The OIES Review of Energy Costs

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1 INTRODUCTION

> Those who either from want of knowledge or from interested motives advocate the universal adoption of oil fuel in place of coal generally claim that it would be quite possible to supply oil of the necessary quality at 30s or 35s a ton, and that oil as a fuel is worth twice as much as coal, so that there would be an economy in cost as well as the enormous conveniences of liquid fuel for power production. Such an idea is a mass of fallacies; the fuel oil supply is totally inadequate; there is no guarantee of a continuous supply; the price of fuel oil is now £3 a ton and over, and its value as a fuel only one and a half times that of coal; and as the general adoption of liquid fuel must be a commercial question, it is not likely that keen businessmen will look at oil as a general fuel as long as this country can produce coal at anything like the present price. (Professor Vivian B. Lewis FIC, FCS in "Oil Fuel" 1913).

The availability of energy alternatives and their relative values are just as relevant in our present troubled times as when the good professor wrote his two long sentences in the year before the storm clouds of the First World War broke. At that time the ratio of the price of fuel oil to that of coal on a straight tonne for tonne basis was nearly 3 to 1. This ratio subsequently became more favourable for oil although today the price ratio is not too different. Between 1913 and 1991 rather a lot of 'keen businessmen' have indeed looked at fuel oil as a 'general fuel' instead of coal.

It is, of course, always easy with hindsight to make fun of profound statements. But the excerpt does illustrate how static cost and price comparisons, taken by themselves, can be misleading in judging the way in which energy supply will develop in the future. However, an informed view of the relative technical costs of making additional energy available is a fundamental consideration in choosing to develop a particular source of energy. These costs do, of course, have to be seen within the context of the other influences involved in the choice of energy supply. These other influences, such as convenience, efficiency of use, availability, technological development and price and taxation policy, play roles of varying and changing significance. Ultimately, however, they all need to relate directly or indirectly to the actual financial cost of investing in new projects and to the total technical costs of energy production.

The oil crises of the 1970s saw the analysis and public discussion of energy costs increase substantially as research and development into oil alternatives was stimulated. Interest, particularly in the more exotic alternatives to oil, which generated such excitement at the time, has inevitably waned with falling oil prices. However, a current view of their costs and how they might develop in future is as relevant as ever - as indeed, are the costs of making incremental volumes available from more conventional sources of energy.

Indications of the cost of individual supply projects are often available but difficulties arise when trying to make a comparison on a more general basis across a number of projects and energy forms. Published cost estimates, those quoted by governments and at technical conferences and even those used within individual energy and manufacturing companies, often vary widely. It is very difficult to ensure that one is comparing like with like, and to avoid misleading comparisons.

There are many reasons why such estimates differ. It can simply be due to loose reporting or to very different and often unclear and unstated financial criteria. Different estimates are also made by organizations for specific purposes and with varying motives. They may, in addition, have been made at different dates for different periods or locations which are not always specified. In the latter case, a host of factors, including varying exchange rates and the cost of delays in a high or low inflation situation, can be the cause of substantial variations. Differences in the size of the project or its scale of operation and utilization, the changing state of development and knowledge of the technology involved and the pace and pattern of the construction programme all contribute to the confusion. In some cases also deliberate biases and distortions behind the estimates have to be taken into account and, where possible, eliminated if a genuinely fair comparison is to be achieved.

This paper attempts to make such a fair comparison for the financial cost of producing and supplying most of the relevant forms of energy. The following section describes the role of cost in making the choice between the variety and abundance of energy supplies that are available. Section 3 looks at some of the main considerations and uncertainties to be taken into account in comparing the technical cost of energy projects, including the need to protect the environment. Comparative cost estimates are presented on a uniform and consistent basis in a number of charts in Section 4. Section 5 covers the background to these costs and the basis on which they have been estimated. There is an overview and conclusions in Section 6.

2 COST AND THE ABUNDANCE OF CHOICE

One of the effects of the present situation in the Gulf will be further to encourage and accelerate the diversification of supply sources, whether by individual companies or countries. Even without such a stimulus, there has probably never been such a broad and varied choice of sources or forms of energy from which to meet the world's needs as there is today.

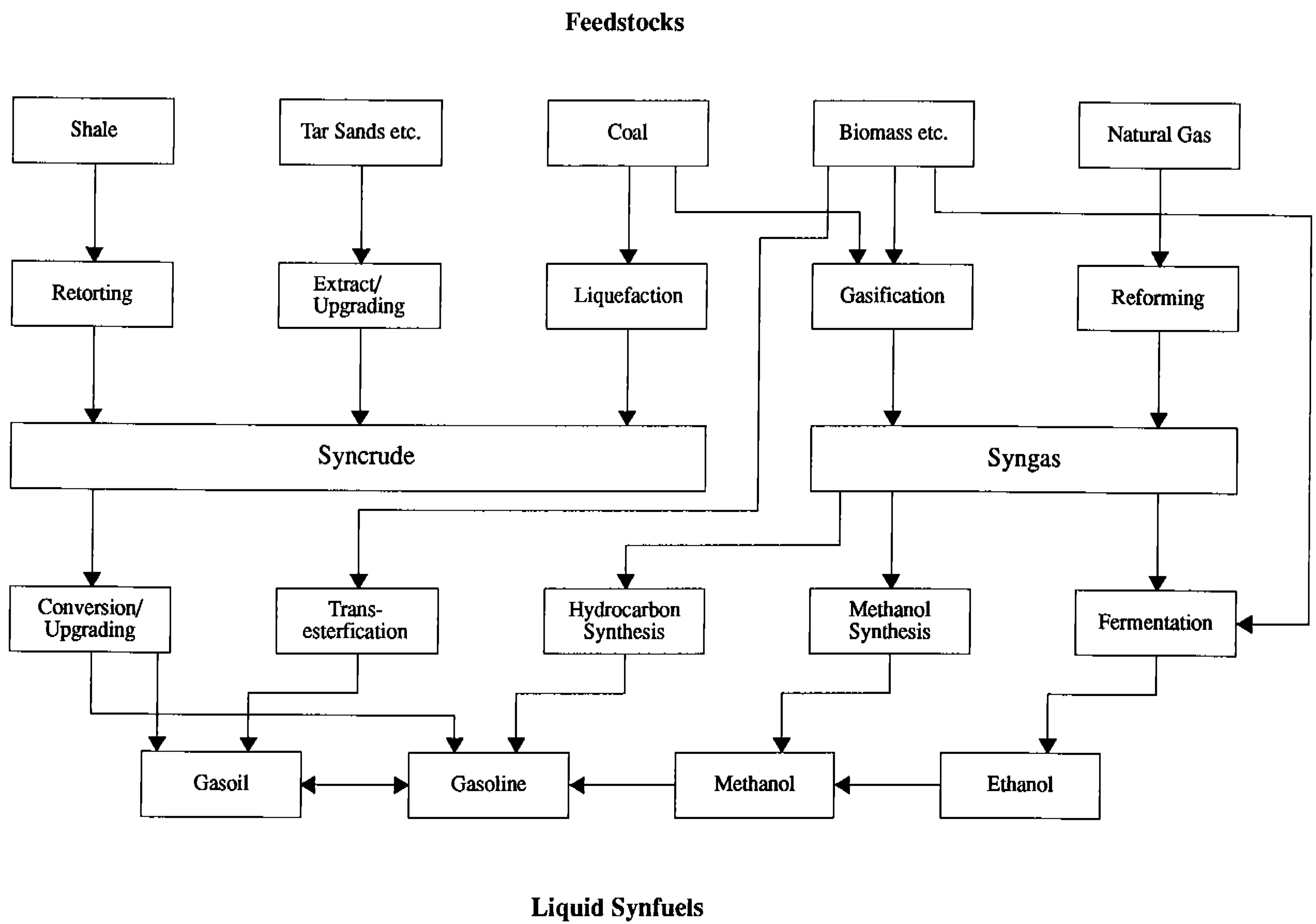
The number of countries that produce oil and gas and the trading routes and methods involved continue to increase. We have seen a simultaneous loss of oil exports from two of the largest Gulf producers made up with little real difficulty. The ability to move natural gas through a growing network of pipeline and LNG routes to and from almost any region makes gas potentially available on a scale and over distances not previously considered. Coal, the other major primary fuel source, has production and associated export facilities that are more than adequate for present demand with still more new capacity under construction.

Electricity generation represents a way in which most forms of energy can be used and where individual fuels and sources of energy compete intensely with one another. Electricity itself is, in its turn, a competitor with these same fuels in many markets. The expansion of electricity grids has priority in most countries, although the amount of electricity traded internationally is still very small. None the less, the movement of nuclear-based electricity from France through Western Europe, the growth of common carrier transmission lines or the development of an ASEAN electricity grid based on hydro power and gas are just a few examples that point to a much greater expansion of electricity trade in the future. This is bound to result in more choice, particularly between the primary energy sources from which electricity is generated.

The development of unconventional forms of energy has slowed in recent years and some technologies appear to be all but moribund. This may now change. The Gulf war will add weight to the need to achieve diversity and security of supply. This could be seen as being partly achievable through a revival of activity in the development of new and unconventional forms of energy.

The ability to convert from natural gas to liquid fuels and from coal or biomass to gas and liquid fuels could add considerably to long-term flexibility of choice and the lessening of reliance on Middle East oil. These technologies have already been successfully demonstrated in one form or another, as have the conversion of heavy oil to Orimulsion and the use of shale oil and tar sands to produce 'synthetic' fuels. Their production on a commercial and competitive basis, particularly in substitution for conventional oil-based transport fuels, would represent an enormous new area of supply choice. Chart 1 illustrates the variety of routes that are available to obtain synfuel

CHART 1: Routes to Synthetic Transport Fuels



substitutes for gasoline and diesel fuel.

Some substitutes for conventional oil based transport fuels can be produced directly from biomass by fermentation and other means. However, most feedstocks have to go through a number of different stages of varying complexity before their products are of acceptable quality. For tar sands and heavy oil, the processes followed for upgrading are similar to those in use for conventional oil and this is reflected in the comparative costs of the products. For the liquefaction of coal, either through a synthesis gas stage or directly, the processes involved are innovative and more complex with a resultant impact on cost; as indeed they are for natural gas and biomass. All of the feedstocks shown in Chart 1 can also be used for burning under boilers to produce steam for electricity generation or for industrial processes. In contrast to the production of synthetic transport fuels, only relatively inexpensive and well-established treatment processes are needed for these outlets.

There should also be scope for more energy to be supplied from the wind and perhaps from solar heat, tidal and wave power. Some of these so called 'renewable' technologies are able to put the control of energy supply directly in to the hands of the consumer, thus eliminating costly transmission systems. This strengthening of consumer power could eventually transform the structure and pattern of energy supply and use.

However, costs are not the only determinant of the pattern of energy supplies and diversification. The choice of process is strongly related to feedstock availability and product need. The large areas of sugar cane in Brazil, for example, coupled with a low world price for sugar stimulated the production of ethanol through sugar cane fermentation. The availability of low-cost, low-grade coal and high demand for electricity, presents opportunities for the mine mouth generation of electricity.

A country or a company decides to develop a particular source of energy, or a consumer chooses to use it, for a variety of reasons. Some, such as the need to diversify supply sources or to encourage indigenous energy production for security or social reasons may override the impact of basic costs. The substantial financial and other support given to European coal producers and in some countries to nuclear power are glaring examples.

In electricity the investment needed for a power generating project is usually many times that needed to develop a new oil or gas field for the supply of an equivalent amount of energy - as the charts in Section 4 illustrate. These cost differences usually work through to the final price to the consumer but do not prevent electricity demand growing faster and having a much higher level of investment than most other sources of energy. Electricity's unique properties and applications and its efficiency of use to the consumer are more relevant; it represents a high value market, although at the margin electricity does compete with other forms of energy on price. However, the different types of electricity generation, whether based on gas, coal, water, uranium or whatever, do compete with one another strongly and very directly on a basis of cost. Thus, the comparative cost of generating electricity has a highly significant bearing on the ultimate pattern of demand and supply for primary energy through this route as well.

Oil is a prime example of where basic technical costs may have little relevance to the price paid by the consumer. The cost of producing most Middle East oil is well under 5 per cent of the selling price, even before the addition of downstream taxes. Nevertheless, relative technical costs, allied to the prevailing fiscal and other regimes, are a guide to future areas of development as well as to the scope for flexibility in encouraging indigenous development.

There are many other considerations to be taken into account, but a detailed comparison of technical costs obviously plays a major part in any assessment of the relative economics of competing energy projects. For such an evaluation of individual projects, costs are highly specific and can only really be estimated and compared on the basis of the actual conditions and the actual plant involved.

A much wider view of comparative energy costs is, however, involved in any realistic consideration of energy policy and strategy, although not always spelled out explicitly. Such a view of costs is also fundamental to any assessment of future patterns of energy supply and demand. It is for these purposes that the comparisons in this paper are relevant.

3 AN UNCERTAIN MEASURE

Cost estimates often have a commercial value or may be considered as government secrets to be maintained on a confidential basis. When project costs are quoted publicly, the basis on which they were calculated is often unclear. The extent of their reliability and how representative they are is just as uncertain.

Only rarely are the cost estimates for one energy project directly comparable with those for another. This is particularly so when a different technology or energy source is involved. There has been an element of wishful thinking or deliberate understatement in many estimates for the cost of new forms of energy.

The early estimates of the cost of nuclear electricity and photovoltaic cells are examples. It was said in the 1950s that nuclear electricity would be too cheap to be worth metering. This optimism, derived largely from scientific enthusiasm, was soon proved foolish. However, it did not stop the continued understatement of actual costs during the 1970s in order to boost orders and get the industry off the ground. It is only now with, for example, the privatization of the electricity industry in the UK and the public enquiries in the USA, that the actual cost of developing nuclear power is coming to light.

The cost of photovoltaic cells, for the generation of electricity from sunlight, was expected by the US Project Independence of 1974 to fall, with the aid of a government programme, to well below $1 per peak Watt by the end of the 1980s. Costs did seem to be on a fast learning curve in the late 1970s and 1980s. However, at current costs of around $5 to $7 per peak Watt for the array alone they are still far from the desired competitiveness with conventional electricity sources.

There are also surprises as costs move more quickly than expected on the learning curve. The advent of intense competition amongst suppliers of wind generators in the USA and the phasing out of tax credits as well as an increase in generator size has led to significant reductions in their cost and price. The average price of wind generators in the 10 to 20 metre diameter range fell, between 1982 and 1986, from $1625 per kW to $792 per kW.

The project now underway to liquefy Nigerian natural gas for export is said to be costing $2 billion. In 1985, the same project was estimated to cost $4.3 billion. The original proposal by Phillips for an LNG scheme in Nigeria made in the late 1970s was estimated at $10 billion! The dramatic difference between the latest estimate and that for 1985 is largely the effect of:

- Using gas from non-associated fields, thus avoiding compressor costs for associated fields.

- Keen competition amongst contractors and designers.

- The use of second-hand tankers.
- A single route for the gas from production to LNG delivery for the three groups participating in the venture.
- Technical advances of an unspectacular, but effective, nature stemming from earlier practical experience in plant design and operations.

Compared with some recent LNG ventures, the Nigerian plant is now expected to be some 20 per cent less expensive in capital cost and about 4 per cent higher in thermal efficiency. The impact on capital charges as a result of the investment savings could mean, for example, that gas can be delivered to North West Europe at $20 per boe rather than $30 per boe - thus making the project commercially acceptable under present price conditions.

The economics of tar sands extraction in Canada have also gradually improved over recent years. This is partly the result of moving from the initial starting-up stages to more efficient operation as experience is gained. Cost reductions have also been encouraged by low oil prices and the generally poor investment climate. This has been in addition to the considerable benefits to effective costs from favourable taxation and royalty regimes and from government subsidies for research. A more fundamental factor affecting actual technical costs of producing tar sands has been the use of small modules constructed one at a time. This has reduced the risk and high initial investment needed as well as construction times. The All Sands mining project was planned in the wake of the first oil crisis to produce 140,000 boe/d of syncrude for a unit investment of C$100,000 per boe/d. The cost of a current mining project on a much smaller scale is more than 50 per cent less; whilst the cost of extending the existing Cold Lake tar sands plant, which uses an *in situ* process, is only some C$6000 per boe/d.

Clearly, progress in reducing energy costs will continue to be encouraged by low oil prices but the steady improvement in energy supply technology is likely to continue even under high prices. Improvements in the practical application of new processes to existing practice, such as multiple well development for offshore oil or horizontal drilling for hydrocarbons, can have a surprisingly rapid impact on technical costs. So can the overall state of the economy or the industry situation on manufacturing capacity and contractors availability and the willingness to shave costs.

Oil and gas development costs reacted quickly to the fall in oil prices in 1986; projects that were initially trumpeted as having become hopelessly uneconomic at the low prices of the time none the less went ahead. In practice, with the very high tax rates prevailing at the time, the actual impact on the companies involved in existing fields was small. The average cost of fields under development in the North Sea was quoted for 1986 in the UK 'Brown Book' as £14 per barrel. In 1987 it was £11 and by 1990 it had fallen to £8 per barrel. Although there were many factors at work to cause this change, such as a changing pattern of development, this is, nevertheless, a remarkable turnaround from the steady increase in costs that was taking place in the 1970s and early 1980s and which appeared unstoppable. The estimated costs of the UK Forties field for example were said to have risen from £350 million in 1972 to £750 million by the middle of 1975.

Oil company representatives are reported to have stated at the time that this escalation rendered the development of all but the largest fields uneconomic and discouraged further North Sea exploration!

Costs for a particular energy source also vary considerably in relation to the location and quality of the source available. The technical costs of producing oil in the easy development conditions onshore in the Middle East are generally under $1 per barrel. In contrast, new oil production from, say, offshore Brazil might cost over $10 per barrel and the development of North Sea oil from the remoter and more difficult areas some $20 per barrel.

There is also a particularly wide variation in the level of investment needed to develop hydroelectric resources. For example, it apparently costs five times as much to put in place the same amount of hydroelectric generating capacity in some parts of Mali as it does in Nigeria. Variations between the indigenous and imported contents of similar projects can also have a significant effect on comparative costs.

Whatever the arguments used in developing policy on environmental matters, the economic consequences cannot be ignored and need to be assessed. The cost of environmental protection for new supply projects or retrofitting existing plant is a growing area of uncertainty and of regional variation. The addition of stack gas scrubbing to remove sulphur dioxide from the emissions from a coal-fired power station adds between $150 to $300 per kW to capital costs. This may represent 20 per cent or so on the total cost of the plant although, in terms of cost of electricity generated, it only adds some 10 per cent. Interestingly, it would allow an additional premium of around $20 per tonne to be paid for low sulphur coal before the additional costs of scrubbing become worthwhile. This is before taking into account the additional operating and maintenance costs that are also involved.

The table below compares electricity generating costs for a number of conventional power plants operating at base load. It assumes a cost for internationally traded coal of $40 per tonne, gas at $2 per mBtu and fuel oil at $80 to $100 per tonne. On the assumptions made, the cost of generating electricity from gas-fired turbines is less than the alternatives - all of which, except arguably nuclear, have a greater adverse effect on the environment. The relatively low capital cost and short construction time for natural gas turbine generators are added bonuses.

Table 1: Efficiency, Costs and Environmental Impact of Electricity by Type of Fuel

	Overall efficiency per cent	Capital cost US cents/kWh	Total cost US cents/kWh	Construction time - years	Environmental impact
Coal	33	2.0-4.3	3.8-6.9	3-5	High
Nuclear	32	3.8-10.0	5.3-11.8	4-12	High(low?)
Fuel oil	33	2.0-2.5	4.8-5.7	3-5	Medium
IGCC	29	3.3-4.5	7.5-8.9	5-7	Medium
Gas turbine	32	0.8-1.1	3.4-3.9	1-2	Low
Gas cc	45	1.4-1.9	3.1-3.8	2-3	Low

Notes:

1) Cost computed on the basis of an 8 per cent after-tax earning power.
2) IGCC - Integrated coal gasification combined cycle.
3) Gas cc - Natural gas combined cycle.

Estimates for the additional cost of decommissioning nuclear plants are much more uncertain, ranging from 5 per cent to over 50 per cent of the original capital costs. These additions can have a significant impact on the effective cost of electricity produced and can make all the difference in nuclear's competitive position versus fossil fuels. As yet, there is no experience of the complete decommissioning of a major commercial plant to act as a guide. The OECD appears to believe that decommissioning costs will have a small effect on the cost of electricity generated from nuclear power, although this is disputed. The cost of treating radioactive waste and of its disposal are also not usually included in quotes of nuclear costs. Any estimate of the cost of fully dismantling deep-water oil platforms also lacks practical knowledge. Indeed, there are additional environmental costs waiting in the wings for most other forms of energy, not just nuclear.

The construction of projects as a series in a standardized form usually makes a substantial difference in costs from those that are of unique design or constructed on an individual basis. The difference between the capital cost of French nuclear capacity, built using the 'convoy' system, and capacity in the USA or UK, built on an individual basis with many local variations, can be as much as a ratio of 1 to 3.

The availability of an existing infrastructure also helps to reduce capital costs. Whereas, the need to provide roads and basic facilities and to bring in construction materials to remote areas may more than double the cost of a project. This is often the main reason for the difference in cost between projects in developing countries and those in the OECD.

The Australian North West Shelf liquefied gas project is an example of a recent major development based on an offshore gas field in a remote area without an existing infrastructure. The capital cost of the actual liquefaction plant was some A$700 million but the total cost of the whole liquefaction phase of the project came to some A$3 billion. Over A$350 million was spent on providing water, power, housing and other community facilities.

Quoted costs are also highly sensitive to the choice of discount rate and the treatment of capital in general. The choice is obviously a matter for the company or country concerned. The value adopted is in practice based on views of the cost of borrowing, on the opportunity cost of capital or on social preferences, taking into account specific policy objectives and constraints. It is not always clear at what level of uncertainty about the future a discounted cash flow exercise ceases to have any merit when fuel and product prices cannot be predicted.

The effect of differing 'earning powers' on the unit cost of output is shown in the example.

Table 2: Costs of a Notional Shale Oil Project. US Dollars/boe

	Utility Project (1)	Commercial Project (2)
Capital	7	21
Operating, maintenance and upgrading	14	14
Total unit cost	21	35

Notes:

1) Capacity of 50,000 boe/d for a total investment of $2.5 billion.
2) No taxes, 3 per cent interest on debt. 30 year life.
3) 8 per cent return on equity after tax @ 50 per cent. 20 year depreciation.

At a commercial rate of return on capital this shale oil project is clearly not viable against an oil price of $25 per barrel. In contrast, the acceptance of a utility style rate of return, by whatever means it is achieved, does make the project look competitive.

The fluid and creative nature of cost estimates is well illustrated by the way most alternatives have apparently always managed to keep just ahead of the oil price, whether it be at $15 or $30 per barrel.

Table 3: Cost of a Project for the Production of Substitute Natural Gas from Coal in Different Years, 1972-1983. US Dollars/boe

	Cost per unit of output	Oil price
1972/1973	5-9	2.5-3.0
Project Independence. End-1973	11-18	5.0
USA N.E.O. 1976	18-25	11.5
N.Dakota project. 1976	15	11.5
1977	26	12.4
1978	27	12.7
1983	42	29.0

Notes: Capacity of the project 250 million cubic feet/day. Costs in US Dollars, money of the day.

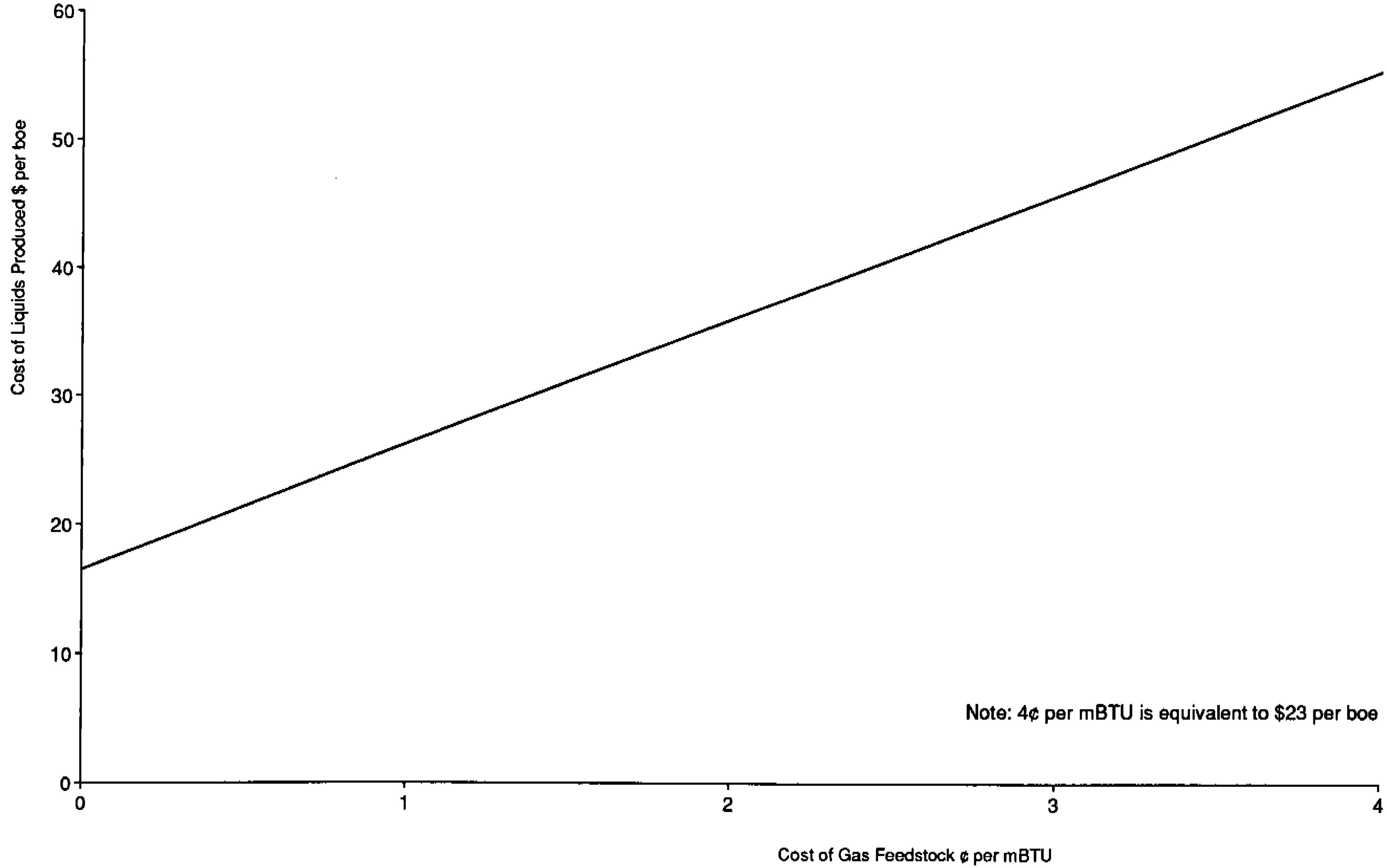
The cost estimates made in different years for a substitute natural gas from coal project, which was completed but later disposed of by the US government, were indeed perhaps not always to be taken seriously.

There are, however, valid reasons why alternatives have increased ahead of the oil price. Obviously, with pioneer projects, there is always great uncertainty about process operating conditions and about equipment sizing and materials needed. This allows plenty of scope for cost overruns. Estimates for the cost of new alternatives also increased because energy costs are an important cost component in the raw materials and activities used in many of the processes.

Where a fuel plays a major part as a feedstock, as with a liquefied natural gas project or plants converting coal or gas to liquid fuels, then that fuel is also influenced strongly and directly by the price of oil. For example, gas for a natural gas to methanol plant could represent anywhere between 20 and 70 per cent of the final cost. Chart 2 illustrates the impact of the cost of the feedstock on the cost of methanol from such a plant.

In order to produce liquids that could compete with oil delivered at, say, $20 per barrel, a netback of only $0.50 per mBtu or just under $3 per boe would have to be accepted for the gas feedstock. If oil prices rose to $40 per barrel this netback could be increased to $2.5 per mBtu or $14.5 per boe and the project still remain competitive. However, the temptation particularly for governments to try to recover more from their gas in a high oil price situation would be difficult to resist.

CHART 2: The Impact of Feedstock Cost on a Notional Methanol from N. Gas Plant



The high inflation rates and interest rates at the end of the 1970s and the beginning of the 1980s also boosted the cost of what were generally capital-intensive projects. Certainly the impact of inflation was underestimated in a number of cases. Another element was the technical reappraisal that was usually found necessary once actual commercial designs had to be made.

Many of the technologies on which so much research and newsprint were lavished in the early 1970s and 1980s stayed firmly on the wrong slope of the learning curve. For some projects, there was considerable padding of costs and ineffectual financial monitoring. This is, no doubt, inevitable with massive government-sponsored research in a near panic atmosphere allied with weak control and much opportunism. It was, perhaps, assumed that the seemingly inexorably rising oil prices would absorb any extravagance.

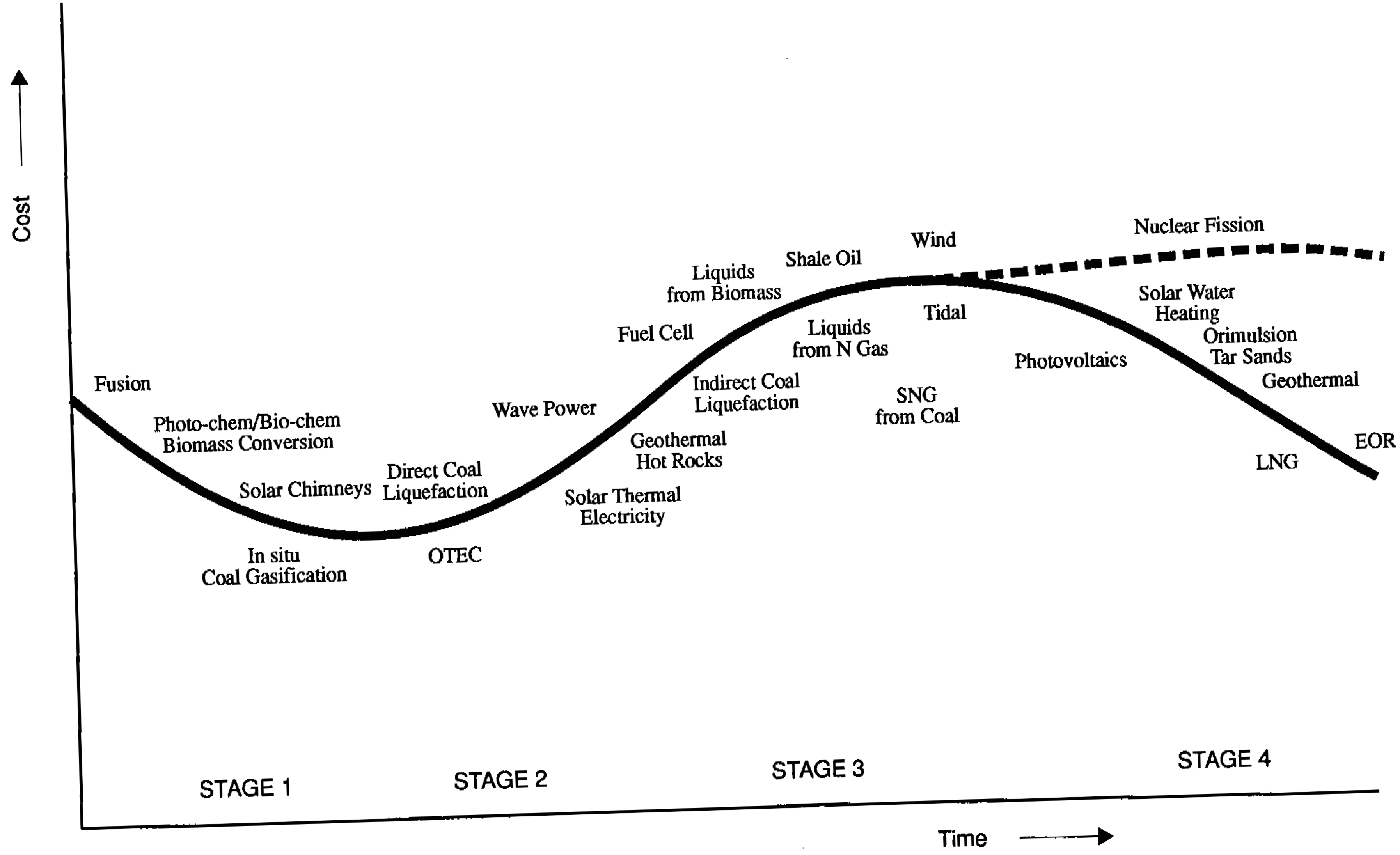
Projects involving new technology often seem to move through a number of stages. This is shown simplistically in Chart 3 which illustrates the relative position of many of the newer energy supply technologies. The distinction between stages is, of course, less defined in practice.

