GREENHOUSE GAS MITIGATION TECHNOLOGY
RESULTS OF CO_2 CAPTURE & DISPOSAL STUDIES

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ABSTRACT

In response to the increase in the global concentrations of greenhouse gases, the IEA Greenhouse Gas R&D Programme is carrying out an assessment of greenhouse gas abatement technologies with particular reference to carbon dioxide emissions from fossil-fuel power generation systems. The work is supported internationally by 16 Countries as well as the Commission of European Communities and two sponsors RWE AG (Germany) and EPRI (USA). The Programme has examined, on a consistent basis, the options available for capturing and disposing of the CO_2 product from a range of gas and coal fired power generation plant types, each with an output of 500MW(e). Systems under consideration include PF+FGD, IGCC, NGCC and a CO_2/O_2 recycle scheme. CO_2 capture technologies considered include chemical and physical absorption, solid adsorption, cryogenics, membrane separation and gas separation membranes. Carbon dioxide disposal options considered are; disposal in the oceans, in aquifers, in depleted gas reservoirs and terrestrial storage as a solid. In addition, a number of studies have evaluated the utilisation of CO_2 for enhanced oil recovery and the manufacture of chemicals, including a detailed investigation of dimethyl carbonate production. Comparison is also made with the alternative stance of compensatory forest plantations and substitution of fossil fuels with biomass. Emphasis has been placed on a requirement to determine the impact of the various technologies on the cost of electricity generation. This has been achieved by analysing the costs of specific schemes, on a common basis, and comparative results are presented for various CO_2 abatement options. A number of studies have also been carried out to evaluate transport options and the environmental impact of these technology combinations for carbon dioxide disposal. The results indicate that by combining the most favourable technologies for CO_2 capture and disposal to efficient power generation technology, electricity generation costs could be increased by around 50%. Alternative schemes have similar or even greater cost penalties. Analysis shows that the cost of CO_2 capture dominates these added figures unless CO_2 transport distances are very large. Carbon dioxide disposal is the area where further R&D is urgently required to provide environmental impact data.

THE IEA GREENHOUSE GAS R&D PROGRAMME

The Programme is a co-operative research and development programme concerned with technologies relating to greenhouse gases derived from fossil fuel. In the debate on cutting emissions of greenhouse gases to the atmosphere, much attention has been focused on fossil fuels and in particular, fossil fuel power stations. Task 1, now complete, was an initial three year programme aimed at assessing technologies which produce, capture, utilise and dispose of carbon dioxide generated from the use of fossil fuels in electrical power production. The countries that agreed to sponsor the work programme were; Australia, Canada, Denmark, Finland, Italy, Japan, The Netherlands, Norway, Spain, Sweden, Switzerland, the United Kingdom, and the United States of America as well as The Commission of the European Communities, in addition, RWE AG and DMT were sponsors. The project structure, organisation, objectives and work programme have been described previously (1). A second Task started in November 1994, which will look at many wider issues. This new Task includes EPRI (USA) as a sponsor and Poland and Venezuela as new member countries. The range of technical assessment activities, which constituted Task 1 fall into four broad categories, namely; power generation options, CO_2 capture technologies, CO_2 disposal, and CO_2 utilisation options. This paper assesses the cost penalties associated with the capture and disposal of CO_2 from fossil fuel power plant and examines in some detail the main disposal and utilisation options in terms of their global storage capacity and environmental impact.

POWER GENERATION AND CO_2 CAPTURE OPTIONS

The four power generation options chosen for assessment represent technologies in widespread use today

	Efficiency (%)	CO_2 conc (% dry)	Generation Cost (mills/kWh)
PF+FGD	39.9	14	49
NGCC	52.0	4	35
IGCC	41.7	7	52
CO_2 recycle	32.8	91	78

Table 1 Electricity generation costs for the four base cases

and also those more suitable for incorporating CO_2 capture technologies. These studies provide the base case data for electricity generation costs and CO_2 emissions to which the costs of CO_2 capture and disposal can be added in a consistent manner, thereby allowing accurate comparisons to be made. Table 1 shows

	Generation Efficiency (%)	Generation cost, (mills/kWh)	Cost of CO_2 avoided ($/t C)	Cost of CO_2 captured ($/t C)	Capture Efficiency (%)	CO_2 emission (g C/kWh)
PF+FGD Base case	39.9	49				226
+ Membranes	31.1	78	165	136	80	53
+ Membranes+MEA	29.7	75	154	106	80	61
+ MEA	29.1	77	169	114	80	62
+ Cryogenics	N/A	N/A	N/A	N/A	N/A	N/A
+ Adsorption PSA	28.5	114	308	216	95	16
+ Adsorption TSA	29.5	117	968	609	70	91

Table 2 Summary of capture data for the PF+FGD base case

the results of these assessments; in all cases plant costs were derived for an electrical output of 500MW and fuel costs assumed were $2/GJ for coal and $3/GJ for gas. This work has been reported previously (2); all efficiencies and calorific values quoted are based on Lower Heating Values (LHV). The second phase of feasibility studies comprised assessments of CO_2 capture options. Where appropriate, each of the main options of adsorption, absorption, cryogenic and membrane systems was applied to the gas streams from the four power generation options and the additional cost and efficiency penalty calculated. Some capture technologies are, however, unsuited to some of the flue gas condition; cryogenics, for example is only practicable when the CO_2 concentration in the gas stream is high and gas-solid adsorption when the CO_2 concentration is low. The studies have generated a large amount of data on CO_2 capture, an example of which is given in Table 2 just for the PF+FGD base case generation option. From this data it has been possible to select the most favourable capture options for each of the power generation cases. Gas-liquid scrubbing using MEA as solvent, despite the high regeneration energy penalty, is the most attractive option when the CO_2 concentration in the gas stream is low, as in the PF and natural gas cases. When CO_2 concentrations are higher, as in IGCC with shift and with CO_2 recycle, a physical solvent such as Selexol is more attractive. Gas-solid adsorption is only practical at very low CO_2 concentrations (400ppm-1.5%) and even then is more expensive than MEA; cryogenic technology is restricted to high CO_2 concentrations and is more expensive than Selexol. Membranes offer the potential of lower energy penalties but the cost of a large scale plant is difficult to estimate at present.

	Base case efficiency (%)	Capture technology	Efficiency (%)	Generation Cost (mills/kWh)	Cost of CO2 avoided ($/t C)
PF+FGD	39.9	MEA	29.1	77	170
NGCC	52.0	MEA	42.0	55	240
IGCC	41.7	Shift+Selexol	37.1	67	77
IGCC	41.7	CO2 recycle	38.3	68	80

Table 3 Generation costs inclusive of CO2 capture

Table 3 combines favourable CO_2 capture options with power generation options to produce data for the cost of power generation with CO_2 capture. CO_2 recycle has been associated with the IGCC base case rather than with conventional PF as in the base case example given in Table 1; this involves recirculating CO_2 back to the gas turbine combustion chamber (as opposed to the PF furnace) and would require the development of a novel gas turbine. In all cases, there has been a drop in the overall thermal efficiency of the power plant due to the high power consumption requirements of the CO_2 capture plants and in this respect IGCC has advantages over conventional PF plant. Despite the CO_2 emissions from the NGCC being only half those from the coal-fired plants, a large efficiency penalty is still incurred; however, the

	Base case efficiency (%)	Capture technology	Efficiency (%)	Generation Cost (mills/kWh)	Cost of CO_2 avoided ($/t C)
PF+FGD	39.9	MEA	26.7	86	232
NGCC	52.0	MEA	40.6	57	275
IGCC	41.7	Shift+Selexol	35.5	73	107
IGCC	41.7	CO_2 recycle	37.3	71	100

*Compression, assuming 8°C liquid CO_2 at 52.6bar (780psi).

Table 4 Generation costs inclusive of CO2 capture& compression

overall cost of electricity generation remains the lowest. Membrane technology may have the potential to reduce the power consumption penalty. A further cost penalty is incurred by the requirement to dry and compress the captured CO_2 to a pressure at which it is a liquid or dense fluid; this is a requirement for efficient pipeline transport and disposal. The efficiency penalties and estimated costs when drying and compression are included, are shown in Table 4. The data indicates that power generation costs will increase by at least 50%, based on present day generation costs using conventional technology (with disposal costs still to be added).

CARBON DIOXIDE DISPOSAL OPTIONS AND STORAGE POTENTIALS

Disposal options are largely independent of the type of power plant and capture technology employed an are more dependent on geographical location. Four primary disposal options have been studied, ocean disposal, disposal in aquifers, disposal in depleted oil/gas reservoirs, and storage as a solid in a thermally insulated repository. The estimated cost of disposal for each of the above options and also the cost of pipeline transport derived in each of the studies are shown in Table 5. The costs are based on schemes designed to dispose of 150kg CO_2 per second (the CO_2 product from a 500MW(e) PF+FGD power plant fitted with an MEA-based CO_2 capture system). The studies have shown that the cost of disposal, with one exception, is inexpensive compared to capture costs; with modest transport distances disposal is estimated to add only 0.2 cents/kWh to electricity costs; even with distances of 1000km, the cost addition for disposal is estimated to be < 1 cent/kWh. The natural gas NGCC case would benefit from having less CO_2 to transport but there are significant advantages of scale so this benefit would not be pro-rata. The

	Ocean	Aquifers	Gas reservoirs	Solid CO_2
Disposal cost ($/t C)	4.1	4.7	8.2	600
Cost addition to PF+FGD case (mills/kWh)	1.1	1.2	1.9	90
Pipeline cost ($/t C/100km)	2.5	3.6	3.6	N/A
Cost addition to PF+FGD case (mills/kWh/100km)	0.7	1.0	1.0	N/A

Table 5 Disposal & transport costs from CO_2 disposal studies

benefits of scale in reducing the cost of CO_2 pipeline transport have also been estimated by other workers (3) and the costs reported are, if anything, lower than those reported in Table 5. The storage of CO_2 as a solid was proposed as a theoretical concept (4); the concept is valid but our studies have shown that translating this concept into a practical scheme results in prohibitively high capital cost and there is also a significant power consumption penalty for the production of solid CO_2. Although all the major disposal options would appear to have usefully large potential storage capacity, there is considerable uncertainty about the exact storage potentials. Table 6 summarises the data available in the literature and compares it with data derived for our studies.

The differing concepts associated with various storage options make capacity comparisons difficult. The ocean represents the largest sink, capable of dissolving several million Gt C. Only 1400Gt would be buffered by CO_3^{2-}, so outgassing would occur as the CO_2 enriched water worked its way to the surface waters. Whilst 20×10^7Gt C is clearly an over-estimation, equally 1400Gt C is a gross under-estimation; the role of hydrates and sediment interaction would also enlarge storage capacity. There is, therefore, little

Disposal/Utilisation Scheme	Potential global CO_2 capacity (GT C) Literature values	IEA GHG Studies
Ocean disposal	$2*10^7$[a] 1400[a1]	No estimate
Solid CO_2 disposal	No estimate	No estimate
Aquifers	87[b] 116[b1] 2700[b2]	<87[4]
Exhausted gas wells	83[c] 142[c1] 314[c2]	140[5a] 4[5b]
Exhausted oil wells	42[c] 187[c3]	40[5a] 1[5b]
Enhanced Oil Recovery	17[6a] 63[6]	65 (0.4GtC/y)
Direct biofixation	No estimate	0.7-3/y
Indirect biofixation	500-620mhectares[7]	0.16-0.78/y
Chemicals	>1[8]	0.089/y

(1),Based on current estimate of dissolved inorganic carbon (DIC) extrapolated to maximum solubility of CO2 in sea water (Ormerod et al, 1993)(1a),Storage from buffering capacity of dissolved CO32-(Wong, 1993)(2)Areal method, including depleted gas wells (Koide et al, 1992)(2a),Prudent estimate (Hendriks et al, 1993)(2b),Less prudent estimate (Hendriks et al, 1993)(3,Based on proven reserves, assuming all reservoirs can be refilled (Holt et al, 1992)(3a),Based on proven reserves and depleted reservoirs assuming all can be refilled (Hendriks et al,1 993)(3b),Including unproven fields (Hendriks et al, 1993)(3c),Including unproven fields (extrapolated from (3))(4,Stanley Industrial Consultants Ltd(5a)TNO (maximum value for depleted fields + proven reserves)(5b),TNO (minimum value for depleted fields + proven reserves)(6a),Tanaka early paper, based on current usage(6),Tanaka, Based on current reserves in 1991(7),Based on estimates by Hall (500 million) and Houghton and Grainger (580-620 million) (8),Aresta.

Table 6 CO_2 storage & disposal potentials

doubt that the oceans have the capacity to store all the CO_2 produced from fossil fuel combustion; much more important is the criteria for site selection to ensure adequate retention time. The capacity that can be associated with terrestrial storage of solid CO_2 is dependent on land availability; the method is prohibitively expensive unless a natural site in a permafrost climate area is considered. This would limit the capacity potential severely but no data is available to estimate the potential and there is no requirement to do so.

	Maximum Storage Capacity (Gt C)		Time to Depletion (years)	
	Oil	Gas	Oil	Gas
Asia Pacific	2.2	10.1	19	59
Western Europe	0.9	8.6	10	23
Eastern Europe	4.2	56.7	18	62
Middle East	20.1	32.0	104	377
Africa	2.8	8.4	27	128
South America	3.3	5.0	43	84
North America	6.9	21.1	19	13
World	40.4	141.9	45	62

Table 7 CO_2 storage potential/expectancy

The potential capacity of aquifers and depleted oil and gas reservoirs is much more open to debate. In the case of aquifers, prudent assumptions on occupancy of pore space by CO_2 and economic restrictions would lead to a very low estimate of capacity (lower than the lowest estimate in Table 6). There are however many reasons which suggest that the storage capacity of aquifers could be much larger; only areas of interest for oil and gas production have been studied in any detail so the areas with suitable aquifers could be much higher, the requirement for a structural trap may be unnecessary as formation water velocities are very low, pore occupancy could be higher and restrictions on economic utilisation may be over-restrictive. In suggesting that the potential for CO_2 storage in aquifers is lower than 87Gt C, a cautious approach has been adopted in assuming 2% occupancy and 1% economic utilisation. The potential storage capacity of depleted gas reservoirs is greater than that of depleted oil wells and much more likely to become available due to the greater level of depletion that is normally achieved with gas wells. The assumption that all the volume previously occupied by oil or gas is available for CO_2 would seem to be over-optimistic, certainly in the case of oil reservoirs; on the other hand potential gas and oil reserves are clearly greater than proven reserves. The capacity data, presented in the IEA GHG Study, suggest that, based on proven reserves, the capacity of depleted gas reservoirs will be <140Gt C as it is unlikely that no water invasion has occurred; however it would be less correct to assume total water invasion of gas reservoirs. Closer examination of the availability of gas reservoirs (Table 7) shows that >50% of the potential is in Eastern Europe and >30% in the Middle East. However Western Europe and North America have more immediate availability and are more likely candidates for CO_2 storage schemes in the near future. The depletion times in Table 7 are based on present consumption rates; gas consumption rates in particular are likely to rise in the future. Any use of depleted oil reservoirs without EOR would seem unlikely and an estimate of storage capacity based on CO_2 utilisation in EOR schemes, associated with proven reserves, gives a potential utilisation of 4Gt C [9].

ENVIRONMENTAL IMPACT OF LARGE SCALE CO_2 DISPOSAL

Despite the environmental advantages associated with reducing CO_2 emissions to the atmosphere, the environmental implications associated with disposing of large quantities of CO_2 represent a significant barrier to any potential CO_2 capture and disposal scheme. In this respect the use of depleted oil and gas reservoirs has the advantage of a database derived from oil and gas production and from EOR projects, possibly sufficient to provide the basis for an environmental impact statement. Aquifers may also be able to make use of this source of data as suitable aquifers are often associated with hydrocarbon deposits, as was the case for the Alberta Basin example chosen for the IEA GHG study. Several types of environmental risk exist; short term and catastrophic, for example a large leak of CO_2 from an injection well; long term effects of CO_2 on the new storage environment; the risk of a return of CO_2 to the atmosphere at a rate faster than predicted.

Ocean Disposal

To achieve long retention times the CO_2 should be injected into as deep water as possible. Model simulations indicate that retention times of >1000 years would be achieved by injecting at depths of 3000m (10). Furthermore at depths >3000m the density of liquid CO_2 exceeds that of seawater allowing it to sink to even greater depths or collect in pools on the ocean floor. Installing subsea pipelines and structures at this depth is outside the experience of current technology and laying pipelines at 3000m is not, at present, a practical option. However injection via vertical pipes, from a ship or platform, is being actively considered(11). The practical difficulties of injecting CO_2 directly into deep water has led to the consideration of natural ways whereby CO_2 could be transported to deep water. In certain places, natural currents transport ocean water to greater depths. An example from one of the earliest studies on ocean disposal (12), is where the high saline, high density Mediterranean water spills into the Atlantic Ocean. More recently (13), it has been proposed that carefully controlled injection into shallow water could produce a solution of CO_2 in seawater with a density greater than the surrounding water. The resulting dense plume of CO_2 enriched seawater could, in conditions of low stratification and with the assistance of a slope, sink to much greater depths. At shallow depths careful nozzle design would be required to constrain dilution by entrainment (14) but at depths below 1200m unconstrained injection would produce a plume of sufficient density to sink (15). Either of the above proposals offer the concept of injecting at depths of <1000m and these depths may be reached within 100-200km of the coastline in many places. Current pipe-laying depths have reached 850m and current technology is capable of 1000m; greater depths can be anticipated in the future. Consideration of the marine environment suggests however that the impact on the marine environment would be much more acceptable if injection was below 1000m. Steep environmental gradients are present in the water column as a result of light attenuation and biomass concentrations decrease logarithmically with depth. Exploratory commercial fishing is being practiced at depths approaching 1000m and many surface species migrate either seasonally or daily to depths approaching 1000m. Below 1000m however the only link to the biological activity in the shallow waters is by sedimentary processes. The lack of information regarding the physiological effects of dissolved CO_2 on marine life is probably the most important piece of knowledge missing in terms of understanding the total environmental effect of storing CO_2 in the deep ocean; interaction with sediment could also result in damaging effects. Dissolving CO_2 into ocean waters means there is no possibility of a sudden, catastrophic release of CO_2 other than from a failure of the injection system.

Underground Disposal

Underground disposal in depleted hydrocarbon reservoirs or aquifers would be constrained to reservoirs and aquifers below 800m; CO_2 is a dense fluid at such pressures and at these depths the possibility of leakage into freshwater supplies is small. The large quantity of CO_2 being stored means that there is the potential for a catastrophic leak to the atmosphere but in practice, malfunctioning of the surface installations and the wells would be minimised by high quality construction, operation and maintenance and by comprehensive metering and control systems. When using depleted hydrocarbon reservoirs, avoiding leakage of CO_2 from the storage reservoir requires a comprehensive knowledge of the properties of the reservoir trap; the main characteristic of the trap is the caprock (seal). In most cases the trap is open for fluid flow at the outer boundaries allowing fluid migration into the trap structure (spillpoints). The structural highest spillpoint determines the storage capacity of the structure; The risk of CO_2 escaping from a storage location can be reduced by using peripheral observation wells, usually near known spillpoints. Whilst attempts should be made to ensure that geological pathways are identified, the consequences of leakage should be evaluated. The situation with aquifers is very similar; with prior geological investigation, the chances of major fingering or directional leakage of CO_2 from the aquifer are not high. Injection rates must take into account local fracture pressure near the seal. The very low velocities of the formation waters suggest that any ingress of CO_2 into surface waters would be very slow and unlikely to lead to measurable pH changes. CO_2 in an aqueous environment will chemically react with some rock structures (15); this could permanently fix the CO_2 but could also affect the integrity of seals. There is a therefore a requirement to quantify these effects by experimental measurements in a CO_2 environment. Storage of solid CO_2 in a contained, insulated repository, could be accurately monitored and controlled to reduce both the short and long term environmental risks. It is unlikely to be a practical option however.

Utilisation options

The most sensible CO_2 utilisation option is to replace CO_2 currently produced for the chemical industry with re-cycled flue gas CO_2. This option has to be carefully considered as the original source of CO_2 may be a by-product, e.g. from fermentation, and may be vented to atmosphere if not used but there is the potential to substitute the CO_2 currently used by the chemical industry with recycled CO_2 and to expand the use of CO_2 in the industry. Price will be important, but potentially it could be available at zero cost.

Option	(Gt C/year)
Chemical industry:	
Current use of CO_2	0.03
DMC in petrol	0.002
Forestation:	
long rotation	0.94
short rotation (biomass fuel)	0.56
combined	1.27
EOR	0.39

Table 8 CO_2 potential for utilisation

Current major uses of CO_2 are in the food and drink industries, refrigeration and in inerting applications. To expand the use of CO_2 in the chemical industry, emphasis should be placed on the options which have the greatest market potential; dimethylcarbonate (DMC) has been identified as having a market potential in excess of 2Mt/year; it holds promise in a number of applications and has the added environmental benefit of replacing phosgene, used as a chemical intermediate (1Mt/year). Detailed projections of cost and energy balance, indicate that it can be produced from CO_2 at a cost below current market costs but zero cost CO_2 would be an added market force. The manufacture of DMC involves energy usage such that the amount of CO_2 avoided is much lower than that used in manufacture; costs of CO_2 avoided are therefore high ($1000/t CO_2). It is not therefore a CO_2 sequestration option. Table 8 which summarises the global potential of the various options for CO_2 utilisation, shows that the contribution that chemical utilisation can make to mitigating greenhouse gas emissions is very small.

EOR sits on the border of being a CO_2 disposal option and a utilisation option; it has the advantage over all other disposal and utilisation options of being commercially proven, although at present projects are totally dependent on the economic value of the additional oil produced. The study carried out indicated that the potential for EOR is considerable (16Gt C, based on proven oil reserves of 136Gt). Based on current oil production of 3.15Gt/year, EOR could potentially use 1.4Gt CO_2/year (0.4Gt C/y) which is an order of magnitude higher than the estimated potential use in the chemical industry (Table 8). This potential optimistically assumes the availability of CO_2, extracted from flue gas, at any oil producing site in the world, but on the other hand is based only on proven reserves. 47% of the cost of EOR is associated with the cost of buying CO_2. With oil prices of $100/t ($13.6/bbl), CO_2 would have to be available for <$25/t CO_2 for even the most efficient EOR applications to be economic. However if oil prices doubled, CO_2 prices of $40/t could be tolerated. A subsidy, or zero cost CO_2, would make the process very viable. World Energy Council data (1993) predict a 36% increase in oil consumption by the year 2020, thereby increasing potential CO_2 use in EOR to 2Gt CO_2/y (0.5Gt C/y). The barrier preventing current extensive use of EOR is the economics of the process; current oil prices do not justify EOR unless CO_2 is available at a cost of <$20/t, to give a 10% return on investment. Zero cost CO_2 would transform this situation but transportation of CO_2 to oilfields remote from industrial countries, e.g. the Middle East, would pose problems and limit potential.

Reforestation and biomass based fuels are often seen as the 'natural' way to solve the CO_2 emission problem. In its favour is the scale on which it could be potentially achieved, the relative low costs involved and the prospect of immediate implementation. Globally there is a potential forest plantation area available of 288Mha capable of sequestering 0.94GT C/year, which is 16% of the 1990 CO_2 emissions to atmosphere and sufficient to offset the CO_2 emissions from 480GW(e) of coal-fired power plant. Costs were estimated to average $16/t C avoided in tropical areas and $76/t C in industrialised countries. Although more recent data has indicated that these relatively low costs can only be applied to the first tranches of offset forestry options. Cost predictions in this area are highly sensitive to the assumed land price and establishment costs. Producing a biomass fuel from short rotation cropping, represents a more efficient use of land and a more sustainable option but costs are higher ($30/t C in tropical countries and $120/t C in industrialised countries). The higher costs are partly the result of energy wastage during cropping but also the result of less efficient and more expensive power generation cycles. Power plant technologies involved would be FBC and IGCC, but development of CHP schemes would be an essential feature of a biomass fuel strategy due to the small scale power plant envisaged in any particular scheme. Long term forestation and production of biomass fuels are essentially complementary strategies; much of the land in the tropical countries is too isolated and hilly for short rotation cropping and the demand for heat and power is low. A combined global potential for offsetting/substituting CO_2 of 1.27Gt C/y has been calculated (Table 8); assumptions made in calculating this potential were quite conservative and other studies have calculated higher potential. The long term fate of forests planted purely for C-sequestration requires more detailed consideration but the potential for C-storage could be much greater if forest management was aimed at maximising C-storage rather than the commercial production of wood.

Photosynthesis by microalgae and cyanobacteria is accelerated by high concentrations of CO_2 and biochemical processes using these organisms have the potential to use flue gases directly without need for purification or separation; the energy penalty of CO_2 capture and compression and transportation of CO_2 is therefore avoided. As a CO_2 sequestration process it has the disadvantage of being climate dependent and only functioning in daylight hours; even with 2-shifting, only 54% of the power plant annual CO_2 production can be utilised. Costs are also calculated to be high; with the solar radiation levels experienced in Japan (mean of 155W/m^2) and with present day technology, carbon avoidance costs are calculated to be $350/tC. Under ideal radiation conditions (395W/m^2) and assuming maximum photosynthetic efficiency, costs could fall to $150/t C. Land requirements are however much lower than for forestation schemes and microalgae have the potential to use land unsuitable for other plants (desert conditions and saline water). Any future large scale use of these biochemical processes however will be dependent on the development of algal strains which can produce high value biochemical product and in particular strains which can yield liquid/gaseous hydrocarbon fuels. Algal strains such as *Botryococcus braunii* which can produce long chain hydrocarbons representing 86% of its dry weight and *Nannochloris sp.* which has a high lipid content from which triglycerides can be extracted for producing bio-diesel fuel are examples. Concepts such as genetic engineering offer the prospect of significant development in this area in the future.

CONCLUSIONS

The assessment studies undertaken by the IEA Greenhouse Gas R&D Programme have shown that the concept of applying CO_2 capture and disposal technologies to large stationary sources of CO_2 such as power plant stacks is a viable method of reducing CO_2 emissions from the combustion of fossil fuel. Applying the technology to power plant would increase present day electricity costs by at least 50% but the overall power generation costs still remain favourable compared to many renewable energy options. Most of the cost increase is associated with the capture technology and in particular with the parasitic energy demands of the process. Further R&D offers the potential of reducing these costs. Storage/disposal of CO_2 in the deep ocean, in aquifers and in depleted oil or gas reservoirs can be achieved at relatively low cost but further R&D effort is required to provide CO_2-specific data to establish the environmental credibility of each of the disposal options. The specific knowledge available on oil and gas wells and the experience of using CO_2 for enhanced oil recovery, suggests that depleted gas reservoirs would be the first disposal option for a practical demonstration. In dealing with the production of electricity from fossil fuels and its associated emission of greenhouse gases into the atmosphere, it is important to examine other possible emissions of greenhouse gases and usage of fossil fuel, external to the actual power generation process; for example that associated with the process of supplying the fossil fuel to the power plant. Three full fuel cycle studies were undertaken to examine on a common basis the cost and efficiency of CO_2 capture and disposal and to determine the impact of taking into account the full fuel cycle, from fuel extraction to disposal of the CO_2 product. Results from these studies are reported separately at this Conference.

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NORWEGIAN CARBON TAXES AND THEIR IMPLICATION FOR FOSSIL FUELS

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Abstract:
The Scandinavian countries, and in particular Norway and Sweden, have since 1990/91 taxed CO_2-emissions with carbon tax of about US $/50 per ton of CO_2. One may therefore say that these countries have placed themselves in a role as "carbon tax laboratories". These very high CO_2-taxes have been in place for about four years and the first lessons from this experience are reported. In general it would seem as if the taxation mechanism is less efficient than economists have expected. The CO_2-emissions are increasing in both Norway and Sweden and the stabilization goal to the year 2000 will not be achieved in spite of the high taxation.
The fossil fuel industry will have to learn to live with the climate change question which is inherently hostile to fossil fuels. It is argued that a more informed and active participation by the fossil fuel industry is needed in the climate change discussion. In addition the image of fossil fuels will benefit from showing real and potential improvement in the area of greenhouse gas emissions in the whole energy chain from production to combustion. The R&D effort being done into CO_2-capture and -disposal is creating such an option for the future. It is argued that the image of the entire fossil fuel industry will benefit from the creation of a "CO_2-free" option or vision for oil, gas and coal. A number of examples are shown where today (or in the near future) actual CO_2-disposal in underground formations are taking place.

THE POLICY AND PSYCHOLOGY OF CLIMATE CHANGE

Nearly all of those present at this conference would probably like to see the climate change question turn out to be a scientific mistake and fade from the agenda. The fossil fuel industry is without doubt *the* enfant terrible in the climate change discussion since approximately 80% of the world's existing energy demand is produced from coal, oil and natural gas.
Some may think that the worst is over. That the 1992 Earth Summit (UNCED) in Rio marked the peak of attention with respect to climate change. In my opinion this is wishful thinking and not how things will turn out. We will see renewed attention this year following the Conference of Parties (COP-1) in Berlin (March) and also following the 2nd main report from the UN International Panel on Climate Change (IPCC) due late this year. The fossil fuel industry can expect additional challenges as national governments roll out their agenda 21 implementation plans. Pressure will also be applied from sections of society who wish to change things quickly. There is sufficient evidence to justify concern about the increase in greenhouse gases in the atmosphere although large uncertainties exist over the actual consequences. The uncertainties-and they are both numerous-revolve around both the climate science and about the impacts on societies of a changed climate. These uncertainties are the subject of much research and the

industry is contributing to this effort. For example, several companies support work currently carried out by the Massachusetts Institute of Technology's Joint Programme on the Science and Policy of Global Change. The framework of this programme integrates all key elements-scientific, economic, technological and societal implications. A smaller, but very well managed programme in the same area, is carried out by the Carnegi Mellon University in Pittsburgh. The work of programmes like these will give us much needed policy related information. In the meantime, however, the uncertainties are no excuse for inactivity. The fossil fuel industry would benefit from supporting the approach proclaimed at Rio-namely the use of cost effective measures which have merit in their own right. Such measures includes fuel switching, improvements in the efficiency of primary fuel conversion and also improved end use efficiency.

It is well known that people do not behave "rational" when dealing with highly uncertain matters that are probabilistic in character. Their willingness to gamble against very low odds is one example. Another characteristic example is our (or at least some peoples) willingness to take high voluntary risks like in climbing difficult mountains while at the same time they are not prepared to take very low involuntary risks like having a nuclear power station built in their neighbourhood.

Psychology plays a substantial part also in the climate change discussion. In the following I will point to only two of those psychological effects. The first is the tendency in very uncertain situations to "decide on a solution" and stay with it whatever happens. This is often called *anchoring*. One of those anchoring effects in climate change is, to my belief, the IPCC prediction that a doubling of the CO_2-content in the atmosphere compared with preindustrial times will lead to a global temperature increase of between 1,5 and 4,5°C with a most probable increase of about 2,5°C. When going back into the literature we find that the same estimate has been more or less an official truth for at least two decades and is based mainly on two assumptions. The first and rather well established assumption is that a doubling of the atmospheric CO_2 content will increase the global temperature *directly* by about 1,2°C. Much less consensus can be found regarding the *indirect* temperature effects or feedback effects that will follow in a $2xCO_2$ world which is 1,2°C warmer. The by far most important feedback effect is more and different clouds. For clouds we do not even know whether the feedback is positive or negative, something that brings me to question the IPCC anchoring to a most probable increase of about 2,5°C. In my mind I am presently anchored more to the +1,2°C increase as illustrated in figure 1.

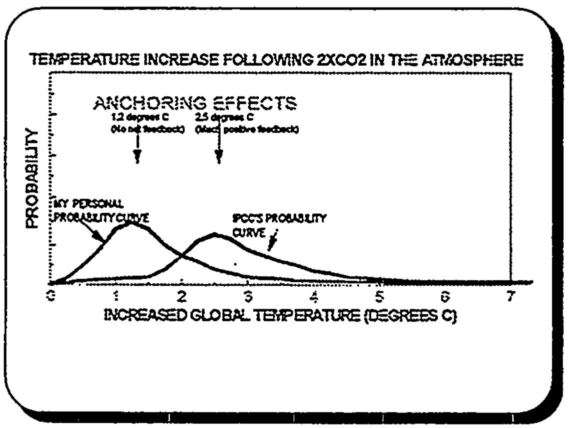

Figure 1: Assumed (not real) probability curves illustrating the global temperature rise following a doubling of the atmospheric content of carbon dioxide. The "IPCC-curve", as interpreted by the author, illustrates the IPCC attitude that the temperature increase will be between 1,5 and 4,5°C and with greatest probability anchored around 2,5°C. There is still, however, some smaller probabilities that the temperature increase will be less or higher than the 1,5-4,5°C span. The curve marked "My personal probability curve" is anchored around (have the highest probability) about 1,2°C, but allows for (with low probability) that the temperature may rise to 3 or 4 or even 5 °C.

One view, as illustrated by the authors personal curve in figure 1, would tend to be that there will probably be a change in the climate, but it will most likely be within the natural variability of an interglacial period as we have been in for the last 10 000 years. Another and opposing view, illustrated by the dotted oval in the lower right corner of figure 2, is that the consequences of a large change in climate is so drastic that we cannot afford to take any chances.

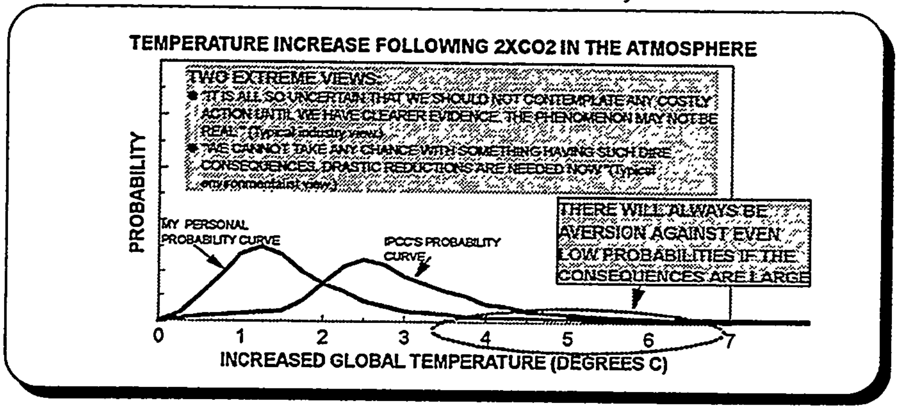

Figure 2 Illustration of the position of two extreme views on climate change. The extreme view that denies the possibility of any climate change following $2xCO_2$ is not shown.

What lessons can we draw from this exercise in psychology? One lesson seems to be that we cannot expect that one day we will all agree on the likelihood or seriousness of climate change. There will always be opposing attitudes towards risk taking that almost no amount of increased scientific understanding can mitigate. Today there seems to be too many people at both extremes and too few in between.

Another lesson, at least to this author, is that we should always be on the lookout for psychological anchoring both in the form of stifled thought patterns and in the form of deliberate manipulative attempts.

SCANDINAVIA AS A CARBON TAX LABORATORY

Carbon taxes have been seriously considered, though not adopted, as a basis for climate policy in the European Union and in the United States. Northern Europe, and Scandinavia in particular, has for a number of years been active in pushing the anthropogenic climate change discussion. In fact it was the Swedish scientist Svante Arrhenius (1896) who made the first calculation of the climate effect of carbon dioxide, estimating that a doubling of CO_2 would raise global mean temperature by 4-6°C--about the upper end of the range of the current IPCC estimate.Bert Bolin, also from Sweden, has been the leader of the IPCC work from the outset. The Norwegian premier Gro Harlem Brundtland chaired the UN World Commission on Environment and Development which in 1987 published the "Brundtland Report" titled "Our Common Future". This report formed the basis for IPCC and also for the 1992 Rio Earth Summit.

If we to this adds the exceptionally strong positions of economists in governmental positions in all the Scandinavian countries, we may glimpse the reason for why Norway, Sweden and Denmark (and to a lesser extent Finland) are the only countries in the world to have adopted carbon taxes on a substantial scale. After four years of high carbon taxes, we may call Scandinavia the carbon tax laboratory of the world. Figure 3 illustrates the national greenhouse gas goals and carbon tax levels of the Scandinavian countries, the European Union and the United States.

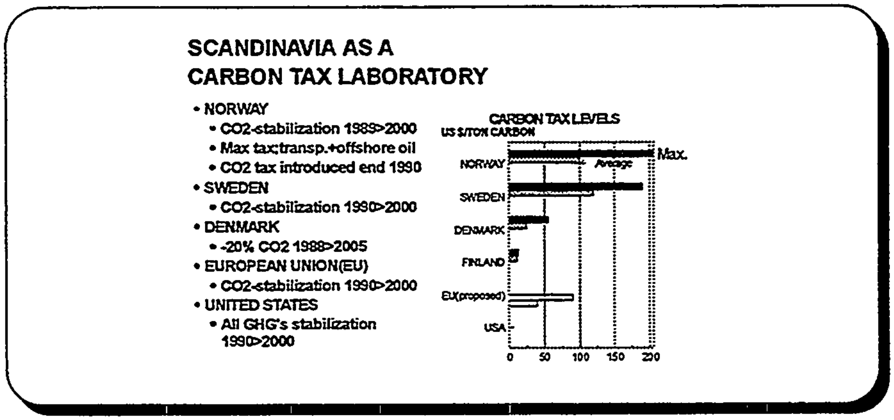

Figure 3 Greenhouse gas goals and carbon taxes in Scandinavia, EU and USA. The maximum carbon tax in Norway, being applied to automotive fuels and the offshore oil and gas industry, is about 52 US$/tCO2 or approximately 200 $/ton of carbon.

The structure and area of application of these carbon taxes varies between the Scandinavian countries. In general the areas that are most systematically taxed are automotive fuels, fuel oil used for heating purposes and other sectors of society where those being taxed do not have much choice. The energy intensive export industries in Sweden and Norway are to a large extent shaded from the worst effects of carbon taxes since they rely on abundant hydroelectricity (Norway and Sweden) and relatively cheap nuclear power (Sweden). The exception to this is the Norwegian offshore oil and gas industry which has been subjected to full carbon taxation on emission of CO_2 from gas turbines (83% of the CO_2), flaring (10% of the CO_2) and a few other sources since January 1st, 1991. For a new offshore oil platform with minimal flaring and high technical process efficiency the carbon tax can be about 20% of the total yearly operating expenses. The offshore oil and gas industry pays about 42% of the total Norwegian carbon taxes, a share that is on the increase due to a doubling in the natural gas exports. In Norway the carbon tax today covers about 60% of the total CO_2-emissions and (since other greenhouse gases are not taxed) only about 45% of the total greenhouse gas emissions. In the four year period since 1991 the CO_2-emissions in Norway have increased slightly and is due to increase more in the coming years: This increase is mostly due to compression energy required for the before mentioned doubling of the natural gas exports.

DO CARBON TAXES WORK AS INTENDED?

Carbon taxes are one of several types of policies for reduction of greenhouse gases.

Other possible policies are economic instruments other than taxes (like tradable quotas), direct regulations like minimum efficiency standards for cars and informative measures which informs about possibilities and aims at voluntary change of behaviour.

In general it is difficult, at least in Europe, to find economists that do not favour carbon taxes as *the* measures to reduce CO_2-emissions. A recent report from EPRI seems to draw the same conclusions (EPRI, 1994). The EPRI-study refers, however, to another recent study by the Energy Modelling Forum (EMF) at the Stanford University who had brought a number of economic modelers together to analyse carbon taxes. They differed by a factor of 5 in their conclusions about how large a tax would be required to achieve specific emission goals.
In their World Energy Outlook report, 1994 Edition, OECD treats carbon taxes with some caution. One of their major conclusions is that the application of a modest carbon tax seems to prove rather ineffective as a means of reducing emissions in the OECD. The OECD work suggests that reducing emissions from current levels would require the imposition of implausibly high taxes.
It seems to be a safe conclusion that we are not dealing with more exact science in the economic area than in the other areas of climate change.

In general the Scandinavian countries would seem to have been more keen on implementing carbon taxes than in finding out whether they work as intended. If Scandinavia is a "carbon tax laboratory" as postulated earlier, good laboratory practice would have been to watch the progress of the experiment closely. The only analytical effort in this direction so far seems to be a recent work done by ECON, Centre for Economic Analysis for the Norwegian Oil Industry Association(ECON, 1994). The results from this detailed study of the Norwegian offshore oil and natural gas industry are briefly reported in the following;

- In the 4 year period of carbon taxation there has been a reduction of about 8% CO_2-emissions for the production of one unit of oil or natural gas (but an increase in the total emissions due to an increasing production level). When the measures following the carbon tax are fully implemented it is expected that the reduction will increase to about 9%
- About 4/5 of the reduction is due to measures which are economically viable even without carbon taxes. When measures are fully implemented about 2/3 will be economically viable even without tax
- There is evidence that the CO_2-tax has in general increased the attention from management and the entire organisation to energy use and CO_2-emissions. This has brought forward ideas about ways of saving energy that in the years past have gone unnoticed due to the low cost of energy at the source. It is likely, however, that most of the measures to save energy would have been implemented in the next 1-5 years even without the CO_2-tax due the present low oil-price drive to reduce costs and waste in the Norwegian offshore industry
- From the detailed studies it seems likely that even for future oil and gas installations the CO_2-emissions will be reduced by only a few %-points in a tax situation compared with a no-tax situation
- Due to the higher energy consumption (and CO_2-emission) for natural gas production and transport compared with oil, the tax may make the development of distant gas fields marginal or uneconomical. Conversion to LNG is especially hampered by a carbon tax regime due to the energy used for liquefaction

- The economic sizing of pipelines for a given throughput will likewise increase to lower energy use and gas turbine-CO_2 for compression. In this case the amount of pipeline steel (and CO_2 for making steel) will increase. This illustrates the point that we may easily end up "leaking" CO_2 across borders in the form of energy intensive products

Let us ask the following questions about carbon taxes;

- *Do carbon taxes reduce CO_2-emissions?* The answer to this is of course that carbon taxes does have an effect. The effect is, however, small for low carbon taxes and also small even for high taxes in those sectors where the alternative is to reduce activities that is seen as important and where there is little scope for alternative solutions. For sectors where there are alternatives (like fuel switching), the carbon taxes will probably be quite efficient in achieving reduced emissions down to a level given by the carbon content of the fuel per unit of energy.
- *Are carbon taxes a cost effective way of reducing CO_2-emissions?* This question cannot really be answered based on the four years of experience in the "Scandinavian carbon tax laboratory". One potentially important lesson seems to be, however, that some reduction may be achieved profitably even without taxation given a sufficient management attention to the problem. The question of using energy efficiently are often below the attention level of both the management and the organisation
- *What are the carbon tax revenues used for?* The answer to this is that all the countries in question collect the carbon tax as an ordinary tax to be used as all other taxes. No earmarking for special purposes or recirculation are done.
- *Have the Scandinavian experience given rise to ideas about alternatives or modification to the present system of carbon taxation?* The ECON-study points out that the present CO_2-tax presents the industry with a double cost since the investments and operating expenses connected to the emission reducing measures comes in addition to the tax. This might be partly remedied a)by taxing only the marginal CO_2-emissions and not the total, b)by introducing tradable quotas for CO_2 and c) by recirculating the entire carbon tax or part of it to the tax paying company provided they can prove that effective measures will be carried out

HOW SHOULD THE FOSSIL FUEL INDUSTRY APPROACH THE CLIMATE QUESTION?

First of all there is no reason to believe that the damage potential of anthropogenic climate change will be scientifically established within the next decade. This does not mean that we can be completely relaxed about the topic nor that we need to be constantly on the alert. More likely there will be occasional years of high awareness following periods of unusual weather or some scientific or political event. Looking further into the future the level of attention will be decided by actual experiences of climate change providing the changes are sufficiently large to be sorted out from natural variability.

One thing we can be sure of, however, is that fossil fuels of all sorts will continue to be the villains of anthropogenic climate change in the foreseeable future.

So, what do we do and not do while waiting to see if there will be a changed climate?

As a start we should stop denying that there is a possibility of climate change as a result of CO_2-emissions. Firstly because it is in all probability true (but to some unknown degree), but secondly because fossil fuels are in the same situation as tobacco manufacturers saying that smoking is not bad for your health.

A better strategic path, already taken by a number of fossil fuel companies, is to

- take active part in the climate change discussion on various arenas and in various ways. Many governments and also the IPCC have come to realise that there will be no progress without the understanding and participation of industry. Our most valuable insight to the process is our knowledge of energy systems. What is possible and what will it cost?
- to show how fossil fuels can improve their climate performance

Figure 4 seeks to illustrate how the fossil fuel industry can contribute to the last of the above points;

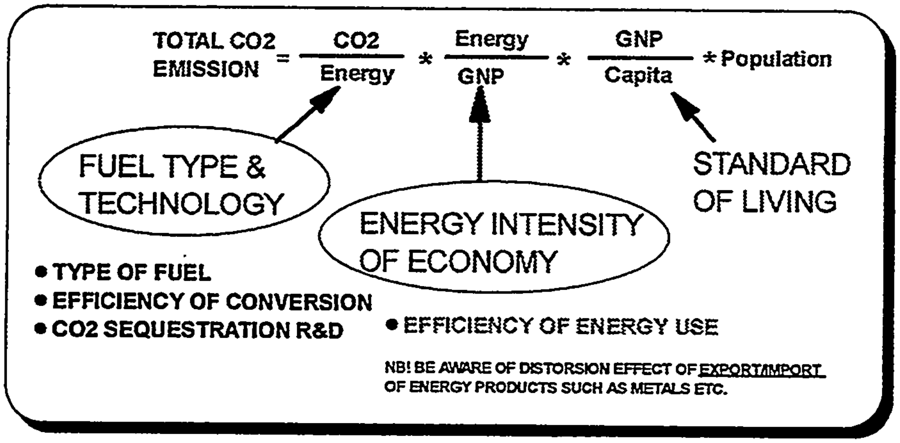

Figure 4 How the fossil fuel industry can contribute by improving their climate performance. The equation shows how the CO_2-emissions from a country (or globally) are dependent on the carbon dioxide emissions per unit of energy used in that country multiplied by energy consumption per unit of gross national product multiplied by gross national product per capita and finally multiplied by the number of people living in that country.

Starting from the right side of the equation, the fossil fuel industry can do very little with regard to the size of the population (except for the personal contribution) or the standard of living in a country. More, and maybe quite a lot more, can be done by the industry, however, in the area of efficiency of energy end use.

Obviously there is possibilities for fuel substitution, but tactfully I will dwell no further on this topic at a coal conference.

The efficiency of conversion from primary fossil fuels to more suitable energy carriers are very much a topic these days. In my opinion the competition between coal fired power stations and natural gas fired combined cycle power stations has been quite valuable and has given a push to both types of technologies that are beneficial also for the environment and the climate.

The anthropogenic climate change question is basically a long term problem area. Long term investments in the right type of R&D for the future generations of capital stock will most likely be more valuable than a similar size effort on today's conversion and end use equipment. The type of R&D we should concern ourselves with is the same as shown in figure 4;

- Look for both incremental improvements and breakthroughs in end use efficiency. Here the focus should be not only on the industrialised countries, but also on technologies for less developed countries.
- R&D into increased conversion efficiency for primary fossil fuels. A lot is going on in this area today, but we might also concern ourselves more about industrial cogeneration as a way of increasing the overall conversion efficiency
- R&D into CO_2 capture and disposal as an option in the long term.

R&D into CO_2 capture and disposal may turn out to be the fossil fuel equivalent to fusion power; i.e. along term solution for CO_2-free fossil fuels.

The necessary R&D is low cost. Through organisations like the IEA Greenhouse Gas R&D Programme there is already a reasonably good overview of technologies and costs connected with this future option.

By presenting to the world a carbon dioxide free solution, the fossil fuel industry can, in a sense, escape the role as a climate villain by making CO_2-emissions a question of cost rather than a choice between good and evil.

A CO_2-free option will also be seen as a backstop technology against which some of the wilder carbon tax proposals can be shown to be meaningless.

The possibility of capture and disposal of carbon dioxide on a large scale sounds like science fiction to most people today. The capture technologies will be touched upon by other papers, but I will seek to show that at least on of the disposal options, namely the disposal in deep geological traps, are well within the realm of reality.

Figure 5 seeks to illustrate how the twin energy carriers electricity and hydrogen, produced in processes with CO_2 capture and disposal underground or in the deep ocean (from coal, oil or natural gas) can form a coherent option for fossil fuels in a climate driven world. Figure 6 shows that USA and Canada have altogether about 60 projects where carbon dioxide is pumped underground to enhance oil recovery. Figure 7 shows the location of the Statoil operated gas field Sleipner West where 1 mill tons/yr of CO_2 recovered from carbon dioxide rich natural gas from 1996 on will be injected into a deep aquifer for climate and taxation reasons. Figure 8 gives the location of the Natuna gas field in the South China sea. This field contains huge amounts of a mixture of natural gas (30%) and CO_2 (70%). The field is under study for development and is planned with a huge scheme for injection of CO2 back into the ground.

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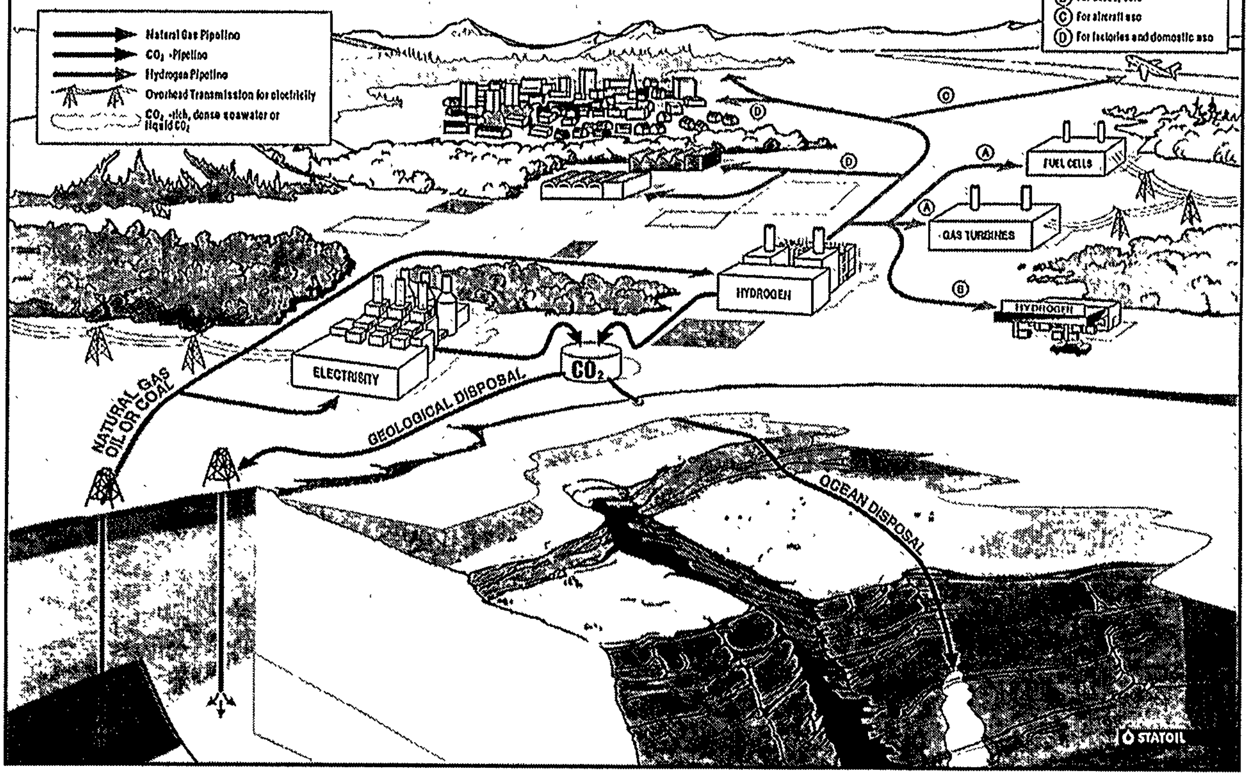
ECON, 1994: The effect of the CO2-taxation on the oil and natural gas industry in Norway (in Norwegian), ECON, Center for Economic Analysis, Oslo, Norway, October 1994

EPRI, 1994 : Economic Impacts of Carbon Taxes. EPRI TR-104430-V1, Final Report, November 1994

Figure 5

ELECTRICITY AND HYDROGEN FROM NATURAL GAS (OR OIL, COAL) WITH CO_2 -REMOVAL



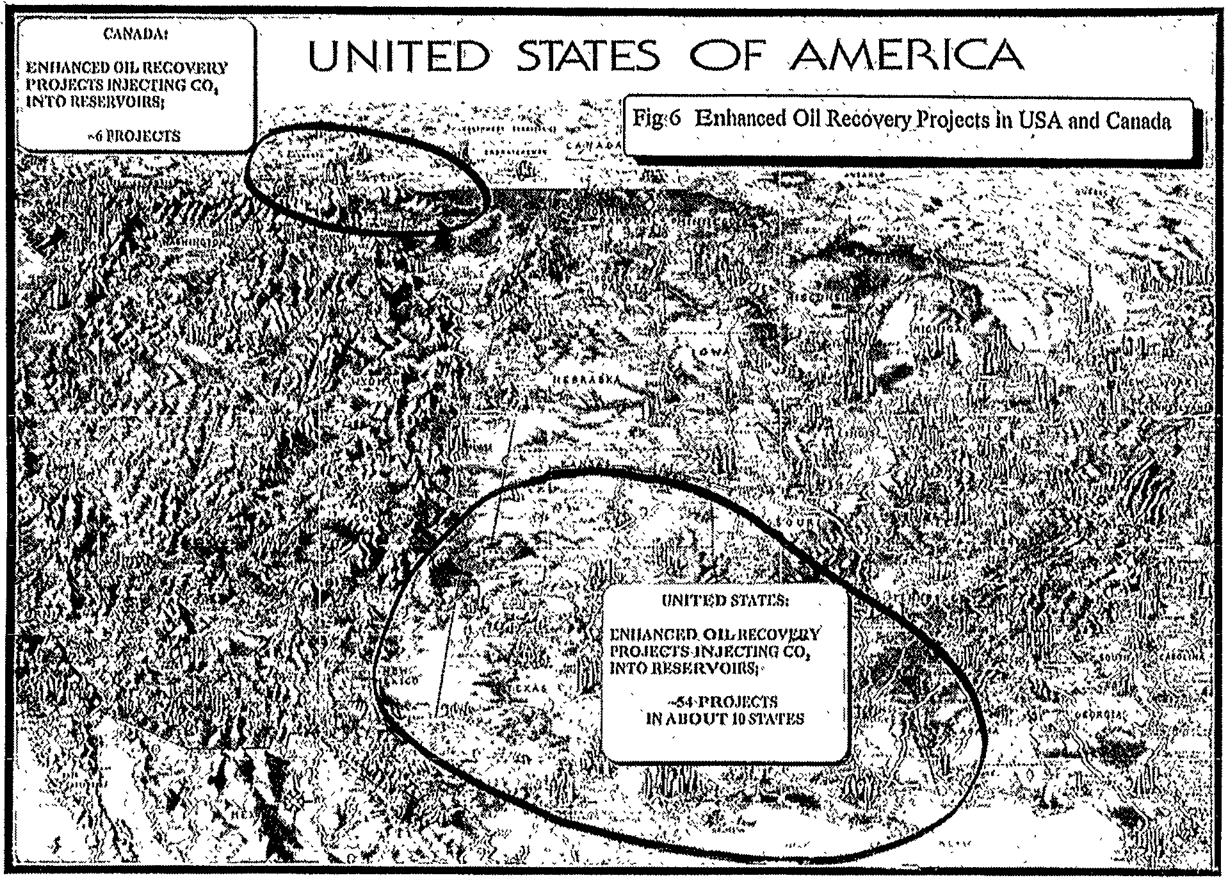


Fig 6 Enhanced Oil Recovery Projects in USA and Canada

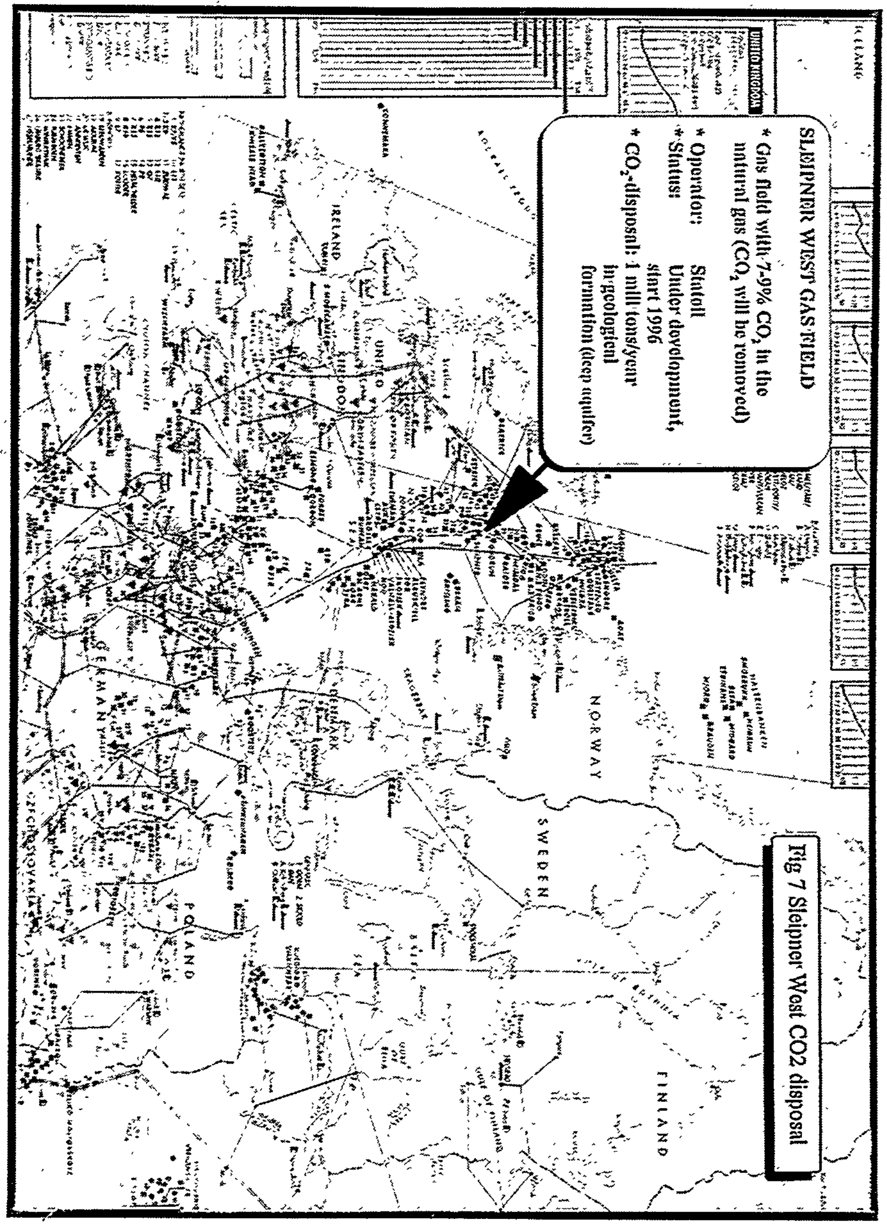


Fig 7 Sleipner West CO2 disposal

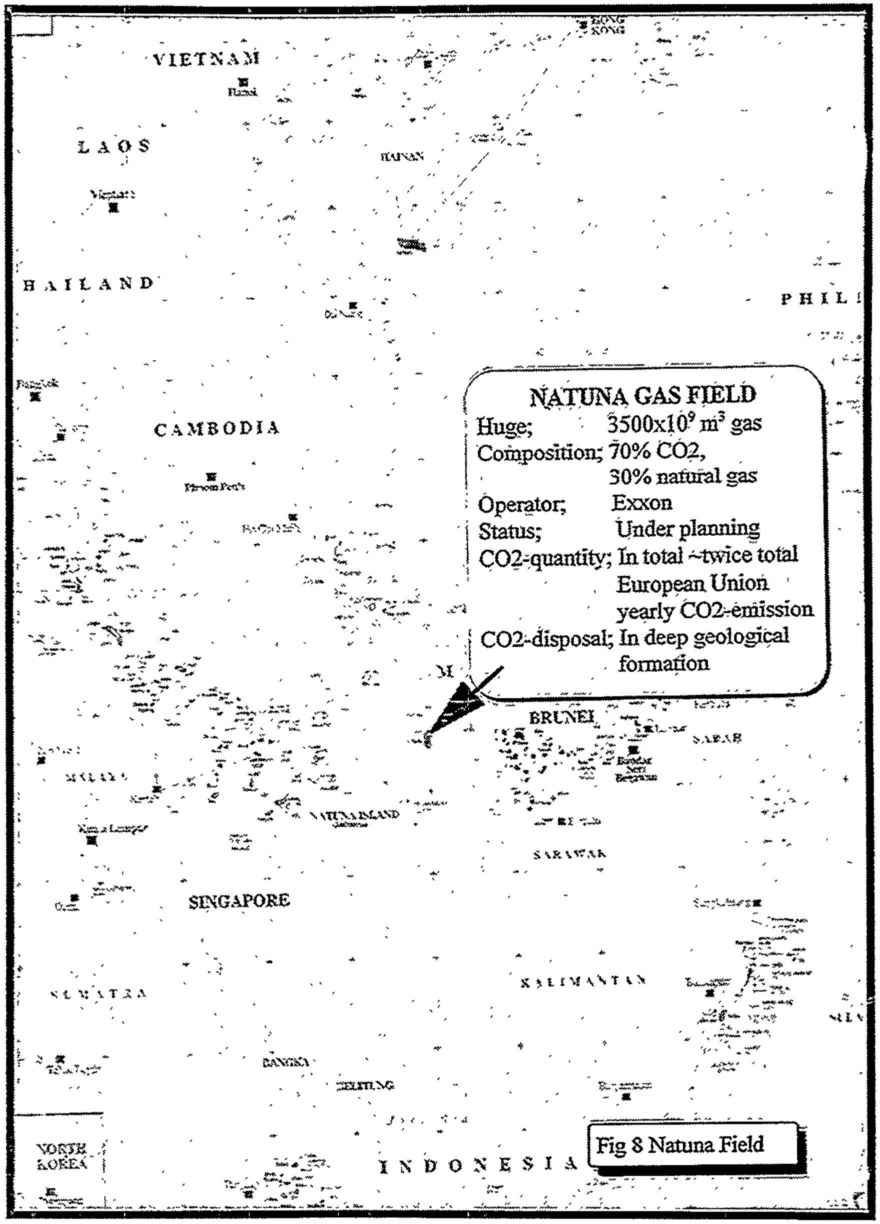


Fig 8 Natuna Field

THE FULL FUEL CYCLE OF CO_2 CAPTURE AND DISPOSAL

CAPTURE AND DISPOSAL TECHNOLOGY

LAWRENCE SAROFF

U.S.DOE, Office of Fossil Energy
(For the IEA Greenhouse Gas R&D Program as a Visiting Scientist)

ABSTRACT

The overall objective of this study was to develop a methodology for the evaluation of the energy usage and cost both private and societal (external cost) for full fuel cycles. It was envisioned that other organizations could employ the methodology with minor alterations for a consistent means of evaluating full fuel cycles. The methodology has been applied to three fossil fuel electric generation processes each producing 500 MWe (net). These are: a Natural Gas Combined Cycle (NGCC) power plant burning natural gas with direct CO_2 capture and disposal; an Integrated Gasification Combined Cycle (IGCC) power plant burning coal with direct CO_2 capture and disposal; and a Pulverized Fuel (PC) power plant burning coal with a managed forest indirectly sequestering CO_2.

The primary aim is to provide decision makers with information from which to derive policy. Thus, the evaluation reports total energy used, private costs to build the facility, emissions and burdens, and the valuation (externalities) of the impacts of the burdens. The energy usage, private costs including capture and disposal, and emissions are reported in this paper. The valuations and analysis of the impact of the plant on the environment are reported in the companion paper.

The loss in efficiency (LHV) considering the full fuel cycle as opposed to the thermal efficiency of the power plant is; 0.8, 2.4, and 4.6 for the NGCC, IGCC, and PC+controls, respectively. Electricity cost, c/kWh, including capital, operating and fuel, at a 10% discount rate, ranges from 5.6 to 7.08 for NGCC and 7.24 to 8.61 for IGCC. The range is dependent on the mode of disposal, primarily due to the long pipeline to reach a site for the proper disposal in the ocean. For the PC+ controls there is a considerable range from 7.66 to over 16 c/kWh dependent on the size and cost of the managed forest.

INTRODUCTION

Due to the near consensus within the scientific community that the continuing rate of increase of greenhouse gas (GHG) emissions will result in climate change, the International Energy Agency (IEA) initiated an implementing agreement for studying the technical means and the associated economics of mitigating the emissions of GHG's, in anticipation of the perceived climate change. Although the effects are not yet fully understood, a number of countries have agreed to limit the emissions of GHG's, and in particular, to reduce CO_2 emissions. Attention has been focused on large stationary sources, as electric power production, even though most emissions of CO_2 are transportation related.

The IEA Greenhouse Gas R&D Program initiated technical studies to evaluate options for capture and disposal of CO_2 from fossil fuel power generation facilities. Subsequently, a study was to be undertaken to evaluate the energy usage, costs, and environmental burdens and impacts from 'cradle-to-grave' i.e. full fuel cycle, for a number of generating options. This study included the development and testing of a methodology for the evaluation of the private and societal (external) costs and impacts of selected fossil fuel fired power generation routes when combined with capture and disposal of CO_2.

Until recently, apart from energy policy considerations, most power generation technologies were selected primarily on the basis of the least private cost (i.e. capital, operating and maintenance costs). This selection process has been modified by internalizing certain costs and/or benefits that previously were not reflected in the private costs (i.e. the 'externalities') e.g., by using a selection of regulations to limit emissions. Typically, this internalization of part of the externalities covers areas such as; controls on the emissions of sulphur and nitrogen oxides, disposal of solid wastes, health and safety regulations etc. Governments have used externalities as an aid in energy policy decision making. This process has recently been complicated by the need to consider the potential climate changes due to greenhouse gas emissions.

Decision makers require information which reflects all the costs and impacts of a technology being evaluated. A methodology to provide a consistent standard for the comparison of private and external costs of power generation options is required, and was used in the 'Full Fuel Cycle' analysis presented in this and the companion paper. The methodology can be refined and applied to the evaluation of alternative processing routes and energy systems.

The developed methodology has been applied to three electric power generation technologies to evaluate the full fuel cycle costs, energy usage and emission:

- A Natural Gas Combined Cycle (NGCC) power plant burning natural gas to produce 500 Mwe (net). CO_2 is captured and disposed of directly.

- An Integrated Gasification Combined Cycle (IGCC) power plant burning imported coal to produce 500 MWe (net). CO_2 is captured and disposed of directly.

- A Pulverized Fuel (PC) power plant burning imported coal to produce 500 MWe (net). A managed forest is used to indirectly sequester the CO_2.

The consistent methodology was developed for the analysis of the above cycles and was a key component of the study. For each of the fossil fuel power generation routes:

- Material and energy balances and an estimate of the private costs of power generation for the full 'cradle-to-grave' carbon cycle were made. These assessments include; drilling/mining, purification/benefaction or other pretreatment, piping/shipping, power generation and distribution, and CO_2 capture and disposal.

- Assessments of the energy requirement and environmental impacts of construction and manufacture of the required plant and equipment were included.

- An inventory of emissions and their environmental impact was established.

- Overall costs and impacts were produced based on the power production costs established in the first stages of the study and externalities costs based on the impacts established in the second stage of the study.

The full fuel cycle analysis includes all stages of the cycle from extraction of the fuel, its transportation, and use in the power plant, to waste disposal and electricity transmission as far as the national grid. The term full fuel cycle cost encompasses both the private costs, namely the costs associated with construction, subsequent operation of the fuel cycle and the purchase of fuel, and those external costs, arising from the impact of the fuel cycle on the natural and human environment. The power plants include high level abatement technologies for nitrogen and sulphur compounds and carbon dioxide which essentially means that a larger proportion of the environmental costs have been internalized compared to most present day plants. Non-environmental costs have been specifically excluded from this study.

METHODOLOGY

General Principles

The three guiding principles for studies of this nature are:

- Transparency

- Consistency
- Comprehensiveness

Transparency allows detailed critical review of the methods, assumptions, data used, results, uncertainties and conclusions. This is particularly important for the evaluation of external costs. Where due to the present limitations both in developed methodologies and the availability of data, it is not currently possible to evaluate all external costs. Transparency allows a reviewer to ascertain exactly which impacts have been assessed and the extent of the assessment.

A consistent approach allows valid comparisons between different types of impacts, technologies and fuel cycles. In practice, limitations on the availability of data make it difficult to achieve complete consistency. However, the basis for making any given comparison should be apparent if the requirement for transparency is followed throughout.

The requirement for a comprehensive approach is to ensure that any comparison made between technologies is sound. Particular attention must be paid to the range of externalities considered and the spatial and temporal range of assessment.

Definition of the Scenario

In addition to the definition of the fuel cycles and technologies to be considered it is also necessary to define the reference scenario against which the assessment is to be undertaken. The scenario describes the legislative, economic, environmental and social parameters over the period covering the lifetime of the reference plants. The main problem in the definition clearly concerns the impacts of greenhouse gases which persist in the atmosphere for hundreds of years. In theory a time-frame of perhaps 500 years should be considered. However, the projection of parameters such as population and economic growth beyond 100 years is unrealistic and so analyses tend to be restricted to the year 2100.

The scenario primarily comes into play in determining the impacts of the burdens on the environment projected by the power plant. The chosen scenario is the International Program for Climate Change (IPCC92d). This scenario presupposes a heightened environmental awareness where capture and disposal of CO_2 would be deemed necessary in the design of power plants.

The plant location has been chosen to be in the northeast portion of Holland near the Eems river. Presently there are power production facilities operating, therefore environmental impacts for construction and operation of power production facilities are available.

Evaluation of Private Costs

Assessment of the private costs of the full fuel cycle depends on the definition of the system boundaries. In this work two aspects of the full fuel cycle are considered, the power plant and the other supporting activities. The power plant is defined as those activities which take place at the power plant site while the other supporting activities generally take place elsewhere. The evaluation of the private costs is undertaken by carrying out a conventional economic analysis of the power plant and then adding the costs associated with the other supporting activities.

The five basic steps in the conventional economic analysis of a power plant are:

- Definition of processes
- Accurate determination of mass and energy balances
- Plant and equipment sizing

- Estimation of capital and operating costs
- Economic analysis resulting in determination of the private costs.

Burdens Inventory

The burdens inventory forms the important interface between the engineering design and costing work and the evaluation of environmental impacts and external costs associated with the fuel cycle. The inventory is composed of the emissions inventory which compiles data for all known emissions from the different stages in the fuel cycle together with quantitative information describing other burdens, for example, accident rates or noise levels. The burdens inventory data is the source of input data for the evaluation of the environmental impacts. In reality a number of the burdens will prove to be very small and their resultant impacts negligible. However, it is important to consider all possible burdens and then assess their relative importance as part of the impact assessment.

Description of Cases

Natural Gas Combined Cycle

Figure 1 is a schematic of the Full Fuel Cycle including the supply of natural gas to the NGCC power station with CO_2 removal by amine scrubbing and subsequent CO_2 disposal. Natural gas from the Ekofisk field in the southern part of Norway is piped to the Eemscentrale power plant site at Eems.

A flowsheet of the NGCC power plant is shown in Figure 2. The process employs an advanced gas turbine with a higher turbine inlet temperature than presently available, but which is expected to be on the market by 2005. The exhaust gas from the turbine passes through the HRSG where heat is extracted to run the three stage steam turbine system.

The exhaust from the HRSG is used to reheat the amine-scrubbed off-gas before that gas is released to the atmosphere through the stack. The cooled exhaust gas is then washed to remove the water soluble oxides of sulphur and nitrogen which are detrimental to the amine solvent.

CO is removed from the HRSG exhaust gas by a regenerable amine solvent. The removal is limited to 85% because of the low partial pressure of CO_2. The steam required for regeneration is extracted from the steam cycle. The CO_2 product is recovered from the regeneration tower at atmospheric pressure, liquefied in a cold box and then pumped to the disposal pressure of 100 bar. This process requires a minimum energy usage to produce the dense phase CO_2 for disposal.

Liquid CO_2 at 100 bar and 10°C is conveyed from the power plant site at Eemshaven to a depleted local natural gas well by a 75 km long pipeline. The Ameland gas field is a suitable depository because the total capacity of that well in underground volume is larger than that required to accommodate the volume of CO_2 which would be removed from the NGCC power plant over the 25 years of project life. The pipeline is sized to ensure that the operating pressure of the pipeline does not drop below the local vapor pressure of CO_2, ensuring single phase flow. A 250 mm diameter pipeline gives an adequate margin to allow for the expected range of temperature and elevation variations along the pipe.

An alternate deep ocean disposal site has also been considered. This site is described in the IGCC discussion.

Integrated Gasification Combined Cycle

Figure 3 is a schematic of the Full Fuel Cycle including the supply of coal to the IGCC power station with integrated CO_2 removal and subsequent CO_2 disposal. Open cut coal from a mine in New South Wales, Australia is transported to Eems. The mining operation and any coal preparation at the mine site, is all considered as a single operation. Coal is transported by train to the coast and then shipped to the power plant at Eems. As a sensitivity study an alternate coal from the Appalachian region of the USA was considered.

A flowsheet of the IGCC power plant is shown in Figure 4. In this process scheme the removal of CO_2 is integrated with fuel gas production. The process steps are: production of fuel gas (CO & hydrogen) by gasification of coal; catalytic shift conversion of CO to CO_2 for increased hydrogen production; separation of CO_2 from hydrogen; generation of electrical power from the combustion of hydrogen in a gas turbine combined cycle; and liquefaction and pumping of the recovered CO_2 to the disposal site.

Gasification converts coal into a gas suitable for the subsequent processing, in particular CO_2 removal. A wet-feed entrained-phase oxygen-blown gasification process is selected for this purpose. Oxygen-blown gasification was selected to avoid the dilution of the fuel gas with nitrogen from air which would adversely affect the partial pressure of CO_2 in the CO_2 removal process. An entrained-phase gasification process was selected because the high operating temperature maximizes the yield of CO, which can be converted to CO_2, for optimal CO_2 removal. A comparison of the effectiveness of wet feed and dry-feed gasification processes when CO_2 removal is required, shows that a wet-feed process results in a higher overall thermal efficiency than dry feed. If CO_2 is not removed dry feed gasification would result in a higher efficiency.

Catalytic shift converts CO to CO_2. A high degree of conversion is required because any unconverted CO will not be removed and will therefore be burned in the gas turbine and the corresponding carbon will report as a CO_2 emission. The conversion of CO to CO_2 is favored at low temperature so the final stage has a low exit temperature of 250°C which is the minimum temperature at which an adequate rate of reaction can be obtained. In this way the maximum conversion is obtained.

Acid gas removal is employed to separate the CO_2 and leave a hydrogen rich fuel gas suitable for burning in a gas turbine with minimal CO_2 emissions. A glycol/ether physical solvent acid gas removal process was selected for the removal of CO_2 and H_2S. The H_2S-rich stream is sent to a Claus process to recover elemental sulphur.

The hydrogen-fueled gas turbine process area was the same as advanced gas turbine as in the NGCC case. An integrated steam cycle design is adopted to make best use of the heat recovered from the gasifier, shift converter and HRSG for the generation of power and the provision of steam for shift conversion.

The CO_2 product is recovered from the glycol/ether acid gas removal process, liquefied in a cold box, and then pumped to produce dense phase CO_2 for disposal. In this case the nominated disposal method is discharge into the deep ocean. A disposal site 1500 m deep in the Bay of Biscay, 1185 km from the power plant site was selected as it is the closest deep water location. In view of the long disposal route it is doubtful that the plant would be constructed at a locale this far from the disposal. Therefore, to minimize the cost such CO_2 disposal the pipeline would have to be as large as practicable in order to benefit from economy of scale. Accordingly a pipeline of 1 meter diameter was specified. A pipeline of that diameter would have the capacity to transmit the CO_2 from 6 power stations. A consequence of these considerations is that the liquid CO_2 delivery pressure from the power plant is 168 bar in order to avoid the need for additional pumping costs. An alternative disposal in a disused gas well was investigated.

Pulverized Coal Fired Supercritical Steam Power Plant with Flue Gas Desulphurisation and Denitrifigation (PC+FGD/SCR)

Figure 5 is a schematic of the Full Fuel Cycle including the supply of coal to the PC+FGD/SCR power station and the sequestration of CO_2 by a managed forest. The coal supply arrangements for this case are the same as in the IGCC. As the CO_2 control activity is decoupled from the fuel utilization, the power plant configuration is essentially a state-of-the art coal-fired power plant.

A simplified flowsheet of the PC+FGD/SCR power plant is shown in Figure 6. The boiler is a single conventional balanced draught, tangentially fired dry bottom unit using overfire air and low NOx burners. The boiler generates heat to raise supercritical steam in a double reheat steam cycle. The plant produces 500 MWe (net) at the busbar.

For NOx control, SCR is used. Ammonia is injected into the flue gas duct. The flue gas is passed over SCR catalyst. NOx concentrations are reduced by 90%. Particulate control by electrostatic precipitators is 99.7%

A forced air oxidation limestone/gypsum FGD process removes 95% of the sulphur dioxide. The cooled gas is brought into contact with a countercurrent flow of limestone/water slurry in a single spray tower. Air is subsequently pumped into the slurry to oxidize the calcium sulphite to by-product gypsum.

In this case a more sophisticated supercritical steam cycle is used to make effective use of the higher temperature heat source which is available for steam raising. The steam cycle is a double reheat system. As with the steam cycles for the other two cases, a condenser pressure of 0.025 bar is used.

The emitted CO_2 is sequestered by a managed forest.

RESULTS AND DISCUSSION

Full Fuel Cycle Efficiencies and Carbon Released

Table 1 summarizes the full fuel cycle carbon and energy flows for the three cycles reported. Thermal efficiencies are based on the lower heating value (LHV). The overall thermal efficiency of the NGCC power plant is 45.1% but it is reduced to 44.3% taking into account gas used in the plant and CH_4 losses. Carbon emitted on a full fuel cycle basis is 84% of the carbon feed to the cycle. The plant recovers greater than 84% of the carbon. However, about 4% of the carbon emitted is in the form of CH_4 which has a higher global warming potential than CO_2. For a plant incorporating CO_2 abatement, small emissions of CH_4 assume a greater significance than is the case in a conventional gas fired power plant. In terms of CO_2 equivalent the overall emission from the NGCC plant is 28 grams of carbon per kWh of power generated.

Table 1 shows that the NGCC case has the highest overall efficiency. Comparison of the carbon balances shows that the IGCC and NGCC cases achieve a similar level of abatement while the PC+FGD/SCR essentially achieves 100% CO_2 abatement due to the design of the forestry sequestration option.

Private Costs

The private costs for the three reference cases are summarized in Table 2. The discount rate is 10%. Sensitivity studies based on differing discount rates and fuel prices were accomplished, but are not reported here. The lowest costs are for the PC+FGD/SCR. However, these do not include the forestry costs which can add at least 2 c/Kwh to 11 c/kWh to the price of the electricity dependent on the forest size and the number of years the forest is required to absorb the CO_2 equivalence of GHG's emitted during the operation of the plant.

Previous studies of the cost of carbon sequestration have concentrated on afforestation in tropical countries. Though this is a less expensive option than a managed forest in an OECD county, the concept of using land in less developed countries to 'dump' carbon may not be acceptable. In this study a managed forest in the UK was chosen as the UK forest Commission was able to perform detailed assessments. The wide range of cost are primarily due to the size of the forest. The lowest cost arises from a forest sized to absorb the CO_2 over 200 years and the highest cost are for a forest to absorb the CO_2 over the plant life of 25 years. Credit was taken for the ability to absorb more CO_2 than emitted over the life of the plant.. Afforestation cost include; land purchase, planting, providing roads, fencing to keep out herbivores as required, and etc.. Previous studies may not have included all the costs associated with the development and managing the forest.

The costs for both IGCC cases are higher than those for the NGCC alternatives. Though it is not possible to 'break out ' the capture costs as the plants steam cycles are integrated with the design, previous studies by the IEA GHG R&D Program for retrofit capture and disposal indicated that the cost of capture is in the range of 1.2 to 2 c/kWh and between 0.1 to 0.2 c/kWh for a 200 Km long pipeline for disposal.

Emissions Inventory

Comprehensive emission inventories have been derived for each of the fuel cycle. Emissions to the atmosphere, to land and to water were used as the basis for the evaluation of the external costs associated with the fuel cycles. By far the most important emissions from the fuel cycles are those to the atmosphere. These are summarized in Table 3. The inventory includes emissions arising in all stages of the fuel cycle. The high CO_2 emissions presented for the PC+FGD/SCR case do not take into account the subsequent sequestration of the CO_2 by the forestry option. Comparison of the different fuel cycles shows that the NGCC emits lower amounts of CO_2, SO_2, NOx, N_2O, CO and dust than the coal fired processes. The inventories revealed a number of interesting points. First, in the IGCC cases where sulphur removal in the power plant is very good, the major sulphur emissions arise from the transportation of the coal by ship to the plant. The coal ship is also the major source of NOx, N_2O, CO and PAHs in these fuel cycles. Second, in the IGCC and PC+FGD/SCR cases the major emissions of CH_4 and VOCs arose at the mines while in the NGCC case they resulted from leaks and vents during production. Higher levels of CH_4 and VOCs are emitted for the deep US mine than the open-cut Australian mine. Third, the levels of particulate from the conventional PC+FGD/SCR case are substantially higher than those from the IGCC and NGCC cases

CONCLUSION

The overall objective was to develop a methodology for the evaluation of full fuel cycles and to apply this method to various electric power generation processes. This study determined both the private costs, energy usage and the externalities associated with the full fuel cycles. The additional loss on efficiencies due to consideration of the full fuel cycle relative to the power cycle only range from 0.8 to 4.6 dependent on the fuel and method of producing electricity. Costs variation of producing power for each of the NGCC and the IGCC cases depend on the pipeline distances. The PC+FGD/SCR cycle cost variations are a function of the size of the forest and the years the forest is considered to absorb CO_2. At a minimum, for a managed forest in the UK that will require 200 years to absorb the CO_2 equivalence of the greenhouse gases emitted during the life of the plant, the cost of afforestation is about 2 c/kWh, similar to the cost of capture and disposal.

Figure 1. Full Fuel Cycle schematic - NGCC with gas field disposal of CO_2

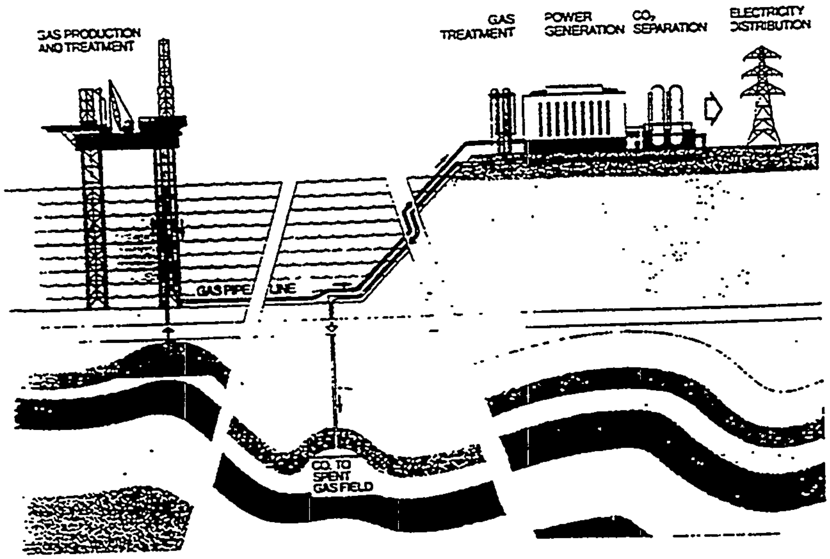


Figure 2. NGCC with CO_2 removal from flue gas

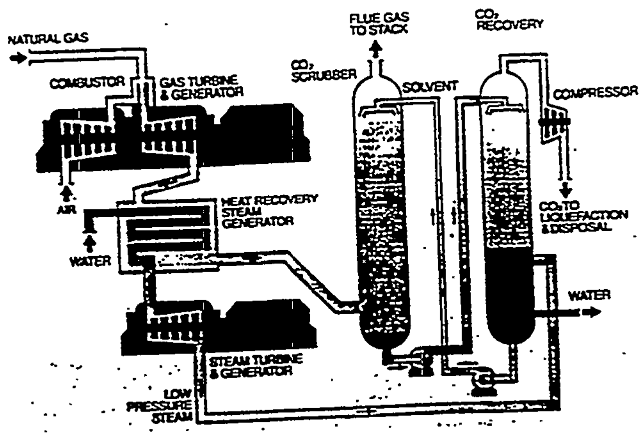


Figure 3. Full Fuel Cycle schematic - IGCC with ocean disposal of CO_2

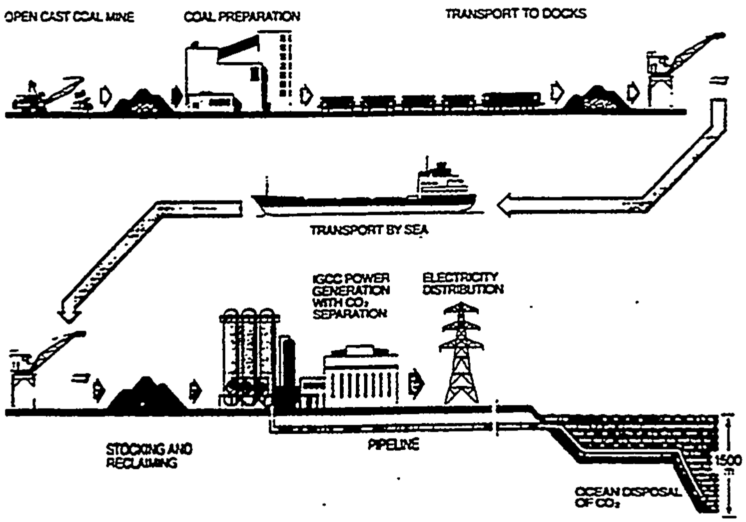


Figure 4. IGCC with H_2S and CO_2 scrubbing

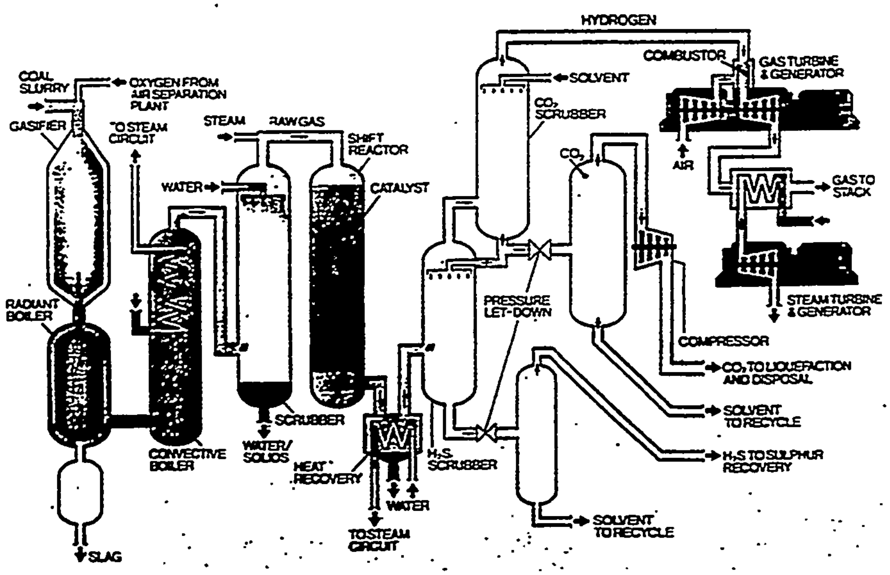


Figure 5. Full Fuel Cycle schematic - Pulverised coal with CO_2 capture by managed forest

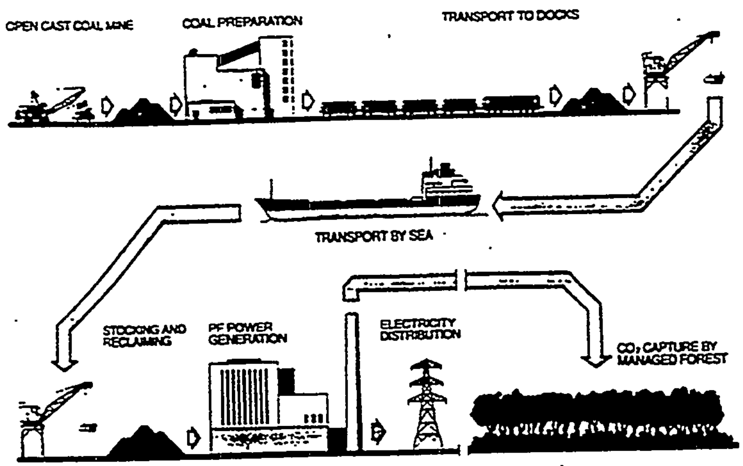


Figure 6. PC+FGD with SCR schematic

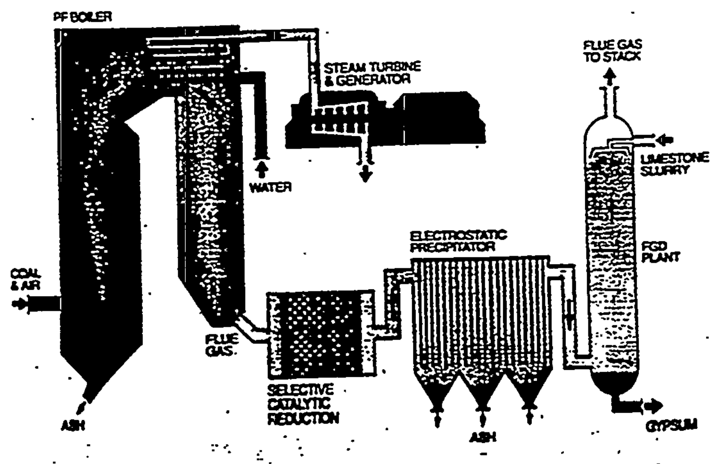


Table 1 Energy and Carbon Balances of Fuel Cycles

Fuel Cycle	Thermal efficiency of power plant (%)	Overall efficiency of full fuel cycle (%)	Overall CO_2 abatement[1] (%)	Overall CO_2 emissions[1] (g/kWh)
PC+FGD without CO_2 abatement (Australian Coal)	45.6	41	100	0
IGCC with CO_2 abatement (Australia coal, ocean disposal)	36.4	34	83	47
NGCC with CO_2 abatement (Ekofisk gas, gas well disposal)	45.1	44.3	84	28

Note:
[1] These figures consider total greenhouse gas emissions, expressed as CO_2 equivalents,

abatement while the PC+FGD essentially achieves 100% CO_2 abatement due to the design of the forestry sequestration option.

Table 2 Comparison of the private costs

Case		Case 1	Case 1a	Case 2	Case 2a	Case 3
Power Generation Technology		NGCC	NGCC	IGCC	IGCC	PC+FGD
CO_2 Sink		Gas well	Ocean	Ocean	Gas well	Forest
Fuel Source		Ekofisk	Ekofisk	Drayton	Drayton	Drayton
DCF Rate	%	10	10	10	10	10
Fuel costs	c/kWh	3.57	3.58	1.95	1.94	1.54
Capital charges	c/kWh	2.46	2.92	5.63	4.43	3.45
Operating costs	c/kWh	0.53	0.58	1.03	0.87	0.67
Total	c/kWh	6.56	7.08	8.61	7.24	5.66*

* The total cost does not include the forestry costs, these are discussed separately

Table 3 Emissions to air related to combustion, losses and power plant construction (500 MW_e net output basis) (Tonnes per year)

Fuel Cycle	CO_2	SO_2	NO_x	N_2O	CO	CH_4	VOCs	PAHs	Carbon Particles	Dust	Hg
PC+FGD without CO_2 abatement (Australian Coal)	2283780	1650	3520	125	940	430	70	630	170		0.02
PC+FGD without CO_2 abatement (USA coal)	2620000	1730	1330	50	230	6560	760	160	140		0.025
IGCC with CO_2 abatement (Australia coal, ocean disposal)	503300	515	4550	144	1120	540	39	300	[illegible]	17	0.015
IGCC with CO_2 abatement (USA coal, ocean disposal)	418500	240	1822	60	300	8500	1000	220	[illegible]	5	0.015
NGCC with CO_2 abatement (Ekofisk gas, gas well disposal)	232600	0.3	300	24	9	760	340	200	12	0	~0
NGCC with CO_2 abatement (Groningen gas, gas well disposal)	238400	0.3	300	24	9	740	330	220	12	0	0.009

THE FULL FUEL CYCLE OF CO_2 CAPTURE AND DISPOSAL

ESTIMATION AND VALUATION OF ENVIRONMENTAL IMPACTS

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ABSTRACT

This paper reports on the assessment and valuation of environmental impacts arising from the full fuel cycles of three fossil fuelled power generation plants. Two of the plants have integral facilities for the capture and subsequent disposal of CO_2; the other plant has no capture facilities for CO_2 but it is sequestered in a managed forest at a site remote from the power plant. A wide variety of emission impacts have been assessed at local, regional, and global level. The potential impacts assessed include; accidents to workers and the public, the effects of atmospheric emissions on health, and global warming impacts. Under the heightened environmental awareness scenario assumed for the study it was found that those external environmental costs which were able to be monetised were low in relation to the private costs of power generation. The quantifiable environmental costs for each of the three cycles assessed were less than 0.5c/kWh. However, several impacts thought to be potentially large were not able to be assigned a cost. A number of major methodological and valuation issues are addressed.

BACKGROUND

Within the scientific community there is near consensus that a continuing increase in the rate of emission of greenhouse gases will result in climate change. Over 150 countries have signed the UN Framework Convention on Climate Change with the ultimate objective of stabilising greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Although the effects of emissions and their impacts are not fully understood, it is agreed that intervention will be required to stabilise the atmospheric concentration of greenhouse gases. The level at, and date by, which emissions need to be stabilised is a matter of much debate. Response options initiated by policymakers need to be implemented in a manner that minimises the net cost to society. However, an underlying problem with all assessments of the costs of global warming, including that reported in this paper, is that they are based on long term predictions; eg of population growth, economic development, etc. There is no consensus on these predictions and the problem is dealt with by assuming scenarios such as those used by the IPCC in their climate change assessments. It is not always made clear that such scenarios are a limited selection of possible futures chosen to provide a wide range of outcomes; they are not predictions of the future based on an assessment of probabilities. Although the transport sector is the greatest source of CO_2 emissions, attention has focused on electrical power generation because emissions are from large point sources. The major options for reducing CO_2 emissions within the electrical supply industry are:

- Increased efficiency in generation and use.
- Switching to less carbon intensive fuel cycles eg natural gas, or non-fossil derived power.
- CO_2 capture and disposal, including other fuel cycle decarbonisation options.

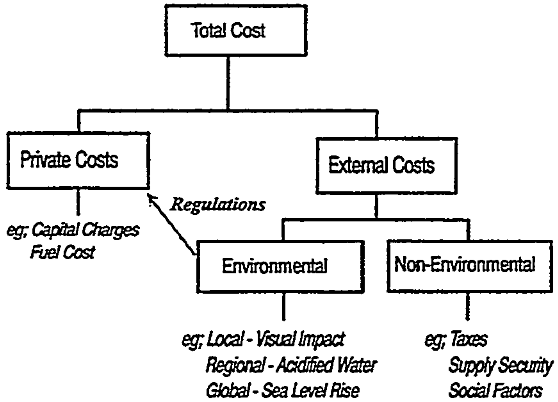

Figure 1 - Cost breakdown

Each of these options present the possibility of significant reductions in the emissions of CO_2 and other greenhouse gases. However, there is as yet no agreed method by which to evaluate competing claims about their relative costs and environmental impacts. The debate is complicated by the lack of accounting procedures which cover those costs (and benefits) to society which are not included in conventional economic evaluation. It is clear that the private costs (see Figure 1) are only part of the total societal cost and decision makers need to have further information which reflects other impacts; eg impacts on the environment, social impacts, impacts on security, etc. The distinction between private costs and externalities is not fixed. Environmental costs in particular, are to an increasing extent internalised to form part of the private costs by the imposition of environmental and health regulations. Until very recently, these regulations were largely imposed on the basis of technical and economic feasibility rather than any attempt to relate the cost of controlling an emission to the cost of its impact. However, there is now an accumulation of knowledge on the costs and benefits of environmental externalities impacting at the local and regional levels which is being used as an aid to making decisions on energy policy (1)(2). This paper reports on a study which attempts to extend that knowledge by establishing a methodology whereby global environmental impacts can be included in the assessment. In recognition of the need for environmental and energy decision making to be based on credible information which reflects in full the costs and impacts of the technology being evaluated, the members of the IEA Greenhouse gas R&D programme agreed to the study reported here, in which, the environmental costs and impacts of three selected fossil fuel power generation routes combined with CO_2 mitigation would be assessed, and a general methodology for such assessments developed. The intention was that the methodology could be used (and refined where necessary) by others and thus, provide a consistent standard for the environmental comparison of power generation options aimed at mitigation of greenhouse gas emissions. The scope of the study was set at a three day meeting of experts nominated by the members which was held in April 1993. Non-environmental externalities were specifically excluded as they are highly dependant upon the perceived views and values of the decision maker.

OBJECTIVES

The overall objective was to develop a methodology for the full 'cradle-to-grave' assessment of the costs and other impacts arising from the use of fossil fuels to generate electrical power in combination with CO_2 mitigation schemes. The methodology was to be developed such that it could be applied to fossil fuel based energy cycles, locations, and scenarios, other than those selected for the study. An eventual aim is that the methodology be extended to enable the comparison of fossil fuel based greenhouse gas mitigation options with alternative energy cycles which do not use fossil fuels.

Specific objectives included testing the methodology in a transparent manner on fuel cycles based on three technologies and two fuels. Emissions and efficiencies were to be established on a full cycle basis and conventional costs derived for the cost of power generation combined with CO_2 mitigation by direct and indirect capture. These conventional or 'private' costs are reported at this Conference in a companion paper (3). The external costs applicable to each cycle were to be assessed where adequate information existed and in particular any environmental impacts identified as being specific to the adoption of CO_2 capture and disposal technology were to be highlighted.

METHODOLOGY

The fundamentals of the methodology developed are similar to those for a Life Cycle Analysis, ie the energy cycle must be defined within clear boundaries and the cycle needs to be assessed within a specific social and temporal context. Because the global warming implications of greenhouse gases are involved, a time-frame of say, 500 years should have been adopted. However, projection of many of the key parameters over such a long time period is completely unrealistic and analysis was therefore restricted to the period up to 2100. Because of the many uncertainties, this assumption is believed to have little effect on the conclusions.

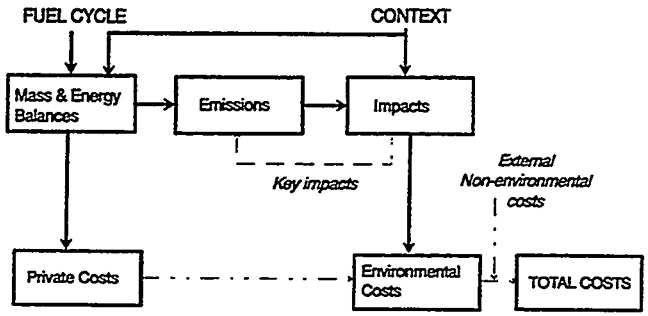

Figure 2 - Full fuel cycle methodology

Figure 2 illustrates the main component steps of the methodology and shows the two major input assumptions which are: (i) the cycle to be assessed, and (ii) the context within which the cycle operates. Where possible, the results of the analysis should be expressed in a common unit of measurement and for the purposes of this study the most useful is the cost/unit of power delivered to the system boundary (cents/kWh). Although the methodology has to be comprehensive, it also has to be practicable. Hence, system boundaries have to be drawn so as to include significant areas but avoid. including areas of insignificant consequence. The necessity for, and justification of, such 'scoping' is recognised in Environmental Impact Assessments where impacts significant in some contexts can be insignificant in others. The cut-off level for inclusion of impacts and other factors was specified as being at 1 to 2% of total impact.

The full fuel cycles are defined as including all stages of the cycle from abstraction of the fuel, pretreatment, transport, power generation, to by-product disposal, and CO_2 capture and disposal. Because the assessment is aimed at the evaluation of power generation schemes, it is assumed that new plant is built for all those parts of the cycle located at the power generation site or specifically required to dispose of the emissions from the site. Other components of the cycle such as the coal mine, natural gas rig, and fuel and raw material transport facilities are all assumed to exist. The energy input into construction of the new plant is included; second order effects such as, the energy that went into building the plant that makes the process solvent, were excluded from the analysis. The technology chosen for assessment was selected on the basis of being as well documented and as advanced as possible given the requirement to derive accurate costs and impact assessments. A possible future development would be to extend the methodology to include the evaluation of less well defined technology.

The context within which the fuel cycles operate is defined by assuming sites for the activities and a scenario within which they take place. A comprehensive analysis would require that a number of scenarios be set and the results and conclusions compared. The time and resources available for this study did not allow more than one scenario to be examined but it is possible that sensitivity to scenario assumptions will be examined in future work on this topic. The central assumption made for this study is that increasing concern about the climate change issue leads to large scale adoption of CO_2 mitigation options by the year 2005. To be consistent, it is also assumed that increased concern on other environmental issues, such as, acid rain and pollution of the oceans, leads to action to alleviate these problems. A major effect of this scenario of heightened environmental awareness is to internalise many of what are at present external costs. This is reflected, for instance, in capital expenditure on pollution control equipment for the power plant which leads to comparatively high private costs for power generation. Our scenario is based on one of six developed for the IPCC which vary with respect to: economic growth rates, population levels, energy supply sources, and environmental legislation. The selected scenario (IS92d) assumes tight environmental controls consistent with the adoption of CO_2 mitigation. The other major assumption on the context is definition of specific sites for the activities involved. Damages associated with local and regional emissions are site specific because of various geographical and demographical factors which influence the pattern and dispersal of an emission and the number of people effected. The site selected for the study is on the NE coast of the Netherlands. There were a number of reasons for selecting this site amongst which were: the site is nominated as suitable for either coal or gas fired power generation, costs in the Netherlands are believed to lie at about the norm for countries which are members of the programme, coal and gas are imported into the Netherlands from the sources nominated for the study, an existing NGCC plant and various plans for developments in the region ensured the availability of data. Specific sites were also chosen for the CO_2 disposal options and other components of the cycle.

The steps of the methodology are shown in the boxes of Figure 2. The first step in the evaluation is to derive material and energy balances. Following derivation of the balances the private costs can be derived and an inventory of emissions (or burdens; ie including visual intrusion etc as well as material emissions) established. The information produced in the first stage of the evaluation is relatively accurate. The material balances are accurate to +/- 0.1% on a carbon basis and the efficiency is accurate to +/- 1%. The private costs are quoted to an accuracy of +/- 25%; higher levels of accuracy can only be obtained by a fully engineered design and are both impractical and unwarranted within the context of this study. In the second stage of the methodology the impacts of the emissions are quantified and evaluated. The emissions were categorised as being local, regional, or global each of which were dealt with differently to assess their impact. Typically, local impacts are primarily dependant on identification of the population effected and hence, significant quantities of local data were needed. Regional impacts are typically dependant upon their fall out pattern and hence, atmospheric dispersion modelling was required. Global impacts were assessed by the adoption of a logic parallel to that used by the IPCC, in which an arbitrary concentration (560 ppm ie twice pre-industrial levels) of CO_2 in the atmosphere is assumed and the time to reach that concentration under a particular scenario is modelled. The regional effects of global impacts were derived by reference to an appropriate standard run from a global climate model (GCM). These steps in the methodology are probably the least satisfactory and transparent of those used and part of the future development of the methodology could be aimed at advancing the state-of-the-art and simplifying the procedure. Where possible the evaluations are expressed in financial terms but as explained later there are significant problems in achieving a common unit of measure which equates to the c/kWh used for the private costs. The emission to impact analysis step is an iterative procedure in which some emissions are excluded from the analysis once it has been established that their impact is not significant.

As indicated in Figure 2, an ultimate objective for the methodology would be to provide policymakers with the means of deriving the overall costs of the fuel cycle. For reasons outlined later, and presented in detail in the report, this is not possible with the present state of knowledge.
There are large uncertainties associated with the present state of knowledge of environmental externalities. Probabilistic assessment techniques could help to reduce, or at least quantify, the uncertainties. A method based on establishing highest and lowest credible values at low levels of probability, which thereby indicates the most probable range of the impact value, was tried as part of the methodological development. A selection of other environmental externalities deemed to be non-quantifiable were assessed in a ranking exercise as part of a further experimental development of the methodology.

RESULTS AND DISCUSSION

In this paper, the externality related aspects are addressed and overall aspects of the study including the major sensitivities discussed. The companion paper mentioned earlier (3) deals with technology issues and the private cost aspects but some of the private cost aspects are referred to here to aid the understanding of the reader.

The three full fuel cycles assessed were as follows:

i) A combined cycle (NGCC) fired by natural gas from the Norwegian sector of the North Sea. A chemical solvent (MEA) is used to capture CO_2. A local natural gas is also assessed.

ii) An oxygen blown gasification combined cycle (IGCC) using an open-cut hard coal from Australia. A physical solvent is used to capture CO_2. A deep mined coal from the Eastern USA is also assessed.

iii) A pulverised coal fired plant (u/sc PF) operating on an advanced ultra-critical steam cycle. The plant is equiped with advanced SO_2 and NO_x control facilities but the CO_2 is captured indirectly in an offset forest remote from the power plant.

In cycles using the direct capture of CO_2 the disposal method and distance to the site have a significant effect on the overall assessment. Therefore, two disposal options were applied to both the IGCC and the NGCC cases. The disposal options used were a local disused gas reservoir, and an ocean disposal site remote from the power plant in the nearest deep ocean (off the Atlantic coast of France). Each of the cycles was assumed to deliver a net 500MW to the local distribution grid.

The general philosophy used for the outline plant designs was to incorporate the most advanced emission controls likely to be available in 2005 and then, to aim for the highest possible power plant efficiency. This approach results in relatively high costs for power production because of the efficiency loss and extra capital required when compared to power plant which does not capture CO_2, or have such tight controls on other emissions. Future work to quantify this penalty is possible but the choice of appropriate reference cases is not as simple as it might first appear. As instances, under the heightened environmental awareness scenario chosen for the study the choice is between alternative power generation schemes each of which mitigate against the global warming consequences of greenhouse gas emissions. These cases could be compared with each other, or with a common base case which could be any number of possibilities such as: a power station representing the OECD average (say, 36% LHV efficiency for a coal fired plant with FGD but not SCR), a power station representing the world average (say, 30% LHV efficiency for coal fired plant without FGD), an existing power station assumed to be displaced by the new plant, a highly efficient advanced plant built under a 'business-as-usual scenario' etc. Even comparisons solely on an engineering and private cost basis are not straightforward, eg where shift conversion of syngas is required as in our study, wet feed entrained gasifiers such as the Texaco type have a slight advantage; if CO_2 capture is not required, dry feed gasifiers such as the Shell type give a greater efficiency.

Emissions and private costs

Table 1 presents the greenhouse gas emissions on a full fuel cycle basis. Because of the extensive clean-up facilities these emissions are very low. In the IGCC case the power plant is the main source of residual CO_2 emissions and transport of coal by ship the next most significant contributor.

Table 1 : Net greenhouse gas emissions to atmosphere; full cycle basis

Cycle	Fuel	Carbon store	g CO_2/kWh	mg CH_4/kWh	mg N_2O/kWh
NGCC	natural gas	gas well	75	197	6
IGCC	bituminous coal	ocean	135	145	39
u/sc PF	bituminous coal	managed forest	0	0	0
u/sc PF	bituminous coal	none	775	120	35

Note: Managed forest sized to compensate for all greenhouse gases.

Table 2 presents a summary of the private costs of avoiding greenhouse gas emissions. Because of the extensive emission control facilities, the investment in efficiency recovery, and the greater complexity of the plants considered, these power generation costs are considerably higher than costs in the 4 to 5c/kWh region that would be expected for power plant not including CO_2 capture and disposal.

Table 2: Private cost of avoiding CO_2 emissions

Cycle	u/scPF	u/scPF	IGCC	IGCC	NGCC
Carbon store	none	managed forest	ocean	gas well	gas well
Fuel	bituminous coal	bituminous coal	bituminous coal	bituminous coal	natural gas
Private costs:(1)					
(fuel)	1.54	1.54	1.95	1.94	3.57
(capital charges)	3.45	3.93	5.63(4)	4.43	2.46
(operating)	0.67	2.19(3)	1.03	0.87	0.53
Total (c/kWh)	5.7	7.7 (to 16.8)(5)	8.6	7.2	6.6
\$/tonne CO_2 avoided(2)	—	26 (to 143)	46	23	13
Cost \$/tonne C avoided		95 (to525)	166	84	48

Notes : (1) at 10% DCF; coal at \$ 1.93 / GJ ; natural gas at \$ 4.48 / GJ. (2) avoided costs referenced to u/scPF plant without CO_2 capture. (3) includes establishment costs for the forest. (4) includes cost of a 1200 km long CO_2 disposal pipeline. (5) range due to land and establishment costs.

Even the minimum value in the range given for the cost of the managed forestry option is considerably greater than has been reported elsewhere for forests established to capture CO_2 but is believed to be valid for a temperate European country. It should be noted that a number of the low costs given in the literature are for improved management of existing forests and do not include any land or establishment costs. The cost of afforestation is highly dependant on: the assumed costs of land and plantation establishment, assumptions made about the life of the forest and the quantities of carbon stored, alternative demands for the large land areas required, and the availability of adequate water supplies. Work is needed on long term storage mechanisms (100+ years) not least on how to guarantee the forest is left to stand. Options based on long or short term rotation ie cropping offer some solution but seem unlikely to offer a major long term capacity. Our study reports that 348,000 ha (860,000 acres) of land is necessary to sequester the emissions of CO_2 from the 500MW coal fired plant. It equates to 2.2 tC/ha. year and was derived assuming that the forest had to absorb the carbon emitted from the power plant by the end of the power plant's life. If the permitted sequestration period is allowed to be 200 years, ie the period for which the forest continues to grow and absorb carbon, the land required is reduced to 62,000 ha but the impact of CO_2 emissions before they are eventually captured needs to be assessed. Although Table 2 presents figures for the cost of CO_2 avoidance it is important to note that the cost per tonne of CO_2 emission avoided is not a constant for a given capture and sequestration route; it depends upon the non avoidance technology assumed as a reference.

Uncertainty, discount rates, and value related issues

The private costs reported for our study are presented using DCF rates of 10% and 5% as part of the analysis. These rates are commonly accepted as being appropriate for the evaluation of private costs, the first representing a 'commercial' rate and the second a 'utilities' rate. There is however no agreement on DCF rates appropriate for use in the assessment of environmental effects. Environmentalists argue that the use of discount rates greater than about 3% is not justified because a major environmental damage some time in the future would appear in present day terms to have a low value. It has been argued that intergenerational equity and sustainable development considerations demand the use of zero or negative discount rates. Another approach that has been suggested is to link the choice of discount rate with whether the environmental damage is reversible or irreversible. Most environmentalists appear to be moving towards use of a 1.5% DCF rate which is the core rate used in our assessment, but there are fairly convincing arguments that if a rate is to be applied it should as a minimum be in the 2 to 4% region. It is not likely that agreement by all parties will ever be reached on this issue; it is essentially a value judgement that has to be made by the decision maker.

There are high levels of uncertainty associated with the assessment of external costs. At best, the external costs in our study are thought to be only accurate to a factor of two and in many cases they were deemed by the study team to be unquantifiable. One major problem is that many of the valuations are based on assigning some value to a human life. Calculations using the statistical value of life (SVOL) are based on the willingness of a society to pay to avoid the risk of deaths eg by the installation of safety instrumentation in chemical plant and aeroplanes. These calculations are about risk, they should not be confused with the willingness of an individual to pay to avoid certain death. Our study uses a SVOL of 3$million/life which is within the range commonly used in USA and UK studies. However, if for instance, values based on loss of potential earnings, life insurance taken out by individuals, or years of life remaining for those most at risk, were used much lower environmental damage would be derived. It has been pointed out for instance that those already suffering from chronic bronchial problems are most at risk from air pollution. These alternative approaches lead to SVOL's in less developed countries considerably lower than in developed countries, which many people find unacceptable. As with the DCF issue discussed earlier, there is no unique solution and the assumed SVOL has to be based on the values of those intending to make use of the information.

Another major cause of uncertainty associated with the assessment of external costs is a consequence of the lack of adequate information with which to quantify a complicated chain of emission and impact interactions. Perhaps the prime example of this is illustrated by the weakness of information on damage to forests by acid rain, where the study team came to the conclusion they were not able to assign a damage in c/kWh despite the equivalent of millions of US$ spent studying the problem. (The problem is caused by factors such as variation in critical loads for different soils, reversibility of the effect, lack of a common measure for damage, long tree life etc.) In principle, uncertainty of this type can be reduced by scientific investigation but the cost of reducing this uncertainty can be huge.

The uncertainty associated with the assessment of environmental impacts increases with scale ie global>regional>local. Reasons for this include the increasing complexity and the state-of-the-art in a rapidly moving field. Local impacts are relatively well documented but there is little to no consensus on the level of global warming impacts . Local impacts in our study were determined using Environmental Impact Assessments (EIA's). Because the area is not densely populated the number of people affected is low and the valuation is low. Many of the local impacts identified were not significant in the overall context of the study. Regional impacts are mainly associated with atmospheric releases such as acid gases, particulates, and precursors of photo-oxidants ie NO_x and VOC's. Models are available to map the dispersion of emissions but the overall accuracy of data in this area is quite variable. Good models exist for predicting the effects on crops of regional deposition of SO_2. However, as mentioned earlier, forest damages are still a topic of much debate and lack of information hinders the assessment of damages to buildings. Global impacts arise from the residual emissions of greenhouse gases emitted by the fuel cycles. Existing computer models at the forefront of developments were used to derive the climate change impacts. The heightened environmental awareness scenario chosen for the study together with the capture of most of the greenhouse gases resulted in valuations in this area being small. The global warming costs were in effect internalised by the adoption of CO_2 mitigation measures. In general, the global warming costs are thought to be accurate to an order of magnitude. It should be noted that the levels of emissions control in this study were not set at a socially optimum cost but at levels appropriate to the scenario.

Environmental costs and impacts

Table 3 presents the totals for those impacts calculated in monetary terms for a case from each of the three fuel cycles. Other major impacts exist but were unable to be expressed in monetary terms. The comprehensiveness and extent of the impacts assessed in the study needs to be emphasised. For instance, 69 local impacts were considered even though only one of these was found to be significant in the overall context.

Table 3 : Summary of environmental costs and impacts.

Significant Impacts	Damage/Benefit(1)		
	NGCC (gas well)	IGCC (ocean)	u/sc PF (forest)
Local :	0.006	0.2	0.2
Regional :	0.1	0.1	0.2
Global :	0.01	0.01	-0.1(2)

Notes:*(1) cents/kWh at 1.5% DCF. Positive indicates damages, negative indicates benefits. (2) Does not include the forestry recreation benefits discussed below.*

The quantified externalities (<0.5c/kWh) even at a DCF rate of 1.5% are an order of magnitude less than the private costs. Hence, in the heightened awareness scenario of this study the environmental externalities could be taken as not having a significant effect on the relative merits of the options assessed. If less stringent environmental restrictions were assumed the private costs would be decreased and the environmental externality costs increased. The minor benefit shown as accruing to the forestry case arises from matching the absorption and emission rates and selling excess carbon absorption capacity after the life of the power station. The major contributors to the environmental costs were: local - occupational accidents (some of the cost of which can be assumed to be internalised by owners insurance schemes), regional - public health, global - sea level rise.

Environmental impacts arising specifically from the adoption of CO_2 mitigation were identified separately. The major impact assigned a monetary value was the benefit from provision of recreational facilities in the forest (1.3 c/kWh). This relatively large figure needs to be treated with some caution because of the many uncertainties some of which were raised earlier. Another major issue considered is the possibility of external costs arising from fracture of the CO_2 disposal pipeline. CO_2 is heavier than air and a significant rupture combined with an atmospheric inversion could lead to loss of life. It should be noted however, that there are about ten CO_2 pipelines operating inthe USA of the size that is required to handle the output of a 500MW power station. The potential environmental impact of CO_2 storage options were also considered. The oceans covering 70% of the world's surface and having an average depth of over 3000 metres offer a huge potential store but very little data is available on the likely effects and practically none on the assessment of likely damages or benefits. Although most of the CO_2 emitted to atmosphere will eventually reach the deep ocean much more information on potential environmental impacts is needed to justify accelerating this process by direct injection. However, as

CO_2 would be rapidly diffused in the deep ocean there appears to be no mechanism whereby large numbers of human lives could be placed at risk. The potential for storage in gas fields is limited but potential sites are reasonably well mapped. There is a low risk of releasing large quantities of the stored gas but otherwise the environmental effects appear minimal. Again however, more work is required to establish the environmental acceptability of this storage option.

CONCLUSIONS

The conclusions of the full fuel cycle study work for power generation options which include CO_2 capture and disposal options are that: [1] Monetised external environmental costs are small. [2] For all the power generation cycles assessed private costs dominate; those external costs which it was possible to monetise are at least an order of magnitude less than the private costs. [3] External costs which cannot be monetised are similar for all the cycles and are thus unlikely to influence a ranking made on the basis of private costs. [4] The environmental impact of the power generation component of the cycle is much greater than other components of the cycle. [5] The impact of cycle components other than the power generation step is greater for the coal cycle than for the natural gas cycle.

The full fuel cycle evaluation of the three cycles has shown that point of release CO_2 capture and disposal options incur a cost penalty in the region of 2c/kWh which is of the same order as the minimum cost for an offset forest in a temperate European country. The study highlights the weakness of much of the externality data but has suggested a way forward by use of statistical techniques to put ranges on quoted values

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AN EVALUATION OF THE EFFECTS OF HIGH SYSTEM PRESSURE ON THE PERFORMANCE OF PNEUMATIC COAL CONVEYORS

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INTRODUCTION

The Air Blown Gasification Cycle(ABGC), formerly known as the British Coal Topping Cycle, is based on the partial gasification of coal in an air blown spouted bed at elevated pressures of typically 25 barg and temperatures of up to 1050°C. A sorbent, such as limestone, is also injected into the gasifier to retain most of the sulphur which would otherwise be released into the fuel gas. Between 70 and 80% of the coal substance is converted to a low calorific value gas. This fuel gas, after cooling and cleaning is burnt to produce a gas at high temperature and pressure which is expanded through a gas turbine. The solid residue from the gasifier, containing a mixture of mineral matter, char and sulphided sorbent residue, exits the gasifier in two main streams; as a coarse solid from the base of the gasifier and as a fine material elutriated from the gasifier bed and captured in a hot cyclone and a high efficiency ceramic barrier filter. Both solid residue streams are depressurised, cooled and burnt in a circulating fluidised bed combustion boiler, thereby raising steam which is used to generate further power in a steam turbine. An outline diagram of the cycle is shown in Figure 1. A cycle efficiency approaching 50% is achievable with ABGC.

In the UK, a collaborative research and development programme, including GEC Ahlstom, PowerGen, Babcock Energy Ltd, Coal Technology Development Division and the UK Government Department of Trade and Industry, has been established to provide the basis for the demonstration of this technology. As part of this initiative, an R&D programme has been put into place to establish and address the issues associated with the storage and feeding of fuels to the ABGC gasifier at elevated pressures and the depressurisation of the solid off-take streams. The focal point of these activities is the recently formed Coal Technology Development Division (CTDD), arising form part of the Coal Research Establishment of the British Coal Corporation.

Funded by the UK Department of Trade and Industry and the European Coal and Steel Community, this programme will enable the specification of the pressurised fuel handling systems for a demonstration scale plant to de defined. This will be a fully integrated plant of 75 MWe, known as the Prototype Integrated Plant (PIP). The technology is thought to be most economic at around 400 MWe, which would be the proposed size of commercial plants.

The preferred method of feeding coal and sorbent into the gasifier is continuous pneumatic transport to the gasifier spout. Other feed systems are available, but are either unproven at the high system pressures required, affect the performance of the gasifier or have capital/operational cost disadvantages.

A pilot scale gasifier has been in operation for 5 years at the Coal Technology Development Division site at Stoke Orchard near Cheltenham in the UK. The operational envelope and physical size of this gasifier precluded the detailed investigation of the effects of high system pressure on the operation of the pneumatic conveyer.

To ensure that the pneumatic conveyor can be successfully scaled to higher system pressures using larger bore and longer pipelines, whilst still maintaining high availability and low particle degradation, it was decided to conduct a programme of pneumatic conveying trials.

A suitable facility, shown in Figure 2, already existed at Glasgow Caledonian University and collaborative work was undertaken to conduct a series of trials.

The trials were conducted in three discrete stages. The first stage examined the relationship between conveying performance and the system pressure for a given material and pipeline configuration, the second stage will determine the effects of the pipeline length and the third stage will look at conveying different material sizes and types.

This paper presents some of the findings from the first stage of these trials.

THEORETICAL BACKGROUND

The pneumatic conveying of coal, or other bulk materials, at ambient conditions, i.e. normal temperature and pressure (NTP) at the conveyor outlet, has been extensively studied over many years. The ability to predict suitable conveying conditions from a knowledge of the material and system properties is, however, some way off and consequently there is still a requirement to perform pneumatic conveying trials for a high proportion of cases.

The requirement to feed a bulk material into a high pressure reactor is a fairly recent development, although the injection of coal and ore into blast furnaces at medium pressures is well documented[1].

The principal effect of the high system pressure is to increase the density of the conveying gas, typically $1.2kgm^{-3}$ for air at NTP to around $25kgm^{-3}$ at 20 barg with a consequential change in average coal particle terminal velocity from approximately $7ms^{-1}$ to approximately $1.5ms^{-1}$. This has several beneficial effects; the superficial gas velocity will remain relatively constant through the pipeline because the line pressure drop is small compared to the system pressure and thus little gas expansion takes place; lower pick up and conveying gas velocities can be achieved because the particles are more buoyant in the denser fluid; and because of the lower gas velocities the particle velocities are lower which reduces material degradation and pipeline erosion.

At the initiation of the programme very few publications were available which dealt with high system pressures, but recently some workers have published reports on this subject[2,3,4,5,6].

The work of Ling[2] deals with high pressure conveying of powdered coal in small bore (6.2, 9.2 and 12.5mm) pipelines and although some scaling criteria are available for pipeline bore and length at atmospheric conditions in is unclear at this time if these are applicable at elevated pressures. Similarly tests completed by Plasyinski[4] were carried out in a 25mm bore pipeline and only in a vertical orientation. Although both workers were using coal the particle and pipeline sizes are still significantly smaller than would be expected in a demonstration or commercial scale ABGC plant, making scaling from these data, without further testing, extremely unreliable.

HIGH PRESSURE PNEUMATIC CONVEYING SYSTEM

The test rig comprises a gas pressure/flow control system, a $0.6m^3$ blow tank, a pipeline and a receiver fitted with a gas filtration unit. The conveying gas is split into two streams and their mass flow rates controlled by a series of convergent/divergent critical flow nozzles housed in a nozzle bank. Pressure regulating valves are fitted before the nozzle bank and after the receiver vessel to enable the system pressure to be controlled. The blow tank is of the bottom discharge variety and is fitted with a discharge valve; primary conveying gas is fed into the body of the vessel, secondary conveying gas is fed directly to the conveying line before the vessel discharge point and there is the facility to apply a measured flow of gas into the base of the vessel at two different locations to fluidise the coal if required. The coal is conveyed from the blow tank to the receiver through a 78m long, 49mm bore pipeline incorporating eight 90° long radius bends. The receiver vessel is mounted on load cells to monitor the mass flow rate of the coal. The specially designed reverse jet bag filter unit, used to clean the conveying gas before it is vented to atmosphere, is fitted inside the receiver vessel. Expanding the gas by reducing its pressure before cleaning would have entailed an extremely large filter area to maintain a sensible face velocity, but because the gas is cleaned at the system pressure a much smaller filter area is required.

The safety aspects of handling coal in the blow tank and downstream filter system at high pressure meant that nitrogen was the preferred conveying gas. A high pressure nitrogen supply system, based on standard sixteen cylinder bottle packs, was designed and built at Glasgow. This option was chosen because of its simplicity, low capital and operational costs and noise levels compared to a system based on a high pressure compressor. The gas supply system consists of two header bars which act as manifolds for the cylinder packs, with each header capable of accommodating a maximum of fourteen cylinder packs. For high pressure/high flow rate testing both header bars are used, giving a total of 448 cylinders connected to the conveying rig. The gas is piped to the conveying rig through 50mm bore pipeline. A coiled section of this pipeline passes through a heated water bath to ensure that any lowering of the conveying gas temperature, due to the Joule-Thompson effect, is corrected and a constant gas temperature is maintained during each conveying test.

A data acquisition system was used for the collection of conveying variables during each test. The signals recorded for analysis after the conveying trial were :-

a) gas mass flow rate
b) solids flow rate
c) gas supply pressure and temperature
d) blow tank pressure and temperature
e) supplementary pressure and temperature
f) receiver vessel pressure and temperature
g) conveying line differential pressure

Data was sampled at 1Hz per channel using an analogue to digital converter card fitted to an IBM PC clone and associated software.

Before and after each test, representative samples were taken to monitor the degradation of the coal by measuring the size distribution. If significant degradation has taken place then the coal was replaced with a fresh batch. Random repeat conveying tests were made to ensure that data points could be replicated and the data was not being affected by degradation of the coal.

PRESENTATION AND DISCUSSION OF RESULTS

The test work for the first part of this programme was completed in February 1995. Consequently the in depth analysis of the data has not been completed. It is intended to provide a flavour of the results to date and identify key areas of interest to the development of the ABGC. As the test programme progresses future publications will examine these areas in greater detail.

Although the information derived from this programme of work will be extensive, it is unlikely that all the potential conveying parameters for all possible ABGC system designs will be available. It is part of the programme to attempt to compare the test data with correlations that are currently available and, where necessary, produce new or modified expressions which will enable reliable pneumatic transport systems to be designed.

Conveying Characteristics
The results of the conveying test runs can be plotted on a graph which represents the potential conveying envelope for a given material in a given conveying pipeline using a given gas supply system. Each data point is expressed in terms of material mass flow rate, maximum gas velocity (or gas flow rate) and the associated conveying line pressure drop.

The velocity range encountered in the conveying pipeline is dependent on the range of absolute pressures experienced and the mass flow rate of gas supplied to the pipeline. At elevated pressures, the velocity range for a given conveying line pressure drop will be considerably reduced when compared with a similar pressure drop at atmospheric conditions. This is because the expansion of the gas from the pipeline inlet to the exit will be smaller at elevated pressures.

This effect can be demonstrated graphically and is shown in Figure 3. The conveying characteristics for conveying the coal into a receiving vessel at atmospheric conditions and into a pressure of 20 barg are presented on the same graph. Due to the greater expansion effects at atmospheric conditions, a significantly higher maximum velocity (velocity at the end of the pipeline) is observed than would be experienced at 20 barg. If the maximum velocity conditions determined at atmospheric conditions were used for design of a high back-pressure system, very low conveying rates would be achieved due to the very high air-only pressure drops experienced with high density gas. At the lower conveying line pressure drops, it would not be possible to convey any material at all. However, since lower velocities are possible at higher pressures particle breakage and pipeline erosion will be reduced.

Minimum Conveying Conditions
The minimum conveying velocity is an important parameter in most pneumatic conveying systems but it is especially significant in this application. The gasifier has air supplied as a consequence of the pneumatic feed system and a second main air supply. An excessive proportion of the required air delivered with the coal will reduce the potential operational envelope and turn down of the system. The air required for conveying needs to be further compressed over that required by the main gasifier air, to overcome line pressure drop, and cooled to ~80°C, both operations representing an efficiency penalty to the ABGC cycle. It is therefore essential to identify the limits of conveying and thus the quantities of air likely to be delivered to the gasifier from this source.

For many bulk materials which exhibit little or no dense phase capabilities, such as coal, the saltation velocity is frequently used as a measure of the minimum pickup/conveying velocity[5,7,8]. One of the more useful correlation for determining the saltation velocity is that proposed by Rizk[9]. This expression has been identified by several workers as the simplest to use and frequently the most reliable when compared to conveying trials[3,7,8]. The Matsumoto correlation[10] has also been used with some success for coal conveying systems operating at high pressure[7].

Figure 4 shows the variation between the saltation velocities, predicted by the Rizk and Matsumoto correlations, and experimentally derived minimum conveying velocity over a range of system pressures whilst conveying coal at a rate of 5 tonnes/hr. The particle terminal velocity has also been included to provide a frame of reference for the other data. As can be seen, at high system pressures there is good agreement between experimental and predicted values, but at low system pressures there is considerable discrepancy. This can be explained by considering the expansion of the conveying gas at ambient and elevated system pressure. At ambient or close to ambient system pressures there is considerable expansion of the conveying gas as it passes along the 78m long conveying pipeline, carrying the coal with it; typically a pickup velocity of 10.45 m/s will increase to an exit velocity of 23.5 m/s driven by a pressure gradient of 1.2 bar and carrying around 5 tonnes/hr of coal. The expansion of the conveying gas is much less pronounced at system pressures of 5 barg and above resulting in an almost constant gas velocity through this long pipeline.

This preliminary result indicates that suspension flow is the dominant conveying regime for this grade of coal over the range of test pressures and any increases in solids concentration will result in blockage. Analysis of operational data from the CTDD pressurised gasification pilot plant conveying systems also indicates that minimum conveying conditions occur close to calculated saltation velocities. Further investigation of the data at alternate feed rates and with other materials should confirm this supposition.

CONCLUSIONS

The preliminary analysis of this data indicates that significant reductions in the minimum conveying velocity are possible at high system pressures, with the consequent reductions in coal degradation, pipeline erosion and booster compressor and air cooler power consumptions. The transposition of test data into conveying characteristics will enable reliable pneumatic transport systems for demonstration and commercial scale ABGC plant to be designed.

Examination of the data indicates that both Rizk and Matsumoto correlations for predicting saltation velocity closely match the experimentally derived minimum conveying velocity at system pressures of 5 barg and above.

ACKNOWLEDGEMENTS

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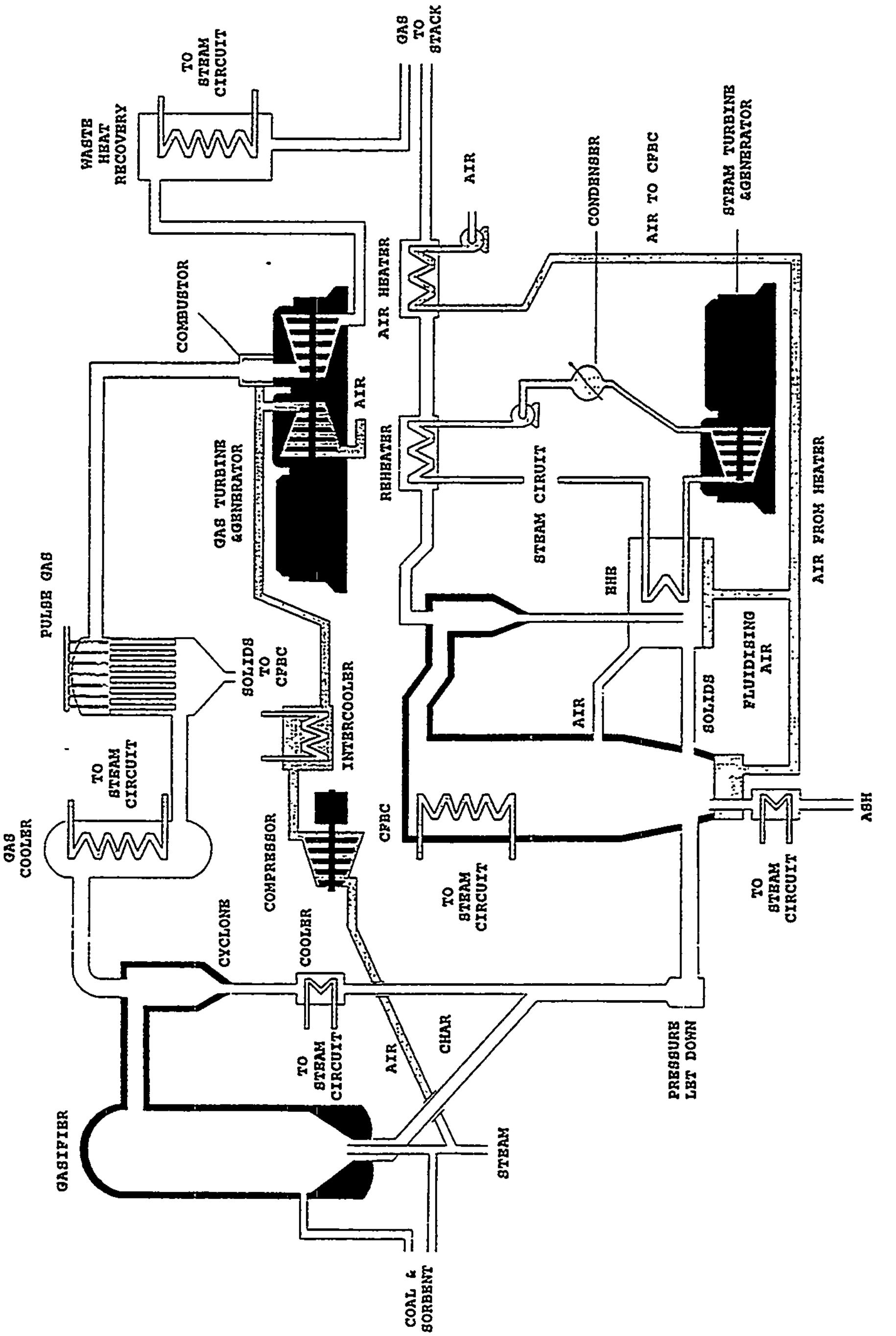

FIGURE 1 THE AIR BLOWN GASIFICATION CYCLE

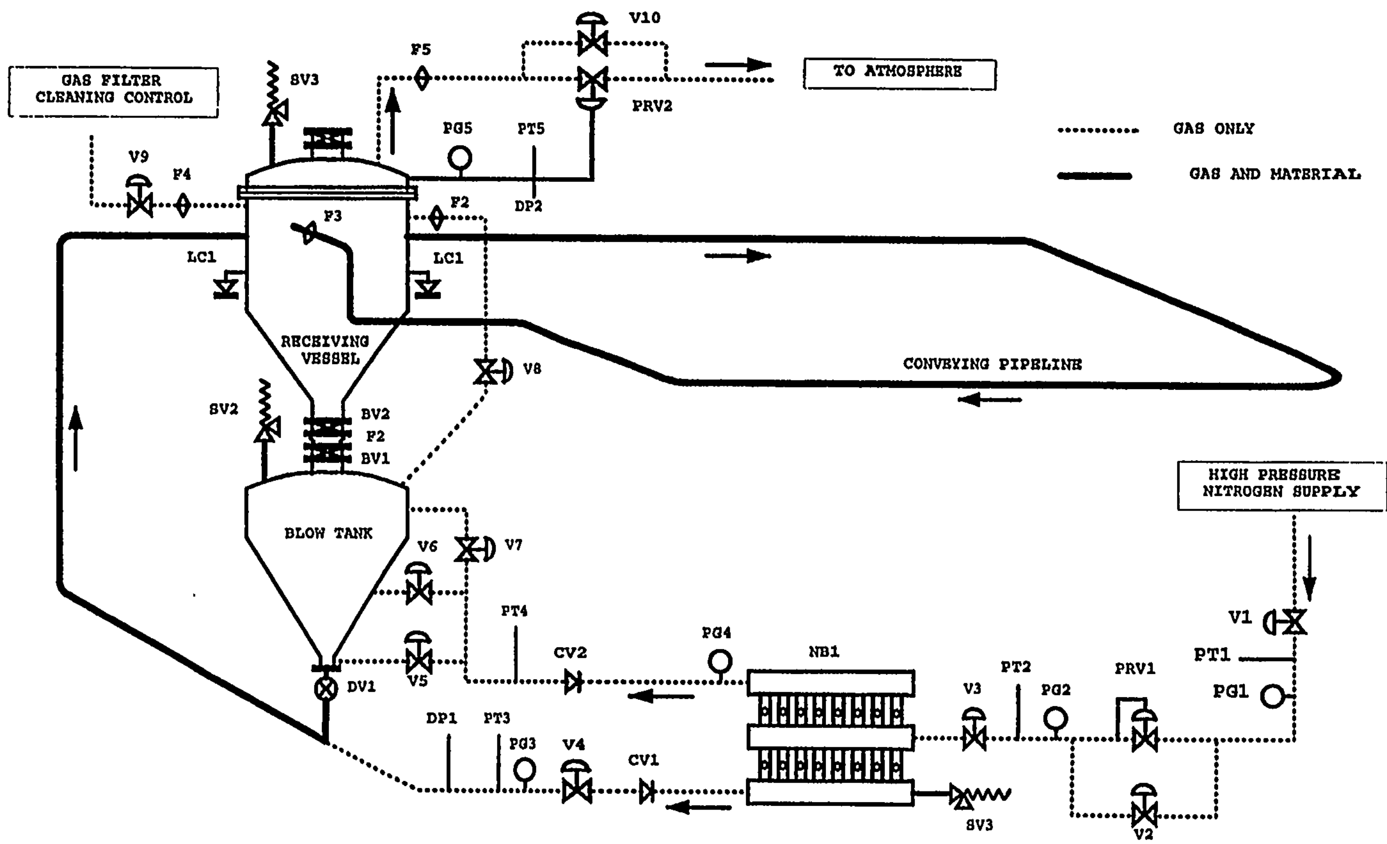

FIGURE 2 HIGH PRESSURE PNEUMATIC CONVEYING SYSTEM SCHEMATIC

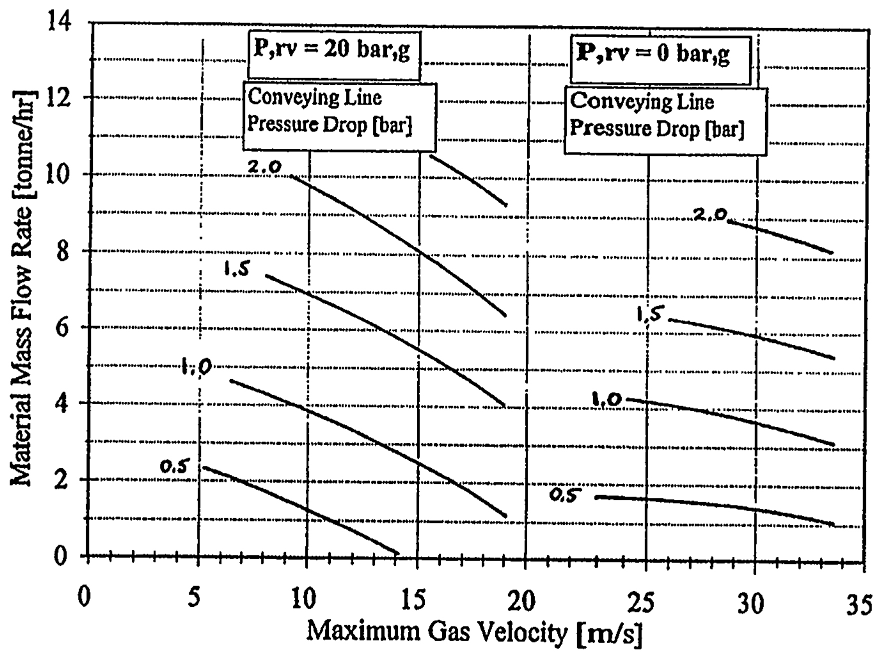

Figure 3 - Conveying Characteristics for Coal at System Pressures of 0 barg and 20 barg

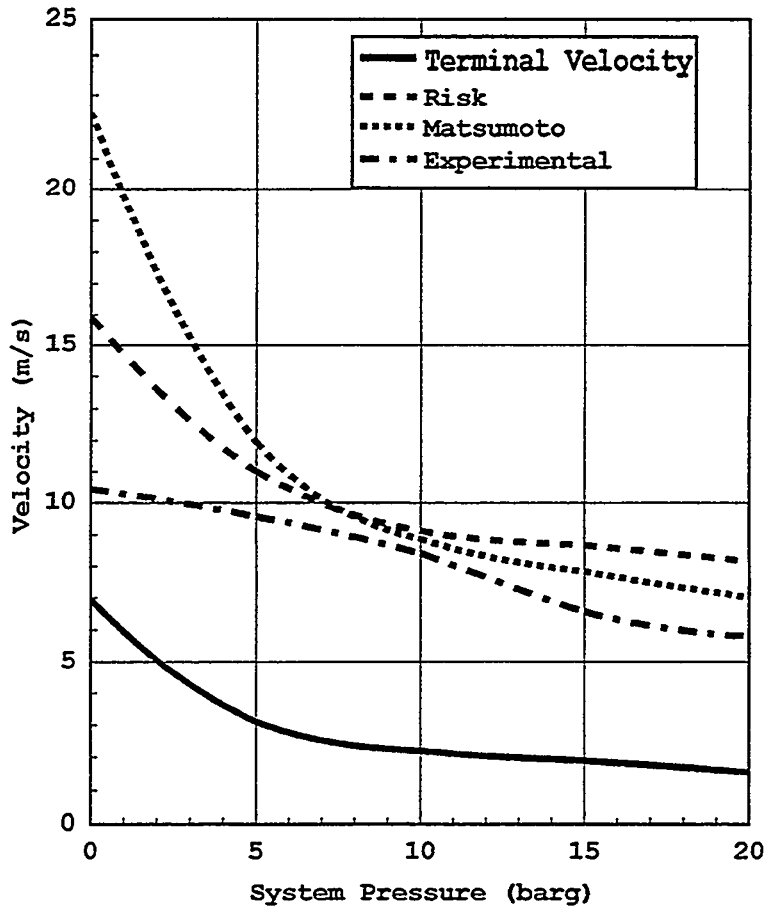

Figure 4 - A Comparison of Experimentally Derived Minimum Conveying Conditions and Calculated Saltation Velocities

COAL LOG ABRASION IN PIPELINES

by

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ABSTRACT

Coal log pipeline (CLP) is an emerging technology for long-distance transportation of coal that has many potential advantages over conventional modes of coal transportation including truck, unit train, and slurry pipelines. For CLP to be technically and economically feasible, the coal logs must be water-resistant and wear-resistant. No more than 3% of weight loss due to wear can be tolerated during pipeline transport. This paper gives data that suggest that such logs can be produced by compaction in a mold. Various factors that affect coal-log wear resistance are described, and methods to produce high-quality logs are discussed. Both laboratory and field tests data are used.

INTRODUCTION

Coal log pipeline (CLP) is the transportation of coal in cylindrical forms (coal logs) by pipelines. It is an emerging technology of many potential advantages over coal slurry pipeline including larger throughput, more water and energy efficient, easy dewatering and restart, lower cost and being a more versatile type of fuel.

Extensive R&D has been conducted on CLP since 1990 at the Capsule Pipeline Research Center, University of Missouri-Columbia. The R&D program covered all key areas of CLP including coal log compaction, hydrodynamics, injection system and pumping system design, automatic control of CLP, economics of CLP, and legal aspects of coal pipelines.

An important sub-area studied under hydrodynamics is coal log wear (abrasion) in pipe. It is important that coal logs wear as little as possible in pipe so that they can be transported by pipelines over long distances without suffering much damage or weight loss. This paper summarizes some key findings of the study on coal log wear. More details can be found in a recently completed Ph.D. dissertation (Cheng 1994).

CONCEPT OF LIFT-OFF

Before one can properly understand how coal logs wear in a pipe, one must have some understanding of the concept of "lift-off."

When the water velocity in a pipe is low, coal logs (which are circular cylinders heavier than water) slide along the pipe bottom. The contact friction between the logs and the pipe wall is high, and this generates high headloss (high pressure drop) and excessive abrasion. As the water velocity in the pipe increases, more and more hydrodynamic lift force is developed on the logs, and their contacts with the pipewall lessen. Consequently, less headloss and wear are encountered as the water velocity increases. When the water velocity in the pipe exceeds a critical value called "lift-off velocity," the logs in the pipe develop so much lift that they become totally suspended by the flow. However, such total suspension is not desirable because the logs become very unstable. They vibrate a great deal as they are transported by the flow, causing impact with the pipe wall. Experiments have revealed that operating a coal log pipeline at a velocity 15% below the lift-off velocity V_L appears to produce the least wear in pipe, where the lift-off velocity is calculated from (Liu 1982):

$$V_L = 7.2\sqrt{(S-1)gak(1-k^2)D} \tag{1}$$

where S is the specific gravity of the coal log (usually in the neighborhood of 1.3); g is gravitational acceleration (32.2 ft/sec^2); a is the aspect ratio which is the length of the coal log L_c divided by the diameter of the coal log D_c (namely, $a = L_c/D_c$); k is the diameter ratio which is the coal log diameter D_c divided by the pipe inner diameter D.

From Eq. 1, a 12-inch-diameter pipeline transporting logs of a = 2.0 and k = 0.92 yields V_L = 11.9 ft/sec. Operating this pipeline at 0.85 V_L means that the operational velocity will be about 10 ft/sec. At 90% linefill and 95% availability, this 12-inch coal log pipeline can transport 5.6 million short tons of coal per year. In contrast, a coal slurry pipeline of the same diameter will be operating at 6 ft/sec and transporting only half the coal carried by this coal log pipeline--2.7 million tons instead of 5.6 million tons by CLP.

COAL LOG WEAR MECHANISM

The coal log wear mechanism is closely tied to lift-off. At or near the lift-off velocity, the coal-log front starts to rise, assuming an angle-of-attack similar to that of an airplane taking off. The rear end of the coal log touches the pipe floor, causing some wear to the rear edge of the coal log especially if the edge is sharp. The wear of the rear edge of coal logs is usually uniform around (see Fig. 1), indicating that the logs rotate in the pipe near lift-off velocity.

In contrast, when the fluid velocity is much below the lift-off velocity, there is no lift-off and no angle-of-attack. The log slides along the pipe floor, causing front-end damage due to coal log impact with rough joints. Such damage is especially severe in pipelines having weld protrusions, or misalignment of the bottom part of pipes at joints. Because the fluid velocity is low and friction is high in this case, the log sides along the pipe floor without rotation. Consequently, the damage is all on one side and it gets progressively worse--see Fig. 2.

A typical wear test results for flow near the lift-off velocity is shown in Fig. 3. A single log was used in the test, and the percent weight loss is plotted against the time that the coal log has been in circulation through a closed-loop pipeline in the laboratory. Note that initially (within the first few minutes), weight loss is rapid due to rear-edge being rounded off. However, after about 10 minutes, the rear edge has become rounded, and further weight loss is at a much smaller rate over a longer period--the steady-state regime. Finally, after a long time, weight loss increases suddenly, causing catastrophic failure of the coal log. This last stage is due to coal log fatigue, caused by having the log bouncing against the pipe wall at velocity above the lift-off velocity.

FACTORS AFFECTING COAL LOG WEAR

More than twenty factors that affect coal log wear have been identified. Only a few can be discussed herein.

(1) Coal Type--Coal logs made by subbituminous coal is several times more wear resistant than those made of bituminous coal--see Fig. 4.

(2) Fluid Velocity--Operating coal log pipelines at velocities above 85% lift-off velocity causes increased wear--see Fig. 5.

(3) Bevel-Ended Log--When the rear end of a log is beveled (edge rounded), much less wear occurs than for a flat-end log with sharp (right-angle) edge--see Fig. 6.

(4) Aspect Ratio--Less wear logs for logs having large aspect ratios--see Fig. 7.

(5) Diameter Ratio--Larger diameter logs suffer less wear--see Fig. 8.

Other factors affecting coal-log wear include pipe interior roughness and alignment, pipe bends, pipe material, coal-log compaction conditions (temperature, pressure, amount of binder, etc.), mold type, mold condition, lubricants and so forth.

FIELD TEST

A field test of coal logs was conducted in Conway, Kansas, in 1994 (Liu 1994). The test involved sending 5.3-inch-diameter coal logs into a 6-inch nominal diameter steel pipe 5 miles long. The pipeline had rough joints (unknown amount of weld protrusions) and the maximum water velocity through the pipe was 6 ft/sec which is only two-third of the calculated lift-off velocity of 9 ft/sec. Twenty four (24) logs made of different processes were tested; three samples for each case. One set of logs was tested through the pipe twice—10 miles. The two weakest logs broke in the pipe before they completed the 5-mile journey--see Fig. 9. Interestingly, they did not cause jamming problems. The strongest logs traveled through the same distance with less than 1% weight loss. Due to the rough joints encountered and the low water velocity, the test condition was judged to be adverse--conducive to severe wear. Had the pipe joints been smooth and the velocity being higher by 20%, the logs would have had much less wear. Unfortunately, neither the pipe joints can be smoothened, nor the flow velocity increased without great costs. This experiment showed the importance of having smooth pipe joints and well-aligned pipes for future commercial coal log pipeline. According to our industrial consultant on pipeline construction (Sandmeyer 1994), such joints can be prepared by using existing construction technology with a minor increase in construction cost.

CONCLUSION

Extensive tests in coal log wear in pipe and advancement in coal-log fabrication technology have made it possible to produce water-resistant and wear-resistant coal logs for long-distance transportation by pipelines. For such logs to have less than 3% weight loss in 1,000 miles, the pipeline joints must be smooth, the logs must be compacted with a single-piece mold having a tapered outlet, the logs produced must have the tail end beveled, diameter ratio must be above 0.9, aspect ratio must be above about 1.6, the coal needs to be heated to 90°C prior to compaction and/or it needs a small amount of asphalt binder, and the water velocity should be at or near 85% lift-off velocity. More R&D is being conducted to further improve the quality of the coal logs, and to lower the manufacturing cost of coal logs. The goal is to demonstrate within two years that high quality logs can be mass produced at a cost no more than $3 per ton. Accomplishing this goal will not only hasten the commercialization of the coal log pipeline technology, it will also provide a low-cost method for coal agglomeration that is more economical than conventional briquetting and pelletizing.

ACKNOWLEDGMENT

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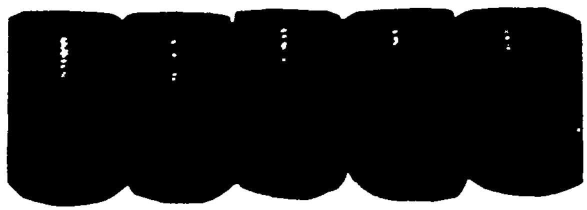

Fig. 1 Wear of 1.75-inch-diameter-Coal Logs at or near Lift-Off Velocity (Note that all the five coal logs tested in pipe had rear-end wear--rear being the bottom in the picture.)

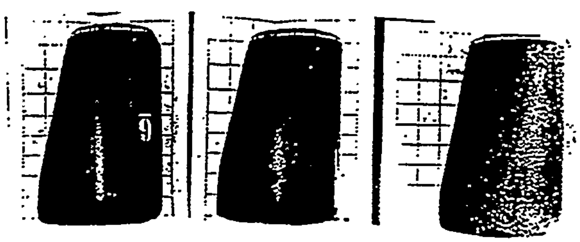

Fig. 2 Wear of 5.4-inch-diameter Coal Logs at 2/3 Lift-Off Velocity (Note the skewed wear on coal log front--topside of the picture.)

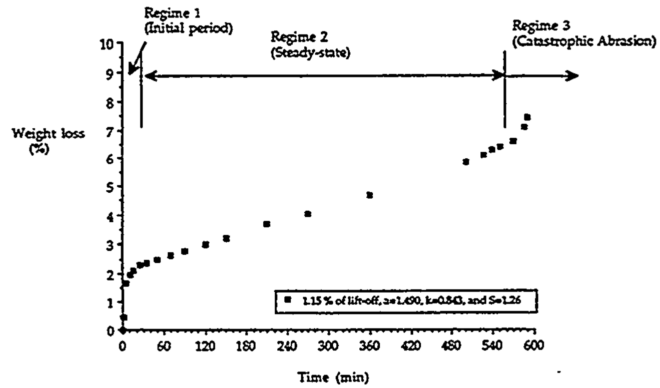

Fig. 3 Typical Result Illustrating the Three Stages (Regimes) of Coal-Log Wear in Pipeline (Note: Flat-end log compacted at 10,000 psi and 97°C with 2% binder; 1.75-inch-diameter log tested at 15% above lift-off velocity.)

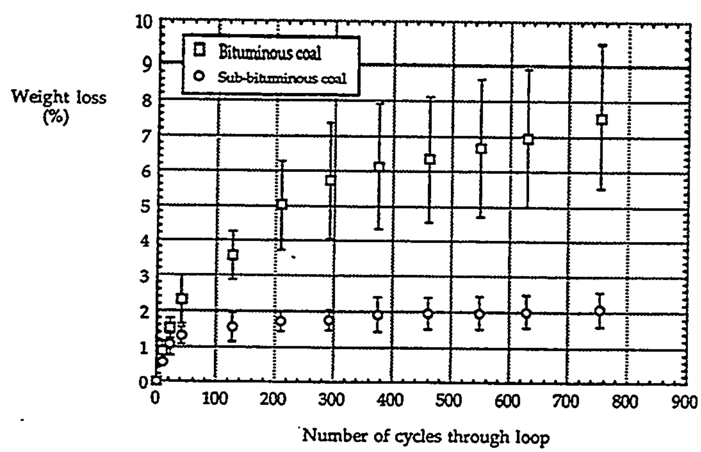

Fig. 4 Effect of Coal Type on Coal-Log Wear Resistance (Note: Flat-end logs compacted at 20,000 psi and 97°C with 2% binder; 1.75-inch-diameter logs tested at lift-off velocity.)

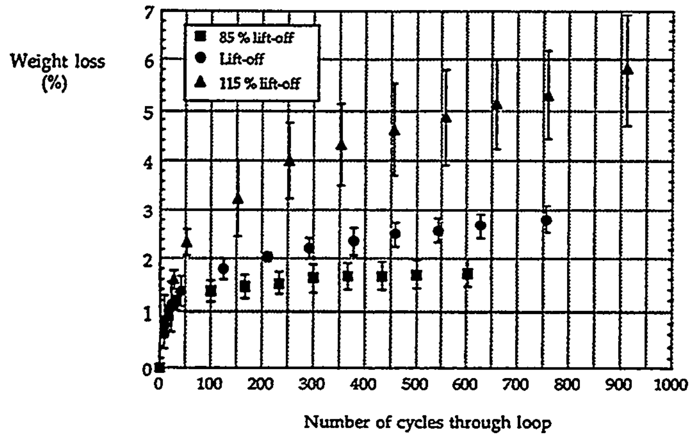

Fig. 5 Effect of Fluid Velocity on Coal-Log Wear Resistance (Note: Flat-end logs of 1.75-inch diameter compacted at 6,000 psi and 97°C, with 2% binder.)

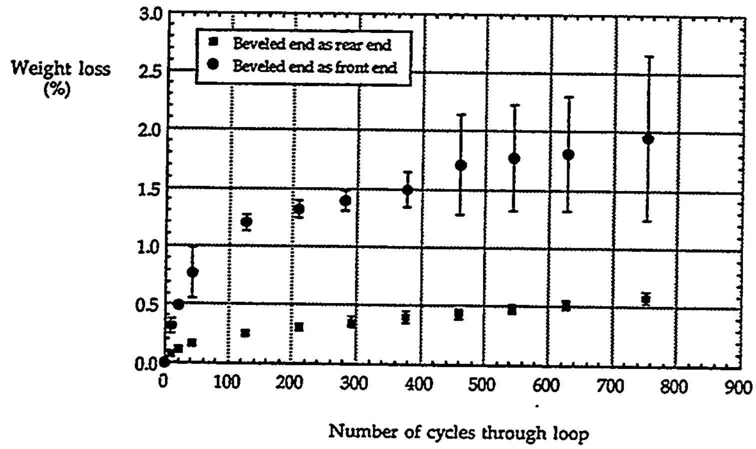

Fig. 6 Effect of Rear-End Edge Shape on Coal-Log Wear Resistance (Note: One-end-beveled logs compacted at 20,000 psi and 97°C with 2% binder; tested at lift-off velocity.)

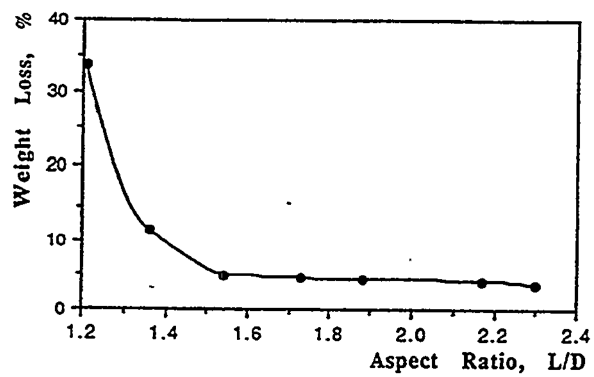

Fig. 7 Effect of Aspect Ratio on Coal-Log Wear Resistance (Note: Flat-end logs compacted without heating and with 2% binder. Data from Coal Log Compaction with Hydrophobic Binders for Pipeline Transportation, M.S. Thesis by B. Zhao, Mining Engineering Department, University of Missouri-Rolla, 1995.)

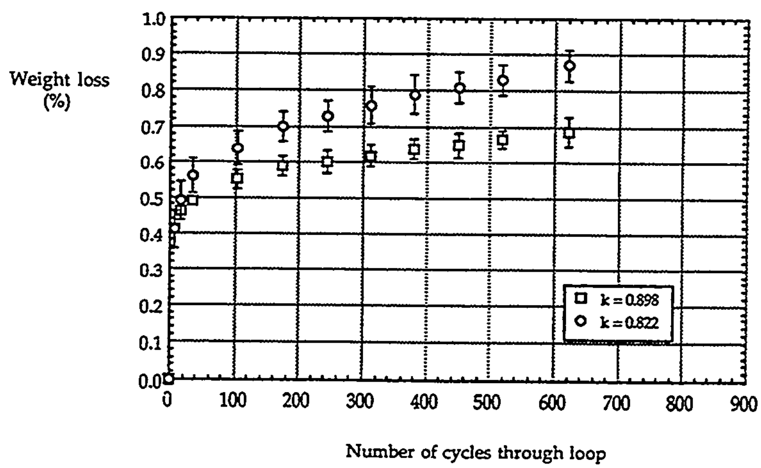

Fig. 8 Effect of Diameter Ratio on Coal-Log Wear Resistance (Note: Rear-end beveled logs compacted at 20,000 psi and 97°C with 2% binder; 1.75-inch-diameter logs tested at lift-off velocity.)

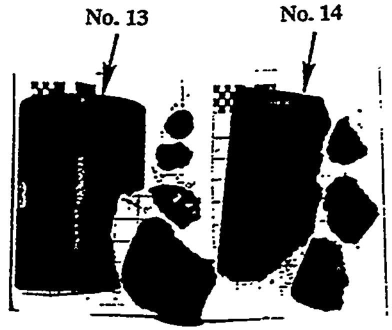

Fig. 9 Broken Logs in the Field Tests in a 5-Mile-Long 6-Inch-Diameter Commercial Steel Pipe with Rough Interior (Note: 5.3-inch-diameter logs tested at 2/3 lift-off velocity.)

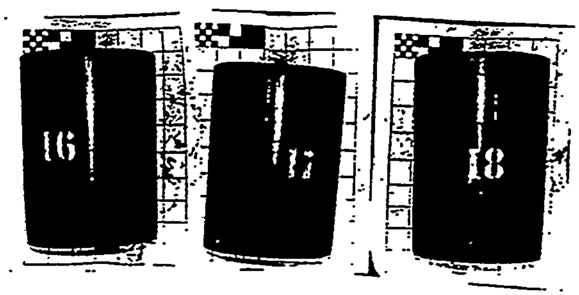

Fig. 10 Logs that Received Less Than 1% Weight Loss Due to Wear in a 5-Mile-Long 6-Inch-Diameter Commercial Steel Pipe with Rough Interior (Note: 5.3-inch-diameter logs tested at 2/3 lift-off velocity.)

EXPERIENCE WITH LATEST METHODS, AND OTHER MEANS, FOR DESIGNING AND ANALYSING PNEUMATIC CONVEYING PIPELINES

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SYNOPSIS

Pneumatic conveying pipelines are an essential part of coal utilisation systems of many types. In spite of this importance, the methods used for design (or analysis of operation) of these pipelines was largely neglected for a long time and it is only in the last few years that these methods have been developed significantly. The Wolfson Centre has undertaken much research on the subject, and some time ago developed an approach which has particular advantages. This has now been applied many times and the purpose of this paper is to report the experience gained in using this particular design method as compared with the use of other means, such as mathematical modelling and pipeline conveying characteristics.

The approach developed by The Wolfson Centre is described, and the relative merits of this versus other approaches will be discussed in the context of the type of requirement to be fulfilled in any given study; for example whether it is an entirely new design, improving the operation of an existing system, changing the coal specification, or other purpose.

INTRODUCTION

Application and design of pneumatic conveyors

Pneumatic conveyors, often known as "blowing lines", are frequently used in coal handling applications where particle size is relatively small (typically either pulverised fuel or sizes up to about 25mm, although occasionally sizes up to 80mm are handled in this way). The advantages of using pneumatic conveyors, compared with belt or en-masse conveyors, are that they can negotiate corners and vertical rises, the coal is contained to avoid spillage, and there are fewer moving parts to service. Where interfacing with an air-swept mill such as on a conventional pulverised-fuel fired furnace, there is clearly no other sensible choice for transporting the fuel from mill to burner. Other common examples include the injection of pulverised fuel into fluid bed combustors, bulk tanker delivery of powdered or granular coal or coke to small installations, and direct injection of coal into blast furnaces.

It is of course the pipeline which is the key element of a pneumatic conveying system, but such systems also require an air mover to provide the flow of air (usually a blower or compressor), a device for feeding the coal particles into the air stream, and a separator for disentraining the coal from the air at the destination.

One of the key difficulties in the use of pneumatic conveyors is the actual design of the pipeline and selection of conveying conditions. Design starts with a known conveying rate and pipeline route; the designer has to select the pipe bore and air flow required, then predict the pressure drop in order to choose a suitable air mover. There is a trade-off between the pipe size, air flow and pressure; smaller pipelines need less air, but at higher pressure, for any given duty. This has consequences for energy usage and capital cost. A key question usually asked at the design stage of a conveying system is "is it to be a lean phase or dense phase system?; the answer to this question has a strong bearing on the choice of pipe size, air flow and pressure.

Lean and Dense Phase conveying

These fundamentally different modes of conveying are illustrated in figure 1. In lean phase (suspension) flow, sometimes referred to as dilute phase flow, the air velocity is high enough to carry the particles in the flow as a suspension. In dense phase (non-suspension) flow, the air velocity is lower; here some or all of the particles slide along the pipe in a moving bed, or in slugs or plugs of material.

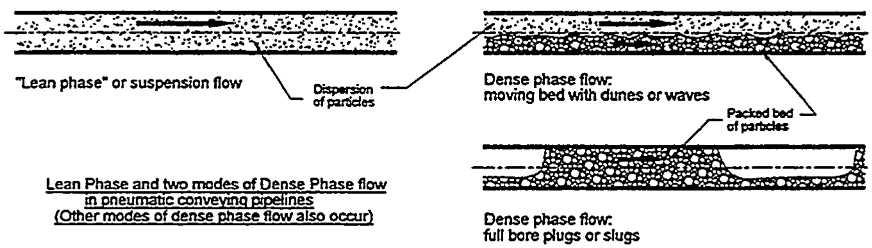

Fig. 1
Modes of flow in pneumatic conveying systems

Dense phase flow offers certain advantages because of the lower air velocity. Compared with lean phase flow there is less breakdown of the particles, and less wear of the pipeline bends. Also, the pipeline will be smaller for a dense phase conveyor. The energy consumption is also lower, but because of the higher pressure needed to convey in dense phase the capital cost of the conveying plant is higher. An in-depth discussion of choice of modes of flow, and other aspects of pneumatic conveyor design can be found in reference 1.

Prediction of pressure drop

Whatever the choice of conveying mode, or system requirement, it is necessary for the designer to predict the pressure drop along a proposed pipeline, if he is to make an economic choice of pipe bore, and a suitable selection of air mover and feeder. Getting the pressure drop prediction wrong can mean poor performance, or even total failure of the conveyor.

The ordinary Darcy equation, used for prediction of pressure drop in gas or liquid flow, cannot be used. The difficulty is exacerbated by bends in a conveying pipeline, which can contribute a substantial proportion of the overall pressure drop (sometimes as much as 80% in a lean phase system), whereas in a liquid or gas system their effects are small.

To understand the advantages of the improved method of predicting pressure drop, which is the true focus of this paper, it will be useful to review the background which led to its development.

HISTORICAL METHODS OF PRESSURE DROP PREDICTION

From experience

A method used by some designers, when faced with the need to design a pneumatic conveying pipeline, has been to base their design on records from a previous successful system. They take the figures for pipe bore and length, air flow, and actual pressure drop, and then "scale" the conditions to the new pipeline by using factors for changes in these quantities.

One difficulty with this method is that the new pipeline will often be conveying a different specification of coal from the old one. It is well documented that coals of different sizes and from different sources will give widely differing pressure drops when conveyed under the same conditions. For this reason alone, this method is a recipe for failure. Even if the conveyed solids are exactly the same, the data will only cover one combination of air velocity and concentration of solids in the air, out of a whole range of possible ones which could have been used. Because of this, the designer's choice will be limited, often to a condition which gives a poor economic choice.

An additional difficulty is in the "scaling" technique, i.e. in making the calculations to allow for differences in length, bore, throughput, number of bends etc. between the old and new systems. