-scale development led the government to analyze its options, resulting in a number of policy recommendations affecting the oil and gas industry.[58]

The recommendations resembled more those of an OPEC country than of an OECD member (in fact, cooperation with OPEC was one of the steps recommended).[59] Conservation of finite hydrocarbon resources for their very valuable uses as raw materials and even food was felt to be necessary,[60] and the potential disruption to the economy of a booming offshore drilling and service industry, and of large revenues from oil and gas exports was recognized. The policies that were recommended, and pursued, included: (a) a moderate development of oil and gas resources; (b) a gradual introduction of oil and gas revenues into the domestic economy; and (c) government majority control of as much of the industry as possible (upstream, downstream, service, and petrochemical).

By releasing tracts for exploration at a slow rate, maintaining a high tax rate, and requiring participation by Norwegian state-owned companies, Norway has met these objectives. The production ceiling of 90 million tonnes of oil equivalent (1.8 million bbl/d of oil equivalent) set in 1974 is still well above current production levels, although ongoing field development, and especially the beginning of Troll production in the late 1990s, could see this level reached.

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[58] Petroleum Industry in Norwegian Society, Parliamentary Report No. 25 (1973-74), Royal Norwegian Ministry of Finance, Oslo, Norway.

[59] ibid., p. 14.

[60] ibid., p. 16.

At the same time, however, the non-petroleum sectors of the economy have suffered, in part because oil prices were so much higher than anticipated when the moderate pace of oil development was defined. The manufacturing share of GDP has shrunk from 18.2 percent in 1979 to 13.6 percent in 1984, while the mining and quarrying sector (dominated by oil and gas) has doubled to 18.6 percent over the same period. This occurred despite the benefits to the manufacturing sector of having captive demand for equipment from the offshore oil and gas industry. In fact, high inflation and low productivity growth have hurt the international competitiveness of the Norwegian economy, leading to moves to devalue the kroner.

The weakness in international energy markets has caused some reversal of Norwegian policy. The cancellation of the Sleipner deal by the U.K. government provided the first impetus, and the plunge in oil and gas prices a hearty shove. Whereas in the 1970s the government's concern focused on excessive growth of employment in the oil and gas sector to the detriment of the rest of the economy, now the primary concern is the possibility that reduced exploration and development would create unemployment in that sector. As the 1984-1985 report to the Storting from the Royal Ministry of Finance put it, "The main task in the programme period in Norway will be to ensure employment for everyone and safeguard and develop further the welfare society."[61]

Retaining and creating jobs in the non-hydrocarbon sector still is a main concern of the Norwegian government, but one focus of the Troll

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[61] *op. cit.*, p. 20. Emphasis added.

contract was to provide work for the offshore industry during a period of weak oil markets. Taxes also have been cut to a major extent to encourage continued investment by foreign oil companies.[62] However, taxes are still the highest in the North Sea, even after the latest revisions, such that the minimum economic field size in the Norwegian sector is 500 million barrels (versus only 100 million barrels in the U.K. sector), although other factors play a role.[63]

Norwegian tax rates have been criticized by the oil industry for years, but revisions to them have been slow. Private companies have continued to seek concessions despite complaints that the fiscal regime yields poor returns, partly because of the size of finds still being made in Norwegian waters.[64] Only recent reluctance on the part of foreign oil companies to bid for exploration licenses, combined with the drastic fall in oil prices, have forced a reconsideration by the Norwegian government. As one Norwegian official said, "...there isn't any support for adjusting the total tax level, as long as it is possible for us to get exploration and production licenses out without trouble."[65]

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[62] OGJ, 7/21/86, p. 35. The industry's "special tax rate" is to be cut from 35 to 30 percent, and the 10 to 15 percent royalty on new field developments will be foregone.

[63] The estimate of viability assumes an oil price of $15/bbl, and is made by Wood, Mackenzie, cited in PIW, 8/18, 1986, pp. 2-3.

[64] As the WSJ, 8/29/84, p. 29, pointed out, Chevron refused a 1972 offer to operate Statfjord, which turned out to be the largest oil field discovered to date in the North Sea, and companies are afraid to repeat that mistake.

[65] Hans Henrik Ramm, Petroleum Adviser to Norway's Finance Minister, cited in ibid.

With oil and gas revenues falling and with the possibility of increased personal income taxes, further concessions for the petroleum industry become increasingly difficult. Projects that are marginal and that would require deep cuts in the government's take may not receive the necessary help. Yet the alternative may look even worse: a shrinkage of oil and gas revenues and of employment. The recent concessions on the Troll/Sleipner development demonstrate that the government is still willing to be flexible.

The United Kingdom

The United Kingdom not only had the first but also the most highly developed manufactured gas industry in Western Europe. By 1961, the United Kingdom accounted for nearly two-thirds of total Western European manufactured gas consumption and, relative to total energy requirements, U.K. gas consumption was five times that of the rest of Western Europe.[66] However, as coal prices increased during the 1950s, the industry's competitive position faltered. By 1956, the price per therm for coal gas used in heating was only slightly cheaper than electricity, and when adjusted for efficiency, it was more expensive than any fuel but butane (see Table 17).

The British Gas Council, which oversaw the 12 Area Boards governing gas distribution, realized it was at a strategic crossroads. To reduce costs, it began centralizing its gas production, at the same time seeking alternatives to coal gas. To that end, investment was made in oil-based

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[66] OECD Energy Balances: 1960/74, Paris, France, 1975.

TABLE 3-17
RELATIVE COSTS OF HEATING FUELS
IN THE UK IN 1956
(COAL GAS = 100)

Fuel	Price per therm	Price per therm adjusted for apparatus efficiency
Coal Gas	100	100
Kerosine	62.5	62.5
Wood	29.2	91.7
Coal or Coke	29.2	54-92
Butane	187.5	187.5
Electricity	120.8	120.8

Note: For coal gas and butane, a small, high efficiency stove is assumed. Otherwise, efficiency drops by about 50 percent.

Source: Petroleum Press Service, May 1956, p. 178.

gas manufacturing systems, while at the same time the Gas Council signed the first long-term contract with Algeria for LNG supplies.

The 1959 discovery of the Groningen field in the Netherlands aroused interest in the North Sea basin, particularly the shallow areas off the southern United Kingdom. (Previously, only two small onshore gas fields had been found, both by the Gas Council.) The first discoveries were made in 1965, and within three years, the United Kingdom was enjoying an abundance of natural gas from a number of large fields. As Figure 8 shows, growth of reserves was dramatic during the late 1960s, as these discoveries were assessed and booked.

Not surprisingly, this gas obviated the need for either more LNG imports or manufactured gas, and within a few years many of the coal-gas plants were shut down. In fact, the quantities of gas discovered were so large that it was difficult to absorb them all. The Continental Shelf Act of 1964 shaped the development of these resources by (a) preventing their export and (b) granting monopsony power to the British Gas Council, except in certain cases of direct industrial use, such as in petrochemical plants.[67]

The British Gas Council (which became the British Gas Corporation (BGC) in 1972) looked upon the southern North Sea supplies as a reservoir of cheap natural gas which it could use both to cover costs of expansion of its system and to penetrate new markets. Most gas was sold to industrial and residential/commercial customers, rather than to the electric generation sector, and prices offered to producers were roughly

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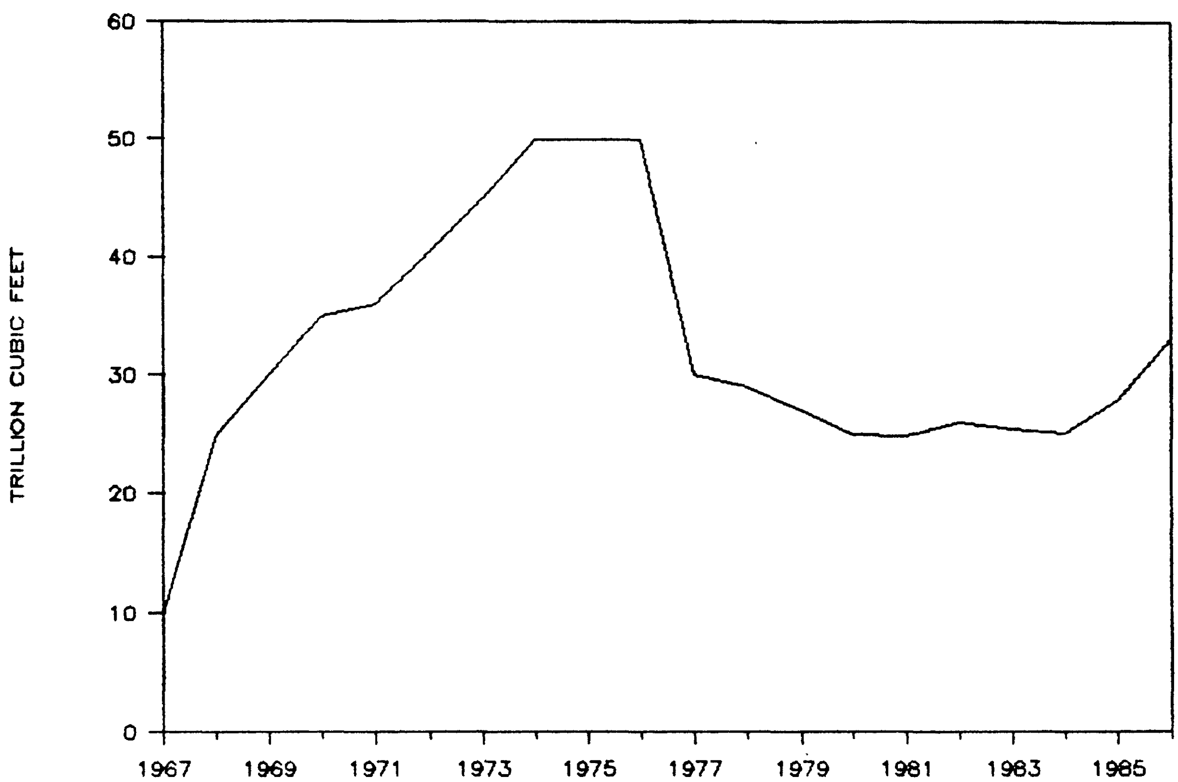
[67] See Davis, op. cit., p. 103.

Figure 3-8

BRITISH NATURAL GAS RESERVES
(January 1)



Source: Oil & Gas Journal

one-quarter the price of manufactured gas.[68] Having no other markets open to them, producers had little choice but to accept these prices, although exploration suffered as a result. Not until many years later were higher prices paid for supplies from the southern sector of the North Sea. (See Table 18.)

However, the BGC continued to seek new supplies, including imports from Norway. Although having lost out on the Ekofisk and Statfjord sales, the BGC managed to contract for gas from Frigg (which straddled the U.K. and Norwegian sectors of the North Sea) and Sleipner (although the government later cancelled the contract). Prices offered for these supplies were higher than those for U.K. fields, and while the BGC did pay a higher price for the more costly northern U.K. gas, a lower price was paid for the U.K. share of Frigg than the Norwegian share, demonstrating BGC's monopsony power. In addition, the cheap gas from the south was "rolled-in" with the higher cost Norwegian and northern sector U.K. gas, keeping average prices low.

BGC has consistently expressed concern about its future supplies, particularly as Frigg volumes decline in the next decade, and is unsure of potential future domestic additions-to-reserves. The Sleipner contract was signed for this reason, but the U.K. government, more confident than the BGC that higher prices for domestic gas would bring on higher supplies, would not approve the contract.

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[68] ibid., p. 98, shows manufactured gas costs as being 4 to 5 pence per therm and the prices to the first fields developed were on the order of 1 to 1.2 pence per therm (p. 106). The BGC was in the unique position of being not only a monopsony purchaser but a partner in the fields.

TABLE 3-18

PRICES FOR UK NORTH SEA GAS

Field	Location	Date	Price [Pence/Therm]	Notes
West Sole	Southern	1967-70	2.08	
		1971-	1.12	
Hewett:	Southern			
Base price			1.195	
Valley gas			0.844	
Leman:	Southern			These prices are for the first 15 years of production.
First 600 MMcf/d			1.196	After that, prices will be 1.196p, 1.167p, and 1.146p per
Second 600 MMcf/d			1.1875	therm respectively for the specified amounts produced per
Remainder			1.792	day for the Leman field; and
				1.208p for first 600 MMcf/d, 1.792p for next
Indefatigable	Southern			600 MMcf/d, and 1.158p per therm for the balance for the
All gas to 1983			1.208	Indefatigable field. (converted at 2.4 d per pence)
Viking	Southern	1972	1.5	
Rough	Southern	1974	3.4	
Frigg	Northern	1974	8.8	Terms of delivery of
(Norwegian sector)		1982	11.5 (est)	British gas probably considerably different, with price closer to that of Brent field.
Brent	Northern	1975	6.5	Production start-up 1976.
		1982	12.5 (est)	
Beryl	Northern	1982	16.0 (est)	Price on shore after delivery via Frigg line. Production start-up 1976.
North Alwyn	Northern	1982	22-23 (est)	Price for North Alwyn associated gas. Production start-up 1987.
Cleeton, Hoton, Hyde, Ravenspurn	Southern		28-30 p/therm (est)	Production due in 1988.
Sean South & Sean North	Southern		23-24 p/therm (est)	

Sources: Davis, 1984, pp. 106 and 144, and trade press.

In fact, the prolonged Sleipner negotiations saw the British extract a series of concessions from the Norwegians. In part, this reflected the short-term glut of natural gas on the continent and the lack of buyers there, and in part the changing expectations for future oil prices as energy markets generally proved weaker than had been expected just a short time before, when the Statfjord contracts were signed. The concessions included the construction of a 40-inch pipeline with capacity far in excess of what the Sleipner contract required; an agreement to share the tax proceeds from the liquids pipeline to Norway (which the British had wanted landed in the United Kingdom), and a reduction of the level of peak supplies, presumably raising the development costs slightly, although exact figures are not available.

After an agreement embodying all these concession was signed, the conflict between the BGC and the oil companies with gas reserves in the southern North Sea intensified. Many of the companies produced projections showing that domestic natural gas supplies would be adequate for the foreseeable future, and that large-scale imports were unnecessary. One company even offered a large gas supply contract without specifying the source of the gas, a move some believed was an attempt to make the Sleipner deal appear unnecessary.[69]

Two other factors affected the government's decisions on this deal. First, given the high unemployment rate in the United Kingdom, the

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[69] One good example would be BP's analysis which suggested that despite declining contracted gas, gas about to be contracted and gas already discovered would cover British needs until about 1995. Only a small amount of newly discovered gas would need to be discovered and developed before the turn of the century. See FT, 5/6/83, p. 8. See also FT, 12/18/84, p. 1, and FTEE, 2/85, p. 1.

government was reluctant to import something that could arguably be produced domestically.[70] Secondly, since the contract price was denominated in U.S. dollars, the depreciation of the pound meant that the price had grown 40 percent, up to 35 p/therm, versus an average purchase price of 15 p/therm at the time.[71]

Since the cancellation of the Sleipner contract, the future purchasing plans of the BGC have been uncertain. Initially, an oversupply situation had developed, and some observers said that the BGC was sitting on domestic reserves.[72] However, contracts have been moving forward gradually and a number of new field developments are to be undertaken. (See below.) Still, certain exogenous policy developments will affect the amount and manner of natural gas contracts that the BGC agrees to in coming years.

For one thing, the privatisation of the BGC will give it the power to pursue its own strategies, and these could include signing new contracts with Norway.[73] Second, a possible cross-channel pipeline

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[70] FT, 1/24/85, p. 2.

[71] See FTEE, 2/85, pp. 1-2, and FT, 1/28/85, p. 16, which put BGC's average purchase price in 1984 at 13.3 p/therm.

[72] See, for example, Offshore, 10/85, p. 21.

[73] We do not take seriously reports that the BGC is considering building 20 coal gasification plants at a cost of £1 billion apiece to replace dwindling North Sea reserves, as reported by The Economist, 4/16/83, p. 61.

link that would allow both exports to and imports from the continent would break the BGC's monopsony power.[74]

The BGC's main response to these threats has been to offer prices that approach world levels for new natural gas supplies, especially from the southern sector. (See Table 18.) And in fact, higher prices have spurred more drilling and discoveries in the southern sector. In 1985, numerous gas discoveries were made in the southern North Sea,[75] and the listing in Table 19 shows that many of these have economic potential. (Although flow rates do not correlate directly with reserves, they are a factor in determining the economics of field development, as is shown below.)

Having raised its buying price for southern North Sea gas, the BGC was overtaken by events in world oil markets. The data presented below suggest that there still is gas available that less than $2.00/Mcf, but marginal costs appear to be increasing and rapid expansion of supply may not be possible. However, maintaining current levels of domestic production should pose no problem. As fields discovered in the last two years are assessed, a clearer picture of the future of natural gas supply from the southern sector will emerge.

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[74] Companies were recently given the power to make direct sales to industrial customers, but with one small exception, BGC has used its old, low-priced purchase contracts to undersell all such efforts. See OGJ, 12/30/85, pp. 48-49.

[75] See Offshore, May 1986.

TABLE 3-19
GAS WELL DISCOVERIES IN SOUTHERN NORTH SEA

Operator	Block-well	Flow Rate
Arco	48/11a-7	34 MMcfd + 230 b/d conden.
Ardmore Petroleum	49/13-one well	n.a.
Amoco	47/9a-7	n.a.
BP	48/18-1	13.7 MMcfd
BP	42/30-4	n.a.
BP	47/5a-4	n.a.
BP	48/7b-5	n.a.
BP	49/4-1	8.5 MMcfd
Britoil	47/14a-6	40 MMcfd
Britoil	47/14a-7	31 MMcfd
Britoil	47/14a-8	n.a.
Charterhouse Petroleum	44/29-one well	n.a.
Conoco	48/11b-6	44.2 MMcfd
Conoco	48/11b-4	48.8 MMcfd + 300 b/d conden.
Conoco	44/22-3	35 MMcfd
Conoco	44/22-one well	3 MMcfd + 33 b/d conden.
Gulf	50/6-1	1.3 MMcfd + 2,074 b/d oil
Hamilton	43/26-1	3.2-14.2 MMcfd
Hamilton	43/26-3	49.5 MMcfd
Hamilton	43/26-5	40.2 MMcfd
Hamilton	43/8a-3	15-33 MMcfd
Hamilton	43/15a-2	27 MMcfd
London & Scottish	43/12-one well	n.a.
Mobil	48/18a-one well	19-34 MMcfd + 652 b/d conden.
Mobil	48/17a-2	34 MMcfd
Mobil	49/29-B4	31 MMcfd

TABLE 19
(cont.)

Operator	Block-well	Flow Rate
Phillips	49/11a-2	34.6 MMcfd + 70 b/d conden.
Phillips	49/11a-3	31.5 MMcfd + 97 b/d conden.
Ranger	48/18b-3	12 MMcfd
Ranger	48/19b-7	29 MMcfd
Shell	48/14-2	n.a.
Shell	48/20a-3	n.a.
Shell	48/19a-6	n.a.
Shell	44/28-2	n.a.
Shell	48/13a-two wells	n.a.
Texas Gas	44/23-4	27 MMcfd
Ultramar	49/5-3	39 MMcfd
Zapata	42/15b-one well	n.a.

Sources: Trade press.

Economics of Gas Supply in the United Kingdom

Excluding imports (i.e., gas from Frigg), U.K. gas supply consists of the southern North Sea and the FLAGS associated gas collection system. Recent developments suggest that while there will be additions to peaking capacity--such as the Rough and Morecambe fields, the latter in the Irish Sea--and continued hookups of small gas and gas/condensate fields as well as associated gas flows from northern and central sector fields, most future U.K. gas production will be from fields in the southern sector of the North Sea.

Unfortunately, new field development in the southern sector has not been sufficient in recent years to allow the kind of analysis of development costs that is possible for oil.[76] When development expenditures are examined relative to capacity and reserve additions, the results fluctuate so wildly as to render them unreliable. This undoubtedly reflects the low level of field development and expenditures for associated gas pipelines (specifically FLAGS) that were made for some years before deliveries actually started, which makes costs difficult to average out.

It is possible to provide some estimate of operating costs, using production rates and aggregate operating expenditures (see Table 20). As can be seen, these inflate at roughly 5.5 percent annually in real terms, although the data are slightly contaminated by the growing impact of associated gas, for which only pipeline expenditures are available.

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[76] See Adelman, "The Competitive Floor Price for World Oil," Energy Journal, October 1986, for an analysis of U.K. oil costs.

Table 3-20

United Kingdom Gas Field Operating Costs
($ 1985)

	Total Gas field Operating Expenditures (million $)	Total Gas Production (Bcf)	Unit Operating Costs ($/Mcf)
1979	295.38	1387	0.213
1980	287.71	1317	0.218
1981	294.70	1321	0.223
1982	363.47	1352	0.269
1983	374.82	1396	0.269
1984	394.52	1418	0.278

Source:

Development of the Oil and Gas Resources of the United Kingdom, 1985. Production from p. 69, (includes associated gas). Expenditures from p. 78, (includes expenditures on FLAGS and the other associated gas gathering pipelines). Expenditures given in sterling of the year in question.
Converted to $ 1985 by dividing by the purchasing power parity, from Purchasing Power Parity and Real Expenditures in the OECD, for the year in question and multiplying by the ratio of 1980 / (year in question) implicit price deflator from the Economic Report of the President.

Table 3-21

British Gas Development-Operating Costs

Esmond Complex (Esmond, Forbes, Gordon Fields)

1.	Development costs	688	($MM)
2.	Reserves	600	(Bcf)
3.	Average production rate	73	(Bcf/year)
4.	Depletion (Q/R)	0.122	
5.	Development costs in ground	1.147	($/Mcf)
6.	Development costs as sold	2.281	($/Mcf)
7.	Operating costs	0.471	($/Mcf)
8.	Development-operating costs as sold	2.752	($/Mcf)

Sources:

1,2,3. Petroleum Economist, July 1985, p. 260. Development costs given in sterling 1985, converted to $ 1985 by dividing by the 1984 Purchasing Power Parity, from Purchasing Power Parity and Real Expenditures in the OECD, and multiplying by the ratio of the 1985/1984 implicit price deflator from the Economic Report of the President.

5. Line 1 / line 2.

6. (line 1 / line 3) * (line 4 + i) i = 0.12.

7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

8. Line 6 + line 7.

Table 3-22

British Gas Development-Operating Costs

Hewett Field
(Expansion of an existing field)

1.	Additional development costs	49 ($MM)
2.	Reserves added	120 (Bcf)
3.	Peak output	36.5 (Bcf/year)
4.	Depletion (Q/R)	0.304
5.	Development costs in ground	0.408 ($/Mcf)
6.	Development costs as sold	0.569 ($/Mcf)
7.	Operating costs	0.067 ($/Mcf)
8.	Development-operating costs as sold	0.636 ($/Mcf)

Sources:

1,2,3. Oil and Gas Journal, April 28, 1986, p. 34.
Development costs given in $ 1986.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. line 6 + line 7.

Table 3-23

British Gas Development-Operating Costs

Morecambe Field

1.	Development costs	2.85 ($Billion)
2.	Reserves	5 (Tcf)
3.	Peak output	438 (Bcf/year)
4.	Depletion (Q/R)	0.088
5.	Development costs in ground	0.570 ($/Mcf)
6.	Development costs as sold	1.353 ($/Mcf)
7.	Operating costs	0.325 ($/Mcf)
8.	Development-operating costs as sold	1.678 ($/Mcf)

Sources:

1. World Oil, August 15, 1981, p. 174 (includes costs of pipeline to shore). Development costs given in $ 1981, converted to $ 1985 using implicit price deflator from Economic Report of the President.

2,3. Petroleum Economist, Febuary 1985, p. 67.

5. Line 1 / line 2.

6. (line 1 / line 3) * (line 4 + i) i = 0.12.

7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.

8. Line 6 + line 7.

Table 3-24

British Gas Development-Operating Costs

Thames Complex (Thames, Yare, Bure)

1.	Development costs	230 ($MM)
2.	Reserves	460 (Bcf)
3.	Peak output	43.8 (Bcf/year)
4.	Depletion (Q/R)	0.095
5.	Development costs in ground	0.500 ($/Mcf)
6.	Development costs as sold	1.129 ($/Mcf)
7.	Operating costs	0.263 ($/Mcf)
8.	Development-operating costs as sold	1.392 ($/Mcf)

Sources:

1,2. Petroleum Intelligence Weekly, Feburary 2, 1985, p. 12. Development costs given in $ 1985.
3. International Gas Report, Febuary 1, 1985, p. 2.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = 0.12.
7. 0.05 * line 1 / line 3 (annual operating expenses/annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.

Table 3-25

British Gas Development-Operating Costs

Victor Field
Gas/Condensate Field

1.	Development costs	139 ($MM)
2.	Reserves	706 (Bcf)
3.	Production rate	91 (Bcf/year)
4.	Depletion (Q/R)	0.129
5.	Development costs in ground	0.197 ($/Mcf)
6.	Development costs as sold	0.380 ($/Mcf)
7.	Operating costs	0.076 ($/Mcf)
8.	Development-operating costs as sold	0.456 ($/Mcf)
9.	Development-operating costs as sold, adjusted for condensate production	0.444 ($/Mcf)

Sources:

1. International Petroleum Encyclopedia, 1984, p. 202. Development costs given in $ 1984, converted to $ 1985 using implicit price deflator from Economic Report of the President.
2. Development of the Oil & Gas Resources of the United Kingdom, 1985, p. 64.
3. Petroleum Economist, October 1984, p. 391.
5. Line 1 / line 2.
6. (line 1 / line 3) * (line 4 + i) i = .12.
7. 0.05 * line 1 / line 3 (annual operating expenses / annual production) annual operating expenses assumed to be 5% of development costs.
8. Line 6 + line 7.
9. Line 8 - (yearly revenue from condensate sales / line 3) = line 8 - ((146,000 bbl) * ($7.50/bbl)) / (line 3 * 1000). Condensate production rate from Petroleum Economist, October 1984, p. 391. $7.50 condensate price assumed.

Table 3-26

British Gas Development-Operating Costs

Vulcan, Vanguard, South Valiant Fields

1.	Development costs	960 ($MM)
2.	Reserves	1.4 (Tcf)
3.	Depletion (assumed)	0.10
4.	Production rate (aR)	140 (Bcf/year)
5.	Development costs in ground	0.686 ($/Mcf)
6.	Development costs as sold	1.509 ($/Mcf)
7.	Operating costs	0.343 ($/Mcf)
8.	Development-operating costs as sold	1.852 ($/Mcf)

Sources:

1. Petroleum Intelligence Weekly, March 3, 1986, p. 12. Development costs given in $ 1986.
2. New York Times, Febuary 26, 1986, p. 5.
5. Line 1 / line 2.
6. (line 1 / line 4) * (line 3 + i) i = 0.12.
7. 0.05 * line 1 / line 4 (annual operating expenses/annual production) annual operating expense assumed to be 5% of development costs.
8. Line 6 + line 7.

However, a number of developments, mostly in the southern sector, have been recently announced in sufficient detail to calculate their costs (see Tables 21 through 26). (Note that Morecambe will be used for peaking purposes and that the Hewett development is an expansion of an existing field.) The variance is high, but all the fields would be viable at oil prices around $15/bbl, assuming that pipeline costs are small. Using reserves as to weight the costs yields a weighted average, for these developments, of $1.65/Mcf.

Associated Gas

The United Kingdom has substantial reserves of associated gas in oil fields in both the central and northern sectors of the North Sea. Approximately 13% of domestic production in 1984 consisted of associated gas.[77] Future levels of supplies depend on the development of a pipeline system to gather the gas now being flared or reinjected into a variety of fields and on the economics of such a system.

For associated gas, most costs will be for gathering and pipelining, since exploration and field development costs are borne by the oil. (Processing costs need not be considered, since recovery of the liquids before flaring is almost always economic.) Thus, the true marginal cost of associated gas consists of costs of the pipeline and associated onshore facilities.

Table 27 summarizes an analysis performed in the late 1970s of the economics of several suggested gas gathering systems. (These include

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[77] Development of the Oil and Gas Resources of the United Kingdom 1984, U.K. Department of Energy, p. 69. Gas used on oil production platforms is excluded.

TABLE 3-27

ASSOCIATED GAS TRANSPORTATION COSTS
(1985 US$)

Proposed System	Total Capital Costs	Annual Capital Costs	Annual Operating Costs	Design Capacity	Costs per Mcf
Central System	1460	175	59	297	0.787
All U.K. Fields	2650	318	100	533	0.785
All U.K. Fields plus Statfjord	3024	363	114	677	0.705
Existing Pipelines	2606	313	100	373	1.108
Recommended	2993	359	114	657	0.721

Source: A North Sea gas gathering system,
U.K. Department of Energy, May 1978.

some gas/condensate fields, as well as oil/gas fields.) In most cases, the range of estimated costs for delivering gas with these systems (excluding the Statfjord/Heimdall legs) was substantially below $1/Mcf. The system that was developed, the Far North Liquid and Associated Gas System, is reported to have cost $1.6 billion.[78] Using the previously described method, this translates into a delivery cost of roughly $0.75/Mcf.

However, the incremental cost of hooking up new fields should be lower, since the trunk pipeline reflects sunk costs. Turning to estimates made during the original gas gathering pipeline study, Table 28 provides some examples of these incremental costs, which range from $0.40 to $1.25/Mcf.

Algeria

With its supergiant Hassi R'Mel field and its close proximity to Western Europe, Algeria is in a uniquely favorable position as a gas producer. It can achieve very high rents by exporting natural gas, partly by pipeline, to the second largest market in the world. However, by demanding too high a price, the Algerians have lost many of their customers and may lose more. At present, they not only have huge surplus export capacity, but there is little prospect in the foreseeable future of significant increases in sales.

Although Algerian natural gas resources include more than just the Hassi R'Mel field, this field dominates the Algerian supply picture.

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[78] Natural Gas Prospects, International Energy Agency, 1986, p. 78.

TABLE 3-28

COST OF HOOKING UP GAS FIELDS, UK NORTH SEA

Field	Distance System (miles)	Peak Capacity (Bcf/year)	COSTS (million 1985$)	($/Mcf)	($/Mcf per 100 mis.)
Field Hookup Pipeline					
Fulmar	147.5	85	471	0.942	0.64
Magnus	33.1	73	203	0.474	1.43
9/18	48	36.5	223	1.038	2.16
Lomond	154.1	75	557	1.263	0.82
Magnus2	49.3	73	251	0.584	1.18
Statfjord	207.7	365	805	0.375	0.18
Beryl	83.2	100	340	0.578	0.69
Proposed Trunkline Options:					
Thelma	136	300	438	0.248	0.18
Thelma2	136	530	538	0.173	0.13
Thelma3	136	675	571	0.144	0.11
Thelma4	136	830	596	0.122	0.09
Onshore Facilities:					
System A		297.11	555	0.317	
System B		532.9	794	0.253	
System C		677.075	973	0.244	
System D		827.455	1062	0.218	

Note: Currency converted at .4665 pounds per dollar, which is average of 1979 and 1980 purchasing power parity exchange rates, from OECD, Purchasing Power Parities and Real Expenditures in the OECD

Pipeline capacity from OGJ 8/12/85; (estimated for Fulmar and Beryl).
Capital costs in January 1980 pounds from A North Sea gas gathering system, Energy Paper Number 44 UK Department of Energy, May 1978, pp. 27-31.

Discovered in 1956, by 1966, its reserves were estimated at 39 Tcf.[79] By 1977 they had grown to 54 Tcf, not including approximately 1.5 Tcf that already had been produced.[80] Other fields, shown in Table 29, contain a reported 129.3 Tcf proved reserves, led by the Rhourde Nousse field with 13.1 Tcf. (The Oil & Gas Journal listed proved reserves of 107 Tcf on January 1, 1986.) At 1985 production rates, the existing reserves have an expected life of well over 100 years.

On the other hand, undiscovered resources are believed to be fairly small. Algeria officially maintains that its possible and probable hydrocarbon reserves constitute one-third of its proved reserves. The U.S. Geological Survey puts the mean expectation for undiscovered gas at only 26 Tcf, less than one-quarter of the amount discovered to date.[81]

Partly due to its small oil reserves and partly due to these low expectations for undiscovered resources, Algeria considers itself to be resource poor. However, for the purposes of natural gas trade, Algeria is a major supplier. Even if the above assessments are correct, resources will not be a constraint on Algeria's natural gas trade position for decades. In reality, these assessments probably reflect an assumption that the minimum economic field size is very large, reflecting the high

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[79] PPS, February 1966, p. 44.

[80] IPE, 1977, p. 239.

[81] January 1, 1986 reserves were 107 Tcf, and gas produced to that date amounted to 12 Tcf. Reserves from OGJ, op. cit. and cumulative production from Energy Information Administration, Department of Energy, The Petroleum Resources of Libya, Algeria, and Egypt, March 1984, p. 77. Undiscovered resources from U.S.G.S. 82-1056, cited in DOE, ibid. The estimated range of undiscovered natural gas is 19 to 35 Tcf, at the 5 and 95 percent probability levels.

TABLE 3-29
ALGERIAN NATURAL GAS RESERVES
(Tcf)

Field	Proven	Probable	Possible
Hassi R'Mel	85.3	--	--
In Salah	5.2	15.2	15.7
Rhourde Nousse	13.1	2.2	2.0
Tin Fouye Tabankort	5.4	5.0	--
Gassi Touil	6.9	1.6	1.0
In Amenas	5.5	1.1	2.0
Stah	7.7	0.6	0.2
Haoud Berkaoui	0.2	--	--
TOTAL	129.3	25.7	21.0

Totals may not add due to rounding.

Source: Sonatrach, cited in Mossavar-Rahmani, op. cit. p. 120.

transporation costs of the gas and perhaps also the Algerian policy environment. In the future, if the minimum economic field size drops, resources should grow substantially.

Algeria initiated the first long-term LNG contract, beginning deliveries to the United Kingdom in 1964. Small contracts with France and Spain followed, usually delivered for under $1/Mcf (in current dollars). These prices were essentially competitive with then-current oil prices, a necessity in marketing the gas. At least one study suggested that these exports were not really economical, but Algeria has argued they were undertaken to develop the technology.[82]

Algeria was well positioned to take advantage of the first oil shock. The first large-scale (135 Bcf/yr) contract for LNG exports had been signed only in 1972, with France, but a number of others were under consideration, including several with U.S. companies. (Spot sales were made to the United States in the winter of 1970, at prices on the order of $1.50/Mcf.[83])

Given both the regulation-induced tightness in the U.S. natural gas market, and competitive prices for LNG, it was natural at the time that U.S. pipeline companies turn to Algeria for supplies. Contract

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82 Clinton Mouer, "The Economics of Liquefied Natural Gas," MIT Sloan School of Management, Masters Thesis, Cambridge, Mass., June 1973, p. 80. When the net present value was set to zero, the internal rate of return was 7 percent, less than the opportunity cost of capital at that time of 8 percent.

83 PPS, 7/70, p. 269. Although the price equates to approximately $9/bbl of oil, far above market prices at the time, transportation costs for natural gas were high enough that the price was probably competitive when delivered along the East Coast, to Boston in particular. Other reports put the price at as little as half those prices. See, e.g., PPS, 4/70, p. 144, which put proposed c.i.f. prices at $0.68 to 0.85/Mcf.

negotiations took place from the early 1970s on, and a number were signed, although some were never initiated. In all, contracts for 16 Bcm/yr (564 Bcf/yr) were signed at one time or another, and an additional 20 Bcm/yr (730 Bcf/yr) was negotiated, although the peak flow to the United States was only 7.2 Bcm (253 Bcf). No deliveries are being made at present.[84]

A number of problems have prevented exports of Algerian LNG to the United States. In one instance, at the end of 1973, the Algerians cancelled a contract when the required approval from the U.S. government, specifically the Federal Power Commission, was not granted within the time they required. The Algerians seemed to be responding to rising world oil prices, which had rendered the original contract price of $0.42/Mcf unappealing,[85] and the contract was renegotiated at higher prices. Subsequent price increases were accepted by El Paso, and approved by U.S. regulatory agencies, in 1979, but Sonatrach abrogated the contract only months later since oil prices were still rising. When U.S. natural gas prices weakened, the importers chose to abrogate the contracts, as their sales prices became increasingly uncompetitive. Trunkline, for example, was able to replace its LNG imports at half the Algerian price.[86]

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[84] In settling claims with Sonatrach, Panhandle Eastern promised to begin good-faith negotiations for marketing LNG in the United States. See IGT Highlights, 7/28/86, p. 1.

[85] PE, February 1974, p. 67.

[86] Platt's Oilgram News, 12/15/83, p. 3. Falling U.S. gas consumption and inflexible take-or-pay clauses in the Algerian contracts also were contributing factors.

Abrogation of the contracts allowed importers to reduce the price of natural gas to their customers.[87]

After the 1973 oil crisis, a number of other LNG contracts were under consideration by customers as diverse as Germany and Czechoslovakia. The contracts actually concluded, mostly after the second oil crisis, were with Spain (for 4.5 Bcm/yr; 160 Bcf/yr), France (for a total of 9.1 Bcm/yr; 320 Bcf/yr) and Belgium (for 5 Bcm/yr; 175 Bcf/yr). In 1984, however, only 19.1 Bcm (675 Bcf) actually was exported; none of the countries had been able to accommodate the full contract quantities, both due to the weakness in energy demand in Western Europe and due to their overestimation of natural gas demand potential. As the highest-priced exporter, the Algerians have suffered proportionally more than most other suppliers.

More recently, Algeria commenced deliveries to Italy via a pipeline beneath the Mediterranean Sea. The Algerians initially delayed deliveries, demanding a higher price. As a result, the start-up of deliveries was delayed by almost two years, increasing interest costs by nearly $250 million.[88]

The result is that Algeria now finds itself with 1550 Bcf/yr of export capacity (1100 Bcf/yr of LNG capacity, and 450 Bcf/yr of pipeline capacity), of which about 60 percent will be utilized in 1986.[89] The

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87 Trunkline cut its prices by 19 percent. See OGJ, 12/19/83, p. 52.

88 PIW, 5/30/83, p. 5.

89 Assuming the Belgians and Spanish are able to take 2.5 Bcm each, the French 8 Bcm, and the Italians 12 Bcm. Yugoslavia is slated to take 1.5 Bcm when the pipeline from Italy has been expanded, but the date

recent Troll contract with Norway should make it difficult for Algeria to increase its sales. Indeed, it may be that the Belgians will abrogate their contract with Algeria altogether. The French and Spanish governments have proven susceptible to political pressure, as well as Algerian threats to respond by limiting imports from them, and so they are less likely to cancel their contracts, although adjustments are being sought.

Algerian Policy

> "If LNG were to be sold on terms comparable to the cost of its real global economic alternative--that is, syngas from coal--Gulf producers would be offered a real incentive to move ahead with their investments. Modest though such a return would be--a little over $1.00/MMBtu, or perhaps one-third of the return on oil--it would at least put a positive value on the gas itself. The days when producer governments would put gas into an LNG plant at zero wellhead value, and content themselves merely with a financial return on their investment, are over."[90]

As mentioned above, Algeria consistently has sought higher than prevailing prices for its gas exports, using a variety of arguments. While its demands for f.o.b. parity with crude oil prices have received the most attention, that is only one approach. The crude oil parity argument was strongly made because it seemed the most simple: To them,

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deliveries would commence has not been announced. The surplus LNG capacity reflects nameplate capacity; actual capacity may be less due to engineering problems and neglect of unutilized machinery.

[90] Nordine Ait-Laoussine, Executive Vice President, Sonatrach May 1979, in "Developments in the Natural Gas Industry of Algeria, OPEC Review, Vol. III, No. 2, Summer 1979, p. 7.

the value of gas exports should be the same as the value of crude oil exports.[91]

Other arguments included the notion, not held uniquely by Algerians, that natural gas should be "reserved" for use in "premium" markets, and priced to reflect that premium value, while less "noble" hydrocarbons, presumably coal, satisfied demand for boiler fuels.[92] When oil was priced at still $14/barrel, they argued that the price should be equated or linked to the cost of synthetic gas, which was well above crude oil equivalency prices.[93] When oil prices rose, Algeria suggested using equivalency with middle distillate.[94] Finally, lacking all else, they suggested that, as pioneers of the technology, they deserved greater rewards for having accepted the risks.[95]

In fact, Algeria has not limited its goal to achieving a crude oil-equivalent price. In 1974, they demanded a ten-fold increase in prices by 1979, well over equivalent oil prices.[96] Later, in 1977,

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[91] Mossavar-Rahmani, op. cit., p. 92.

[92] Nordine Ait-Laoussine, "Towards a New Order in Gas Pricing," OPEC Review, Vol. IV, no. 2, Summer 1980, pp. 50-72. Ait-Laoussine was speaking as a private consultant at this point.

[93] Nordine Ait-Laoussine, "Developments in the Natural Gas Industry of Algeria," OPEC Review, Vol. III, no. 2, Summer 1979, p. 7.

[94] Ait-Laoussine, 1980, op. cit., p. 67. This would have increased prices 10 percent above those of crude oil equivalency.

[95] Algerian Minister of Energy and Petrochemicals Belkacem Nabi, quoted in MEES, 4/21/80, p. 5.

[96] Certainly, the Algerians' expectations of oil prices may have included such an increase, but that is not clear from the information available. Their prices at that time were equivalent to $1.80 to $2.40/bbl of oil, and they asked for an immediate increase to approximately the equivalent of $12/bbl, roughly the prevailing price. See PE, May 1974, p. 177.

they argued that the appropriate price would be $6.50/MMBtu in 1985, or about three times the then-prevailing price![97]

Algeria has never attained its pricing goals. It was, however, highly successful in repeatedly convincing customers to accept higher prices, and has (like others) introduced oil price-indexation into its contracts. It also managed to convert a number of contracts from c.i.f. pricing (i.e., pricing related to end-use markets) to f.o.b. pricing (i.e., "value" pricing).[98]

Their success occurred due to the fears of customers during the past oil crises that their energy supplies would be inadequate, reflecting their belief that prices were not as important as locating supplies. Actual users had little influence (either politically or through the marketplace) until the gas was delivered. Both the French and Italian gas utilities resisted Algerian price increases, but their respective governments overrode them, and provided subsidies to offset the higher-than-market prices. The Italian government agreed to pay about $0.50/Mcf of the price (depending on exchange rates), or more than 10 percent. The French government similarly agreed to a 13.5 percent subsidy

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[97] Ait-Laoussine, 1979, p. 9, quoting himself. The same caveat applies as in the previous footnote.

[98] Ait-Laoussine, 1980, p. 65, criticized this practice, both because of problems with keeping the gas competitive, but also because "...energy prices are expected to increase faster than the transportation charges...," meaning that buyers would receive the rents from the resulting disparity in c.i.f. prices for gas and oil.

to Gaz de France (GdF), which was subsequently rescinded due to budgetary constraints.[99]

When the gas did arrive, customers refused to buy it in the quantities expected. The demand for energy in general had been overestimated, and in addition natural gas prices were losing their competitive advantage. Although government planners felt that gas imports were much preferable to oil imports, consumers held a different view of the differential value of the two. As the price of gas rose in response to renegotiated gas contracts, consumers were less likely to switch to gas.

The recent fall in oil prices has led to strong demands for a reduction in LNG prices. Algeria, maintaining the fiction that its crude oil still is selling at official pre-crash prices, has refused. As a result, the Belgians and Italians unilaterally lowered the price they were paying. Instead of \$3.81/Mcf for LNG f.o.b. Algeria and \$3.45/Mcf for pipeline gas at the Tunisian border, for Belgium and Italy respectively, they are now paying \$2.30/Mcf and \$2.00/Mcf (f.o.b.) while awaiting conclusion of the renegotiation process.[100]

At the same time, the French and Spanish have agreed to an interim price on the order of \$3.18/Mcf f.o.b. (about \$3.60 c.i.f.), indexed to

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[99] The French government did agree to allow GdF to increase prices to offset the loss of the subsidy. See PIW, 3/12/84, p. 4. Even with the subsidy, GdF claimed that half its 1982 deficit was due to the excessive price for Algerian LNG. See PIW, 5/2/83, p. 3.

[100] ibid. They have stated that any difference in the price that is finally negotiated will be paid (or demanded) retroactively.

Dutch and Soviet gas export prices rather than to crude oil prices.[101] Reports suggest that this is an interim price and that negotiations for a new, long-term pricing formula are still underway.[102]

The future direction of Algerian policy is not clear. Although a recent statement by the Energy Minister admitted that it is not possible to market a fuel that is not priced competitively,[103] the Director General of Sonatrach expressed optimism over regaining sales to the U.S. market, based on his assessment of the lack of available gas in Canada and Mexico.[104] Considering the glut in the U.S. natural gas market, and with current spot prices at $1.50/Mcf, LNG imports appear extremely unlikely, at least at prices comparable to those paid in Western Europe.

This optimism no doubt is based on Algeria's past successes in obtaining sales at prices above those prevailing in the market. Algeria has denied that its prices were political in nature,[105] but at the same time it has sought to reinitiate the defunct contracts both through its political contacts[106] and by putting pressure on those U.S. banks through which it has loans to use their influence with the importing pipelines.[107]

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[101] See IGR, 4/11/86, pp. 1-3.

[102] ibid.

[103] Summer of 1985, cited in PIW, 9/16/85, p. 5.

[104] OPEC Bulletin, July/August 1985, p. 57.

[105] IGR, 10/26/84, p. 11.

[106] Such was referred to during a March 1985 visit to the United States by Algerian President Benjedid. See PIW, 3/25/85, p. 6.

[107] WSJ, 3/28/84, p. 36.

At the same time, Algeria is seeking new contracts outside its traditional markets. A small (1 Bcm/yr, or 35 Bcf/yr) barter contract was signed with Brazil last year, which would have used Algerian LNG tankers to deliver and regasify the natural gas at a reported price of \$4.00 to \$4.5/Mcf, c.i.f.[108] However, the contract failed to achieve approval due to internal disputes in Brazil.[109] The Algerians also have sought customers in the Pacific basin, but at crude oil-equivalency prices and given the LNG glut in that market, customers have no incentive to buy additional supplies from a new source.[110]

The Economics of Algerian Natural Gas Supply

In arguing for higher LNG prices, Algeria repeatedly has suggested that the complexity and expense of the liquefaction process requires prices higher than those being paid by customers. Whatever the merit of this argument, cost is an important criteria in investment decisions. Specifically, we need to know the returns that Algeria requires to provide natural gas to the Western European market. To that end, the costs of gas production, liquefaction, and transportation are examined.

At present, the Hassi R'Mel field provides most of Algeria's natural gas production, and an approximate cost can be estimated from available data. Table 30 shows that the development/operating cost of Hassi R'Mel is approximately \$0.05/Mcf, due to its shallow depth and prolific

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108 <u>MEES</u>, 3/25/85, p. A7.

109 <u>IGR</u>, 7/19/85, p. 1.

110 <u>IGR</u>, 11/22/85, p. 1.

Table 3-30

Algerian Gas Development-Operating Costs

Hassi R'Mel

1	Drilling and equipping costs per well	530	($ M)
2	Allowance for non-drilling costs per well	400	($ M)
3	Allowance for gathering per well	280	($ M)
4	Total development costs per well	1210	($ M)
5	Depletion	0.01	
6	Annual development-operating costs per well	218	($ M)
7	Development-operating costs per day per well	600	($)
8	Average production rate per well	120	(MMcfd)
9	Average development-operating costs as sold	0.050	($/Mcf)
10	Marginal development-operating costs as sold	0.054	($/Mcf)
11	Development costs in ground	0.0003	($/Mcf)

Sources:

1. Joint Association Survey, 1984, figure for 7,500', Onshore Texas. 1984 development costs converted to $ 1985 using the implicit price deflator from Economic Report of the President.
2. Assumed to be 75% of line 1.
3. Assumed to be 30% of line 1 + line 2.
5. 1984 Algerian production / Algerian reserves at year end from Oil and Gas Journal, December 31, 1984, p. 74.
6. Line 4 * (0.12 + 0.01 + 0.05), allowing 12% discount rate, 1% depletion, and 5% operating costs.
7. Line 6 / 365.
8. International Petroleum Encyclopedia, 1977, p. 239.
9. Line 7 / ((line 8) * 1000).
10. (line 9) * ((line 5 + i) / i).
11. development costs at wellhead = line 4 * 0.13 / 43,800 MMcf/ year = $0.004/Mcf (0.13 = depletion + discount rate, 43,800 = yearly production).
    Development costs in ground = development costs at wellhead divided by (1 + (i / a)) i = 0.12, a = 0 .01.

production per well. (Any error will be insignificant on an absolute scale.)

Once produced, the gas must be transported. To transport gas from Hassi R'Mel to Arzew requires a 510 kilometer pipeline. In 1984, a contract for $200-$300 million was let to expand capacity by 5 Bcm/yr (175 Bcf/yr) by looping the existing line.[111] Using the methodology described previously, yields a transportation cost of $0.29/Mcf, which is in close agreement with the estimate of $0.25/Mcf made in the 1982 IEA report.[112] The distance to Skikda, where 8.5 Bcm/yr (300 Bcf/yr, or 27 percent) of the liquefaction capacity is located, is about one-quarter longer, and the distance to Cape Bon in Tunisia, where the TransMed pipeline begins, is about twice that. From the Rhourde Nouss field to Hassi R'Mel is about the same distance as from Hassi R'Mel to Arzew. The resulting transportation costs to the various exit points are shown in Table 31.

The major transportation costs are incurred after the gas has reached the sea. According to the 1986 IEA report, the Transmed pipeline, at 12 Bcm/yr (425 Bcf/yr) capacity, cost $1.6 billion, although this includes the Algerian section.[113] Subtracting the onshore section, brings

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[111] PIW, 8/20/84, p. 6, put the cost at $300 million, while WSJ, 8/15/84, p. 31 put it at $196 million. The latter report conceivably could exclude subcontracts, some materials, etc., so we have used the higher number.

[112] op. cit., p. 127. The IEA estimate is from Hassi R'Mel to the Tunisian border, which is slightly further than to Arzew. This cost estimate is approximately one-third higher than U.S. marginal pipeline costs.

[113] op. cit., p. 78. PE, July 1983, p. 257 put the cost at $3 billion.

TABLE 3-31

ALGERIAN NATURAL GAS COSTS
($/Mcf)

COSTS	Hassi R'Mel	Rhourde Nousse
Production	0.050	0.100
Transportation		
to Arzew	0.300	0.600
to Skikda	0.375	0.675
to Transmed	0.600	0.900
LNG costs		
Capital costs	0.600	0.600
Operating (3%)	0.140	0.140
Fuel (10% input)		
Arzew	0.035	0.070
Skikda	0.043	0.078
Total liquefaction costs		
Arzew	0.775	0.810
Skikda	0.850	0.885
"fob" cost		
Arzew	1.125	1.510
Skikda	1.275	1.660
Transmed	0.650	1.000
Transport costs (exAlgeria)		
to S. France	0.110	
to Zeebrugge	0.440	
to Italy	0.400	
Total costs, cif		
to S. France		
Arzew	1.235	1.620
Skikda	1.715	2.100
to Zeebrugge	1.715	2.100
to Italy	1.050	1.400

Source: See text.

the capital cost down to about $1 billion. (This is probably too high.)[114] Applying the previously described method to this capital cost yields a transportation cost of $0.40/Mcf.[115]

There is a possibility that capacity will be boosted to 18 Bcm/yr (635 Bcf/yr), but since looping will be necessary to accomplish this, rather than just additional compression, costs for incremental volumes will not fall significantly.

The LNG plants at Arzew apparently cost on the order of $2.6 billion for 15.5 Bcm/yr (550 Bcf/yr) of capacity.[116] Using this as a base cost[117] yields liquefaction costs of $0.775 to $0.885/Mcf, as shown in Table 31. The table also compares this cost with costs to the point of import for the pipeline. Most other estimates of liquefaction costs are around $1.00/Mcf.[118] Using our estimates, the total costs to

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[114] A recent report estimated the cost of the undersea segment between Tunisia and Sicily at $520 million, or half this amount. The length from Sicily to the Italian coast is noticably longer, but mostly onshore, and should be less than half the cost from the Tunisian coast, so the $1 billion estimate seems to be on the high side. See M.T. Bensalem, "Inspection and Maintenance Techniques for the Algeria-Italy trans-Mediterranean Pipeline," OGJ, 7/7/86, p. 54.

[115] The 1982 IEA report estimated the cost at $1.53/Mcf, which this included transportation to Northern Europe, but the precise distance is not stated.

[116] $1.7 billion in 1978 dollars, according to PE, August 1978, p. 348. The cost was estimated at the beginning of the project at exactly half that (PE, October 1974, p. 378), but such escalation was common for this type of project during the mid-1970s. See the Asia-Pacific report for a more detailed discussion of cost escalation, pp. 48-68.

[117] Industry sources have informed us that the Arzew plant was "gold-plated," reflecting the expectations for very high future LNG prices and little cost control, so we assume that other plants will be no more expensive.

[118] See pp. 26-27 of the Asia-Pacific report.

the point of delivery vary from $1.05 to $2.10/Mcf. Insofar as most production comes from Arzew, the true range is much more narrow.

Since Hassi R'Mel has the capability to produce at current levels for as long as a half-century, suggesting that Rhourde Nousse represents long-term marginal costs overstates the point. Certainly, an additional $0.30/Mcf does not represent a severe escalation over such a long time horizon. Any future increments to transportation capacity appear likely to be via undersea pipelines, suggesting a further moderation of costs.

On the other hand, any new liquefaction capacity probably would be much more expensive than that built in the late 1970s, given cost escalation. (This is one reason why Algeria has concentrated on pipeline deliveries for future incremental volumes.) Also, to the degree to which the Algerian plants have not been able to reach full capacity for technical reasons, our costs would be understated. If the low capacity utilization is the result of price disputes, then that hardly can be counted as a physical cost.

The Algerians are considered to be unreliable suppliers because they have often threatened to stop deliveries if their demands for contract revisions were not met, and have sometimes carried out those threats. Their gas should therefore sell at a discount, although their customers may forego that.

The Soviet Union

The Soviet Union has by far the largest reserves of natural gas in the world. It also has an urgent need for the hard currency that gas exports offer, as well as a willingness to price its resources competitively in order to penetrate markets. Thus, the Soviet Union has the potential to become the dominant natural gas supplier to Western Europe.

However, the location of these resources in a forbidding environment and the vast distances the gas must be transported both suggest that there are economic constraints on delivery of Soviet gas, especially at a time of weak oil prices and saturated gas markets. This section attempts to assess whether continued expansion of gas exports would be profitable to the Soviet economy.

Perhaps comparing expected natural gas prices with long-run marginal costs was superfluous when gas sold at $5.50/Mcf, and when Western European consuming governments were panicked about supply. But the most recent large-scale contract in Western Europe, for the sale of Norwegian offshore gas, is nominally at $3.50/Mcf (with renegotiation available at any time) if oil prices are $28/bbl. So our reference prices will be from $1.75 to $3.50/Mcf.

Is it profitable to develop Soviet gas at prices clearly much below this range?

The closed Soviet economy and the difficulty of translating Soviet costs into Western equivalents make analysis of Soviet gas supplies difficult, but certain limited inferences can be drawn. Based on what information is available, it appears that gas can be produced and delivered from Western Siberia to the West German border for about $2.00/Mcf. Since most of the costs are in rubles, the Soviets should be willing to expand their capacity to sell gas to Western Europe, to say nothing of continuing deliveries, even if Western European natural gas prices are around $2.50/Mcf. Until the pipeline from Urengoi reaches full capacity, the economic incentives to increase sales will be much higher.

Historical Background

The Soviet natural gas industry developed in a manner similar to that of the United States. Before World War II, most gas consumed was manufactured or associated gas. However, during the search for oil to replace reserves in regions occupied or threatened by the Germans prior to and during the war, a number of large natural gas deposits were found in the Northern Caucasus and Volga-Ural areas. At that time, little effort was made to develop or exploit these resources; indeed, investment allocated to gas of all types comprised only 3 percent of all investment in the oil and gas industries in the Fourth Five Year Plan (1946-50), and only 8 percent in the Fifth (1951-55). Even then, a large fraction of the allocated investment was devoted to manufactured gas.[119]

The post-WWII search for oil continued to find natural gas at a far greater rate than the country was exploiting it. From 1946 to 1955, reserves grew twice as fast as production, despite the fact that only 10 percent of exploratory drilling was devoted specifically to gas.[120] By 1956, the Soviets officially recognized the abundance of natural gas resources, which led to formulation of an official goal to

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119 Robert W. Campbell, The Economics of Soviet Oil and Gas, Resources for the Future, 1968, pp. 197-8. Hereafter ESOG.

120 ESOG, p. 198.

increase its share in consumption from 6 percent in 1958 to 21 percent in 1965.[121] Until the mid-1960s, though, the gas industry generally did not meet its goals, unlike the oil industry. This resulted mainly from bottlenecks due to shortcomings in completing pipelines, as well as slowness in developing gas-using equipment.[122]

As Soviet reserves became increasingly concentrated in Siberia and other areas distant from domestic consuming centers, rapid expansion of the pipeline system became necessary. As a result of this effort, approximately 74 percent of the country's population is now connected to natural gas, and only the most remote areas are not part of the system.[123]

At the same time, however, gas supplies became so abundant that the Soviets sought exports to Western Europe, first in the late 1960s, and then again in the late 1970s, totalling 25 Bcm/yr (880 Bcf/yr) and 24 to 32 Bcm/yr (850 to 1130 Bcf/yr), respectively.[124] Currently, the Soviets still have about 15 Bcm/yr (530 Bcf/yr) of excess pipeline capacity from Urengoi, and are drilling in the Yamburg field with the intent of adding 200 Bcm/yr (7 Tcf/yr) of production capacity. Some of this will be devoted to exports to Eastern Europe and some to domestic consumption; additional exports to Western Europe may be sought in the future.