The first stage is when the process is still partly theoretical such as nuclear fusion, wave power or biochemical conversion of biomass. At this stage there may be a distinct tendency for costs to be presented in the most optimistic way possible, particularly as the enthusiasm, and sometimes venality, of researchers and others involved overrides objectivity.

The next stage is the move, after a pilot plant, towards demonstration and initial commercial application. Direct coal to oil conversion appears to be hovering on the brink of this stage. Optimism then tends to be tempered with the experience of practical results. Unfortunately, there may also be at this stage a temptation to deliberately underestimate costs in order to secure an initial commercial foothold and achieve economies of scale.

In the third stage the project moves towards commercial application with the first full-sized plants. The production of motor fuels from natural gas and from biomass and shale oil are largely in this stage. At this stage, where cumulative costs are building up at their fastest rate and product prices are most uncertain, commercialization tends to have a salutary effect on estimates as practical engineering and construction difficulties are encountered. These are sometimes exacerbated by poor project definition and additions that may stem from regulatory impositions.

CHART 3: Cost Escalation for 'New' Energy Projects



By the last stage, a number of successful commercial applications have been made and experience gained. Regulations tend to plateau and their cost can be more readily gauged. Technological improvements and the benefits of series or mass construction, start to take effect so that costs in real terms should level off and eventually start to decline. The advent of commercial competition may also have an impact on costs leading to the cutting back of any 'goldplating' that may have crept in when government or other support was available. Tar sands and nuclear fission are well in to this stage but, in the case of nuclear, costs have yet to fall for a number of reasons mainly connected with environmental protection.

Low energy prices have favoured improvements in the cost effectiveness of alternatives although having a negative effect on their development. There may have been genuine technological cost-effective breakthroughs in, for example, synfuels production from natural gas and gas liquefaction. In addition,there is perhaps more realism now in managing research and development. The conventional alternatives to oil are also being helped by the growing independence of energy prices from one another. But there is little sign for most alternatives to oil that their costs are moving from the relative positions that they have occupied for so long.

It is to be hoped that any accelerated move to the development of new energy technologies as a result of the Gulf war will not be as wasteful and ineffective as many of the activities spurred on by earlier Middle East crises.

There are many elements other than those already mentioned that can add to the confusion over costs. A comprehensive and balanced comparison across the whole spectrum is thus very difficult to achieve. None the less, it is possible to construct an indicative and sensible comparison between the technical costs of most of the relevant forms of commercial energy. For such cost estimates to be of real relevance, they need to be calculated, refined and presented in such a way that, as far as possible, they are on a uniform basis. To be genuinely comparable they also have to be freed from any commercial or political bias. Although clearly impossible to achieve fully, this is the ideal to which the comparative costs in this paper have been aimed.

4 A COMPARISON OF ENERGY SUPPLY COSTS - THE CHARTS

Charts 4 to 7 compare the costs of supplying different sources of commercial energy. These costs have, of necessity, been distilled from many and various sources but have, wherever possible, been put on to a common and uniform basis.

All values in the charts are expressed in 1990 US dollars. There are obvious difficulties in adjusting for changes in the relative value of currencies and in bringing compatibility to project estimates made at different times and for different completion dates. Cost estimates that were originally in other currencies have been converted using a nominal US dollar exchange rate with adjustment for inflation, where necessary. For some new technologies it has been necessary to base estimates on a very narrow base of experience or, where little recent development work has taken place, on old material. Judgements have had to be made on the potential for future cost improvement and, indeed, on the reliability of the estimates made by their protagonists. However, it is not felt that another, perhaps more complex, approach to the one adopted would have made any significant difference to the results of the broad comparison.

Differences in the quality of application, efficiency of energy use and of performance in the final end user market are not taken into account in the estimates; nor is allowance made for less concrete consumer preferences.

Costs in all the charts are intended to represent a broad indication of resource costs. As far as possible, subsidies, expenditure on research and development and similar indirect or direct forms of support have been eliminated.

The cost ranges in the charts are nominally for plant ordered now, for operation in the late 1990s. In the case of the unit costs they are levelled over the life of the project.

The striped area in the charts represents a range covering, in part, the uncertainty of the estimates involved. It also encompasses the span appropriate to the use of differing technologies and different locations.

Chart 4 compares the differing capital needs for the main energy sources. It is an indication of the investment that would be required to put in place capacity able to deliver a notional energy output equivalent to one barrel of oil per day.

The costs shown in Chart 5 represent the comparative technical costs of actually supplying energy, expressed in terms of US$ per barrel of oil equivalent. These unit costs include an element for capital and for operating and maintenance costs and, where appropriate, fuel costs. The capital charge incorporated in the costs shown in Chart 5 is, for most energy forms, based on an 8 per cent earning power after tax, representing a 'commercial' rate of return. Electricity generating costs are also shown in broad terms in Charts 4 and 5 but are compared more specifically by individual types of generating plant in Charts 6 and 7.

Storage and distribution costs to final consumers are not generally included. These vary considerably between energy sources, with the transport and storage of oil being almost always the least expensive. In contrast, the cost of transmitting and distributing electricity, for example, can add between 50 and 60 per cent to the initial cost of generation. This has to be borne in mind, particularly when comparing the cost of centrally-generated electricity with that of locally-based sources of electricity such as stand alone diesels, photovoltaics or small scale hydro.

Differences between the efficiencies of fuels in their final application and in their potential for premium uses, whether in industrial plant, domestic apparatus or in transport vehicles, have a distinct impact on the effective cost to the consumer. The demise of the steam railway locomotive was certainly hastened, in part, by its low fuel efficiency (5 per cent) compared with that of, say diesel locomotives (30 per cent). Consumers are, after all, not interested in purchasing a particular energy as such, only in what it can do for them.

However, in general, the overall relationship between the energy forms indicated in the charts does not change significantly by taking end use efficiency into account or by the addition of inland distribution costs.

CHART 4: Comparative Investment Costs of Alternative Energy Sources

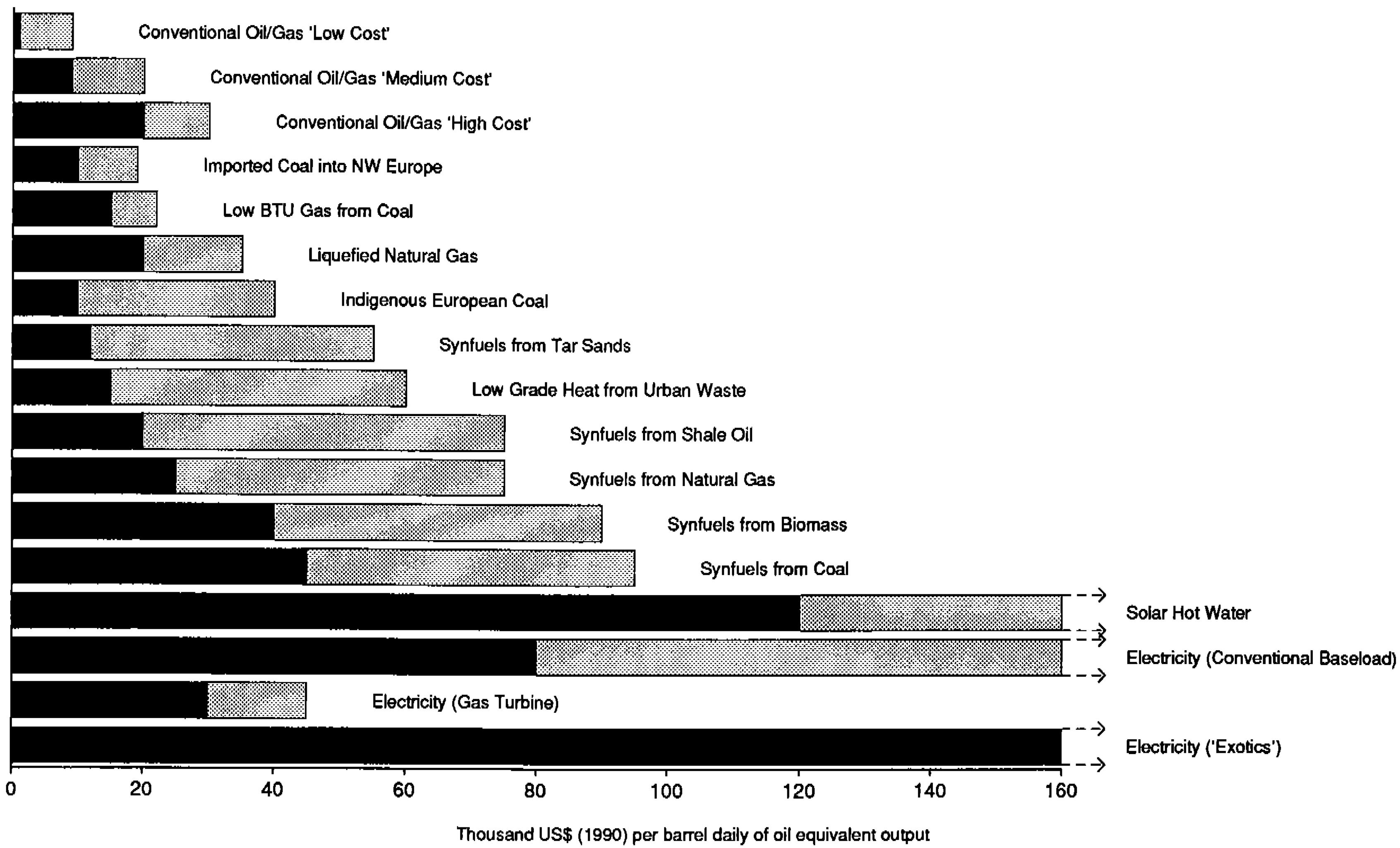


CHART 5: Comparative Unit Costs of Alternative Energy Sources

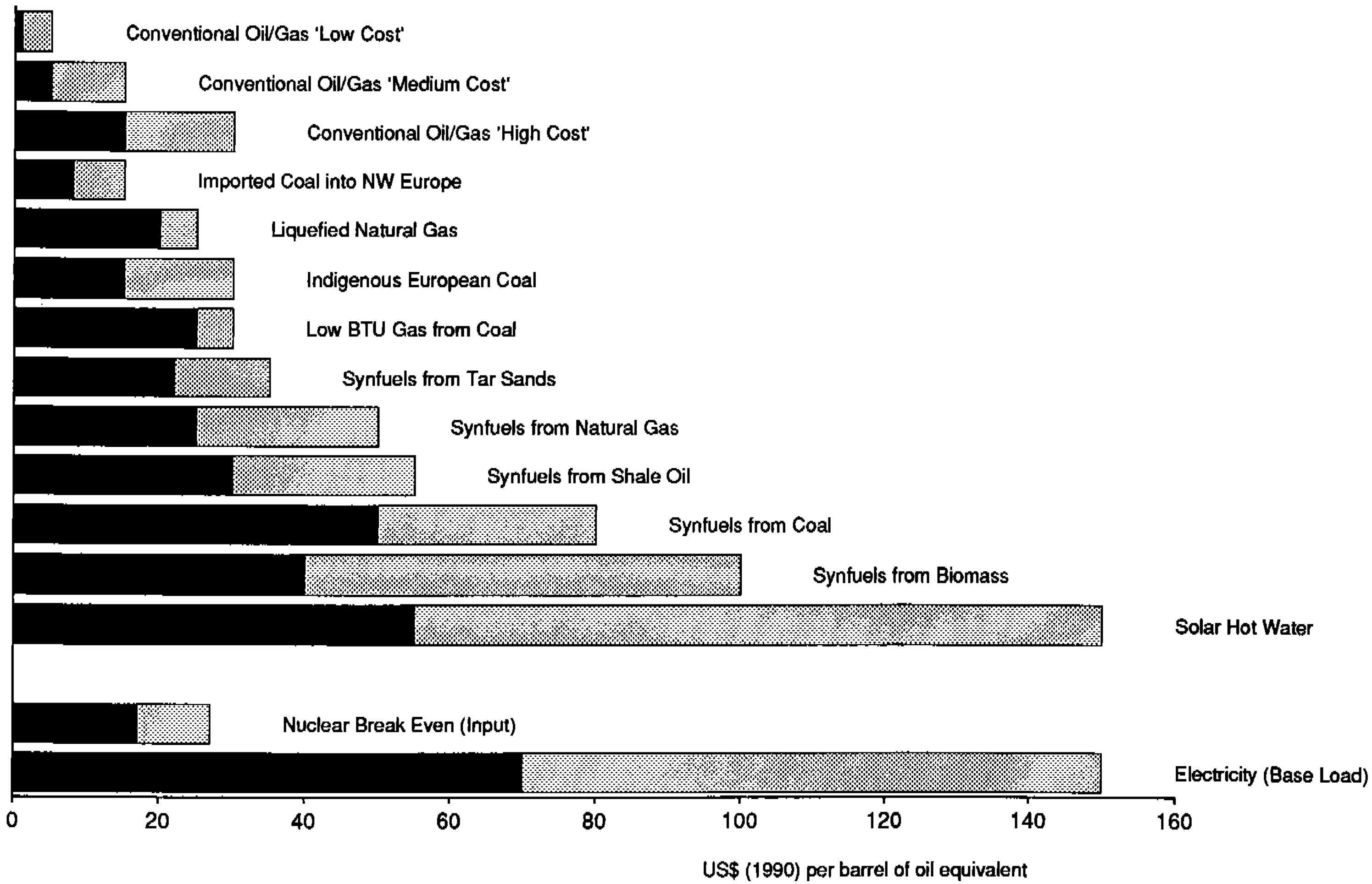


CHART 6: Representative Costs of Base Load Electricity ('Utility' Return)

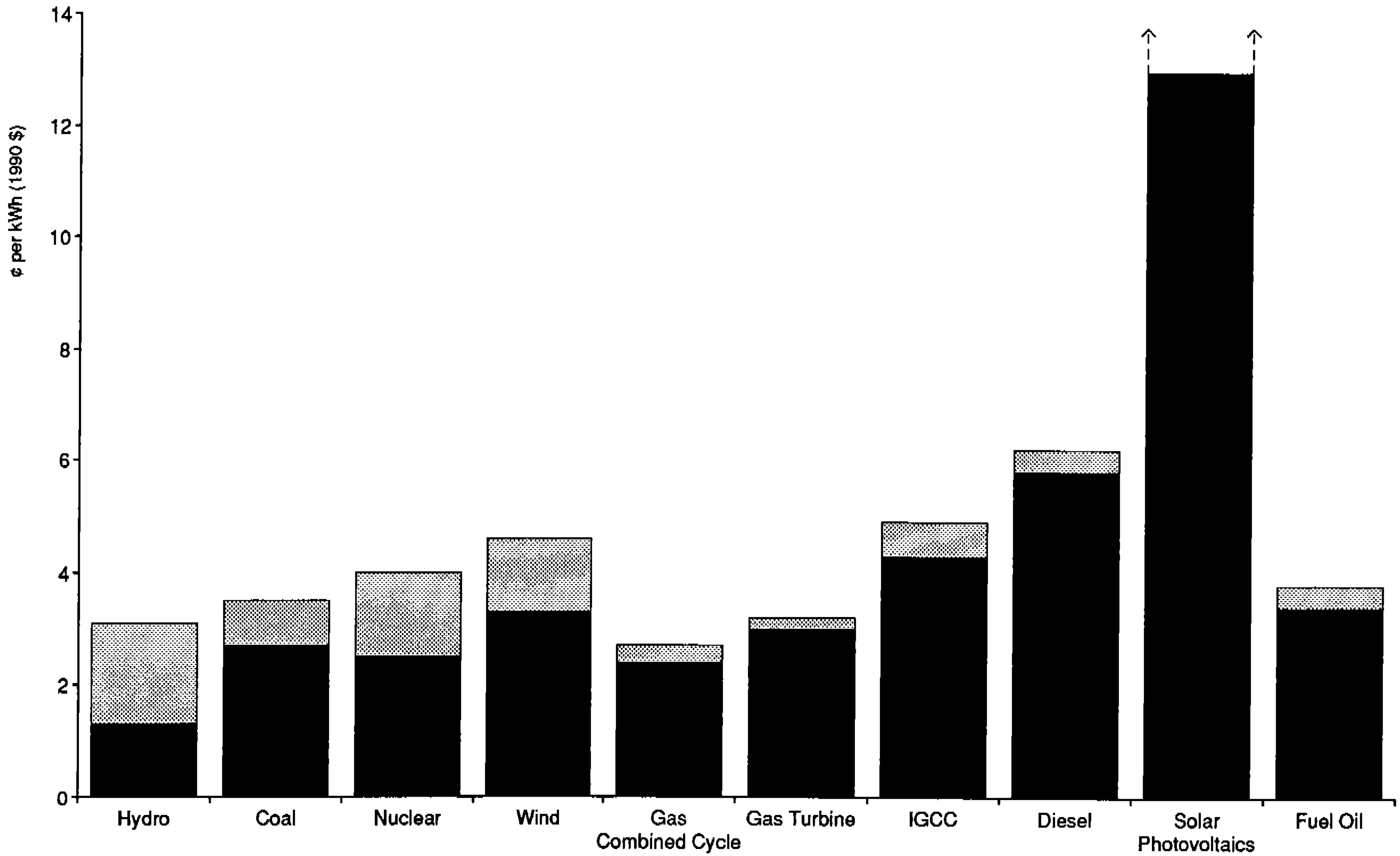
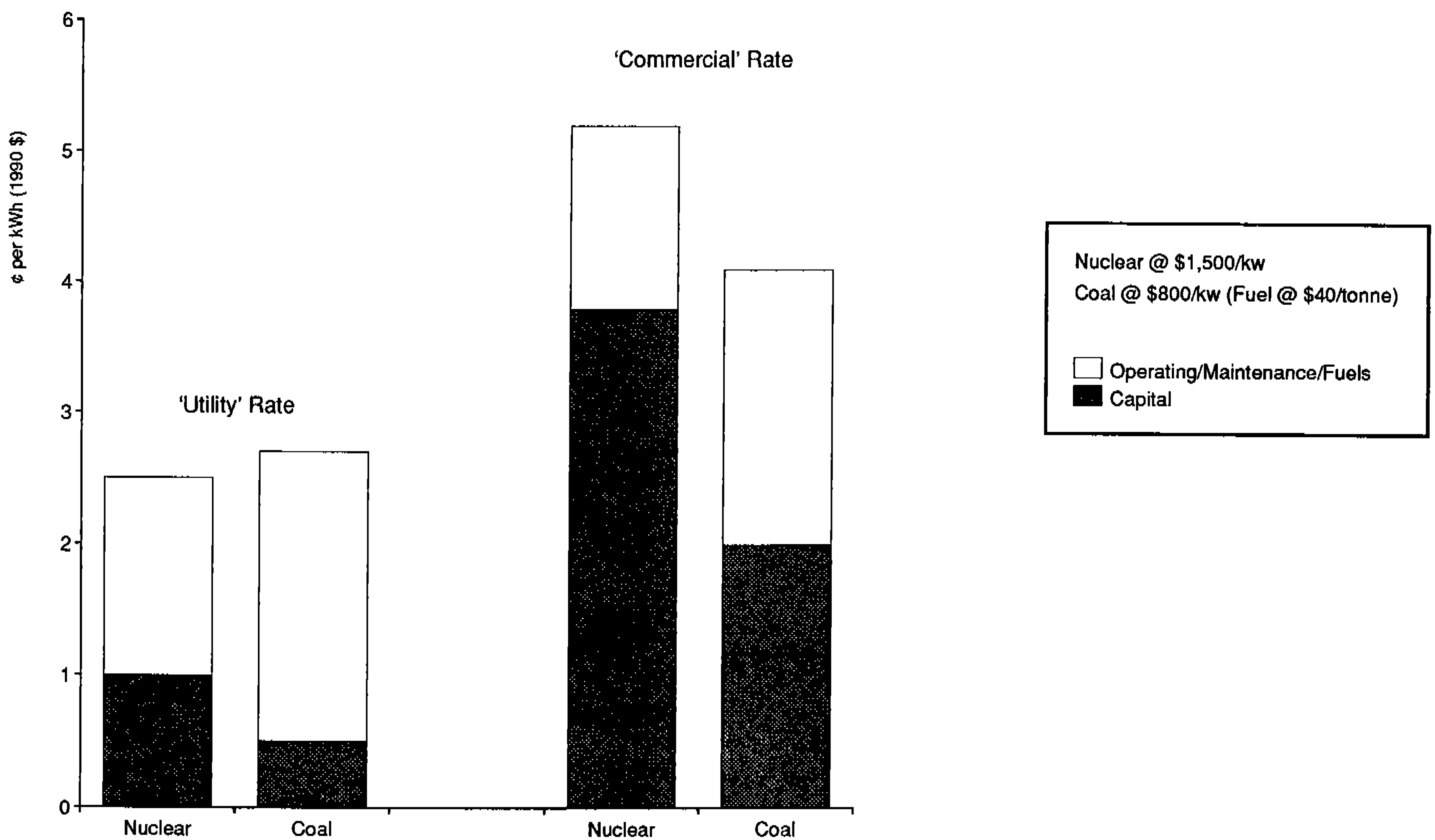


CHART 7: The Cost of Generating Electricity



5 A GUIDE TO THE COST COMPARISONS

5.1 Oil and Gas

The price of oil rather than its supply cost has usually been used in the past as a marker against which to measure the cost of alternatives. This could be acceptable for a snapshot of the present but is not very realistic for looking beyond the immediate situation. The difficulty that almost all 'experts' have in making forecasts of oil prices that bear any resemblance to the levels that actually occur should need no emphasis. In any case, the technical costs of making additional volumes of conventional oil and gas available are of more relevance than price estimates when looking at the long-term development and competitivity of different energy forms. Such costs may also, in future, have a much greater relevance to the price of international oil itself.

The cost of oil and gas varies widely, depending on the characteristics of the field and when, and under what conditions, exploration and development activities take place. The costs of offshore fields are generally well above those for comparable onshore fields because of the more difficult conditions and the greater cost of equipment. Gathering costs vary considerably depending on the number and distance between wells.

A representative cost for oil or gas would include the costs of geological and geophysical activity and of drilling and equipping exploration and development wells. Operating costs should also take into account the cost of materials used for any enhanced recovery and of facilities to extract, treat, gather and store the oil and gas. The cost of future activity needed to maintain production over the lifetime of the field as well as administrative expenses, depreciation and central office overheads, have to be allocated.

In practice, however, it is usually very difficult to know just what has been included in most of the oil and gas costs that are publicly quoted. The levels of reserves and the recovery rates against which costs are allocated also fluctuate very widely and may be highly unreliable. Extremely detailed studies on an individual field basis would be necessary but are rarely attainable. An air of great uncertainty, if not mystery, hangs over many estimates.

Whilst the wellhead cost of producing non-associated natural gas is generally on average only a little higher than oil, the final cost of natural gas is much more dependent on the location of fields relative to demand centres and on the composition and pressure of the gas. Natural gas costs are also more dependent on the level of demand on particular sources than is oil.

Technological advances are successfully being set against the need to extract oil from increasingly difficult and deep sources and growing environmental considerations. There have been some notable advances in drilling and production techniques in recent years, for example horizontal drilling and multiple undersea producing facilities. These techniques, by enabling more hydrocarbons to be produced from the same field or the same facilities, have had a major impact on production costs - as has the widespread use of advanced computer science for data collection and application. Many cost savings have come about, however, not through dramatic breakthroughs but from numerous and often individually small improvements in drilling bits, motors, lubricants etc.

As mentioned earlier in this paper, the costs of producing oil appear to have fallen in recent years. This has been partly due to market pressures amongst contractors, but technological and administrative innovations have played the major roles. A development well on the Alaskan North Slope, for example, is now said to cost one-third in nominal US$ of what a similar well did in 1977. North Sea oil is a particularly well-documented example. The overall cost of oil fields now under development in the offshore fields of the UK is reported to be $12 per barrel compared with an average of $16 per barrel for all fields that started production between 1980 and 1989. Cost-cutting technological advances are unlikely to be at an end, even with increased prices for oil, and additional reductions in costs of perhaps 30 to 40 per cent may well be feasible over the next few years.

There are numerous other elements involved in determining the cost of oil and gas that tend to put a certain amount of haziness over any very precise indication of costs. This is often the case even when the amount of investment involved in exploration and development is recorded and openly stated; and when operating costs seem simple to determine. Much of the uncertainty and confusion stems from the under- and over-estimation of production potential for a variety of reasons and motives as well as from differences in accounting treatment and allocation of the actual costs involved.

The misleading nature of estimates of average finding and replacement costs and the unsupported nature of some estimates of the cost of investment has been frequently pointed out. None the less, the various snippets of material published by companies, governments, oil industry scouts and analysts do seem to present a reasonably consistent and believable picture even when their origins are not particularly clear. Certainly, there is enough to give a broad indication of the costs of producing and shipping oil and gas to act as a sensible cost comparison with alternative forms of energy.

The charts show the technical costs of additional conventional oil and gas in three loose categories. The 'low cost' category includes oil and gas from most of the Middle East as well as from some parts of South America and South East Asia. 'Medium cost' includes most of the North Sea, Nigeria, some South American oil including Brazil, and perhaps 50 per cent or more of the USA and USSR as well as Africa and East Europe. This range of costs also encompasses some enhanced oil recovery by steam flooding but not technology involving the use of polymers or surfactants. Perhaps nearly half of potential production from the USA, China and USSR falls in the 'high cost' category, as does most oil from the High Arctic areas and oil and gas from the more difficult offshore prospects in the North Sea and elsewhere.

It is difficult, and probably unwise, to be precise about the amounts of oil that could actually be produced at costs within these different ranges although such an attempt, for both oil and other primary energy sources, has been made in the *OIES Review of Long-Term Energy Supplies*.

Technical costs are not, of course, the same as commercial costs or the effective cost to a nation. Neither do they necessarily even come anywhere near to approaching the price for which oil and gas is actually sold. However, it is the technical cost of different alternatives that is being compared in this paper and indeed it would be very unwise to ignore fundamental cost comparisons in any assessment of future energy prices and the development of energy demand and supply.

5.2 Liquid Fuels from Shale Oil

The costs indicated by the charts reflect the full process of mining the shale and retorting it on the surface. *In situ* retorting is still in a very early stage of research and an estimate of its cost is not included in the range.

Raw shale oil is heavy, low in hydrogen content, high in metals and difficult to transport. It has to go through a fairly expensive upgrading process to give a good quality refinery feedstock and this has been included in the range of costs shown. The cost of retorting and upgrading is usually over double that for mining and shale preparation. In many countries there would be substantial additional costs involved in the mitigation of the environmental impact of shale mining.

Shale itself can also be used as a fuel directly, as it is in the USSR, but this is not a generally acceptable or likely option for the future.

The economics of shale oil are very site specific. The wide range of costs indicated in the charts is a reflection of the substantial differences in quality, mineability and size of shale oil deposits. The low end is representative of a high quality deposit in Australia and the high end is, for example, indicative of low quality deposits in Morocco and the USA.

This range also reflects a lack of experience in commercially proven technology.

5.3 Heavy Oil and Tar Sands

These costs already reflect the benefit of commercial experience of both *in situ* extraction and mining, particularly in Canada. The range shown represents a spread between a small modular, *in situ*, project and a large-scale tar sands mining project.

There is generally a difference between the treatment of the bitumen obtained from *in situ* deposits and that obtained from mining. The costs for the range are representative of upgrading to a crude oil standard for both routes. As mentioned earlier, there appear to have been improvements in cost over recent years but new plants seem likely to be more costly than the present ones that were launched under more favourable investment conditions and on prime sites.

The effective cost of preparing Venezuelan Orimulsion from heavy oil is not clear. The heavy oil is recovered by standard steam injection techniques at costs said by various sources to be between $3 and $12 per barrel. Emulsification is unlikely to be a costly process so that Orimulsion costs appear very competitive with Canadian tar sands. They are probably at, or below, the low end of the range indicated.

5.4 Coal

The cost of producing coal varies greatly, as one might expect from an energy source which is far from homogenous and has a very substantial and widespread resource base. The range of costs indicated for coal produced in Europe covers, towards the low end of the range, the production of brown coal by open-cast methods as well as significant tonnages of hard coal from modern underground pits in the UK. The high end of the range represents, for example, the cost of mining West German coal from thin and fractionated underground seams.

Significant technological advances in coal extraction and upgrading processes are unlikely during the rest of the 1990s. There is, however, considerable scope for the introduction of higher technical standards in a number of major producing countries, notably China and India, that could eventually reduce their unit costs significantly.

The cost of coal delivered to the main importing regions includes the cost of transport from the mine to the export port, loading and shipping and unloading at the destination. South African coal delivered to North West Europe and Australian coal delivered to Japan are amongst the least expensive imports and coal from the USA East Coast amongst the most expensive. The newer export sources in Colombia, Venezuela and Indonesia are also relatively cheap sources of internationally traded coal.

Operating and maintenance costs involved in coal production, particularly for labour intensive underground mining, are a much more significant proportion of unit costs than with most other forms of energy. It is not always clear, however, to what extent and in what form the costs of renewing the structure and equipment of the mine during its life are included in some estimates.

5.5 Liquefied Natural Gas (LNG)

The cost of LNG includes the cost of liquefying the gas, shipping it to the importing country and then regasifying it at the port of destination. The often substantial cost of investment in any new transmission and distribution facilities needed to supply the final customer within the importing country is not included. Such investment is unlikely to be necessary where gas is fed into established systems in developed countries.

The investment costs shown are for an LNG project including shipping etc but do not cover the cost of the gas producing and gathering facilities. This can, as described earlier, be considerable for new fields in difficult areas.

For the calculation of unit costs, the gas feed has been assumed to have a cost of $1 per mBtu.

From time to time considerable information on the cost of various existing or proposed LNG projects is made public.

As described in Section 3, construction costs seem to have fallen considerably in recent years as projects have increased and experience has been gained. Investment costs in real terms may now be as much as 60 per cent of those quoted in the 1970s.

When put on a comparable basis, the various current estimates indicate a fairly modest spread in delivered costs based, as it is, on a single cost for the initial gas feed. This spread is, of course, partly a function of where the liquefaction plant is located and the eventual destination of the gas.

Transport costs are a significant and varying element in total investment and unit cost. As a proportion of unit costs they can range from say 15 per cent for Algerian gas shipped to Europe to 30 per cent for gas from Qatar to Japan. Any project using spare capacity or surplus tankers would require less capital. The same would be true of those projects expanding on existing liquefaction facilities.

Table 4: Notional Costs of a New LNG Supply Project to NW Europe.

	Price of Gas at Liquefaction Plant		
	$1 per mBtu	$2.5 per mBtu	
Cost of Delivered Gas	2.9	4.4	in $/mBtu
	17	26	in $/boe
Cost Structure	Per Cent	Per Cent	
Gas feed	35	58	
Liquefaction	33	21	
Transport	21	14	
Regasification	11	7	
Total	100	100	

As Table 4 shows, the price considered acceptable for the gas feed has a major impact on the final unit cost and is often the key to the financial success of the project.

5.6 Low Btu Gas and Synthetic Natural Gas from Coal

The production of low Btu gas from coal, i.e. gas with a calorific value of, say, under 200 Btu per cubic ft, is a long-established process that has seen scarcely any significant improvements for decades. It is still used by some industries in coal-producing regions that only require a low grade heat source.

In the 1970s, it was considered by a number of authorities that natural gas in the USA would be in short supply within a decade or so. Subsequently, a considerable amount of research and development was expended on perfecting the technology to produce a substitute natural gas from coal through the upgrading of medium Btu gas. A demonstration plant was finally built which has proved hopelessly uneconomic, and with a very changed natural gas situation, no further work is contemplated. Some coal gasification work was adapted to produce methanol and other liquid fuels but the unprofitability of these routes has led to current work becoming concentrated on the use of synthesis gas as a clean fuel for combined cycle electricity generation - a certain amount of stimulus being given by the events at Chernobyl.

This latter route of integrating coal gasification with combined cycle generation is driven mainly by environmental and strategic factors such as the desire to use indigenous coal rather than by direct economics.

5.7 Liquids from Coal

The massive push to large-scale synfuel development of the late 1970s was encouraged by government incentives and reflected the desire to develop indigenous resources. There was considerable inflation and cost escalation of projects and in the event very little came of the seeming flurry of activity. South Africa has the only commercial-sized plants for the conversion of coal into oil products currently operating and over forty years experience of the process.

Processes are very raw material specific with bituminous coal yielding large quantities of liquids and anthracite hardly any. The actual costs involved are very hard to determine. On the one hand, there is the secrecy surrounding the South African plants and, on the other, the lack of genuine commercial experience with the second generation technology. The high end of the range shown in the charts is based on estimates made for SASOL 1, the first South African plant in operation since the 1950s. This project was provided with substantial incentives, tax breaks and subsidies but by now must have amortized its actual construction costs and effective unit costs should be closer to those of conventional oil.

Unless it is used in very low proportions with gasoline, methanol incurs substantial extra costs for the building up of an additional infrastructure and for the conversion of vehicles. The low of the range shown reflects the possible cost of methanol from coal and of an oil substitute from the latest SASOL type plant. It is also similar to the level of costs quoted for second generation coal conversion projects that were in the early stages of development in the USA and Germany during the 1970s and early 1980s.

Although second generation gasification technology with advanced reactors is now said to be available, little new work seems to have been done on this technology since the mid 1980s. There is great uncertainty as to whether costs of synfuel from a commercial coal conversion plant would, in practice, actually achieve the lower level quoted.

5.8 Liquids from Natural Gas

The conversion of natural gas appears to represent a much more promising route to making additional synthetic motor fuels available. One commercial-sized plant is currently operating in New Zealand where it has proved technically, if not commercially, successful. This plant which uses the Mobil/Texaco process to convert natural gas via synthesis gas and methanol into gasoline is, however, unable to compete with oil at current prices. The decision to build was made in 1979 at a time of high and rising oil prices with the principal objective of reducing crude oil imports by using the country's abundant gas resources. It was anticipated that the plant would break even at a crude oil price of $21 per barrel, equivalent to a much higher level now. The subsequent fall in oil prices has resulted in substantial financial losses.

There are two other plants for the production of liquid fuels from natural gas under construction, in Malaysia and South Africa. Shell's Middle Distillate Synthesis project in Malaysia, appears to have lower unit costs than the New Zealand plant but is still not competitive at oil prices below $25 per barrel even with a relatively low-cost feedstock. Fiscal incentives may be used to encourage projects and there will, in some countries, be other broader benefits for outside investment. However, these considerations by themselves are unlikely to lead to widespread conversion.

If oil prices rise in future, the maintenance of the feedstock price at a realistic level will be of key importance in achieving profitability and preventing costs always keeping just ahead of the oil price. If the linkage remains strong, it is unlikely that these processes can ever be a viable proposition. For example, the capital cost of putting in place an oil from gas plant, without fuel investment costs, would be at least $25,000 per boe/d compared with the investment needed to build a complex refinery of $10,000 per boe/d or less. Thus, when the investment costs for the oil or gas feedstock are roughly similar, the economics of gas to oil are not favourable. The greatest flexibility on the cost of the gas feedstock is likely to be available where there is gas of a 'difficult' quality or where other outlets are few and there are strong incentives to replace imported oil.

The low end of the range represents a second generation of a similar process able to build on the experience of the first and with cost benefits from scaling up. The cost of methanol is towards the bottom of the range. Various other processes for the direct conversion of methane to methanol, which reduce costs by avoiding the intermediate synthesis gas stage, have been considered in the USA and Germany. If used as such, these would still involve additional costs in setting up methanol distribution facilities and converting vehicles; the latter representing a cost per car of perhaps $350 to $500. The use of compressed natural gas (CNG) is a more direct route to obtaining a fuel for vehicles from natural gas but also requires special vehicles.

5.9 Liquids from Biomass

There are many different routes for producing liquid fuels from biomass for the automotive market or for power generation as Chart 1 illustrates. Unfortunately an ample supply of raw biomass is usually only available in remote areas where large plants are expensive to build and distant from markets.

Both gasification and hydrocarbon synthesis from biomass are sophisticated processes. Commercial programmes to produce automotive fuels by simple and established processes using agricultural crops have been initiated on a large scale, notably in Brazil and the USA. All rely heavily on government support of one kind or another and could not stand on their own at present oil prices.

Both the Brazilian and the US projects for producing ethanol from sugar cane and corn respectively were initiated in the early 1980s when oil prices peaked at around $60 per barrel (1990$). Production costs for the 125,000 boe/d Brazilian project are probably around $70 per boe at present and the cost of ethanol from corn in the USA is estimated at well over $100 per boe. These programmes and similar ones proposed for Europe are bound up with complex budgeting, strategic and socio-political issues but are clearly not viable on any straightforward financial basis.

The direct use of biomass in power plants could be economic with a combination of low feedstock costs and high electricity prices. Much depends on local conditions but the gasification of biomass and its use in a combined cycle power plant would be a cost-effective route in some areas.

Liquids currently produced in biomass plants range from a diesel fuel substitute from palm oil or the conversion of waste forest products to methanol and ethanol for direct use or in a blend with gasoline. The dominant cost of almost all of these processes is that of the feedstock. Feedstock costs can range from less than $3 per boe to $70 per boe or more. This gives rise to considerable variations in cost of output from the same technology, depending on the type of feedstock and the extent to which it is a waste product or a premium agricultural crop. Some cost reductions can be expected in future from the use of more productive strains of crops and greater application of fertilizer and other inputs.

The low end of the range indicated in the charts represents simple liquids produced from the pyrolysis of forest residues and the high of the range the cost of ethanol from sugar cane and corn. The cost of special systems to distribute and use these fuels has not been included.

5.10 Low Grade Heat from Urban Waste

Included in the range are the costs of the relatively simple tapping of gas from landfill sites as well as those for large mass burn urban waste incinerator plants. Credits for the avoidance of the cost of waste disposal have not been included.

5.11 Solar Hot Water

The high of the range indicated in the charts is indicative of the cost of a small domestic installation. The cost of a relatively large-scale plant to produce industrial process heat sits close to the low of the range. Considerable variation in costs is caused by differences in location and by the quality of the installation as well as the equipment itself. An additional cost, which is not included in the range of estimates shown, is that of the capital investment needed for some form of backup or supplementary heating equipment.

5.12 Electricity Generation

The cost ranges for electricity generation that are shown are generally indicative of base load operation at an average load factor of 70 per cent. Where plant is unlikely or incapable of being used for the base load, as in the case of windpower or solar, then the most favourable mode of operation that is feasible has been used in the cost estimate.

Clearly the use of different load factors can change the comparative economics of different forms of power generation dramatically. For plant used for peak load generation, such as diesel sets or gas turbines, low capital and other fixed costs are more of a consideration than low fuel costs. Conversely, the high capital costs of base load plants are not as significant as their low fuel and operating costs. Thus diesel generation which appears hopelessly uneconomic in the charts, would be more economic to run than, say, a large conventional coal-fired plant if both were being compared at load factors of around 5 to 10 per cent. Nuclear power stations, with high capital intensity and generally low operating and fuel costs, are normally only economic as base load generators although some load following is practised in France and Sweden. The equally capital-intensive generation of electricity from hydro may span the whole range of generating modes particularly where it dominates local supply as in Norway.

The relative merits of generating plant across the range of utilization on a full cost basis are very sensitive to fuel price changes and to the discount rates chosen. This latter aspect is illustrated by the differences between the costs based on 'commercial' and 'utility' rates, in the simple example shown in Chart 7. Nuclear electricity moves from being cheaper than coal-based electricity on a 'utility' rate to being considerably more expensive on a 'commercial' rate.

The 'merit order' of operation by which plant is scheduled by utilities is, however, usually based solely on variable costs. Plant with the lowest variable cost, i.e. operating costs excluding fixed and sunk costs, is scheduled first. Generally this would be nuclear, hydro and large-scale fossil-fuelled plants. The last to be operated at peak times would normally be gas turbines, diesel sets and certain hydro facilities etc.

Output costs shown in the charts for centrally generated electricity are for net electricity at the power station busbar. They do not include the costs of transmission and distribution. Thus a direct comparison with locally generated electricity that is directly available on site may not be fair. In general, however, the inclusion of considerations of this type and of comparative reliability and the need for additional capacity for backup etc do not dramatically effect the relative cost position of the different generating methods shown in the charts.

5.13 Nuclear

The top of the range of capital costs used in these estimates is close to the latest quoted cost for the Sizewell B reactor which is currently under construction in the UK. Despite the cost of this reactor being estimated less than two years ago on a very detailed and seemingly authoritative basis at some £1.7 billion, its capital cost is now said to be well over £2 billion. £0.2 billion of the increase is apparently due to design changes, additional instrumentation and software costs. A major increase is said to have been the result of the abandonment of the rest of the PWR programme so that fundamental costs can no longer be spread over a number of units as originally hoped.

The range, although broad, does not encompass the full spread of current and recent past costs of nuclear capacity. In the USA, for example, over the past five years or so, the cost per kW of installed capacity has varied by a factor of five. The bottom of the range is an indication of the benefits to be gained from constructing nuclear power stations in series, on a consistent and uncluttered basis as in France and Japan. These estimates do not include the cost of decommissioning or of nuclear waste disposal.

In addition, operating and maintenance costs do not fully reflect the very steep, and probably exceptional, escalation in the USA of their non-fuel elements. These have risen at such a pace that plants once thought economic are now being considered for shutdown on these grounds alone.

The break-even value for nuclear electricity shown in Chart 5 is an indication of the price below which fuel oil and coal needs to be in order to be competitive with nuclear for base load electricity generation.

5.14 Fossil-Fuelled Power Plants

These include the cost of stackgas scrubbing, where appropriate. The cost of fuel plays a major part in the final cost of electricity from these power plants and competitiveness will reflect local availability of fossil fuels and their costs. For the comparison, coal has been valued as internationally traded coal at some $40 per tonne, fuel oil at $100 per tonne and gas at $2 per mBtu. The relativity of the estimates on the chart would change if, for example, a lower-cost indigenous brown coal were assumed as the input or the gas used was much higher cost imported LNG.

5.15 Hydro Electricity

The cost of constructing hydro electric facilities is very much related to specific site conditions. For the cost range shown a range of capital costs between $1500 and $4000 per kW has been used. This could be exceeded in certain areas of hydro potential that have little existing infrastructure. The capital costs of small-scale hydro, i.e. below 1 MW, and geothermal generating plants are usually towards the upper end of the range.

5.16 Wind Power

These costs include site and other installation costs and are for machines of around 200 to 300 kW on the windiest land sites. They are not necessarily indicative of offshore installations or those in remote sites where maintenance may be a greater burden.

5.17 Photovoltaic Electricity

Conversion efficiencies have risen substantially over the last decade or so from 5 per cent to 18 per cent and new silicon forms have lowered the cost of the basic module. Technological improvements have also expanded the areas of viable application but, in practice, the costs of the whole system, are still disappointingly high.

5.18 Other Forms of Electricity Generation

The economics of most of the more exotic forms of electricity generation such as wave power, ocean thermal, solar thermal, salt ponds, solar chimneys, fuel cells and so on are the subject of much debate and fierce partisanship. The methods used in calculating many of the costs that are publicly quoted, the degree of wishful thinking involved and the real potential for development are rarely clear and are open to varied interpretation. Particularly since the reduction in research effort on many of these 'exotics' and with a shortage of commercial experience, it is difficult to get a reliable view of the likely cost of producing electricity from them. None the less, it can be said that at present none of these exotics appears to be anywhere near approaching competitiveness with the more conventional forms of electricity generation.

6 SUMMARY AND CONCLUSIONS

A detailed comparison of technical costs obviously plays a major part in any assessment of competing energy projects. The decision to develop a particular source of energy is, however, made for a variety of reasons. Many of these may override or weaken the influence of the basic technical cost on investors and policy makers. However, a broad view of comparative energy costs is fundamental for the consideration of energy policy and strategy, just as it is in assessing future patterns of energy supply and demand.

The economics of individual energy supply projects are often highly specific and may not be representative of the overall pattern. In addition, it is only rarely that the costs openly quoted for one project are directly comparable with those for another. Published indications vary widely due to the use of different financial criteria that are often unclear and unstated. Different estimates may also be made by different organizations for specific purposes with varying motives.

Even when the bases of cost estimates are clear, there are obvious difficulties in comparing those made in different currencies at different times and for different completion dates. Costs are also highly sensitive to the choice of discount rate and the treatment of capital in general.

Aside from the purely accounting aspects other, more fundamental, reasons contribute to the confusion. Differences in the size of the project, its scale of operation and utilization, the changing state of development of the technology involved, the pace and pattern of construction and the amount of infrastructure already in place, all play their part. In the past there has been an element of wishful thinking or understatement of costs for some of the newer energy technologies. There have also been surprises as costs moved more quickly than expected on the learning curve or responded rapidly to a low price situation.

The fluid and creative nature of many estimates is emphasized by the way in which the cost of most alternatives to oil have, in the past, apparently always managed to just keep ahead of the price of oil. There are many reasons for this, apart from the usual uncertainty and partisan enthusiasm with pioneer projects. Not the least of these is the indirect and direct part played by the oil price in so many of the inputs to the new processes. For some projects, there may also have been considerable padding of costs and ineffectual financial monitoring.

There is a whole array of new energy supply technologies waiting in the wings on which the Gulf war may once more focus attention. Unfortunately many still seem to be in the early stages of development with high costs. For most of the alternatives to conventional oil-based road fuels and the more exotic forms of energy supply, there is little sign of movement from the relative cost positions that they have occupied for so long. However, there may have been genuine technological developments in reducing the relative costs of producing synfuels from natural gas, from tar sands and heavy oil. Certainly, the ability to obtain liquid fuels competitively from natural gas and other sources would add considerably to long-term flexibility of choice and the lessening of reliance on Middle East oil. It is unlikely, however, that the conversion of gas or coal to transport fuels will be competitive with conventional oil, solely on technical cost, for many years.

More conventional alternatives such as liquefied natural gas have also benefited from cost-effective improvements under the influence of low oil prices, as has conventional oil itself. In the case of oil, technological advances are being successfully set against the need to extract oil from increasingly difficult and deep sources. Many cost savings achieved in developing conventional energy have come about not through dramatic breakthroughs but through numerous, and often individually small, improvements. The growing independence of other energy prices from oil is also helping processes based on gas feedstocks to improve their relative costs.

Lessons have been learned and it seems likely that any accelerated development of new energy technologies as a result of the Gulf war will not be as wasteful and ineffective as many of the activities spurred on by earlier Middle East crises.

In whichever direction the arguments used in developing policy on environmental matters evolve, the economic consequences for energy supply cannot be ignored. The cost of environmental protection for new energy supply projects or the retrofitting of existing plant is a growing area of uncertainty and of regional variation. This is not just for nuclear and other electricity generators; there are additional environmental costs waiting in the wings for most other forms of energy.

The charts present, on a comparative and uniform basis, the broad cost of supplying energy in most of its main commercial forms. The ranges shown are, in the main, intended to be for plant ordered now to be in operation by the mid to late-1990s. The widely differing levels of investment needed are shown in Chart 4, expressed as the cost of putting in place capacity able to deliver a notional energy output equivalent to one barrel of oil per day. Chart 5 compares the technical unit costs of actually producing and supplying energy in terms of US$ per barrel of oil equivalent. These unit costs include an element for capital, for operating and maintenance and, where appropriate, for fuel costs. Two other Charts, 6 and 7, compare the cost of a range of different means of generating electricity.

Some specific conclusions can be drawn from the results of these cost comparisons:

- The bulk of conventional oil and gas is available at a technical cost well below those of its main alternatives.

- The investment required for new oil producing capacity in the 'low cost' regions, including the Middle East, is lower than for any other major energy source.

- There is still considerable uncertainty on the cost of most unconventional alternatives to oil.

- The cost of producing synfuels from natural gas and shale oil is uncompetitive with the cost of most sources of refined conventional oil.

- Tar sands appear to be the most economically favourable source of synfuels, but large-scale expansion would probably put them out of contention with 'medium' and some 'high' cost conventional oil sources.

- Synfuels from natural gas may be producible for as low as $25 per barrel with a gas feedstock of $1 per mBtu.

- A clean, high quality, fuel in the form of liquefied natural gas can be delivered to the main consuming areas at between $20 to $25 per barrel of oil equivalent.

- Even under favourable conditions, at a commercial rate of return, nuclear power is only competitive with fossil-fuelled electricity generating plant when fuel oil is over $100 per tonne or coal over $70 per tonne.

- On a utility basis, and also under favourable conditions for nuclear, fuel oil would have to be under $55 per tonne and coal under $40 per tonne to be competitive.

- The investment needed to develop mines and transport facilities for international coal supplies to North West Europe is roughly the same as that needed for new medium-cost oil fields.

- The conversion of coal and biomass to synfuels is still far too costly to be considered except where there is a desperate strategic need for self sufficiency.

- The capital required and the resultant unit cost of obtaining hot water from solar panels make this route uncompetitive on a national scale.

- Although there are exceptions, much indigenous European coal cannot compete with imported coal on a commercial cost basis.

- The investment involved for new electricity generating plant covers a wide range but is always considerably more than that needed for the development of new fossil fuel sources. The advantages and uniqueness of electricity override the cost disadvantage.

- The range of costs for generating electricity overlap, but nuclear generally looks uncompetitive with conventional base load generators.

- Apart from hydro power, wind turbines are the most cost effective of the renewable forms of electricity generation.

- Solar photovoltaics and most of the exotic forms of electricity generation are dramatically uncompetitive on costs alone.

- Gas turbines have the lowest capital costs per unit of output of any conventional generator.

- Plants integrating coal gasification with a combined generating cycle will have to rely on their environmental and strategic advantages rather than economics.

- Combined cycle electricity generators, when fuelled by gas below $3 per mBtu, are the cheapest source of electricity as well as having significant environmental and other advantages.

- There appear to be significant and continuing improvements in the technical cost of oil production and of gas liquefaction and transport.

- The relative costs of most of the alternatives to oil appear little changed from the 1970s and are still uncompetitive against current oil prices.

The picture of comparative costs that emerges is one of considerable and continuing advantage to conventional oil and gas. Although there have been some successes in reducing the cost of alternatives, these have been more than matched by savings made in the cost of developing incremental hydrocarbons.

New conversion processes for synfuels from gas look promising and should open a new era of wider choice, once commercially and economically proven. The linkage between gas and oil prices has to be broken if large-scale development is to occur.

For power generation, the choice is wide but conventional fossil fuels and hydro, where available, are likely to remain the realistic economic choice for power generation. Nuclear may retain a niche under favourable circumstances but, on cost grounds alone, its immediate future does not look bright.

Large-scale gas turbines or gas-fuelled combined cycle plants are an obvious choice where supplies of gas are available. With low capital and unit costs, short lead times and few environmental problems they have everything in their favour.

On the basis of comparative costs alone a fairly conventional future pattern of energy supply will persist well into the next century. There is still interest in unconventional energy but new routes have to be cheaper than the marginal cost of extra supplies from conventional sources and processes. This is not the case at present and there is still, for example, considerable potential for bringing down recovery costs and increasing yields from conventional oil and gas fields.

The Gulf war is already refocusing attention on diversification of energy supplies as well as on reducing intensity of consumption. Projects such as ethanol in Brazil may have been given a new stimulus and, no doubt, funding for research in to unconventional energy will be increased around the world. This time, however, we are unlikely to see the kind of semi-hysteria that developed in some circles over renewables after earlier crises.

Clearly, there will be more interest in energy self sufficiency by oil-importing countries.

The severe fluctuations in oil prices since the war, however unjustified they may be in terms of actual availability, and continuing uncertainty will lead to major responses to reduce fossil fuel usage. These may well be more sustained than in the past. However, oil prices would have to rise significantly and be perceived to stay at high levels before the large and uncertain investments needed for the utilization of the more unconventional alternatives are deployed.

In practice, therefore, the choice for the next couple of decades remains limited. We shall probably see a few more synfuel plants built based on a variety of feedstocks, particularly on natural gas. Even nuclear may see a modest revival in a few areas. Photovoltaics and wind generators may at last fulfil some of their promise with increased encouragement in the form of research funds and subsidies.

At present, and for some time to come, the most cost-competitive alternatives to oil are not those that could replace conventional oil in the road fuels market. The cost-effective alternatives such as low-cost coal, LNG, Orimulsion and the use of gas-fired electricity generating turbines will effect the demand for fuel oil and gasoil. This could lead to a need to expand complex refinery capacity more rapidly than expected.

The search for the security of energy supply that is now so much stronger since the Gulf war is likely to be achieved through diversification in the most cost-effective way, through conventional fuels. Increasing yields from oil and gas fields and more fruitful exploration and development in apparently marginal areas are certainly cheaper than pouring money into, for example, nuclear fusion or coal conversion. The transport of gas over long distances by pipeline and ship and the wider use of gas in all consumer markets will also receive a boost from a new realism engendered by the Gulf war. Hydro, where prime sites still exist, low-cost coal and upgraded heavy oil are also cost-effective answers to reliance on Gulf oil supplies.

There would seem to be no need and little justification for the development of dramatic new and expensive technologies for some years to come.

ABBREVIATIONS AND APPROXIMATE CONVERSION EQUIVALENTS

b/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Btu	British thermal units
kW	Kilowatts
tce	tons of coal equivalent
toe	tons of oil equivalent
kWh	kilowatt hours
mBtu	million British thermal units

boe = 5.8 million British thermal units

boe = 5.7 gigajoules

boe/d = 50 toe

boe/d = 71 tce

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