ASSESSMENT OF ALTERNATIVE ENERGY SOURCES FOR GENERATION OF ELECTRICITY IN THE UK FOLLOWING PRIVATISATION OF THE ELECTRICITY SUPPLY INDUSTRY

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ABSTRACT

The paper makes a critical assessment of alternative energy sources for generation of electricity which will compete with conventional sources following privatisation of the Electricity Supply Industry in the U.K. At the outset, structure of the industry in Europe is reviewed along with profiles of electricity generation in Europe and the U.K. Size, geographic location and time-scale of future electricity demand in the U.K. is evaluated, and shortfalls between estimated demand and predicted generation is assessed. Alternative energy sources are then examined. These include (i) tidal power from the proposed Severn Estuary Scheme, (ii) development of pumped storage such as that proposed at Craigroyston above Loch Lomond, (iii) small-scale hydro using low head hydro-turbines permitting development of previously uneconomic schemes on rivers, (iv) wind power from wind farms which would utilise the favourable wind patterns which exist in the U.K., (v) use of North Sea gas for combined cycle plant, (vi) development of small scale coal-fired stations, particularly those which use the more efficient and cleaner fluidised bed system, and (vii) utilising wave power although there are doubts as to how much would be economically viable.

Other alternatives assessed include generation of electricity by incineration of municipal waste, burning of methane gas generated by decomposition of effluents and rubbish, and the generation of electricity as a bi-product of chemical processes. Small city combined heat and power plants are then discussed. The competitiveness of imports from France via a second Cross Channel Link, and from a 2000 MW Submarine Cable Power Link with Iceland where Hydro and Geothermal power is harnessed, is also examined. Practicallity of inter-connecting the Irish Electricity Supply System, both North and South, with Scotland, via a HVDC connection to the proposed 2000 MW HVDC Submarine Cable Link with Iceland is also discussed.

KEYWORDS: Alternative energy sources, privatisation of electricity supply, tidal power, pumped storage, small-scale hydro, wind power, small-scale coal-fired plant, fluidised bed combustion, wave power, biomas derived fuel, combined heat and power, fuel cells.

1. INTRODUCTION

The Electrical Supply Industry in the United Kingdom is one of the country's largest industries, one of the most diverse in its structures, practices and achievements, and one of the most important in economic life. It has been in existence for at least a century. In earlier times, throughout the first 50 years or so of its development, electricity was a municipal service where private enterprise was often involved. Entrepreneurs rather than municipalities were the driving force behind development. Electricity was seen as an amenity or requisite of life, rather than a product to be bought and sold in the market place.

Electricity supply in Europe is undergoing change in structure and ownership at this time. Privatisation in Austria, Spain and the U.K. aims to transfer ownership from the public to private sectors, while elsewhere there is a need to open up the power market to new entrants who can bring entrepreneurialism which is lacking in larger utilities at this time. In West Germany, the Netherlands and Norway there is pressure for structured change to create a more flexible industry response.

By 1992 the EEC aims to complete a single market among member countries with removal of trade barriers in electricity supply. This implies that electricity should be traded like any other commodity, freely and without constraint. A free market in Europe assumes some equality of opportunity between participants. This equality of opportunity does not exist within the European or U.K. electric utility industry today.

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Until the early 1980's cross-border electricity interchanges were, in general, a load management devise, which grew out of the need to balance the predominantly hydrosystems of Austria, Switzerland and the Scandinavian countries. Then came the French nuclear programme which resulted in a supply of electricity far in excess of the country's needs. This was at a time when the West Germans were forced to support an ailing domestic coal industry and bear stringent environmental controls. There was a deficiency of generation in the South East of England at that time. Exported French power therefore had willing takers in West Germany, Italy and the U.K. [1].

Contract for supply of electricity to both supply utilities and consumers, either directly or via the National Grid, from cross-border producers, for example in France (via a second or third Cross Channel Link), from Iceland (via a Submarine Cable Link) and connections to Northern Ireland (and Eire) are direct possibilities following privatisation of Electricity Supply in the U.K.

This paper makes a critical assessment of alternative energy sources for electricity supply in the U.K. following privatisation of Electricity Supply. Alternatives examined include tidal power, pumped storage, small-scale hydro, power from wind farms, North Sea gas, small-scale coal-fired stations, and power from waves. Other alternatives such as generation of electricity by incineration of municipal waste, burning methane gas generated by decomposition of effluents and rubbish, and as a bi-product of chemical processes are discussed. Competitiveness of electricity imports from France via second or third Cross-Channel Links, from Iceland via a Submarine Cable Link, together with the practicallity of inter-connecting the Irish Electricity Supply (both North and South) with the U.K. is also discussed.

2. COUNTRY PROFILES AND PRIVATISATION

In England and Wales, generation and transmission have been the functions of the Central Electricity Generating Board (CEGB) which owns all public supply generating stations and operates the national grid. Distribution is effected by twelve Area Boards. The industry as a whole is co-ordinated by the Electricity Council comprised of representatives of the CEGB, the Area Boards, and a few full-time Electricity Council employees.

In Scotland there are two utilities which generate and distribute in their respective areas, the South of Scotland Electricity Board (SSEB) in the south, and the North of Scotland Hydro Electric Board (NSHEB) in the north. The SSEB gained its independence from the British Electricity Authority (set up in 1948) in 1955. The NSHEB was created in 1943.