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[121] _ibid._

[122] _ibid._

[123] _OGJ_, 2/10/86, p. 35.

[124] A number of the contracts grow slowly. The higher number assumes all gas, including optional amounts, is sold.

Resources

"Explored" reserves of natural gas in the Soviet Union total 1,500 Tcf. While proved reserves are not reported separately, they are probably about half to two-thirds of explored reserves. Hence, Soviet reserves constitute from 38 to 52 percent of the non-communist world's proved reserves.[125] (The quantities are so enormous that the precise amount is not important.)

Most of these reserves were discovered in the last decade and most (6 out of the 8 supergiants) are located in Siberia. This largely reflects discoveries in the Yamal peninsula, where fields like Urengoi and Yamburg are currently estimated to contain 284 and 168 Tcf, respectively.[126] The fact that Urengoi alone contains more natural gas than current U.S. proved reserves underscores the enormity of the resource base in that area.

Since the first major natural gas discovery in Siberia was only two decades ago, and the Urengoi field, discovered at that time, is only now being exploited, the province can hardly be described as mature. The U.S. Geological Survey estimated West Siberian undiscovered gas at between 235 and 1519 Tcf (see Table 32), with a mean of 702. For the total country, they estimate undiscovered natural gas could be 2000 Tcf,

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[125] OGJ, 12/31/85. The Soviet Union reports "explored" reserves, which includes proved and some probable, according to the U.S. definition. See ESOG, p. 60, or USSR Energy Atlas, CIA (1985), p. 13, for an explanation.

[126] OGJ, 12/12/83, p. 57.

Table 3- 32

Undiscovered Reserves - U.S.S.R.

	Undiscovered Reserves Assessment (Tcf)		
	Low	High	Mean
Middle Caspian Basin	25.5	123.0	62.8
East Siberian Basin	44.8	330.5	158.2
Volga-Urals Basin	19.0	142.0	63.0
West Siberian and Kara Sea Basins	235.0	1519.0	702.0
Timan-Pechora Basin and Barents-Northern Kara Shelf	179.1	498.1	325.2
Total of Areas Given	503.4	2612.6	1311.2

	--- Reserves -----		Cumulative Production
	Demon-strated (Tcf)	Inferred (Tcf)	as of 1/1/81 (Tcf)
Middle Caspian Basin	6.0	n.a.	0.8
East Siberian Basin	32.0	25.0	n.a.
Volga-Urals Basin	75.0	25.0	n.a.
West Siberian and Kara Sea Basins	400.0	260.0	n.a.
Barents-Northern Kara Shelf	11.3	n.a.	7.3
Total of Areas Given	524.3	n.a.	n.a.

Notes:

Middle Caspian Basin: Most giant discoveries should be offshore, the area is oil prone, but gas is more probable at deeper depths.

East Siberian Basin: At the time of assessment, the area was in the early stages of exploration with one well per 3200 square kilometers. Most of the wells have been drilled in previously drilled areas. These wells have found mainly gas.

Volga-Urals Basin: The Orenburg field was discovered in 1975 with 70 Tcf. No major new discoveries are likely.

Timan-Pechora Basin, Barents-Northern Kara Shelf: Only the Southwest portion of the Timan-Pechora basin is highly explored. The Barents-Northern Kara Shelf is mostly unexplored. Significant possiblilities for finding gas giants in structural traps ot the Timan-Pechora basin exist. The eastern and central regions of the Barents-Northern and Kara Shelf are mainly gas prone.

Table 3- 32 (continued)

Sources:

James W. Clarke, "Assessment of Undiscovered and Conventionally Recoverable Petroleum Resources of the East Siberian Basin, U.S.S.R.," USGS Open File Report 84-1027, USGS, Washington, D.C., 1984.

Charles R. Masters, "Assessment of Undiscovered and Conventionally Recoverable Petroleum Resources of the Volga-Urals Basin, U.S.S.R.," USGS Open File Report 81-1027, USGS, Washington, D.C., 1981.

Charles R. Masters, "Assessment of Undiscovered and Conventionally Recoverable Petroleum Resources of the West Siberian and Kara Sea Basins, U.S.S.R.," USGS Open File Report 81-1147, USGS, Washington, D.C., 1981.

Gregory F. Ulmishek, "Assessment of Undiscovered and Conventionally Recoverable Petroleum Resources of the Timan-Pechora Basin, and Barents-Northern Kara Shelf, U.S.S.R.," USGS Open File Report 82-1057, USGS, Washington, D.C., 1982.

Gregory F. Ulmishek and Wyman Harrison, "Assessment of Undiscovered and Conventionally Recoverable Petroleum Resources of the Middle Caspian Basin, and Barents-Northern Kara Shelf, U.S.S.R.," USGS Open File Report 82-296, USGS, Washington, D.C., 1982.

far greater than in any other region.[127] Obviously, the resource base is not a constraint in terms of future gas supply from the Soviet Union. Cost escalation, pipeline capacity, and investment policy will be the determining factors.

The Economics of Soviet Natural Gas Supply

Unfortunately, it is not appropriate to apply the same cost methodology to Soviet resource development as is used for other countries, because much of the Soviet expenditures are in rubles, and the income from export sales is in dollars or other hard currencies. The appropriate exchange rate between rubles and dollars is a matter of debate among economists, with the official rate set at 1.3 dollars per ruble. Since hard currency can be used to obtain goods that are not otherwise available in the Soviet Union, its ruble value is difficult to measure. In theory, the Soviets should be willing to spend more money (in rubles) to develop a natural gas export project than the price (in dollars) they would receive from it. How much more is not clear, but it is very important in determining future export policy, especially in an environment of weak prices.

Of what value are estimates of Soviet natural gas production and transportation costs? Certainly the Soviets are not indifferent to the costs, especially where some are in hard currency. Also, if the costs are known, then indications about opportunity costs can be provided,

[127] See, for example, Charles D. Masters, "World Petroleum Resources--a Perspective," U.S. Geological Survey Open-File Report 85-248, 1985, p. 20. The IEA (1982), p. 362, shows total CPE remaining gas resources as exceeding 3000 Tcf.

given what is known about the costs of substitution, etc. Then, too, the extent to which costs appear to be increasing is a vital indicator of changing investment patterns, and of Soviet willingness to continue exploiting their natural gas reserves.

The estimation of costs will be approached in several ways. First, an evaluation of what the Urengoi field development would cost in the United States will be made for purposes of comparison. Second, the costs of transporting the gas to the West German border will be provided, including the hard currency costs for the Yamal pipeline now coming into operation. Then development costs for the Yamburg field will be presented, to provide some idea of what trends the Soviets face as they exploit their resources in less tractable areas. Finally, there will be some discussion of the trends in long-run marginal costs as demonstrated by both field development described above and other available indicators.

Urengoi as the North Slope

In previous studies, the U.S. Gulf Coast was used as a surrogate to estimate supply costs in Southeast Asia, given the similarities in operating conditions in the two regions.[128] However, the only places outside the Soviet Union that resemble Siberia are the North Slope of Alaska and the Canadian Arctic. While gas fields in northern Alaska are 200 miles and more above the Arctic circle, the weather there is milder than in the Urengoi field, which straddles the Arctic Circle. In fact, no natural gas is being produced in the North American Arctic,

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[128] See East Asia/Pacific report, supply chapter, p. 17.

beyond the associated gas at Prudhoe Bay (which is mostly reinjected), so actual development costs are not available.

However, in the past few years many wells have been drilled in these areas, allowing some indication of well costs. In Alaska, the average cost for onshore gas wells between 5000 and 10,000 feet deep was $3.5 million from 1979 to 1984, which would consist mainly of gas wells on the Kenai Peninsula in the south.[129] Total Alaskan onshore well costs, including oil wells and dry holes, dropped from $3.4 million per well in 1981 to $1.8 million in 1984.[130] In the Canadian Arctic, onshore wells in the Mackenzie Delta were estimated at $1.5 to 2.25 million.[131]

Assuming the operating environment at Urengoi to be harsher than in the North American Arctic and the infrastructure less developed, we use $5 million as a per-well cost in the Urengoi field. Making a similar allowance for non-drilling costs and dry holes,[132] we derive total

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[129] Joint Association Survey of Drilling Costs, American Petroleum Institute et. al., various years. Hereafter JAS. The depth at Urengoi is put at 3400 to 10,400 feet according to IPE, 1977, p. 242, but Gustafson (1983), p. 79, indicates that the average well depth drilled at Urengoi in 1979 was 5350 feet.

[130] JAS. For wells between 7,500 and 9,999 feet deep, in current dollars.

[131] Geological Survey of Canada, Oil and Natural Gas Resources of Canada 1983, Energy Mines and Resources, Canada, 1984, p. 24. The figure given is $2 to 3 million in 1983 Canadian dollars, converted at .75 C$/US$. Costs probably have decreased since then. While the figure is for all wells, shallow oil and gas wells in the United States show similar costs. See JAS.

[132] Adelman and Ward, Annual Review of Energy, 1979. Also see the discussion in Table 5 of the East Asia/Pacific report, Supply Chapter, p. 18.

per-well costs of $10 million for the Urengoi field.[133] Gathering costs are assumed to be 10 percent of per-well costs, or $1 million per well.

Thus, total development costs per well are $11 million. Applying a discount rate of 12 percent and a depletion rate of 3.1 percent,[134] the annual development-operating costs per well are $2.2 million.[135]

Since well productivity appears to be 15 to 20 MMcf/d,[136] and well cost is $6300/d, above-ground costs would be $0.42 to $0.56/Mcf, <u>if this field were being developed in North America</u>.

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[133] In <u>ibid</u>., an allowance was made for (a) a pipeline to shore and (b) the higher costs of overseas operations. Together they were assumed to increase per-well costs by 50 percent. At Urengoi, we assume that Soviet costs are lower than U.S. costs due to lower labor costs, for example, but that this is offset by lower efficiency in the Soviet industry. Therefore, no adjustment is made. The effect of spending rubles is discussed elsewhere. As shown below, this is roughly the same as the estimated costs per well in the Yamburg field, which is located further north and has a less developed infrastructure, suggesting the Urengoi well costs should be lower. However, the Yamburg field is much shallower, which would offset the harsher conditions.

[134] Peak production is planned for 250 Bcm/yr (8.8 Tcf/yr), according to Gustafson (1983), p. 78, and initial reserves were 285.6 Tcf, according to <u>OGJ</u>, 9/22/86, p. 57.

[135] Operating costs usually range from 3 to 5 percent of total capital costs. Total development costs can be converted to annual development-operating costs by multiplying them by the discount rate plus the depletion rate plus operating costs, i.e., $11 million * (.12 + .031 + .05). See Appendix A.

[136] According to Gustafson, (1983) p. 80, 1000 new production wells were planned between 1981 and 1985, intended to increase production by 200 Bcm/yr (19.3 MMcf/well/d). In fact, it appears that production increased by 150 Bcm/yr, but the number of wells drilled to produce that result is not known. If 1000 wells were drilled, then well productivity would be 15 MMcf/d. This is an underestimate, since some wells are offsetting depletion, but the depletion rate was not large in this period, so we have chosen to ignore it.

Transportation of Natural Gas from the Yamal Peninsula

In size and scope, the Urengoi Pipeline resembles nothing so much as the Alaska Natural Gas Transportation System (ANGTS). Planned to transport 3.9 Bcf/d (1.4 Tcf/yr), versus 3.2 Bcf/d or 1.2 Tcf/yr for the ANGTS system, the pipeline covers 2740 miles to the Czechoslovakian border[137] (compared to 4800 miles for the ANGTS system), although the Urengoi passes through only 200 miles of continuous and discontinuous permafrost (plus 200 miles of sporadic permafrost) versus 770 miles for ANGTS.[138] Unlike the Alaskan line, the Soviets use larger pipe (56 inch) with lower compression (1100 psi being the norm, with plans to raise that to 1469).[139] Still, given cost estimates as high as $50 billion for the ANGTS project, the capital costs for the Yamal pipeline are obviously large.

As discussed in a previous study,[140] pipeline costs in Arctic regions are subject to debate. However, for the non-Arctic region, a transportation cost between $1.50 and $2.00/Mcf would be expected,

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[137] Plus roughly 600 kilometers to the West German border.

[138] See Executive Office of the President, Energy Policy and Planning, Decision and Report to Congress on the Alaska Natural Gas Transportation System, September 1977 for information on the ANGTS system, and Central Intelligence Agency, USSR Energy Atlas January 1985, for the Urengoi Pipeline. The CIA lists the pipeline capacity at 32 Bcm/yr or 3.1 Bcf/d, but most other sources put it at 40 Bcm/yr, or 3.9 Bcf/day, reflecting the capacity for a 56 inch pipe with high compression.

[139] The Soviets are apparently having difficulties overcoming the technical problems inherent in the higher pressures, although they claim to be capable of producing pipe that can operate at those pressures. See OGJ, 7/4/83, p. 49. The Alaskan line was planned with 48-inch pipe, with pressures as high as 1680 psi under consideration for some parts of the line. See ANGTS report, p. 75.

[140] North American report, Appendix B.

using U.S. cost factors.[141] The capital costs would run on the order of $12 to $20 billion for that segment.

For the Arctic segment, the best comparison available is the planned Polar Gas pipeline from the Beaufort Sea, which would deliver an annual average of 9.8 Bcm/yr (345 Bcf/yr) for a capital cost of $3.3 billion.[142] Using the methods described above, the cost for new Arctic pipelines appears to be 12.5 cents per Mcf per 100 miles. Thus, the Arctic segment of the Urengoi pipeline appears to cost about $0.50/Mcf.

In fact, total costs for the Urengoi pipeline have been variously reported as ranging from $15 to $22 billion.[143] This suggests that pipeline costs will be from $1.30 to $3.30/Mcf, depending on assumptions about throughput and rate of return. Table 33 shows the sensitivity of per-unit costs to the different assumptions.

Another approach is to use the Soviet rule of thumb of 1 billion rubles per 1000 kilometers of 56-inch pipeline.[144] This yields a cost of $6.5 billion to the West German border, or less than $1/Mcf, well

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141 In the early 1980s, 7.5 cents/Mcf/100 miles seemed to be the cost for new large-diameter pipelines, yielding the $2/Mcf estimated. More recently, construction costs have dropped by perhaps 25 percent, bringing the transportation costs down to $1.5/Mcf. See the East Asia/Pacific report, p. 66. For the spur to Turkey, costs will be under 5 cents/Mcf/100 miles, suggesting the lower number is more appropriate. See OGJ, 7/14/86, p. 44.

142 OGJ, 1/6/86, pp. 76-80.

143 Oil & Gas Pocket Reference 1984, Armco National Supply Co., p. 37, and CIA, USSR Energy Atlas, p. 11, respectively.

144 Gustafson, (1983) p. 39.

TABLE 3-33
SOVIET PIPELINE COSTS
URENGOI TO BORDER
($/Mcf)

THROUGHPUT	REAL RATE OF RETURN 5%	10%
(A. Capital Cost is $6.5 billion)		
30 Bcm/yr (1060 Bcf/yr)	0.74	0.98
35 Bcm/yr (1236 Bcf/yr)	0.64	0.84
40 Bcm/yr (1412 Bcf/yr)	0.56	0.74
(B. Capital Cost is $15 billion)		
30 Bcm/yr (1060 Bcf/yr)	1.71	2.27
35 Bcm/yr (1236 Bcf/yr)	1.47	1.94
40 Bcm/yr (1412 Bcf/yr)	1.29	1.70
(C. Capital Cost is $22 billion)		
30 Bcm/yr (1060 Bcf/yr)	2.51	3.32
35 Bcm/yr (1236 Bcf/yr)	2.15	2.85
40 Bcm/yr (1412 Bcf/yr)	1.89	2.50

Project life assumed at 25 years.
See text for sources.

below the other estimates.[145] However, adding in the Arctic segment separately, and using the cost factors given above, brings the estimate to between $1.25 and $1.50/Mcf, which is at the low end of the range from the other estimates.

Why this large discrepancy in pipeline costs? In the first place, while they do not discuss their methodology, the CIA frequently has estimated Soviet expenditures by measuring the equivalent costs in the United States, i.e., using U.S. labor rates, raw materials costs, etc.[146] While this is a useful approach, it overstates the costs as the Soviets perceive them.

On the other hand, one would expect the CIA to be well-informed about the hard currency costs of the pipeline (which it put at $7 billion), since that involves correlating information about sales from Western European companies. Still, where those goods were bartered for natural gas, and where pricing assumptions for the natural gas were probably optimistic, the $7 billion may thus be overstated.

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[145] The only precise Soviet report of pipeline costs is A. I. Shirkovsky, who in 1965 stated that the 40-inch, 4460 kilometer Gasli-Ural line cost 504 million rubles. Assuming an annual throughput of 350 Bcf, and using the then-official exchange rate of 0.90 U.S. dollars to the ruble, inflated to 1985 U.S. dollars, yields a cost of 2.8 cents per Mcf per 100 miles, about half the current U.S. marginal pipeline costs. For the Urengoi field (non-Arctic segment), this would be the equivalent of $0.66/Mcf. The age of the source reduces the reliability of this estimate. See A. I. Shirkovsky, "Problems of the Development of Gas-Condensate Fields and Modern Ideas for Their Solution," in Proceedings of the Seminar on the Development and Utilization of Natural Gas Resources, Mineral Resources Development Series, No. 25, United Nations, New York, 1965, pp. 158-167.

[146] This method is used in estimating the Soviet defense budget.

Certainly the $6.5 billion estimate seems low, allowing little margin for any ruble expenditures even if the CIA's estimate of hard currency was too high by a factor of 2. Thus, we believe the appropriate figure is somewhere between the two lower ones, which, depending on throughput and rate-of-return assumptions, yields a cost of $1 to $2/Mcf.

Delivered costs of Soviet natural gas from Urengoi to the West German border then appears to be approximately $2/Mcf, plus or minus about $0.50/Mcf. Since much of these costs are borne in rubles, it would seem that the Soviets will be willing to sell natural gas at very competitive prices.

Yamburg Field Economics

Unlike the Urengoi field, we have some direct data about the costs of developing the Yamburg field, which, while slightly smaller than Urengoi, is still the second largest in the world, with reserves of 168 Tcf.[147] Using a cost figure of $5.2 billion for development of 195 Bcm/yr (6.88 Tcf/yr) of production yields a development/operating cost of $0.16/Mcf.[148]

The astute reader will note that this is much cheaper than for the Urengoi field. Two factors are at work that make such an estimate

[147] OGJ, 9/22/86, p. 57.

[148] Field capital expenditures are listed as 4 billion rubles in WO, 2/1/85, p. 9, and converted at the official exchange rate of 1.3 dollars per ruble, yielding an in-ground development cost of $0.031/Mcf. The depletion rate is 4.1 percent, according to the reserve figure given above and the production figure of 195 Bcm/yr given in PE, 12/85, p. 454. Using a 12 percent discount rate gives us an above-ground development cost of $0.122/Mcf. (See footnote 135.) Operating costs, at 5 percent of total capital expenditures divided by annual production, come to $0.038/Mcf.

plausible. First, the Yamburg field is shallower, about 3500 feet deep versus over 5000 feet for Urengoi.[149] This lowers drilling costs substantially, so that the per-well costs in Yamburg, about $10.4 million, are roughly the same as those estimated for Urengoi.[150] Second, well productivity at Yamburg appears to be about twice as high as at Urengoi, again acting to depress relative costs.[151]

To render this estimate comparable to that for Urengoi requires adding the pipeline cost to the Urengoi field, at the start of the trunkline to the west. Using our estimate of 12.2 cents per Mcf per 100 miles for Arctic conditions adds $0.146/Mcf to Yamburg costs, making the total cost at the trunkline entrance $0.306/Mcf. Thus, Yamburg gas can apparently be delivered to the West German border for approximately the same amount as Urengoi gas.

As confirmation, E. G. Altunin, the Tyumen Obkom Secretary for industry, estimated that each increment of 35 Bcm (1235 Bcf) from north Yamal would cost an additional 1.5 billion rubles.[152] This is roughly double the previous figure, but probably includes pipeline costs. Using this as the field development cost and applying the method given

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[149] IPE, 1977, p. 242, and see above for Urengoi.

[150] The Urengoi estimate is obviously much less certain. See WO, 2/1/85, p. 9, for field capital expenditures and number of wells.

[151] With 6.88 Tcf/yr planned peak output and 500 wells being drilled, per-well production would be 38 MMcf/d. WO, 8/86, p. 72, puts per-well yield in West Siberia at as high as 35 to 45 MMcf/d.

[152] Gustafson, (1983) p. 49. This presumably means that the capital costs for 35 Bcm/yr (1.2 Tcf/yr) of capacity are an incremental 1.5 billion rubles, not 1.5 billion rubles for each 35 Bcm of gas produced, which would equate to an additional $1.60/Mcf, which seems to be an excessive amount.

in the paragraph above would suggest an additional \$0.33/Mcf in development-operating costs, which is very similar to the estimate above of development/operating and transportation costs to the Urengoi field.[153]

Marginal Cost Trends

Estimating the costs of any given new Soviet field development does not conclusively demonstrate marginal costs for the country as a whole. This reflects the fact that Soviet gas resources are still in the early stages of development, and the country is not a competitive environment.

Recent reports suggest that the marginal costs of Soviet oil production are rising rapidly. Thane Gustafson estimated that investment in oil more than doubled from 1976 to 1984, while production barely increased.[154] For natural gas, investment tripled from 1971 to 1979, while production doubled, but the rapid expansion which occurred would tend to inflate the increase in marginal costs.[155]

On the other hand, the largest resources are, as mentioned, in Siberia, and the large discoveries available in the Yamal area now are planned for exploitation. Specifically, the Yamburg field is being developed as a follow-up to the Urengoi field and, if demand exists,

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[153] An annual capital charge is derived by multiplying the total capital expenditure times the discount rate (12 percent) plus the depletion rate (4.1 percent). Annual operating costs are assumed equal to 5 percent of total capital expenditures.

[154] NYT, 10/31/85, p. D17.

[155] Gustafson, (1983) p. 7.

its gas will be marketed to Western Europe in the same way as the Urengoi field was, i.e., a large-diameter pipeline transporting large incremental volumes. At present, it is likely to be used to meet increases in domestic consumption and deliveries to Eastern Europe, which has already agreed to take 20 to 22 Bcm/yr (710 to 780 Bcf/yr), and to replace and supplement older, declining fields.

Thus, the incremental cost of developing the Yamburg field can be used as an indicator of marginal costs in the Soviet Union for some time to come. Since Yamburg costs are very close to Urengoi costs, relatively flat marginal costs are implied.

Ed Hewett used reported Soviet investment figures to calculate the marginal costs for oil and gas over the last 15 years, shown in Table 34. As can be seen, oil costs indeed have risen rapidly, while gas costs have been relatively stable.[156] This can be explained in several ways. Oil to date has been more intensively exploited in the Soviet Union than gas. The Soviets still are developing their supergiant gas fields. They also have benefitted from the increasing infrastructure in Siberia, as well as from their own advances in pipeline technology, which, as Gustafson points out, have made the northern gas fields economic today, whereas ten years ago their development was postponed.[157]

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156 Transportation costs have risen, reflecting the greater distance of the new Siberian supplies, but these should remain stable for some time, as most incremental supplies come from the Yamal peninsula.

157 Hewitt, op. cit., p. 36. The pipeline technology existed ten years ago, but the ability to produce it was much more limited and much higher imports from the West would have been required.

TABLE 3-34

MARGINAL COST TRENDS IN SOVIET GAS SUPPLY
(Investment per net increment to energy output)
1969 rubles/bdoe

Period	Extraction Costs	Extraction Plus Transportation Costs
1966-70	3812	n.a.
1971-75	4765	9013
1976-80	4279	11904
1980	4717	n.a.

Source: Hewett (1984), p. 41.

Thus, the expansion of pipelines, gathering systems, roads, and other infrastructure in Siberia should act to depress growth in long-term marginal costs. The presence of extremely large reserves in one area should have a definite dampening effect on incremental costs, although the more rapidly development is pushed, the higher the costs will rise. Still, since most costs are pipeline costs (see Figure 9) and pipelines are not subject to increasing costs, marginal costs should not increase dramatically in Soviet gas production.

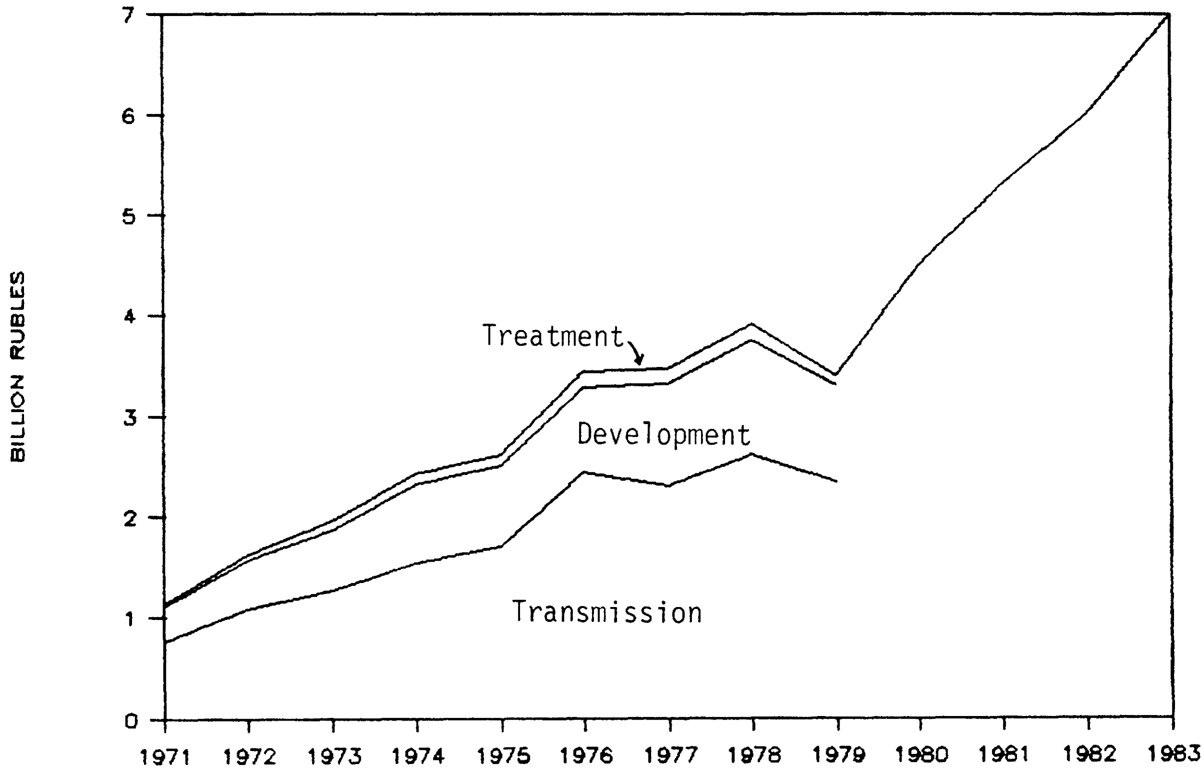
Soviet Gas and the Soviet Economy

An examination of the Soviet economy is beyond the scope of this chapter, but the effects of recent developments can be analyzed, if only qualitatively. These include the drop in oil prices on the Soviet economy, the need for hard currency, and the losses from lower oil prices, as well as the impact of General Secretary Mikhail Gorbachev and his new economic policies.

Because of the insulation of the Soviet monetary system from the West, and the inability of the domestic manufacturing sector to deliver goods of quality and capability similar to Western goods (in most instances), the Soviet Union has a particular need for "hard" currency, that is, money that can be used to purchase goods in Western countries. Since the Soviet ruble is valued by the government at artificially high prices, and due to the low demand for finished products from the Eastern Bloc, most purchases in the West require that the Soviets pay with money earned from exports to the West, i.e., "hard" currency.

Figure 3-9

SOVIET CAPITAL INVESTMENT
IN THE NATURAL GAS INDUSTRY



Source: Gastafson, 1983, pp 39, 42.

As Figure 10 shows, these exports have grown substantially, even in the last decade.[158] In part, this is due to much higher oil revenues, resulting from the explosion in oil prices, as well as from a growth in oil exports to the West. (See Figure 11.) All this has helped the Soviets keep their foreign debt low and stable, much more so than in most of their allies. In the early 1980s, gross hard currency debt to the West remained at approximately $20 billion, while net debt remained at about half that.[159]

Falling oil prices and the weaker dollar could alter that trend. Indications are that falling oil prices are beginning to result in an increase in that debt.[160] Even the contracted-for increase in natural gas deliveries and a reversal of the decline in oil production will leave the country with a drastic decline in hard currency earnings.[161] Short-term effects, such as this year's harvest and the Chernobyl nuclear accident, are difficult to assess; the weather is unpredictable and there is still little data on the economic impact of the Chernobyl disaster.

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[158] Note that the figures are in nominal dollars.

[159] CIA, op. cit., 1985, p. 73, puts the 1984 gross debt at $20.2 billion, and the net debt at $10.4 billion, a decline from $12.5 billion in 1981.

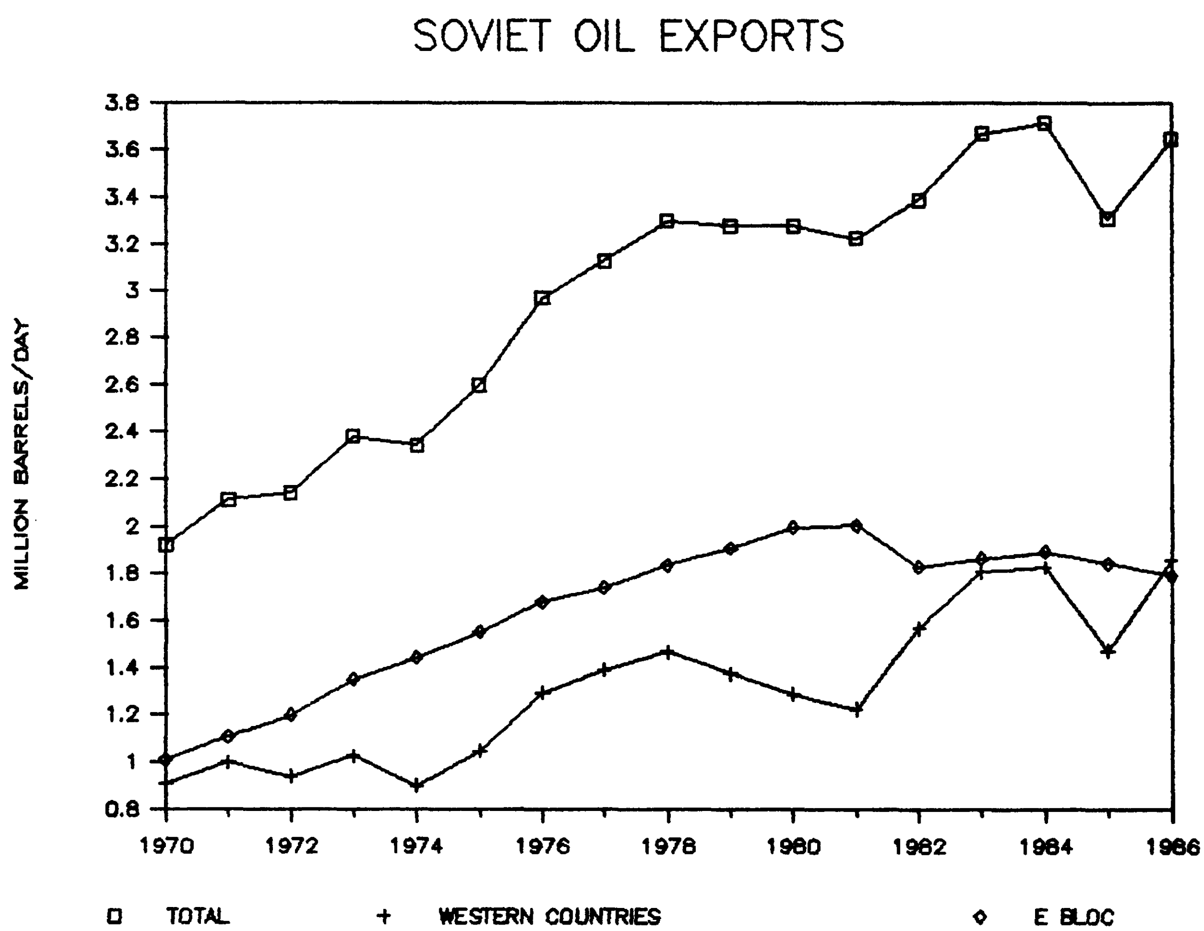
[160] Syndicated Western bank loans to the Soviet Union grew from $100 million in 1983 to $900 million in 1984 and $1.5 billion in 1985. So far this year, two syndicated loans have been announced, totalling $675 million. See WSJ, 4/11/86, p. 31.

[161] Oil production was reportedly up 1.4 percent in the first quarter, according to OGJ, 6/9/86, p. 30. The intensive efforts to bring shut-in wells on-line and debottleneck the industry should see a short-term spurt in production, though it may not last long. Some observers have estimated the decline in hard currency earnings at $4 to $5 billion, (WSJ, 4/11/86, p. 31) while the IMF has estimated a increase in the deficit of $5 to $6 billion. (NYT, 5/5/86, p. A8)

Figure 3-10

Source: Handbook of Economics Statistics, CIA, 1985. Excludes military exports; 1986 is authors' estimate, assuming $15/bbl price of oil.

Figure 3-11



Source: 1985, 1986 estimated. Others from <u>International Energy Statistical Review</u>, CIA.

If, as predicted by Soviet experts, the harvest is good, $3 to $4 billion in grain imports can be avoided.[162] (Grain is unlikely to be affected by fallout.) On the other hand, meat and dairy product imports may have to be increased, as well as fruit and vegetable imports, due to the impact of fallout. Still, these items can be reduced in the Soviet diet much more easily (with less political turmoil) than grain, which is a staple.

The impact of Gorbachev's new economic policy on hard currency needs is not clear. The new five-year economic plan calls for greater worker discipline and better use of existing technology and resources, but not for any major structural changes in the economy.[163] As one official put it, "The changes must be profound . . . but they must also be gradual."[164]

It seems as if the intention is to focus on: (1) more decentralized decision-making, (2) increased efforts on debottlenecking in order to reduce waste and inefficiency, and (3) more automation and increased use of computers.

What does this mean for hard currency exports? Successful debottlenecking, particularly of agriculture, could reduce the need for hard currency by reducing the amount of food lost due to poor planning, inadequate transportation facilities, etc. On the other hand, decentralized authority resulted in a spurt of imports in China, and the

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[162] See Marshall Goldman, "Chernobyl's Economic Fallout," Boston Globe, 5/11/86, p. A21.

[163] NYT, 10/14/85, p. D8.

[164] Abel Aganbegyan, director of the Institute on Production Forces and National Resources, quoted in ibid.

same may happen in the Soviet Union. Certainly, more imports will be necessary in order to increase the use of computers and automated machinery.

The role of natural gas is fairly clear: The Soviet Union has the capacity to deliver to Western Europe approximately 65 Bcm/yr, (2.3 Tcf/yr) 15 Bcm/yr (530 Bcf/yr) more than it has contracted to deliver in the short term. By signing several small contracts with Mediterranean countries,[165] it has managed to reduce this surplus, but it can still move gas to Western Europe without significant further investment. The amount of hard currency provided by these exports would depend on (a) the price of oil at the time, and (b) the relative price of delivered natural gas needed to make the sales. At $3/Mcf, the hard currency revenues from 15 Bcm (530 Bcf) would total $1.6 billion, and at $5/Mcf, $2.6 billion. This would only partly offset the expected loss in oil revenues in 1986. The planned Progress pipeline from Yamburg to Eastern Europe is scheduled to be completed in 1989, with 30 Bcm/yr (1060 Bcf/yr) of capacity, 20 to 22 Bcm/yr (710 to 780 Bcf/yr) of which will be delivered to Comecon countries.[166] If the additional 8 to 10 Bcm/yr (280 to 350 Bcf/yr) capacity is used for hard currency sales, it would result in $1 to 2 billion/yr, although the price on these additional supplies is likely to

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[165] Greece has a contract for 1.5 Bcm/yr (53 Bcf/yr) with options on another 3 Bcm/yr (105 Bcf/yr), and Turkey has agreed to take an initial 1.5 Bcm/yr, with options on an additional 6 Bcm/yr (210 Bcf/yr).

[166] See OGJ Newlsetter, 4/21/86, PIW, 8/12/85, p. 8, and IGR, 3/30/84, p. 5. Since the line is composed of 56 inch pipe, it seems reasonable to assume that capacity could be expanded to 40 Bcm/yr (1.4 Tcf/yr) with the addition of appropriate compressors. PE, 5/84, p. 188, put planned capacity at over 40 Bcm/yr.

be lower than Urengoi gas, especially in light of the recently-signed Troll contracts.

Investment Policy in the Energy Industries

The new economic plan contains a message for the oil and gas producing industries as well. The Soviet version of the old American axiom, is, "If it ain't broke, don't spend money on it." Investment in the Soviet Union frequently emphasizes the troubled sectors of the economy, often at the expense of sectors that are performing well. Thus, when the oil sector was surpassing its quotas in the early 1960s, the government shifted its emphasis to gas. Now that gas is outperforming oil, relative to their respective quotas, the focus of investment is shifting back toward oil. However, officials have insisted that investment levels in gas will be maintained, and Gorbachev himself has noted the incipient problems in the Yamal producing area.[167]

The Security Question

Much analysis of Western Europe natural gas markets has as its origin the fears of excessive dependence on the Soviet Union for natural gas supplies, although to a large degree those fears are higher outside Western Europe than within it. This is not the first time a Soviet pipeline has raised security concerns: In 1962-63, the Kennedy administration pressured Western Europeans to deny export of wide-diameter pipe and other equipment needed by the Soviets for to complete their

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[167] See OGJ, 10/7/85, p. 66.

"Pipeline of Friendship". The arguments then were very similar to those made by the Reagan administration: The infrastructure would benefit the Soviet military, dependence on the Soviet Union for oil supplies would increase Western European vulnerability to Soviet pressure, and the improvement Soviet economic conditions would ease pressure on the Soviet military budget.[168] The outcome then was different, as a combination of political pressure and offers of cheap oil supplies from multinationals convinced the Western Europeans to cooperate. Considering that oil is a much more easily traded and replaced commodity during a disruption than is gas, it is interesting that the oil deal was cancelled while the gas pipeline went forward.

The question of political, economic, and/or military vulnerability resulting from dependence on a particular supply source is beyond the scope of this chapter.[169] However, the question of security of supply and policy issues arising from dependence on a supply source that is perceived to be unstable or insecure do need to be addressed.

The first point is that the United States should not throw stones on the issue of supply security. Aside from embargoes on items such as grain, the United States frequently has resorted to political intervention in the oil industry. In recent years, this has included boycotts of oil from Libya and Iran, as well as of oil field equipment for Vietnam and the

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[168] See Bruce W. Jentleson, "East-West Energy Trade and Domestic Politics," International Organization, Vol. 38, No. 4, Autumn 1984, for an excellent summary and a review of the vehemence with which many American politicians opposed the pipeline.

[169] Some discussions of the topic include Adamson (1985), Hewett (1984), Niebling, Russell and Shubik (1984), and Stern (1980).

Soviet Union. The Reagan administration even has attempted to interfere in the activities of foreign subsidiaries of U.S. companies that attempted to deliver equipment to the Soviet Union.

Of course, other gas suppliers have not always proven entirely reliable, as discussed below. On the other hand, where importers of Soviet gas have argued that the Soviet Union is particularly reliable, some observations must be made.

The Soviet Union, on rare occasions, has resorted to boycotts of fuels for political reasons. During the 1956 Suez Crisis, it announced an oil boycott of Israel, a notable action at a time when the oil industry was less politicized.[170] More recently, the chief of the Soviet coal union announced that no Soviet fuel would be delivered to the United Kingdom until the coal miners' strike ended, although the practical impact was minor.[171] Other instances include actions against Albania, Australia, China, France, Rumania, the United Kingdom, the United States and Yugoslavia, but for the most part the Soviets have appeared to be more concerned with maintaining their exports to hard currency countries.[172]

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[170] In 1955, the Soviet Union provided one quarter of Israel's oil supplies, but ceased deliveries following the Israel's military moves in the Sinai. Although oil and politics always have been closely tied, an embargo at that time was unusual enough to stand out, and was cited as a reason for the wariness of oil importers in considering purchases of Soviet oil in PPS, January 1957, p. 7.

[171] See WSJ, 10/30/84, p. 30, and PIW, 2/4/85, p. 11. Freight costs rose, though, since Soviet ships had backhauled fuel oil from the Mediterranean to the United Kingdom.

[172] A good source on economic sanctions is Gary Clyde Hufbauer and Jeffrey J. Schott, Economic Sanctions Reconsidered: History and Current Policy, Institute for International Economics, Washington, D.C., 1985. Table 1.1, pages 13-20, lists the cases studied. It is worthy of note that since 1945, the Soviet Union appears on the table 6 times, while the

One mistake made by many observers is to overemphasize the danger of embargoes and the intentional withholding of supplies for political reasons. Security of supply is broader. Intentional disruptions are the most dangerous, because the causality implies both an attack on a specific target and an uncertainty about the duration. Further, although Soviet use of natural gas supplies to gain political leverage seems unlikely, there remains the possibility of an intentional disruption from other sources. The Shah of Iran was perceived as a reliable supplier because he did not participate in the Arab Oil Embargo of 1973, but his domestic enemies disrupted production and deliveries in order to damage him.[173]

Soviet natural gas supplies have, in fact, been "disrupted" several times for seasonal reasons. Since Soviet gas exports are a residual of production and consumption, with the domestic grid capable of drawing supplies from the export pipeline as needed, the result has been a reduction in exports during periods of severe winter weather in the western Soviet Union. Since this often coincides with cold weather in Western Europe, some inconvenience has occurred, although the presence

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United States is listed 62 times. Sampling bias probably is responsible for part of the difference between them. Another source which is more specific to the Soviet Union is John Van Oudenaren, "The Urengoi Pipeline: Prospects for Soviet Leverage," The Rand Corporation, Santa Monica, California, December 1984, especially pp. 6-9.

[173] There is no suggestion here that a revolution is likely in the Soviet Union, but it has been known to happen before. Labor actions, though rare and harshly suppressed, are not unknown, and the war in Afghanistan has created a large body of people who are dissatified with the Soviets, although they lack the capacity to affect natural gas shipments seriously. Afghanistan provides 2.4 Bcm/yr (85 Bcf/yr) to the Soviet Union, hardly enough to make a significant difference if it were lost. See BP Review of World Gas.

of the large Groningen field as a "swing producer" has alleviated the problem substantially. (Unfortunately, obtaining data on monthly gas exports and separating the effect of demand changes has proven impossible to date.)

The aspect of this is the impact on supply in Siberia during extremely cold winters. Equipment is more prone to failure and workers less effective when temperatures drop to 65 degrees below zero, as they sometimes do.[174]

There also are reasons to believe that the Soviet export pipeline may be vulnerable to technical difficulties. For example, the pipelines from Siberia are laid side by side, only 100 to 150 feet apart, thus increasing the chances that a leak and explosion in one will affect the others.[175] Some pipelines apparently have "floated" out of the permafrost, as the inadequately cooled gas caused the surrounding permafrost to melt and the pipeline to partially surface. This increases the likelihood of a rupture.[176] This sort of problem is not unknown in the Soviet Union; the pipes in the Samotlor oil gathering system are beginning to experience breaks and explosions, and three or four ruptures frequently occur simultaneously.[177]

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[174] Minus 54 degrees Celsius.

[175] According to John Kean, President of Nuri Corp., cited in Platts Oilgram News, 10/28/83, p. 2. A 1985 gas pipeline explosion in Kentucky left a crater 30 by 100 feet wide, and up to 20 feet deep. See NYT, 4/29/85.

[176] ibid.

[177] OGJ, 8/12/85, p. 67.

In addition, there are indications that the Soviets are not processing all of the liquids from the gas they produce, which places a greater strain on the compressors.[178] Since the American embargo on pipeline equipment resulted in greater reliance on domestically-produced compressors, which presumably are of lower quality, the possibility of reduced gas flows due to compressor problems cannot be ignored. Loss of one compressor should not have a major impact on the system, but it will increase the strain on the other compressors, and thus the likelihood of further failures.

These problems fall under the jurisdiction of commercial prudence, and point to reasons a customer should not be overly reliant on any one given producer, including the Soviets. Still, natural gas supplies from other sources have been threatened or disrupted for both political and commercial reasons.

The most well-known interference with supplies is the "technical problems" that Algeria suffers with its LNG plant whenever it is dissatisified with contract terms, usually prices. In early 1974, gas consumption in France had to be reduced by 25 percent in many areas to offset the failure of the Skikda liquefaction plant to produce LNG, which the French suggested may have reflected a desire for contract renegotiation rather than actual technical troubles.[179] Similarly, in 1980, El Paso's deliveries were deliberately stopped over its refusal

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[178] Gustafson, (1983) p. 81.

[179] PE, 4/74, pp. 149-150.

to agree to higher prices.[180] Algeria's customers have shown willingness to respond in kind when the market turned around, both by refusing to take deliveries of gas that they could not consume, and by unilaterally setting the price while negotiations were still underway.[181]

Both the Netherlands and the Soviet Union have threatened to interrupt supplies if more favorable pricing terms were not accepted by their customers, although in neither case were the threats carried out.[182] Politically motivated embargoes of LNG also have occurred, as when Libya and Algeria imposed an embargo of LNG shipments during the 1973 Arab Oil Embargo. More recently, the caterers strike in the Norwegian North Sea resulated in a two week reduction of production by 2 Bcf/d from Frigg, Statfjord, and Ekofisk (although had the situation been regarded as serious the Norwegian government had the authority to step in and end it).[183] As it was, the BGC was forced to invoke cutoffs of gas to industrial users with interruptible contracts.

For the customer, the most important question is whether the hazards of interruption or decreased deliveries from the Soviet Union, Norway, and Algeria, are independent or correlated. If they are independent, and if supply is drawn in roughly equal proportions from all three, then supply is not insecure. For example, if in any given month there is one chance

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180 WSJ, 7/2/80, p. 19.

181 See IGR, 10/26/84, p. 11, for reduced French takes.

182 PE, April 1980, p. 176.

183 See OGJ, 4/14/86, p. 58-59. Some analysts suggested that the government did not intervene, and indeed may have encouraged the strike, because it wanted to reduce oil production and strengthen the market. See NYT, 4/7/86, p. D12.

in ten of an interruption in each of the three sources, there is only one chance in a thousand of all going down together.

Seasonal interruptions may be correlated between Norway and the Soviet Union, but not Algeria. Political interruptions might be correlated between the Soviet Union and Algeria, but this is unlikely. When the OPEC nations were cutting back oil production, the Soviet Union gladly took advantage of the resulting high prices. Certainly, buyers must be prepared to deal with an interruption of supplies from any given producer, but the simultaneous cessation of supplies seems to be a low-probability event.

Other Potential Suppliers

In the mid- and late-1970s, many other natural gas trade projects to Western Europe were considered, including sales LNG or pipeline gas from Nigeria and Iran. The announcement that Iran would resume gas trade with the Soviet Union, the development of the supergiant North field in Qatar, and the restructured Bonny LNG project in Nigeria all suggest that ideas for such trade have not been completely abandoned, although the distances involved suggest that the economics will be less than favorable.

The driving force behind all these projects is the location of enormous gas reserves in areas that have no ability to use significant amounts of the resource. Iran has 470 Tcf of proved reserves, much of it associated with oil, Nigeria has 47 Tcf, also largely associated, and Qatar has 148 Tcf in the North field.[184] Together their reserves are nearly three times greater than those of Western Europe, including Norway.

But the prospects for these projects achieving economic delivery to Western Europe are not bright. A brief overview of cost estimates for each of the proposed projects is provided below. Although these costs are not always higher than those of alternative supplies, such as Askaladden, they all lie at the high end of the spectrum. For this reason, they have not received as detailed attention as the projects discussed above.

Pipeline Gas from the Persian Gulf

The most attractive of all alternative projects would be some version of pipeline delivery from the Persian Gulf to Western Europe, specifically the IGAT-2 project (or an updated variant).[185] This called for Iranian deliveries of gas to the southern Soviet Union, allowing for diversion of Soviet supplies to Western Europe. Unfortunately, a precise estimate of the economic savings involved and of the resulting delivery costs to Western Europe from this project would require a regional analysis of Soviet gas production and consumption, an endeavor beyond the scope of this study. Suffice it to say that this type of swapping

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[184] OGJ, 12/30/85.

[185] Iran is currently holding discussions with the Soviet Union over resumption of deliveries of natural gas, but observers have suggested the talks are more of diplomatic interest than of relevance to possible energy trade. See WSJ, 8/26/86, p. 29.

probably would result in delivery cheaper than new gas production from West Siberia, i.e., less than $2/Mcf.

A new gas pipeline originating in the Persian Gulf and bypassing the Soviet Union by going through, for example, Turkey, has been considered, both by countries far south of the Soviet Union, and also by Iran, presumably for political reasons. Depending on the producer involved, such a pipeline would be between 3000 and 4000 miles long, before reaching Southern Europe. Mossavar-Rahmani estimates the cost of such a pipeline project at $3.70 to $4.70/Mcf, which would be at least twice as expensive as U.S. transportation costs over equal distance, but is not unreasonable, given the terrain and lack of infrastructure in many places.

LNG from the Persian Gulf

Even though LNG exports were under consideration from the Persian Gulf to as far away as the United States before the second oil price shock, it is difficult to see how they would be economic now, even given a recovery in oil prices. Using factors developed in the East Asia/Pacific report, liquefaction would cost $1.00/Mcf, regasification $0.35/Mcf, and transportation about $2.25/Mcf.[186] Thus, without including production costs, which should, admittedly, be low, a base delivered cost

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[186] The transportation cost estimate reflects an assumption of a route around the Cape of Good Hope of 11,300 miles, and a shipping cost of $0.20/Mcf/1000 miles.

of \$3.60/Mcf is reached.[187] This suggests LNG exports will remain uncompetitive for the foreseeable future.

Natural Gas from Nigeria

The large quantity of associated natural gas in Nigeria (442 Bcf was flared in 1983[188]) and the reluctance of its various governments over the years to see that gas "wasted" has encouraged a number of proposals for delivering the gas to market, including the construction of a pipeline to North Africa and Western Europe (either to Italy or Spain), or an LNG export project. However, the prohibitive costs of both projects have prevented them from progressing beyond the planning stage.

For example, the current, reconfigured plan for LNG exports would require \$5 billion in capital expenditures to deliver 4.25 Bcm/yr (150 Bcf/yr).[189] Compared to \$8 billion to deliver 20 Bcm/yr (706 Bcf/yr) from Troll, this project hardly appears competitive. In fact, the capital expenditures appear to be out of proportion with other LNG export projects, especially considering the low production costs due to the gas being associated. Economies of scale and the high cost of

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187 The IEA (1982), p. 151, estimates costs for such a project at \$2.95/Mcf, plus \$0.25/Mcf for gas gathering. Mossavar- Rahmani, op. cit., p. 98, provides a cost estimate of \$4.65/Mcf, plus \$0.60 for production, gathering, and delivery to the liquefaction plant.

188 International Energy Annual 1984, Energy Information Administration, Dept. of Energy, Washington, D.C., 1985, p. 64.

189 See WO, 8/15/85, p. 107, and PIW, 11/11/85, p. 12. No breakdown of the costs has been given.

capital construction in West Africa are usually cited as the reasons for the higher relative costs.[190]

A TransSaharan pipeline has also been intermittently considered as a means of gathering gas from various deposits in West Africa and moving it to the Western European market, perhaps through Algeria or the Straits of Gibraltar. Aside from the fact that such a pipeline would be vulnerable to the many political conflicts in the region, and that Algeria would be unlikely to look favorably on such a project, because it would further reduce what little market power it now has, the costs would be extremely high. While the estimate of $4.71/Mcf provided by Mossavar-Rahmani[191] seems high, being roughly equal to pipeline costs in Arctic conditions, even using U.S. cost factors the delivery cost would probably surpass $2.00/Mcf. The true figure would probably be much higher, given the isolation of much of the terrain which the pipeline would traverse and the high costs of transporting materials there.

While there are obvious benefits to be gained from diversification of supply, it appears that, economics aside, the political obstacles to transporting Nigerian gas into Western Europe are formidable, although too complex to examine here. Still, there are large amounts of gas available to Western Europe from these areas, some of it at medium level costs (i.e., Iranian gas swapped for Soviet gas), but most of it available only at prices in the $3 to $5/Mcf range, depending on the

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[190] Mossavar-Rahmani, _op. cit._, p. 98, puts the cost of an LNG project from West Africa to Northwest Europe at $3.81/Mcf plus $0.60/Mcf for production and gathering. Applying factors from the East Asia/Pacific study yields a cost of roughly $3.00/Mcf plus production and gathering.

[191] _op. cit._, p. 97. Excludes $0.30/Mcf for production and gathering.

rents required by producers and on other factors such as the amount of liquids that would be produced or the amount of flaring that is occurring. Small quantities may become available over the next decade, but they will not be of major importance relative to the other producers.

CONCLUSION: THE ECONOMICS OF WESTERN EUROPEAN GAS SUPPLY

This section draws together all the threads strung through the individual country discussions to provide a picture of the economics governing future natural gas supply in Western Europe. The impact of policy variables and changing views toward mineral resources are discussed below.

This section also provides an overview of various available supplies of natural gas, as well as their costs and quantities. It does not provide a specific estimate of the costs of future, undiscovered supplies, but short- and long-term cost trends in the different supplier regions are addressed below.

The first question is: How much gas can be delivered if oil prices keep falling, and at what point do supplies dry up <u>for economic reasons</u>? In essence, What are the variable costs of existing capacity? We have seen that the variable costs of producing and transporting most of the natural gas now available are quite low. Low oil prices should not affect <u>existing</u> gas supplies.

However, this does not take into consideration some of the <u>non-cost</u> expenses that private companies incur in producing natural gas, most notably royalties and taxes related to production levels (as opposed to income).[192] In addition, the costs of ceasing deliveries (whether incurred by plugging a well, yielding a lease, or litigation for non-performance), are not considered. The former would promote shut-ins at prices higher and the latter at prices lower than simple economic rationality would dictate.

Therefore most existing capacity will continue to be produced at extremely low price levels, even lower than seems likely to occur. Hence, buyers could safely increase takes from the current levels. However, the development of new capacity, either to increase sales or to replace declining capacity, would require higher prices than those that would equate to $10/bbl oil, for example.

New capacity falls into two categories: replacement and incremental. Replacement capacity is cheaper because it can use existing transportation facilities, whereas incremental capacity may (depending on location and timing) involve the construction of new transport facilities: pipelines or LNG plants.

Geographical diversity makes it impossible to provide any rule of thumb for incremental transportation capacity, but pipeline costs in the North Sea usually have been under $1.00/Mcf, and often half that. For small fields close to existing pipelines, including associated gas supplies, costs can be less, although small volumes may not justify construction of even short pipelines. To develop new liquefaction

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[192] For national oil companies, e.g., Sonatrach, taxes and royalties usually are not an issue. But they sometimes are subjected to rules that make no sense for a state-owned concern.

capacity the costs are higher, on the order of $1.00/Mcf or more,[193] with an additional $0.10 to $0.45/Mcf for shipping.

Costs of new production capacity vary, being extremely low in the Groningen and Hassi R'Mel fields but much more expensive for the smaller North Sea fields. New supplies are available for $1.00 to $2.00/Mcf, with some exceptions (additional Troll supplies being less and Sleipner more, for example).

Thus, replacing declining production with new fields through existing transportation capacity will allow gas to continue to be delivered to Western Europe for as little as $1.00/Mcf.[194] This suggests that, under unrestrained competition, oil will not capture any market share from natural gas in Western Europe except through growth in overall energy demand, even at extremely low prices.

On the other hand, adding capacity would be notably more expensive. Transportation costs will, for any sizeable increments, involve costs approaching $0.50 to $1.00/Mcf. Combined with production costs, incremental supplies will cost as little as $1.50/Mcf for cheaper fields or as much as $2.50/Mcf for smaller, offshore fields not close to shore. For the onshore supergiant Groningen, incremental supplies are available at very low costs, while the supergiant Hassi R'Mel can deliver gas for a

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[193] This was the cost level that appeared to be most common in Asia; the paucity of construction efforts in North Africa makes it difficult to generalize about current costs.

[194] The extent to which some countries are willing to sell gas at these low prices, even if rents are still forthcoming, is discussed below. At certain times in the past, some, like Algeria, have been reluctant to sell even at relatively high profits.

little more than $1.00/Mcf via an undersea pipeline, and the supergiant Troll for perhaps $1.40/Mcf.

Thus, if oil prices remain in the $12 to $15/bbl range, many of the smaller fields will not be viable and the larger fields will increase their market share, although concessions on taxes and royalties probably will be necessary.

EXPECTATIONS FOR THE WESTERN EUROPEAN GAS MARKET

Given the above analysis of the economics of natural gas supply in Western Europe, some conclusions about future market behavior can be drawn. This section first reviews forecasts for Western European gas supply, concentrating particularly on those of the International Energy Agency (IEA); then discusses trends in natural gas supply, both short- and long-term; and concludes by describing the current market situation in Western Europe and its evolution.

Supply Forecasting for Western Europe

Now that the gas market in Western Europe has begun to weaken, it is superfluous to point out that the numerous forecasts of gas production have been very wide of the mark. Nor is it important that the current market weakness was foreseen several years ago by several of the researchers on this project.[195] The history of mistaken forecasts has a different import.

This chapter attempts not to predict what decision makers in natural gas will do, but rather to explain what they can do--to lay out the boundaries that constrain their actions. Thus, the Demand Chapter aims to discover how much gas consumers will take at various prices and at what terms of sale. The Supply Chapter aims to show how much gas it would be profitable to produce, at various prices, and how soon. If

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[195] M. A. Adelman, "The Changing Structure of the Oil and Gas Market," delivered to the IAEE/BIEE International Energy Conference, Cambridge, U.K, 1982, published in Paul Tempest (ed.), International Energy Markets, Oelgeschlager, Gunn & Hain, 1983, pp. 15-25; and Loren Cox and Michael C. Lynch, "European Gas Prices: The Limits to Growth," Energy Laboratory Working Paper, MITEL 83-021WP, August 1983.

the market were competitive and uncontrolled, both these independent inquiries could be brought together to generate a price and volume trajectory over time. (Policy constraints alter the actual results.)

The difficulty with the various forecasts is that they have put largely unelucidated data through unexplained black boxes. There is no way to tell precisely what the forecasters assumed about supply, demand, and policy controls. Since production and sales are determined by all three factors, it usually is unclear what precisely the constraining factors might be.

To correct that deficiency, this section examines a number of forecasts of natural gas supply in Western Europe, focusing particularly on those of the OECD, but including some made by other governments as well as an important private forecasts.

Forecasting Difficulties

The most important difficulty in forecasting future natural gas supply trends is that, until recently, most forecasters focused primarily on oil. Equally important has been the mixed nature of supply and the large role policy interventions play therein. Supply from the Netherlands through the end of this century, for example, is largely determined by government willingness to export. Lower oil prices and decreased demand since 1982 have had the paradoxical result of increasing the desired level of exports.

Moreover, where much of North American natural gas supply depends on the drilling investments of literally thousands of producers, whose actions can be forecast with help from the law of large numbers, in

Western Europe much potential supply still consists of large fields and single-project developments, especially in the Norwegian North Sea and in the Soviet Union. These discrete decisions have proven difficult to predict, especially where cost data are scarce and where governments play a major role.

The Soviet Union is a large supplier of natural gas, with potential for much larger production. While some information is available, on both physical and decision-making aspects, it is generally inferior in both quantity and quality to information about Western supplies. Since economic planning in the Soviet Union is more rigidly controlled by the government than in Western countries, Soviet policy and political changes, which are difficult for outsiders to foresee, play an even larger and more obscure role than in the Western natural gas industry.

In the West, the emergence of a new and bountiful natural gas province has further complicated forecasting. Drilling in the northern North Sea began only recently, with Ekofisk (containing over 3 Tcf of associated gas) being the first major natural gas deposit discovered in 1969 outside of the southern U.K. basin. Frigg, the first dry natural gas field discovered in northern waters (at 60° N), was found in 1972. Thus, the first OECD forecast was reduced to speculating about the potential for natural gas supply from these regions.[196] At that time, although proved and probable reserves in the North Sea were estimated to

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[196] As the authors put it, "Any present assessment of potential natural gas resources in Western Europe must be regarded as provisional, particularly in view of the preliminary knowledge of the geological conditions in the North Sea." See OECD, op. cit., 1974, Volume II, p. 137.

be between 80 and 110 Tcf, additional possible reserves were estimated to range only from 7 to 21 Tcf.[197] Compared with current proved reserves of 104 Tcf for Norway alone, this is obviously a major source of error.[198]

Even the 1982 OECD report was too early to incorporate recent geological developments. The Troll field was not discovered until 1979, and given the deep water technology of the time, it seemed impossibly expensive to develop. Drilling north of 62^{o} began only in 1980. While the Askaladden and Haltenbanken discoveries of 1981 are not currently planned for export to Western Europe, Troll is slated to commence production in the 1990s. The 1982 OECD report certainly recognized the potential of the far northern waters, which were estimated to contain 35 to 71 Tcf of additional reserves.[199] The most recent OECD forecast for Western European gas supply, which was recent enough to incorporate some of the drilling results north of 62^{o} N, was at the high end of the 1982 OECD supply range (see Table 35).

The first major OECD energy study was commissioned prior to the 1973 Arab Oil Embargo, and it was intended to ascertain the degree of future energy dependence on volatile areas and the potential for avoiding it. Of course, the 1973 oil price increases rendered the forecasts inoperative, but the results are still informative. Most of the error of this OECD forecast is due to overestimating offshore production, as Table 35 shows. Forecasters could not allow for the low monopsony prices paid

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[197] ibid., p. 138.

[198] OGJ, 12/31/85.

[199] OECD, op. cit., p. 91.

TABLE 3-35 A

OECD Europe Production Forecasts 1980 & 1985
(Tcf)

Year of forecast	Predicted Production (Years) 1980	Predicted Production (Years) 1985
1974		
onshore	5.1-5.7	5.3-5.9
offshore	4.4	7.2
TOTAL	9.5-10.1	12.5-13.1
1977		
United Kingdom and Norway	2.6	2.8-3.2
The Netherlands	3.6	3.2-3.9
Other	1.7	2.0
TOTAL	7.9	8.0-9.1
1982		
United Kingdom and Norway	--	2.7
The Netherlands	--	2.6
Other	--	1.3-1.5
TOTAL	--	6.6-6.8
ACTUAL PRODUCTION		
United Kingdom and Norway	2.3	2.4
The Netherlands	3.2	2.7
Other	1.5	1.5
TOTAL	7.0	6.6

Sources: 1974 forecast: Energy Prospects to 1985, OECD, 1974.
1977 forecast: World Energy Outlook, OECD, 1977.
1982 forecast: Natural Gas Prospects to 2000, OECD, 1982.

Actual production:
1980: British Petroleum, "Statistical Review," 1980.
1985: Cedigaz, "Natural Gas in the World 1985," Centre International d'Information sur le Gaz Natural et tous Hydrocarbures Gaseux, Paris, France, 1985.

TABLE 3- 35B

OECD Europe Production Forecasts 1990 & 2000
(Tcf)

Year of forecast	Predicted Production Year 1990	2000
1982		
United Kingdom and Norway	2.7-3.0	2.5-3.9
The Netherlands	2.1	0.9
Other	1.3-1.6	1.0-1.6
TOTAL	6.1-6.7	4.4-6.4
1986		
United Kingdom and Norway	2.1-2.4	2.0-2.9
The Netherlands	2.0-2.3	1.8-2.1
Other	1.2-1.4	1.0-1.2
TOTAL	5.3-6.1	4.8-6.2

Sources:

1982 forecast: Natural Gas Prospects to 2000, OECD, 1982.
1986 forecast: Natural Gas Prospects, OECD, 1986

by the BGC, the Netherlands' reluctance to lease offshore areas for drilling, and the belief that oil and gas were appreciating assets whose exploitation could be profitably delayed. Where the analysts not unreasonably assumed that high oil prices and short-term energy scarcity would accelerate development of domestic resources, the price increases actually delayed it.

The follow-up report issued in 1977 reflected some of the lessons learned in the years following the first oil crisis. Production projections were revised downward rather drastically, although they still proved to be one-fourth too high. However, in this instance, the difference was mainly the OECD's overestimation of Dutch production, an error that reflected both Dutch policy and the unexpected lack of demand at prevailing prices, rather than a misestimate of supply.

The 1982 OECD report, partly due to its short prediction horizon, came fairly close accurately forecasting to actual levels of 1985 production. The estimates for both onshore and offshore production were scaled back from those of the previous report, although they still were slightly too high. The authors particularly acknowledged remaining uncertainty about future Groningen production levels, as the Dutch government tried to reformulate policy to cope with a surplus due both to lower-than-anticipated demand and to new discoveries.

The methods used in the 1982 report were stated as follows:

> "The first two scenarios are representative of econometrically based methodologies for projecting energy supply and demand using a combination of econometric techniques and judgement with an underlying assumption of an unchanged energy policy environment. Specific assumptions are made about economic growth, oil prices, and the prices of competing fuels and these are used in conjunction with estimated historical

> price and income elasticities to derive energy demands by end-use sector. Supplies are matched to demands, taking into account judgemental assessments of likely availability, and in this process the 'desired' fuel mix may be altered to reflect constraints on the availability of non-oil fuels. The demand for oil is then determined, at the end of this iterative process, as a residual."[200]

This methodology was applied to both a low- and a high-growth scenario, with oil prices inversely related to growth. A third scenario was used, in which national projections for energy use were taken and altered to reflect continuing reductions in oil use, both for economic and policy-related reasons. The relative price structure of 1980 was used, and policies were assumed to be "strengthened" where necessary to achieve the desired results. The assumption that the mere statement of goals and targets directly reduced consumption is questionable at best.

In essence, these projections are policy driven: Prices do not adjust to reflect the relative supply/demand balance.

In contrast to the OECD, one consulting group took the approach of determining potential supplies, assuming a relaxation of political and policy constraints.[201] Their forecast relied on "...the essential parameters of reserves' availabilty and national economic and political interests of the producing countries."[202] Even so, allowance was made for constraints on production, as well as the constraints on short- and medium-term demand. Still, the group managed to "forecast" much higher

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200 *op. cit.*, p. 33.

201 Energy Advice, *Energy Supplies and Prices in Western Europe to the Year 2000*, Geneva, Switzerland, March 1985.

202 *ibid.*, p. 86.

natural gas production and sales than did the 1982 IEA report, as shown in Table 36.

In summary, most forecasts produced to date have operated under severe handicaps. Aside from incomplete knowledge, two major defects may be noted.

First, most forecasts assumed that the existing policy environment would remain unchanged. In 1974, this would lead one to overestimate future Dutch supplies and in 1980, to underestimate them. Any policy that can be made, can be reversed.

The other major shortcoming was an underestimation of supply.[203] In part, the tendency for policy decisions to restrict production (often by restricting demand) is misinterpreted as a sign that resources are scarce.[204] Additionally, by considering proved reserves of a fluid under pressure to constitute the total resources available, it follows rigorously that production will begin to decline, usually immediately. Although reserves are occasionally revised downward, especially if prices fall, in any large petroleum province such as the North Sea, only gradual changes in additions to reserves per unit of drilling can be expected.

These underestimations of supply have repeatedly led to errors. The Dutch decision to extend export contracts was a recognition in part of new discoveries, as well as lower than projected sales. Similarly,

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[203] This has been discussed extensively in the previous two studies.

[204] This dynamic was also at work in the United States, particularly during the Carter Administration.

Table 3-36

European Natural Gas Supply
(Bcf/yr)

	1984 Production	Potential Peak Annual Production in 1990's	Forecasts 1990	2000
Netherlands	2,439	3,601	2,548	2,744
Norway	1,045	more than 5,295	1,176	2,156
United Kingdom	1,250	1,588	1,764	2,274
Other Producers	1,373	N.A.	1,960	2,234

Source: Energy Supplies and Prices in Western Europe to the Year 2000, [Energy Advice, 1985], p.85.

the U.K.'s decision not to approve the Sleipner deal reflected new confidence that gas discoveries would continue, as they have.[205]

Predicting future policy directions for producer countries (or consumers) is foolhardy at best. But the economic pressures to adopt particular policies can be measured by analyzing the costs of supply, as we have done in this chapter. However, costs are not the only factor affecting long-term supply or policy changes: The trends of supply costs affects decision making, both public and private. The next section examines these trends.

Future Cost Trends for Western European Gas Supply

In assessing the future of Western European gas supply, two trends are important: (1) the short-term cost effects of both the oil price crash and the natural gas supply glut, and (2) the long-term marginal supply cost trend. The latter will prove to be especially important if oil prices remain low over a long period of time, which ultimately would suggest that rising costs of natural gas production will result in a loss of market share to oil, all else being equal.

Short-term Cost Trends

Previous studies by this group noted that the costs of gas production and delivery were driven higher by demand-side inflation. Large-scale rent-capturing occurred as tight labor markets led to rapid growth in wage

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[205] See Offshore, May 1986, p. 89, for a list of discoveries made in 1985, including 11 natural gas strikes in the southern sector of the U.K. North Sea. Table 19 lists discoveries we have found in the trade journals.

levels, as land bonuses and other rents to governments soared, and as inefficiency increased dramatically due to the increased demand for drilling, plant and pipeline construction, and so forth. The post-1982 weakness in oil prices marked the beginning of a reversal of this trend, with drilling, labor, and capital costs all declining.

To some extent, this phenomenon can be seen in Western Europe, particularly in the declining rental costs for offshore drilling rigs. The contract price, which at its peak in the early 1980s was \$90,000/d, by late 1983 had fallen to \$20,000 to \$25,000/d.[206] However, with direct operating costs of \$25,000/day, it has been suggested that this price represents the floor price,[207] despite the surplus of rigs that has occurred due to the fall in oil prices.[208] It is possible that the writing-off of rigs and/or bankruptcies among small oil or drilling companies will lead to further declines in rig rates over the next year or two, and that labor efficiencies will lower the operating cost.[209]

It is important to note that drilling costs are unlikely to behave in the North Sea as they have in the United States, because North Sea drilling should not be as adversely affected by the oil price collapse. In part, the impact will be delayed, and in part, it should be less severe. This delay will come from a combination of company and government

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[206] OGJ, 11/14/83, p. 90.

[207] OGJ, 11/11/85, p. 28. Wood-Mackenzie provided the rig rate data.

[208] OGJ, 5/19/86, p. 22, showed 31 rigs idle in the North Sea in April, versus 9 at the beginning of the year before the oil price collapse.

[209] ibid. In the United States, rigs are reportedly selling for 4.5 to 15 cents on the dollar. See OGJ "Newsletter," 7/21/86.

behavior. Producing governments, anxious to prevent an increase in unemployment, may encourage continued field development where private companies might prefer to delay it.[210] Reductions in taxes, or tax write-offs that act as subsidies, may be used to improve the desirability of either exploration or development. Other policy changes, more difficult to quantify, may keep drilling from declining by reducing development or exploration costs. Certainly, a relaxation in local-content demands for equipment and services is unlikely when employment in the industry is weak, but other constraints can be loosened without serious political or economic side-effects. For example, the Norwegian decision to allow Troll's oil to remain in the ground rather to than require its production greatly improved the economics of the project.

Given the long time span involved in North Sea operations, most private operators will not react immediately to the oil price collapse. The lengthy time necessary to develop some projects (such as Troll), could encourage field operators and purchasers to treat the recent fall in oil prices as a short-term aberration that will be partly or totally reversed by the time deliveries are scheduled to begin. If and when prices remain depressed, the effects on the drilling industry will become more severe, and costs should drop further.

The impact of the oil price collapse on drilling outside North America also will be mitigated by the fact that oil and gas production is much cheaper overseas.[211] In fact, although expenditures by major

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[210] This may be the case with Troll, where much of the financing will come from government sources.

[211] See Adelman, 1986, op. cit., Table III.

oil companies for exploration in the United States has fallen by 40 percent this year, the same companies have cut spending outside of North America by only 18 percent.[212] How rapidly and how far drilling will fall depends in part on the willingness of governments to reduce taxes and royalties.

The very large surplus of capacity to produce and deliver natural gas to Western Europe means that marginal costs will be very low for some time, but only as that capacity becomes utilized. The marginal cost of increasing throughput in the Urengoi pipeline is very small, but Western European countries may prefer to develop and produce the Troll field at a higher cost.[213] Still, the existence of this capacity which can be delivered for a marginal (i.e., variable) cost of less than $1.00/Mcf should act in most instances to keep prices low and markets competitive. The fact that the lion's share of this capacity is found in countries that rely heavily on hydrocarbon exports for revenues will enhance that tendency.

Long-term Cost Trends

Over the long-term, the declining size and increasing depth of oil and gas deposits should increase the marginal costs of the resource. Given that the high costs of transporting natural gas result in a floor

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[212] PIW, 7/7/86, p. 6.

[213] The price probably would be the same for the two, however.

price that is much higher than that for oil,[214] the rate at which natural gas costs will increase over the next decade or two is very important. The more rapid the increase, the more quickly gas will lose market share to oil, all else being equal.

To reiterate, the predominance of transportation costs in natural gas production and delivery costs will sharply mitigate any decline in the resource base. Construction costs may increase at times, but there is no unavoidable upward cost pressure on them analogous to those experienced in resource development. Indeed, manufacturing processes typically become more productive over the long-term, reducing costs.

Of course, in the North Sea transportation costs are usually lower. Pipeline costs tend to be less than $1.00/Mcf, frequently half that, and field development costs comprise a much higher share of total delivered costs, particularly in the United Kingdom and the Netherlands. Those two countries should experience the most severe cost escalation of the major producers, although as the infrastructure in their producing regions improves, some cost savings will occur.

The tendency for increases in long-term resource costs to be mitigated by improving knowledge and technology has been discussed elsewhere,[215] but the North Sea provides a textbook example. The last

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[214] In "The Competitive Floor to World Oil Prices," Adelman demonstrates that enormous quantities of oil could be produced for less than $1.00/bbl. Although there are significant quantities of natural gas that can be produced for approximately $1/bbl of oil equivalent (in the Soviet Union and the Middle East for example), oil costs only $1.00/bbl to transport, while natural gas transportation from e.g., the Middle East or the Soviet Union, typically costs $10-$15/bbl of oil equivalent.

[215] M.A. Adelman, "Scarcity and World Oil Prices," Review of Economics and Statistics, August 1986.

decade has seen rapid improvement in technology, which has had the effect not so much of providing cheaper gas but of allowing previously uneconomic gas fields to become viable. This is especially true in the U.K. sector (since the Norwegians have deliberately delayed exploitation of their resources).

The best example of this is the use of new production systems, including subsea completions, semisubmersible floating production facilities, tanker-based floating production facilities, and tension-leg platforms. These technologies can permit production of fields that are too small and/or too deep to warrant a full production platform and they will, in effect, add to the resources available at current prices.

The dominant factor remains the very large resources that are available now: discovered fields, many undeveloped, and pipelines or liquefaction plants already in place. It will be many years before there is a need for more intensive development in most of the Western European supply regions, and advances in infrastructure and technology will go far to offset the decline in the resource base represented by the next phase of discovery and development.

The Current Market

Although many natural gas supply contracts index the price of natural gas to competing oil products, the market has not cleared. The continued glut in natural gas markets may result in lower gas prices relative to competing fuel prices, especially of oil, but there is no "natural" relationship between the two prices. A previous study noted that the ratio of oil to natural gas prices in the United States has varied considerably over time, even before the market was regulated.[216] In the U.S. market, gas prices declined sharply throughout 1985, before oil prices began their plunge, and a similar situation may occur in Western Europe.

There is no reason to expect that a thoroughly competitive natural gas market will develop in Western Europe. But careful observation suggests the direction in which the shadow equilibrium price is pressuring the market. If demand outstrips supply, then the price will be below competitive equilibrium, and a queue of disappointed would-be buyers would form. If supply exceeds demand, then sellers could not sell as much as they would wish.

There clearly is excess supply at present. The past several years have seen the Norwegians, the Dutch, the Algerians, and the Soviets all unable to sell supplies at current prices. The result has been downward pressure on gas prices _relative to oil prices_. They have not just been following oil prices down, although some buyers have sought to take lower quantities and some sellers have preferred to shut-in production rather than reduce prices.

The Illusion of Oil and Gas as Appreciating Assets

It is widely believed that oil and gas are fixed stocks that can only grow more valuable over time. The net value of the deposit (i.e., price less extraction cost) must rise at the rate of interest in order to induce the holder to keep it in the ground rather than sell it.

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[216] North American report, Supply Chapter, _op. cit._, p. 10.

This belief has exerted a powerful influence over public and government opinion, and has generated a strong bias against producing hydrocarbons, particularly against producing them to sell to foreigners who thus obtain the "irreplaceable resource" at prices less than it is really worth, or will in time be worth.

We cannot review here the whole theory of depletable resources,[217] but we must point out that the evidence is clear that over time the real price of practically every mineral has declined rather than risen. Clearly something is wrong with the argument that mineral resources are an appreciating asset.

We suggest that the limitation on resources is not relevant, because no resource will ever be exhausted. What matters is diminishing returns: the tendency for discoveries to become constantly smaller and less accessible. This tendency has been opposed by increasing knowledge, which has (thus far) more than overborne it. The minimal conclusion is that mineral prices are the uncertain, fluctuating residual of two opposing forces. Hence they are risky assets, and in evaluating them, holders should use high discount rates or any other appropriate means of allowing for risk.

Any actor who preferred to hold rather than sell oil reserves (e.g., in the Persian Gulf) would have (a) gained in 1945-1950; (b) lost heavily during 1950-70, as real prices declined; (c) profitted hugely during 1970-74; (d) not gained during 1974-1978; (e) profitted

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[217] M. A. Adelman is now preparing a paper on the subject, to be issued in the first instance as a Working Paper of the Center for Energy Policy Research at M.I.T. See also Adelman, et. al., Energy Resources in an Uncertain Future, 1983.

in 1978-80 even more than in 1970-74; (f) lost disastrously in 1980-86. Taken as a whole, the gain during the 1945-86 period would have been near zero. For the 1970-86 period, the increase would have been from $3.00 to $8.00 (in 1982 prices), or 6.32 percent (real) annually. This is not an impressive rate of return, especially since it was improved by a one-time change, specifically the imposition of the monopoly after 1970.

With the decline in resource value of the last few years and the increasing realization that the finite nature of oil and gas has been, to put it mildly, overstated, the market has entered a new era. In the past, producer nations often withheld supplies expecting their assets to appreciate, thereby tightening the market and fulfilling their expectations. They now have recognized that the value of their asset has declined in the last few years, and instead are seeking to increase sales, and thereby maintain revenues. As a result, the market has weakened considerably and may very well weaken further, given the number of producers who need to maintain revenues in the face of declining prices, and given the available surplus capacity that is economic to utilize at almost any price.

Higher volumes of gas sales will exert downward pressures on oil prices, while lower oil prices will exert increased pressures on producers to sell more gas. The vicious spiral of increasing competition may be broken by transitory events, such as an oil crisis, but a long-term reversal will come about only when producers feel they have more to gain by withholding their assets than by producing them. Our analysis of the economics of supply suggests that this is most likely to occur at very low prices.

APPENDIX 3A

METHODOLOGY FOR ESTIMATING THE COSTS OF NATURAL GAS SUPPLY

There are a wide variety of methods by which to assess the costs of delivered natural gas, including project evaluation, rate-of-return assessment, etc. Our methods, which have been explained in detail in previous reports,[1] are determined by the type of project and the amount of data available. This section provides a brief review of the manner in which natural gas costs have been determined in this report.

Rationale of Method

The net present value of any given development can be shown by:

$$V = \sum_{t=0}^{T} (R_t - C_t) \quad (1/(1+i))^t$$

$$V = \sum (P_t Q_t - C_t) \; (1/(1+i))^t$$

Where:

V = net present value
R = revenues = PQ
P = price
Q = annual production
i = discount rate or cost of capital, percent/year
C = operating cost

Setting V equal to zero, we are to solve for P. Simplifying assumptions made include:

(1) Production starts at the maximum rate, and declines at a constant exponential rate from the original level Q_0.

[1] See especially the North American report, pp. 22-25, and the East Asia/Pacific report, Table 5.

(2) Capital expenditures are made at one instant, just before production starts.

(3) Operating cost is a constant fraction of capital cost, i.e., $C_t = cK$, where K is total capital expenditures.

(4) All production and receipts are in continuous time.

Some other important relations that will be needed below:

$$Q_t = Q_0 e^{-at}$$

$$\int_0^T Q_t \, dt = R = Q_0 \frac{1-e^{-at}}{a} = Q_0/a, \text{ as } t \rightarrow \infty$$

$$C_t = cK$$

$$K = \int_0^T e^{-it} [P (Ra/(1-e^{-at}) e^{-at}) -cK] dt$$

We will ignore operating costs, cK, and treat them separately below.

Field Development Capital Costs

The objective of calculating field development capital costs is to find the marginal or incremental cost per Mcf of gas obtained by investing in a new project. We first show how to do this when the minimum amount of information is available, then how to incorporate additional data.

In all cases, we end with an equation of the following type:

$$P = f(i, K, R, Q, a, T) \qquad [1]$$

where P = market price *or* supply price (see below);
i = market interest rate *or* project rate of return (see below);
K = capital expenditures;
R = reserves to be developed;
Q = initial or peak output;
a = exponential decline rate;
T = life of project.

Equation [1] can be used in two alternative ways. First, by taking <u>i</u>, the discount rate, as exogenous, P can be calculated as the supply price or cost, the price that would make the investment just profitable. Or, alternatively, by taking <u>P</u> as a market price, we calculate <u>i</u> as the rate of return on the investment, disregarding taxes. A number of examples demonstrate how equation [1] can be employed.

<u>Case 1</u>: K, R are known

<u>Assume</u> a = 1/15 = .067, which is a well-known rule of thumb. In both the United States and the North Sea, <u>a</u> runs almost twice as high, and it is best to use 0.1 as a first approximation.

Reserves = cumulative output, declining exponentially, as shown by the equation:

$$R = Q \int_0^T e^{-at}\, dt = (Q(1-e^{-aT})/a \qquad [2]$$

Assuming T is indefinitely long, then R = Q/a [3]

The revenue stream declines at a rate <u>a</u>, and its value declines at the compound rate (a+i). Thus,

$$PQ \int_0^T e^{-(a+i)}\, dt = [\ PQ\ (1-e^{-(a+i)T})\ ]\ /\ (a+i)$$
$$= PQ/(a+i) \qquad [4]$$

when T is infinite. The present value of revenues must be just equal to the capital expenditures:

$$PQ/(a+i) = K$$

Since Q = Ra,

$$P = (K/R) * (a+i)/a \qquad [5]$$

In other words, the supply price is equal to the cost per Mcf in the ground (K/R) multiplied by the adjustment for holding the stock until produced, (a+i)/a = (1 + (i/a)).

Alternatively, if the price is known, the rate of return can be solved for, as indicated by:

$$i = a((PR/K)-1) \qquad [6]$$

<u>Case 2</u>: K, R, and Q are known

Again, assume T is infinite, take Q/R = a, and use equations [5] or [6].

<u>Case 3</u>: K, R, Q, and T are known

By solving equation [2], <u>a</u> can be found, but by using the actual T rather than infinity. Then insert <u>a</u> and the known <u>T</u> into the following equation, and solve for either <u>P</u> or <u>i</u>:

$$P * \frac{1-e^{-(a+i)T}}{a+i} = (K/R) * T \qquad [7]$$

With realistic values of <u>i</u>, <u>a</u>, and <u>T</u>, the left-hand side is equal simply to P/(a+i).

In the special case of a zero decline rate over the known time period T, R=QT, and Q=R/T. Then:

$$V = (PR/T) * (1-e^{-iT})/i - K = 0 \qquad [8]$$

A single unit produced each year over the life of the project is worth its present value, stated at the left hand side of the equation. There will be T units delivered, each one costing (K/R) up-front.

<u>Note</u>: In the foregoing example, we assume that all capital expenditures are made at one time, in year zero. We assume peak output occurs initially, followed by an exponential decline. In fact, capital

expenditures stretch over several years, usually peaking just before year zero, when production starts. Typically, production builds up over several years, then holds approximately stable for a few more, then declines steeply.

The errors are mutually offsetting. Adelman and Paddock showed that for North Sea fields, the value of P calculated as above gave an excellent prediction of the values as calculated form the actual production plans, tabulated by Wood, Mackenzie & Co.[2]

The result of the Adelman-Paddock test is not surprising. McCray[3] gives the following formula slightly adapted here for calculating the expected decline period, which our short method equates to infinity:

$$T = \frac{R}{Q_0 - Q_f} * \ln (Q_0/Q_f)$$

where T is the period in years, R=reserves=estimated cumulative output, Q_0=initial-year output, and Q_f=final-year output. Obviously when the final-year output is zero, the period is infinite.

Consider proved reserves of 100, initial-year output of 10. Not nowing the final output, we set the depletion/decline rate equal to 10/100 = 0.1. Setting the price to unity, and the discount rate to 10 percent, the present value of the reserve is equal to 10/.20 = 50.

Suppose we know, however, that final-year output is 2. Then we can calculate:

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2 M.A. Adelman and James L. Paddock, "An Aggregate Model of Petroleum Production Capacity and Supply Forecasting," M.I.T. Energy Laboratory Working Paper MIT-EL 79-005WP, Cambridge, Massachusetts, 1980.

3 A. W. McCray, Petroleum Evaluations and Economic Decisions (Englewood Cliffs, N.J., Prentice-Hall, Inc., 1975, p. 323.

$$T = \frac{100}{10-2} * \ln 5 = 12.5*1.6 = 20.1 \text{ years}$$

Since the final-year output is 0.2 times the initial-year output, the average decline must be the reciprocal of 0.2 to the power 1/20.1, or 1/0.923 = 1.083. Then the present value of the deposit, again setting the price to unity, is:

$$PV = 10 * [\int_0^{20.1} e^{-(.083+.10)20.1} dt] = 10*[(1-e^{-3.68})/.183] = 53.3$$

Thus our method, which assumes infinite time, understates present value, and overstates cost, by a factor of 6.6 percent. If output stays on an initial plateau before declining, cost is further overstated.

In the North Sea, where detailed data on reserves, production levels, and field development investments are available, the in-ground costs can be readily calculated and converted into above-ground costs using equation [5]. In some instances, particularly the recent proposed Troll field development, there is no meaningful decline rate. In such cases, given the internal rate of return, life of production, and field development costs, the supply price can be calculated using the formula shown in equation [7].

In some areas, such as Algeria and the Soviet Union, few or no reports of investment costs exist. In these cases, the method applied in the East Asia/Pacific report is used: well costs are estimated using reported U.S. drilling costs for the same depth class and adjusted for non-drilling costs and overseas conditions, as shown.[4] Multiplying by the discount rate plus the decline/depletion rate yields the annual capital

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[4] See Table 5 in the supply paper, p. 18.

charge, which can then be divided by the well productivity to yield a per Mcf development cost.

Operating Costs

In most of our examples, an industry rule of thumb has been that operating costs are 3 to 5 percent of capital expenditures. This can be seen in Table A-1, where a detailed breakdown of capital and operating costs was made for a number of types of projects: production, pipeline and liquefaction.[5] For this study, we take the high end of the range (i.e., 5 percent), although in the case of LNG plants, where operating costs are skewed by fuel consumption, 3 percent is assumed as the operating cost and fuel costs are added separately. Fuel costs are assumed to be the delivered cost of the gas, since anything in excess of this will be rent to the producer.[6]

Pipeline Costs

For many producers, pipeline costs comprise a substantial fraction of the delivered costs of their gas, either due to distance or environment (e.g., offshore projects). Unfortunately, because of the substantial differences in operating environments, no generalization is possible in estimating the capital costs of pipelines. For example, Soviet pipelines face many river crossings as well as mountains and

[5] One private corporation provided detailed cost estimates for several large LNG projects. In them, operating costs usually were 4 percent for gas fields and 7 percent for liquefaction plants, the latter presumably due to high fuel costs.

[6] The role of inflated plant-gate fuel prices in raising LNG cost estimates is discussed in the East Asia/Pacific report, on pages 38-42.

TABLE A-1

OPERATING COSTS RELATIVE TO CAPITAL COSTS

Source	Total Capital Costs	Annual Operating Costs	Ratio
PIPELINES			
Trans Alaska Gas System Phase I			
Total System	7173	78	1.1%
Pipeline	4548	20	0.4%
TAGS Phase II			
Total System	7121	128	1.8%
Pipeline	3635	35	1.0%
North Sea Gas Gathering Projects:			
System A	1460	59	4.0%
System B	2650	100	3.8%
System C	3024	114	3.8%
Existing Pipelines	2606	100	3.8%
Recommended System	2993	114	3.8%
Processing facilities (North Sea Gas Gathering Project):			
System A	199	11	5.5%
System B	285	16	5.6%
System C	349	19	5.4%
System D	381	21	5.5%
Venture Gas Field	2446	100	4.1%
LNG PROJECTS			
LNG Project	800	30	3.8%
Liquefaction plant			4.0%
Regasification plant			3.5%
Nixon library	15	1	6.7%

Sources: See next page.

TABLE A-1
(cont.)

Sources:
TAGS is from "Trans Alaska Gas System: Economics of an Alternative for North Slope Gas," January 1983, Exhibit A2, A3. Fuel is excluded.
Venture is from "Venture Gas Project: Application to the National Energy Board for an Export Licence," vol. II, pp. 6-13, 6-16.
North Sea Gas Gathering Project estimates are from "A North Sea gas gathering system," UK Dept. of Energy, May 1978.
LNG Project is basic project costs estimated in LNG Handbook, a Commemorative publication of LNG-6, courtesy of JGC corporation. Fuel is excluded.
Liquefaction and regasification plants from Robert DiNapoli, "Economics of LNG Projects," Oil and Gas Journal, 2/20/84, p. 50.
Nixon library from NYT 9/29/86, p. B8. Operating costs based on assumed rate of return on endowment of 10 percent.

Arctic conditions for part of their routes. Algerian pipelines might traverse relatively easy terrain for much of their routes, but more equipment and personnel have to be imported than elsewhere. North Sea pipelines may reflect typical cost profiles for undersea pipelines, but if Norwegian pipelines cross the Norwegian trench, their costs will be higher.

To compound the problem, there are so few examples of pipeline construction in any given area that it is difficult to draw overall conclusions about transportation costs: An initial pipeline may be excessively expensive due to unexpected difficulties with the terrain, lack of existing infrastructure, or the costs of developing and using of new pipelaying technology. Also, the period when any given pipeline is lain may be one of inflated or deflated capital construction costs, depending on the state of the industry and its position on the business cycle at the time of contracting and construction.

Thus, although we sometimes make comparisons between reported construction costs and more general estimates of normal costs (for example for undersea pipelines), this paper relies on actual specific project costs to the extent possible. When considering the cost of new supplies, what has been observed about past pipeline costs will be incorporated, with the <u>caveats</u> discussed above.

The method used for converting pipeline capital costs, which are the most commonly reported costs, to per-unit natural gas costs will be as follows: The annual capital charge is taken as 12 percent of total capital costs, the same as that for a project with a real rate of return of 10 percent and a life of 20 years.[7] Operating costs are the same as described above, and throughput is assumed to be 100 percent, except where noted.

Discount Rates

For field development projects, a discount rate of 12 percent is assumed, reflecting their inherent geological uncertainty inherent. For pipelines, which can be utilized by any field in their locale, a 10 percent discount rate is assumed (see previous paragraph).

Accounting for Inflation and Currency Conversion

Inflating costs to current dollars is difficult for several reasons. First, real exchange rates vary over time, but must be accounted for in some manner. Second, there is not necessarily a direct correspondence between any given price deflator and the various costs involved in developing and transporting natural gas. In the United States, a price deflator for field development exists--the IPAA drilling index--but it cannot be freely translated to North Sea conditions. Nor can a general price deflator reflect the boom and bust conditions extant in the oil industry, and the accompanying boom and bust in costs.[8]

Our approach thus is as follows: When given field development or pipeline costs from the past several years, no inflation is applied. For older examples (pre-1983), the implicit price deflator for U.S. GNP is used to inflate to 1985 U.S. dollars. When the report is not in

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[7] See IEA, Natural Gas: Prospects to 2000, 1982, p. 53.

[8] Short- and long-term cost trends are discussed in the main body of the paper.

U.S. dollars, the currency exchange rate we use is the purchasing power parity index, published by the OECD.[9]

Natural Gas Liquids

Field development costs for natural gas liquids include only those processing costs that are specifically necessary for their production. We need not bother with the meaningless argument that liquids should be assigned their "fair share" of exploration and development costs.

Data on the costs of processing the gas in the North Sea for liquids are not available. Presumably estimates of capital expenditures for gas field development include the investment necessary for gas processing and liquids recovery. Therefore, we estimate the revenue from the gas liquids, and treat it as an offset to, or subtraction from, the development-operating cost of the gas. Representative prices are used for natural gas liquids that reflect an assumption of low oil prices, i.e., $10/bbl.[10]

The same method could be applied to oil field developments where associated gas is produced as a byproduct. However, since gas pipeline costs make up the vast majority of the costs of producing associated gas,

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[9] See Michael Ward, Purchasing Power Parities and Real Expenditures in the OECD, OECD, Paris, France, 1985.

[10] Condensate values have been described as 15 percent less than naphtha prices, roughly the same as crude oil. See Gas Gathering Pipelines (North Sea) Ltd., Gas Gathering Pipeline Systems in the North Sea, Her Majesty's Stationery Office, London, England, 5/78, p. 53. There is not really a spot market in condensate, but an examination of Algerian condensate prices, which are roughly competitively priced, shows them to be close to crude oil prices. LPG, because of its lower heat content, is much lower in price.

and pipeline costs are known, most of the incremental costs of producing and delivering the gas can be shown.

There are three systems that deliver associated gas from the North Sea: FLAGS (northern British sector), Norpipe (Ekofisk) and Statpipe (Statfjord area). Although some non-associated gas is included, the amounts are small, and the data are insufficient to allow production cost estimation except in a few cases.

APPENDIX 3B

CONTRACT VOLUMES

Table 3B-1 shows the volumes exported/imported by country, for 1987-2017, under the existing contracts as used under the Blitzer model's low demand scenario. Also shown are 1984 actual deliveries. The volumes are actual contracted volumes adjusted to conform to the low demand scenario.

Contract volumes and durations were ascertained from a variety of sources. Contract volumes, durations, and sources are listed in Table 3B-2 which also details calculations and assumptions. The base sources for this information were Ente Nazionale Idrocarburi (ENI), Energy and Hydrocarbons, 1981 and 1983. The ENI data was adjusted for contract revisions/adjustments as reported in trade periodicals, journals, and newsletters. Among the sources reviewed for contract revisions/adjustments were: International Gas Report, Petroleum Economist, Oil and Gas Journal, International Petroleum Encylopedia, and BP Review of World Gas.

In most cases, the volumes contracted greatly exceeded the expected imports (expected imports = gross demand - nonexported domestic production) under the low demand scenario. To conform gas flows under existing contracts with import demand, all contracted volumes were adjusted by decreasing the expected takes as a percentage of contracted volumes. The expected take percentages were determined by considering both the actual contract take provisions and historic performances under the given contracts. Reduced expected takes as a percentage of full contract volumes are as follows:

Algerian contracts with France and Italy	80%
Algerian contract with Belgium	30%
Russian contracts	50%
Dutch contracts	50%
Norwegian contracts	80%
Norwegian Sleipner/Troll contract	
During build-up	100%
Post build-up	80%

Table 3B-1

Contracted Volumes
Adjusted for Low Demand Scenario
(Bcf)

Exporter	Importer	1984	1987	1990	1993	1996
Algeria						
	Belgium	55	53	53	53	53
	France	287	251	237	237	237
	Italy	232	339	339	339	339
	TOTAL	574	643	628	628	628
	Austria	144	71	71	71	42
	France	158	274	339	339	339
	Germany	448	565	565	565	297
	Italy	268	424	424	424	226
	TOTAL	1018	1333	1398	1398	904
The Netherlands						
	Belgium	204	74	74	74	53
	France	276	175	125	115	115
	Germany	644	455	455	455	455
	Italy	14	106	106	106	0
	TOTAL	1137	810	761	750	623
Norway						
	United Kingdom	480	268	268	268	268
	Belgium	69	106	106	120	144
	France	77	120	120	177	273
	Germany	193	323	323	380	477
	The Netherlands	107	106	106	120	144
	TOTAL	926	923	923	1065	1306

Net imports by country

	1984	1987	1990	1993	1996
United Kingdom	480	268	268	268	268
Austria	144	71	71	71	42
Belgium	328	233	233	247	250
France	798	820	821	867	963
Germany	1286	1344	1344	1400	1228
Italy	513	868	868	868	565
The Netherlands	-1031	-704	-655	-630	-479
Norway	-926	-923	-923	-1065	-1306

Table 3B-1 (continued)

Contracted Volumes
Adjusted for Low Demand Scenario
(Bcf)

Exporter	Importer	1999	2002	2005	2008	2011
Algeria						
	Belgium	53	53	0	0	0
	France	141	141	0	0	0
	Italy	339	339	339	339	0
	TOTAL	533	533	339	339	0
	Austria	42	42	0	0	0
	France	339	282	226	226	0
	Germany	297	297	0	0	0
	Italy	226	226	226	226	0
	TOTAL	904	847	452	452	0
Netherlands						
	Belgium	53	53	53	0	0
	France	0	0	0	0	0
	Germany	455	455	455	455	0
	Italy	0	0	0	0	0
	TOTAL	508	508	508	455	0
Norway						
	United Kingdom	0	0	0	0	0
	Belgium	97	92	92	56	56
	France	299	275	275	226	226
	Germany	342	318	318	226	226
	The Netherlands	97	92	92	56	56
	TOTAL	836	777	777	565	565
Net imports by country						
	United Kingdom	0	0	0	0	0
	Austria	42	42	0	0	0
	Belgium	203	198	145	56	56
	France	779	699	501	452	226
	Germany	1094	1070	773	681	226
	Italy	565	565	565	565	0
	The Netherlands	-411	-417	-417	-399	56
	Norway	-836	-777	-777	-565	-565

Table 3B-1 (continued)

Contracted Volumes
Adjusted for Low Demand Senerio
(Bcf)

Exporter	Importer	2014	2017
Algeria			
	Belgium	0	0
	France	0	0
	Italy	0	0
	TOTAL	0	0
	Austria	0	0
	France	0	0
	Germany	0	0
	Italy	0	0
	TOTAL	0	0
Netherlands			
	Belgium	0	0
	France	0	0
	Germany	0	0
	Italy	0	0
	TOTAL	0	0
Norway			
	United Kingdom	0	0
	Belgium	56	56
	France	226	226
	Germany	226	226
	The Netherlands	56	56
	TOTAL	565	565

Net imports by country

		2014	2017
	United Kingdom	0	0
	Austria	0	0
	Belgium	56	56
	France	226	226
	Germany	226	226
	Italy	0	0
	The Netherlands	56	56
	Norway	-565	-565

Table 3B-2

Sources

1984 actual volumes: Cedigaz, "Natural Gas in the World 1984," Centre International d'Information sur le Gaz Natural et tous Hydrocarbures Gaseux. Paris, 1985.

Contracts listed by exporter by importer

Algeria:

Belgium: Contract 1982-2002 @ 176.5 Bcf/year, BP _Review of World Gas_, London, 1985, p. 14.

France: Contract 1964-1989 @ 17.65 Bcf/year, BP, _op. cit_.
Contract 1972-1997 @ 119.14 Bcf/year, BP, _op. cit_.
Contract 1982-2002 @ 176.50 Bcf/year, BP, _op. cit_.

Italy: Contract 1983-2008 @ 423.60 Bcf/year. Contract initiation, BP, _op. cit_. Contract duration, Ente Nazionale Idrocarburi, _Energy and Hydrocarbons_, 1981, Italy, 1982, p. 76. Contract volume, Cedigaz, _op. cit_.

USSR:

Austria: Contract 1975-1995 @ 35.3 Bcf/year, _Energy and Hydrocarbons_, 1981, _op. cit_.
Contract 1984-2004 @ 52.95 Bcf/year, Ente Nazionale Idrocarbi, _Energy and Hydrocarbons_, 1983, Italy, 1984, p. 98. 20 year duration assumed consistent with German/French/Italian Trans-Siberian agreements.

France: Contract 1976-2001 @ 141.2 Bcf/year. Volume, _ibid_. Duration, _Petroleum Economist_, January 1975, p. 17.
Contract 1984-2009 @ 282.4 Bcf/year, _Petroleum Economist_, March 1982, p. 105. 1987 volume, _International Gas Report_, June 21, 1985, p. 2.

Germany: Contract 1973-1993 @ 335.35 Bcf/year, _Energy and Hydrocarbons_, 1981, _op. cit_.
Contract 1984-2004 @ 370.65 Bcf/year, _ibid_.

Italy: Contract 1974-1994 @ 247.1 Bcf/year, _ibid_.
Contract 1984-2009 @ 282.4 Bcf/year, _ibid_.

Table 3B-2 (continued)

Sources

The Netherlands:

Belgium: Contract 1966-95 @ 147.91 Bcf/year + 1996-2005 contract extension @ 105.9 Bcf/year, Petroleum Economist, March 1985, p. 103.

France: Contract 1967-1987 @ 328.29 Bcf/year, Energy and Hydrocarbons, 1981, op. cit. 1988-1998 extension @ 229.45 Bcf/year, Petroleum Economist, March 1985, p. 11.
Contract 1970-1990 @ 21.18 Bcf/year, Energy and Hydrocarbons, 1981, op. cit.

Germany: Contracts, various, entered into 1966-1975: Per Petroleum Economist, February 1985, p. 66, contracts extended 10 years, with total volume to be taken over contract life plus extension = 17,297 Bcf. Yearly volume = 910.74 Bcf = 17,297 / (remaining remaining contract period + 10). Original contract expirations estimated to be 1993. Estimated as the volumetric (contract volumes) weighted average of the Netherlands/German contracts. Expirations and contract volumes, Energy and Hydrocarbons, 1981, op. cit.

Italy: Contract 1974-1994 @ 211.8 Bcf/year, ibid.
Assumed contract not extended.

Norway:

United Kingdom:
Contract 1977-1997 @ 335.35 Bcf/year, ibid.

Germany: Contract 1977-1997 @ 289.46 Bcf/year, ibid.
Volume, Energy and Hydrocarbons, 1983, op. cit.
Contract 1986-2007 @ 123.55 Bcf/year. Duration, International Petroleum Encylopedia, 1983 p. 186. Volume, Energy and Hydrocarbons, 1983, op. cit.
Contract 1993-2020 (Troll/Sleipner). Duration and volumes, Oil and Gas Journal, June 9, 1986, p. 19. Initial production (1993) under the Norway/ European utility group contracts given, peak production and takes by each country (Germany, the Netherlands, Belgium, and France) also given. Calculations assume constant production increase from 1993 to 2000 with constant production thereafter. Also assumed each country pruchases, over time, in proportion to its expected takes in the year 2000.

Table 3B-2 (continued)

Sources

The Netherlands:
Contract 1977-1997 @ 88.25 Bcf/year, Energy and Hydrocarbons, 1981, op. cit.
Contract 1986-2007 @ 42.36 Bcf/year. Duration, International Petroleum Encylopedia, 1983, p. 186. Volume, Energy and Hydrocarbons, 1981, op. cit.
Contract 1993-2020 (Troll/Sleipner), see Norway/Germany.

Belgium: Contract 1977-1997 @ 88.25 Bcf/year, Energy and Hydrocarbons, 1981, op. cit.
Contract 1986-2007 @ 44.13 Bcf/year. Duration, International Petroleum Encylopdia, 1983, p. 186. Volume, Energy and Hydrocarbons, 1983, op cit.
Contract 1993-2020 (Troll/Sleipner), see Norway/Germany.

France: Contract 1977-1997 @ 88.25 Bcf/year, Energy and Hydrocarbons, 1981, op. cit.
Contract 1986-2007 @ 61.78 Bcf/year. Duration, International Petroleum Encylopdia, 1983, p. 186. Volume, Energy and Hydrocarbons, 1983, op. cit.
Contract 1993-2020 (Troll/Sleipner), see Norway/Germany.

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PROSPECTS FOR NATURAL GAS DEMAND IN WESTERN EUROPE, 1986-2000

by

Arthur W. Wright

INTRODUCTION

Western Europe is easily the most complex and least tractable of the world's major markets for natural gas. No fewer than five countries are key suppliers, two of which lie outside the region (the Soviet Union and Algeria) and three within it (Norway, the Netherlands, and the United Kingdom), with the latter two also being important consumers. On the demand side, some 14 different national energy policies are at work, and the Soviet Union's role as a major supplier injects a controversial national security element into the analysis. Furthermore, the Western European market trades two physically distinct types of natural gas: Dutch gas at some 0.8 million Btu (MMBtu) per Mcf, and all other gas at about 1.0 MMBtu per Mcf.

Some of this variety shows up in the diversity of how gas is used in the countries of Western Europe. In 1984, the share of natural gas in total primary energy use was about 14 percent. In France, however, it was only about 12 percent, while it was some 46 percent in the Netherlands. The shares of natural gas consumption in primary energy use by major sectors for these two countries show even greater disparities:

	France	The Netherlands
Residential/Commercial	23.3%	46.3%
Industrial	21.9%	71.4%
Electricity Generation	0.0%	57.5%

This broad variation in policies, influences, and consumption patterns is the abiding characteristic of the Western European gas market. Differences in weather and in the structures of national output do not explain much of the diversity. And different resource endowments account for some of it only because nationalist energy policies have prevented the development of natural gas markets according to strictly economic criteria. Had it not been for policy barriers based on political criteria, the gas resources of the Netherlands and the North Sea, for example, might have supported a rather homogeneous development of demand in the core countries (the United Kingdom, France, Germany, Italy, Belgium, and the Netherlands).[1]

Yet, for all this policy-driven complexity, prospects for natural gas demand in Western Europe over the next 15 years depend on the same economic factors as in North America and Japan. The most important factor is the price of oil (or, more accurately, expectations about the future levels and price structures of refined oil products). The institutions for trading natural gas, in particular how it is priced, also exert a strong influence, as do the rates and composition of economic growth. Finally, long-run strategic (or "disequilibrium") considerations also play a large role. This chapter addresses each of these factors.

The complexity of the Western European market for natural gas shapes the analysis by forcing us to be selective. Economy dictates focusing on only four countries in detail: France, Italy, the United Kingdom, and West

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[1] Indeed, if one accepts the general thrust of the results of Blitzer's dynamic programming model (described in Chapter 5), the unconstrained development of the Western European natural gas market would have greatly reduced the roles of both Algerian and Soviet gas supplies--both of which are sources of political controversy and instability in the market.

Germany.[2] We consider only in broad terms the prospects for demand in the Western European market as a whole, and in the other ten countries in the region.

Before examining the Western European market, this chapter first sets forth the concepts and principles that underlie the subsequent analyses. We then present an overview of natural gas demand in the entire Western European market, followed by detailed analyses of the four major countries. The chapter concludes by synthesizing the general and the specific analyses, using as a framework the three different scenarios that form the basis of the demand side of Blitzer's modeling work (see Chapter 5).

THE NATURE OF DEMAND FOR NATURAL GAS

Natural gas demand is influenced by a host of factors. The most central is its price relative to those of close substitutes, especially oil products but also coal and electricity. Other factors include the level of energy prices generally, economic growth (both rate and composition), expectations about both future prices and reliability of supplies, demographics, new technologies, and environmental policies. This section provides a framework of economic analysis to help sort out how these factors apply to the Western European natural gas market.

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[2] These four countries, together with the Benelux countries, account for about 95 percent of current Western European gas use (OECD/IEA, Natural Gas Prospects, Paris, France, 1986, p. 41). One could argue that the Netherlands, as a major user of natural gas--currently consuming more than both France and Italy combined--merits detailed treatment, too. However, owing to its now-lengthy history of gas use (stretching back to the 1950s), the Dutch market appears to be almost fully saturated; evidently, this applies even to family automobile use. If so, future increases in gas demand turn mainly on economic growth. In contrast, the four countries studied here all offer significant possibilities for demand growth through substitution and economic growth.

Economic Demand Functions for Natural Gas

Throughout this chapter, the term "demand" is used in its economic sense; that is, demand is a function that relates different quantities demanded by buyers to different prices charged by sellers. Typically, a change in one or more shift parameters will increase or decrease the entire function; that is, more or less gas will be demanded at higher or lower prices than before the shift occurred. The most important shift parameter is the price of the competing oil product (e.g., residual fuel oil).[3] Other shift parameters are stocks and prices of user equipment, technologies, and people's tastes.

As holds true with most goods, demand curves for gas "slope downward." Greater amounts will be demanded at low prices than at high prices, assuming that shift parameters are held constant, and the quantity demanded will be more responsive to a given price change in the long run than in the short run. If prices change suddenly, purchasers' quantity responses will be restricted by their existing capacities to use gas. With time, however, replacement of capital stock and other adjustments will widen the scope of these responses.

The importance of user equipment as a shift parameter introduces a strategic or dynamic element into the analysis. Expectations about both future prices and reliability of supplies help frame investors' decisions to install gas-using capacity. Thus, supply expectations may shape the course of gas demand over time. This factor was clearly evident in the development of the U.S. natural gas industry between the end of World War II and the late

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3 We discuss the problem of incorporating oil prices into the analysis of gas demand below.

1960s (when regulation-induced shortages first appeared in the market for new reserves). The discovery of a new field (Mid-Continent, Groningen, Western Siberia), a cost-reducing technological development (high-pressure, "seamless" steel pipe), a shift in government policy (binding price ceilings in the United States in the late 1960s; Oslo's recent new approach to gas exports -- all these are capable of profoundly altering future demand for natural gas.

Categories of Gas Demand[4]

The demand for natural gas is not homogeneous. Three consuming sectors commonly are distinguished: residential/commercial, industrial, and electric utility. In all three sectors, levels of demand depend on the price of gas. But the price often varies by customer class, and other factors of the demand functions also may differ.

In the residential sector, the prices of near substitutes--mainly middle distillate fuel oil and, increasingly, electricity--are important shift parameters, as are household income and user equipment. However, the derived demands of commercial, industrial, and electric utility customers do not depend directly on income. Stocks of equipment and technology also are important. The long-run decision to install "dual-fuel" (gas and oil) capability makes fuel switching a short-run possibility. For most commercial sector demands, as for most residential ones, relevant long-run substitutes include distillate fuel oil and/or electricity. Industrial users can substitute distillate in both process-heat and feedstock applications, and residual fuel oil under boilers; conversions in the latter case tend to be to dual-fuel capabil-

[4] A useful supplement may be found in OECD/IEA, op. cit., pp. 33-41.

ity, given the high proportion of fuel bills in total costs. In electric generation, residual fuel oil is the effective short-run substitute for natural gas. Coal and nuclear (base load) and distillate fuel oil (peak load) are all long-run substitutes, as of course are hydro and pumped storage.

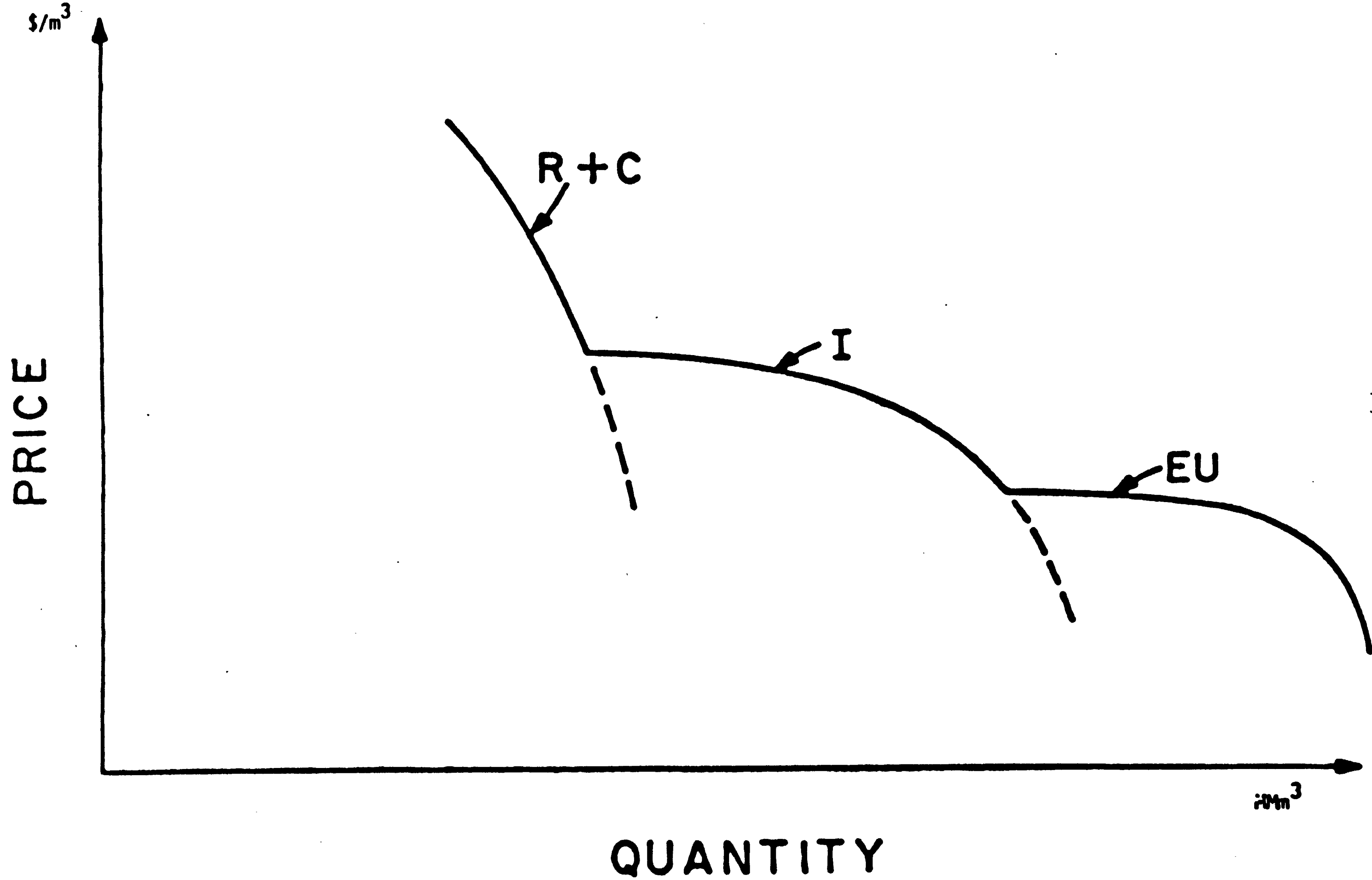
Broadly speaking, residential (R) and commercial (C) gas demands are less "price-elastic" than industrial (I) and electric utility (EU) demands. For any given percentage change in price, the percentage change in quantities demanded for R and C use is relatively smaller than for I and EU uses. R and C demands sometimes are labelled "captive," suggesting that homeowners and shopkeepers are prisoners of capital outlays, which represent a larger fraction of their total costs of gas use, and this therefore retards their range of possible adjustments to price changes.

Exceptions, of course, do exist. Some large commercial users (e.g., apartment houses) find it worthwhile to invest in fuel-switching capability. And certain large industrial users--e.g., petrochemical producers and some firms using process heat--employ techniques expressly designed to use natural gas. Thus, they have less elastic demands than the "penny-switchers" who swing from gas to residual fuel oil and back again in response to relative-price movements of as little as one penny per MMBtu.

These arcana of natural gas economics are important to understand how gas markets operate. Differences among market segments both in marginal use value and in price elasticities imply the existence of distinct ranges in the total demand curve in a given gas market. Figure 4-1 depicts a stylized market for natural gas at end-use. The highest demand prices and steepest slopes occur in the region labelled "R+C", followed by "I", and then by "EU". The range of the R+C region of the demand curve below which the I region begins is not

Figure 4-1

STYLIZED MARKET FOR NATURAL GAS AT END USE



relevant: No seller will sell gas for R+C use if I use will fetch a better price. And similarly for the range of the I region below which the EU region begins.

Prospects for the growth of gas demand will vary considerably, depending on whether gas prices are clearing (or are allowed to clear) below the R+C range. All other factors being constant, if the market clears in the R+C range, sellers will realize greater revenues than they would if it cleared in the I or EU range. Among buyers, the range of market-clearing prices will shape the rates of penetration by gas into the various market categories.

Not long ago, natural gas was viewed as a "premium" fuel in many parts of the world--in North America (except on the Gulf Coast), Western Europe, and Japan (but not in the Soviet Union)--because incremental units of gas delivered to many markets fetched R+C prices. Today, many have begun to view gas more as a "blue-collar" fuel that will clear in the I range (against residual fuel oil) or even (in the long run) in the EU range (against coal)--in the process opening up new markets to natural gas in other categories. This view is now common in North America and to a lesser extent in Western Europe.

The Critical Role of World Oil Prices

As noted above, when studying the demand function for natural gas, the most important shift parameter is the price of the competing oil product. An expected increase in oil prices will tend to reduce total energy demand--quantities demanded at every price--and vice versa. Movements in the relative prices of oil, gas, and other fuels will shift gas demand, in some cases quickly and significantly. Thus, investors in fuel-using equipment are forced, willy-nilly, to form expectations about future oil prices.

The sharp drop in world crude oil prices since November 1985 has forced us to think harder about how oil-price expectations are built into our analyses. As of mid-1986, the range of possible and plausible oil-price expectations looks to be quite wide. We argue here that where expectations actually settle in the range will shape significantly both the level and the forms of investment in energy-using equipment--and hence also the future course of demands for natural gas.

Since 1973, there have been three major oil-price shocks. In the first two (1973-74 and 1979-80), crude oil prices rose severalfold. In the third (1985-86), prices thus far have fallen by 50 percent or more.

These three oil-price events have one thing in common: Few, if any, analysts were able to provide a coherent account <u>and</u> forecast of these precipitous price movements. Many thought the oil price increases of the 1970s were permanent--that "high" and ever-rising oil prices were here to stay. On that basis, natural gas buyers were willing to sign gas contracts with price and other terms set at "premium" levels and tied to oil at or near thermal parity.

As it turned out, high oil prices were <u>not</u> here to stay. However, it does not follow from this that oil prices, now fallen, will stay low. In fact, we cannot be sure how actors in energy markets will form their expectations about future oil prices. Choosing one particular assumption about expectations would leave our analysis vulnerable to becoming irrelevant. It therefore is best to resort to sensitivity analysis to cope with the wide range of possible assumptions about oil price expectations.

To do this, we postulate a <u>reference oil price</u> that participants in gas markets use when deciding whether to invest, how much, in what, where, and when.[5] Any given reference oil price necessarily is associated with some set of expectations about world oil prices. We may think of a reference price as an expected value or mean, plus some measure of the probability that the actual price will diverge from the mean in any particular period. Reference oil prices may well differ not only in their <u>means</u> but also in their <u>divergences</u> from the means.

We further postulate that the key element in oil price expectations is the market structure that decision makers believe will prevail in the world oil market over the decision horizon: say, 10 to 20 years.

Three structural scenarios for the world oil market are postulated:

(1) <u>A Strong Oil Cartel Re-forms</u>: At one extreme is a re-formed world oil cartel, with a coalition of larger exporting countries again led by Saudi Arabia. The reference price in this extreme scenario would be around \$28 per barrel (bbl), ± \$2.[6] Loosely speaking, this scenario resembles oil market conditions in the mid- to late-1970s.

(2) <u>Competition Prevails in the World Oil Market</u>: At the other extreme, competitive forces eventually may prevail in the world oil market, pushing prices down to near long-run marginal cost. A plausible competitive reference price might be \$8/bbl, ± \$1. This scenario may be likened to conditions in the world oil market over the 1950-70 period.[7]

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[5] M.A. Adelman is the source of this concept, but he is not to blame for any misrepresentation or misuse in its application here.

[6] All prices are quoted in 1986 dollars.

[7] See M.A. Adelman, "The Competitive Floor to World Oil Prices," <u>Energy Journal</u>, forthcoming, for an analysis of long-run marginal costs for oil production in different producing regions of the world.

(3) The Oil Cartel Waxes and Wanes: Intermediate between these two extremes is an oil market in which the cartel's grip is loosened but not completely broken. There is general uncertainty from one period to the next about just how tight the cartel's grip is going to be. The reference price under this "clumsy-cartel" scenario might be \$15/bbl, ± \$5.[8] Something resembling this scenario has appeared in the world oil market since early 1982, and some might argue that it also prevailed during 1975-77.[9]

These three oil-price scenarios have quite different implications for future gas demand. Natural gas markets may clear in different price ranges of

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[8] The existence of price volatility suggests that organized futures trading in natural gas could be economically viable under this scenario. The possibility has been considered in the United States--indeed, one model contract has been submitted to the U.S. Government for approval--and references are made to applying it to Western Europe (e.g., with respect to the "swing" role that Groningen gas plays in that region). Regulatory impediments (especially restrictions on gas deliveries and prices) appear to be the most serious barrier to organized trading in natural gas.

[9] The urge to speculate about which of the three variants is most probable over the next 15 years or so is irresistible. Giving in to the urge, but entirely as an aside, we opt for (3), for at least three reasons.

First, energy supplies in general are much more price-elastic now than than they were in the early 1970s. Low or even "soft" energy prices will not cause much of a permanent loss in existing capacity, plus acquired exploratory knowledge, gained in response to the high oil prices of the 1970s. More price-elastic energy supplies make variant (1) less likely to occur today than (admittedly with hindsight) in the early 1970s.

Second, energy demands in general are more price-elastic than they were in the early 1970s. The investments in energy-saving and fuel-switching capacity prompted by the oil prices and expectations of the 1970s will not go away for many years. More price-elastic demands also reduce the probability that a strong cartel will re-form.

Third, prospects for variant (2) are dimmed by the inability, or unwillingness, of the major energy-consuming nations to learn from sad experience and kick the cartel while it is down. A vigorous oil stockpiling program would be much cheaper to implement now than it was five years ago; moreover, the mere existence of a large stockpile would pose a credible threat to any re-forming oil cartel and reduce its ability to disrupt the market. The energy users' failure to take measures like stockpiling, plus the financial stake of the big oil exporters in gaining and exercising market power, make the competitive variant unlikely.

the demand curve, and investments relating to fuel use and interfuel choice are likely to vary across the three oil-price scenarios. Moreover, the various scenarios likely will have quite different effects on macroeconomic activity and performance, and especially on economic growth.

Under scenario (1), a re-formed and cohesive oil cartel, gas markets would be more apt to clear in the "premium" or R+C range.[10] In contrast, at the opposite extreme of scenario (2), gas markets could well clear in the "blue-collar" or I and EU ranges, with their relatively price-elastic demands. The mixed oil price scenario, (3), would see gas demand less stable than in the two extreme cases. This instability would create substantial uncertainty about where gas markets would clear, which in turn would affect investment decisions, to which we now turn.

High oil prices (scenario 1), which pull up other energy prices, on the one hand would encourage investment in more energy-efficient capacity, thus tending to retard the growth of total energy use, and with it growth of gas demand. On the other hand, provided gas prices were not closely linked to oil prices, high oil prices also would tend to encourage investment in gas-only capacity (e.g., in process-heat applications, petrochemicals, new residential and commercial buildings, and conversions of existing heating plants), and in add-on capacity to permit fuel-switching from oil to natural gas.[11] The low

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[10] This is particularly true if governments respond (as did those of many Western countries in 1974) by placing restrictions on gas use and taking other measures that turn gas into a political good. In this case, both economic and political criteria will make gas a "premium" fuel.

[11] Following the first two sharp oil-price rises, in 1973-74 and 1979-80, gas prices in many new contracts were linked tightly to oil prices, often at premia in terms of cost per usable Btu. This can be traced, in our view, to the unique supply conditions existing in gas markets at the time, and these would be unlikely to occur again if our scenario (1)--a reprise of the mid- to late-1970s--came to pass. Those unique gas supply conditions were the

oil prices at the opposite extreme (scenario 2) would push these investment choices in just the opposite directions. Under scenario 2, prospects for increased natural gas demand would hinge to a large extent on expectations about the volatility of gas prices relative to those of oil, and on macroeconomic forces.

The large price variances associated with scenario (3) would provide the greatest incentive to invest in fuel-switching capacity. This is because a premium would be placed on the flexibility of fuel-switching capacity. In addition, the instability of oil prices under this scenario could enhance the penetration of gas into previously single-fuel uses. This presumes, of course, that gas prices are less tightly tied to oil prices than they were in the past, as we expect them to be (see footnote 9).

Oil price expectations exercise their macroeconomic effects both through "real" impacts on aggregate supply and through governments' responses in fiscal and monetary policies. Lower oil prices tend to increase aggregate supply, and thus to stimulate economic activity; the converse is true for higher oil prices. If past policymakers' responses to oil price shocks are any

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(continued)

regulation-induced shortages in North America and the infancy of the industry in the Pacific basin region and in Western Europe (outside the Netherlands). These conditions made for short- and intermediate-run supply price elasticities of supply that were low enough to confer market power on suppliers. With today's more "mature" gas industries all around the world, supply elasticities will be greater, even in the short run. This point is reinforced but does not depend on the current gas "gluts" found in various regions of the world.

The investment behavior discussed here depends on governments not responding high oil prices as discussed in footnote 7, so natural gas becomes a "premium" fuel by fiat. Government restrictions on gas trading and use, of course, will have a chilling effect on all new investment in gas-using capacity.

guide, fears of the inflationary effects of higher oil prices would tend to push macro policy toward restraint, aggravating the deflationary impact of the higher prices. Conversely, policymakers may feel freer to pursue expansionary macroeconomic policies under low oil prices, thus enhancing the stimulative effect of the low oil prices.

In terms of natural gas demand, these macroeconomic "income" effects work against the fuel-substitution effects of the associated scenarios. Any increased demand for gas that higher oil prices would bring would be weakened to the extent that those same oil prices would reduce economic growth. The offset would be even greater if restrictive macroeconomic policies reinforced the aggregate supply effects of higher oil prices. The opposite holds true for lower oil prices: The decline in demand for gas due to lower oil prices would be mitigated by stepped-up economic activity, and the more so as macroeconomic policies pushed economic expansion.

Whether the substitution or the income effects will win out is an empirical question. The experiments in North America during the first two oil-price shocks (1973-74 and 1979-80) were spoiled by coterminous government-induced shortages of natural gas and the related passage of the U.S. Natural Gas Policy Act of 1978. In Western Europe and Japan, one cannot reject the hypothesis that the higher oil prices of the 1970s spurred gas demand, but again the experiments are clouded: by policy favoring diversification in Japan and by the relative infancy of the gas industries in both regions. In the calculations used to generate demand scenarios for the modelling exercise (see Appendix A and Chapter 5), macroeconomic effects outweigh substitution effects in all four of the countries studied in detail.

The relationships just discussed have some interesting applications in several of these countries. In particular, an examination of how they interact with national energy policies yields some interesting results.

OVERVIEW OF NATURAL GAS DEMAND IN WESTERN EUROPE

A Timely Case Study: "Norway's $64 Billion Gas Deal"

On June 3, 1986, Statoil of Norway and a consortium of six natural gas companies in Belgium, France, Germany, and the Netherlands announced a major new contract that the New York Times labelled "Norway's $64 Billion Gas Deal." The contract calls for deliveries of Norwegian gas to the consortium beginning in 1993 and rising by 1998 to peak annual volumes of 20 Bcm. A new pipeline said to cost nearly $3 billion (presumably at 1986 prices and exchange rates) will transport part of the gas from the Sleipner and Troll fields in the Norwegian North Sea to Zeebrugge, Belgium; this pipeline will pass by the Ekofisk field, where it will hook up to an existing pipeline to permit the rest of the gas to be transported to Emden, West Germany. According to various press reports, the deal presumes that an onshore trunk pipeline will be built through France to southern Europe, and Statoil officials also have mentioned the possibility of building a spur pipeline to the United Kingdom.[12]

This contract (which took a year and half to negotiate) highlights many salient features of the Western European gas market in the mid-1980s:

(i) major potential suppliers;

(ii) the complex roles of large supplier-users;

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[12] See, for instance, Wall Street Journal, June 4, 1986, p. 35.

(iii) the existing West German (Ruhrgas) monopsony of access to gas supplies;

(iv) the diversity of national energy policies;

(v) the national security element; and

(vi) notions of what constitutes "stability" in this market.

All these features will affect the course of natural gas demand (as well as supply, contracts, and policy) in Western Europe for the remainder of this century.

The new contract[13] is based on the ability of the Norwegians to supply significant quantities of natural gas to the core industrial countries of Western Europe. In 1985, Norway lost a sizable contract to supply Sleipner gas to the United Kingdom just before it was to have been signed. Under the newly signed contract, the Norwegian government will bear much of the front-end risk of financing the development of gas reserves in the Troll field and of building the new pipeline to Zeebrugge. This is a newly aggressive stance compared with Oslo's previous reticence toward oil and gas development (see Chapter 3).

The new contract also involves the Netherlands and potentially the United Kingdom, both of whom are major gas producers and major consumers. The Netherlands also exports sizable amounts of gas. The Dutch firm, Gasunie, is a member of the buyers' consortium, and (as mentioned) Statoil already is considering extending a spur line from the new pipeline into the United Kingdom.

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[13] Our sources state privately that it is in fact a contract and not just a "letter of agreement" committing both sides to negotiate further. A tentative design and construction schedule already exists. However, the Wall Street Journal recently wrote that ". . . the Norwegian government . . . wants the consortium of buyers, oil companies and governments to approve the contract by year's end . . ." (August 12, 1986; emphasis added).

While much of the public discussion in the two countries has been couched in terms of planning for future supplies when domestic resources "run out," moving Norwegian gas into both countries now in order to displace their own gas south and east in fact could prove very economical. Displacements of this kind have been common for years in the North American and Soviet/Eastern European markets.

The new Norwegian contract raises several interesting questions about the energy policies of some major actors in the Western European gas market. Gaz de France (GdF) was slated to take 8 Bcm annually--40 percent of the 20 Bcm peak volume. Given existing contracts and nuclear power plans, could that volume of gas be sold in French markets? Or, more to the point: Would the gas be priced to fit into the French market, and how would its price affect existing contracts and goals for nuclear power in electric generation? And how much of its gas would GdF have to moved on into Spain, Switzerland, and Italy? If France does boycott the deal, will German, Dutch and Belgium buyers take over its share of the gas in the orgianl deal?

What does the new contract imply about Dutch policy regarding rates of development and export of its gas reserves? Will the Dutch in fact use the Norwegian gas to displace more of its own production into the export market, or will they substitute the imported gas at home and cut back on production? Will the United Kingdom, also a major producer of gas, permit construction of the proposed spur pipeline to its shores and begin exporting its own gas to the continent? Will the prices associated with the new contract force the U.K. government to reconsider both its export and domestic policies toward gas?

Construction of the new trunk pipeline to Zeebrugge would break Ruhrgas's monopsony as gas transshipper in the Western European market.[14] Yet Ruhrgas is a member of the consortium. From what we have been able to gather, the Norwegians insisted on the construction of the trunk pipeline to Zeebrugge, in addition to the connection into Emden. Ruhrgas resisted this until it learned that Statoil also was negotiating separately with Elf Aquitaine to bring the line _only_ to Zeebrugge. The inference might be that Ruhrgas, seeing its monopsony doomed in either event, preferred to be part of the new deal (indeed, in a lead role, taking the same percentage of peak volumes as GdF) rather than sitting on the sidelines.

The national security element in the Western European market was front and center in press coverage of the contract. The _New York Times'_ front-page headline stressed ". . . Cutting Reliance on Soviet Supply." In the _Wall Street Journal_, a lead sentence stated that the contract ". . . reduces Europe's potential long-term energy dependence on the Soviet Union." The _Journal_ went on to quote a "senior Reagan administration official" to the effect that the contract had calmed U.S. fears about Western European reliance on Soviet gas. And _Petroleum Intelligence Weekly_, listing Austria as "among prime candidates for future Troll contracts," noted that country's near 80-percent dependence on Soviet gas.[15]

News accounts also suggested that the Norwegian gas delivered in the core Western European market would carry a security premium compared with Soviet

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[14] One news report cited a Norwegian belief that it has ". . . already lost _possible_ gas sales to Switzerland as a result of high Ruhrgas [pipeline] rates . . ." (emphasis added), _Petroleum Intelligence Weekly_ (PIW), June 9, 1986, p. 2.

[15] _ibid._

gas. Underlying this suggestion, however, is the notion that Norwegian North Sea gas will be "expensive" to produce and transport. This raises the question of what precisely makes Norwegian gas "expensive": resource costs, or taxes and other components of government revenues? West German sources say that price terms in the contract, translated at current values of the formula referents, in fact do work out to be somewhat higher than Soviet gas. But, this raises the further question of which Soviet gas: current "spot" gas? long-term contracted minimum takes? at current formula values? The same sources state that the price of the Norwegian gas also works out to be somewhat less expensive than Groningen gas, on a thermal-equivalent basis. However, volume terms for Groningen gas are the most flexible in the market, and questions similar to those for Soviet gas also arise in this comparison.

In fact, while the idea that the new contract contains a security premium cannot hurt Western European relations with Washington, we are skeptical that any such premium in fact could survive competitive pressures down the road when (and if) deliveries actually begin or, alternatively, that Washington would come up with financial assistance to offset the penalty. Reliance on buyers' willingness to absorb a premium penalty seems a slender reed on which to support several billion dollars of up-front investment in pipeline and other development.

More fundamentally, it is highly speculative to attach prices to the Sleipner-Troll gas, and then to compare those prices with their Soviet or Dutch counterparts. The supply prices of the Norwegian gas, and in turn the economic viability of the entire project, turn on two interrelated variables: the Norwegian government's take, and the disposition of the remainder of Troll's potential supplies. The economics of both wellhead production and pipeline shipment of Troll gas would be much more favorable if all of it could be sold, not just the 25 percent involved in the new contract. In fact, without substantial further sales out of Troll, the project probably will not go forward.[16] Calculations by Adelman and Lynch (see Chapter 3) suggest that Troll gas will offer a good rate of return at a wellhead price below $2.00/Mcf--but this assumes development and transportation of the entire reserves of the field, not just 25 percent of them.

A Wall Street Journal header on June 4, 1986 (p. 35) asserted that the new contract "Will Stabilize Western European Market." By "stabilize" the Journal meant the security blanket of the old, familiar long-term contract. Given today's energy-market conditions, that time-honored institution is obsolete; attempting to use it is likely to leave one or another party to the contract unhappy.[17] Moreover, appearances are deceiving: While the Norwegian contract is multi-year and contains provisions that govern its entire term, it almost certainly is not a long-term gas contract in the old sense. Evidently, the price terms--the formula itself--may be reopened at the option of either side every four years. In addition, the quantity terms appear to be renegotiable and to contain provisions for market-outs in case of "hardship." If this is true, the locus of interest turns on how the project is financed, particularly regarding the development of Troll reserves and the construction of the new pipeline to Zeebrugge. Statoil, with help from the Norwegian Ministry of Finance, will finance the pipeline. The private producer participants in

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[16] See Wall Street Journal, August 12, 1986, p. 32.

[17] This theme was very much present in the two earlier reports of this project.

Troll, who will have to outlay substantial capital to develop the reserves, have raised serious questions about the viability of the new contract.[18] The pricing package includes cuts in taxes, in royalty oil payments by producing companies, and in the companies' obligations to pay the government's share of exploration costs. Such provisions confirm the suspicion that earlier estimates of the "high costs" of Norway's North Sea petroleum production contained significant economic rents.

The announcement of the Norwegian contract was surprising to many because of the widespread impression that the Western European gas market (like others around the world) faces excess supplies, based on existing contractual commitments, that should last well into the future. And yet here is a contract for new supplies, with a peak contract volume equal to a third or more of current gas imports (both pipeline and LNG) into Western Europe. These facts make the new contract seem more destabilizing than otherwise. Where will all that gas go in France and in the other three countries who are parties to the deal?

"Excess supplies" cannot be defined, of course, without reference to prices. As in North America and the Pacific Basin, the realization slowly has dawned in Western Europe that the prices embodied in gas contracts signed in the mid- and late-1970s are not sustainable. That is to say, insistence on adhering to the price terms of many of those contracts would precipitate breachers of contract, defaults, and bankruptcies. Realism therefore dictates that actual transaction prices for natural gas be lower than those thought reasonable several years ago. These lower prices will help clear up "excess supplies."

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[18] Wall Street Journal, op.cit., p. 32.

But even with lower price terms, the Norwegian contract still looks risky, particularly if real oil prices remain in their present range ($12-15/bbl).[19] A more dynamic interpretation is required to comprehend fully the broader implications of the contract. The Norwegian deal must be seen as a bold (if risky) attempt to change expectations about the future availability of gas in Western Europe. As suggested earlier, a strategic shift of this sort could increase the demand for gas over the long run through its effects on investors' expectations about both the price and the supply security of natural gas in Western European markets.

Media reports have made much of the "strategic" importance of the Norwegian contract. It would establish Norway as a major gas supplier throughout the core Western European market, as well as provide it with access to several peripheral markets. As noted above, the new pipeline to Zeebrugge would break Ruhrgas's monopsony on transshipment in the region and, through France, open up a second major trunk pipeline system in the core market. In turn, this new pipeline configuration would give Norway access to the Austrian, Spanish, and Italian markets. Indeed, the capacity of the proposed pipeline to Zeebrugge would be larger than that required to fulfill just the deliveries envisioned in this contract.[20]

If this interpretation is correct, "Norway's $64 Billion Gas Deal" could be just the sort of stroke that we found the Canadians contemplating in North America and that we argued Japan should consider.

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[19] Recent reports suggest that the Norwegian calculations for the project require minimum oil prices of about $20 per barrel (ibid.)

[20] One news report puts total annual capacity for the pipeline at 46 Bcm, split 25-21 between Zeebrugge and Emden. See PIW, June 9, 1986, p. 2.

The Current Western European Pattern of Gas Use

As noted, there really are no "typical" Western European patterns of gas consumption. This holds true also for overall primary energy use and for the structure of gas use itself. In 1984 the shares of the various sources of primary energy in Western Europe as a whole, in the four countries examined in detail, and in the Netherlands, are shown in Panel (a), and the pattern of gas use by major sector in 1983 is presented in Panel (b). Again excluding the Netherlands, the noteworthy features of these panels include:

(1) the relatively large share of gas devoted to residential/commercial use in the United Kingdom;

(2) the relatively small share in the same sector in West Germany; and

(3) the relatively large shares of gas used to generate electricity in Italy and West Germany.

Finally, Panel (c) shows the diversity across Western Europe in the percentage share of total energy consumption occupied by natural gas, in 1983, in the following sectors: (a) industry; (b) residential/commercial; (c) total fossil fuels used to generate electricity; (d) total electric power generated in "conventional thermal" plants; and (c) total electric power generated.

Western Europe is sufficiently small and economically compact that the major gas resources of the Netherlands and the United Kingdom[21] alone could support quite uniform development of the gas industry throughout the entire region. However, as noted earlier, political barriers, reflecting nationalistic energy policies, prevented this development. The "haves" (in terms of

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[21] Norway is an exception to the analysis in this paragraph. The reasons include its much lower population density and its relatively low degree of industrialization, compared to the nations in the industrial heartland of Western Europe.

Panel (a)

PRIMARY ENERGY USE, BY ENERGY SOURCE, 1984
(millions of metric tons of oil equivalent [mtoe])

	Total	Nat. Gas	Oil	Coal	Hydro	Nuclear
W. Europe:	1,249.4 (100%)	190.1 (15.2%)	591.0 (47.3%)	256.7 (20.5%)	107.0 (8.6%)	104.6 (8.4%)
France:	187.0 (100%)	23.5 (12.6%)	86.2 (46.1%)	25.2 (13.5%)	13.7 (7.3%)	38.4 (20.5%)
Italy:	140.2 (100%)	26.5 (18.9%)	84.7 (60.4%)	15.3 (10.9%)	11.3 (8.1%)	2.4 (1.7%)
U.K.:	191.9 (100%)	45.2 (23.6%)	88.7 (46.2%)	45.3 (23.6%)	1.2 (0.5%)	11.5 (6.0%)
W.Germany:	260.9 (100%)	41.1 (15.8%)	110.9 (42.5%)	83.3 (31.9%)	4.7 (1.8%)	20.9 (7.9%)
Neths.:	66.7 (100%)	31.2 (46.8%)	28.9 (43.3%)	5.7 (8.5%)	0.0 (0%)	0.9 (1.3%)

SOURCE: BP Review of World Gas, London, England, August 1985, p. 2.

Panel (b)

GAS USE BY MAJOR SECTOR, 1983
(billion cubic meters [Bcm])[a]

	Total[b]	Industry	Res./Comml. et al.[c]	Elec. Gen.	Misc.[d]
W. Europe:	197.6 (100%)	69.6 (35.2%)	91.4 (46.3%)	26.3 (13.3%)	10.0 (5.0%)
France:	25.7 (100%)	11.3 (44.0%)	12.5 (48.6%)	1.0 (3.9%)	1.8 (7.0%)
Italy:	25.6 (100%)	10.4 (40.6%)	11.4 (44.5%)	3.4 (13.3%)	0.4 (1.6%)
U.K.:	48.5 (100%)	14.8 (30.5%)	28.9 (59.6%)	0.4 (0.8%)	4.4 (9.1%)
W.Germany:	44.0 (100%)	16.4 (37.3%)	16.3 37.0%)	8.8 (20.0%)	2.4 (5.5%)
Neths.:	33.4 (100%)	9.11 (27.2%)	15.2 (45.6%)	8.3 (24.9%)	0.7 (2.1%)

Notes: a. Totals may not equal sum of components due to slight errors in converting from mtoe to Bcm.
b. = domestic production + net imports + net stock reductions.
c. Also includes agriculture, public service, and "other (non-specified)". Whenever the last category is of any magnitude, it covers mainly residential or commercial uses.
d. = returns and transfers + statistical differences + manufactured gases + petroleum refineries + own use and losses (all net).

SOURCE: OECD, Energy Balances of OECD Coluntries, 1982/83, Paris, France, 1985.

Panel (c)

PERCENTAGE SHARE OF NATURAL GAS IN TOTAL SECTORAL ENERGY CONSUMPTION, 1983

	Industry	Res./Comml. et al.[a]	Fossil Fuels Used in Elec. Gen.	"Conventional Thermal" Elec. Power Gen'd.	Total Elec. Power Gen'd.
W. Europe:	24.6%	32.8%	14.4%	15.2%	9.5%
France:	21.9	23.3	4.5	6.1	1.7
Italy:	24.8	30.5	10.6	10.5	7.5
U.K.:	31.7	47.4	0.7	0.6	0.5
W. Germany:	21.7	20.4	11.2	12.7	9.9
Neths :	46.3	71.5	61.8	61.9	58.2

Notes: a. Also includes agriculture, public service, and "other (non-specified)." Whenever the last category is of any magnitude, it covers mainly residential or commercial uses.

SOURCE: OECD, Energy Balances of OECD Countries, 1982/83, Paris, France, 1985.

natural gas resources) elected to expand intensively their domestic consumption of gas through subsidies, rather than to export their gas to the highest bidders. Even the Dutch, who for year have exported natural gas as far as Italy, have overdeveloped domestic consumption of gas relative to what they would have done had their policy been to maximize the economic present value of their gas resources.

The energy policies of the have-nots also help to explain the diversity of natural gas use across Western Europe. For example, France has concentrated on developing nuclear power as the major basis for electricity production. Belgium also has stressed nuclear power, as has West Germany, although to a lesser degree.

For internal political reasons, West Germany and the United Kingdom long have subsidized their domestic coal industries. The retarding effect of this on the development of natural gas use has been greater in West Germany than in the United Kingdom, partly because the latter also promoted the development of domestic gas resources. In addition, though, the United Kingdom has had to deal with air pollution problems related to the widespread use of coal in the residential sector; in contrast, West Germany has pushed the use of its domestic coal mainly in industry and electric generation. And in Italy, which lacks major domestic resources of either fuel, the move to natural gas began only after the oil-price shock of 1973-74. The noteworthy feature of Italian energy policy is the practice of assigning dominant positions in energy markets to huge, state-run enterprises: ENI in oil and SNAM in natural gas.

Finally, note the sizable variations in energy pricing policies among the various countries. These variations derive from differences in taxation and subsidy practices and in contract terms (e.g., the linkage of gas to oil product prices). The details of certain of these pricing policies are described below.

Macroeconomic Policies and Economic Growth

As mentioned earlier, macroeconomic policies are important determinants of natural gas demand, because of their impacts on economic growth. Since the oil-price shock of 1973-74, economic growth in Western Europe has been pallid compared with that of the 1950s and 1960s. For the 1973-83 period, the OECD gives an average annual growth rate of real GNP of about 2.2 percent. Unemployment rates persistently have run double what they were before the slowdown.

The relevant question here is whether this pattern will change, and (if so) when. A common view is that the confluence of higher oil prices and increasing structural defects in Western European labor markets in the 1970s raised fears of escalating inflation among Western European governments and discouraged them from adopting expansionary macroeconomic policies. By this same view, the declines in oil prices, in interest rates, and in the value of the U.S. dollar since late 1985 should give these governments enough slack in terms of aggregate supply that they can afford to pursue more expansionary fiscal and monetary policies. This holds true even without structural reforms in labor and goods markets (like those now mooted in France by Premier Chirac).[22] Oil prices (and expectations) at about $8/bbl, as in scenario (2) above, would reinforce this point.

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[22] See *ibid*.

We cannot predict what macroeconomic policies the various Western European governments will pursue. The important point is that, for two of the oil-price scenarios discussed earlier--(2) low ("competitive oil market") and (3) variable ("weak cartel")--Western European governments could pursue more expansionary policies than they have recently with less fear of rekindling unacceptable rates of inflation.

Some Demand Forecasts

Table 4-1 summarizes three recent, independent forecasts of natural gas demand in Western Europe. We present them to illustrate several points about such forecasts, and because in part they form the basis for the demand scenarios analyzed in Chapter 5. The first point is that forecasts have half-lives approaching those of subatomic particles. Another point is that basic underlying assumptions are the all-important ingredient in any forecast.[23] Third, one forecast rarely agrees with another.

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[23] Accordingly, before commenting on the three forecasts in Table 1, we should briefly list the assumptions that underlie them.

"Roland" refers to a forecast from a 1984 working paper by Kjell Roland, "Natural Gas Supply and Demand in Western Europe, 1990 and 2000," manuscript, Stanford Energy Modelling Forum, Stanford, California, February 1984, p. 5. For economic growth rates, "Roland" assumes an average annual increase in GDP of 2.5 percent from 1983 onward. The rates for France and West Germany average 3 percent a year in 1983-85 and then decline to the regional average; the United Kingdom experiences growth rates of half a point less than the region as a whole. Income elasticities of gas demand are assumed to range from 0.7 to 0.9 except for the Netherlands, which has a "significantly lower elasticity" (ibid., p. 4). Relative fuel prices "are not drastically changed," including incentives in the United Kingdom for "continuing substitution of gas for crude oil and to some extent for coal." [This last assumption is no longer valid.] Real crude oil prices fall during the late 1980s but then increase at 1-1.5 percent per year through 2000.

"IGU" refers to projections of "potential economic demand" reported in International Gas Union, Report of Task Force: World Gas Supply and Demand, 1983-2020, no date or place of publication available, 1985, p. 23. "The potential gas demand figures are central estimates ... Actual gas demand . . . is more likely to be below the . . . potential [figures] . . . than above them" (ibid., p. 22).

Table 4-1

FORECASTS OF WEST EUROPEAN GAS DEMAND

	"Current" Use			FORECAST				
				1990		2000		2010
Roland (1984)	(1982)	212 Bcm		236-252 Bcm		276-307 Bcm		N.A.
AAPC:*			1.35-2.18%		1.6-2.0%			
IGU (1985)	(1983)	203 Bcm		240 Bcm		261 Bcm		271 Bcm
AAPC:*			2.4%		0.85%		0.4%	
I.E.A. (1986)	(1984)	212 Bcm		(a):224 Bcm		248 Bcm		258 Bcm
				(b):244 Bcm		280 Bcm		305 Bcm
AAPC:*			(a):0.9%		1.0%		0.4%	
			(b):2.4%		1.4%		0.85%	

(a) = "Low Growth/High Oil Price"

(b) = "High Growth/Low Oil price"

*Average Annual Percentage Change Between Years.

The "Roland" forecast dates from 1984 and therefore may be forgiven for failing to predict such imponderables as the steep, post-1985 decline in oil prices. Roland and his colleagues also did not foresee the change in U.K. gas pricing policy that has accompanied the "privatization" of the British Gas Corporation (BGC); thus, their figures for the United Kingdom may be too high. The "Roland" projections also underestimated the growth of gas use in Italy, which surpassed their 1990 figure in 1984.

The IEA's 1986 "illustrative projections" update its 1982 forecast, which foresaw substantially greater future gas use than do these later figures. The IEA's earlier forecasts came under fire because actual figures have lagged behind those forecast.[24] In fairness, it should be pointed out that, since the early 1980s, the trimming of demand growth estimates for natural gas (and for other forms of energy) has taken place worldwide. The 1986 IEA report is a near-model of circumspection and balance.

(continued)

"IEA" refers to "illustrative projections" given in OECD/IEA, Natural Gas Prospects, op.cit., pp. 57ff. and 123. According to Appendix I, pp. 119-21, the two sets of estimates are both based on declining real oil prices until 1990, then a steady increase indefinitely thereafter; case (b) assumes a more rapid rate of increase than does case (a)--e.g., $45/bbl versus $30/bbl in 2000 (1984$). Economic growth rates in cases (a) and (b) are assumed to be 3.5 percent and 2.5 percent annually, respectively, over the period 1983-2010. U.S. dollar exchange rates are assumed to revert to 1983 levels from those of 1984-85. Perhaps most significant, the IEA forecasts assume that the ratio of burner-tip gas prices to oil prices remains the same as in early 1985 throughout the forecast period.

24 See, for example, Energy Advice, Energy Supplies and Prices in Western Europe to the Year 2000, place of publication not available, 1985. This document can serve as a caution to the arrogant among oil-price forecasters: "Once the realization of oil as a 'permanent' high-cost commodity dawned, ..."

The IGU's 1985 forecasts of "potential economic demand" for gas over the next 35 years are based on much less explicit assumptions about growth and oil prices than the other two studies. In fact, they derive from a survey of IGU members who are gas users.

Appendix A describes the methodology used to derive the gas demand figures that were fed into the dynamic programming model (discussed in Chapter 5) as part of this study. These figures are not "estimates" of Western European gas demand, much less "forecasts." Rather, they are the product of postulated macroeconomic growth rates that generate total energy demands, coupled with a price-based rule for choosing the share of gas in total energy demand, for each of the four countries discussed in detail below. Thus, they merely are illustrative of how different macroeconomic and gas-choice assumptions _may_ affect future gas demand. The various demand trajectories actually used in the model runs are not strikingly different from the forecasts just discussed.

Peripheral Areas Affecting the Western European Gas Market

Before turning to the four countries, a few words are in order about other areas that affect the Western European gas market but to which this chapter does not otherwise give detailed attention.

The first is the Benelux countries: Belgium, the Netherlands, and Luxemburg. The dominant gas-using member of the group is the Netherlands, which accounts for about 80 percent of total Benelux gas use and commonly is viewed (with reason ... see earlier Tables) as having a "saturated" gas market that leaves little room for future demand growth (except through economic growth.) Belgium accounts for most of the remaining 20 percent and has some potential to expand use in its residential/commercial and industrial sectors; further, it currently uses very little gas in the electric generation sector. However, even with a significant rate of economic growth, total Belgian gas consumption would not be large enough to affect the market significantly.

The second peripheral area is a polyglot of smaller countries: Switzerland, Austria, and Spain. Spain has considerable potential for future growth in gas demand. Its total energy use is 20 to 25 percent greater than that of the Netherlands, and its economy is still less industrialized than the countries to its north. At present, only LNG is available in Spain, but the recent Norwegian contract may change that fact by the mid-1990s. Switzerland can tap into gas flows in any direction between France, Italy, and Germany. Swiss purchases improve the economics of pipeline capacity, but the relatively small size of its demand levels limits its impact on the overall market. The same holds true for Austria, which is able to tap into Soviet gas entering Central Europe. Its total energy demand being of roughly the same magnitude as Switzerland's, Austria's impact on the overall market also is limited.

The third peripheral area is Communist Eastern Europe. Although gas demand in this region would make a fascinating story by itself, here it is of interest primarily as a possible competitor for Soviet gas supplies to Western Europe. As suggested in Chapter 3, competition is apt to be mainly short term (e.g., due to periods of severely cold weather or during a breakdown in the Soviet supply mechanism). The Soviet supply picture (discussed in detail in Chapter 3) suggests that, in the long term, Eastern Europe will not be an effective constraint on exports to Western Europe, especially considering Soviet needs to obtain hard currency.

DETAILED DEMAND ANALYSES OF FOUR COUNTRIES

This section discusses the prospects for natural gas demand in the four countries--France, Italy, the United Kingdom, and West Germany--that seem most likely to shape future demand in Western Europe. As argued earlier, world oil prices, economic growth, and gas pricing will drive the demand for gas in these countries. However, differences in national energy policies also are important.

France

France consumed 31.0 Bcm of natural gas in 1985, or 11.7 percent of its total energy consumption. In 1985, domestic production provided 5.4 Bcm and imports 25.6 Bcm, up from 23.5 Bcm in 1984. Sources of imports in 1984 were as follows:[25] Algeria, 9.0 Bcm; the Netherlands, 7.3 Bcm; the Soviet Union, 4.9 Bcm; and Norway, 2.3 Bcm.

Natural gas currently meets just under one-quarter of total energy demand in the residential and commercial sectors, and just under one-fifth of demand in the industrial sector.[26] In the electric generation sector, however, the share of gas is a mere 1 percent. These shares are the lowest of the four countries discussed.

It is the stated intention of the French government to phase out gas in the generation of electricity by 1990 in favor of nuclear power. Nuclear

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[25] CEDIGAZ, "Natural Gas in the World, 1985," Centre International d'Information sur le Gaz Natural et tous Hydrocarbures Gaseux, Paris, France, 1986; and British Petroleum PLC, "Review of World Gas," London, England, August 1985, Table 12.

[26] DRI Europe, The Outlook for Natural Gas in Western Europe, 1985-2000, London, England, November 1985.

power now accounts for nearly one-half of French electricity production,[27] and by 1990 it is targeted to provide some three-quarters (see Table 4-2).

The French pro-nuclear program began in the 1970s with what were plausibly economic-efficiency motives, given perceptions and expectations at the time. The large state-run utility, Electricite de France (EdF), succeeded in expanding nuclear generating capacity, backing out now-dearer oil, and contributing to the modernization of French agriculture and industry.

However, lagging demand growth--not unique to France--has left EdF with excess capacity. The responses to this have been bureaucratic, not economic. Government-subsidized rates to spur electricity use effectively have given EdF a fiscal role, not only in producing electricity but also in shaping the distribution of income. This has added bureaucratic to economic obstacles to natural gas's penetration of the electric generation sector. Natural gas also faces competition from subsidized electric power in the residential, commercial, and industrial sectors.

Despite this, however, gas use has increased steadily in the residential and commercial sectors, from 5.8 Mtoe in 1974 to 11.1 Mtoe in 1983. In the industrial sector, it has increased some two-thirds over 1974 levels (see Table 4-3). The combined share of gas from these three sectors is about the same as that of the electric generation sector. However, the use of electricity is slated to expand (largely at the expense of oil; their shares of total final energy consumption in 1983 were 44 and 39 percent, respectively) far more rapidly than natural gas. The drop in oil prices since late 1985 may

[27] Financial Times Energy Economist, "World Status: Electricity," Issue 45, London, England, July 1985.

Table 4-2

FRENCH ELECTRICITY CAPACITY & GENERATION

1983

	Capacity (GW)	Production (TWh)	% of Production
Nuclear	25.5	125	47
Hydro	19.9	66	25
Coal, etc.	30.7	76	28
TOTAL	76.1	267	

1990

	Capacity (GW)	Production (TWh)	% of Production
Nuclear	56.0	273	74
Hydro	26.1	69	18
Coal, etc.	27.8	31	8
TOTAL	110.9	373	

Source: Edf.

Table 4-3

	1983 (MTOE)	%Demand	1982	%Demand	1980	%Demand	1977	%Demand	1974	%Demand
FRANCE GAS										
ENERGY BALANCE										
PRODUCTION	5.69		5.63		6.33		6.56		6.49	
IMPORTS	19.33		16.67		16.61		12.84		9.3	
SUM SUPPLY	25.02		22.3		22.94		19.4		15.79	
SUM DEMA.	25.02	1	22.32	1	22.94	1	19.43	1	15.8	1
EXPORTS	0.13	0.01	0.12	0.01	0.13	0.01	0.15	0.01	0.12	0.01
STK CHNGES	2.04	0.08	0.68	0.03	0.88	0.04	1.28	0.07	1.26	0.08
MAN GASES	0.11	0.00	0.08	0.00	0	0.00	-0.11	-0.01	-0.36	-0.02
OWN & LOSS	0.58	0.02	0.28	0.01	0.61	0.03	0.59	0.03	0.63	0.04
ELEC. GEN	0.91	0.04	1.05	0.05	0.97	0.04	1.76	0.09	2.27	0.14
SUM INDUST.	10.12	0.40	9.73	0.44	10.16	0.44	8.17	0.42	6.1	0.39
IRN & STL	1.01		1.01		1.57		1.22		1.06	
CHEMS	4.28	FEED STCKS	4.05		5.99		3.4		2.29	
N FER MTLS	0.09		0.08		0.06		0.07		0.05	
N MET MINS	1.32		1.35		1.15		1.47		1.17	
TRANS	0		0		0		0		0	
MACHINERY	1.34		1.36		0		0		0	
MIN & Q	0.2		0.19		0.23		0.2		0.19	
FD & TOB	0.66		0.59		0.43		0.27		0.2	
PPP	0.44		0.4		0.31		0.15		0.19	
WOOD	0		0		0		0		0	
CONSTR	0		0		0		0		0	
TEXT	0.18		0.16		0		0.09		0.07	
OTHER	0.6		0.54		0.42		1.3		0.88	
SUM TRANS	0	0.00	0	0.00	0	0.00	0	0.00	0.01	0.00
SUM ALL OTH	11.13	0.44	10.38	0.47	10.19	0.44	7.59	0.39	5.77	0.37
AGRI	0		0		0		0		0	
COMMERCE	5.07		4.66		4.39		3.18		2.08	
PUB SERVS	0		0		0		0		0	
RES	6.06		5.72		5.8		4.41		3.69	
OTHER	0		0		0		0		0	

alter these plans but, given the excess capacity in electricity generation, probably by retarding the back-out of oil rather than by increasing gas use.

As shown in Table 4-4, GdF sets gas prices according to category of end use: "domestic" or household (which includes so-called "collective heating"), commercial, and industrial. In addition to prices set by GdF, the consumer also pays a value-added tax (VAT), which is deductible against income tax (in the case of commercial and industrial users, at a rate of 18.6 percent in 1983-84). Residential and commercial customers all pay essentially the same price; there are few geographic differences. In contrast, prices to industrial customers reflect geographic location, a monthly demand charge, and a commodity charge that varies with the quantity taken. Table 4-5 provides examples of gas prices paid by residential/commercial and industrial consumers in the Paris region from 1978 to 1984.

Given all this, the price of oil should have little effect on gas demand in France--probably the least effect of the four countries examined here. If oil prices are high, the nuclear commitment will look good, and if they are low, the nuclear commitment will look bad. However, the use of nuclear power is so central to French energy policy that additional penetration by gas may be modest at best, regardless of oil-price expectations. Barring serious problems with further development of the nuclear industry--worse, apparently, than the political effects of the Chernobyl accident--the central question about French gas demand is whether France's gas industry can maintain its present shares in the non-electric markets. The recent 23 percent cut in industrial gas prices suggests that GdF is aware of this problem.[28]

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[28] International Gas Report, no. 53, April 11, 1986.

Table 4-4

FRANCE: CONSUMER TARIFF GROUPS AND PERCENT OF GAS SALES TO GROUP

		1980	1981	1982	1983
	Domestic Users:				
1.	Heating Tariffs	26.8	26.6	27.1	27.3
2.	Other Tariffs	4.9	4.5	4.5	4.8
3.	Collective Heating	9.9	10.0	10.6	11.0
4.	Commercial Users	15.0	14.4	15.0	15.3
5.	Industrial Users	43.4	44.6	42.8	41.6
	TOTAL	100.0	100.0	100.0	100.0

Source: European Economic Community publication, Eurostat, Gas Prices 1978-1984.

Table 4-5

FRANCE: EXAMPLE DOMESTIC & INDUSTRIAL CONSUMER PRICE (PARIS AREA)

Domestic (Annual Consumption 8.4 GJ per customer) FF/GJ

		Taxes Included	Excl. Taxes
January	1978	48.7	41.4
	1979	53.6	45.6
	1980	67.9	57.7
	1981	76.8	65.3
	1982	90.8	77.2
	1983	100.3	84.6
	1984	107.6	90.7

Industrial (Annual Consumption 419 GJ per customer) FF/GJ

		Taxes Included	Excl. Taxes
January	1978	19.8	16.9
	1979	21.6	18.3
	1980	30.2	25.7
	1981	35.7	30.4
	1982	46.6	39.6
	1983	51.9	43.7
	1984	56.5	47.6

GJ = gigajoules.

Source: EEC, Eurostat, Gas Prices 1978-84.

Italy

In 1985, Italy consumed 33.4 Bcm of natural gas, or 17.4 percent of its total energy consumption. In 1984, domestic production accounted for 13.7 Bcm, and imports for 19.7 Bcm. Sources of imports in 1984 were as follows: the Soviet Union, 8.2 Bcm; Algeria, 6.3 Bcm; and the Netherlands, 5.2 Bcm.[29]

In the past decade, Italy has increased natural gas as a percentage of its total energy consumption, reflecting the government's desire to reduce dependence on imported oil. Gas use in the electric generation sector has more than trebled (see Table 4-6), although the share of gas inn total electric power generated is still below the Western European average. Nevertheless, current policy envisions reducing the share of gas in electric generationt to 8.9 percent in 1990, and further to 6.1 percent in 1995.[30]

The most important aspect of Italian gas use is its regionality. In both the residential/commercial and the industrial sectors, SNAM (the state-owned gas production and import corporation) currently supplies over 80 percent of total delivered gas to the more economically developed northern and central regions. However, SNAM recently has publicly expressed interest in connecting new residential/commercial customers in the less-developed south, although demand forecasts for this region suggest this still would constitute only 25 percent of total energy demand in this sector.[31] Although natural gas is accessible to nearly three-quarters of all residences in the northern region,

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[29] CEDIGAZ, op.cit.

[30] Financial Times, "International Gas Report," No. 29, London, England, April 26, 1985, p. 3.

[31] SNAM S.P.A. (ENI Group), "Natural Gas Development Program, 1984-87," Milan, Italy, 1985.

Table 4-6

	1983 (MTOE)	%Demand	1982	%Demand	1980	%Demand	1977	%Demand	1974	%Demand
ITALY GAS										
ENERGY BALANCE										
PRODUCTION	10.79		12.03	10.46	11.53		12.83			
IMPORTS	12.34		11.25	11.99	10.84		3.48			
SUM SUPPLY	23.13		23.28	22.45	22.37		16.31			
SUM DEMA.	23.25	1	23.31	1	22.5	1	22.35	1	16.33	1
EXPORTS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
STK CHNGES	0.33	0.01	1.13	0.05	-0.62	-0.03	0	0.00	0.04	0.00
MAN GASES	0.03	0.00	-0.12	-0.01	0.03	0.00	-0.04	0.00	-0.07	0.00
OWN & LOSS	0.28	0.01	0.3	0.01	0.25	0.01	0.31	0.01	0.35	0.02
ELEC. GEN	3.02	0.13	2.69	0.12	2.02	0.09	3.21	0.14	0.93	0.06
SUM INDUST.	9.24	0.40	9.54	0.41	11.45	0.51	11.41	0.51	9.97	0.61
IRN & STL	1.5		1.72		2.05		1.65		2.15	
CHEMS	2.75	FEED STCKS 1.5	2.5		3.13		3.48		3.2	
N FER MTLS	0.12		0.13		0.13		0.1		0	
N MET MIN	2.51		2.77		3.35		3.32		0.07	
TRANS	0		0		0		0		2.61	
MACHINERY	0.72		0.74		0.89		0.79		0	
MIN & Q	0.01		0.01		0.04		0.06		0.65	
FD & TOB	0.7		0.7		0.75		0.61		0.05	
PPP	0.3		0.37	0.45	0.39		0.45			
WOOD	0		0		0		0		0.34	
CONSTR	0		0		0		0		0	
TEXT	0.4		0.39		0		0		0	
OTHER	0.18		0.21	0.66	1.01		0.45			
SUM TRANS	0.26	0.01	0.26	0.01	0.26	0.01	0.3	0.01	0.18	0.01
SUM ALL OTH	10.15	0.44	9.51	0.41	9.11	0.40	7.16	0.32	4.93	0.30
AGRI	0.01		0.01		0.01		0		0	
COMMERCE	9.72				9.07		0		0	
PUB SERVS	0		0		0		0		0	
RES	0.42		0.43		9.1		7.16		4.93	
OTHER	0		0		0		0		0	
SOURCE OF OEC										

growth potential has not been exhausted. SNAM's gas development plan (see Table 4-7) involves 580 communes, more than half of which are northern communes planned to be connected to the existing grid. This of course conflicts with SNAM's public statements, which emphasize the connection of new consumers in the south.

SNAM's forecasts for 1990 put residential consumption in the north and central regions at 12.4 Bcm, compared with 9 Bcm in 1982. SNAM expects that by the end of 1986, 40 percent of southern households will have end-use capacity.

By contrast, gas use in electric generation is greater in the south than in the north (currently 1.7 and 1.1 Bcm, respectively). Demand in 1990 is forecast to reach 2.4 and 2.6 Bcm, respectively. However, as stated above, the government ultimately wishes to reduce the share of gas in electric generation.

The story is similar in the industrial sector. Despite massive state aid, the southern region has a very thin industrial base. Given this fact, there is considerable doubt associated with any demand forecast for this region. However, SNAM's objective is to raise the number of large commercial users in the south from 83 in 1982 to 522 in 1990.

Total natural gas consumption in Italy rose considerably more than SNAM had forecast from 1983 to 1984, by 17.1 percent to 32 Bcm (residential & commercial sector, 7.4 percent; electric generation sector, 82.8 percent). The residential/commercial sector accounted for 40.7 of total gas use;[32] elec-

[32] Financial Times, "International Gas Report," no. 33, London, England, June 21, 1985, p. 16.

Table 4-7

	1982	1983	1984	1985	1990	
NATURAL GAS CONSUMPTION BCM						
ESTIMATE	26	26.7	31.5	33	37.5-39.5	
SNAM'S DIRECT CUSTOMERS						
	North & Center 1982	1990	South 1982	1990	Total Italy 1982	1990
RESIDENTIAL						
COMMERCIAL	1646	2064	83	522	1729	2586
INDUSTRIAL	2479	3460	364	920	2843	4380
PETROCHEMICAL	17	17	5	7	22	24
TRANSPORT	127	170	5	50	132	220
ELECTRICITY	9	9	4	7	13	16
TOTAL	4278	5720	461	1506	4739	7226
NATURAL GAS SALES BCM						
RESIDENTIAL						
COMMERCIAL	11	15.6	0.4	1.3	11.4	17
INDUSTRIAL						
CHEMICAL						
TRANSPORT	9.5	12.5-13.3	2.3	3.5-3.7	11.8	16.0-17.0
ELECTRICITY	1.1	2.3-3.9	1.7	2.2-2.6	2.8	4.5-5.5
TOTAL		30.5-31.9	4.4	70-76	26	37.5-39.5
POTENTIAL HOUSEHOLD MARKET FOR GAS						
MILLION FAMILIES	9.1	11.1	1.6	3.8	10.7	14.9
HOUSEHOLD GAS SALES BCM						
COOKING	0.8	1	0.1	0.3	0.9	1.3
WATER HEATING	1	1.3	0	0.2	1	1.5
SPACE HEATING	7.2	10.1	0.3	0.7	7.5	10.8
TOTAL	9	12.4	0.4	1.2	9.4	13.6
SOURCE SNAM						

Table 4-8

TOTAL POPULATION IN MEZZOGIORNO
SERVED BY GAS

REGION	COMMUNES SERVED BY GAS		%POPULATION SERVED	
	MARCH '81	MARCH '85	MARCH '81	MARCH '85
MARCHES	2	10	49.5	74.5
MATIUM	12	18	26.2	38.2
ABRUZZO	30	58	52	61.7
MOLISE	10	14	41.5	46.1
CAMPANIA	16	23	39	42.4
APULIA	16	27	29.5	34.7
BASTILICATA	3	7	19.4	25
CALABRIA	3	6	9	15.1
SICILY	1	7	7.7	16.1
TOTAL	93	170	25.8	32.3

SOURCE SNAM

tricity generation 18 percent; and industry 30 percent. This unexpected increase in demand appears to be due in part to pricing issues.

Prices in Italy are determined at two levels. First, SNAM determines prices for primary distribution in conjunction with local utilities and Cofindustria (the association representing large private users). Second, local utilities impose a tariff, which is determined by negotiations between the distributor and the Interministerial Price Committee. Table 4-9 shows 1982 gas sales patterns.

The number of consumers served by distributors is much greater than those served directly by SNAM: in 1983, 8,600,000 and 4,851, respectively.[33] To understand Italian end-user prices, it is important to realize that VAT rates vary with consumer type. VAT rates have varied over the last few years; more recently, the fixed primary distribution tariff has been some 6 percent of the total price. This is linked to inflation indices and is reviewed annually. A variable component is tied to the end-user price of #2 heating gasoil. This additional tariff is designed to give the local utilities a "fair rate of return." These tariffs vary from city to city and depend on the different costs each utility faces for gas purchases, investment, labor, maintenance, and general expenses. Also, different residential consumers are subject to different tariffs, depending on which of three use categories they fall into: cooking and water heating, individual space heating, and grouped central heating. Table 4-10 shows sample prices for consumers in the residential/commercial and industrial sectors.

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[33] Eurostat, EEC, Luxembourg, "Gas Prices, 1978-84," Italy, p. 47.

Table 4-9

ITALY: PATTERN OF GAS SALES, 1982

(1) SNAM DIRECT SALES: 57%

Of which:	Power Stations	38.5%
	Chemicals	7.0%
	Motor Fuel	1.0%

(2) SALES VIA DISTRIBUTORS: 43%

Of which:	Small Domestic Consumers	10.0%
	Individual Central Heating	17.0%
	Collective Heating	8.0%
	Non-Domestic Users	8.0%

SOURCE: EEC

Table 4-10

ITALY: EXAMPLE DOMESTIC AND INDUSTRIAL CONSUMER PRICES (ROME AREA)

<u>Domestic</u> (Annual Consumption: 8.4 GJ) LIT/GJ

	Taxes Included	Excl. Taxes
January 1978	5064	3989
1979	4504	3461
1980	6763	5421
1981	11759	10099
1982	12519	10804
1983	17754	15484
1984	20026	17754

<u>Industrial</u> (Annual Consumption: 419 GJ)

	Taxes Included	Excl. Taxes
January 1978	3965	3478
1979	3125	2741
1980	6134	5381
1981	9034	7856
1982	9844	8560
1983	12780	10830
1984	14475	12267

Source: EEC, <u>Eurostat</u>, Gas Prices, 1978-84.

The point to be made from the foregoing discussion is that gas prices in Italy vary considerably from customer to customer. For example, net of VAT, the domestic user in Rome paid approximately $0.340/cubic meter in 1984 versus $0.295 in Milan (or about 15 percent less).[34] Gas price tariffs are currently under review in an effort to reduce these discrepancies. In 1984, before taxes, gas was highly competitive with other fuels on a heat-equivalent basis; it was approximately 6 percent cheaper than heavy fuel oil, 20 percent cheaper than light fuel oil, 30 percent cheaper than LPG, and 300 to 400 percent cheaper than electricity.

Using the information developed above, we can apply the three oil price scenarios developed earlier to illuminate future natural gas demand in Italy. Overall, gas demand in Italy will be considerably more sensitive to oil prices than in France, for example. Given the heavy fuel-switching from oil to gas that took place in the early 1980s, any significant price differential in favor of gas also will increase gas demand. However, this fuel-switching mostly takes place in the electric generation sector, and as Italian policy is to phase out hydrocarbons in this sector over the next ten years, any switching effect likely cannot hold over the long term. In conclusion, the prospects for growth in natural gas demand in Italy appear to be the best of the four countries examined, given the potential for demand growth in the residential/commercial and industrial sectors as Italy's gas grid continues to be expanded.

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[34] Financial Times, "International Gas Report," no. 46, London, England, December 20, 1985.

The United Kingdom

The United Kingdom consumed 56.0 Bcm of natural gas in 1985, or 21.1 percent of its total energy consumption. In 1984, domestic production provided 42.3 Bcm and imports from Norway the remaining 13.7 Bcm.

The United Kingdom is the second largest gas user of the four countries, consuming only 4.0 Bcm less than West Germany in 1985. Gas has a very high penetration in the residential/commercial sector (in 1983, 60 percent of total energy consumption [see Table 4-11]). This can be explained by historical patterns of gas use (see Chapters 2 and 3 for a fuller discussion) and by U.K. gas pricing policies to domestic users. Through the control of gas supply and participation in all early offshore developments, the British Gas Council (today the British Gas Corporation [BGC]) developed an extensive distribution system and, with it, established prices for gas that were highly competitive with those of alternative fuels. For 1974 through 1983, residential/ commercial gas use increased approximately 60 percent, versus 40 percent for all sectors. Therefore, short-term future gas use does not depend on increased penetration through further development of the distribution system, as it does in other Western European countries (and most importantly, in Italy); the distribution system already is largely in place in the United Kingdom.

The United Kingdom uses very little gas in the electric generation sector (a mere 1.0 percent of total energy consumption) in 1983. Electric generation historically has been based on coal, and this trend continues (80 percent in 1983), although nuclear is accounting for an increasing amount. This is due to the abundance of coal in the United Kingdom and the concommitant reliance on coal-fired electric generation plants. In addition, the phasing-out of oil-fired plants, which was accelerated by the 1979-80 hike in oil

Table 4-11

	1983 (MTOE)	%Demand	1982	%Demand	1980	%Demand	1977	%Demand	1974	%Demand
UK GAS										
ENERGY BALANCE										
PRODUCTION	33.37		32.37		31.91		34.72		30.05	
IMPORTS	9.82		9.07		9.17		1.54		0.56	
SUM SUPPLY	43.19		41.44		41.08		36.26		30.61	
SUM DEMA.	43.19	1	41.44	1	41.05	1	35.9	1	30.64	1
EXPORTS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
STK CHNGES	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
MAN GASES	-0.13	0.00	-0.17	0.00	-0.23	-0.01	-0.11	0.00	-1.25	-0.04
OWN & LOSS	4.06	0.09	2.86	0.07	2.7	0.07	2.18	0.06	2.47	0.08
ELEC. GEN	0.36	0.01	0.38	0.01	0.57	0.01	1.43	0.04	2.54	0.08
SUM INDUST.	13.17	0.30	13.18	0.32	13.75	0.33	13.5	0.38	11.5	0.38
IRN & STL	0.79		0.84		1.03		1.09		0.9	
CHEMS	5.68	FEED STCKS	5.64		5.29		4.95		4.44	
N FER MTLS	0.36		0.35		0.4		0.43		0.38	
N MET MINS	1.01		0.98		1.08		1.27		1.16	
TRANS	0		0		0		0		0	
MACHINERY	2.2		2.25		2.59		2.62		2.19	
MIN & Q	0.04		0.08		0.08		0.1		0.07	
FD & TOB	1.2		1.16		1.23		1.04		0.81	
PPP	0.67		0.64		0.73		0.76		0.67	
WOOD	0		0		0		0		0	
CONSTR	0		0		0		0		0	
TEXT	0.44		0.43		0.46		0		0	
OTHER	0.78		0.81		0.86		1.24		0.88	
SUM TRANS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
SUM ALL OTH	25.73	0.60	25.19	0.61	24.26	0.59	18.9	0.53	15.38	0.50
AGRI	0		0		0		0		0	
COMMERCE	0.01		0.01		2.56		2.02		1.69	
PUB SERVS	2.43				2.32		2.19		1.25	
RES	20.5		20.15		19.5				12.44	
OTHER	2.79		2.71		0.01				0	

prices, helped to preserve coal's dominance. In sum, there appears little likelihood that gas can achieve any significant penetration in this sector.

In contrast, gas accounts for a substantial percentage of total energy demand in the industrial sector (approximately 30 percent in 1983, or 13.2 Mtoe). A substantial proportion of these sales was made on an interruptible supply basis,[35] suggesting the potential for some of these sales to be replaced by coal in the future. However, given current and past competitive gas pricing policies, any significant change in demand likely would be driven by a price hike. This likelihood is discussed below.

A potentially significantly impact on gas demand is the privatization of the BGC. The government has announced that "free" imports and exports of gas will follow the floatation of BGC stock, and competition in the industrial sector will be encouraged legislatively (until recently it appeared that the BGC would be able to continue to monopolize the gas distribution system through price setting, denying competitors fair access.)[36] The new regulatory structure has yet to be disclosed; however, the purchasing and marketing of post-deregulation gas clearly will have profound influence on demand levels. The preference for gas in both residential/commercial and industrial sectors is unlikely to continue after the privatization has been completed. Thus, although there still is potential for increased gas demand in both these sectors, it appears that deregulation-related price increases may restrain this growth.

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[35] International Gas Union, World Gas Supply and Demand, "1983-2020 Demand--West Europe: The Markets for Gas," Report Submitted to the Task Force, p. 63.

[36] Financial Times, "International Gas Report," nos. 45 and 48, London, England, December 6, 1985, p. 12, and January 31, 1986, p. 9.

Gas prices in the United Kingdom are set according to tariffs established by the BGC in conformity with government-determined financial goals. No direct taxes are levied on gas sales. Table 4-12 shows BGC sales by number of consumers and sales. In the residential/commercial sector, there essentially are two types of tariffs: the credit and the domestic prepayment tariffs (essentially a two-part tariff combining a standing [or fixed] and a quantity-used charge). Since 1983, small consumers in all sectors have benefitted from a rebate granted if the standing charge is higher than the quantity-used charge.

In the industrial sector, there is a wide range of prices paid. Recent policy has been aimed at reducing this range, which currently favors large consumers who often have interruptible contracts.

Gas prices relative to those of competing fuels are relevant to future gas demand (see Table 4-13). Historically gas has been highly competitive with both heavy fuel and gasoil, but less so with coal. This largely corresponds with actual usage patterns in the industrial sector. Table 4-14 provides examples of gas prices paid by both domestic and industrial consumers in London from 1978 to 1984.

West Germany

West Germany consumed 60.0 Bcm of gas in 1985, or 15 percent of its total energy consumption. Domestic production provided 17.2 Bcm and imports 42.8 Bcm. In 1984, total imports were 35.5 Bcm: 15.0 Bcm from the Netherlands, 13.5 Bcm from the Soviet Union, and 7.0 Bcm from Norway.[37]

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[37] CEDIGAZ, op.cit.

Table 4-12

BRITISH GAS SALES 1982-83

	Users	Consumers	Sales
	Domestic Sales:		
1.	Prepayment Tariff	10.8	2.2
2.	Credit Tariff	85.5	50.1
3.	Commerical Sales	3.0	11.8
4.	Industrial Sales	0.5	34.0
5.	National & Local Government	0.2	1.8
	TOTAL	n = 15929428	16463 M therms

Source: EEC, Eurostat, Gas Prices, 1978-84.

Table 4-13

PRICES OF FUELS USED BY MANUFACTURING INDUSTRY PENCE/THERM (DELIVERED)

	1977	1978	1979	1980	1981	1982	1983	1984
Coal	8.20	8.90	10.36	13.43	15.52	18.43	19.07	19.09
Heavy Fuel Oil	13.48	12.64	15.70	22.24	26.65	28.15	31.00	36.86
Gas Oil	18.23	18.30	23.83	34.93	40.68	44.27	45.82	47.07
Gas	9.26	11.71	13.67	17.57	21.59	23.24	24.06	26.34
Electricity	50.33	55.67	61.53	69.35	79.29	86.10	85.09	84.67

Source: Digest of UK Energy Statistics, 1985, Department of Energy, U.K.

Table 4-14

UNITED KINGDOM: EXAMPLE DOMESTIC & INDUSTRIAL CONSUMER PRICES (London)

Domestic (Annual Consumption: 8.4 GJ) UKL/GJ

	Taxes Included	Excl. Taxes
January 1978	2.79	2.79
1979	2.79	2.79
1980	3.00	3.00
1981	3.79	3.79
1982	5.51	5.51
1983	6.79	6.79
1984	6.67	6.67

Industrial (Annual Consumption: 419 GJ) UKL/GJ

	Taxes Included	Excl. Taxes
January 1978	1.76	1.76
1979	1.76	1.76
1980	2.32	2.32
1981	2.55	2.55
1982	2.65	2.65
1983	3.27	3.27
1984	3.43	3.43

Source: EEC, Eurostat, Gas Prices, 1978-84.

Table 4-15

	1983 (MTOE)	%Demand		1982	%Demand	1980	%Demand	1977	%Demand	1974	%Demand
GERMANY GAS ENERGY BALANCE											
PRODUCTION	13.65			12.96		14.59		14.91		15.84	
IMPORTS	33.98			33.48		36.23		24.48		17.63	
SUM SUPPLY	47.63			46.44		50.82		39.39		33.47	
SUM DEMA.	47.64	1		46.44	1	50.85	1	39.39	1	33.51	1
EXPORTS	7.15	0.15		8.14	0.18	7.53	0.15	0.09	0.00	0.09	0.00
STK CHNGES	1.28	0.03		0.71	0.02	0	0.00	0.38	0.01	0.09	0.00
MAN GASES	0.86	0.02		0.75	0.02	-1.04	-0.02	-0.59	-0.01	-3.11	-0.09
OWN & LOSS	1.29	0.03		1.23	0.03	1.48	0.03	1.1	0.03	1.16	0.03
ELEC. GEN	7.86	0.16		7.95	0.17	12.39	0.24	12.68	0.32	11.54	0.34
SUM INDUST.	14.58	0.31		13.79	0.30	16.39	0.32	13.16	0.33	15.51	0.46
IRN & STL	2.31			2.18		3.81		3.67		6.69	
CHEMS	4.47	FEED STCKS	1.45	4.21		3.34		3.82		3.71	
N FER MTLS	0.44			0.43		1.36		0.7		0.75	
N MET MINS	1.5			1.42		0.57		2.76		2.66	
TRANS	0.61			0.58		1.51		0		0	
MACHINERY	0.41			0.39		0.48		0.01		0	
MIN & Q	0.32			0.31		0.43		0		0.04	
FD & TOB	0.89			0.85		0.35		0.57		0.45	
PPP	0.53			0.5		0.89		0.65		0.37	
WOOD	0			0		0		0		0	
CONSTR	0			0		0		0		0	
TEXT	0			0		0		0		0	
OTHER	3.1			2.92		3.16		0.96		0.84	
SUM TRANS	0.08	0.00		0.06	0.00	0.06	0.00	0	0.00	0	0.00
SUM ALL OTH	14.54	0.31		13.81	0.30	14.04	0.28	12.57	0.32	8.23	0.25
AGRI	0.01			0.01		0		0		0	0
COMMERCE	0.09			0.08		3.2		4.84		2.99	
PUB SERVS	0.06			0.07		0		0		0	
RES	8.91			8.47		10.84		7.73		5.24	
OTHER	5.47			5.18		0		0		0	

The central theme of West German gas policy is to allow competitive forces to drive the market. This broad policy nothwithstanding, efforts to protect the domestic gas industry from supply disruptions include diversifying supply sources, improvements in storage capacity, and expansion of pipeline networks.[38] In 1983 total demand, excluding exports, grew 4.3 percent over 1982 levels; in the residential sector it grew by 5.2 percent, reflecting a shift in consumption from the electric generation to the domestic sector and to a lesser extent to the industrial sector (see Table 4-15).

Gas use in the electric generation sector is indirectly driven by government policies toward coal. The West German government provides extensive support for coal production, largely in response to political pressures from miners. Some substitution of oil and gas due to government subsidies of the coal industry as taken place over the last five years; these include price supports, production and exploration grants, and investment tax credits. Future demand increases in the electric generation sector are planned to be met both by hard coal-fired plants and by new nuclear generation capacity (which accounted for 23.5 percent of electricity generation in 1984). Therefore, there appears little opportunity that gas will increase its share of the market in this sector; in fact, it is having difficulty in maintaining even its current share, which fell in 1985 about 10 percent from 1983 levels.[39]

Any real growth in gas demand will come from the residential/commercial and industrial sectors. Gas currently accounts for 23 percent of

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[38] International Energy Agency, "Energy Policies and Programs of IEA Countries, 1984 Review," Paris, France, 1985.

[39] Ruhr Gas Aktiengesellschaft, "Ruhn Gas Statistics," Essen, Germany, 1985.

residential/commercial use. Limited demand growth in these sectors has followed the growth of the distribution system. According to Ruhrgas, the major supplier of gas in West Germany, the number of households expected to use gas for space heating will increase from 6 million in 1982 to some 8 million by 1990, as the distribution system is further developed.[40] This appears to be a reasonable forecast, given increases in the numbers of households connected to the gas grid in the last few years (approximately 250,000 to 300,000 annually).

Gas meets about 21 percent of energy demand in the industrial sector. In a recent DRI forecast,[41] annual demand growth was forecast to be 3 percent in 2000, approximately half coming from increased market penetration in this sector and half from industrial growth itself. Increased penetration is forecast to come from additional gas use in the process industries, although this will be offset by declines in some traditional gas-using industries, such as steelmaking.

Figure 4-2 shows recent changes in natural gas consumption patterns in West Germany. Gas use in the industrial sector has risen modestly, significantly in the residential/commercial sector, and declined about equally in the electric generation sector. As in the other three countries, demand for gas is highly correlated with its price competitiveness via other fuels.

Table 4-16 provides a breakdown of consumers according to prices paid, to which VAT at 14 percent is added (deductible from income tax for industrial

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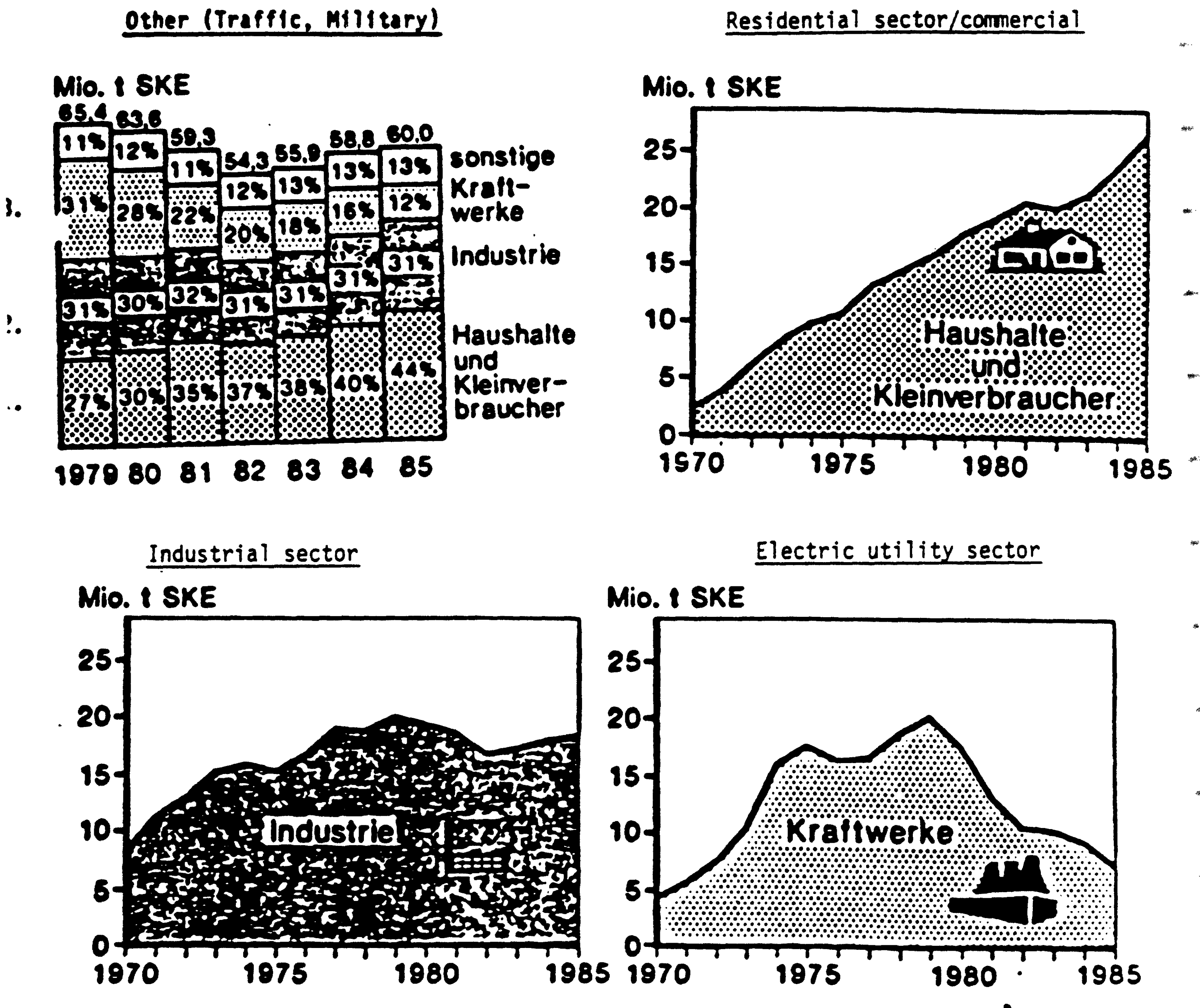
40 Idem., "Natural Gas on the Road into the Next Century," Essen, Germany, August 1983.

41 CEDIGAZ, op.cit.

Figure 4-2

Natural Gas Consumption in the Federal Republic of Germany by Consumer Groups [in Mill.tons coal equivalent]



1985 Zahlen geschätzt

RUHR gas 1986

Table 4-16

GERMANY: NATURAL GAS, PERCENTAGE SALES BY TARIFF GROUP

		1980	1981	1982	1983
	Domestic Users:				
1.	Heating Tariffs	26.8	26.6	27.1	27.3
2.	Other Tariffs	4.7	4.5	4.5	4.8
3.	Collective Heating	9.9	10.0	10.6	11.0
4.	Commercial & Similar Uses	15.0	14.4	15.0	15.3
5.	Industry	43.4	44.6	42.8	41.6
	TOTAL	100.0	100.0	100.0	100.0

In 1983 the total number of customer was 8,425,000.

Source: EEC, Eurostat, Gas Prices, 1978-84.

Table 4-17

WEST GERMANY: EXAMPLE DOMESTIC & INDUSTRIAL CONSUMER PRICE (DUSSELDORF)

Domestic	(Annual Consumption: 8.4 GJ)	DM/GJ
	Taxes Included	Excl. Taxes
January 1978	29.42	26.27
1979	29.42	26.27
1980	29.69	26.27
1981	35.97	31.83
1982	46.76	41.38
1983	--	--
1984	45.24	39.68

Industrial	(Annual Consumption: 419 GJ)	DM/GJ
	Taxes Included	Excl. Taxes
January 1978	14.45	12.90
1979	14.45	12.90
1980	14.58	12.90
1981	19.36	17.13
1982	24.45	21.64
1983	--	--
1984	22.20	19.47

Source: EEC, Eurostat, Gas Prices, 1978-84.

and commercial users). There are considerable differences in the final price paid by end-use sector. These price differences result from the problems of applying local distribution charges equitably. Supply contracts for all households are revised annually. In a manner similar to domestic users, prices for industrial consumers are set by negotiations with suppliers. Prices paid by industrial users are not required to be published although, as with domestic users, there is considerable dispersion in prices paid. In general, after a sharp rise in the early 1980s, gas prices in West Germany have been relatively stable.

Summary

Overall, the Western European natural gas market is relatively young compared to those of North American, and it is also highly complex. The current patterns of gas consumption--both in terms of its share of total energy use and in its distribution among residential, commercial, industrial, and electric generation sectors--vary widely among the countries of Western Europe. Indeed, the gas industries of certain countries (such as the Netherlands and, as regards residential use, the United Kingdom) are "mature," while those of other countries (such as West Germany) are still in their adolescence.

Despite this complexity, the same core factors will shape the course of natural gas demand over the coming 15 years in Western Europe as they will in North America and the Pacific Basin. These factors are the price of natural gas relative to those of other fuels, economic growth, and the energy policies of individual countries. In addition, strategic considerations (to some extent tied to policy and how gas is priced) will have an impact on the levels and patterns of future gas demand.

The Relative Price of Gas

As a determinant of future natural gas demand in Western Europe, the price of gas has two elements: its price *per se* and its price relative to the (expected) prices of crude oil and refined products. If, as seems likely, future gas prices are tied less mechanistically to those of oil, natural gas demand will be less dependent on oil prices. Gas prices doubtlessly still will rise or fall as oil prices move up or down, but the prices at which the various regional sub-markets for gas clear also will depend on the structure of gas demand and on supply conditions.

We postulate three main possibilities for oil-price expectations, based on the market structure one expects to prevail in the world oil market. These structural possibilities are: (1) a strong, reconstituted oil cartel (with "high" oil prices); (2) a competitive market, with no cartel (and with "low" oil prices); and (3) a weak cartel, of varying cohesiveness (and correspondingly variable oil prices). We suspect that gas demand will vary according to which structural expectation prevails, although we have, as yet, little idea exactly by how much. High oil prices would retard *all* energy-using investments, gas included; the weakening of the gas/oil price link (if it occurs) would partly offset this retarding effect on gas demand. Low oil prices would have the opposite effect, but gas would have to compete against cheap oil; this would increase the importance of freeing gas prices from linkage to oil prices. Finally, variable oil prices would put a premium on fuel-switching capability, spurring investments in fuel-switching capacity wherever energy accounted for a significant share of total costs. For gas to compete in the "penny-switcher" market would require greater freedom to vary prices among classes of users than has been permitted in many parts of Western Europe.

Economic Growth

This chapter did not undertake a separate analysis of economic growth factors, which is an important determinant of natural gas demand, although some general observations can be made. Economic growth in Western Europe has been sluggish in the 1980s, apparently as the result of governments' reluctance to pursue expansionary macroeconomic policies for fear of renewed inflation. Absent structural reforms in labor and other markets, this reluctance may persist, despite beneficial supply-side impacts of lower oil prices. If so, an important source of growth in the demand for natural gas--still incompletely developed in most of Western Europe, as discussed--will be lacking.

Note that the likelihood of instituting more expansionary macroeconomic policies likely varies with expectations about oil prices. High oil prices would pose more difficulties for macroeconomic policymakers fearing inflation than would low oil prices. We therefore expect that Western European governments would resist expansionist policies more resolutely under high- than under low-oil-price expectations. For governments subject to and concerned with short-term, "political business cycle" effects, variable oil prices would pose problems of their own. This latter set of oil-price expectations perhaps would cause instability in macroeconomic policies that would reduce economic growth in Western Europe and hence weaken overall growth in gas demand.

National Energy Policies

We asserted at the very outset of this chapter that differences in national energy policies largely explain disparate patterns of current natural gas use in the countries of Western Europe. Some of these policies pertain directly to gas, others indirectly but with no less impact. Thus, Dutch and U.K. government measures deflect domestically-produced gas supplies from international to internal uses. The French government's singleminded pursuit of nuclear power development in the generation of electricity includes restrictions and subsidies that singificantly retard possibilities for development of gas use. And West German policies favoring the use of domestically-produced coal in the generation of electricity pose obstacles to penetration by gas in that sector, even if gas prices were to become more favorable. Clearly, in Western Europe, national patterns of gas use will not become more similar until these policy barriuers are reduced.

As with economic growth, national energy policies likely will vary with different expectations about oil prices. High oil prices probably would reinforce many of the policies that contribute to diversity in gas use, such as the French commitment to nuclear power. In contrast, low oil prices could undermine such policies, thereby fostering more homogeneous gas development throughout the region. Our guess is that variable oil prices also would reinforce the more idiosyncratic policies that were adopted in response to the oil price shocks, and thus weaken any trends toward common patterns of gas use in Western Europe.

Strategic Considerations

In our study of North America, we argued that strategic decisions by both the U.S. and the Canadian governments would largely shape the future evolution of gas use.[42] In the case of Japan, the strategic decision concerned the construction of a national gas grid, if not of steel pipe, then of LNG terminals and transshipment facilities. In the case of Western Europe, strategic issues also are important. Certain of them involve the energy policies of individual countries--e.g., French willingness to consider curtailing nuclear power development or West German reconsideration of its policy of prohibiting gas use in electric utility boilers (perhaps as part of an anti-acid rain campaign), and these should not be overlooked.

But the overriding strategic issue in Western Europe is whether the Norwegians will be able to implement not only the large deal announced in June 1986, but also other large deals involving the other three-quarters of the Troll field. To do so, they must in effect increase demand in Western Europe by persuading enough customers that it can supply gas at competitive prices over an extended period, in order to induce new investments by its customer-countries both in infrastructure and in gas-using equipment. If the Norwegians can build the pipeline into Zeebrugge, Belgium, and if it then is extended through France, the West German monopsony position in the West European gas market will have been broken. The result then should be more vigorous competition throughout the entire region, and with it will come larger volumes of natural gas both demanded and delivered. Only then will it be possible to exploit Troll gas to the fullest extent envisioned.

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[42] In Washington, the issue is pipeline policy. In Ottawa, the two issues are wellhead supply and export pricing.

It appears that the decision to proceed with the Zeebrugge pipeline according to the current schedule hinges critically on expectations about oil prices. Even though growth in total energy demand might be greatest under our low-price scenario, the associated price of gas could be too low to support both development of Troll reserves and new pipelines to transport the gas to customers. (This point suggests another important determinant of the viability of the Norwegian strategy, namely, the size of compressible economic rents and whether the Norwegian government politically can allow enough of them to be squeezed out, if need be.) High oil prices would make gas prices much more attractive, but the macroeconomic effects could at least defer Norwegian plans further into the future, if not kill them altogether. From the narrow perspective of Norwegian gas development and export, perhaps the most favorable oil-price scenario would be variable oil prices, a development that would stimulate the demand for flexible fuel systems--primarily oil/gas dual-fired systems.

* * * *

The net result of this analysis, as applied to the four major energy-consuming countries of Western Europe, is not the derivation of one single, overall forecast of future natural gas demand. The imponderables are simply too numerous and too weighty to make such an endeavor worthwhile. Even without a strategic breakthrough on Norway's sales of Troll gas, there still is some room for natural gas demand to grow in all four countries. Italy offers the most favorable prospects, in all sectors, particularly if certain of its regional policies begin to click in the less-developed south. France and West Germany both should use more gas in the residential and commercial sectors, and probably in the industrial sector as well, but barring policy shifts, neither country is apt to increase gas use in the electric generation sector. In fact, currently envisioned decline in this sector in West Germany could cancel out any growth in gas use in the other sectors.

If the Norwegians succeed on a large scale in bringing Troll reserves onstream before 2000, the picture sketched about would be quite different. Some of the market for Troll gas would be in entirely new regions (e.g., Spain), but the Norwegians' plans only can succeed if France and Italy at a minimum, and probably West Germany and the United Kingdom as well, use more gas than is currently planned. That is to say, the success of Norway's strategy regarding Troll depends more on the development of favorable price terms than many decision makers in the four countries now expect will happen.

APPENDIX

DERIVATION OF DEMAND SCENARIOS

by

Arthur W. Wright

This study did not attempt to construct a model that would supply econometric or other estimates of natural gas demand in Western Europe. However, for the simulation runs using the dynamic natural gas trade programming model described and applied in Chapter 5, it was necessary to obtain natural gas demand scenarios for various oil-price assumptions based on relative prices and economic growth. We therefore constructed a simple "calculator," which takes parameters for GNP or GDP growth, generates associated total energy use levels in each year, and then calculates the share of natural gas in total energy demand.[1] For each of the four countries studied in detail, future gas demands were calculated for the period 1984-2017 for the three oil-price scenarios.

Our approach to estimating future natural gas demand must exhibit certain characteristics. First, it must be dynamically stable in the sense that estimated energy or gas use should not go suddenly "off the charts" in some future year. Second, it also had to reproduce the historical values early in the time period (1984 and 1985). Obtaining even a simple calculator having these two characteristics proved to be challenging. We repeatedly made simplifying, ad hoc assumptions, or abandoned particular derivations that posed difficulties, as became desirable on theoretical or other grounds. It

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[1]1 We gratefully acknowledge the assistance of Charles Blitzer and David Wood, who are only partly to blame for the results of this exercise.

turned out that, given the supply conditions input to the model, the simulated results were insensitive to the demand numbers. Therefore, we suspended the search for a more satisfying set of assumptions until such time that we have the resources to conduct further research into better ways of capturing particular relationships.

The key idea of the "calculator" is to divide both total energy use and natural gas use into two components. One is driven by the stock of existing capital equipment in use at the beginning of the time span studied (1984). The energy/gas efficiency characteristics of this historical capital stock are fixed, and so energy/gas consumption is "captive." We assume that this stock depreciates at a constant rate, so that the effect of the old equipment decays at an exponential rate. The second component of energy/gas demand depends upon the efficiency characteristics of new capital goods. We "model" this component as depending upon economic growth (to contain the level of new investment) and relative energy prices (to capture efficiency effects). Algebraically, for total energy use:

$$E_t = E_0(1 - d_e)^t + I(\cdot)[Y_t - Y_0(1 - d_e)^t] , \qquad (1)$$

where: E_t = total energy use at time t (0 = 1984);

d_e = the constant annual rate of economic depreciation of energy-using capital stock;

I = a function that determines the energy intensity of new capital stock; and

Y_t = GNP or GDP at time t (0 = 1984).

For natural gas:

$$G_t = G_0(1 - d_g)^t + S(\cdot)[E_t - E_0(1 - d_g)^t] , \qquad (2)$$

where: G_t = total gas use at time t (0 = 1984);

d_g = the constant annual rate of economic depreciation of gas-using capital stock; and

S = a function that determines the share of natural gas in new gas use.

Substituting equation (1) into equation (2), we express gas use as follows:

$$G_t = G_0(1 - d_g)^t + S(\cdot)I(\cdot)[Y_t - Y_0(1 - d_e)^t \ . \qquad (3)$$

For oil prices, we assumed that they fell from an OECD weighted average for 15 products in 1984, $27.68/bbl, to an estimated $16.00/bbl in 1986, and then (high) rose to $28.00 or (low) fell to $8.00/bbl in 1987 and stayed there through 2017. The middle, or variable, oil-price scenario is taken to be the mid-point between the high and low scenarios.

Assumptions about economic growth over the period 1986-2017 were adjusted to reflect expected differences between the oil-price scenarios as well as inter-country differences (e.g., the United Kingdom produces oil and the other three countries do not). The economic growth assumptions used in the model runs presented in this report were as follows:

For France, Italy, and West Germany:

	Strong Cartel (High Oil Prices)	Competition (Low Oil Prices)
1986	3.0%	3.0 per year for the entire period
1987	0.0%	
1988-90	1.5%	
1990-99	2.0%	
2000-17	2.5%	

For the United Kingdom:

1986	-1.0%	-1.0%
1987	2.5%	-2.0%
1988	2.5%	-1.0%
1989	2.5%	0.0%
1990-91	2.5%	1.5%
1992-94	2.5%	2.0%
1995-99	2.5%	2.5%
2000-17	2.5%	3.0%

As noted, the growth rates for the United Kingdom differ because of its sizeable oil production. By the year 2000, however, the special effects of oil prices (both ways) wear off, and U.K. growth rates become the same as for the other three countries.

The calculator as it now stands is quite sensitive to assumed economic growth rates. Scaling the rates up or down moves both energy use and gas use around quite significantly. (Again, though, changes in gas demand do not push the model runs around very much.)

In calculating the term for "new" energy use, we assumed an energy/GNP elasticity of unity. This was based on the view that (except in transition periods) the long-run energy/GNP elasticity tends to be about unity. During transition periods (e.g., after the oil-price shock of the mid-1970s), the observed elasticity may be less than unity, but that is because of the delayed adjustment to the new conditions. Here, though, we only are estimating the elasticity for new capital equipment.

To derive energy and gas use attributable to the capital stock existing at the beginning of the time span, we started with estimated rates of economic depreciation for different classes of capital equipment.[2] By assigning the equipment to industrial sectors, judiciously choosing an average figure for each sector, then weighting them by sectoral shares in energy or gas use, we were able to calculate average rates of depreciation. The figures for total energy use were reassuringly grouped right at 0.12. Those for gas use varied

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[2]1 See Hulten, Charles R. and Frank C. Wykoff [1981], "The Measurement of Economic Depreciation," in C.R. Hulten (editor), Depreciation Inflation and the Taxation of Income from Capital, The Urban Institute Press, Washington, D.C.

considerably more, reflecting the disparate patterns of gas use across the four countries:

France	0.10
Italy	0.07
United Kingdom	0.09
West Germany	0.08

The choice of the component of gas use by far proved the most difficult task. The initial notion was that gas use might be expected to vary with its price relative to that of oil, from some maximum at a very low relative price (say, the Dutch share of natural gas in total energy use) to some minimum at a very high relative price. If one knows the relative prices at which maximum and minimum values occur, the share function could be approximated elegantly by a logit function, or inelegantly by a bounded linear function. Postponing the logit approach until further research is possible, we used the inelegant, bounded linear approximation.

Unfortunately, we had to estimate the values of the relative prices of gas at which the maximum and minimum shares would be reached; depending on what one chooses, of course, the slope of the linear approximation may vary quite significantly. Moreover, the results of applying the calculator proved very sensitive to the choice of this slope, and we ended up using ad hoc assumptions both in order to get the various countries' results to track actual data for 1983 and 1984, and to prevent gas use from going off the charts. As a rule, where it proved necessary to assume relatively high share factors in the early years to get the calculator rolling for a particular country, we assumed that they would decline over time, at least in the direction of the more conservative factors used for France and Germany. This is clearly an area warranting further study, in order to sharpen the choice of gas as a share of total energy use with new capital equipment.

The linear share factors estimated by the procedure described above for the four countries were as follows:

High Oil Price Scenario

France:	1983-87	0.137
	1987-2017	0.150
Italy:	1984	0.300
	1985	0.250
	1986-87	0.225
	1988-89	0.220
	1990-94	0.210
	1995-99	0.205
	2000-17	0.200
United Kingdom:	1984	0.265
	1985-86	0.250
	1987-88	0.240
	1989-94	0.220
	1995-99	0.200
	2000-10	0.190
	2011-17	0.180
West Germany:	1984-87	0.147
	1988-2017	0.150

Low Oil Price Scenario

France:	1984-2017	0.137
Italy:	1984	0.300
	1985	0.250
	1986	0.225
	1987	0.220
	1988-89	0.200
	1990-94	0.180
	1995-2017	0.170
United Kingdom:	1984	0.265
	1985	0.225
	1986-89	0.200
	1990-94	0.180
	1995-99	0.160
	2000-17	0.150
West Germany:	1984	0.195
	1985-87	0.190
	1988-90	0.180
	1991-2017	0.175

The results of the foregoing assumptions are reported in the following Tables, two each (for high and low oil price expectations) for the four countries. The tables show the GNP or GDP figures used, total energy use, total gas use, and the implied year-to-year percentage changes in gas use.

FRANCE: "Strong Cartel" Variant

YEAR	GNP/GDP: (billion 1975 US $) HIGH Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$397.97				
1983	$407.40			24.9	(actual '83)
1984	$414.53	187.0		26.6	0.069
1985	$422.82	192.5	0.029	28.2	0.059
1986	$435.51	199.8	0.038	29.9	0.062
1987	$435.51	201.0	0.006	30.6	0.022
1988	$442.04	205.1	0.021	33.1	0.084
1989	$448.67	209.2	0.020	34.3	0.035
1990	$455.40	213.2	0.019	35.3	0.031
1991	$464.51	218.3	0.024	36.5	0.033
1992	$473.80	223.3	0.023	37.6	0.030
1993	$483.27	228.4	0.023	38.7	0.028
1994	$492.94	233.5	0.022	39.7	0.026
1995	$502.80	238.7	0.022	40.7	0.025
1996	$512.85	243.9	0.022	41.6	0.024
1997	$523.11	249.1	0.022	42.6	0.023
1998	$533.57	254.4	0.021	43.5	0.022
1999	$544.24	259.8	0.021	44.4	0.021
2000	$557.85	266.6	0.026	45.6	0.026
2001	$571.80	273.5	0.026	46.8	0.026
2002	$586.09	280.5	0.026	47.9	0.025
2003	$600.74	287.7	0.026	49.1	0.025
2004	$615.76	295.0	0.026	50.4	0.025
2005	$631.16	302.6	0.025	51.6	0.025
2006	$646.93	310.2	0.025	52.9	0.025
2007	$663.11	318.1	0.025	54.2	0.025
2008	$679.69	326.2	0.025	55.5	0.025
2009	$696.68	334.4	0.025	56.9	0.024
2010	$714.09	342.8	0.025	58.3	0.024
2011	$731.95	351.5	0.025	59.7	0.024
2012	$750.25	360.3	0.025	61.1	0.025
2013	$769.00	369.4	0.025	62.6	0.025
2014	$788.23	378.6	0.025	64.2	0.025
2015	$807.93	388.1	0.025	65.8	0.025
2016	$828.13	397.9	0.025	67.4	0.025
2017	$848.83	407.9	0.025	69.0	0.025
2018	$870.05	418.1	0.025	70.7	0.025
2019	$891.81	428.6	0.025	72.5	0.025
2020	$914.10	439.3	0.025	74.3	0.025

FRANCE: "Competition" Variant

YEAR	GNP/GDP: (billion 1975 US $) LOW Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$397.97				
1983	$407.40			24.9	(actual '83)
1984	$414.53	187.0		26.6	0.067
1985	$422.82	192.5	0.029	28.2	0.059
1986	$435.51	199.8	0.038	29.9	0.062
1987	$448.57	207.3	0.037	31.5	0.054
1988	$462.03	214.7	0.036	33.1	0.049
1989	$475.89	222.3	0.035	34.5	0.045
1990	$490.16	229.9	0.034	36.0	0.041
1991	$504.87	237.7	0.034	37.4	0.038
1992	$520.02	245.6	0.033	38.7	0.036
1993	$535.62	253.6	0.033	40.0	0.035
1994	$551.68	261.8	0.032	41.4	0.033
1995	$568.24	270.1	0.032	42.7	0.032
1996	$585.28	278.7	0.032	44.1	0.031
1997	$602.84	287.5	0.031	45.4	0.031
1998	$620.93	296.4	0.031	46.8	0.030
1999	$639.55	305.6	0.031	48.2	0.030
2000	$658.74	315.1	0.031	49.6	0.030
2001	$678.50	324.8	0.031	51.1	0.030
2002	$698.86	334.7	0.031	52.6	0.029
2003	$719.82	344.9	0.031	54.1	0.029
2004	$741.42	355.5	0.030	55.7	0.029
2005	$763.66	366.3	0.030	57.4	0.029
2006	$786.57	377.4	0.030	59.0	0.029
2007	$810.17	388.8	0.030	60.8	0.029
2008	$834.47	400.6	0.030	62.5	0.029
2009	$859.51	412.7	0.030	64.4	0.029
2010	$885.29	425.1	0.030	66.2	0.029
2011	$911.85	437.9	0.030	68.2	0.029
2012	$939.21	451.1	0.030	70.2	0.029
2013	$967.38	464.7	0.030	72.2	0.029
2014	$996.40	478.7	0.030	74.4	0.029
2015	$1,026.30	493.1	0.030	76.6	0.029
2016	$1,057.09	507.9	0.030	78.8	0.030
2017	$1,088.80	523.2	0.030	81.2	0.030
2018	$1,121.46	538.9	0.030	83.6	0.030
2019	$1,155.11	555.1	0.030	86.0	0.030
2020	$1,189.76	571.8	0.030	88.6	0.030

ITALY: "Strong Cartel" Variant

YEAR	GNP/GDP: (billion 1975 US $) HIGH Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$231.91				
1983	$228.00			25.4	(actual '83)
1984	$233.93	140.2		29.8	0.174
1985	$239.19	141.8	0.011	31.7	0.063
1986	$246.37	144.6	0.020	33.1	0.046
1987	$246.37	143.6	-0.007	34.3	0.036
1988	$250.06	144.8	0.008	35.4	0.031
1989	$253.81	146.1	0.009	36.7	0.035
1990	$257.62	147.5	0.010	36.7	0.002
1991	$262.77	149.7	0.015	37.8	0.029
1992	$268.03	152.1	0.016	38.8	0.026
1993	$273.39	154.6	0.016	39.7	0.023
1994	$278.86	157.2	0.017	40.5	0.021
1995	$284.43	159.9	0.017	40.6	0.002
1996	$290.12	162.8	0.018	41.3	0.018
1997	$295.93	165.7	0.018	42.0	0.017
1998	$301.84	168.7	0.018	42.7	0.016
1999	$307.88	171.8	0.018	43.4	0.016
2000	$315.58	175.9	0.024	43.4	-0.001
2001	$323.47	180.1	0.024	44.2	0.020
2002	$331.55	184.4	0.024	45.1	0.020
2003	$339.84	188.9	0.024	46.0	0.020
2004	$348.34	193.5	0.024	46.9	0.020
2005	$357.05	198.2	0.024	47.8	0.020
2006	$365.97	203.0	0.024	48.8	0.020
2007	$375.12	208.0	0.025	49.7	0.020
2008	$384.50	213.1	0.025	50.8	0.020
2009	$394.11	218.4	0.025	51.8	0.021
2010	$403.97	223.8	0.025	52.9	0.021
2011	$414.07	229.3	0.025	54.0	0.021
2012	$424.42	235.0	0.025	55.1	0.021
2013	$435.03	240.8	0.025	56.3	0.021
2014	$445.90	246.8	0.025	57.6	0.022
2015	$457.05	253.0	0.025	58.8	0.022
2016	$468.48	259.2	0.025	60.1	0.022
2017	$480.19	265.7	0.025	61.5	0.022
2018	$492.19	272.3	0.025	62.8	0.023
2019	$504.50	279.1	0.025	64.3	0.023
2020	$517.11	286.1	0.025	65.7	0.023

ITALY: "Competition" Variant

YEAR	GNP/GDP: (billion 1975 US $) LOW Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$231.91				
1983	$228.00			25.4	(actual '83)
1984	$233.93	140.2		29.8	0.174
1985	$239.19	141.8	0.011	31.7	0.063
1986	$246.37	144.6	0.020	33.1	0.046
1987	$253.76	147.7	0.021	35.0	0.056
1988	$261.37	151.0	0.022	35.2	0.006
1989	$269.21	154.6	0.024	36.7	0.044
1990	$277.29	158.4	0.024	35.9	-0.023
1991	$285.61	162.4	0.025	37.0	0.031
1992	$294.18	166.6	0.026	38.0	0.029
1993	$303.00	171.0	0.026	39.1	0.027
1994	$312.09	175.6	0.027	40.1	0.026
1995	$321.45	180.4	0.027	39.4	-0.017
1996	$331.10	185.4	0.028	40.3	0.023
1997	$341.03	190.6	0.028	41.2	0.022
1998	$351.26	196.1	0.028	42.1	0.022
1999	$361.80	201.7	0.029	43.1	0.022
2000	$372.65	207.5	0.029	44.0	0.022
2001	$383.83	213.5	0.029	45.0	0.023
2002	$395.35	219.7	0.029	46.0	0.023
2003	$407.21	226.1	0.029	47.1	0.023
2004	$419.42	232.8	0.029	48.2	0.023
2005	$432.01	239.6	0.029	49.3	0.024
2006	$444.97	246.7	0.030	50.5	0.024
2007	$458.32	254.0	0.030	51.7	0.024
2008	$472.06	261.6	0.030	53.0	0.025
2009	$486.23	269.3	0.030	54.3	0.025
2010	$500.81	277.3	0.030	55.7	0.025
2011	$515.84	285.6	0.030	57.1	0.026
2012	$531.31	294.1	0.030	58.6	0.026
2013	$547.25	302.9	0.030	60.2	0.026
2014	$563.67	311.9	0.030	61.8	0.027
2015	$580.58	321.3	0.030	63.4	0.027
2016	$598.00	330.9	0.030	65.1	0.027
2017	$615.94	340.8	0.030	66.9	0.027
2018	$634.42	351.0	0.030	68.7	0.027
2019	$653.45	361.5	0.030	70.6	0.028
2020	$673.05	372.3	0.030	72.6	0.028

UNITED KINGDOM: "Strong Cartel" Variant

YEAR	GNP/GDP: (billion 1975 US $) HIGH Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$251.01				
1983	$259.90			49.5	(actual '83)
1984	$266.14	191.9		50.8	0.027
1985	$272.79	190.7	-0.006	51.4	0.012
1986	$270.06	184.8	-0.031	50.8	-0.012
1987	$276.81	184.8	.000	50.9	0.002
1988	$283.74	185.3	0.003	51.6	0.013
1989	$290.83	186.4	0.006	50.1	-0.029
1990	$298.10	187.9	0.008	50.5	0.008
1991	$305.55	189.8	0.010	50.9	0.009
1992	$313.19	192.1	0.012	51.5	0.010
1993	$321.02	194.7	0.014	52.0	0.011
1994	$329.05	197.7	0.015	52.6	0.012
1995	$337.27	201.0	0.017	49.7	-0.055
1996	$345.70	204.5	0.018	50.3	0.011
1997	$354.35	208.4	0.019	50.9	0.012
1998	$363.20	212.4	0.020	51.5	0.013
1999	$372.29	216.8	0.020	52.2	0.014
2000	$381.59	221.3	0.021	50.8	-0.028
2001	$391.13	226.0	0.022	51.5	0.015
2002	$400.91	231.0	0.022	52.3	0.016
2003	$410.93	236.2	0.022	53.2	0.017
2004	$421.21	241.6	0.023	54.2	0.018
2005	$431.74	247.1	0.023	55.1	0.018
2006	$442.53	252.9	0.023	56.2	0.019
2007	$453.59	258.9	0.024	57.3	0.020
2008	$464.93	265.0	0.024	58.4	0.020
2009	$476.56	271.4	0.024	59.6	0.021
2010	$488.47	277.9	0.024	60.9	0.021
2011	$500.68	284.7	0.024	59.1	-0.030
2012	$513.20	291.6	0.024	60.3	0.022
2013	$526.03	298.7	0.024	61.7	0.022
2014	$539.18	306.0	0.025	63.0	0.022
2015	$552.66	313.5	0.025	64.5	0.023
2016	$566.48	321.3	0.025	65.9	0.023
2017	$580.64	329.2	0.025	67.4	0.023
2018	$595.15	337.3	0.025	69.0	0.023
2019	$610.03	345.7	0.025	70.6	0.023
2020	$625.28	354.3	0.025	72.3	0.024

UNITED KINGDOM: "Competition" Variant

YEAR	GNP/GDP: (billion 1975 US $) LOW Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$251.01				
1983	$259.90			49.5	(actual '83)
1984	$266.14	191.9		50.8	0.027
1985	$272.79	190.7	-0.006	50.3	-0.010
1986	$270.06	184.8	-0.031	47.9	-0.048
1987	$264.66	177.9	-0.037	46.3	-0.033
1988	$262.02	173.0	-0.027	45.1	-0.026
1989	$262.02	170.1	-0.017	44.2	-0.018
1990	$265.95	169.7	-0.002	41.9	-0.052
1991	$269.93	169.6	.000	41.5	-0.011
1992	$275.33	170.7	0.006	41.3	-0.005
1993	$280.84	172.0	0.008	41.1	-0.004
1994	$286.46	173.6	0.009	41.0	-0.002
1995	$293.62	176.3	0.015	38.1	-0.070
1996	$300.96	179.2	0.017	38.2	0.001
1997	$308.48	182.4	0.018	38.3	0.003
1998	$316.19	185.8	0.019	38.5	0.005
1999	$324.10	189.5	0.020	38.7	0.007
2000	$333.82	194.3	0.025	37.3	-0.037
2001	$343.84	199.3	0.026	37.7	0.013
2002	$354.15	204.6	0.026	38.3	0.014
2003	$364.78	210.1	0.027	38.9	0.016
2004	$375.72	215.8	0.027	39.6	0.017
2005	$386.99	221.8	0.028	40.3	0.019
2006	$398.60	228.1	0.028	41.1	0.020
2007	$410.56	234.5	0.028	41.9	0.021
2008	$422.88	241.2	0.029	42.9	0.022
2009	$435.56	248.2	0.029	43.8	0.023
2010	$448.63	255.4	0.029	44.9	0.024
2011	$462.09	262.8	0.029	46.0	0.024
2012	$475.95	270.5	0.029	47.1	0.025
2013	$490.23	278.4	0.029	48.3	0.026
2014	$504.94	286.6	0.029	49.6	0.026
2015	$520.08	295.1	0.030	50.9	0.026
2016	$535.69	303.8	0.030	52.3	0.027
2017	$551.76	312.9	0.030	53.7	0.027
2018	$568.31	322.2	0.030	55.2	0.028
2019	$585.36	331.7	0.030	56.7	0.028
2020	$602.92	341.6	0.030	58.3	0.028

WEST GERMANY: "Strong Cartel" Variant

YEAR	GNP/GDP: (billion 1975 US $) HIGH Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$496.07				
1983	$496.70			43.9	(actual '83)
1984	$509.61	260.9		46.2	0.051
1985	$522.35	270.5	0.037	48.2	0.043
1986	$540.64	282.8	0.046	50.5	0.048
1987	$540.64	284.7	0.007	51.0	0.010
1988	$548.75	290.9	0.022	52.7	0.033
1989	$556.98	297.0	0.021	53.8	0.021
1990	$565.34	302.9	0.020	54.8	0.019
1991	$576.64	310.4	0.024	56.0	0.022
1992	$588.18	317.8	0.024	57.2	0.021
1993	$599.94	325.2	0.023	58.3	0.020
1994	$611.94	332.6	0.023	59.5	0.019
1995	$624.18	340.1	0.022	60.6	0.019
1996	$636.66	347.6	0.022	61.7	0.018
1997	$649.39	355.2	0.022	62.9	0.018
1998	$662.38	362.8	0.022	64.0	0.018
1999	$675.63	370.6	0.021	65.1	0.018
2000	$692.52	380.3	0.026	66.6	0.023
2001	$709.83	390.2	0.026	68.1	0.023
2002	$727.58	400.3	0.026	69.7	0.023
2003	$745.77	410.6	0.026	71.3	0.023
2004	$764.41	421.2	0.026	72.9	0.023
2005	$783.52	431.9	0.026	74.6	0.023
2006	$803.11	442.9	0.025	76.3	0.023
2007	$823.19	454.2	0.025	78.1	0.023
2008	$843.77	465.7	0.025	79.9	0.023
2009	$864.86	477.5	0.025	81.8	0.024
2010	$886.48	489.5	0.025	83.7	0.024
2011	$908.64	501.9	0.025	85.7	0.024
2012	$931.36	514.5	0.025	87.7	0.024
2013	$954.65	527.5	0.025	89.8	0.024
2014	$978.51	540.7	0.025	92.0	0.024
2015	$1,002.97	554.3	0.025	94.2	0.024
2016	$1,028.05	568.2	0.025	96.5	0.024
2017	$1,053.75	582.5	0.025	98.8	0.024
2018	$1,080.09	597.1	0.025	101.3	0.024
2019	$1,107.10	612.1	0.025	103.7	0.024
2020	$1,134.77	627.4	0.025	106.3	0.024

WEST GERMANY: "Competition" Variant

YEAR	GNP/GDP: (billion 1975 US $) LOW Oil Price	TOTAL ENERGY USE (mtoe)	YR TO YR CHANGE IN ENERGY USE	GAS USE (BCM)	YR TO YR CHANGE IN GAS USE
1980	$496.07				
1983	$496.70			43.9	(actual '83)
1984	$509.61	260.9		46.1	0.051
1985	$522.35	269.5	0.033	47.8	0.036
1986	$540.64	279.2	0.036	49.9	0.045
1987	$556.86	287.1	0.028	51.8	0.037
1988	$573.56	294.5	0.026	52.1	0.006
1989	$590.77	301.5	0.024	53.5	0.029
1990	$608.49	308.1	0.022	55.0	0.028
1991	$626.75	314.6	0.021	55.5	0.008
1992	$645.55	321.0	0.020	56.8	0.025
1993	$664.92	327.4	0.020	58.3	0.025
1994	$684.86	333.8	0.020	59.7	0.025
1995	$705.41	340.3	0.020	61.2	0.025
1996	$726.57	347.1	0.020	62.7	0.025
1997	$748.37	354.0	0.020	64.3	0.025
1998	$770.82	361.2	0.020	65.9	0.025
1999	$793.94	368.7	0.021	67.6	0.026
2000	$817.76	376.5	0.021	69.4	0.026
2001	$842.29	384.6	0.022	71.2	0.026
2002	$867.56	393.1	0.022	73.1	0.027
2003	$893.59	401.9	0.023	75.1	0.027
2004	$920.40	411.2	0.023	77.1	0.027
2005	$948.01	420.8	0.023	79.2	0.027
2006	$976.45	430.9	0.024	81.4	0.028
2007	$1,005.74	441.4	0.024	83.6	0.028
2008	$1,035.92	452.3	0.025	86.0	0.028
2009	$1,066.99	463.8	0.025	88.4	0.028
2010	$1,099.00	475.6	0.026	90.9	0.028
2011	$1,131.97	488.0	0.026	93.5	0.028
2012	$1,165.93	500.8	0.026	96.1	0.029
2013	$1,200.91	514.1	0.027	98.9	0.029
2014	$1,236.94	527.9	0.027	101.8	0.029
2015	$1,274.05	542.3	0.027	104.7	0.029
2016	$1,312.27	557.2	0.027	107.8	0.029
2017	$1,351.64	572.6	0.028	110.9	0.029
2018	$1,392.18	588.5	0.028	114.2	0.029
2019	$1,433.95	605.0	0.028	117.5	0.029
2020	$1,476.97	622.1	0.028	121.0	0.029

WESTERN EUROPEAN NATURAL GAS TRADE MODEL

by

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with the assistance of
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INTRODUCTION

This chapter provides a brief description and overview of the natural gas trade model for Western Europe, which was developed as part of the M.I.T. Center for Energy Policy Research (CEPR) study of international natural gas trade. The model provides a framework for integrating the supply and demand components of this study and has four principle objectives.

Our first objective for use of the model is to check the feasibility and consistency over time of various demand forecasts and supply constraints. These constraints include reserve levels, installed pipeline capacities linking various countries, and minimum or maximum export/import flows associated with either contracts or exogenous policies. This integration provides a mechanism for isolating some of the principal bottlenecks that are likely to emerge in the evolution of natural gas trade in Western Europe.

A second use of the model is to calculate least-cost production and trade patterns to meet projected levels of future demand growth in different countries. The model derives these to be consistent with various supply-side constraints and cost assumptions, as well as with existing and anticipated minimum contract deliveries from individual exporters to individual importers.

A third, closely related objective is to estimate the marginal costs of expanding production or increasing consumption in different countries, or the marginal costs of additional exports from one specific location to another. On the production side, the model includes both operating and investment costs. Operating costs are always incurred when there is production from a particular reserve. Investment costs are not automatic, but come about whenever additional capacity is built to expand production above the level of capacity previously installed. Since the model is dynamic, it can keep track of yearly reserves and whether low-cost reserves are being fully utilized. Whenever this occurs, the model calculates the so-called "user cost" associated with depletion of low-cost reserves, which forces additional use of higher cost gas. Similarly, the marginal costs of transporting gas from one location to another include the marginal operating costs, capital costs,[1] and the user costs of having to use alternative routes and reserves when a particular pipeline is fully utilized.

Finally, the model can be used to perform a variety of sensitivity tests. Among the variables used in developing a specific scenario are: the time pattern of gas demand growth by country, country-specific gas reserves and production costs, major expansions of the pipeline network, minimum delivery requirements under existing and foreseen contracts, and various policy constraints that can be imposed by specific importing or exporting countries. By having the model calculate the least-cost solution for each scenario, it is possible to estimate optimal build-up and depletion profiles, export patterns, and the real costs (in terms of

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[1] Due to lumpiness in pipeline investment, the choices about pipeline expansion that the model itself can make are restricted. This point will be amplified below.

production and transportation costs) of supply diversification strategies.

It is important to stress that the model, as presently formulated, does not determine either the time path of gas demand or the market clearing prices in Western Europe either as a whole or for individual countries. Rather, these are taken as projections derived in the Demand chapter. Of course, the model can be solved repeatedly to investigate what would happen to costs and trade patterns if demand were to grow more or less rapidly. In this respect, the model is similar to the model developed for Pacific Basin LNG trade and is different from the North American model, which included specific demand curves for Canadian gas exports. In the future, it may be possible to extend the model to examine optimal gas consumption levels, but the feasibility of this extension will depend on the availability of data, from which explicit price-sensitive demand functions could be estimated.

The specific structure of production and transportation costs, contracts, reserves, demand growth, etc. associated with each scenario are based on work described elsewhere in this report. A linear programming algorithm is used to find the least-cost solution for each scenario.[2] There is no presumption that the least-cost solution is the most likely to emerge in the future. Rather, the purpose is to ascertain the cost of deviations that may be due to government intervention, diversification objectives, pre-existing contractual relationships, taxation policies, and so forth.

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[2] The model is formulated and solved on an IBM PC-XT using the GAMS/MINOS system developed at the World Bank and Stanford University.

Natural gas production, exports, and required new investment levels are calculated at three-year intervals beginning in 1984 and continuing until 2017. This long time horizon is required to account fully for the long investment lags and long operating lives of major capacity expansion projects. Dynamic relations also are important because production in earlier periods affects marginal production costs in the future. Because of the well-known and inevitable problems with terminal conditions, we report results only through 2014.

The remainder of this chapter is divided into three sections. The next section presents and discusses the algebraic formulation of the model. The following section reviews the model's internal pricing structure. The last section describes and discusses the results of various model runs.

MODEL FORMULATION

In technical terms, the model is formulated as a mathematical programming problem in which a computer algorithm is used to find the optimal time path of the values of the endogenous variables (e.g., production and trade flows in each country, investment in new gas production capacity, etc.). This section reviews the formulation of the model. It should be understood that this modeling framework is considerably more flexible than this summary may indicate, in the sense that additional constraints, projects, producing regions, policy interventions, etc. could be added.

The model takes account of gas demand in eight countries. Five of these countries--France, West Germany, the Netherlands, Italy, and the

United Kingdom--are considered "major," in the sense that their demands are relatively large, and all but the Netherlands (for reasons explained in Chapter 2) were the focus of attention in the Demand component of this study. The "minor" consuming countries include Austria, Belgium, and Norway. They are included for completeness and because considerable volumes of traded gas flow through these countries. For all countries future gas consumption levels are exogenous to the model, having been forecast as part of a particular scenario. Gas consumption in 1984 and future growth rates are summarized in Table 5-1.[3] It should be noted again that these demand projections are conditional on the availability of supply (which this model is designed to test), as well as on specific assumptions concerning oil and gas prices and economic growth.

In addition to these consuming countries of Western Europe, the model also includes exports from Algeria and the Soviet Union.[4] Domestic production of natural gas in the "minor" producing countries--Austria, Belgium, France, West Germany, and Italy--is handled exogenously. This implies that for these countries, net imports of gas are part of the *ex ante* design for each scenario. However, the pattern of where these imports come from is endogenous to the model, except for possible limits imposed by existing contracts.

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[3] 1984 consumption, production, and trade data are based on data from British Petroleum. Some minor modifications were made to the consumption data to ensure equality with domestic production plus net imports.

[4] Significant exports from other countries outside the region were ruled out on *a priori* grounds of relative costs.

Table 5-1

Natural Gas Consumption and Average Annual Growth Rates

Countries	1984 consumption (Bcm)	Demand Scenarios low	medium	high	"super"
France	29.50	2.94%	3.19%	3.43%	5.00%
West Germany	50.20	2.33%	2.52%	2.70%	4.41%
Italy	33.20	2.21%	2.35%	2.49%	4.25%
United Kingdom	47.50	0.87%	0.53%	0.18%	3.28%
Netherlands	38.60	0.50%	0.45%	0.40%	1.00%
Belgium	9.00	2.94%	3.19%	3.43%	5.00%
Austria	4.10	2.33%	2.52%	2.70%	4.41%
Norway	3.70	1.20%	1.00%	0.80%	3.00%
Total/Average	215.80	1.88%	1.96%	2.05%	3.85%

Table 5-2

Reserves, Capacity, Production, and Costs

Countries	1984 reserves (Tcm)	1984 production capacity (Bcm)	1984 production (Bcm)	marginal operating costs, $/Mcf	marginal capital costs, /Mcf/year
Algeria	3.1	42.5	17.2	0.10	1.30
Netherlands-1	4.0	85.0	69.1	0.01	0.10
Netherlands-2	2.0			0.45	5.25
Norway-1	1.0	31.2	29.6	0.20	1.50
Norway-2	1.5			0.30	2.50
Norway-3	2.0			0.45	4.80
Norway-4	1.0			0.50	5.00
Norway-5	1.0			1.00	12.50
USSR (Export only)	41.1	65.3	29.4	0.15	1.50
United Kingdom-1	1.5	51.1	35.4	0.30	2.25
United Kingdom-2	1.0			0.45	5.25
Austria	na	na	1.3	na	na
Belgium	na	na	0.0	na	na
France	na	na	6.0	na	na
Italy	na	na	13.1	na	na
West Germany	na	na	14.7	na	na
Total	59.2	275.1	215.8		

Gas production in Algeria, the Netherlands, Norway, the Soviet Union, and the United Kingdom are all endogenous variables. For the Netherlands, Norway, and the United Kingdom, rising production costs are simulated by specifying several reserve "pools" in each country, each of which has different production costs and different levels of ultimate reserves. The model determines the ordering and timing of development in each. For each country, the endogenous variables include production, required capacity expansion, and remaining reserves. Table 5-2 summarizes data on reserves, production, and costs.

Gas trade takes place though a series of pipelines linking adjoining countries.[5] For simplicity, we assume that pipeline capacity linking two adjoining countries can be used both for trade in either direction and for transshipments. For example, the pipeline capacity between the Netherlands and West Germany is used both for the Netherlands's exports to West Germany and Italy and for Norway's exports to the Netherlands, Belgium, and France. Similarly, Norway's exports to France flow through four "pipelines:" Norway-West Germany, West Germany-the Netherlands, the Netherlands-Belgium, and Belgium-France. Table 5-3 lists all 12 pipelines in the system and the directions and amounts for each.

The following sub-sections describe the model in greater detail. The format is to provide the underlying motivation of specific

[5] Algeria exports LNG to France and Belgium rather than shipping thorough a pipeline. The fact that gasification and regasification facilities are limited implies that the model's considering this link as similar to a pipeline (although including the additional costs of LNG) does not greatly distort reality.

Table 5-3

Export Flows and Pipelines

Pipeline Segment	Export Flows in Pipeline Segment	1984 Flow (Bcm)
Norway - United Kingdom	Norway to United Kingdom	12.1
Norway - W. Germany	Norway to W. Germany	7.0
	Norway to Netherlands	2.8
	Norway to Belgium	1.7
	Norway to France	2.3
		13.8
USSR - W. Germany	USSR to W. Germany	13.5
	USSR to France	4.9
		18.4
USSR - Austria	USSR to Austria	2.8
	USSR to Italy	8.2
		11.0
Algeria - Italy	Algeria to Italy	6.7
Algeria - France (LNG)	Algeria to Belgium	1.5
	Algeria to France	9.0
		10.5
Netherlands - W. Germany	Netherlands to W. Germany	15.0
	Netherlands to Italy	5.2
	Norway to Netherlands	2.8
	Norway to Belgium	1.7
	Norway to France	2.3
		27.0
Netherlands - Belgium	Netherlands to Belgium	5.8
	Netherlands to France	7.3
	Norway to Belgium	1.7
	Norway to France	2.3
		17.1
France - Belgium	Netherlands to France	7.3
	Algeria to Belgium	1.5
		8.8
France - W. Germany	USSR to France	4.9
Italy - W. Germany	Netherlands to Italy	5.2
Italy - Austria	USSR to Italy	8.2

constraints and to describe them specifically in prose and algebraic equations. In general, endogenous variables are represented by capital letters and parameters by lower-case letters. Bars over letters indicate exogenous variables. The subscripts "i" and "j" refer to producing and/or consuming countries, "k" refers to different reserve structures with different costs in producing countries, "p" refers to pipelines, and "t" refers to the time period. Variables with bars are predetermined. All volumes of gas are denominated in billions of cubic meters per year (Bcm per year) and costs are in U.S. dollars per thousand cubic feet ($/Mcf), except as noted.

Supply-Demand Balances

We begin with the identity that total gas production in each country plus imports of gas to that country from all other countries equals exports of gas from that country to all others plus domestic consumption. These supply-demand balances are expressed in the following relationship:

$$\begin{bmatrix}\text{Total}\\ \text{production,}\\ \text{country i}\end{bmatrix} + \begin{bmatrix}\text{Total}\\ \text{imports,}\\ \text{to country i}\end{bmatrix} = \begin{bmatrix}\text{Domestic}\\ \text{consumption,}\\ \text{country i}\end{bmatrix} + \begin{bmatrix}\text{Total}\\ \text{exports,}\\ \text{from country i}\end{bmatrix}$$

Let $X_{i,k,t}$ represent annual production from reserves of type k in country i in year t; $C_{i,t}$ represent consumption in country i in year t; and E(i,j,t) represent exports from country i to country j in period t. Algebraically, we have:

$$\sum_k X_{i,k,t} + \sum_j E_{j,i,t} = C_{i,t} + \sum_i E_{i,j,t} \qquad (1)$$

For the minor producing countries, production and consumption are predetermined for each scenario.

Production-Reserve Relationships

There is a recursive relationship between production in any one period and the remaining reserves in the next period; that is:

$$\begin{bmatrix}\text{Remaining reserves}\\ \text{k in country i,}\\ \text{start of year t}\end{bmatrix} = \begin{bmatrix}\text{Remaining reserves}\\ \text{k in country i,}\\ \text{tart of year t-1}\end{bmatrix} - \begin{bmatrix}\text{Number}\\ \text{of Years}\\ \text{per Period}\end{bmatrix}\begin{bmatrix}\text{Production}\\ \text{from reserve k}\\ \text{in country i,}\\ \text{year t}\end{bmatrix}$$

Defining $R_{i,k,t}$ as reserves (in Bcm) in country i at the start of period t, and recalling that periods are three years in length, the equation is:

$$R_{i,k,t} = R_{i,k,t-1} - 3X_{i,k,t-1} \qquad (2)$$

The following constraint represents a simple approximation to the limitations on annual production imposed by the level of remaining reserves. That is, production from each reserve in each country in each year can be no greater than an exogenously specified fraction of reserves remaining at the beginning of that year:

$$\begin{bmatrix}\text{Production}\\ \text{from reserve k}\\ \text{in country i,}\\ \text{year t}\end{bmatrix} \leq \begin{bmatrix}\text{Maximal rate}\\ \text{of reserve}\\ \text{depletion}\\ \text{country i}\end{bmatrix}\begin{bmatrix}\text{Remaining reserves}\\ \text{k in country i,}\\ \text{start of year t}\end{bmatrix}$$

These maximal rates, $a_{i,k}$, can represent either technical/engineering limits or more restrictive policy interventions. Initially, technically imposed bounds are assumed.[6] That is:

$$X_{i,k,t} \leq a_{i,k} R_{i,k,t} \tag{3}$$

Production-Investment Relationships

Annual gas production in each country also is constrained by available production capacity, which in turn depends on previously undertaken investment projects. Base year extraction capacity is predetermined, but endogenous investment activities allow that to be augmented at constant capital costs per unit production in each reserve type in each country.[7] That is:

$$\begin{bmatrix}\text{Production} \\ \text{from reserve k} \\ \text{in country i,} \\ \text{year t}\end{bmatrix} \leq \begin{bmatrix}\text{Production} \\ \text{capacity, reserve} \\ \text{k, country i,} \\ \text{year t-1}\end{bmatrix} \begin{bmatrix}\text{one} \\ \text{minus} \\ \text{depreciation} \\ \text{rate}\end{bmatrix} + \begin{bmatrix}\text{New capacity} \\ \text{reserve k} \\ \text{country i,} \\ \text{year t}\end{bmatrix}$$

Let $K_{i,k,t}$ stand for production capacity from reserve k in country i in year t, $I_{i,k,t}$ stand for new capacity introduced in year t, and d_i stand for the rate of depreciation in country i. We then may derive the following relationships:

$$X_{i,k,t} \leq K_{i,k,t} \tag{4}$$

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[6] We recognize that the technical relationship between production and reserves is more complicated than represented here, but have adopted this formulation for its simplicity. If data were available, it would not be difficult to substitute more complex equations.

[7] Initial productive capacity for high-cost reserves in the Netherlands, Norway, and the United Kingdom are taken to be zero. For these reserves all production capacity is determined endogenously.

$$K_{i,k,t} = (1-d_i)K_{i,k,t-1} + I_{i,t} \tag{5}$$

Pipeline Flows and Restrictions

Total natural gas flows through a specific pipeline segments equal the sum of all the "from-to" exports that must flow through that pipeline segment. In some cases, only one export flows through a pipeline (e.g., Norway-United Kingdom), while in other cases up to five exports share the same pipeline segment (e.g., the Netherlands-West Germany). That is:

$$\begin{bmatrix} \text{Flow in pipeline p} \\ \text{(between countries} \\ \text{k and l),} \\ \text{year t} \end{bmatrix} = \begin{bmatrix} \text{Sum of exports,} \\ \text{country i to} \\ \text{country j,} \\ \text{year t} \end{bmatrix}$$

Let $PF_{p,t}$ represent total flows in year t in pipeline segment p. There are 12 pipeline segments and 16 export activities. Table 5-4 lists which exports flow through each pipeline segment. Equation (6) defines the flow through pipeline p, where the summations are only for those export flows, $E_{i,j,t}$, which are associated with pipeline segment p. This relationship is summarized as:

$$PF_{p,t} = \sum_i \sum_j E_{i,j,t} \tag{6}$$

Annual flows through each pipeline segment are limited by available capacity in that year. Unlike with production, the model has relatively little freedom to choose the optimal pattern of pipeline expansion. The reason for this is that there are significant economies of scale in

Table 5-4

Pipeline Capacity and Operating Costs
(units: Bcm/year and $/Mcf)

Pipeline segments	operating costs	1984	1987	1990	1993-2017
Norway - United Kingdom	0.11	20	20	20	20
Norway - W.Germany	0.20	15	35	35	66
USSR - W.Germany	0.25	55	55	65	81
USSR - Austria	0.30	15	15	15	15
Algeria - Italy	0.20	12	18	18	18
Algeria - France b/	0.20	15	15	15	15
Netherlands - W.Germany c/	0.01	81	81	81	81
Netherlands - Belgium	0.025	a/	a/	a/	a/
France - Belgium	0.02	a/	a/	a/	a/
France - W.Germany	0.05	a/	a/	a/	a/
Italy - W.Germany	0.075	a/	a/	a/	a/
Italy - Austria	0.05	a/	a/	a/	a/

NOTES:

a/ Pipeline capacity is not explicitly constrained.

b/ Algerian LNG exporting capacity to France is 31 Bcm per year; France can expand its LNG importing capacity from 15 to 31 Bcm per year at a capital cost of $50 per installed Mcm per year.

c/ Initial capacity can be expanded endogenously at a given, constant capital cost of $22 per Mcm.

pipeline construction. In general, it pays to build excess capacity initially and then have demand catch up, rather than continually make small additions. For this reason, the capacities of pipeline segments from Norway, the Soviet Union, and Algeria are treated as exogenous or "scenario" variables. Since other pipeline segments within Western Europe either have surplus capacity or can be expanded at low capital cost, they are not explicitly bound. However, all rules have exceptions; in this model there are two. Because of its large magnitude and the relative unimportance of economies of scale problems (due to the fact that this link is not just one, but a multitude of pipelines each of which can be expanded marginally), the expansions of the Netherlands-West Germany pipeline links are determined endogenously using constant marginal cost. The other exception is LNG exports from Algeria to France. Algerian export capacity is taken as exogenous, but the model calculates how much additional regasification capacity to install in France, up to the limit imposed by Algerian capacity.[8] That is:

$$\begin{bmatrix} \text{Flow in pipeline} \\ \text{p, year t} \\ \ \end{bmatrix} \leq \begin{bmatrix} \text{Installed capacity} \\ \text{of pipeline p,} \\ \text{year t} \end{bmatrix}$$

Let $PCAP_{p,t}$ represent installed capacity in year t for pipeline segment p, and $IP_{p,t}$ represent additions to pipeline segment p, which is first available for use in year t. The variable IP with a bar over it indicates that it is an exogenous value (pre-set for each scenario), and IP without a bar indicates the variable is endogenous. We then have:

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[8] For details, see Table 5-4.

$$PF_{p,t} \leq PCAP_{p,t} \tag{7}$$

$$PCAP_{p,t} = PCAP_{p,t-1} + IP_{p,t} + IP_{p,t} \tag{8}$$

Cost Calculations

The model considers four sets of out-of-pocket costs. These are: (1) operating (or current) costs of gas production; (2) capital costs associated with investment and capacity expansion in gas extraction; (3) marginal operating costs of shipping gas through particular pipeline segments (including the Algeria-France LNG link); and (4) investment expenditures associated with the endogenous expansion of pipelines. The costs of pipeline expansion, which is part of the different scenarios, are given to the model as a constant. While constants do not affect the solution of any one run of the model, these costs are important when comparing different scenarios. That is:

$$\begin{bmatrix}\text{Extraction}\\ \text{operating}\\ \text{costs,}\\ \text{country } i\\ \text{year } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{extraction}\\ \text{operating}\\ \text{costs,}\\ \text{country } i\end{bmatrix} \begin{bmatrix}\text{Total}\\ \text{annual}\\ \text{production,}\\ \text{country } i\text{,}\\ \text{year } t\end{bmatrix}$$

$$\begin{bmatrix}\text{Extraction}\\ \text{capital}\\ \text{costs,}\\ \text{country } i\\ \text{year } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{extraction}\\ \text{capital}\\ \text{costs,}\\ \text{country } i\end{bmatrix} \begin{bmatrix}\text{Increased}\\ \text{production}\\ \text{capacity,}\\ \text{country } i\text{,}\\ \text{year } t\end{bmatrix}$$

$$\begin{bmatrix}\text{Pipeline } p\\ \text{operating}\\ \text{costs,}\\ \text{in year } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{operating}\\ \text{costs,}\\ \text{pipeline } p\end{bmatrix} \begin{bmatrix}\text{Total flow}\\ \text{pipeline } p\text{,}\\ \text{year } t\end{bmatrix}$$

$$\begin{bmatrix}\text{Pipeline } p\\ \text{capital}\\ \text{costs,}\\ \text{in year } t\end{bmatrix} = \begin{bmatrix}\text{Unit}\\ \text{expansion}\\ \text{costs,}\\ \text{pipeline } p\end{bmatrix} \begin{bmatrix}\text{New capacity}\\ \text{pipeline } p\\ \text{installed in}\\ \text{year } t\end{bmatrix}$$

Define OC_t as total operating costs in year t, $oc_{i,k}$ as the unit marginal operating costs of gas production in country i from reserve k, and op_p as the unit marginal operating costs of pipeline segment p. The following equation defines the sum of these costs:

$$OC_t = \sum_i \sum_k oc_{i,k} X_{i,k,t} + \sum_p op_p PF_{p,t} \quad (9)$$

Define IN_t as total investment costs in year t, $cc_{i,k}$ as unit capital costs for expansion of gas production from reserve k in country i, and cp_p as the capital expansion cost associated with an increase in pipeline segment p's capacity by one Bcm per year. These costs are annualized and discounted to reflect the fact that new capacity that become available in year t incurs its investment expenditures in the previous year.[9] The following equation defines total investment costs in year t:

$$IN_t = \sum_i \sum_k cc_{i,k} I_{i,k,t} + \sum_p cp_p IP_{p,t} \quad (10)$$

<u>Objective Function</u>

The objective function represents what the model is attempting to achieve, or how it selects among alternative programs that are feasible in the sense that all constraints are satisfied. Here, the model is asked to find the feasible program with the lowest discounted present

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[9] In addition, to account for terminal conditions and the long life of investments, the capital costs near the end of the planning horizon are truncated.

value cost. Other objective functions could be utilized in models such as this one. These include maximization of revenue to producers or taxes to governments, or simulation of competitive or monopolistic market behavior. However, to use other objective functions would have required more data than was available for this study.

Define TDC as the total discounted costs of any solution, and δ_t as the discount factor in year t.[10] This total is calculated using the following equation:

$$TDC = \sum_t \delta_t [OC_t + IN_t] \tag{11}$$

PRICE STRUCTURE OF THE MODEL

In addition to solving for the endogenous variables described above, (technically called primal variables), the model calculates a set of implicit or "shadow" prices (dual variables). Each constraint or equation has an associated shadow price, that represents the marginal cost--in terms of the objective function--of that constraint being "tightened" by one unit. These are calculated based on the model's internal cost structure and are used in determining the optimality of any intermediate solution. In effect, the model knows that an optimal solution is found whenever: (a) all variables that are not at their upper or lower limits have the property that the marginal benefits (MB) from increasing that variable by a small amount exactly equal the

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[10] In principle, the discount rate need not be constant over time. Also, different discount factors could be applied to different flows if these differed substantially in their risk characteristics.

marginal costs (MC) of doing so; and (b) there are no variables for which marginal benefits exceed marginal costs.[11] These costs and benefits are calculated using the shadow price structure. The shadow prices also are useful in that they can be employed in evaluating specific projects outside the model, so long as those projects are not too "large."

To illustrate how the shadow price structure works, we examine the interrelations among a few key prices and variables. Consider first the costs and benefits of exporting a small additional amount from country i to country j; that is, increasing variable $E_{i,j,t}$ by one Bcm. This variable appears in three or more equations: the supply-demand balance (equation (1)) for the exporting country, the supply-demand balance (equation (1)) for the importing country, and as many equation (6)'s as there are pipelines through which that export of gas must flow. The shadow prices associated with each of these equations or constraints can be used to perform a cost-benefit test on whether this variable should be increased or decreased. The production cost of the gas is the shadow price of equation (1) for the exporting country. To this must be added transportation costs, which are the sum of the shadow prices of all pipeline capacity constraints through which the gas flows on its way to country j. This must be compared with the implicit value of gas imported into country j, which is the shadow price of equation (1) for that country. If the total cost of increasing $E_{i,j,t}$ is less than the

[11] These are known as the "complementary slackness" conditions and hold for all constrained optimizing problems.

cost of $E_{k,j,t}$, where "k" is exports from another country, then the model will choose to increase exports from i to j and reduce them from country k.

The next step is to see what determines the marginal production cost of gas in country i. Here we examine the equations where $X_{i,k,t}$ appears. Marginal operating costs of extractions are $oc_{i,k}$ times the shadow price of equation (9), which is merely the discounted value of expenditures in year t. Capital rental charges for equipment are added from equation (4). Together these form total out-of-pocket marginal production costs. In addition to direct costs, there are "user" costs related to resource depletion. These appear as the shadow prices of constraints (2) and (3). The shadow price of (3) is the value of being able to produce one additional unit from a low-cost reserve in which production is constrained by an upper limit related to remaining reserves. The shadow price of (2) represents the cost of limiting future production from the reserve because depletion now decreases the upper bounds on possible production in later years. The value of the gas in producing country i is the shadow price of equation (1) for that country.[12]

To determine the costs of using a particular pipeline, the model calculates the marginal operating costs from equation (9) and the capital rental charges from equation (6). While the former costs are

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[12] Note that whenever a country is producing from more than one resource or reserve base in a given year, the model adjusts the user costs of the lower-cost resources so the total costs of producing from all resources is identical. If this were not the case, it would pay to stop producing from one or more reserve.

always positive, the latter are positive only when a pipeline is being fully utilized. The total capital costs for pipeline expansion are derived from equation (10) when the model itself determines the optimal expansions. But in other cases where, for reasons of economies of scale, the pipeline expansion is taken as part of the exogenous scenario, these costs are added directly to the objective function as constant increments to total cost.

RESULTS

This section illustrates how the model can be used to analyze the factors that determine least-cost supply patterns and marginal costs of delivering gas. The simulations use data that were developed as part of the Supply and Demand chapters, as summarized in Tables 5-1 to 5-6.

Table 5-1 summarizes the four different demand scenarios that were developed for this study.[13] The "low" and "high" demand growth scenarios correspond to "high" and "low" average oil prices, respectively. As explained more fully in the Demand chapter, the reason why gas demand grows relatively slowly when world oil prices are high is that the negative income effect of high oil prices on economic growth outweighs the positive substitution effect of lower relative gas prices. The reverse holds true when oil prices are low.[14] The relatively minor

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[13] This table contains the average annual growth rates for gas demand in each scenario. However, the model actually utilizes a time sequence of demand growth rates for each country in which yearly growth rates often diverge substantially from the average. The Demand chapter provides more detail on these derivations.

[14] Note that for those countries that are net oil exporters, gas demand grows more rapidly in the "low" case because both their economic growth and oil prices are positively correlated.

differences between the average annual growth rates are explained by the fact that the opposite signs of the income and price substitution effects associated with changes in world oil prices nearly cancel each other. The "super" demand growth scenario is meant to represent an upper limit on how rapidly demand might grow through a combination of faster economic growth, reductions in the relative price of gas, and other demand promoting effects.

The reserve and production cost data used in the model are presented in Table 5-2. (The Supply chapter discusses their derivation in greater detail.) Tables 5-3 to 5-5 summarize assumptions about the pipeline network, including the marginal costs of shipments through each segment, and the capital costs of expansions. One of the questions the model can be asked is whether there are additional costs associated with meeting import demand under existing contracts, which may not represent the lowest costs of production and transportation. The estimated minimum deliveries corresponding to existing gas contracts are summarized in Table 5-6.[15]

Although these tables summarize our best estimates, we recognize that there is great uncertainty about supply costs, future expansions in the pipeline network their costs, and future demand growth. Therefore, the results discussed here should be interpreted as tentative and illustrative. The model is available for others to use substituting their own assumptions.

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[15] For details on the derivation of these numbers, see Appendix B of the Demand chapter.

Table 5-5

Pipeline Expansion Costs

Pipeline	Size of Increment (Bcm per year)	Investment Cost ($ bils.)	Full Capacity Annual Usage Cost ($/Mcf)
Norway - United Kingdom	20	1.0	0.21
Norway - W.Germany	20	1.5	0.32
USSR - W.Germany	40	7.5	0.80
USSR - Austria	20	3.8	0.80
Algeria - Italy	12	1.6	0.57
Algeria - France	10	0.5	0.21
Netherlands - W.Germany	1	0.022	0.09

Table 5-6

Minimum Contracted Volumes, Adjusted for Take Provisions
(units: Bcm/year)

Exporter/Importer	1984	1987	1990	1993	1996	1999	2002	2005	2008	2011	2014	2017
Algeria/Belgium	1.6	1.5	1.5	1.5	1.5	1.5	1.5	0.0	0.0	0.0	0.0	0.0
Algeria/France	8.1	7.1	6.7	6.7	6.7	4.0	4.0	0.0	0.0	0.0	0.0	0.0
Algeria/Italy	6.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	9.6	0.0	0.0	0.0
USSR/Austria	4.1	2.0	2.0	2.0	1.2	1.2	1.2	0.0	0.0	0.0	0.0	0.0
USSR/France	4.5	7.8	9.6	9.6	9.6	9.6	8.0	6.4	6.4	0.0	0.0	0.0
USSR/W. Germany	12.7	16.0	16.0	16.0	8.4	8.4	8.4	0.0	0.0	0.0	0.0	0.0
USSR/Italy	7.6	12.0	12.0	12.0	6.4	6.4	6.4	6.4	0.0	0.0	0.0	0.0
Holland/Belgium	5.8	2.1	2.1	2.1	1.5	1.5	1.5	1.5	0.0	0.0	0.0	0.0
Holland/France	7.8	5.0	3.6	3.3	3.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Holland/W. Germany	18.2	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	0.0	0.0	0.0
Holland/Italy	0.4	3.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Norway/Belgium	2.0	3.0	3.0	3.4	4.1	2.8	2.6	2.6	1.6	1.6	1.6	1.6
Norway/France	2.2	3.4	3.4	5.0	7.7	7.9	7.8	7.8	6.4	6.4	6.4	6.4
Norway/Holland	3.0	3.0	3.0	3.4	4.1	2.8	2.6	2.6	1.6	1.6	1.6	1.6
Norway/UK	13.6	7.6	7.6	7.6	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Norway/W. Germany	5.5	9.2	9.2	10.8	13.5	9.7	9.0	9.0	6.4	6.4	6.4	6.4

To demonstrate how the model can be used, summary results are presented for five cases. Case 1 assumes a medium level of demand growth for natural gas. For the period 1984-2017, the average rate of demand growth is about 2 percent per year, with consumption growing somewhat faster in France, West Germany, and Italy, and more slowly in the United Kingdom and the Netherlands. In addition, we assume that the model is free to disregard existing contracts in choosing the minimum cost pattern of meeting demand. Pipeline capacity is shown in Table 5-4.

Table 5-7 summarizes the results for Case 1. The top portion of the table lists the assumptions about the underlying scenario and the total discounted costs of meeting this level of demand.[16] The scenario assumptions are summarized in terms of which demand-growth pattern is used, whether exports are constrained by policy and/or existing contracts, and if new pipelines are added in addition to those specified in Table 5-4. The next portion of the table summarizes the time pattern of trade flows. The most striking result is that, through the 1990s, Continental import demand is met by exports from the Netherlands for those countries (West Germany, France, Italy, and Belgium) where there is a choice among sources. This is due to relatively low production and transportation costs in and from the Netherlands.

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[16] These include all costs associated with those internal choices the model can make. Not included are the costs of domestic production in the minor producing countries and the fixed costs of the pipelines, which are exogenous for each scenario. These are shown in Table 5-4. Solutions that include other pipelines have their investment cost added to the total.

Table 5-7

Summary Results: Case 1

Demand Scenario --medium
Export Constraints--none
New Pipelines --none

Discounted Cost ($ bils.) = 13.88

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	3.6	4.2	5.1	6.1	7.3
Belgium from Algeria	1.5	0.0	0.0	0.0	0.0	0.0
Belgium from Netherlands	5.8	12.1	14.5	17.0	11.3	6.7
Belgium from Norway	1.7	0.0	0.0	0.0	8.6	16.6
France from Algeria	9.0	0.0	15.0	22.4	31.0	31.0
France from Netherlands	7.3	33.6	26.5	27.3	0.0	0.0
France from Norway	2.3	0.0	0.0	0.0	0.0	0.0
France from USSR	4.9	0.0	0.0	0.0	28.4	39.6
Netherlands from Norway	2.8	0.0	0.0	0.0	0.0	0.0
Italy from Algeria	6.7	0.0	18.0	18.0	18.0	18.0
Italy from Netherlands	5.2	27.4	14.4	19.7	17.8	27.7
Italy from USSR	8.2	0.0	0.0	0.0	8.9	7.7
United Kingdom from Norway	12.1	0.0	11.9	20.0	0.0	16.7
W. Germany from Netherlands	15.0	45.1	51.1	0.0	0.0	0.0
W. Germany from Norway	7.0	0.0	0.0	2.9	22.9	49.3
W. Germany from USSR	13.5	0.0	1.9	60.1	52.6	41.4
Total Gas Trade Flow	105.8	121.7	157.6	192.4	205.6	262.0
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.45	0.49	0.76	1.11
Belgium from Algeria		NA	NA	NA	NA	NA
Belgium from Netherlands		0.15	0.42	0.46	0.75	1.10
Belgium from Norway		NA	NA	NA	0.75	1.10
France from Algeria		NA	0.44	0.48	0.76	1.12
France from Netherlands		0.17	0.44	0.48	NA	NA
France from Norway		NA	NA	NA	NA	NA
France from USSR		NA	NA	NA	0.76	1.12
Netherlands from Norway		NA	NA	NA	NA	NA
Italy from Algeria		NA	0.48	0.52	0.81	1.16
Italy from Netherlands		0.21	0.48	0.52	0.81	1.16
Italy from USSR		NA	NA	NA	0.81	1.16
United Kingdom from Norway		NA	0.33	0.36	NA	0.71
W. Germany from Netherlands		0.14	0.40	NA	NA	NA
W. Germany from Norway		NA	NA	0.44	0.71	1.07
W. Germany from USSR		NA	0.40	0.44	0.71	1.07

As low-cost reserves in the Netherlands are depleted and absolute demand levels increase, other supply sources are needed. By the turn of the century, France and Italy begin importing from Algeria, while West Germany imports increasingly from the Soviet Union. When pipeline (and LNG) capacity from Algeria reaches its upper limit, France and Italy begin importing from the Soviet Union. Norwegian exports to West Germany rise rapidly because the pipeline from the Soviet Union to West Germany reaches its upper capacity limit, and it is less expensive to satisfy French demand with that gas than for France to import from Norway.

The United Kingdom is a special case because the model can choose to meet its demand through either increased domestic production or imports from Norway. In the early years, it is less expensive to produce domestically than import, but the reverse is true in later years as low-cost reserves are depleted.

The last panel in Table 5-7 presents the marginal costs of each import in the optimal solution.[17] These include the marginal costs of production and transportation from exporting to importing country. These are "pure" marginal costs in the sense that they do not include any rents or taxes. Also, the amortization costs associated with capital investments, such as pipeline or initial production capacity, are exogenous to the model. For these reasons, the marginal costs may appear low. However, they are consistent both with the production and

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[17] Values are shown only for imports that have positive levels. Imports which potentially might have been included in the solution but are not, are indicated by "NA."

transportation costs shown in Tables 5-2 and 5-4 and with the fact that demand does not grow rapidly in this scenario. Toward the end of the projection period, costs begin to increase quite rapidly as low-cost reserves either become depleted (e.g., the Netherlands) or not available at the margin due to pipeline limitations (e.g., Algeria).

These results may be considered infeasible in the sense that they are inconsistent with existing gas delivery contracts. Case 2 differs from Case 1 in that the minimum "takes" associated with existing contracts are imposed as a minimum condition. These are summarized in Table 5-6. Demand above these minimums can be satisfied by the least-cost trade patterns. Table 5-8 contains summary results for this scenario. Through the end of this century, the model chooses to deliver the minimum levels from Norway, Algeria, and the Soviet Union. Additional quantities come from the Netherlands, which is the lowest cost producer. The bottom portion of Table 5-8 shows the differences between the unit costs from the Netherlands and from other exporters to each importing country.

As contracts expire and as low-cost reserves in the Netherlands are depleted, the model selects a balanced trade pattern based entirely on cost considerations. The main difference between the trade pattern for later years in Cases 1 and 2 is that the Netherlands remains an exporter for a longer period, exporting much less in the 1990s in Case 2 than in Case 1. In the case of the United Kingdom, the minimum imports from Norway in Case 2 mean that domestic reserves are greater in later years, which implies that domestic production in the first decades of the next century will be cheaper than continuing to import from Norway after

Table 5-8

Summary Results: Case 2

Demand Scenario --medium
Export Constraints--minimum contracts imposed
New Pipelines --none

Discounted Cost ($ bils.) = 17.71

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	3.6	4.2	5.1	6.1	7.3
Belgium from Algeria	1.5	1.5	1.5	1.5	0.0	0.0
Belgium from Netherlands	5.8	7.6	8.9	12.9	18.3	8.3
Belgium from Norway	1.7	3.0	4.1	2.6	1.6	15.1
France from Algeria	9.0	6.7	5.8	4.0	24.5	31.0
France from Netherlands	7.3	13.9	20.8	29.9	13.5	0.0
France from Norway	2.3	3.4	6.7	7.8	6.4	6.4
France from USSR	4.9	9.6	8.3	8.0	15.0	33.2
Netherlands from Norway	2.8	3.0	4.1	2.6	1.6	1.6
Italy from Algeria	6.7	7.8	9.6	18.0	18.0	18.0
Italy from Netherlands	5.2	9.7	16.4	13.3	20.3	27.7
Italy from USSR	8.2	9.8	6.4	6.4	6.4	7.7
United Kingdom from Norway	12.1	7.6	7.6	0.0	0.0	20.0
W. Germany from Netherlands	15.0	21.6	31.1	45.6	12.9	0.0
W. Germany from Norway	7.0	8.5	13.5	9.0	10.8	42.9
W. Germany from USSR	13.5	14.9	8.4	8.4	51.9	47.8
Total Gas Trade Flow	105.8	132.3	157.3	175.0	207.2	267.0
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.45	0.45	0.64	1.11
Belgium from Algeria		0.32	0.32	0.32	NA	NA
Belgium from Netherlands		0.10	0.15	0.27	0.62	1.10
Belgium from Norway		0.46	1.10	0.52	0.62	1.10
France from Algeria		0.30	0.30	0.30	0.64	1.12
France from Netherlands		0.12	0.17	0.29	0.64	NA
France from Norway		0.48	1.12	0.54	0.64	1.12
France from USSR		0.45	0.45	0.45	0.64	1.12
Netherlands from Norway		0.43	1.08	0.49	0.60	1.08
Italy from Algeria		0.30	0.30	0.33	0.68	1.16
Italy from Netherlands		0.16	0.21	0.33	0.68	1.16
Italy from USSR		0.50	0.50	0.50	0.69	1.16
United Kingdom from Norway		0.33	0.98	NA	NA	0.74
W. Germany from Netherlands		0.08	0.13	0.26	0.60	NA
W. Germany from Norway		0.42	1.07	0.48	0.59	1.07
W. Germany from USSR		0.40	0.40	0.40	0.59	1.07

existing contracts expire. Of course, this conclusion is sensitive to assumptions about demand growth in the United Kingdom, which in this scenario grows very slowly.

Note, however, that the total discounted costs are significantly greater under existing contracts than they would be if trade patterns depended solely on costs. In Case 2, the increase in discounted costs is almost $4 billion, an increase of more than 27 percent over Case 1. Similar results were obtained by exogenously constraining the level of total exports from the Netherlands, either in absolute amounts or relative to remaining low-cost reserves.

The model also can be used to estimate the implications of different patterns of gas demand growth. Simulations were conducted using each of the scenarios summarized in Table 5-1 with and without minimum contract "takes" imposed. Results for the "super" demand scenario are presented in Tables 5-9 (no minimum contract constraints) and 5-10 (minimum contract takes). Here, gas demand in Western Europe grows at a rate so rapid it cannot be satisfied (at any cost) without building more pipelines than those that were initially assumed and summarized in Table 5-4.

For these cases the model was run with numerous alternative pipeline additions, with the discounted capital costs of "new" pipelines being added to production and pipeline operating costs, which are determined in each solution. The results for the configuration with the lowest total discounted costs are reported in Tables 5-9 and 5-10.[18]

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[18] Since all possible configurations were not tried, this trial-and-error procedure does not necessarily lead to a true minimum-cost solution. However, comparison of the many solutions obtained suggests that our results are not too far from the global optimum.

Table 5-9

Summary Results: Case 3

Demand Scenario --"super"
Export Constraints--none
New Pipelines --1996: Algeria-Italy +12 Bcm
2002: Norway-UK +20 Bcm, USSR-W. Germany +40 Bcm
2005: Algeria-Italy +18 Bcm, USSR-Austria +20 Bcm
2008: Norway-UK +20 Bcm
2011: USSR-Austria +30 Bcm, USSR-W. Germany +40 Bcm
2014: Norway-W. Germany +30 Bcm, Algeria-Italy +18 Bcm
2017: USSR-W. Germany +40 Bcm
Discounted Cost ($ bils.) = 26.39

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	4.8	6.3	8.2	10.7	13.8
Belgium from Algeria	1.5	0.0	0.0	0.0	0.0	0.0
Belgium from Netherlands	5.8	15.0	19.7	24.8	31.6	40.0
Belgium from Norway	1.7	0.0	0.0	0.0	0.0	0.0
France from Algeria	9.0	12.0	15.0	31.0	31.0	31.0
France from Netherlands	7.3	31.3	43.5	8.8	11.4	17.7
France from Norway	2.3	0.0	0.0	0.0	0.0	0.0
France from USSR	4.9	0.0	0.0	35.5	55.3	76.5
Netherlands from Norway	2.8	0.0	0.0	0.0	0.0	0.0
Italy from Algeria	6.7	18.0	30.0	30.0	30.0	66.0
Italy from Netherlands	5.2	18.3	18.7	25.5	26.4	0.0
Italy from USSR	8.2	0.0	0.0	6.9	24.3	38.2
United Kingdom from Norway	12.1	0.8	20.0	22.6	58.1	35.1
W. Germany from Netherlands	15.0	59.4	18.6	0.0	0.0	0.0
W. Germany from Norway	7.0	0.0	1.0	15.5	66.0	86.0
W. Germany from USSR	13.5	0.0	58.8	85.5	65.7	84.5
Total Gas Trade Flow	105.8	159.6	231.6	294.3	410.6	488.9
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.55	0.95	2.18	0.45
Belgium from Algeria		NA	NA	NA	NA	NA
Belgium from Netherlands		0.28	0.51	0.94	2.17	3.24
Belgium from Norway		NA	NA	NA	NA	NA
France from Algeria		0.30	0.53	0.96	2.19	3.26
France from Netherlands		0.30	0.53	0.96	2.19	3.26
France from Norway		NA	NA	NA	NA	NA
France from USSR		NA	NA	0.96	2.19	3.26
Netherlands from Norway		NA	NA	NA	NA	NA
Italy from Algeria		0.34	0.57	1.00	2.23	0.50
Italy from Netherlands		0.34	0.57	1.00	2.23	NA
Italy from USSR		NA	NA	1.00	2.23	0.50
United Kingdom from Norway		0.36	0.41	0.82	1.03	1.14
W. Germany from Netherlands		0.27	0.50	NA	NA	NA
W. Germany from Norway		NA	0.50	0.91	2.14	3.21
W. Germany from USSR		NA	0.50	0.91	2.14	3.21

The most important additions to the network for reducing costs are periodic increases between Algeria and Italy, the Soviet Union and Germany, and Norway and the United Kingdom.

The pattern of gas trade in Case 3 is not too different from that in Case 1, although the trade volumes are much larger in each time period. The Netherlands initially is still the primary exporter, with Algeria and the Soviet Union becoming major exporters in the 1990s, and Norwegian exports growing rapidly afterwards. This is similar to the results obtained when demand grows more slowly, but the transitions in that instance are much accelerated.

Not surprisingly, it would be quite costly to meet this level of demand growth. The total discounted costs of Case 3 are about twice those for Case 1. The differences are more pronounced in the later years, when the absolute differences in gas consumption are larger. In Case 1, the marginal costs of one additional Mcf of demand averaged about $0.75 in 2008. In Case 4, the marginal costs are nearly 3 times as high, averaging about $2.20 in 2008.

The only difference in the scenarios for Cases 3 and 4 is that minimum contract takes are imposed in the latter. As expected, the effect of these additional constraints is to increase total costs by slowing exports from the lowest cost source (the Netherlands) and using higher cost gas from Norway, the Soviet Union, and Algeria. But in comparison with Cases 1 and 2, the absolute and relative effect of these constraints is much less. The reason is that demand grows so rapidly that exports from higher cost suppliers are needed by early in the 1990s in any case.

Table 5-10

Summary Results: Case 4

Demand Scenario --"super"
Export Constraints--minimum contracts imposed
New Pipelines --1996: Algeria-Italy +12 Bcm
2002: Norway-UK +20 Bcm, USSR-W. Germany +40 Bcm
2005: Algeria-Italy +18 Bcm, USSR-Austria +20 Bcm
2008: Norway-UK +20 Bcm
2011: USSR-Austria +30 Bcm, USSR-W. Germany +40 Bcm
2014: Norway-W. Germany +30 Bcm, Algeria-Italy +18 Bcm
2017: USSR-W. Germany +40 Bcm

Discounted Cost ($ bils.) = 28.52

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	4.7	6.3	8.1	10.7	13.8
Belgium from Algeria	1.5	1.5	1.5	1.5	0.0	0.0
Belgium from Netherlands	5.8	10.5	14.1	20.7	30.0	38.4
Belgium from Norway	1.7	3.0	4.1	2.6	1.6	1.6
France from Algeria	9.0	6.7	11.0	13.5	31.0	31.0
France from Netherlands	7.3	23.6	32.5	18.7	28.3	38.5
France from Norway	2.3	3.4	6.7	7.8	6.4	6.4
France from USSR	4.9	9.6	8.3	35.3	32.0	49.3
Netherlands from Norway	2.8	3.0	4.1	2.6	1.6	1.6
Italy from Algeria	6.7	7.8	30.0	30.0	48.0	66.0
Italy from Netherlands	5.2	18.6	12.3	26.0	8.4	0.0
Italy from USSR	8.2	9.8	6.4	6.4	24.3	38.2
United Kingdom from Norway	12.1	7.6	9.3	22.6	56.2	30.3
W. Germany from Netherlands	15.0	35.9	53.9	12.9	12.9	0.0
W. Germany from Norway	7.0	8.5	13.5	9.0	29.7	58.9
W. Germany from USSR	13.5	14.9	11.1	79.1	89.0	111.7
Total Gas Trade Flow	105.8	169.4	225.0	296.9	410.2	485.7
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.45	0.64	1.16	0.45
Belgium from Algeria		0.32	0.36	0.66	NA	NA
Belgium from Netherlands		0.17	0.32	0.62	1.15	1.26
Belgium from Norway		0.51	1.00	0.94	1.16	1.26
France from Algeria		0.30	0.34	0.64	1.17	1.28
France from Netherlands		0.19	0.34	0.64	1.17	1.28
France from Norway		0.53	1.02	0.96	1.18	1.28
France from USSR		0.45	0.45	0.64	1.17	1.28
Netherlands from Norway		0.48	0.97	0.91	1.13	1.24
Italy from Algeria		0.30	0.48	0.68	1.21	0.50
Italy from Netherlands		0.23	0.48	0.68	1.21	NA
Italy from USSR		0.50	0.50	0.69	1.21	0.50
United Kingdom from Norway		0.38	0.78	0.81	1.03	1.14
W. Germany from Netherlands		0.16	0.40	0.61	1.14	NA
W. Germany from Norway		0.47	0.87	0.90	1.12	1.23
W. Germany from USSR		0.40	0.40	0.59	1.12	1.23

Another possible application of the model is to evaluate, at least in part, the economics of building additional pipeline capacity. For instance, note that in Case 1 it is optimal to fully utilize the exogenous pipeline capacity of 18 Bcm per year between Italy and Algeria from 1996 onward. This full utilization implies that the model would choose larger volumes of Algerian exports to Italy if it could, because that would satisfy Italian demand at lower total cost. However, the capital costs of building a pipeline must be compared with the potential savings.

The results of such an experiment are shown in Table 5-11. The underlying scenario is identical with Case 1 except export capacity between Algeria and Italy is increased by 12 Bcm per year beginning in 1996. This additional capacity is utilized, with Italian imports from the Netherlands (and later from the Soviet Union) being reduced accordingly. This permits greater exports from the Netherlands to Germany and France, with those countries reducing their higher cost imports from the Soviet Union and France. In total, the effect of these reallocations is to reduce production costs and marginal transportation costs by $210 million (discounted to present value). However, when the discounted cost of the additional pipeline is included, the total discounted costs of this scenario are $310 million <u>greater</u> than for Case 1.

In closing, we again emphasize that these results are meant to be illustrative of the model's structure and potential applications. The outcomes of the scenarios reported here are highly sensitive to specific cost data for each country, projected pipeline construction and costs,

Table 5-11

Summary Results: Case 5

Demand Scenario --medium
Export Constraints--none
New Pipelines --1996: Algeria-Italy +12 Bcm

Discounted Cost ($ bils.) = 14.19

	1984	1990	1996	2002	2008	2014
Imports (Bcm/year)						
Austria from USSR	2.8	3.6	4.2	5.1	6.1	7.3
Belgium from Algeria	1.5	0.0	0.0	0.0	0.0	0.0
Belgium from Netherlands	5.8	12.1	14.5	17.0	16.4	6.7
Belgium from Norway	1.7	0.0	0.0	0.0	3.6	16.7
France from Algeria	9.0	0.0	4.9	13.3	31.0	31.0
France from Netherlands	7.3	33.6	36.6	36.4	0.0	0.0
France from Norway	2.3	0.0	0.0	0.0	0.0	0.0
France from USSR	4.9	0.0	0.0	0.0	28.4	39.6
Netherlands from Norway	2.8	0.0	0.0	0.0	0.0	0.0
Italy from Algeria	6.7	0.0	30.0	30.0	30.0	30.0
Italy from Netherlands	5.2	27.4	2.4	7.7	12.8	15.7
Italy from USSR	8.2	0.0	0.0	0.0	2.0	7.7
United Kingdom from Norway	12.1	0.0	20.0	20.0	0.0	14.3
W. Germany from Netherlands	15.0	45.1	53.0	2.9	0.0	0.0
W. Germany from Norway	7.0	0.0	0.0	0.0	22.9	49.3
W. Germany from USSR	13.5	0.0	0.0	60.1	52.6	41.4
Total Gas Trade Flow	105.8	121.7	165.6	192.4	205.6	259.6
Marginal Import Cost ($/Mcf)						
Austria from USSR		0.45	0.45	0.48	0.64	1.11
Belgium from Algeria		NA	NA	NA	NA	NA
Belgium from Netherlands		0.14	0.28	0.45	0.63	1.10
Belgium from Norway		NA	NA	NA	0.63	1.10
France from Algeria		NA	0.30	0.47	0.64	1.12
France from Netherlands		0.16	0.30	0.47	NA	NA
France from Norway		NA	NA	NA	NA	NA
France from USSR		NA	NA	NA	0.64	1.12
Netherlands from Norway		NA	NA	NA	NA	NA
Italy from Algeria		NA	0.34	0.51	0.69	1.16
Italy from Netherlands		0.20	0.34	0.51	0.69	1.16
Italy from USSR		NA	NA	NA	0.69	1.16
United Kingdom from Norway		NA	0.33	0.36	NA	0.71
W. Germany from Netherlands		0.13	0.27	0.43	NA	NA
W. Germany from Norway		NA	NA	NA	0.59	1.07
W. Germany from USSR		NA	NA	0.43	0.59	1.07

and exogenous demand projections. One obvious implication of these data is that the marginal costs of importing gas to Western Europe are low in comparison with existing contract prices, and that they do not rise very sharply unless demand grows extremely rapidly. This suggests that different results would doubtlessly obtain if the data contained in Tables 5-1 through 5-5 were revised substantially.

FLEXIBILITY AND PRICE TERMS IN CONTRACT NEGOTIATIONS IN EUROPEAN NATURAL GAS MARKETS

by

John E. Parsons

INTRODUCTION

This chapter analyzes two key issues involving long-term natural gas contracts in the Western European market. The first is the extent to which the various suppliers will need to depend upon contracts with high take provisions, as opposed to more flexible provisions or spot sales, under various conditions. A treatment of contracts in an earlier study discussed the criteria by which such a decision is made;[1] this chapter applies them to the various suppliers in the Western European gas market. Second, an analysis is undertaken of the price indices typically used in this market, the problem of price renegotiations, and the extent to which changes in the contract delivery prices can be anticipated. Appendix A provides a summary of the source material of the parameters used in the country analyses discussed in this chapter.

The chapter shows that there is an increased possibility for more flexible contracts in Western European natural gas markets. However, this possibility is supplier- and field-specific. The Groningen fields will

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[1] International Natural Gas Trade Study Group, Final Report: East Asia/Pacific Natural Gas Trade, MIT Energy Laboratory Report No. MIT-EL 86-005, Cambridge, Massachusetts, March 1986.

continue to play the role of flexible supplier, as they have in the past. The large new contribution to flexible supplies will be the Troll fields. This chapter also shows that the cost figures developed in the Supply chapter by Adelman and Lynch for the Troll field justify development without use of strong take-or-pay contracts; however, the numbers indicate that the field cannot be a flexible supplier in the same fashion as Groningen, and some security is needed in the form of take commitments. Supplies from Algeria and the new Troll field represent an intermediate case, with liquefaction (for Algeria) and transportation costs high enough to make take-or-pay commitments an important contribution to project returns. While marginal Soviet gas deliveries may be made using current excess capacity, new Soviet gas will be developed only with traditional take-or-pay commitments. This chapter also explains why contract prices likely will remain tied to oil prices, and why renegotiations will only partially respond to short-term gas sale prices. The price renegotiated will continue to be referenced partially to project costs.

CONTRACT FLEXIBILITY

As explained in the earlier study, one primary objective of take-or-pay contracts in gas markets is to eliminate opportunistic behavior by buyers, thereby guaranteeing the supplier a price that will cover the cost of the large capital expenditures necessary to develop and deliver natural gas, as well as a reasonable profit. This problem is particularly important in the Western European gas market, which is characterized by a small number of buyers (primarily France, Italy, the Federal Republic of Germany, and the United Kingdom), some of which have monopsonistic power.

For example, the British Gas Corporation (BGC) exercises this power over fields in the North Sea, and Ruhrgas exercises significant power in brokering purchases from both the USSR and Norway. An important fact to bear in mind, and one often overlooked, is that monopsonistic power can be used not only to negotiate a relatively low price relative to other markets (as the BGC did for many years), but--due to the large capital expenditures targetted specifically for delivery of gas to a given customer--monopsonistic power also can be used opportunistically to bargain a price that renders the initial investment unprofitable. This second factor is a problem not just for the seller, but for the buyer as well. The buyer's future ability to engage in opportunistic behavior will be anticipated by suppliers, who will require some form of guarantee--such as a strong long-term contract--that will reduce the profitability of the relationship. This problem has been perpetuated by the failure of Western Europe to develop a common carriage system (see the Demand chapter for a detailed discussion).

A key task is to determine exactly how important these opportunism problems are, and exactly how much change in the nature of take-or-pay contracts can be anticipated. The earlier treatment of contracts in the East Asia/Pacific natural gas trade study presented a model ("CONTRACT," which is included as an appendix to the Contracts chapter in a previous study [see Footnote 1]) for estimating the portion of a field's net present value that is secured by means of long-term contracts. This chapter applies the CONTRACT model to the Western European natural gas market in order to assess opportunities for introducing more flexible contract relationships between buyers and sellers. A brief review of the model follows.

The opportunistic bargaining problem basically is rooted in the small number of buyers facing any given supplier and in the high capital costs needed to develop both a natural gas field and its delivery system. If a supplier were to install capacity without being assured of a given rate of return via strong long-term contract commitments, then it would face the danger that buyers might be in a position to negotiate a lower delivery price from the supplier. The problem is determining the significance of this danger, and estimating the lower range of prices that a supplier can anticipate if capacity is installed without such commitments.

CONTRACT provides this estimation. It takes as input various parameters both of a potential supplier's cost structure and of the prices that would be the likely outcome of negotiations for long-term contracts (including the possibility that negotiations would fail to reach any agreement). The model then projects a probability distribution of prices that a supplier could anticipate from sales made to that same market or to buyers after capacity has been installed on a "spot" or short-term basis.

The model essentially evaluates the importance of the opportunistic bargaining power that the installation of capacity yields to the potential buyers. In instances where there is excess demand, competition among suppliers will neutralize any opportunistic bargaining power that the installation of capacity may have yielded to buyers. In instances where there is excess supply, the price may be bid down as a result of the bargaining power that the installation of capital yields to buyers. How low the price will be bid depends critically upon the cost structure of the gas field. For example, if there are high capital costs, then prior to the installation of capacity the supplier will not accept a low price, and the buyers either will accept a price that makes the development of the field worthwhile or they will refuse such a price and the field will be cancelled. Once the capacity has been installed, however, the buyers are aware that the supplier may accept price terms below those which will yield it an acceptable rate of profit on its initial capital expenditures, and their bargaining position therefore will be more aggressive. Their ability to negotiate a lower price then depends upon the probability that there will be excess supply available at prices below those necessary to yield an adequate return on the supplier's capital. In the results presented below, note that suppliers with very low capital costs per Mcf of natural gas have significantly greater leeway in developing fields in the absence of strong take-or-pay contract provisions.

The key inputs to the model are: (1) the number of potential buyers, which determines the competitive pressures that buyers will face during negotiations for the supplier's capacity; (2) the range of possible reservation prices (i.e., the prices above which each buyer may be willing to purchase the gas--this must be a range, since from the supplier's point of view, there is a significant degree of uncertainty in negotiations about the actual price it can demand from buyers; and this uncertainty is a central issue behind the value of long-term contracting); and (3) per unit operating costs. The probability that the reservation price of enough buyers will be at the lower end of the range of reservation prices, so there is excess supply at a price below total unit costs, is the determining factor in assessing the value of long-term take-or-pay contracts.

The primary results of applying the CONTRACT model to the Western European natural gas market are as follows.

Opportunities exist in that market to increase the flexibility of contract provisions in the coming years. However, this increased flexibility will be provided by particular suppliers, and does not represent a feature to which all suppliers must adapt. For instance, the Netherlands can continue to operate as a flexible supplier. Norway's Troll field represents the new and large addition to gas supplies that can be prudently developed without reliance on strong take-or-pay provisions.

Our analysis of the Troll field, based on publicly available cost data, demonstrates that long-term, inflexible take-or-pay contracts are unlikely to increase the security and value of the Troll field by a magnitude comparable to Soviet fields or traditional gas projects. In many of the press reports about the announcement of the development of this field, there has been much discussion of the suprisingly flexible or low commitment of contracted gas. Our results demonstrate that this is neither a peculiar marketing strategy nor a dangerous experiment in new markets on the part of the Norwegians, but simply a consequence of the project's cost structure.

Alternately, one may view our results, along with the information that the Troll field contracts are very flexible, as evidence that the field developments costs probably are in the low range, as has been claimed. However, the capital costs for Troll given by Adelman and Lynch are slightly higher than those given for low-cost Algerian gas. Both Troll and low-cost Algerian gas can be developed with increasingly flexible contracts. A key variable determining the possibility for flexibility of both is the number of markets that each supplier feasibly can serve. If there is a difference in flexibility between Troll and low-cost Algerian supplies, it is likely to come as a result of the development or failure to develop alternative routes and markets to supply. While marginal additions to USSR and high-cost Algerian supply, using existing excess delivery capacity, may be possible on the basis of short-term sales, the model suggests that strong long-term contracts remain an essential ingredient for future development of significant capacity for these two suppliers.

The following material summarizes results for each of the major suppliers.

USSR

To assess the importance of strong take-or-pay contracts in the future development of USSR natural gas fields and pipeline capacity, data for the CONTRACT model must be developed. Cost data for development, production, and transportation costs are taken from estimates provided by Lynch's Appendix B to the Supply chapter. At the high end of what he terms "sensible estimates," the above-ground costs for field development and new pipelines are around $2.56/Mcf, of which about two-thirds, or $1.70, are capital costs. Operating costs (that is, short-run variable costs of supply) account for the remaining $0.86/Mcf. USSR gas currently flows to three primary buyers: France, Italy, and the Federal Republic of Germany. A range of possible reservation prices is used for each of these three buyers, running from $1.50 to $4.25/Mcf, with an expected delivery price of about $3.32/Mcf.

As noted earlier, an important question concerns the probability that the negotiated price would fall below the total project costs of $2.70/Mcf. For a project with an annual delivery of approximately 9 Bcm at an expected base price of $3.32/Mcf, a long-term contract with high take requirements would yield the USSR a net present value of $1.69 billion. Increasing flexibility or anticipating that much of the gas would be sold through spot market or short-term sales would cut the expected net present value by almost 34 percent, or by $0.57 billion. In the case of the USSR, if the range of possible prices is as specified and the cost structure is close to that estimated by Lynch, then the danger is significant that the price of gas sold absent strong take-or-pay contracts will yield an inadequate rate of return. This indicates that, for USSR gas, there should be little significant shift to spot sales. The USSR reasonably could seek to use its current excess capacity for spot sales, but this should not be viewed as anything other than a temporary feature of the market.

The above calculations used future natural gas prices higher than those currently prevailing. One should not take current spot sales as an indicator of the long-term clearing price for fixed-commitment contracted gas. (This issue is discussed in greater detail below; for the moment, note that the high prices currently reported for Troll gas are a reminder that such an identification would be in error.) The picture regarding moves to flexibility in USSR gas contracts is, however, even starker if one believes that current natural gas prices represent a long-term trend, for this implies smaller margins and a greater cost due to opportunistic behavior.

These figures apply only to gas contracts requiring capital expenditures on new fields and pipelines. For existing extra capacity, the importance of long-term contracts will be less. However, once new capacity is needed, then the amount of gas being sold under short-term arrangements from pre-existing fields must be incorporated into calculations for the new field; otherwise, the contracts for the new field supply merely will replace the supply delivered under short-term arrangements, therefore failing to provide the supply security for which they were intended.

One important caveat concerns the USSR's Eastern European customers. If the quantity of gas demanded and supplied to these buyers continues to increase significantly, then the negotiating relations between the USSR and its Western European buyers will be altered significantly. The issue is not related to problems of long-term supply limitations or increasing supply costs and their effect on which buyers will have access to gas at what price; rather, given an anticipated level of gas deliveries to Western Europe, the salient point is that the existence of potential Eastern European customers able to draw from the same field and delivery system significantly reduces the ex post bargaining problem for the USSR. Given an expected level of demand in both Western and Eastern Europe, the possibility that one set of buyers--in Western Europe, for example--may seek to negotiate lower delivery prices after the capacity has been installed is less threatening to the USSR. Although the additional gas that the USSR would need to divert from Western to Eastern Europe probably could be sold in Eastern Europe only at a price lower than in Western Europe, this lower price represents a floor on opportunistic bargaining that the USSR may face.

The results of running a similar simulation for USSR fields, which included a total of six potential buyers under the assumption that it is possible to switch delivery of supplies from one buyer to another, show that the importance of long-term contracts falls significantly, although still remaining notably large. The importance of long-term contracts both to the net present value (NPV) of a field and to pipeline capacity development drops from 30 to 9 percent of the NVP under the best assumptions, or to $152 million of a field NPV of $1.69 billion.

NORWAY: THE TROLL FIELD

Calculations concerning Norwegian gas from the Troll field yield a significantly different conclusion regarding possibilities for flexible contracts. According to cost figures presented by Lynch and Adelman in the Supply chapter, the capital expenditures necessary to develop Troll are dramatically below the expected price of gas, even under several dismal future price scenarios. Therefore, the dangers inherent in developing the Troll field, absent strong take-or-pay terms, are likely to be minimal, and it is reasonable to expect that this field will be developed using innovative and flexible purchasing commitments.

For our simulation of the value of long-term contracts for the Troll field, we used a figure of $1.09/Mcf in capital costs, and $0.40/Mcf in operating expenses. Notice that long-term contracts are important only when the short-term sales price can be opportunistically bargained below this relatively low cost--an event with low probability. To examine the extreme danger case, the model assumes three potential buyers, with reservation prices ranging from $0.50 to $4.00/Mcf, yielding an expected price of $2.75. For this set of possible scenarios, long-term contracts offer the project a moderate amount of security, guaranteeing 9 or 10 percent of the project's NPV and prices only $0.10/Mcf greater than those that would result from short-term sales with opportunistic bargaining.

Of course, if Norway increases the capacity of the Troll field so it approaches a capacity satisfying the total demand of its potential customers, then the danger of opportunistic bargaining increases. Nonetheless, the extremely low cost of development makes even this situation relatively danger-free, at least compared to other gas projects. At the extreme assumption of an expected price of $2.35 and a possibility that the price drops as low as $1.60 in take-or-pay contract negotiations and to $0.50 in short-term sales negotiations, the take-or-pay contracts secure 13 percent of the NPV, a relatively low figure for most natural gas markets.

THE NETHERLANDS

Costs of Dutch gas from Groningen are far below expected prices, and a relatively large portion of the costs are in operating expenses. Under these conditions, the value of long-term contracts is nil.

Of course, deliveries from Groningen were the first to be cut back in times of excess supply (such as in the early 1980s), perhaps creating the impression that, absent long-term contracts, the Dutch face buyers who cancel their initial commitments and potentially demand lower prices, thereby creating the impression that long-term contracts would be useful in securing more stable markets. In fact, this impression is the result of confusion regarding the role that the Dutch fields play <u>given</u> the low importance of long-term contracts in securing the NPV of their development. The realized flexibility in actual supplies in no way contradicts the conclusion that long-term and inflexible contracts would not add to the value of the Dutch fields. The cutbacks in purchases made in times of excess supply do not represent opportunistic behavior on the part of buyers, or an unanticipated event, or an effort on the part of buyers to force renegotiation of long-term prices lower than originally anticipated. The Dutch are able to meet the needs of consumers and thereby are able to extract a premium price--a premium price on average. In times of excess supply they will cut back their deliveries and in times of shortage they will deliver with a premium charge. This role for Groningen gas will continue into the future, with the possible amendment that it will face competition from the new Norwegian fields, Troll in particular.

The other Dutch fields are significantly more expensive. The costs for the Zuidwal field ($1.133/Mcf), while significantly above those for Groningen, nevertheless are notably below the range of long-term expected natural gas prices. Thus, even for these more expensive Dutch fields, there is a great amount of room for contract flexibility not possible for the USSR or Algerian fields.

However, since the other Dutch fields are more expensive than Groningen, it could make sense for the Dutch to sell gas from these fields first, preserving Groningen gas for the premium flexible market.

ALGERIA

The final major supplier is Algeria. As mentioned above, there is significant possibility for increased flexibility in Western European markets stemming from the gas fields in the Netherlands and, to a dramatic extent, from the Troll field. However, as emphasized before, this does not imply that all producers should adapt their practices to this new development. Like the USSR, Algeria must expend large amounts of initial capital to make its gas deliverable to the Western European market. This suggests that long-term take-or-pay contracts are likely to remain a significant feature of Algerian contracts. However, note that Algeria, like Troll, represents a somewhat intermediate supplier: It is not as dependent upon long-term contracts as is the USSR, but nevertheless it is unable to choose the flexible supply market as its targetted market.

Again, note that this conclusion refers primarily to new investments in capacity and does not concern marginal additions to capacity or sales of current excess capacity.

Using the CONTRACT model and inputting data from Adelman and Lynch's supply cost estimates, Algeria seems in a better position than its current insistence on relatively high-priced inflexible contracts would justify. We begin by using cost estimates for the Hassi R'Mel project in Algeria, in which the total capital costs c.i.f. to South France are $0.92/Mcf and operating costs are $0.32/Mcf. We assume only two buyers, and possible reservation prices range from $1.00 to $5.00/Mcf, with the expected price being $2.80/Mcf. In this situation, the long-term contracts secure at most 10 percent of the project development NPV. If the expected price is $3.00/Mcf, then the importance of the long-term contracts drops to between 2 and 7 percent of project NPV. When the number of potential buyers is three and the expected price $2.50/Mcf, then the importance of long-term contracts is negligible.

For the set of highest-cost estimates--those for the Rhourde Nousse field--the results are more tentative. If an expected price of $2.50/Mcf is calculated for two buyers, then the certainty of a take-or-pay contract provides Algeria with an NPV 30 percent higher than without. When there are three buyers, the importance of long-term contracts falls to 9 percent. For higher expected prices, the value of long-term contracts falls only marginally.

The example of Algerian supply allows us to emphasize the importance of understanding the role of long-term contracts in interpreting the behavior of actual gas markets, and to contrast this with an understanding of typically competitive commodity markets. In most clearing markets, the price of a good is determined by the marginal value of the commodity and by the marginal cost. A producer's actual cost of production does not determine the profit that producer will earn. If one producer has a cost of production higher than other producers, then it will earn a smaller rate of profit in long-run equilibrium. The rate of profit it can expect to earn may affect its decision to enter the market at all, but there is no other connection between its costs and the market price of its product.

In seeming contradiction of this basic principal of economics, Algeria often has claimed that its high costs of liquefaction require that it receive a higher price for its gas than other suppliers receive for theirs. In a clearing market, this is unjustifiable. A buyer will purchase from the lowest-price supplier, and if the Algerians wish to be the supplier, then they must offer the clearing price regardless of their own costs. However, gas markets are much more complicated than is indicated if only the moment at which is market clears is considered, and this is one point embedded in the CONTRACT model.

Consider a case where Algeria signs a long-term contract to deliver LNG at the current market-clearing price, but requires that the buyer commit to purchasing a given volume over the next 20 years, then embeds these terms in stringent take-or-pay clauses. These conditions are embedded in the contract to ensure that the buyer will not renegotiate opportunistically. They yield to Algeria a minimum payment, regardless of the buyer's future decisions. Now assume that the prices of substitute fuels move downward, so that buyers now wish to renegotiate the price of their takes. Under this new circumstance, the gas market may clear among other buyers and suppliers (for instance, the Netherlands), so the new clearing price is significantly lower than it was at the time the original contracts were signed. Should we therefore anticipate that Algeria will be forced to readjust its price closer to this new clearing price? Would it be in Algeria's best interest to do so?

Although the common answer to this question is yes, it may not be correct. The Algerians may either refuse to reopen their contract or they may accept renegotiations--on the principal that the price to be negotiated should be above the price of Dutch gas "because the costs of liquefaction are high." This would be a reasonable position in which the price paid is "determined" _ex post_ by the costs of production, although at the time the contract was signed the price was set in expected value to clear against all other suppliers, i.e., according to the marginal value of the gas. This _ex post_ reference to cost is an effort to enforce the _ex ante_ efficient contract, which was written in reference to the clearing price. This confusion between _ex post_ and _ex ante_ efficiency and the stubborn insistence that current deliveries or even renegotiated contract prices should be related to the then-current clearing price for new gas is a major one in discussions of gas contracts and renegotiation problems.

PRICE INDICES

This chapter began with a discussion of those economic features of the natural gas industry that compel producers to demand long-term contracts. The central conflict created by the decision to require long-term contracts is the need to reconcile the object of specifying the obligations of the consumer or buyer, that is, the need to constrain the flexibility on the one hand, and the need to adapt the contracts or the obligations of the buyer so they respond fairly to the sometimes drastically changing market circumstances that occur during the term of the contract. If two parties sign a contract when an alternative fuel--oil, for example--is priced at $28/barrel, then when oil becomes available at $15/barrel, the obligation to continue purchasing natural gas at higher prices negotiated earlier may have disasterous consequences for the buyer.

In standard commodity markets, the price response of a good to the changing costs of supply and to changing market prices for substitutes is determined by the concurrent forces of supply and demand: Buyers either may continue purchasing the commodity at the going price or switch to the substitute commodity. For reasons discussed above, and in greater detail in the East Asia/Pacific study, it is not often possible to permit this form of price determination in the natural gas market, or in any market requiring long-term contracts. If the buyer were free to demand a lower price for natural gas by threatening to abrogate the contract, then the objective of the contract--to protect the producer against opportunistic behavior on the part of the buyer in _ex post_ price negotiations--is undermined. The buyer also would be free to seek renegotiations to exploit the advantage of the supplier's capital commitment under the guise of changed circumstances, making cheaper alternative supplies available. The problem of price indices and price renegotiations primarily is an exercise in attempting to resolve this contradiction. That is, it is an attempt to incorporate the equilibrium price and quantity adaptations that would occur in a clearing market when there is a supply shift in a related market without also permitting opportunistic behavior.

Since the mid-1970s, natural gas delivery prices commonly have been pegged to the price of oil. Under certain simple assumptions, this is a convenient way to resolve the central contradiction of long-term contracting in the natural gas market.

Take the following situation. In a current market, natural gas is competitive with fuel oil in the industrial market. If supply conditions in the crude oil market change and if buyers are free to switch between fuel oil and natural gas, then the equilibrium prices for both oil and natural gas would change accordingly. We would expect the prices of oil and natural gas to move together--that is, in the same direction--although not in lock-step. This does not imply that natural gas always will trade at some fixed discount from fuel oil, but it does imply that if the price of fuel oil declines, then the price of natural gas also will decline by some determinable amount. Note that this is a purely counterfactual experiment--we conjecture what would happen if the market were competitive and absent any of the strategic and opportunistic elements that mandate the use of contracts in the first place.

Bearing this in mind, then a contract in which the price of natural gas is pegged to the price of oil in accordance with this equilibrium relationship can provide a resolution to the problem of contract rigidity.

A buyer faced with declining oil prices will receive a break on the price of natural gas, and renegotiations will be unnecessary. Therefore, a supplier may safely interpret a buyer's pursuit of a price renegotiation as an attempt to exploit opportunistically the bargaining power that the buyer has gained over the supplier. The legitimate objectives that a price renegotiation serves when future prices are fixed by contract and not subject to changes in alternative markets would have been satisfied by the indexing clause, and hence the supplier has no need to concede to a renegotiated price.

There are several problems with this resolution. The first is purely technical. The most appropriate price index is not necessarily the counterfactual equilibrium price relationship between oil and natural gas (hence forward referred to as "the counterfactual equilibrium relationship"). A price index that simply mimics the counterfactual equilibrium relationship simply shifts the full price risk to the supplier, and achieves no efficiency gains. One objective of imposing a price index is not simply to pass the benefits of the cost decrease to the buyer, but to induce the buyer to make "efficient" future take decisions under the changed market conditions. If the producer has the right to determine the volume of subsequent takes, for example, based on the new price, then one objective of the price index would be to induce the most efficient take decisions *ex post*, and thereby to improve the *ex ante* efficiency of the contract. The price might conform more or less to the counterfactual equilbrium relationship, depending upon the divergence necessary to induce the proper incentives.

This is related to the fact that, although gas prices recently have been pegged to oil prices, the gas market has not "cleared." This may be currently inefficient, *ex post*, but it also may be interpreted as an outcome that, as one element of an entire earlier contractual relationship, formed an efficient market *ex ante* (as argued above in terms of the Algerian renegotiation position).

A second problem is that the counterfactual equilibrium relationship may be very complex and poorly understood. While true, it still may significantly improve flexibility.

The third and most serious problem is that it probably holds true only over a narrow range of prices. If, for example, the price of oil falls significantly over an extended period, then natural gas might more directly compete with fuel oil in the industrial market, making the relationship between oil and natural gas in this range more elastic. But as we cannot predict the future, any index is likely to encounter difficulties. This is Adelman's point when he decries the persistent efforts of many suppliers to index the price of natural gas to the price of oil. There is no single, persistent, pre-determinable relationship between the two. Yet, while this may be true, it is not sufficient reason to recommend against using the price of oil as an index. For the reasons just given, this index yields an *ex post* delivery price that is, on average, more in accordance with what one might expect from a clearing market--but it avoids instituting this clearing market and thereby preserves some advantages of long-term contracts not present in a clearing market. It is a compromise and an imperfect resolution to the central contradiction that arises out of the need to contract, but its strengths are real.

Finally, we must distinguish between the short- and long-run equilibrium price relationship between the oil and gas markets. The short-run relationship may differ significantly from the long-run relationship. One typically would wish to write the price formulae in terms of the long-run relationship.

The problem of short- versus long-run raises an additional complication in the area of appropriate incentives. The responsiveness of natural gas prices to changes in demand is supposed to stimulate decisions to shift in and out of natural gas. If price changes are preprogrammed, then it is not clear that the desired long-run adjustments in the various consuming segments that would justify the long-term price adjustment will in fact occur. In fact, it typically is necessary to write the price index so the contract price does not completely adjust so much as it would in the reduced form counterfactual equilibrium relationship. If the price of oil rises, then the contract price of natural gas also rises, but remains below market-clearing levels. Conversely, if the price of oil falls, the price of natural gas falls but not enough to permit the gas market to clear. This feature of the necessary price index reinforces the comments above regarding Algeria's bargaining strategy.

One example of this type of problem is particularly relevant to pegging the price of natural gas to oil. The development of new natural gas supplies was one of many market responses to the OPEC cartel. To the extent that natural gas supplies are pegged to oil prices in a manner that guarantees the oil suppliers that, if they raise their prices, then the price of gas will rise as well, can work to stabilize or strengthen the power of the cartel. However, if the corresponding rise in gas prices is less than what the cartel would establish, and is equal to what would arise in our counterfactual equilibrium relationship under competition in which cheaper gas supplies replace oil (albeit at higher prices, due to higher oil prices), then this effect will not take place.

The decision regarding which alternative fuels should be the basis for indexing therefore is fundamentally a decision about what one believes is the comparative static reduced-form relationship of the equilibrium prices for the counterfactual negotiations. If one believes that natural gas will compete with distillate fuel oil and that the movements of distillate fuel oil prices will determine the equilibrium prices for natural gas, then one would choose distillate fuel oil as the price index. However, this does not imply that natural gas must remain in lock-step with distillate fuel oil: One might choose a much looser, non-linear relationship.

In Western Europe, where differences in national energy policies and in economic and consumption factors produce a variety of price elasticities, one would expect that contracts written between different countries would be indexed to different alternative fuels. However, in constructing the index, other features also are important: the availability of the index prices series and its objectivity and accuracy.

The past several decades have seen several periods of price renegotiations and several cases of unilateral alterations in contract terms. Some contracts provide that, after a specified period of time, the original price formula may be renegotiated. In all other cases, the force majeur clause is invoked to achieve the same end.

This raises the question of what efficacy the price index has if the parties to the contract renegotiate price. Some analysts assert that the original price clauses have little meaning when this happens. But this interpretation of renegotiations may ignore some forces prevailing at the time of renegotiation and how these were anticipated when the original contract was written.

A variety of conditions and forces play a role in renegotiation, and there is a commensurate variety of ways in which they may be interpreted in terms of the objectives of long-term contracts.

First, the forced renegotiations are not purely and simply a case of reopening the original contract negotiations based upon new market conditions. In the original contract negotiations, both parties were free to accept or reject offers based on their perceptions of the alternatives available to each. In the original negotiations, there is no compelling basis for either party to accept a "fair price," except insofar as their best available alternative is that price. In renegotiations, however, another factor is present: What are the consequences if an agreement on "fair price" is not reached? The nature of these possible consequences and the notion of "fair price" need to be carefully defined.

If the contract were litigated and adjudged to be fully in force, then the possible consequences might be paying a pre-established penalty for breach of contract and the fair price might be considered the originally contracted-for price. However, in many cases the legal system will not enforce a contract to the letter of the original agreement, or it is incapable of enforcing the original penalties. Alternatively, this may not be the enforcement rule to which the supplier and buyer would have agreed *ex ante*. Also, the cost of litigation may be prohibitively expensive.

In some instances, the original contract may have been negotiated on the understanding that the price formula would apply only so long as market conditions remained within a prescribed range. If, however, conditions changed dramatically in ways not originally anticipated, then both parties might wish to abrogate. In this case, the two parties instead might wish to renegotiate the contract so it reflects what they would have agreed upon had they, at the time of the original negotiation, known these new circumstances. In this context the notion of a "fair" price becomes meaningful. It may be the reasonable task of the renegotiations, perhaps supported by agreed-upon arbitration or even litigation, to identify the price that would have been negotiated--the "fair" price.

When it is possible to specify the rules governing this process, they may be included in the contract. When it is not possible, then the arbitrartion or legal system may be called upon to determine the appropriate price formula, perhaps based on principles embodied in the original contract.

One simple example of a case where it is possible to specify a basis for identifying the price that "would have been" negotiated without having to identify a particular price <u>formula</u> comes from U.S. natural gas contracts signed in the 1960s and 1970s. In these contracts, a "Most Favored Nation" clause stipulated that a buyer must pay to one pipeline the best price that it was currently paying to other pipelines as a result of contract negotiations. Assuming that new contracts are being continually signed, then the sequence of prices the buyer agrees to pay is in some respects comparable to a spot market, and the price clause simply maintains the price of the contract at the going spot price. This accomplishes the objective stated above of having the contract price correspond to the price of a counterfactual equilibrium price, thereby permitting the seller the power to allow the buyer the right to make decisions on the size of take based upon this price. Further, it accomplishes this without resorting to the imperfect process of using a price index pegged to an alternative fuel.

However, in the Western European natural gas market, there are not enough new contracts being signed to make the Most Favored Nation clause a satisfactory surrogate to the counterfactual equilibrium price. The Western European market is characterized by a few big sellers, by some monopsonistic buyers, and at times by cooperative agreements among buyers. Nevertheless, a comparable purpose is served by the notion that there exists a "fair" price that can be determined after sufficient investigation. The notion of "fair" may assert the supplier's right to receive a given level of return on capital assets (as is the case in U.S. regulatory pricing of utility services), or the notion of fair may be determined as relating to the price of the fuels with which natural gas currently is competing. The availability of data may determine which definition is most appropriate.

The principles used during arbitration or litigation may be based on principles stated in the original contract. For example, if the parties originally pegged prices to the price of oil, then the arbitrator may use a similar benchmark, albeit with modifications, in resolving subsequent renegotiations. Alternatively, if the parties set the original price based on a specified parity relationship, then this principal may govern renegotiations. However, if the purpose of renegotiations is to break out of a previously agreed-upon relationship that no longer retains its validity, then the arbitration authorities must seek alternative solutions.

CONCLUSIONS

This chapter has discussed the possibilities for increased flexibility in natural gas take-or-pay contracts in the Western European market. At price levels existing prior to the recent cut in world oil prices, the prospects for increasing such flexibility were good. This conclusion still holds for prices below 1985 levels, although not so low as current clearing prices for short-term natural gas sales. Since current low oil prices are not likely to persist in the long run, prospects for flexibility remain.

This conclusion may not apply to particular fields and to purchases made from particular buyers. USSR current delivery capacity likely will require take-or-pay levels that were used in the past. This also holds true for certain fields, such as Algerian gas delivered from the Rhourde Nousse plant. Norwegian gas from Troll delivered to the Continent (although not to the United Kingdom) can be sold on terms similar to the sale of less expensive Algerian gas, especially if planned additional pipeline capacity to Belgium is built. These last two suppliers can be expected to sell gas on terms moderately more flexible than historically has been true in Western European markets. Nevertheless, there does not exist an alternative source for major quantities of flexible supplies such as those the Groningen field has provided.

In contrast with views expressed elsewhere in this study, this chapter's conclusion regarding oil product price indices is that oil prices will continue to play a central role in natural gas contract price terms.

Appendix A: Terms of Western European Gas Contracts by Elise L. Erler (May 1986)
(Sources: Data Resources Inc., various issues of Energy Economist, International Gas Report, Petroleum Economist).

SUPPLY CONTRACTS FOR ALGERIA (Sonatrach)

Consumer	FRANCE (Gaz de France) (3 Contracts)	ITALY (Snam)
Base Price	\$4.70/MMBtu \$4.41/MMBtu at Tunisian border	\$4.80/MMBtu
Price Index (May 1986)	100% OPEC crude oil paying in dollars	100% OPEC crude oil
Price Review	Every 3 Years	
Contract Length	#1: 25 Years #2: 25 Years #3: 20 Years	
Renegotiation	1985-1986: Price	1985: Index formula, delivery flexibility
Flexibility Terms	1984: 90%-100% take-or-pay	1984: 86%-100% take-or-pay
Delivery Level	9.1 Bcm (5/86)	1983: 2.13 Bcm 1984: 6.56 Bcm 1990: 12.0 Bcm
Price	3/86: \$3.80/MMBtu f.o.b. 12/84: \$4.46/MMBtu at Sicily	3/86: \$3.80/MMBtu f.o.b.
Basis of Supply	Supply Basis	Supply Basis
Notes	#1: 1964 contract for 0.57 Bcm/yr #2: 1972 contract for 3.83 Bcm/yr #3: 1964 contract for 5.68 Bcm/yr 12/85: France gained flexibility in take; prices are high and subsidized by French government	Second Trans-Mediterranean pipeline is being built Contracts re-established in 1982 Prices were high; subsizidized by Italian government for 3 years

Appendix A: Continued.

SUPPLY CONTRACTS FOR NETHERLANDS (Gasunie)

Consumer	France (Gaz de France)	Italy (Snam)	West Germany (Ruhrgas)
Base Price	\$3.70/MMBtu	\$4.20/MMBtu	\$3.50/MMBtu
Price Index (May 1986)	65% fuel oil; 35% gasoil; Inflation indicator 1984: Paying in ECUs	65% fuel oil; 35% gasoil; Inflation indicator 1984: Paying in dollars; want to pay in ECUs	65% fuel oil; 35% gasoil; Inflation indicator
Price Review	1984 - Every 3 Years	1984 - Every 3 Years	1984 - Every 3 Years
Contract Length	10 years added in 1984 until 2003	10 years added in 1984 until 2003-2010?	10 years added in 1984 until 2003-2010?
Renegotiation	Every 3 Years 1985: Price lowered	Every 3 Years 1985: Price lowered	Every 3 Years 1985: Price lowered
Flexibility Terms	1984: 30% take-or-pay	1984: 30% take-or-pay	1984: 30% take-or-pay
Delivery Level	1985: 5.3 Bcm (8% increase for first 6 months)	1984: 4.6 Bcm 1985: 3.4 Bcm (6% increase for first 6 months)	1985: 11 Bcm (10% increase for first 6 months)
Price	2/85: \$3.57/MMBtu	12/84: \$4.16/MMBtu at border	
Basis of Supply	Supply basis	Supply basis	Supply basis
Notes	Price index changed to compete with electricity.	Contract represented 14% of Italy's natural gas consumption.	

Gasunie has flexible swing capacity with extra natural gas available for purchase (when peak demand creates contract shortages for other natural gas suppliers or when the Soviet Union cannot make its contracted deliveries).

Appendix A: Continued.

SUPPLY CONTRACTS FOR NORWAY (Statoil)

Consumer	France (Gaz de France)	West Germany (Ruhrgas)
Base Price	$4.20/MMBtu $3.75/MMBtu (Troll) $5.50/MMBtu (Statfjord)	$4.20/MMBtu $3.75/MMBtu (Troll) $5.50/MMBtu (Statfjord)
Price Index (May 1986)	60% fuel oil; 40% gasoil Troll index includes inflation	60% fuel oil; 40% gasoil Troll index includes inflation
Price Review	Troll: Regular review for each buyer Statfjord: 10/85 and 2/86 for 6 to 9 months Sleipner: Cancelled	Troll: Regular review for each buyer Statfjord: 10/85 and 2/86 for 6 to 9 months Sleipner: Cancelled
Contract Length	Troll: 1985-2020 Statfjord: 1986-2007	Troll: 1985-2020 Statfjord: 1986-2007
Renegotiation		
Flexibility Terms	Troll: 80% to 105%	Troll: 80% to 105%
Delivery Level	Troll: Start in late 1990s; plateau at 15 Bcm after 2000	Troll: Start in late 1990s; plateau at 15 Bcm after 2000
Price	Statfjord: $3.76/MMBtu (1986 short term) Sleipner: $4.00/MMBtu (cancelled)	Statfjord: $3.76/MMBtu (1986 short term) Sleipner: $4.00/MMBtu (cancelled)
Basis of Supply	Field dedicated except Troll (supply basis)	Field dedicated except Troll (supply basis)

Notes: Final Statfjord terms not included. U.K. government rejected purchase of Sleipner gas. Norway has been selling natural gas on a dedicated field basis Except for Troll).

Appendix A: Continued.

SUPPLY CONTRACTS FOR SOVIET UNION (Soyuzgazeksport)

Consumer	France (Gaz de France) (3 contracts)	Italy (Snam) (2 contracts)	West Germany (Ruhrgas) (5 contracts)
Base Price	$3.70/MMBtu	$4.20/MMBtu	$4.20/MMBtu
Price Index (May 1986)	#1,2: 50% fuel oil; 50% gasoil; Inflation indicator #3: 40% fuel oil; 40% gasoil; 20% inflation indicator	40% fuel oil; 40% gasoil; 20% crue oil; pays in dollars	50% fuel oil; 50% gasoil
Price Review			
Contract Length		#1: 1984-2000 #2: Until 2008	#1,2,3: Until 2000 #4: 1984-2008
Renegotiation	1985: #3 price and take; next in 1987		1985: #4 contract plateau level reduced from 10.5 Bcm to 8.0 Bcm
Flexibility Terms	1984: 80% take-or-pay 1985: #3: 80%-105% take-or-pay	1984: 80% take-or-pay	1984: #4: 64%-100% take-or-pay
Delivery Level	#1,2: 4 Bcm #3: 8 Bcm 1985: Total take lowered	#1: 7 Bcm #2: Flexibly building to 6 Bcm in 1992	#1,2,3: 11 Bcm #4: 10.6 Bcm #5: 0.65 Bcm
Price		2/86: $3.10/MMBtu at border 12/84: $4.25/MMBtu at border	10/84: #4: $3.80/MMBtu
Basis of Supply	Supply basis	Supply basis	Supply basis
Notes	#1,2: Signed in 1982 to replace dwindling domestic and Dutch gas supplies.	By 1991, Italy will buy 13 Bcm per year from Soviet contracts.	#5: For West Berlin. Ruhrgas wants less contract and more spot gas from Soviet Union.

Soviet Union is increasing its natural gas sales to Western Europe to replace decreasing revenues from declining oil output.

TECHNOLOGIES FOR NATURAL GAS UTILIZATION

by

David C. White

INTRODUCTION

The use of gaseous fuels dates from the late 18th century, when town gas produced by coal gasification was used for street lighting, in residences, and in some industrial processes. The first half of the 19th century saw an excess of clean-burning and low priced gaseous fuel, as natural gas associated with petroleum production entered the market (see Chapter 2 for a fuller discussion of the history of natural gas use in Western Europe). In the United States, the petroleum, petrochemical, and other energy-intensive industries grew in close proximity to the oil fields and used natural gas as the fuel of choice for process heat, steam and electricity production, and as a chemical feedstock. The excess of associated gas plus the discovery of major natural gas fields in the United States led to the construction of natural gas pipeline networks to other major industrial centers (the distribution networks established from town gas gave a ready market for this low-cost fuel). The development of this natural gas delivery system was well-established in the United States by the mid-1900s. It has developed rapidly since the 1960s in Europe and is still expanding; and since the 1970s natural gas (mostly in the form of LNG) has been part of Japan's growing mix of fuel supplies.

Alongside a worldwide supply and transmission network for natural gas and a growing base of proven reserves, there has developed a broad set of technologies to exploit this fuel for its inherent advantages over alternative sources of energy.

Natural gas is ideal for residential, commercial, industrial, and electric generation applications that require a high-quality, thermally-controllable source of energy. Because it can be delivered essentially pollution-free (no sulfur, inorganic solids, or heavy hydrocarbons), it is possible to build simple combustion systems that produce high-temperature heat and, depending upon application and design, that emit only CO_2, H_2O, and some NO_x.

Natural gas-fired systems have the lowest capital costs of any system using a hydrocarbon fuel as its primary energy source. It can be burned as an open flame for cooking, baking, and other process applications where product contamination would render other hydrocarbon fuels prohibitive. It can be used in combustion chambers to produce steam or to heat other fluids, such as in petroleum refineries, most industrial process steam applications, or in electric power production. It can be used in internal combustion engines or gas turbines over a full range of sizes from a few horsepower to the hundred thousand horsepower gas turbines.

The large range of applications for which natural gas can and has been used, plus nearly a century of development of natural gas-burning equipment, has produced a wide spectrum of commercially available equipment. New equipment reaching commercialization in the last decade include the phosphoric acid fuel cell system, which uses reformed natural gas, and the large-scale gas turbines operating at higher temperatures and having increased thermal efficiencies (45%+) than those developed for aircraft propulsion and modified for utility peak-load applications. The increased price of natural gas in all markets worldwide following the high crude oil price rises of the late 1970s stimulated further development of natural gas-consuming equipment. Efficiency improvements were sought to help maintain its cost competitiveness with both other hydrocarbon fuels and electricity. Today much of this development work is yielding improved efficiences in gas-consuming equipment used in all consuming sectors. Thus, as natural gas markets return to price competitiveness in today's era of lower world crude oil prices, a full set of technologies and commercially available equipment are in place, ready to exploit natural gas's other important attributes--namely, that of its being a clean-burning, low-polluting, easily useable fuel.

The major problem with natural gas is that it is difficult both to transport and to store. Conventional crude oil and its many liquid derivatives are much easier to transport and store, and have much higher energy density per unit volume under normal temperatures and pressures.[1] Both pressurization and liquefaction are used to transport natural gas, but the former process entails the costs of constructing and maintaining pipelines from source to end user, and the latter entails the costs of

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[1] One cubic foot of middle distillate has, under standard conditions, a heat at combustion of 10^6 Btu/ft^3, while natural gas (or methane) is only 10^3 Btu/ft^3. By going to higher pressure (140 bars), the energy density increases to 180,000 Btu/ft^3 or by liquefying at approximately -160^o, increases to 675,000 Btu/ft^3.

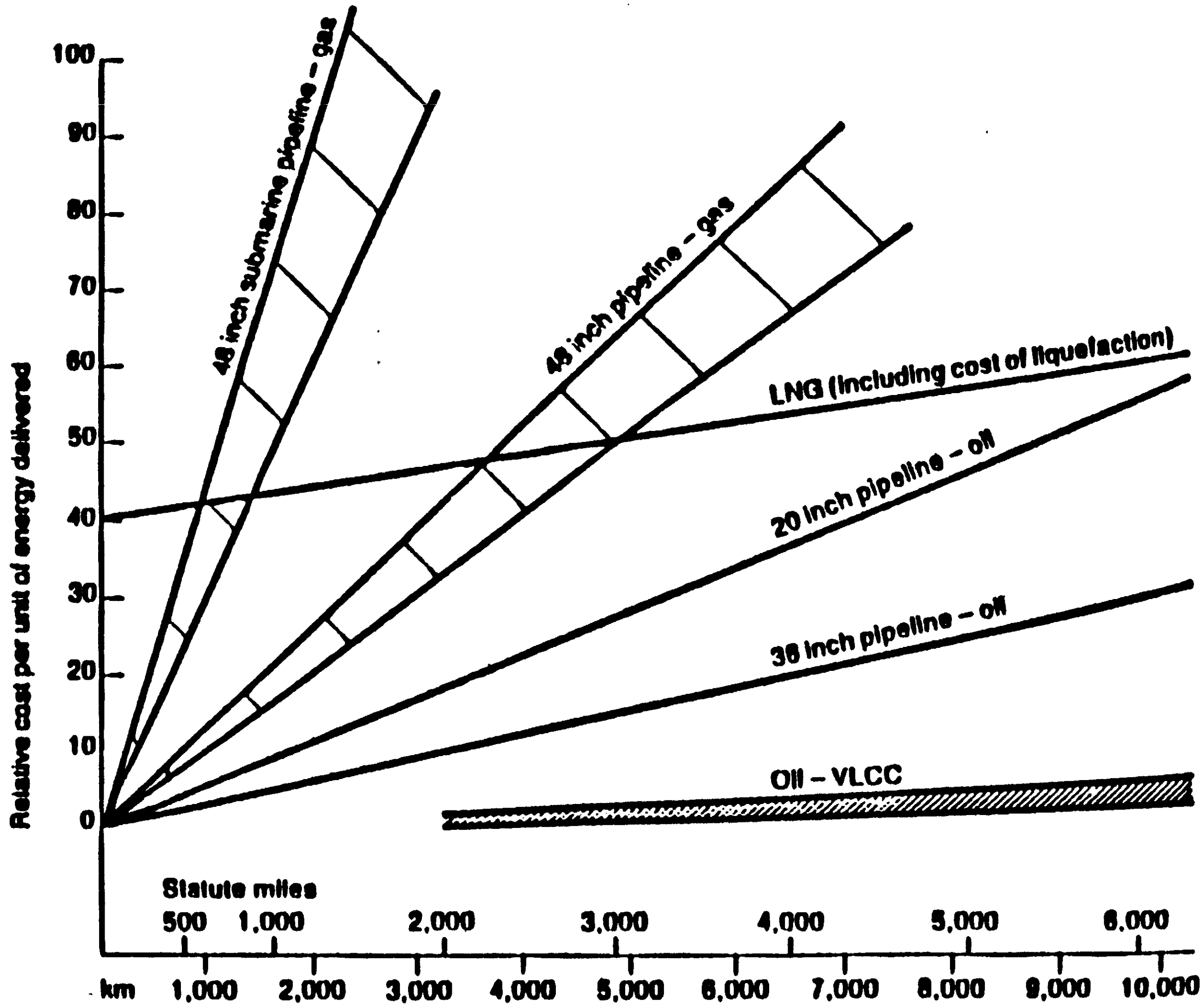
liquefying, transporting in special temperature-controlled vessels, and regasifying it for final use.

For contiguous land masses and during periods of high demand for natural gas, a pipeline system has proven to be an efficient and economic delivery system. The network of natural gas pipelines in North America has functioned well for over 50 years; at present, it gathers, transports, and distributes natural gas to meet fully 25 percent of total U.S. energy demand. The Western European system still is expanding; natural gas represents a major energy source, meeting about 15 percent of total energy demand. Figure 7-1[1] shows the relative costs of delivering hydrocarbon fuels by pipelines and ocean transport, including liquefaction of natural gas.

Liquefaction of natural gas is a well-developed, mature technology whose major disadvantage is the costs involved in liquefaction, transport, and regasification, except for long distances (over 3,000 miles), where it competes with gas transported by pipeline. For large facilities, say 1 Bcf/d, Adelman and Lynch in a previous study give typical liquefaction and regasification costs of $1.50/Mcf, plus transportation charges of $0.20/1000 miles.[2] Thus, processing and transport charges over distances of 3000 to 4000 miles are typically $2.00 to $2.50/Mcf. To this must be added the resource cost, plus profits, taxes, etc. Adelman and Lynch give typical discovery and development costs of $0.30/Mcf, so LNG delivered from supplier to large consumer at prices of $3.00 to $4.00/Mcf should be feasible and still allow for reasonable profit margins at all parts of the system. At these prices, with world crude oil priced around $20/bbl, LNG is competitive with other major clean liquid fuels, such as middle

Figure 7-1

Comparison of Oil and Gas Transportation Costs



Note: 48 inch pipeline bands cover terrain variations

Source: The Petroleum Handbook (Sixth Edition), Elsevier Publishing Company, New York, New York, 1983, p. 532, Figure 8.7.

distillates. Because natural gas is difficult and expensive to store and transport via pipelines or LNG, the potential for large rents by resource owners and developers, under normal supply/demand conditions, is substantially less for natural gas than it is for crude oil.

Today, delivery of natural gas to end users can be by pipeline, conversion to LNG and transport, or conversion to a liquid such as methanol, gasoline, or middle distillate. If a transportation fuel is desired, chemical conversion to methanol, gasoline, and middle distillate is technically feasible but expensive relative to petroleum-derived liquid fuels, mainly due to processing costs and primary energy lost in conversion.

Significant R&D programs by major oil and chemical companies are exploring ways to transform the methane molecule to a more useful liquid hydrocarbon. The high chemical stability of the CH_4 molecule makes this a difficult and expensive task in terms of process economics and energy lost. New chemical conversion technology may come in time, but basing projections on inventions not yet made is even more risky than predicting world crude oil prices. History has not treated such forecasts kindly.

The following sections discuss specific technologies based on methane and methane-derived chemical or transportation fuels. The data given are derived from the extensive published literature on natural gas-consuming equipment and technologies to convert natural gas to other products, including liquid hydrocarbon fuels. The major message from this review is that natural gas for combustion applications--including process heat, steam raising, thermal engines, and similar applications in the residential, commercial, industrial, and electric generation markets--is not constrained by the availability of cost-effective, high-performance, end-use equipment. Rather, the central issue for all these applications is natural gas supplied at competitive prices in an unconstrained marketplace. Data presented in the Supply chapter of this study indicate that natural gas, free of present policy constraints, should be available at prices competitive with world crude oil. Both the resource base and the delivery system are adequate and capable of expanding to meet current and projected demand. The technology to use natural gas is also available. These technologies will help sustain demand and, depending on other factors--prices, environmental issues, energy policy--could help natural gas obtain a growing share of future energy demand.

TECHNOLOGY FOR NATURAL GAS UTILIZATION

Technologies that use natural gas in the consuming sectors--industrial, commercial, residential, and electric utility--are well developed, mature, and available in a world-competitive marketplace. Technology for natural gas use by the transportation sector exists for speciality markets, but not as a general competitor with vehicles designed to use petroleum-based liquid transportation fuels.

Below are listed a few technologies for each consuming sector; these represent areas with new market potential and highlight developments currently underway for equipment using natural gas.

Industrial

Cogeneration:
- --gas turbine: process steam
- --energy drives (methane gas): process steam
- --fuel cell: process steam

Process Heat:
--regenerative burners (increased efficiency)
--engine-driven dryers/process heaters

Heavy Oil- or Coal-Fired Boilers:
--gas injection to reduce NO_x after combustion; can also include sulfur sorbent injection to reduce SO_x

Commercial

Packaged Cogeneration:
--engine-driven systems, consisting of electric generation, refrigerant compressors, and absorption chillers

Space Conditioning:
--gas-fired heat pumps plus, for cooling, desiccant dehumidification
--gas-fired desiccant dehumidification plus electric cooling systems

Residential

Furnaces:
--pulse combustion and condensing system (increased efficiency)
--modular heaters with advanced controls and simplified piping

Electric Generation

Base Load:
--gas turbine-combined cycle systems using advanced higher efficiency gas turbines in the 100 MW-size range

Environmental Control:
--natural gas injection for NO_x reduction after comustion; also can include sulfur sorbent injection to reduce SO_x
--natural gas in conventional boilers to reduce emissions

Transportation

CNG-Fueled Vehicles:
--currently fleets of vehicles are the most feasible application

INDUSTRIAL NATURAL GAS UTILIZATION

Natural gas has a broad market in most industrialized countries. Typically, 30 to 40 percent of the natural gas is consumed by industry in the developed Western countries (see Table 7-1).

Table 7-1[3]

Country	Industrial Gas Consumption/Total Sector Energy
United States	41
United Kingdom	32
France	22
West Germany	24
Italy	26
Japan	6

The principal uses of natural gas are in boilers to produce process steam, as process heat in the primary metals, chemicals, and paper industries, and as process drying in the food and textiles industries. The specific advantages of natural gas in these applications are:

--natural gas boilers and burners can be controlled over a wide temperature range;

--specific temperature requirements can be maintained for product quality control;

--high exhaust air temperatures can be used for preheating combustion air, which increases efficiency;

--natural gas is a "clean" fuel, and thus can be used for direct heating of liquids, foods, etc.; and

--natural gas combustion can be designed for very low pollutant emissions, and also can be useful in special applications to reduce emissions from other hydrocarbon fuels.

Natural gas faces price competition from residual oil and coal for boiler applications, a factor complicated by the fact that most industrial boilers are dual-fired, and thus allow rapid shifts from one to another fluid hydrocarbon fuel as prices change.

For process heat, natural gas and electricity compete in some applications. The more precise temperature control and improved delivery of heat energy to the work surface that is possible with some electrical heaters favor electricity over natural gas. Such applications are very price/cost sensitive, and manufacturers of gas-fired end-use equipment continue to improve their products to maintain a share of these specialty markets. To a major degree, it is the relative price of electricity versus natural gas, rather than technology advances, that determines which energy form is used.

There are social, economic, and technological reasons for industry to continue to use natural gas, but there are no specific technology innovations on the horizon that offer major opportunities for natural gas use in industrial applications. The current R&D programs sponsored by the U.S. utility industry are typical of the programs of end-use technology improvement currently underway in North America, Western Europe, and Japan.

The U.S. gas utility industry, through the Gas Research Institute (GRI), is working on selected projects to increase efficiency of natural gas industrial equipment and to develop new applications.[4] The major R&D activities include:

--Improved gas-fired engine drives for cogeneration, heat pumps, and compressors;

--Development of higher temperature and higher efficiency recuperators and heat recovery systems;

--Advanced burner and combustion controls;

--Improved and new processes for the metals, glass, and ceramics industries;

--Development of fuel cells for both cogeneration and direct production of electricity; and

--Development of improved absorption chillers and dessicant dehumidification systems for cooling.

In the United States, the general approach to R&D is to have cost-sharing on end-use equipment by the gas supply industry and the manufacturers of end-use equipment. This is helping to overcome the economic constraints of a large, disaggregated market of both buyers and suppliers. To a major extent, the technology is mature and well known, so market penetration for product innovation is difficult, although the above approach to risk sharing is proving effective in bringing forth products with improved efficiency or with new industrial applications.

Industrial Cogeneration in the United States

The installation of cogeneration facilities is economic when the electric power generated produces revenue (or savings) that justifies the capital required to build a cogeneration facility over a simple steam-raising facility. For plants in the range of 125×10^6 to 1000×10^6 Btu/hr, the additional capital for the cogeneration part of the system is approximately 130 percent for the smaller and 85 percent for the larger system. Thus, a cogeneration plant will involve a capital investment approximately two times that of a boiler producing process steam. The ability to generate sufficient revenue from electricity production to justify the larger capital investment makes cogeneration systems very sensitive to the plant steam-load factor. In general, load factors of at least 50 percent or larger are required for cogeneration to be economically feasible.

A U.S. Department of Energy (DOE) study using a real rate of return greater than 7 percent indicated that, in the United States, there could be a potential 39,000 MW of cogeneration installed in industrial sites by the year 2000.[5] Eighty percent of the plants and 90 percent of the power are in six major industrial sectors (SIC 20 - Food; SIC 22 - Textile Mill Products; SIC 26 - Pulp and Paper; SIC 28 - Chemicals; SIC 29 - Petroleum and Coal Products; SIC 33 - Primary Metals) (see Table 7-2). Over 40 percent of the power produced is in plants from 10 to 50 MW in size and nearly two-thirds in plants from 2 to 50 MW. The total potential natural gas demand represented by these industrial cogeneration facilities is between 2 and 3 Tcf. Natural gas will have to compete in price with middle distillate and residual fuel oil to obtain this market. Dual-fuel capability is usually standard practice in package boilers and cogeneration facilities.

Table 7-2 summarizes the results of the DOE study. Regionally, 40 percent of the cogeneration potential is along the eastern seaboard, and 24 percent in the southwest. The cogeneration potential is greatest, therefore, in those areas where for electric utilities the gas turbine combined cycle systems are most promising (see p. 7-26 section on "Electric Utility Use on Natural Gas" for a fuller discussion). The Tabors study projected 28 MW additional capacity to utilities along the eastern seaboard.[11] The industrial cogeneration potential in this same region is approximately 16 MW. Since both are supplying the same electricity demand, the industrial cogeneration installed will reduce the need for utility generation capacity. Should the full industrial cogeneration potential be

Table 7-2

Potential Number of Cogeneration Plant Sites, Megawatts and Sizes for ROI 7% (uninflated)[5]

SIC	Potential MW	%	Potential No. of Plants	%
20	7,005	18	734	20
22	1,882	5	499	14
26	7,962	20	437	12
28	10,316	26	547	16
29	5,836	15	236	6
33	2,397	6	434	12
Remaining Sectors	3,950	10	730	20
TOTAL	39,348	100	3,644	100

Size (MW)	Total MW Production	%
2	1,162	3
2 - 10	7,844	20
10 - 50	16,881	43
50 - 100	7,621	19
100	5,842	15
TOTAL	39,348	100

installed, the need for electric utility capacity would be reduced correspondingly. The opportunity for cooperation and net savings in capital investments between industry and utilities is substantial across the country and even greater in the eastern Atlantic coastal states. The advantage of cooperation between industry and the electricity utility sector is being recognized and used as an effective alternative way for U.S. utilities to add generation capacity to meet future electricity demand.

RESIDENTIAL AND COMMERCIAL NATURAL GAS UTILIZATION

The residential and commercial markets are major consumers of natural gas. For most countries the residential market is the largest, ranging from 35 to 60 percent, except for Italy and West Germany, which have very small residential demand. The commercial market is very country-specific, as shown in Table 7-3.[3] The sum of these markets in most countries is slightly larger than the industrial demand.

Table 7-3

(%) Residential/Commercial Sector Consumption of Natural Gas/
Total Sector Energy

Country	Residential	Commercial
United States	52	53
United Kingdom	58	--
France	36	71
W. Germany	4	17
Italy	18	42
Japan	36	39

Seasonal variations in residential demand place constraints on the supply system, because they require some storage capacity; it also stimulates selective sales of interruptable gas or other marketing procedures to reduce demand variations.

The general focus of R&D for residential end-use equipment is to increase furnace efficiency by pulsed combustion or by condensing exhaust gases. Efficiency gains from approximately 60 to over 90 percent for poorly designed and adjusted furnaces have been obtained in new, commercially available equipment. In the United States, gas-fired heat pumps are under development for colder climates.[4] Coefficients of performance (COPs) from 1.2 to 1.7 are possible in these systems. Some R&D is underway on residential-size air conditioning equipment, but this market is dominated by electric air conditioning systems and is not promising.

Another area of important R&D for the residential market is for new systems of interior piping. Flexible copper and steel tubing is being investigated, along with rapid-disconnect outlets, to accommodate gas-fired room heating equipment. The Japanese market is the most advanced in this new technology. Western Europe, and particularly the United Kingdom, also are developing this approach for new and retrofit construction. The U.S. market has not yet developed, delayed by building codes and other institutional constraints. Both end-use and gas service technologies may contribute to continued growth in residential gas demand. Western Europe residential demand has been and is projected to be an important part of future demand, so such R&D will likely help this market.

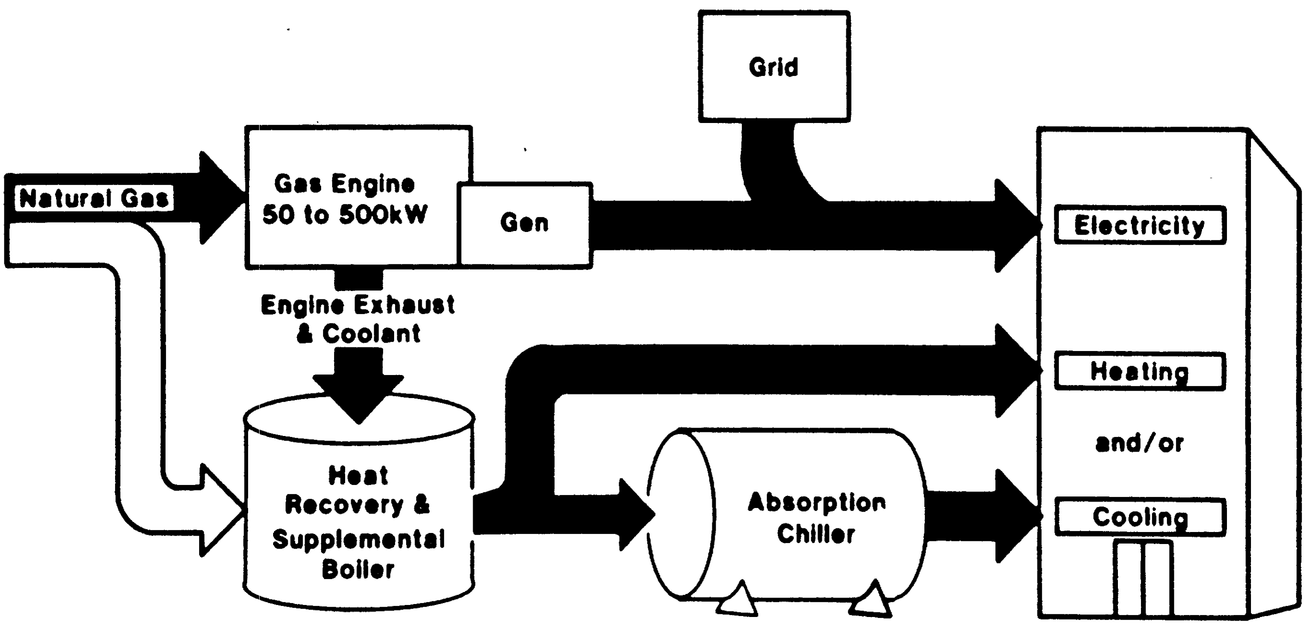
The commercial market is very country-specific, and is largely determined by building heating and cooling loads. Historically this market has consisted of packaged boilers and chillers to supply heating and cooling and other hot water requirements. Research and development to improve these conventional equipments is underway. One major thrust for U.S. markets is for package cogeneration systems, sized to thermal load, as characterized in Figure 7-2. This technology offers the promise of economic savings for commercial building owners, reducing electricity demand growth for electric utilities, and helping gas utilities to add year-round gas load. The technology under development[4] includes a range of engine-driven systems from 15 to 650 kW electric capacity. The phosphoric acid fuel cell is also part of the cogeneration strategy. Over 40 units of 40 kW size are being tested, and a 200 kW unit is under development.

Heat Pump/Air Conditioning Systems

A heat pump is a machine in which the application of external energy causes heat to flow from cold to hot regions. All heat pumps require an external source of energy. Electric, gas, solar, geothermal, and waste heat sources all have been used to drive heat pumps. Most types of heat pumps operate on a vapor compression refrigeration cycle. For a gas-fired heat pump (GFHP), the conversion from chemical energy to mechanical work is performed at the site where heating/cooling is needed; thus, thermal energy normally wasted in producing mechanical work can be captured to provide additional space heating in winter months or domestic water heating in summer months. This ability to capture and use energy normally wasted

Figure 7-2

Commercial Cogeneration
(Sized for Thermal Load)[6]



makes the gas-fired machine potentially more efficient in utilizing primary energy. Since it can combine waste heat recovery with heat extracted from the cold, outside air or from conditioned space, the GFHP also is superior to gas furnace/air conditioner systems in utilizing primary energy. If wasted heat is not captured and used during the cooling season, the efficiency advantage of a gas-fired machine is lost.

To produce mechanical work, one alternative to the thermal engine is to use an electric motor for the compression of refrigerant. The electric heat pump (EHP) is a relatively mature technology, and it is possible to obtain good performance and long life from it at a reasonably low system cost. In contrast, to perform the compression function the GFPH requires several complex components. The development of cost-competitive, yet efficient equipment represents a difficult technology challenge facing gas heat pumps.

An alternative way to produce cooling is with an absorption system, where the equivalent of refrigerant compression is accomplished by absorbing the refrigerant in a liquid solution at low temperatures, pumping the solution to a boiler with a liquid feed pump, then boiling the refrigerant out of the liquid solution by applying gas heat. Current absorption technology yields a heating COP of about 1.25 and a cooling COP of 0.5 for residential-size equipment.[4]

Modifications that can be made to improve performance of the basic absorption cycle include: multiple components, e.g., two boilers (double effect); additional heat exchangers; higher operating temperatures and/or pressures; different fluid pairs; multiple cycles; and combined cycles, e.g., regeneration. In the double-effect cycle, the latent heat of the refrigerant produced in a high-pressure generator is used to produce additional refrigerant in a low-pressure generator. A double-effect cycle is expected to improve the heat pump efficiency by 50 percent over the basic single-effect in residential-size equipment. The performance improvement requires a significant increase in hardware complexity and investment over the single-effect cycle.

Most cooling systems, whether gas or electric, actually provide two types of cooling: sensible cooling (temperature reduction) and latent cooling (dehumidification). In a desiccant-based cooling system, the latent cooling load is met by means of a desiccant, or drying agent, which removes moisture from the air. The desiccant is regenerated by the application of a heat source that releases the moisture, which is ejected to the outdoors as exhaust. Sensible cooling can be incorporated by including standard electric cooling components with reduced capacity.

In the U.S. market, Cargocaire Engineering Company provides the equivalent capacity of an 80-ton electric air conditioner by substituting 15 tons of desiccant for 60 tons of electric cooling.[6] In a typical 30,000 square-foot supermarket located in the humid southeast United States, the desiccant-based system reduces the electrical load to the customer by 27 percent, while increasing annual gas consumption by 750 to 1,500 Mcf.

Desiccant systems for cooling applications are another way to utilize waste heat from cogeneration systems or other thermal engines. In the United States, research on total desiccant cooling systems in the size range of 5 to 20 tons is under development under GRI sponsorship.[4]

Attaining COPs of 1.2 is a design objective for early systems, with 1.7 an objective for advanced systems.

Gas-fired engine-driven heat pump systems have heating COPs from 1.2 to 1.7 and cooling COPs from 0.6 to 1.0. The competitive system is the electric heat pump. In very cold climates, the GFHP is best for heating. In small sizes (particularly in residential applications) the gas-fired systems are not economically competitive with electric systems.[7] In large systems (commercial applications) either gas or electric systems may prove the best choice (see Figure 7-3). In any system comparison, size, operating conditions, regional temperatures, and gas and electricity prices all must be considered. Companies and electric utilities in North America, Western Europe, and Japan are supporting research on improving the performance and cost of their respective systems, and in time, systems with improved efficiencies are expected to reach the commercial market.

An assessment of current and projected GFHP technology was performed by GRI, and some of the results are shown in Figures 7-3, 7-4, and 7-5. While the development of new and improved technology may help retain current demand, there is no basis for projecting a significant natural gas demand growth in either the residential or commercial space conditioning markets based on outstanding gains in GFHP equipment. Lower natural gas prices may have a more dominant effect on future demand than end-use technology gains.

NATURAL GAS FOR ELECTRICITY GENERATION

Gas Turbine and Steam Turbine Cycles

Gas-fired boiler-steam turbine drives for electricity generation have a long history of use in the United States. Before 1970, natural gas was

Figure 7-3

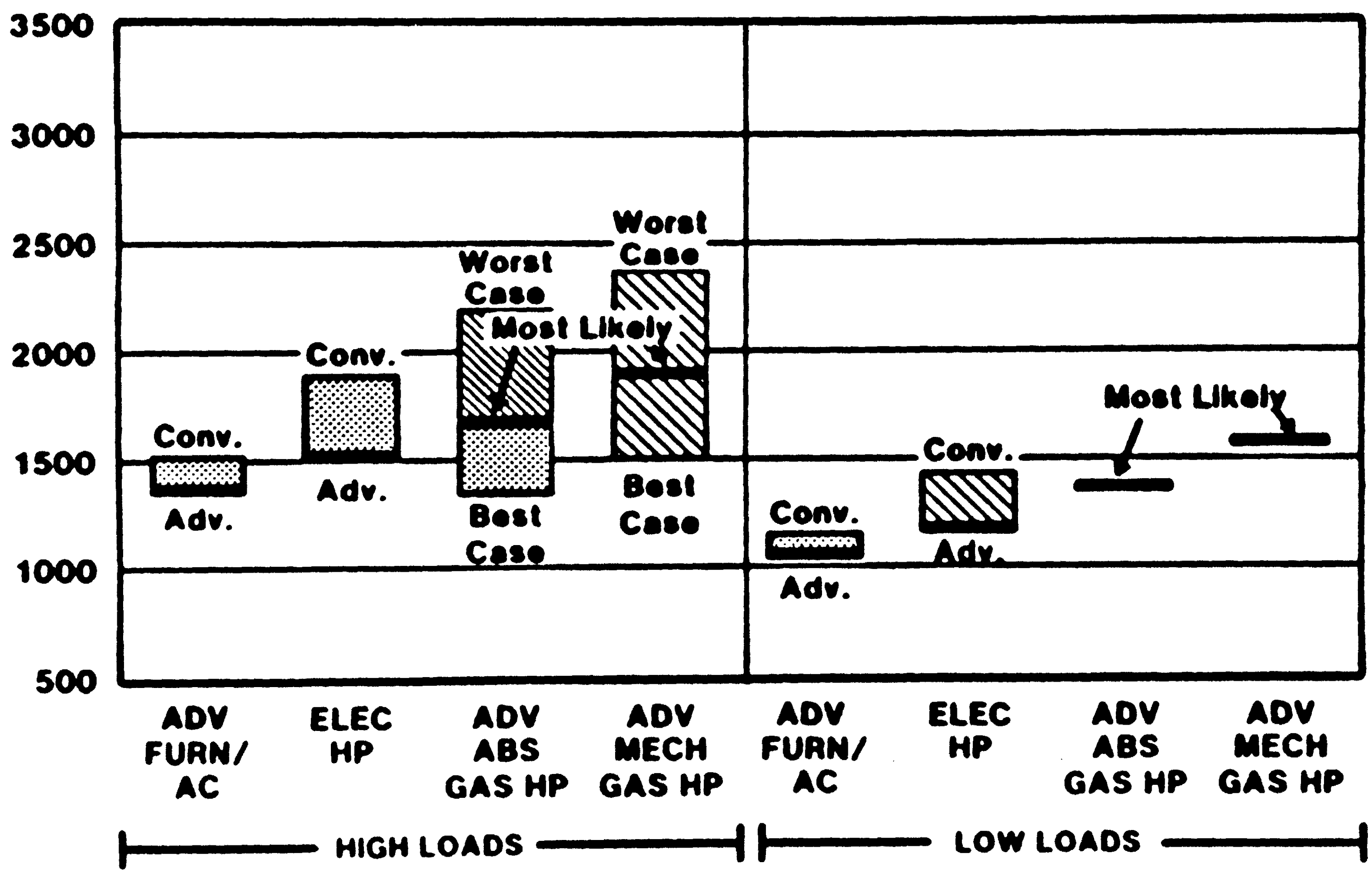
Performance and First Cost of Commercial Chiller Systems[6]

		Average Cost, $/Ton	
Existing Equipment	**COP***	**150-Ton System**	**400-Ton System**
Electric Centrifugal	5.5	300	220
Single-Effect Gas Absorption	0.7	330	240
Double-Effect Gas Absorption	1.0	500	350
Advanced Equipment			
Engine-Driven Chiller			
30% Efficient Gas Engine	1.7	330	280
With Absorption Heat Recovery	2.1	390	320
High-Efficiency Engine-Driven Chiller			
34% Efficient Gas Engine	2.0	330	280
With Absorption Heat Recovery	2.4	370	300

*Coefficient of performance, cooling output/energy input in consistent units measured at 95°F

Figure 7-4

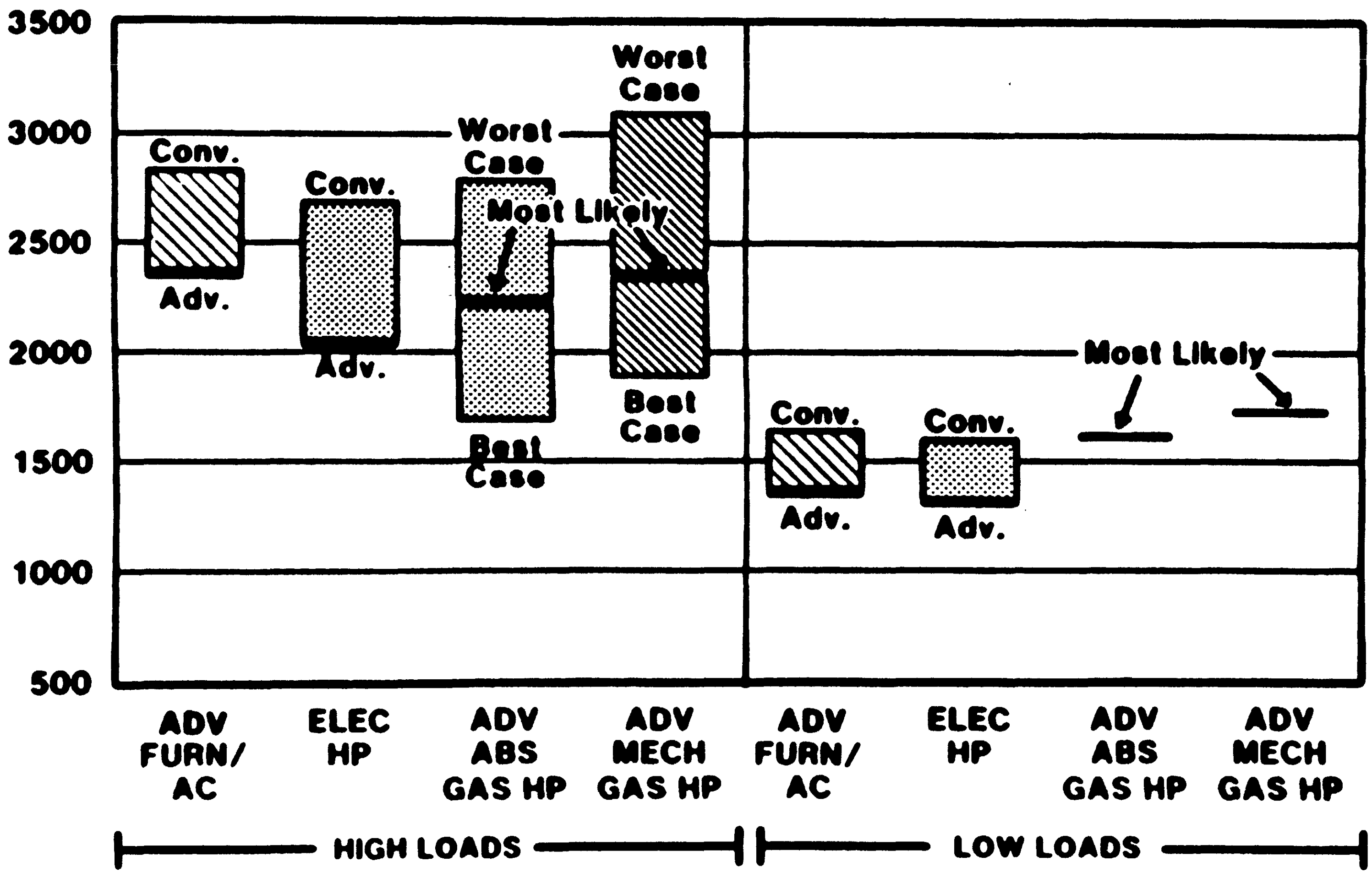
Annualized Life-Cycle Cost: West South Central Region
Base Case 1995
(1982$/Yr)[7]



Abbreviations: ADV = advanced
AC = air conditioning
HP = heat pump
ABS = absorption

Figure 7-5

Annualized Life-Cycle Cost: Mid-Atlantic Region
Base Case 1995
(1982$/Yr)[7]



Abbreviations: ADV = advanced
AC = air conditioning
HP = heat pump
ABS = absorption

the dominant industrial and utility boiler fuel in the southwestern United States. In 1985, because of excess natural gas capacity and hence favorable prices, 3 Tcf of natural gas were burned by electric utility companies. The 1986 drop in world crude oil prices may affect the consumption of natural gas. Nevertheless, the lower capital costs of natural gas boilers, considering combustor design and emission controls, make such systems competitive with residual fuel oil and even coal, if long-term, competitively priced natural gas is available.

While uncertainties in both government regulations and the future price of natural gas make conventional boiler steam turbine systems unlikely in the United States, there is growing interest in gas turbine combined cycle systems (GTCC) for electric utility applications. Several U.S. utility companies currently are planning GTCC installations based on using middle distillate or natural gas by obtaining a Federal Energy Regulatory Commission (FERC) waiver of the Fuel Use Act for a specified period (usually 10 years).[8]

The largest commitment to GTCC systems comes from the Japanese utility industry.[9] The plan is for 7,200 MW to be built by 1994. In 1985, Tohoku Electric brought on-stream two 548 MW GTCC systems in 1985 that were supplied by Mitsubishi. The measured efficiency was 49.1 percent (low heating value [LHV] for methane). Using the high heating value (HHV) typically used in U.S. efficiency calculations yields a 44 percent efficiency. The NO_x level was 10 ppm, obtained using a low NO_x combustor, followed by selective catalytic reduction using ammonia hydroxide in the exhaust streams. The combination of high efficiency and very low emitted pollution is a major accomplishment. The approximate 10 point gain in efficiency over conventional scrubbed coal or heavy fuel oil-fired steam plants is a significant fuel savings for these gas-fired GTCC systems. While less than one year of operation has been logged on these plants, their current and projected availability is high, making them attractive competitors for base- as well as intermediate-load applications.

The first of the GTCC systems at Tohoku Electric was built in approximately 30 months and placed into commercial operation just 34 months from the start of construction. Modular design and factory construction of the heat recovery boiler (four units: economizer, evaporator, SCR module, and super heater) plus three gas turbines (118 MW) and one steam turbine (191 MW) helped to reduce the plant construction time.

In the East Asia/Pacific region, where there is significant present and future natural gas available, the GTCC system is a promising and very competitive technology.

In the electric utility sector of the Federal Republic of Germany, existing regulation hinders the use of gas. Gas-fired power plants for base-load generation currently are not licenced by the authorities. Only if the regulation changes could base-load gas-fired power plants be built.

In France, for example, the electric utility sector uses primarily nuclear fuel and therefore natural gas plays only a minor role. Since the electric utility industry in France has a very high nuclear capacity, it provides electricity at relatively low cost to the industrial and residential sectors. Natural gas is not likely to be a factor, unless this situation were to change drastically.

In Western European countries with indigenous gas resources, such as the Netherlands and Norway, planning and construction of combined cycle power stations for electricity generation are under way. In Norway a 1000 to 2000 MW station will be built, and in the Netherlands existing power stations will be replaced with combined cycle stations. The driving force for these decisions is not technology but the availability of cheap natural gas. In the current, government-managed gas markets of most Western European countries, technology will not be a major influence on natural gas demand.

Table 7-4 shows typical use of natural gas for electricity production in four Western European countries, and in the United States and Japan.

Table 7-4[3]

Country	% Natural Gas for Electricity/Total Sector Energy
United Kingdom	-0-
France	2
West Germany	15
Italy	12
Japan	22
United States	14

Electric Utility Use of Natural Gas in the United States

The U.S. electric utility industry currently uses approximately 3 Tcf of natural gas annually, of which two-thirds are under firm contracts and one-third are interruptable.[10] Of this gas, over 98 percent is used in steam boilers and approximately 1.2 percent is used for combustion turbine peaking power. North American Electric Reliability Council (NERC) projections for natural gas consumption in 1992 are for 20 percent lower demand than present levels.[10]

The potential for increased use of natural gas by electric utilities is difficult to assess with any reliable accuracy. For gas turbine applications, natural gas and middle distillate fuels are perfectly substitutable--price alone determines the choice. An indication of this potential market can be obtained from a recent study by Tabors and Flagg,[11] who used the Electric Power Research Institute (EPRI) Electric Generation Expansion Analysis System (EGEAS) to project the generation choice for the period 1990 to 2004 for the six "model" EPRI regional utilities. The growth rates used in these studies were: NE, 2.1 percent; SE, 3.7 percent; EC, 3.5 percent; SC, 4.2 percent; WC, 3.2 percent, and W, 3.5 percent. (These are approximately 0.1 to 0.2 percentage points higher than the 1983-1992 growth rates projected by NERC.[10]) The capital costs and heat rates used by Tabors et al. for the plant types considered, updated to $1984, were:

Table 7-5a

Plant Costs and Heat Rates[11]

	$1984	Heat Rate (Btu/kWhr)
Light water reactor	2100	10,700
Atmospheric fluidized bed coal (AFB)	950	9,640
Gas turbine combined cycle	330	7,260
Advanced gas turbine combined cycle	480	6,210
Advanced combustion turbine	250	10,300

Comparing these numbers to data from the EPRI/Fluor study[12] for advanced gas turbine and combined cycle systems, we typically have:

Table 7-5b

Plant Costs and Heat Rates[2]

EPRI/Fluor	Capital Cost ($1984)	Heat Rate (Btu/kWhr)
Advanced gas turbine combined cycle	500	8,000
Advanced combustion turbine	250	11,900

Thus, the capital costs of the Tabors study are equivalent to those of the EPRI/Fluor study, but the heat rate is 15 to 20 percent lower and will understate fuel usage, and hence fuel cost, in their expansion planning study. However, the data used are sufficiently representative that their conclusions can be used to indicate potential gas demand following upon electric utility installation of GTCC systems. These systems, designed for natural gas, ultimately could be converted to integrated gasifier GTCC systems if the cost of gas were to increase sufficiently to make the capital cost of the coal gasifier economically desirable.

The low capital costs--$250/kW for combustion turbines and $500/kW for the GTCC system fired with natural gas at $4.00/MMBtu--make the GTCC system a dominant choice in 4 of the 6 model EPRI regional utilities for the 1990-2004 planning period. The essential results of the Tabors study can be gleaned from the relative amount of GTCC installed in 2004.[11]

Table 7-6

GTCC Installed by the Year 2004[11]

REGION	GTCC (MW)	TOTAL (MW)
NE (Northeast)	12,000	12,000
SE (Southeast)	16,000	16,000
EC (East Central)	9,000	16,000
SC (South Central)	13,000	25,000
WC (West Central)	9,000	17,000
W (West)	500	12,000

The choice of unit additions from the available technologies considered in Table 7-5a were either GTCC or AFBC, and the MW additions for each were approximately linear over the 15-year planning study. The essential feature of the study is that on the eastern seaboard, where coal costs are high, the choice is 100 percent GTCC. In the three central regions, gas and coal are competitive and split the market 50/50. In the west, low coal costs capture the total market. Based on this study, the projected incremental gas consumption by regions in the United States is:

Table 7-7

U.S. Electric Generation Incremental Gas Consumption (106 Mcf)[11]

Region	1990	1994	1999	2004
NE	420	1040	1690	2410
SE	80	710	1900	3350
EC	0	230	360	640
SC	0	280	340	640
WC	30	130	400	710
W	0	60	10	20
TOTAL	530	2450	4700	7770

Of the projected increase in natural gas demand of 0.5 Tcf in 1990 to almost 8 Tcf in 2004, 80 percent is consumed on the eastern seaboard (NE and SE). Thus, in this scenario, the availability and price of natural gas in the eastern states is a critical factor. For the early 1990s, the low capital costs and rapid construction potential of the GTCC system are a powerful driving force. By the mid- to late-1990s, the coal gasifier technology should be fully commercial, so for an additional $800/kW ($1984),[12] an environmentally clean, coal-fired base-load plant can be available, which is already producing revenue and whose capital costs are partially subsumed in the rate base. The phased construction being studied by EPRI[12] gives an additional dimension to the Tabors-Flagg study, making their results usable on a basis to project potential electric utility natural gas demand to the year 2000. Even if their results are 50 percent too high, they still project a 200+ percent growth in natural gas consumed by the electric utility industry.

The Tabors-Flagg study performed some fuel- and capital-sensitive studies. Under conditions of a 25 percent increase in fuel cost, from $4.00 to $5.00/MMBtu, gas turbine combined cycle units are not chosen until approximately 1995. This sensitivity to fuel prices and consequently also to heat rates needs more attention. The study used heat rates that were 15 to 20 percent low, and thus there is a bias toward GTCC systems that, under realistic conditions, may significantly overstate their choice. The potential for reducing risk in uncertain load growth projections and for spreading capital commitments over a longer time period are not included in the Tabors-Flagg study; these approaches conceivably could help counterbalance the negative effects of higher heat rates or higher natural gas costs.

A current example of a GTCC system in the advanced stage of planning is the generating facility being planned by Ocean State Power of Burrillville, Rhode Island. The first of two 235 MW, $165 million generating facilities is in the final stages of authorization of construction to be completed in 1989.[19] Ocean State Power is a partnership between TransCanada Pipelines Ltd. (Toronto, Canada), Eastern Utilities Associates (Massachusetts), Newport Electric Corporation (Rhode Island), and J. Makowski Associates, Inc. (Boston, Massachusetts). The plant will be fueled by natural gas under a 20-year supply agreement signed with ProGas of Calgary, Alberta, a company that represents a consortium of 269 Canadian natural gas producers. Transportation of natural gas from Calgary will be provided by TransCanada Pipeline within Canada, and by Tennessee Gas Transmission within the United States. The electrical output of the first 235 MW plant has been contracted to four New England utilities.

This plant has several important features, which may represent important new arrangements in how electric generating facilities are funded and how natural gas for electricity generation is sold. The financial partners include a gas transmission company, two electric utilities, and a financial firm. The gas, purchased by long-term contract between a distant gas producer and the customer, will be transported under common carriage arrangement by two transmission companies, one in Canada and one in the United States. The bulk of the electricity output is being sold to electric utilities that have no financial ownership in the plant. The projected cost of the electricity to the electric utilities purchasing the power for their systems is below avoided costs and lower than projected costs from other generating sources based on other fuels (coal, oil, nuclear). This particular case study is consistent with the U.S. electric planning study done by Tabors et al.[11] It helps to establish a new marketing procedure for Canadian gas, and gives further evidence that electric generation may be a source of significant growth in demand for natural gas in the United States.

Other Factors Affecting GTCC Power Plant Costs

The initial low capital overnight cost of GTCC systems--$500/kW in the United States and $400 to $500/kW in Japan--is aided further by the short construction period in holding down final plant costs. Assuming a 3 percent escalation rate and 12 percent interest, the following shows the percentage increase in overnight costs during time of construction, assuming a linear construction expenditure rate.

Construction	Increase in Overnight Cost by Escalation and Allowance for Funds Used During Construction
3 years	+25%
5 years	+46%
10 years	+116%

The lower capital cost of GTCC plants allows them to use more expensive fuels and still be cost competitive. Typically, coal-fired power plants will cost at least two times more than GTCC plants. At $500/kW for

GTCC systems and with a 14 percent rate of return on capital, this results in at least a \$1.50/MMBtu fuel price premium that can be paid for a gas-fueled system. The lower operating and maintenance costs of GTCC- over coal-fueled plants yield at least another \$1.00/MMBtu cost advantage. Thus, the lower capital and operating costs of gas-fired plants allow fuel premiums of \$2.50/MMBtu or larger on a comparative cost of producing one kWhr of electricity. The higher thermal efficiency of the GTCC systems (approximately 20 percent) further help to offset the premium paid for a clean-burning fuel.

The advanced GTCC systems, which have heat rates of 8,000 Btu/kWhr (and efficiencies of 42+ percent), are believed to offer even further potential for improvement. Efforts to achieve higher gas turbine temperatures through material improvements and interblade cooling are under development and are expected soon to be available in commercial equipment having projected heat rates around 7,500 Btu/kWhr. Further potential efficiency gains may be possible using the isothermal turbine concepts employing interstage reheat. Gas turbines for stationary base-load electric power generation have the potential, through continual design optimization, to add another 5 to 10 percentage points to overall thermal efficiencies over the next 20 years.

EPRI has conducted detailed analyses of the phased installation of integrated gasifier GTCC systems--starting with gas turbines, later adding a heat recovery system steam cycle to produce a combined cycle system, and finally, if desired, adding a front-end coal gasifier to produce an integrated gasifier-gas turbine combined cycle gasifier (IGTCC) system. The final integrated system is modeled after the demonstration IGTCC system now operating in the Southern California Edison system at Cool Water, California. This demonstration was developed under EPRI sponsorship with multi-industry funding: EPRI, Southern California Edison, Texaco, General Electric, Bechtel, and Japanese utilities. A detailed study of the economics of phased IGTCC systems has been conducted by Fluor for EPRI and a report is available.[12] Table 7-8 and Figures 7-6 and 7-7 show typical data from this study.

Methane Gas for Electricity Generation: Via Fuel Cells

Fuel cell systems using phosphoric acid electrolytes and hydrogen as fuel are under commercial development by United Technologies. Funding from GRI and DOE have resulted in the development of a 40 kW system, and units are being field-tested in the United States and Japan. Concurrently, EPRI and DOE are funding, at United Technologies, a parallel development of an 11 MW phosphoric acid fuel cell. Recently, United Technologies and Toshiba of Japan entered into a joint agreement to develop the phosphoric acid fuel cell. These two companies currently are seeking purchase commitments for twenty-three 11 MW systems from utilities worldwide to begin initial production.

The phosphoric acid fuel cell system based on methane uses a steam reformer step to change CH_4 to H_2, a fuel cell to convert H_2 to direct current (dc) electricity, and a power conditioner to convert dc to ac with acceptable wave form and load handling characteristics. The maximum system

Table 7-8

Typical Data on Phased Construction of Systems Composed of Gas Turbine, Steam Cycle, and Coal Gasification[12]

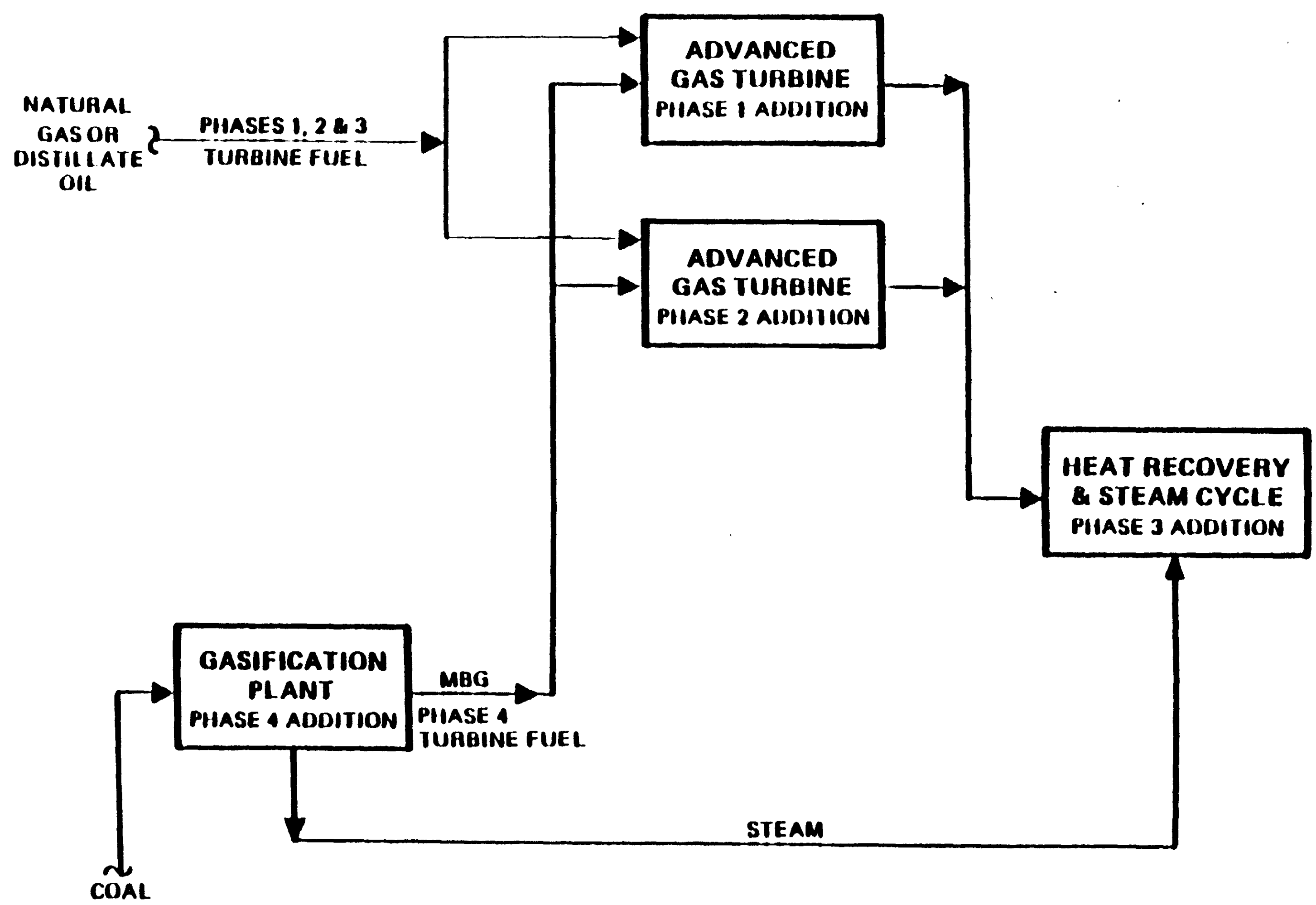
Equipment	Unit Costs ($/kW)** 1 Unit	2 or 3 Units	$88^{\circ}F$ Ambient* Heat Rate (Btu/kW)	Fuel
Current Gas Turbine	260	245	12,300	NG or Middle Dist.
Advanced Gas Turbine	240	230	11,900	NG or Middle Dist.
Gas Turbine and Steam Cycle	---	500	8,000	NG or Middle Dist.
Phased IGCC				
Current GCC + Texaco Gasifier		1,420	10,100	Coal
Advanced GCC + Texaco Gasifier		1,320	9,600	Coal
Advanced GCC + Texaco Gasifier (gas quench)		1,270	10,100	Coal
Advanced GCC + Texaco Gasifier (radiant and convective coolers)		1,380	9,000	Coal
Unphased IGCC				
Advanced Gas Turbine and Texaco Gasifier		1,308	9,600	Coal

* Heat Rate: 100% - $88^{\circ}F$ - 100% Load
97% - $20^{\circ}F$ - 100% Load
95% - $20^{\circ}F$ - 130% Load

**($ January 1984)

Figure 7-6

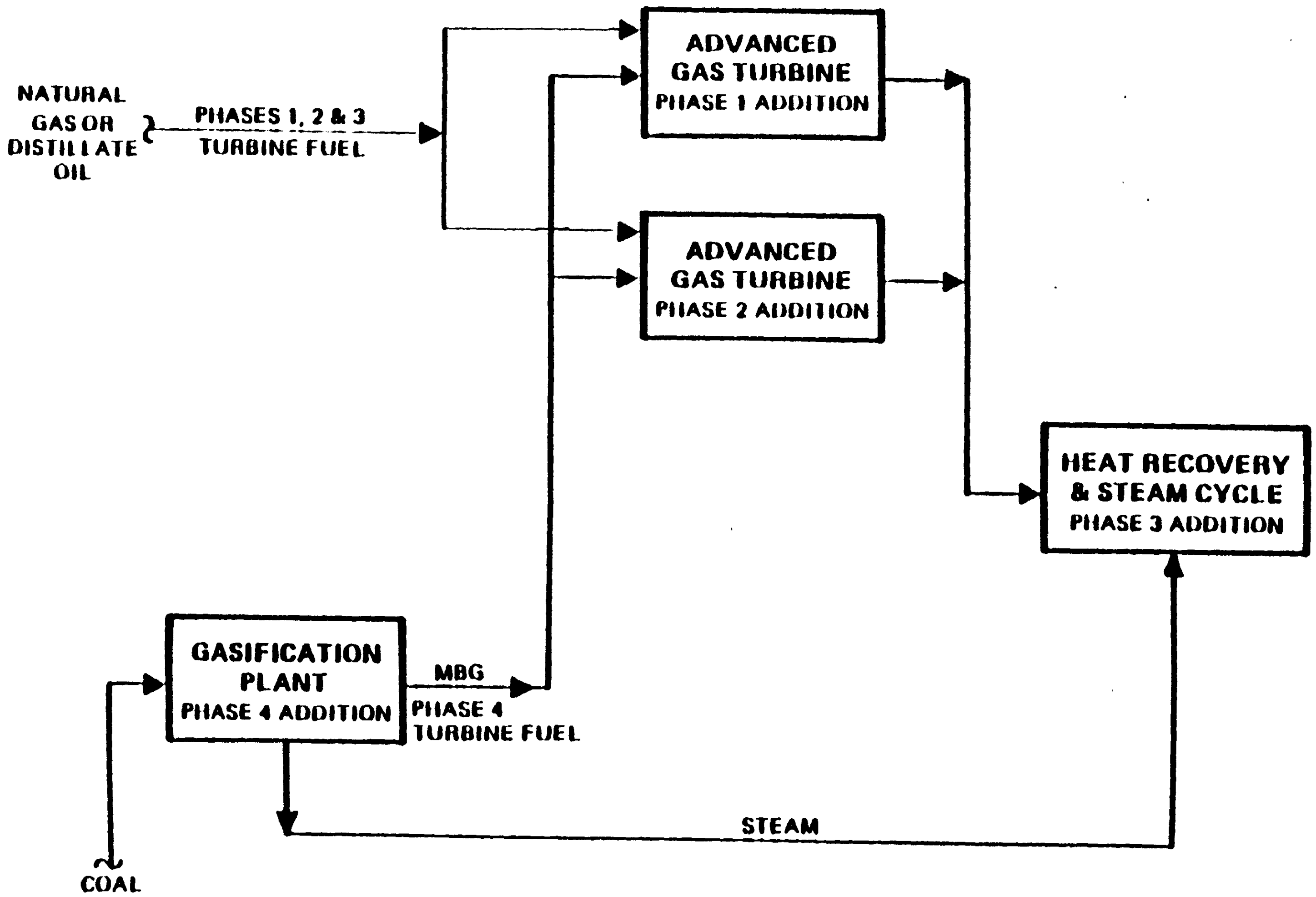
Phase GCC Plant (Separate Steam Cycle Phase)
Phasing Sequence[12]



PHASE	NET CAPACITY ADDITION
1	104 MW
2	104 MW
3	102 MW
4	52 MW
	362 MW

Figure 7-6

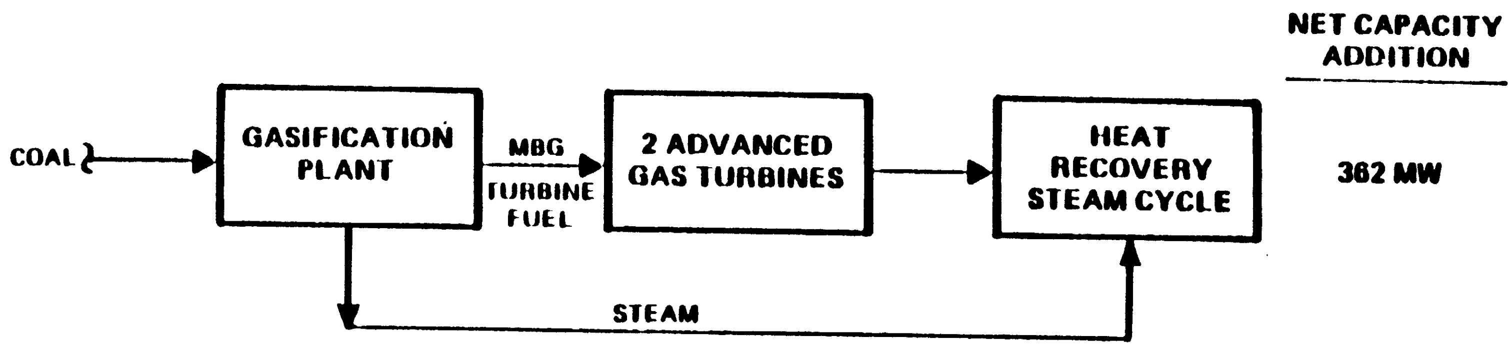
Phase GCC Plant (Separate Steam Cycle Phase)
Phasing Sequence[12]



PHASE	NET CAPACITY ADDITION
1	104 MW
2	104 MW
3	102 MW
4	52 MW
	362 MW

Figure 7-7

Unphased GCC Plant Phasing Sequence[12]



efficiency is approximately 41 percent, and the cost exceeds $2000/kW (the current price is $2000/kW + site costs). While theoretically the fuel cell can have very low losses (no Carnot thermal efficiency limits), its potential has not been obtained in practical systems. Fuel cell efficiency typically is 60 to 65 percent, reformer efficiency is 65 to 70 percent, and power conversion is approximately 95 percent, leading to an overall 40+ percent system efficiency. The high capital cost and low efficiencies, coupled with no appreciable gains in cost as unit size increases, make fuel cells a poor bet for large-scale electric power generation. The GTCC system is much more promising for intermediate- and base-load power applications.

Specialty applications in commercial or large residential complexes may be a feasible approach, however. Modest power generation in a city's central core, where load exceeds what existing transmission facilities can accommodate, is one potential area of application. However, fuel cell systems are unlikely to be major sources of natural gas demand in the next decade, if at all, unless new technology not now foreseen becomes available.

COMPRESSED NATURAL GAS-FUELED VEHICLES[13]

Natural gas is an excellent fuel for use in internal combustion engines. Presently-used fuels--gasoline and diesel--have specific combustion characteristics that require engines to be designed to match the fuel for optimum performance--spark ignition (gasoline) and high compression auto ignition (diesel). Natural gas, which has an octane of approximately 130 (compared to 87 to 92 for no-lead gasoline), needs higher compression ratios (15/1) plus spark ignition because it does not auto ignite, as does diesel fuel. While dual-fueled engines, both gasoline and diesel, can and have been built, the efficient use of natural gas likewise requires dedicated engines.

All general-purpose vehicles need, in addition to their design and manufacturing infrastructure, an operational fuel supply system. Developed nations have an existing transportation system based on gasoline and diesel fuel. So long as reasonably priced petroleum-derived fuels exist, it is hard to imagine a set of conditions that would bring forth both the manufacturing infrastructure and a compressed natural gas fuel supply system that would allow natural gas to compete with the existing complex and highly competitive auto/truck manufacturing and fuel supply systems. However, in nations where the indigenous resource base is predominantly natural gas--Canada, New Zealand, Australia, and Indonesia (i.e., many nations in the East Asia/Pacific region)--an alternate mobile vehicle infrastructure could and may be a logical development.

For most countries, the most probable gas-fueled vehicles market is for fleet vehicles--short-range intercity vehicles, such as taxis, delivery trucks, postal service and police vehicles, school busses, and government fleet vehicles. Special engines and fuel delivery systems could be developed to serve such a market. In the United States, there are 4 X 106 fleet automobiles in fleets of 10 or more, and 3 X 10^6 fleet trucks in fleets of 6 or more. Manufacturing to supply the special engines for this fleet is technically feasible, and the national network of natural gas pipelines to distribute the fuel is already in place.

To use natural gas in mobile vehicles, the present technology is to use storage systems at 2400 to 3000 psig for compressed natural gas (CNG) or to use liquefied natural gas (LNG) stored as a cryogenic liquid at temperatures near the atmospheric boiling point of methane. Typical CNG steel storage cylinders are 10.5" in diameter and 38" in length, weigh 100 pounds, and store 320 cubic feet at 70°C (3.2 equivalent gallons gasoline). Weight reductions by a factor of two are possible, by using cylinders made of aluminum liners overlapped with glass fibers or Kevlar. Typical small vehicles use two or three cylinders, an equivalent of 6 to 10 gallons of gasoline. Trucks usually have more potential storage space for cylinders and can carry more fuel. However, both full development and U.S. Department of Transportation certification of such alternate cylinders has not yet occurred.

For CNG to be used in the engine, pressure reduction to about 1 psig is required. Two stages of pressure reductions normally are used, and the heat of expansion needs to be supplied to avoid regulator freeze-ups during operation. Safety requires overpressure protection of the cylinders and isolation of the passenger compartment from methane intrusion.

The engine has a high compression ratio (usually about 15/1), spark ignition, and requires a spark adjustment with speed to obtain optimum performance. Full optimization of gas-fueled engines has not been achieved. Emission levels are lower from gas-fueled engines, and it may be a preferred fuel in congested city areas. Ford Motor Company, Caterpillar, and Cummins Engine all have developed prototype engines for natural gas operation. The engine design problems are manageable and only need a market to justify the development costs.

A typical conversion factor (clearly engine specific) for natural gas to gasoline is 125 cubic feet of natural gas = 1 gallon of gasoline. Thus, if the average gasoline consumption per vehicle is 1000 gallons per year, it would require 8 X 10^6 vehicles to create 1 Tcf of natural gas demand.

Methane to Chemicals

The typical petrochemicals derived from methane are shown in Figure 8. In addition to carbon black, the major primary products, often used as feedstocks for other products, are ammonia, methanol, and acetylene. The methanol and ammonia streams follow after producing synthesis gas (CO, H_2) from methane by steam reforming or partial oxidation. These products can be derived from synthesis gas produced from any feedstock (coal, heavy petroleum, etc.), but for products with a hydrogen/carbon ratio of 2 or greater, methane is the preferred feedstock to produce the hydrogen at minimum energy and processing costs.

The methane found as associated gas from petroleum production by petroleum exporting nations, plus the general surplus of methane in remote locations or in nations with modest populations or modest industrialization, have resulted in a worldwide excess of petrochemical production from methane. Since chemicals derived from methane are a logical way to obtain markets, there is good reason to believe this excess of methane-produced chemicals will continue and will be exported to the developed Western world. In North America and Western Europe, where pipeline networks allow methane to be delivered for fuel use to a wide range of consumers--residential, commercial, industrial, and electric power methanol and concludes that properly designed engines can give about 20 percent higher output for the same size, consume about 15 percent less energy at part load, and operate at high load more economically than can comparable diesel engines.

Reference 16 has results comparable to those given above, using a research engine, and further shows that 10 to 20 percent H_2O added to methanol can yield greater energy efficiency and lower emissions. In this study, a single-cylinder test engine using methanol and also isooctane was operated under conditions that met standard U.S. Environmental Protection Agency emission requirements. It was shown that a properly designed methanol engine could have greater efficiency than a gasoline engine. As much as 40 percent greater output per unit of energy consumed was obtained by increasing the compression ratio from 8 to 12 and also by adding 10 to 20 percent H_2O to reduce NO_x emissions. The higher octane rating of methanol, plus its cleaner burning characteristics, if exploited in a dedicated engine designed for methanol, does partially offset the lower energy per unit volume or weight of methanol over gasoline. Both the laboratory work of Reference 16 and the field test data on multi-cylinder engines in Reference 15 support this potential. However, it is not feasible to use methanol in today's commercial gasoline engines without major retrofit.

In today's world, with transportation vehicles optimized for gasoline or diesel fuel use, it is very difficult to postulate a methanol fuel strategy. The problems of developing markets for methanol-fueled vehicles (in addition to the comparative cost of methanol and gasoline) are substantial and perhaps insurmountable. If methane is to become a significant resource for transportation vehicles, the methane-to-methanol-to-gasoline process developed by Mobil or the middle distillate Shell process may be the only feasible way to use methane as a primary source for transportation vehicles.

Gasoline from Methanol

The Mobil process, which uses the shape-selective zeolite ZSM-5, yields the following methanol-to-gasoline conversion:[17]

$$\begin{array}{ccccc} X\ CH_3OH & \rightarrow & (CH_2)_x & + & X\ H_2O \\ 100\ \text{lbs} & \rightarrow & 44\ \text{lbs} & & 56\ \text{lbs} \end{array}$$

Approximately 95 percent of the energy in the methanol is contained in the hydrocarbon yield. With additional processing, 88 weight percent of the hydrocarbon can be in the gasoline range. Thus, the gasoline yield and energy yield are reasonable for the overall process. However, even at these yields, it takes approximately 2.5 gallons of methanol to yield 1.0 gallon of gasoline. The Mobil-M route takes methanol to a product compatible with existing transportation equipment and is the only commercially operating process for going from methane to gasoline. Methane to synthesis gas to methanol to gasoline involves significant processing costs, plus energy loss from the primary feedstock. Methane is not a promising economic route, particularly if crude oil prices are in the range of $20 per barrel or lower.

Middle Distillate from Methane

The production of middle distillate fuel from synthesis gas has been developed by Shell and also by Gulf-Badger. These processes essentially are Fischer-Tropsch reactions optimized to produce aliphatic straight-chain hydrocarbons in the middle to upper part of the C_1 to C_{50} range. The yields by percent weight of the new Shell catalysts are shown in Figures 7-9, 7-10, and 7-11.

The Shell process first produces a product that is 40 to 70 percent wax, depending upon process conditions, then hydrocracks the wax to the desired end products (see Figures 7-9 and 7-10). Typical final product yields are 60 percent gas oil, 25 percent kerosene, and 15 percent tops/naptha for a process maximizing gas oil. For a maximum of kerosene, the yields typically are 50 percent kerosene, 25 percent gas oil, and 25 percent tops/naptha (see Figure 7-11).

Overall thermal efficiency of methane to hydrocarbons is about 60 percent. The Shell process for middle distillate or gasoline is an alternative to the production of methanol as a way to obtain liquid fuels. Well-optimized methanol processes usually will yield better thermal efficiency--say, 65 to 70 percent, compared to about 50 percent for the higher hydrocarbon fuels preferred for transportation.

CONCLUSIONS

New technology does not appear to be a major determinant in natural gas end-use market demand. Gas-consuming technology is mature and available from many competitive manufacturers worldwide. The recent

Figure 7-9

Product Distribution in Fischer-Tropsch Synthesis[18]

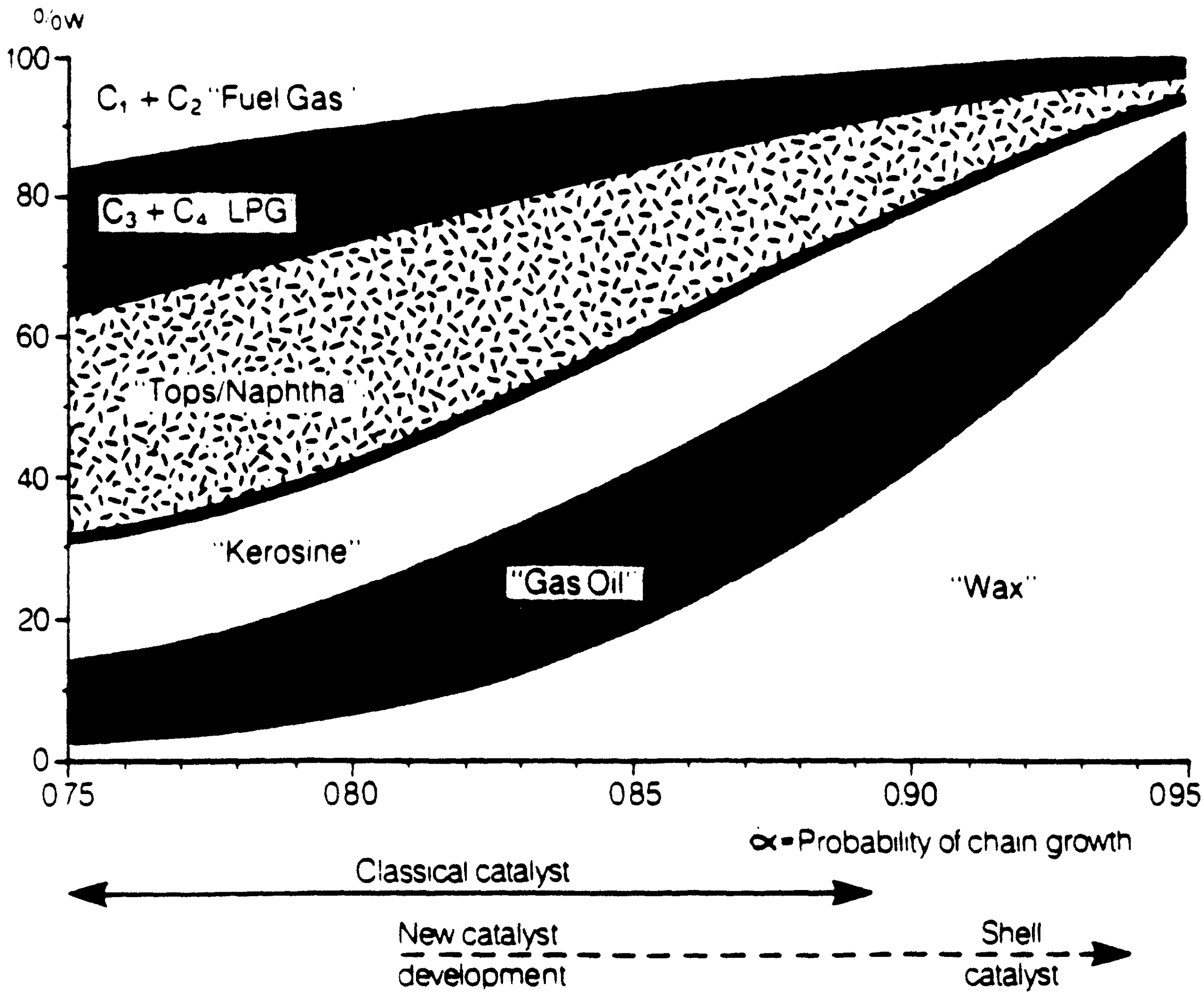
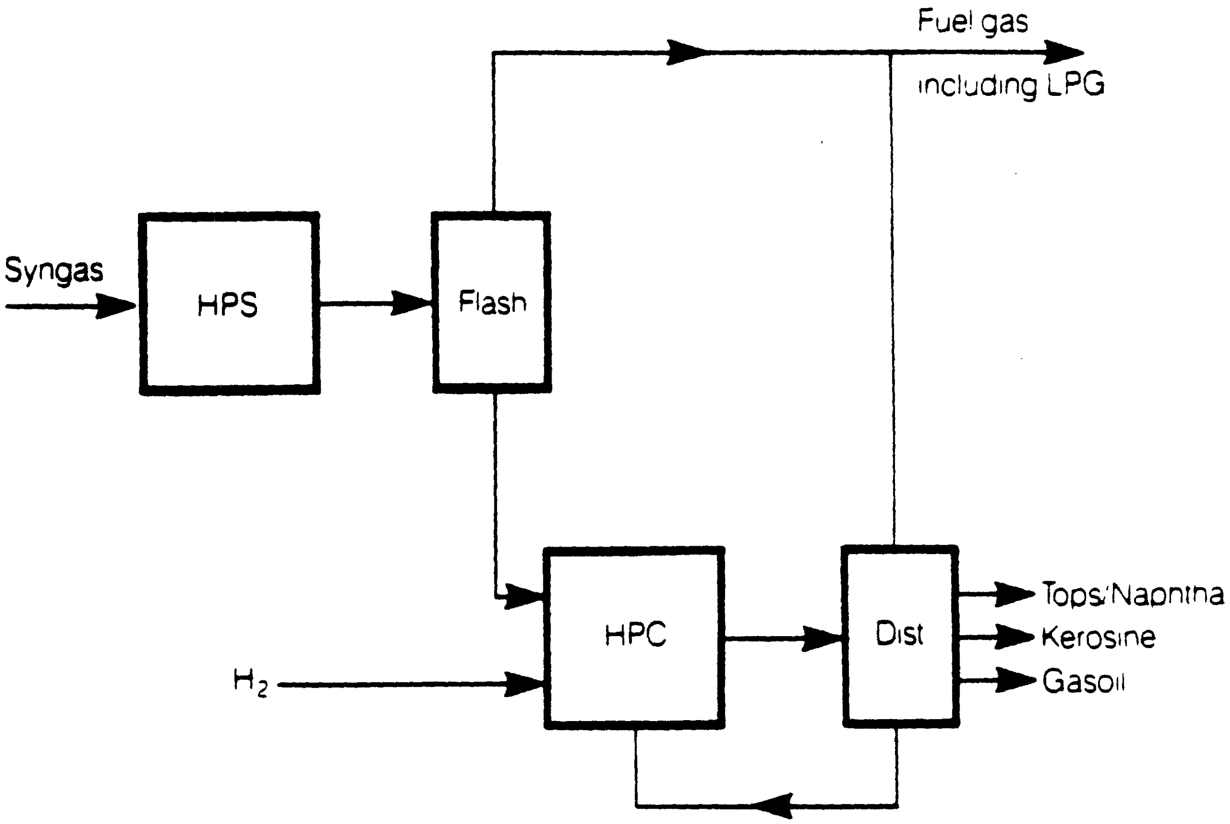


Figure 7-10

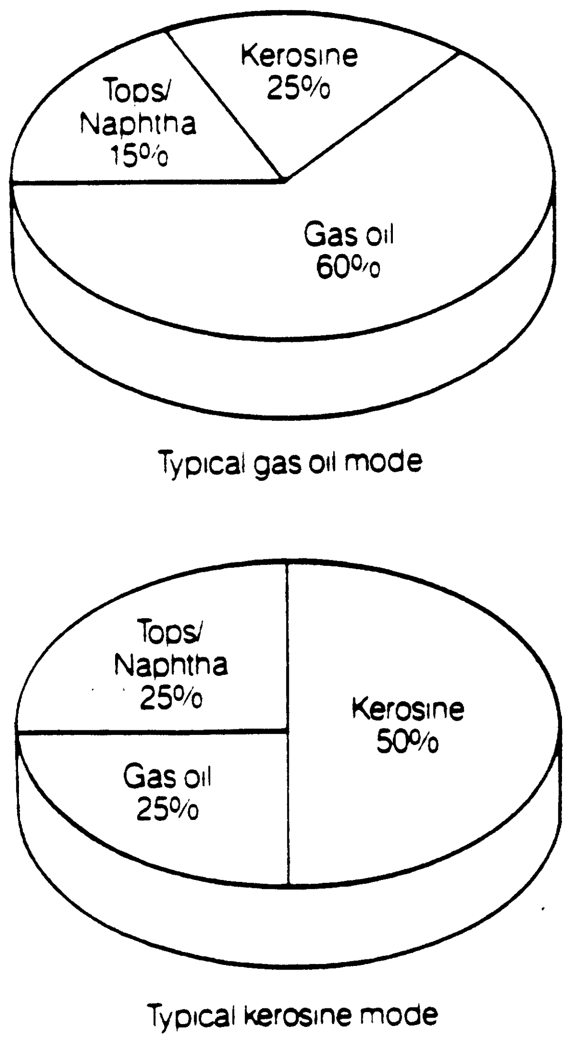
Shell Middle Distillate Synthesis
Simplified Flow Scheme[18]



HPS Heavy paraffin synthesis
HPC Heavy paraffin conversion

Figure 7-11

SMDS Product Breakdown[18]



changes in world oil markets appear to be increasing natural gas supply at competitive prices. The general availability of natural gas delivery systems to most consuming sectors in the United States, Western Europe, and Japan, plus well-proven end-use technologies, could be a stimulus to gas demand, which in turn also could stimulate R&D on end-use equipment to gain a larger market share. New technology opportunities do exist, even for mature end-use equipment.

The prospect that new technology will be a major driving force for methane to develop new markets is excellent for GTCC systems used in the generation of electric power. In the United States and probably in most other consuming countries, this requires the delivery of methane to the burner tip at prices below $4.00/Mcf. For base-load plants with a 70 percent load factor using an advanced GTCC system with 8,000 Btu/kWh, every $1.00/Mcf represents a $0.01/kWhr fuel cost. For capital charges of 14 percent, every $500/kW plus a 70 percent load factor also represents a $0.01/kWhr capital cost. Considering all factors (clean emissions, modestly sized units of capacity, low capital costs, well-established technology, etc.), the gas turbine or gas turbine combined cycle system gives methane a reasonably competitive position against any other electric power generation system: heavy fuel oil, coal, or nuclear. A 1,000 MW GTCC system at 8,000 Btu/kWhr and 70 percent load factor represents a potential annual natural gas demand of 50 Bcf. Electric power generation thus represents one major potential source of new natural gas demand.

Natural gas is a highly desirable fuel in the industrial market and, if prices are competitive at the burner tip, it will maintain its market share. Speciality markets in primary metals production may offer an additional potential market. Similarly, industrial cogeneration systems could be a source of new demand, particularly in the United States, under current economic and regulatory conditions facing electric utilities. Advanced technologies to meet this market's needs are under development, and some advanced systems are commercially available.

Natural gas demand in the residential and commercial sectors is more dependent upon the delivery system than on development of new end-use technology. While considerable improvements have been made in furnaces for all applications and in gas-driven thermal machines for air conditioning, process drying, compression, etc., there is no outstanding technology development that appears to offer unique opportunities for new natural gas applications in conventional markets. Natural gas always has been and still is a very desirable primary energy source for these markets, when it can be delivered at competitive prices. The availability of package cogeneration systems for commercial applications may represent a growing market in the United States. To a large degree, this demand growth will be influenced by the policies of electric utility companies in their planning to meet future electric load growth. There is growing evidence that utilities may help stimulate this potential market.

The potential exists for natural gas use in the transportation market, but has the disadvantage of requiring special engines and a dedicated delivery system. The transformation of methane to gasoline and middle distillate has significant process and energy costs. While the technology has improved, no outstanding breakthroughs have been made, nor can any be forecast with any degree of assurance. The stable CH_4 molecule is difficult to transform into the higher energy density and more transportable higher-order liquid hydrocarbons.

In summary, the ability of advanced technology to stimulate natural gas demand is relatively limited. Commercial technology is available to all end-use markets. The growing willingness of natural gas suppliers to face marketplace competition from other hydrocarbon fuels is a strong indication of a potential expansion in natural gas demand. Both existing and improved technology will be available to support this potential demand growth. The end-use market sector that will have the largest growth in natural gas demand appears to be country-specific and heavily influenced by each country's fuel policies. For any country facing severe constraints on electric generation using nuclear power, the combination of cost-effective technology and the low environmental impact of natural gas represents a significant potential for new demand by the electric utility sector. Current economics indicate that natural gas delivered to the burner tip at prices below $4.00/Mcf is and will be very competitive with other fuels. However, beyond the economic considerations alone, natural gas offers the additional advantages of reducing other externalities--such as pollution costs--that may, in the future, render it appreciably more attractive.

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