WORKING PAPER

THE INFLUENCE OF TECHNOLOGICAL CHANGES ON THE COST OF GAS SUPPLY

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Foreword

In spring 1986 a Task Force Meeting on *The Methane Age* was jointly organized by IIASA and the Hungarian Committee for Applied Systems Analysis to define the directions of research for IIASA's **Methane Study**, an activity inside the TES (Technology, Economy, Society) Program. One of the issues raised in this meeting concerned the cost structure of supplying natural gas to the final consumers.

This paper analyzes the cost of supplying natural gas to a virtual consumer in Central Europe from all presently conceivable sources. The sensitivity of the price of supplying the gas to changes in the cost of single components is also investigated. The authors could partly build on the data base collected during the IIASA International Gas Study, which included the economic and technical features of supplying natural gas in Europe--although on a lower level of disaggregation.

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The Influence of Technological Changes on the Cost of Gas Supply

M. Strubegger and S. Messner*

Introduction

Since the early 1950s the importance of natural gas as a primary energy source has been growing steadily. Presently (mid-1986) it supplies nearly 20% of global primary energy consumption, constituting the third largest source of energy after crude oil and coal.

Technological innovation and improvements in performance during the previous century have made this high degree of gas use both possible and economically viable. In the same way, the future role of natural gas will be influenced by developments in gas technology. In this paper we try to investigate the effects of technological improvements on the gas extraction and transport system. The focus is on natural gas supply options for Western Europe, considering presently feasible, but not necessarily economical, supplies from known gas fields around Europe.

Historical Perspectives

An early example of a technological push occurred in the Appalachian region, USA. After gas production there had reached its peak, around 1917, the subsequent decline lead to a doubling of gas prices within five years. This stimulated further technological development in gas transportation systems, to make gas from other fields accessible to the consumption centers in question. As a result, about a dozen pipelines of more than 20 cm in diameter and longer than 200 miles were built in the USA between 1927 and 1931 (Tussig and Barlov, 1984). The longest pipeline constructed at that time connected the Panhandle/Hugoton Field with Chicago, Ill., covering a distance of 1100 miles.

* We thank Dr. M. Korchemkin from the Estonian SSR Academy of Sciences, USSR, for his valuable comments and his help in compiling the cost data for the Soviet gas supply system.

More recent developments are the production of natural gas from rather hostile areas, such as the North Sea or permafrost regions in the USSR, and its transport over long and difficult routes by pipelines or even as liquid nitrogen gas (LNG). The relative youth of the technologies involved makes us confident in forecasting further technical improvements and thus cost reductions.

To assess future cost developments, two phenomena have to be separated:

(a) *cost reductions* due to technical improvements, economies of scale, and growing experience, and

(b) *cost increases* due to the necessity to use gas extraction sites at more unfavorable locations – in terms of geology, climate, and distance to the consumer.

Figure 1 shows these two effects on the capital needed for extracting coal, oil, and gas in different countries. Whereas, with growing experience, the capital–output ratio for oil and gas production decreased strongly in areas with similar geology – in the FRG it dropped by more than 6% p.a. between 1960 and 1974 – it is considerably higher at hostile locations, such as the North Sea. However, the trend in the capital required to produce an additional amount of oil or gas is similar to the development experienced in the FRG. It is also important to note that the longer a technology has been in operation, the smaller the cost decreases become. Currently, Norway experiences the highest unit cost reductions per year.

In contrast to the capital–output ratio for oil and gas production, the specific capital needs for coal mining are increasing in all countries, as shown in Figure 1. The long tradition of coal mining in these countries necessitates the exploitation of coal from areas with thinner seams, poorer quality, and greater depths - resulting in an increasing capital intensity. But also the shift to opencast mining and, even more, the automation of underground mining have lead to higher investment needs.

Similar dynamics were experienced with oil and gas production in the USSR. There the average capital–output ratio (in roubels per energy unit) for oil production increased by 15% and for gas production by 24% in the period from 1966 to 1975 (Smolik, 1981). Figure 1 indicates that, owing to the development of North Sea oil and gas fields, a similar trend holds for Western Europe as a whole. This trend will continue when oil and gas production moves further north to locations like Haltenbanken or Troms off the Norwegian coast. However, technological progress and growing experience will again decrease the initially high costs, once the move toward yet untouched reservoirs has bee made.

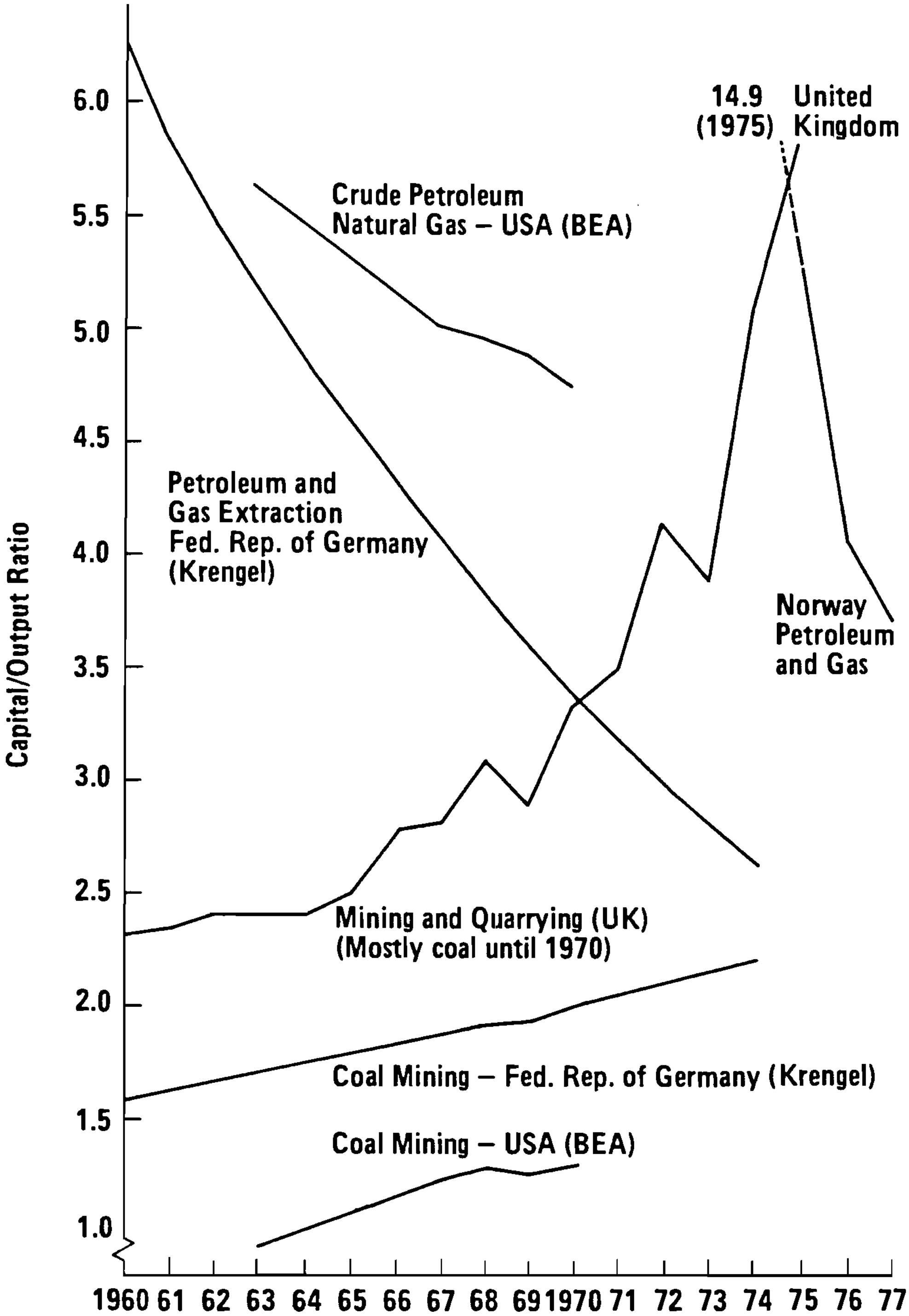

Figure 1. Capital–Output Ratios for the Extraction of Energy Resources.

Source: Smolik, 1981.

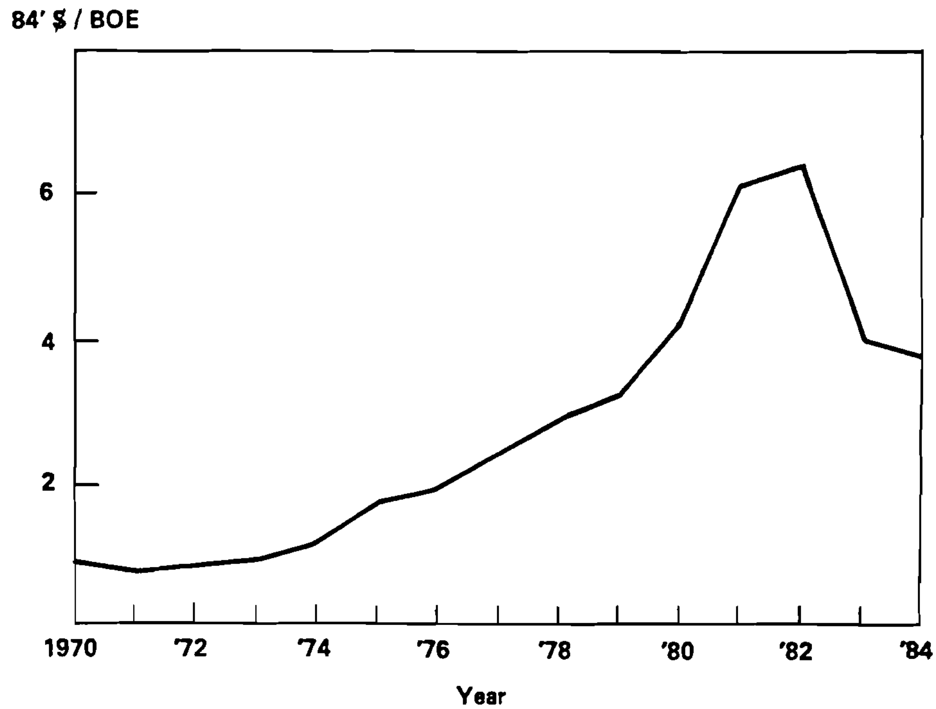

Figure 2. Drilling Costs per Million boe of Oil and Gas Produced, USA 1970–1984, in 1984 US$.

Source: Rose, 1985.

These cost reductions, however, do not hold for the total drilling costs. An investigation of the drilling costs in the lower 48 states of the USA (Rose, 1985) shows that average drilling costs per foot rose considerably during the period 1960 to 1983. Figure 2 shows the total drilling costs per boe[1] of oil and gas produced in the USA during the period 1970–1984 (API, 1986; OECD, 1984, 1986). The increase in total drilling costs from less than $1 to over $6 per boe is mainly related to the time required for drilling (Adelman and Ward, 1980). The increasing depths and more difficult geological formations require more time per foot drilled and thus increase the associated costs. The sharp drop in costs at the end of the period reflects a changed strategy regarding drilling depths. The number of wells drilled to 15000–20000 feet dropped by nearly half – from 1140 in 1982 to 652 in 1984 – and the number of wells drilled to depths below 20000 feet fell from 138 to

[1] 1 boe = 1 barrel of oil equivalent = 6.12×10^9J.

37. Another reason for this cost reduction was that the fall in deep drilling activities affected mainly gas wells. This lead to overproportional cost savings, for gas wells are usually deeper than oil wells – on average by 40% in 1984. Moreover, they are approximately 17% and 24% more expensive than oil wells at depths of 15000–20000 feet and below 20000 feet, respectively. The largest increase in the number of wells was experienced at depths less than 5000 feet, which are about 10 times cheaper than wells deeper than 15000 feet (API, 1986).

In contrast to the rather strong changes in capital–output ratios experienced in resource extraction, capital needs for gas transmission and distribution dropped by only 2–3% per year. For comparison, changing conditions in the USSR, with the shift of gas production from the European to the Siberian part of the country, resulted in a tripling of the gas transportation costs between 1970 and mid-1986.

The cost of distributing natural gas to the final consumer – today usually the dearest component of a gas system – was relatively low during the first phase of its introduction in Europe. In densely populated areas it was often possible to take advantage of existing grids, which were built earlier for the distribution of 'town gas' produced from coal. In many other areas the gas grid could be constructed simultaneously with the development of new housing areas. This phase came to an end during the 1970s, when all the areas damaged during World War II had been finally reconstructed and the erection of satellite towns stagnated.

Table 1. Price Structure for the Supply of Natural Gas and Oil Products in Austria (%).

	Gas	Oil
Production	7	7
Transport	24	7
Distribution/Storage/Refining	49	26
Taxes and Profits	20	60

Source: Safoschnik, 1985.

Table 1 shows the cost structure of supplying natural gas to the end-user in Austria for 1984, and compares it with the supply of refinery products. This example shows that, in 1984, 30% of the total *cost* of gas supply (i.e., *price* less the taxes and profits shown in Table 1) was necessary to transport the gas to the centers of consumption and that another 60% was used for storing and distributing it. Only 10% of the overall cost is incurred in extraction. It was mainly these high costs for transportation and distribution that left just 20% of the selling price of gas for profits and taxes. For crude oil, on the other hand, profits and taxes accounted for 60% of the selling price in 1984. This high intrinsic value was, however, only valid for oil producers in the Middle East. For the North Sea the production costs are obviously much higher, resulting in a smaller intrinsic value. Thus, the oil price decrease of 1986 from over $25 to around $10 per boe made many North Sea gas and oil projects uneconomic and resulted in a reevaluation of investment plans.

The supply cost of natural gas, its composition, and possible future developments is investigated in the following sections, giving a first order approximation of the relevance of technological improvements in the coming decades.

The Cost of Natural Gas Supply

The following analysis focuses on supplying a consumer in Central Europe with natural gas from various sources. These different supply sources include the Norwegian part of the North Sea, the USSR, Africa, and the Middle East. Domestic supply from conventional sources is not taken into account, since an increase in production sufficient to match additional demands seems unlikely. Also, the influence of profits and/or taxes on the *price* of gas is not examined. We only analyze the *cost* structure of gas supply and the influence of cost–reducing technological changes along the entire gas chain.

Extraction

Table 2 gives an overview of the costs of producing natural gas from various fields. The estimates of production costs[2] for natural gas range from US$9/1000m^3 in the Middle East to US$100/1000m^3 for gas produced in the northern North Sea. The production costs at the high end of the range represent some US$14/boe,[3] which makes the related projects uneconomic at the oil price prevailing in mid-1986.

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[2]If not stated explicitly, cost figures are expressed in 1984 US$.

[3]1boe ≈ 190 m^3 of Dutch gas, 164 m^3 of Soviet gas, or 137 m^3 of Norwegian gas.

Table 2. Natural Gas Fields and Production Costs (1984).

Field	Proven Reserves in 1985 $[10^9 m^3]$	Depth [m]	1984 Exports to Western Europe Pipe $[10^9 m^3]$	LNG	Costs ($/1000 m^3) Capital[a]	Operating	Total
NORWAY							
Statfjord	400	145	-	-	31.2	7.4	38.6
Ekofisk	216	68	-	-	24.2	11.8	36.0
Valhall	20	70	-	-	36.9	18.1	55.0
Gullfaks I	12	180	-	-	74.3	32.2	106.4
Heimdal	31	120	-	-	70.4	19.4	89.8
Sleipner	140	100	-	-	-	-	69.0
Troll	480	350	-	-	-	-	75.0
Troms	250	200	-	-	-	-	65-92
Total	1548	-	12.6	0.0	-	-	-
NETHERLANDS							
Groningen	1422	-	-	-	-	-	11.0
Offshore	338	40	-	-	-	-	16.0
Total	1760	-	37.4	0.0	-	-	-
USSR							
Urengoy	10000	-	-	-	-	-	22.0
Other W.Sib.[b]	20000	-	-	-	-	-	26-30
Total	30000	-	33.2	0.0	-	-	-
AFRICA							
Algeria	3155	-	6.6	11.0	-	-	10.2
Nigeria	1370	-	0.0	1.1	-	-	12-15
Total	4525	-	6.6	12.2	-	-	-
MIDDLE EAST							
Pers.Gulf	22394	-	0.0	0.0	-	-	9.0
TOTAL	60227	-	89.8	12.2	-	-	-

[a]Capital costs are discounted with 10% p.a.
[b]Includes Yamburg, Yamal, Medvezh'ye, Vyngapur and other fields in North Western Siberia.
Sources: *Petroleum Economist* (various issues from 1978 to 1986); Lorentsen *et al.*, 1984; Stern, 1984.

Compared with costs for other energy carriers, e.g., domestic coal or biomass fuels, the average costs for extracting natural gas – as given in Table 2 – are in most cases modest (a cost of \$30/1000m^3 is equivalent to \$5/boe). However, a major problem for the gas industry is the large initial investment needed to start up a new field. For the development of the Viking field (with reserves of 92 bcm),[4] in the most southern part of the North Sea, close to Great Britain, the capital requirements were \$250 million and for the Frigg field (226 bcm), in the central part of the North Sea, they were even about \$3600 million. The investment costs for developing the Sleipner and east Troll fields (for a planned extraction of 450 bcm) are estimated to be in the range of \$6 to \$8 billion. Similar costs are reported for the development of the Soviet Yamburg gas field (7500 bcm) – 4 billion roubels, equivalent to some \$5 billion (1984 currency units) (Shamrayev, 1984). But also the annual operating costs, most of them independent from production level, are considerable. For the Frigg field they are of the order of \$235 million per year (all North Sea cost data from Lorentsen, *et al.*, 1984).

Apart from these large capital needs, frequently the initial estimates of costs and field performance differ substantially from the costs experienced once a field is in operation. A comparison of original cost estimates against actual costs was performed for 23 North Sea fields in 1984 (Castle, 1985). It shows that the investment costs were overestimated for only 3 of these 23 fields. On average, the actual investment costs were 95% higher than the original estimates, with the highest overrun by nearly a factor of 10 for the Cormorant Field. Similarly, estimates for field production through 1983 were not reached by 21 fields; on average, production was 38% lower than originally estimated. In total, a reevaluation of all 23 fields yielded a 624% overrun for the operating costs over the expected life of the fields.

Transport

Apart from the costs for gas extraction, the construction of transportation pipelines often requires even heavier investments. Probably the largest investment so far was the pipeline system linking West Siberian gas fields to European USSR and to West and East Europe. The costs for this system are estimated at \$30 billion, enabling the transport of 130 bcm per year over distances of up to 4800 km. New plans are made for another multibillion dollar gas project in the USSR – a pipeline system, planned to transport some 250 billion m^3 per year (Kirby, 1984) from Yamburg to the western border of the USSR; costs initially estimated at some

[4]bcm = billion m^3 = $10^9 m^3$ = 37.26 PJ.

\$40 billion (*Pravda*, June 19, 1986). Not only is the transportation of gas via pipelines a rather capital intensive undertaking; so is the transport of LNG. The investment costs for a LNG chain able to transport 11 bcm per year from the Middle East to Europe are of the order of \$7 billion (in 1981 US\$) (IEA, 1982).

Table 3. Transportation Costs (US\$ 1983/1000m^3) and Distances (km) for Selected Gas Transport Routes.

	Pipeline	Liquefaction	Regasification	Sea Transp.	Total Costs	Length Land	Sea
Ekofisk–Emden	16.0	-	-	-	16.0	442.	-
Valhall–Emden	17.0	-	-	-	17.0	470.	-
Statfjord–Emden	40.0	-	-	-	40.0	1140.	-
Gullfaks–Emden	41.0	-	-	-	41.0	1160.	-
Heimdal–Emden	23.5	-	-	-	23.5	790.	-
Troll–Emden	42.0	-	-	-	42.0	1100.	-
Troms–Emden	80.0	-	-	-	80.0	2700.	-
Sleipner–Emden	20.0	-	-	-	20.0	690.	-
Emden–CE	7.0	-	-	-	7.0	< 1000.	-
Groningen–CE	6.5	-	-	-	6.5	< 1000.	-
NL offshore–CE	10.9	-	-	-	10.9	< 1000.	-
Urengoy–CE[a)]	95.3	-	-	-	95.3	5000.	-
West Siberia–CE[a)]	102.0	-	-	-	102.0	6000.	-
Algeria–Italy–CE	66.4	-	-	-	66.4	3000.	-
Alg.–Fos-sur-Mer–CE	8.5	64.7	17.9	7.2	98.2	600.	500.
Nigeria–Alg.–Spain–CE	98.7	-	-	-	98.7	6000.	-
Nigeria–W'haven–CE	11.8	57.9	15.3	45.1	130.1	500.	4500.
Gulf–Turkey–Italy–CE	91.0	-	-	-	91.0	5600.	-
Gulf–Turkey–Yug–CE	80.0	-	-	-	80.0	5265.	-
Gulf–Syria–Triest–CE	41.7	57.9	13.6	17.0	130.2	2400.	1450.

[a)]Based on the costs for the first stage of the Urengoy–Uzhgorod pipeline. Costs will be reduced by ~ 10% when, during the second stage, the capacity will increase from 26 to 55 bcm per year; CE is Central Europe.
Sources: Runge, 1983; Benzoni, 1985; Astakhov and Subbotin, 1985.

Table 3 summarizes the gas transportation costs from the areas considered to Central Europe. They lie in the range of US\$7 per 1000m^3 for onshore pipelines in relatively easy terrain to US\$130 per 1000m^3 for pipelines in hostile environments, such as the permafrost areas in Siberia, or for LNG schemes. Thus, the transportation costs for natural gas are at the same level as the extraction costs.

Storage and Distribution

Whereas cost estimates for natural gas extraction and transportation can be compiled from data on specific projects, such an undertaking is much more difficult for the cost of storing and distributing gas. For storage this is because the composition of gas consumers - and therefore the daily and seasonal load variation - differs widely between countries and even between regions in a country. The need for storage depends:

- on the type of contracts between the exporters and importers (i.e., take-or-pay clauses or seasonal variability in the contracts),
- on how much of the peaks in gas consumption for domestic space heating can be compensated by interruptible contracts with industrial consumers, and
- on how much domestic supply the importing country uses for peak shaving.

The costs of storage systems differ widely because different storage types have completely different investment costs and performances. Gas can be stored, depending on geological conditions, in depleted oil or gas fields, artificial caverns in salt domes, or aquifers. Sometimes it is appropriate to store gas in the form of LNG or to use liquid petroleum gas (LPG) for peak supply. Table 4 provides an overview of the costs of some gas storage systems.

Table 4. Costs for Different Gas Storage Systems.

Storage Type	Size [a] $10^9 m^3$	Capacity $10^9 m^3$/day	Specific Cost US$/1000m^3
Salt Caverns	1.-22.	.2-5.	.60-1.00
Depleted Gas Fields	50.-3000.	.05-2.	-
Aquifers	.05-.50	.3-1.6	.40-.80
LNG [b]	15.-75.	2.-10.	1.4-3.50
Gasometer [c]	.005	-	24.3-34.8

[a] Typical sizes for European installations.
[b] Includes liquefaction plant.
[c] For weekly load shaving.

Source: Mönig, 1984.

Gas storage capacity in Europe amounted to only 18.1 bcm in 1984, i.e., some 8% of 1984's gas consumption. The maximum daily offtake was 361.4 million m^3. For comparison, the storage capacity in the USA represents 43% of the annual gas consumption in the same year. This large difference in how supply and demand are matched is not so much a reflection of different storage costs in the two regions.

On the one hand, it is the result of the different distances between the areas of production and consumption. On the other, it is historically caused by institutional regulations in the US gas market, which favored investments in gas storage facilities and called for constant extraction rates (IEA, 1986). The storage needs will also grow in Europe, after the fields with flexible production rates in the southern North Sea and the Groningen field have been exhausted. The main supplies of natural gas will then be provided by gas transported over long distances or from fields with rather inflexible production rates in the central and northern parts of the North Sea.

The average costs of gas distribution are even more difficult to estimate than are storage costs. Different energy consumption densities and topographical features substantially influence the cost of the distribution grid . As mentioned earlier, cheap options have already been taken; thus, with increased gas utilization, the distribution costs will rise. This is mainly because regions with a lower energy consumption density and more areas with an existing building structure will have to be added to the system. This is also true for countries that have not yet introduced gas, like Sweden, Norway, Turkey, or Greece. In North Europe the areas of high energy density are largely supplied by district heat, leaving only limited demand for natural gas. In the south, energy consumption density for residential use is, due to climatic conditions, much lower than in the north.

Figure 3 shows the cost variations for the construction of a new gas distribution system in areas with existing housing stock and in areas under construction (STOSEB, 1981). These two graphs show clearly that the introduction of natural gas will be limited by the exponential increase of costs for the construction of a distribution system in less densely populated areas. This is especially so when new gas grids are to be introduced into areas already inhabited.

The costs for storage and distribution are estimated to be $170 per 1000 m^3 for Germany (Mönig, 1984) or $150 per 1000 m^3 for the Austrian gas system (Safoschnik, 1985). In our subsequent analyses we use $160 as the cost for storing and distributing 1000 m^3 of natural gas to a domestic consumer. For large scale industrial users or the generation of electricity and/or district heat the costs are estimated to be in the range of $10–$30 per 1000 m^3, depending on the distance from the gas main line and annual consumption. This cost differential between large- and small-scale users shows that the average cost of delivering gas to the end-user will depend largely on the composition of the gas users. The more gas that is used in industry or for electricity generation, the cheaper will the average m^3 of gas be.

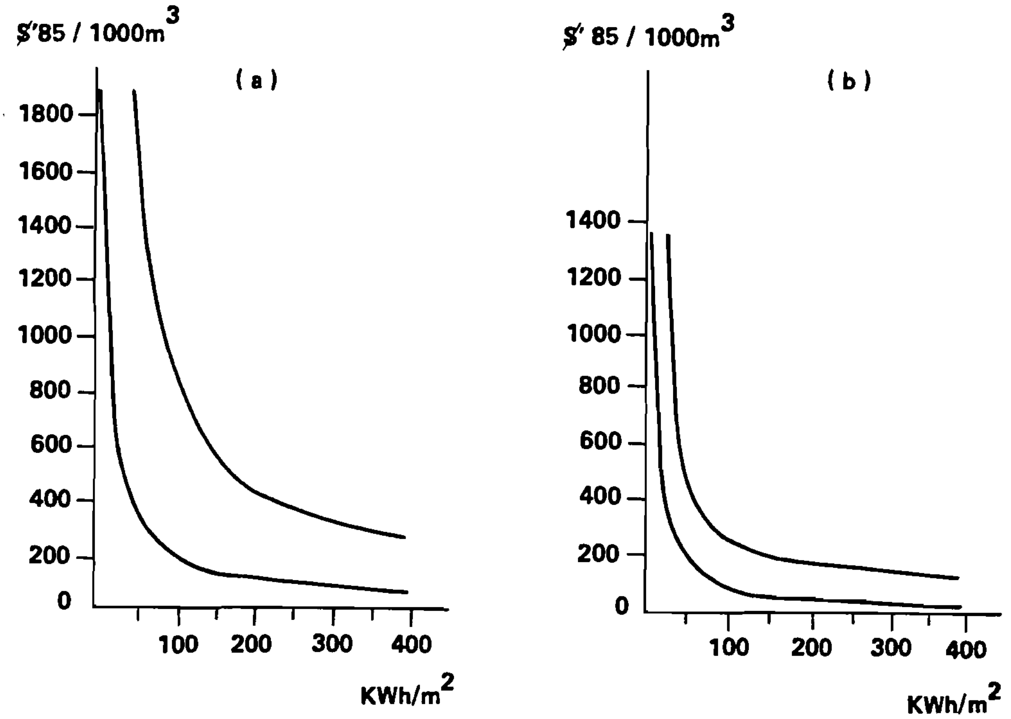

Figure 3. Costs for Constructing New Gas Distribution Systems in Areas (a) with and (b) without Existing Housing Structure.

Technological Improvements

Reductions in drilling costs will be driven mainly by information on the actual situation at the bottom of the bore hole. Presently, such information is rather limited, as – due to insufficient space and generally unfavorable conditions – on-line measurements are very difficult to undertake and quite expensive. It is only recently, after decades of drilling activities, that initial measurements (Varnado, 1986) have shown a strong vertical oscillation of the drilling bit, which reduces the efficiency of drilling. If such problems can be solved, a further reduction in drilling costs seems achievable.

Similarly, if technological progress reduces the high cost of long-range transport, the cost of supplying Europe with Nigerian or Middle East gas will be cut considerably. One option certainly would be the construction of pipelines instead of using LNG tankers to transport the gas to Europe. However, each possible pipeline route runs through a number of countries and thus represents a risk to security of supply. Additionally, the LNG route could pave the way to a spot-market for gas, reducing the need for long-term, bilateral contracts.

According to Runge (1983) it seems unlikely that cost reductions beyond 5% can be achieved in pipelines and LNG operations. This would result in a reduction of total costs by some 2% and would thus not change the situation dramatically. However, for pipelines running from Western Siberia to Europe cost reductions of up to 15% may be achieved, once full capacity has been utilized and the gas-driven compressors are replaced by electric ones.

An improvement of the order of 5% to 10% can be achieved for most of the operations along the gas chain by, e.g.:

- increasing the size of the gas pipes from 1400 mm to 1500 or even 1600 mm,
- increasing the pressure in the gas pipes from a maximum of 80 bar to 100 bar, (e.g., planned for the first 500 km of the pipeline from Yamal in Northern Siberia) or, later, even to 200 bar,
- using electrical compressors instead of gas ones,
- improving pipe laying through a higher degree of standardization, or
- increasing the load factors of the transportation systems.

Gas distribution will, apart from the introduction of plastic tubes to replace cast iron, not become much cheaper in the future. Minor improvements could stem from the automation of pipe laying, but they will be offset by the worsening of conditions, as mentioned before. For areas that require very expensive distribution systems, it may even pay to convert gas into electricity and utilize the existing electricity distribution system to supply energy to the end-user, especially when heat pumps can be used to produce low-temperature heat. Even if the existing grid is not sufficient, an upgrading would often be cheaper than the introduction of a new gas grid.

The Effect of Cost Reductions in the Gas Supply System

Compiling the costs incurred in supplying a Central European consumer with natural gas from the areas considered yields a cost range from $177 to $350 per 1000 m^3 (see Table 5). The costs for delivering the gas to the region (i.e., without costs for distribution) range from $17.5 to $160 per 1000 m^3 (or $0.5 to $5 per MBTU). Comparing the latter value with the mid-1986 energy price situation shows that most of the cost figures exceed mid-1986 crude oil import prices (~ $12/boe = $2.07/MBTU). Gas prices for the residential consumers – $360 per 1000 m^3 in Austria, June 1986, equivalent to $265 in 1984 currency[5] – are already approaching

[5]In converting from 1986 to 1984 US$ the decrease in exchange rates (from 20 AS to 15.5 AS per US$) and the US$ inflation (5.2%) were taken into account.

the current delivery costs (see Table 5). However, the contract signed in June 1986 for gas from the Norwegian Troll and Sleipner fields is, with $3.6/MBTU (equivalent to $21/boe) (*Petroleum Economist*, 7, 1986), well above the mid-1986 energy prices. In fact that price indicates that the buyers' consortium is expecting an oil price of about $29 per boe in the late 1990s.

Table 5. Total Costs and Cost Structure for Gas Delivered from Various Locations to Central Europe.

	Costs		Cost Structure (%)		
	Excluding Distribution[a] [$/MBTU]	Including Distribution [$/1000 m^3]	Extraction	Transport	Distribution[b]
Groningen	0.50	177.5	6	4	90
NL Offshore[c]	0.76	186.9	9	6	86
Ekofisk	1.67	219.0	16	11	73
Algeria	2.17	236.6	4	28	68
Valhall	2.24	239.0	23	10	67
Statfjord	2.42	245.6	16	19	65
Pers.Gulf[d]	2.52	249.0	4	32	64
Sleipner	2.72	256.0	27	11	63
Pers.Gulf[e]	2.83	260.0	3	35	62
Algeria*	3.07	268.4	4	37	60
Nigeria	3.18	272.2	5	36	59
Urengoy	3.32	277.3	8	34	58
Heimdal	3.41	280.3	32	11	57
Troll	3.51	284.0	26	17	56
Other W.Sib.	3.68	290.0	10	35	55
Pers.Gulf	3.94	299.2	3	44	53
Nigeria*	4.07	303.6	4	43	53
Gullfaks	4.36	314.1	34	15	51
Troms[f]	4.87	332.0	26	26	48
Troms[g]	5.01	337.0	25	27	47

*Gas is transported as LNG.
[a]That is, delivery costs to Central Europe (multiply by 35.31 to convert into $/1000$m^3$).
[b]Cost for distribution are $160/1000$m^3$ for all projects.
[c]NL = Netherlands.
[d]Transported by pipeline via Yugoslavia.
[e]Transported by pipeline via Italy.
[f]Gas from Troms transported via onshore pipeline across Sweden to Hamburg.
[g]Gas from Troms transported via offshore pipeline to Emden.

Since the cost structure depends heavily on the location of the gas field, the figures given in Table 5 differ widely. Whereas the extraction costs for fields in Algeria, Nigeria, or the Persian Gulf represent about 5% of the total cost of delivering gas to the end-user, they approach 10% for new fields in Western

Siberia, and even exceed 30% for new fields in the North Sea. The transport of gas from areas with cheap production costs to Central Europe is quite costly, reversing the cost structure in relation to fields in the North Sea. These costs can amount to 35% of the total costs for pipeline transportation and even to more than 40% for LNG routes.

Given this cost structure and assumptions on cost reductions for each element of the gas delivery chain, we estimate ***the effect of technological improvements*** on the total costs of delivering gas to the end-user. Proposing that capital costs for drilling in the North Sea can be further reduced by 7% per year – as indicated in Figure 1 – and that Troms will be developed 20 years from now, the following can be concluded:

- investment costs would be reduced to 25% of the mid-1986 estimate,
- the effect on the total extraction cost – of which investment costs for drilling represent about 60% (Lorentsen *et al.*, 1984) – would be a 45% reduction,
- the cost of gas delivered to Central Europe, and thus the cost of supplying large consumers, would be reduced by 23%, and
- the total cost of gas produced from Troms and delivered to a domestic consumer would be reduced by 12%.

Thus, gas from such remote sites would be 12% or 23% more competitive than the mid-1986 cost estimates suggest. This is, compared with the reduction in investments in drilling equipment, a relatively small effect for domestic consumers.

Major effects could only be expected from changes in distribution costs. Such changes are not foreseeable with the technologies used today, so a real innovation is required.

Taking the Methanol or Gasoline Route

Techniques to reduce the costs of transporting natural gas over long distances could be based on its conversion into methanol, gasoline, or the middle distillates. A number of studies were undertaken to investigate these options (e.g., Jawetz, 1984; Kliman, 1984; Musgrove, 1984). Most of the studies conclude that the production of a liquid fuel from natural gas is a viable option. This might be the case when high-priced imported oil products are compared with relatively cheap domestic natural gas supplies – as for New Zealand and Australia. This is also true when gas, which is currently flared in the Middle East, i.e., is regarded as having no value, is used as feedstock for the production of methanol, gasoline, or the middle distillates (gas oil, kerosene, naphtha). The latter option may be very valuable for the developing countries, where easily transportable and storable fuels are needed urgently to replace crude oil imports, and where the implementation of a gas infrastructure is too costly. The production of kerosene could also help to ease the shortage of fire wood, a severe problem in many countries.

The costs of gasoline or middle distillates produced from natural gas are estimated to be $337 or $318 per ton of product[6] ($7.9 or $7.5 per MBTU) respectively (Thackeray, 1986). The production of methanol would cost some $2.5 per MBTU.

The major drawback of such operations is the high loss of the original thermal content of natural gas: the efficiency of producing methanol from natural gas is 60%, that for producing gasoline as low as 50%. This means that 30–50% of the original energy content of natural gas is lost (Jawetz, 1984; Thackeray, 1986), whereas only 17% or 7% of the gas originally extracted is lost with LNG chains or pipeline systems, respectively [example taken for gas transported from Algeria to Europe (IEA, 1982)]. The conversion of gas into middle distillates or gasoline will probably be restricted to domestic projects for the reasons outlined above. The first country following this route is New Zealand, where gas is converted into gasoline at a plant near Motunui. For international trade the methanol route may represent a feasible option when methanol is used in the transportation sector.

New developments in the energy supply system may improve the economics of methanol produced from natural gas. One option is to use nonfossil heat from nuclear or solar sources in a steam reforming process to produce methanol. Such a system could produce 800 PJ of methanol from 1000 PJ of natural gas. It would additionally provide 300 PJ of hydrogen, utilizing 740 PJ of nonfossil high temperature heat (Häfele *et al.*, 1984). Processes like this would be specifically suited for countries in which other sources of carbon are available. Coal or heavy crudes could be upgraded using the hydrogen produced by the process.

Deep Gas: A New Chance

The discussion as to whether hydrocarbons are of biogenic or abiogenic origin has been revived recently. This question was discussed as early as the nineteenth century, when a number of scientists (e.g., A. v. Humboldt and D. Mendeleev) argued that hydrocarbons are a product of methane outgasing from the

[6]Based on a gas price of $1.00 per MBTU and capital charges of 10%, using 1985 US$.

center of the earth and do not stem from animal and plant debris (Graf, 1925). During the following decades the latter explanation became accepted. Only recently, new findings on the formation of the earth and the detection of large amounts of methane in space gave new momentum to the old ideas as to the origin of oil and gas (Gold and Soter, 1980; Gold, 1985). A by-product of the theory of an abiogenic origin of hydrocarbons is the proposition that huge amounts of methane can be found at greater depths. Currently, a number of drilling activities, aiming at depths between 6 and 15 km, are underway to test this hypothesis and obtain more information on the geological and physical conditions at such depths. Amongst them is a project in Siljan, Sweden, which was established explicitly to find abiogenic gas, and projects in the USA, the FRG, and the USSR, which partly serve purely scientific purposes.

However, we do not intend here to investigate whether such gas is available and can be produced. Given the assumption that deep gas exists, we simply want to indicate those conditions under which it could be competitive. If abiogenic gas stems from the center of earth, it can be assumed to be found at many locations, i.e., much closer to the point of consumption than many fields mentioned earlier in this paper. Transportation costs, in the range of $20 to $120, could be saved (see Table 5). Compiling the costs for supplying an industrial user, the relative savings would, due to the low distribution costs, be much higher than for residential consumers.

But how competitive is the drilling operation itself? The three main factors that determine the cost of producing deep gas are the depth and size of the deposit and the amount of gas produced per well per day. A formula for estimating drilling costs is given by Holmes *et al.* (1984):

$$Cost = \left[\frac{Depth + 6}{l}\right]^m ,$$

where the depth is given in 1000 feet and costs in $1000. Given the parameters l and m, which were estimated for 13 regions in the USA, this formula yields, for a depth of 30000 feet, drilling costs of between $4.6 and $27 million.[7] However, this formula seems to underestimate at greater depths. A comparison with actual drilling costs (API, 1986) shows, for depths below 15000 feet, 20–30% higher costs than the highest value obtained by the above equation. An estimation using the equation

[7] First value for parameters estimated for North Eastern Luisiana (l=1.637, m=2.732), second for North Texas (l=3.412, m=4.329).

$$c = \alpha e^{\beta d} d^{\gamma}$$

	value	t-statistic
α	0.4175	47.7289
β	0.1663	12.5562
γ	0.6466	8.0989

(d=depth in 1000 feet, c=cost per well in US$ million) with the 242 data points given in API (1986) yields a very good result (r^2 = 0.906) up to a depth of 22500 feet. Based on this formula the costs for a 30000 foot well would be $55 million. This is probably an overestimation, as the deepest wells included in the data set are, for reasons explained earlier, still very expensive. But drilling costs are actually also a function of time – as experience grows, costs go down – therefore, a more realistic estimate for the cost of a producing deep well could be of the order of $40–$50 million.

Assuming a similar field performance as experienced on average in the North Sea, i.e., 300m^3 per day per well, and an average production of 10 years per well, annualized capital costs would be in the range of $60–$70 per 1000 m^3.[8] If all the assumptions used to calculate this value are close to reality, it compares favorably with the costs for gas produced from Sleipner or Troll, some $110 per thousand cubic meters, including transportation and operation and maintenance costs (see[9] As the operation and maintenance costs are presumably much smaller for an on-shore deep gas well than for a North Sea off-shore operation and as additional investments are only minor, gas produced from deep wells could well be competitive with gas produced from difficult North Sea fields.

Final Remarks

Natural gas, even if extracted from fields at unfavorable locations, became increasingly attractive during the era of high crude-oil prices. Its market share grew steadily as technological progress made extraction from previously unattainable locations and transport over ever longer distances feasible. Despite this technological progress, it will always be a more costly operation to supply an end-user with gas rather than oil produced under similar conditions. The costs of transporting, storing, and distributing gas cannot, mainly because of the different

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[8]Discounted over 10 years with a 10% discount rate.

[9]The annualized costs, calculated as above, for the initial investments ($8 billion), are $55 per 1000 m^3.

energy contents per volume, meet those of crude oil and its products. On the other hand, it is often more efficient and cheaper to use gas in end-use technology than other fuels, especially when costs stemming from environmental damage are taken into account.

However, further technological improvements along the entire production and supply chain will reduce the cost of gas supplies and make it more competitive, even at crude prices of around $20/boe. For this and other reasons, such as supply security or ecological considerations, natural gas might well become an even more important energy carrier during the coming decades than today (mid-1986). A more surprise-free future in terms of energy supply can only evolve when a shift back to cheap OPEC oil is avoided during an oil glut. A strong sign of such a policy was set by the contract to develop the expensive Troll field, signed in 1986 between Norway and the European consortium of buyers lead by Ruhrgas.

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