Northern Ireland Electricity (NIE) is a state-owned utility which serves mainly the province of Ulster. There are no interconnections with Eire. Terrorist activities cut off existing ties in the 1970's, and attempts to renew these connections have not met with success. Submarine cable links between Ulster and Scotland have been discussed over innumerable years.

Eire Electricity Supply Board (ESB) is state-owned and generates almost all the country's power. The Board operates under strict government control.

France's electricity is 90% provided by the nationalised utility Electricity de France (EdF) which was created in 1946 from several hundred private utilities. Significant amounts of capacity however are owned and operated by two other companies, namely Cie Nationale du Rhone (2887 MW) and Charbonnages de France (3754 MW). Nuclear power generation dominates the French electricity system today.

Belgium has three privately-owned utilities which produce 90% of Belgium's electricity, the remainder coming from, for example, industrial auto producers and public companies. Belgium is the nearest thing Western Europe has to a wholly private - as opposed to state or municipal - system of electricity supply. The companies are integrated gas/power utilities. They also have non-energy interests, such as in telecommunications. Development of nuclear

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power has been the key to utility development in Belgium in recent years.

In the Netherlands, electricity supply is essentially municipal with all but 10% of national supply coming from municipal or provincial concerns. The Dutch electricity supply industry is being restructured at this time. This is to prepare the industry to move away from natural gas towards coal and nuclear power. A blueprint for reorganisation was laid down by the former Industry Minister in 1985. The plan was to wrest control of the national grid from the electricity producers association so freeing consumers to take power from the cheapest available source, while at the same time reducing the number of power generating companies from 11 to 3.

Iceland has one power company with a high per capita user and a small population to supply. It has abundant hydro and geothermal resources which could be harnessed to supply the U.K. 2000 MW of hydro power could be developed for export to the U.K. over the next 10 ~ 15 years. At least a similar amount of geothermal power could be developed for export to the U.K. Cost of development of hydro and geothermal power for export to the U.K. is very attractive at this time.

2.1 England and Wales

The White Paper [2] attempts to shift balance of power towards new supply utilities which at present are the Area Boards. It is assumed this will make the electrical supply industry more responsive to the needs of its consumers.

The CEGB will be split three ways. The grid will go to a new company which will be owned jointly by the twelve Area Boards. The non-nuclear power stations will be split between two companies. "Big G" will own 60%, "Little G" will own the remaining 40% . ['Big G' will be known as 'National Power' and 'Little G' will be known as 'Power Generation']. The Magnox and AGR Nuclear stations will continue to be owned by the government and will not be privatised.

The Areas Boards will in general retain their present structure but will play a more active role in power station development. Following privatisation, new power stations will be constructed on the basis of long-term contracts with the twelve new Supply Utilities (currently Area Boards) which are to be set up.

There will be competition in power generation between "Big G" and "Little G", but with possibilities of increasing inputs from Scotland, France (via Cross Channel Links) and new entrants (Submarine Cable Power from Iceland, Wind Generation, Tidal Power, Power from Waste etc.). Power stations will be forced to cut fuel and operating costs so reducing the price of electricity to the consumer.

The privatisation measures will include a "bill of rights" for consumers, giving them redress in the event that supplies fail to reach agreed standards of service. New entrants will have a right to request wayleave to construct power transmissions lines to connect their sources of generation to their customers.

The White Paper proposes to replace "merit order" operation of power stations by power pooling arrangements based on the current power station merit order system and the retention of short term supply contracts between Area Boards (Distributors) and the Power Generators. Merit order operation brings power stations on-line as demand rises on the basis of their economics, efficiency and location in the transmission network. This ensures that the most efficient stations are run most often. In the White Paper contracts between Distributors (the Supply Utilities) and the Generators (Generating Companies) will be (i) direct contracts negotiated with Generators, either by individual Boards or by Groups, for new or existing generating capacity, and (ii) contracts via the Grid in which Distributor contracts for electricity from the Grid Company. The White Paper would appear to keep the advantages of the CEGB integrated system while at the same time abolishing it.

The White Paper also states that the public and privatised industry should be given a clear statement of its strategic priorities. The legislation provides a statutory obligation on the Distribution Companies to contract for a specified minimum proportion of non-fossil-fuelled generating capacity. The government will have powers to vary the specified level taking into account the time it takes to commission new power stations. Distribution Companies will be expected to meet this obligation by contracting for nuclear capacity, and also through contracts for renewable sources of energy such as wind power, hydro (and geothermal) power supplied by submarine cable from, for example, Iceland, and tidal power. The distribution companies will be able to seek capacity from any source provided the necessary safety, planning and other consents are obtained. The Generating Companies in England and Wales, Scotland, France, Iceland, the Atomic Energy Authority, and British Nuclear Fuels, as well as the new state company which will operate all nuclear plants in England and Wales and the seperate state company which will be responsible for nuclear capacity in Scotland, are all potential sources of supply.

In 1986, U.K. maximum net capacity of plants was 55177 MW of conventional thermal, 4190 MW hydro, and 7144 MW nuclear. Capacity from self producers was 2879 MW of conventional thermal, 107 MW of hydro and 665 MW nuclear. Sales of electricity by the CEGB was 228456 GWh to Area Boards, 4155 GWh direct to consumers, and 188 GWh to EdF. Imports from EdF were 6590 GWh, from the SSEB 989 GWh, and from outside sources in England and Wales 2206 GWh. In England and Wales 2491 GWh was used for pumping at pumped storage stations. 36.1% of total sales was domestic, 36.1% industrial, and 23.5% commercial. Other sales included 1.5% farm, 1.1% traction and 0.9% public lighting.

2.2 Scotland

The SSEB was formed from two distribution Area Boards in the South of Scotland with related generation in the area in April 1955. The NSHEB has been independent since its creation in 1943.

The SSEB retained close links with the British Electricity Authority's successor, the Central Electricity Authority throughout the 1960's, but other forces drew the SSEB towards the NSHEB. It was argued that the NSHEB's hydro facilities would be ideally complemented by the SSEB's thermal stations and that the two utilities would be strong as a unit. The chairmen of the respective boards were granted seats on each other's boards in the later 1960's and co-operation between the two utilities have proceeded on a more or less friendly basis to this day.

Installed capacity in the SSEB System includes 1400 MW, 1320 MW and 360 MW nuclear at Toreness, Hunterston B and Hunterston A respectively, 2400 MW, 2028 MW, 1200 MW and 400 MW conventional thermal at Longannet, Inverkip, Cochenzie and Kincardine respectively, and 33 MW, 24 MW, 21 MW and 17 MW hydro at Galloway, Glenlee, Kendoon and Bonnington respectively. The effective capacity has been reduced by placing in storage 1325 MW of oil-fired installed capacity at Inverkip.

The NSHEB's generating capacity is based on hydro, comprising 1062 MW of conventional hydro, 700 MW pumped storage, with 1320 MW, 102 MW and 32 MW steam, diesel and gas turbine respectively, and 43 MW of diesel and gas turbine plant on standby. 3 MW of wind farm generation is under construction. The 1320 MW oil/gas station at Peterhead, commissioned in 1982, burned natural gas until 1986 and then oil. It will burn natural gas under a long term supply deal in future years.

Although the SSEB favours bringing both utilities into a single holding company with two subsidiary operational companies corresponding to the SSEB and the NSHEB after privatisation, there is little competitiveness in two integrated utilities. Creating one company where two existed before does little to introduce market forces. Under privatisation the SSEB and the NSHEB will operate much the same as at this time, but some redistribution of the two board's assets will take place to correct the balance. A new state company will be responsible for and will run and operate Torness and Hunterston Nuclear Power Stations. Protective legislation against take over by some other privatised electricity company, for example the SSEB, taking over the NSHEB, will also be introduced.

2.3 Northern Ireland

The NIE system in Ulster is based on four power stations. These are Ballylumford with a capacity of 960 MW (oil-fired), Belfast West, rated at 240 MW (coal-fired), and Kilroot Phase 1, rated at 600 MW and originally oil-fired but recently converted to coal/oil dual firing, and Coolkeeragh, rated at 360 MW and oil-fired..

NIE do not require any additional new generating capacity until about the year 2000 following completion of additional new coal/oil dual fired units at Kilroot Phase 2 scheduled for 1995.

Options under consideration are (i) development of lignite deposits together with an associated minemouth power station, (ii)reboilering and refurbishment of Belfast West power station, and (iii) installing a DC Submarine Cable Link to Scotland.

The present Northern Ireland demand is in the range 300–1400 MW and this is expected to increase to the range 430–2000 MW by the year 2010. Previous DC link studies from Northern Ireland to Scotland examined capacity sizes of 1 x 250 MW, 2 x 175 MW, and 2 x 250 MW based on maximum import restrictions for security reasons of 20% of system demand. In the event that an Iceland–South England HVDC link were built, then it would be possible to consider an HVDC spur to Northern Ireland. This is because this alternative may prove more economic and practical than laying further submarine cables from Iceland specifically to supply Northern Ireland, even if the connection is extended to mainland UK.

The proposed lignite development which has high capital cost and low running cost, may have a lower capital cost per MWh than an Icelandic link based on 500 MW at 0.6 load factor. Future generation developments, however, do not need to be finalised until about 1992.

Privatisation proposals that lignite, which had been known for many years but which became attractive only in the early 1980's when the price of oil rose, should be used in a private 450 MW power station (the Crumlin scheme) and also the scheduled Kilroot Phase 2 plant could introduce competitiveness in power generation in Ulster when privatisation goes ahead. This is on the assumption the 450 MW lignite power plant is constructed and operated by a private company.

3. SUPPLY AND DEMAND IN THE U.K.

An analysis of electricity supply in the U.K. indicates that 3000 MW of additional generation will be required in the South of England by the year 1995, 10,000 MW by the year 2000 and up to 25,000 MW will be required in England and Wales by the year 2010. To satisfy this demand, ten new power stations would be required. The Scottish utilities already have generation capacity which will suffice until the year 2010.

It is envisaged that coal and nuclear plant will be developed in England and Wales over the next 10 ~ 20 years to supply electrical demand in the south. Generation mix will depend on the government-specified level of non-fossil fuelled generation that is required [2]. Generation mix may vary over the years, for example on account of policy concerning the greenhouse effect.

3.1 The U.K. Electricity Supply System

The division of generation and consumption in 1989/90 is illustrated in Figure 1. The main transmission system is comprised of 400 KV, 275 KV and 132 KV lines. One double-circuit 400 KV line and one double-circuit 275 KV line connects the Scottish and English systems. The maximum power transfer on these interconnections is limited by stability considerations to about 900 MW. This restriction may be raised by (i) uprating the 275 KV lines to 400 KV, (ii) making use of a HVDC Link which may form part of a 2000 MW submarine cable link between Iceland and the South of England should this development go ahead [3], and (iii) both. Generation capacity and demand in (a) Scotland and (b) England and Wales up to the year 2010 is shown in Figure 2.

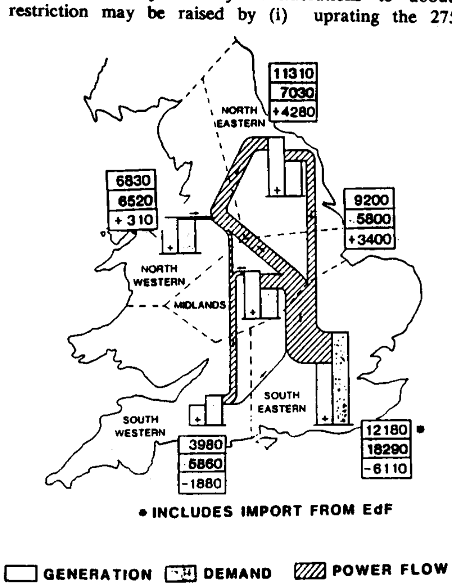

Figure 1 UK Generation and Demand, 1989/1990.

3.2 Connections to other countries

At present the U.K. imports the equivalent of 2000 MW of nuclear power via a 2000 MW Cross Channel HVDC cable link with France.

3.2.1 France

Nuclear power dominates the French electricity system. In the years 1974–1982, EdF was ordering some 6000 MW of nuclear capacity annually. In 1986 net nuclear capacity was 44700 MW, conventional thermal 24600 MW, and hydro 22800 MW. In 1987, nuclear power accounted for 76% out of a total 327000 GWh produced by EdF, hydro accounted for 20%, leaving coal and oil with a combined 4%. Planned nuclear power capacity in France in 1995 will be 60300 MW while the total for West Europe (including Yugoslavia) will be 128800 MW and in the U.K. 12600 MW. Installed world nuclear capacity was about 290000MW in 1988. Due to overcapacity French trade in electricity is more or less at cost, growing significantly to 29800 GWh in 1987 due mainly to increased sales to the U.K. In 1986/87, CEGB imports from France was 6590 GWh while CEGB sales to the Area Boards was 228456 GWh. Under in depth consideration is the provision of a second 2000 MW link to the South East of England and possibly a third link to the Southampton area. The Distribution Companies will assess along with the necessary safety, planning and other consents being obtained whether competitiveness of additional French imports coupled with the statutory obligation for a specified minimum proportion of non-fossil fuelled generating capacity will fulfil their needs.

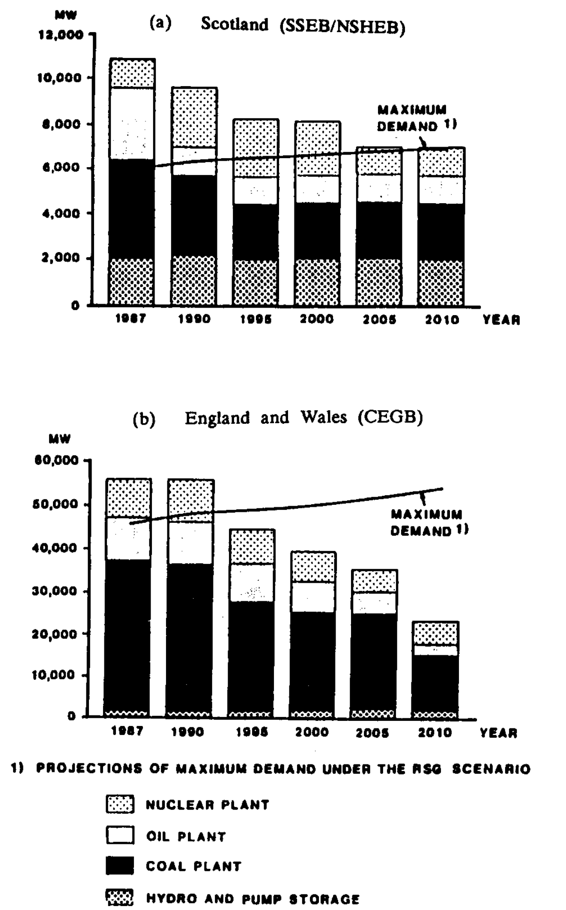

Figure 2 Projection of Generating Capacity and Demand to 2010.

3.2.2 Iceland

Power from Iceland via a proposed 950 Km, 2000 MW Submarine Cable Link extended to the South East of England by up to 1000 Km of HVDC overhead line would also help satisfy the statutory obligation for non-fossil fuelled generating capacity while, at the same time, permitting additional exports to England from Scotland using the HVDC overhead transmission line to the South. Energy from Iceland would be very competitive with that from new coal-fired or nuclear power plants, and availability of the connection should at least equal that of electricity from coal and nuclear power stations. The first 500 MW of Icelandic power could be available at inverter stations in seven to ten years, 1500 MW could be supplied before the year 2010, and about 2000 MW could be developed by 2010 ~ 2015. Tap-in of surplus power from Central Scotland in the early years (1000 MW) could provide 2000 MW at inverter stations in England by the turn of the century. The proposed HVDC overhead line from the North of Scotland to Central Scotland (and England) might also be used to feed power from a proposed 1200 MW fast breeder reactor plant at Dounreay, either at the end of the century or early into the next century, as well as electrical power from North Sea gas from a plant at Peterhead (Scotland). At rated load total losses of the Iceland/England Link would be between 7.7% and 12.5% of the power supplied and running costs over 40 ~ 80 years would be low. An advantage of Icelandic hydro (and geothermal) power is that the source is renewable and does not contribute to the greenhouse effect or to acid rain. Northern Ireland is considering tapping into the connection (in Central Scotland) as this alternative may prove to be more economic and viable than routing one or more 500 MW cables via Northern Ireland as previously discussed.. Economically harnessable Icelandic power is considerably in excess of the 2000 MW which is envisaged for development in the initial scheme.

Cost of energy over the first year at January 1989 prices at the North of Scotland and the South of England for a 2000 MW development at 0.6 load factor is 1.97p and 2.19p/KWh with interest at 4.5% p.a. For a load factor of 0.9, corresponding cost would be 1.62p and 1.76p/kWh respectively. At 8% interest p.a. respective cost is 3.05p and 3.39p/kWh at 0.6 load factor and 2.52p and 2.75p/kWh at 0.9 load factor respectively [3]. Payback period is assumed to be 80 years for hydro and 40 years for submarine cables, d.c. lines and convertors.

On an Equal Annuity basis, average cost of energy delivered to the South of England over a 40 year period with interest at 4.5% p.a. and 0.9 load factor (at January 1989 prices) is 1.27p/kWh. It is 1.70 p/kWh with interest at 8.0% p.a. This is based on the assumption that submarine cables and convertor stations are written off over 25 years and hydro development, a.c. transmission development and d.c. lines is written off over 40 years [3]. After repayment of the initial investment, there would be only operational and maintenance expenses, and cost of energy would be quite low. Lifetime of hydro developments may be 100 years or more.

3.2.3 Fast Breeder Reactor Generation

Prospects for Fast Breeder Reactor (FBR) generation in the near future is unclear, with large scale utilisation unlikely before 2020. The need for continuing development and retention of FBR technology is however recognised and actively pursued by USA, USSR, France, Japan, Germany, Italy and the UK. The present UK Government policy on FBR research however may mean that the 250 MW Prototype Fast Reactor at Dounreay might cease operation in the mid 1990's, ahead of schedule.

In West Germany a complete 300 MW FBR is available but unable to obtain a licence for operation. France experienced a sodium leak in the fuel handling facility at the superphenix plant a few years ago, which halted reactor operation whilst the problem was resolved. A new plant rated at about 1200 MWe (similar to that proposed for Dounreay) is to be contructed in France in the 1990's. The future of the pan-European agreement on FBR co-operation is unpredictable.

4. TIDAL POWER

The Severn Estuary has one of the world's highest tide ranges, and over the past 60 years various studies have examined the possibility for harnessing this tide range to generate electrical power. There are two proposals, (a) a barrage between Cardiff and Western-Super-Mare, and (b) a barrage adjacent to the English Stones.

In 1985 the Interim Study which examined a barrage between Cardiff and Western-Super-Mare was extended to include examination of a barrage located at the English Stones with the following objectives: (i) to assess the commercial viability of a barrage (built and operated by the private sector), (ii) to assess, with others, its effects on the environment, (iii) to obtain an assessment of regional planning implications, in liaison with local authorities and others, and (iv) to define what further work would be required prior to a construction decision. The report concluded the scheme was technically feasible, but further environmental work would be necessary.

4.1 English Stones Barrage

The English Stones barrage is the smaller of the two proposals in terms of output power and cost of construction. The cost per KWh is estimated at best to be similar and, at worst, twice that of the Cardiff/Wester-Super-Mare development. The English Stones site would suffer from siltation problems which would reduce generating capacity or involve expensive dredging. It is unlikely that this alternative would be developed.

4.2 Cardiff-Western Barrage

The Cardiff/Western-Super-Mare scheme is the favoured alignment. The proposed barrage would be 16 Km long with an installed capacity of 7200 MW costing at least £7500 million at January 1989 prices. The output would be equivalent to a firm capacity of 1100 MW resulting in an annual average output of just over 14.4 TWh. Increase in value of the energy would be obtained by selection of pumping times to permit extra generation at times of high tariff.

4.3 Construction

The construction programme to first power generation would be seven years. Full power would be produced after nine years. A pre-construction time of six years is estimated to cover environmental studies, engineering design, and obtaining parliamentary and planning approvals. The earliest projected date for start of generation is now the year 2003.

4.4 Private Sector Investment

Examination of the projects suggest that, while there is no distinct threshold, a real rate of return less than 10% would be insufficient to attract private sector investment. To achieve a return of 10% would require a tariff level of nearly three times the current level. To reach such a level by the time the scheme started generating would require energy prices to increase in real terms by over 7% per annum between now and the year 2003. This may be ruled out.

Energy generated valued on the basis of the Scenario of the CEGB submission to the Sizewell enquiry shows an internal rate of return of 7.4%. The internal rate of return is sensitive to changes in real terms of fossil fuel prices which are difficult to predict.

Calculating the cost of the scheme's output using a 5% real discount rate used recently by the CEGB in publishing figures for nuclear and coal-fired stations, the cost of electricity from the Cardiff/Western barrage at January 1989 prices would be 3.30p/kWh. This compares with corresponding CEGB figures of 3.23p for the Sizewell B pressurised water reactor (PWR) plant and 4.72p for a coal-fired power station. Cost of coal-fired electricity has dropped, however, since the above cost was made known. Hence the economics of a Severn Barrage Scheme would be comparable with nuclear, and cheaper than coal-fired generation of electricity based on the figures which were applicable at the time.

The major difficulty in formulating proposals for private sector financing is that the electricity generated would have to be sold at a price determined by cost of generation in the now public sector electricity supply industry which normally works on lower rates of return on capital employed. It would equally be difficult to finance any other form of power generation capacity as a 'stand-alone' project within the private sector when its output must be sold in the same market as is principally supplied by the now public-sector generation.

4.5 Environment

Concerning environmental conclusions, there would be an improvement in the harsh environment of the existing estuary. The capability of the estuary to support bird and fish life is unlikely to be decreased and may be enhanced.

With regard to the siltation problem the Cardiff Western Scheme is without doubt preferred.

4.6 Other Factors

Energy benefits not quantified in the analysis include (a) strategic diversity of energy sources, (b) insurance against unpredictable increases in primary energy costs, (c) non-pollution of the environment, and (d) long operating life (perhaps 100 years). While benefit of long life cannot be easily quantified, its value in 1989 money would be in excess of £550 million annually provided that the debt had been fully discharged.

4.7 Mersey Barrage

A preliminary study has recently been completed on the proposed Mersey Barrage. The capacity of this development is approximately one tenth of that of the proposed Severn Cardiff-Western Scheme. The proposed development would appear to take prominence over the Cardiff-Western Barrage at this time. This is on account of greatly reduced investment that would be required.

A disadvantage of tidal power is that its availability is determined by the moon's position.

5. PUMPED STORAGE

During periods of low demand surplus capacity is used to pump water to an upper reservoir, and when the demand peaks the water is used to generate electricity. Because of the nature of pumped storage, schemes can only be developed in mountainous areas, but, unlike large-scale hydro, there are a number of sites which could be developed in the U.K. such as Craigroyston above Loch Lomond.

The economic case for pumped storage rests on low capital cost per installed kW in comparison with thermal plant and improved flexibility of operation. Savings are made by avoiding use of the more expensive plant except in exceptional demand or loss of generation. Installed pumped storage plant in the U.K. relative to installed generating capacity is much lower than in most industrial countries. This is on account of area where pumped storage can be located and transmission restrictions between generation and load demand. Pumped storage does not produce energy. It is an effective method of storing large amounts of electrical power. Conversion efficiency is typically 75% pumping to generating.

5.1 Craigroyston

Feasibility studies for a pumped storage plant at Craigroyston were undertaken by the NSHEB in the early 1970's. The development was for a 1600 MW scheme with a maximum storage capacity of 32 GWh and costing of the order of £330 per kW at January 1989 prices [5]. An alternative developemnt rated at 3200 MW was also considered. Construction time would be of the order of 10 years. Such a scheme is not required until at least the year 2000 on account of surplus generating capacity in Scotland together with transmission restrictions between the generation and load areas in England. The situation could change if a high-capacity HVDC line is constructed between Scotland and England as part of a HVDC power link between Iceland and the U.K.

5.2 Capacity

There is 1728 MW of pumped storage at Dinorwig, N. Wales which will be owned and operated by the Grid Company. There are 400 MW and 300 MW pumped storage plants at Cruachan and Foyers respectively in Scotland which at present, are owned and operated by the NSHEB. Under privatisation the 400 MW Cruachan plant will be transferred to the private electricity company which will succeed the SSEB.

6. SMALL-SCALE AND LOW-HEAD HYDRO

At present, installed capacity of hydro generation in continuous operation in the U.K. is of the order of 1762 MW, representing approximately 2% of U.K. generating capacity at this time. Up to 500 MW of additional capacity corresponding to 1.8 TWh/year could be developed by utilising small-scale and low-head schemes. This represents less than 1% of current electricity demand [1], [6].

Small-scale hydro is associated with a power range of up to 1MW and heads greater than about 3m. Factors such as compensation water and fisheries limits the potential which could be exploited in the U.K. However, the 1989 Water Bill which imposes only administrative costs of licencing stations smaller than 5 MW, together with rates reform, should improve economic viability of U.K. small-scale, low-head schemes.

Drawbacks in economic terms are high capital investment and payback periods of up to 12 years. Specific schemes will be viable in the 1990's and water authorities have found it viable in specific cases to produce electricity themselves.

7. WIND POWER

The cost of electricity produced by wind power in the U.K. based on January 1989 prices is given as 3.0 ~ 5.0p/kWh [7]. This compares quite favourably with cost of energy from fossil and nuclear plant. Availability of existing wind farm power plant could be improved

In California, where 95% of current world wind power is generated, average availability of wind turbines is not high. New wind farm turbines achieve an availability which is significantly better. Current cost of wind turbines in the U.K. is £530/kW, but this cost would be expected to reduce considerably by bulk supply.

U.K. land-based wind turbines could, if developed, produce 45TWh/year equivalent to 17% of present U.K. demand. Theoretical studies suggest that up to 50% of generating capacity could be wind power plant before system operating problems would arise. Installing a thousand MWs or more of wind turbines should therefore have no adverse effect on power system operation in the U.K.

Estimates made recently by the Chairman of the CEGB intimate that wind energy could save burning 1 million tonnes of coal a year in the U.K. by the year 2000, and could supply 1000 MW of power by the year 2005, 1% of the country's electricity requirements. At present there are four experimental 1 MW wind turbines in operation at Carmarthen Bay (North Wales), and two more are expected to be erected at the same site. There is a 3 MW wind power plant in operation at Burgar Hill in Orkney (Scotland) at this time. 3 wind farms are at the planning stage. The first wind farm is expected to be constructed at Capel Cyon in S.Wales in 1990, with others to follow in 1991 (Cornwall) and 1992 (Durham). Each wind farm will comprise 25 machines with a total capacity per farm of 8 MW.

It should be noted that if wind power were to produce 20% of current needs some 20,000 machines similar to one of the 1 MW machines at Burgar Hill in Orkney would be required. There are 180,000 wind turbine sites on the U.K. landmass which would be suitable for wind turbines, but when national parks and areas of outstanding natural beauty are excluded this figure is reduced to 144,000 sites.

Wind farms are a prospect for producing a limited amount electrical energy in the U.K. at this time.

8. NORTH SEA GAS

A report in 1988 suggests that gas would increase its share of European power generation from 5% in 1988 to 16% by 2010. Most of this would come from combined cycle plant.

Until the early 1980's small-scale gas turbine units were used for peak lopping in electricity utilities and industrial plant. Developments in the aero engine sector in recent years have led to units rated at 200 MW or more becoming available. Gas turbine stations can be fitted with a waste heat boiler and a steam turbine-generator to increase output and thermal efficiency thus avoiding problems of siting new plant. In recent months, the NSHEB have entered into a contract with an oil company to supply natural gas at a sufficiently low price to make it economical to convert the 1320 MW Peterhead power station to gas. The station may operate base-load on North Sea Gas.

In addition, private consortia have suggested that a 1000 MW combined cycle gas turbine power plant located in the London area would be viable and save £2000m ~ £2500m at January 1989 prices within 40 years of commissioning based on cost of nuclear generation.

9. SMALL-SCALE COAL-FIRED PLANT

Privatisation of electricity supply could lead to a significant reduction in the number of new large coal-fired power stations (1800 MW or more) since initial costs of construction of large power plants are high and payback periods long. A recent debate in the House of Lords suggested that new coal-fired power stations would more likely be rated at 500 MW or less.

9.1 Fluidised Bed Combustion

A more promising technology for small power plant is fluidised bed combustion (FBC). The combustion efficiency of this technology is greater than that of conventional stoker fired plant, being at least equal to that presently obtained by large pulverised coal plants. FBC has advantages both in terms of pollution and flexibility of the plant. Because of temperature and other considerations within the fuidised bed, this technology can often make use of fuels which would cause corrosion problems in conventional combustion plant.

9.2 Combined Heat and Power

Combined heat and power (CHP) uses waste heat from power stations to provide low grade heat, for example, for district heating (DH) schemes.

The use of CHP in conjunction with small-scale power stations and standby generators is likely to increase following privatisation of the electricity supply industry in the U.K. Combined heat and power is discussed in more detail in Section 12.

10. WAVE POWER

Since 1983 several countries including the U.K., Japan, Norway and China have continued research into smaller shore-based wave energy machines. The most common designs are variations on oscillating columns of water which pump air through a Well's air turbine to produce electricity. One such device (being developed by Queen's University, Belfast) is currently undergoing trials on the Scottish Island of Islay [8]. The device uses a natural gully to direct and increase the oscillating movement of the waves. There is potential to build installations with 1MW rating to generate electricity at January 1989 prices at between 3.1 to 4.6 p/kWh. However, the economic prospects of wave energy are poor both in comparison with other renewable energy technologies and with conventional thermal plant [9]. While wave energy is intermittent and unpredictable and output is not related to daily variation in demand, benefit arises mainly by fuel savings and from plant displaced. This can vary from year to year as prices change.

11. BIOMASS DERIVED FUEL

Biomass refers to all matter that can be derived directly or indirectly from plant photosynthesis. Two methods used to convert biomass to energy are (i) anaerobic digestion which is digestion of biomass by microbiological process to produce bio-gas (a mixture of methane and carbon dioxide), and (ii) combustion in furnaces or use of the material in a gasification process. The four sources which produce significant amounts of biomass are (a) agricultural such as by intensive livestock rearing and straw, (b) urban which includes sewage and municipal waste, (c) industrial and commercial waste, and (d) forestry.

11.1 Agriculture

Agricultural sources are wastes and energy crops. Intensive livestock rearing produces waste which has great potential as a source of energy. Straw is the most promising of the dry agricultural wastes. It is estimated there are 7 million tonnes available for use in the U.K. annually. This represents 1% of the U.K. energy demand.

11.2 Urban

Urban waste is sewage and municipal waste.

The U.K. produces some 28 million tonnes of municipal waste each year, 90% of which is disposed of in landfill sites. Estimates intimate that most landfill sites could be exploited for gas. There are currently 30 sites operational with a further 30 at the planning and construction stage. 13 sites are generating electricity with a total capacity of 16 MW. It is anticipated installed generating capacity from landfull gas will be around 50 MW by 1992, with an estimated 150-175 MW intalled post 2000.

10% of U.K. municipal waste is incinerated. A more promising methid would be to partially process refuse to produce refuse-derived fuel which is then used in circulating fluidised beds or water-tube boilers. At least five such plants are in operation in the U.K. at this time. This method is attractive in having very short pay-back periods in addition to presenting the opportunity for quick profits.

11.3 Industrial

The bulk of industrial and commercial waste is equivalent to 8.5 million tonnes of coal per year. Development work is necessary before this waste could become a more widespread commercial option. Anaerobic digestion could lead to savings, with the benefit of producing fuel gas.

11.4 Forestry

Total waste produced from forestry in 1985 was the equivalent of 84,000 tonnes of coal. The most likely use of this material is in boilers in the range 0.2 to 10 MW. Average payback period for installing wood burning plant is estimated to be 6.6 years. This energy source is more economically used for heating than for the production of electricity.

12. COMBINED HEAT AND POWER

Combined heat and power uses waste heat from power stations to provide low grade heat at low cost for, say, a district heating (DH) scheme. In theory it would seem most viable where excess heat from large power stations is used to heat towns and cities. It is important for economic and practical reasons to have a high density of users as close to the source of heat as possible. Unfortunately, most power stations in the U.K. are not situated close to centres of high population. Under these circumstances significant pipe networks would be required.

12.1 Smaller Schemes

Use of CHP with smaller and mini-power stations is more attractive. Standby generators which for the most part are rarely used but which could provide 10% of the country's electrical power at peak demand could in many instances be converted for CHP. Independent consultants have found that some schemes could be developed and provide payback in as low as two and a half years.

12.2 Combined Heat and Power in Belfast

A CHP/DH scheme for Belfast could save the equivalent of 150,000 tonnes of coal per year and utilise Northern Ireland lignite resources. The project would use 3 x 150 MW electrical ouput turbines each with 120 MW heat [10]. It has a favourable long term cash inflow but anticipated returns to an investor would not be sufficient to attract private sector financing of the scheme. The return indicated is high enough for a considerable degree of optimism that a significant part of the funding would be provided by the private sector provided the government or supernational sources offered to underwrite a substantial part of the risk.

A study for CHP/DH for Edinburgh carried out for Edinburgh at approximately the same time and in similar circumstances to that for the proposed Belfast Scheme resulted in similar conclusions.

13. FUEL CELLS

Prototype fuel cell power plants rated at 1MW, 4.8MW, 11MW, 20-30MW and 150MW for evaluation programs have been constructed in Connecticut (1977), New York and Tokyo (1983), Minnesota (1984) and California (1983) respectively.

Bus-bar power costs for the gasification/fuel cell plant are competitive with direct-fired power plants.

Little improvement in capital costs and plant performance of alternatives such as fluidised bed and direct-fired boiler plants can be expected since these configurations incorporate mature technologies. This is not true of the gasification/fuel cell plant. Development of such plant should result in significant reductions in capital cost together with an increase in overall plant efficiency.

Advanced fuel cell generation using molten carbonate technology as a second generation cell (rather than phosphoric acid technology) seems both practical and economic in 5 to 10 years.

Fuel cell power plants can be constructed and commissioned in 2 ~ 3 years and have an efficiency in excess of 45% (electrical). Phosphoric acid plant use synthesis gas, methane, methanol, and napha as fuel. Molten carbonate plant employ fuel cells which operate at high temperature (600 ~ 700°C) to enhance reaction rates and decrease electrode polarization.

Fuel-cell power generation plants appear to be a viable future alternative for small-scale power generation [11], [12].

Current research on fuel-cell power plant technology is centred in Japan.

14. CONCLUSIONS

Demand for electricity in the U.K. is likely to continue to rise well into the next century while, at the same time, many existing plants using coal and oil together with the older nuclear plants will be decommissioned. An extra 10 GW of generating capacity will be required by the year 2005, possibly rising to 25 GW by the year 2010. Difference between generating capacity and demand will not be spread evenly over the U.K. Scotland will have a match between capacity and demand in later years, while the biggest shortfall may be in the South East.

Cost of alternative sources of generation appears to be marginally cheaper from wind turbines, followed by power from Iceland, France, small hydro developments, and barrage schemes. Wave power is the least attractive of the alternatives at this time.

Wind power could provide 1000 MW by 2005 if reliability problems are resolved, Iceland up to 3000 MW (if Geothermal potential is also developed) by 2015, France up to an additional 4000 MW relatively soon, small hydro developments 400 MW, and tidal power 7000 MW at peak (equivalent to 1100 MW firm capacity). Landfill gas, industrial refuse and wood-derived fuel could provide the equivalent of 1 to 3 Mtce/year respectively. Combined heat and power utilising mini-power stations and standby generators could contribute several thousand MWs of capacity in future years. Alternative sources are capable of contributing significantly to future generating capacity requirements to well past the year 2010, and are competitive with conventional coal, oil and nuclear fuelled power plant.

Privatisation will change emphasis from long term security and investment to provision of dividends for investors in the Power Generation Companies and the Electric Utilities that are formed. Privatisation may also make it more attractive to import electricity from abroad. Prospects include increased profit demand and shedding of risks.

Private investors require payback periods which are short. This is inconsistent with the construction by the private sector of large fossil-fired or nuclear power plants, hydro developments, and barrage schemes. The size of new power stations is likely to decrease, so that designs in the 500 MW ~ 1000 MW range will become more common following privatisation of electricity supply. Pumped storage development is less expensive than installing conventional plant, so more use may be made of pumped storage in future years. Fluidised bed combustion is well placed to be taken up by the private sector, and coal-based generation cost will become dependent on the world price of coal in the same way as oil-based generation cost is dependent on the world price of oil today.

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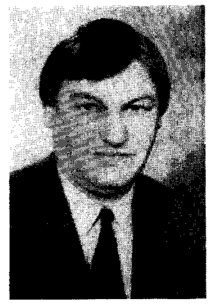

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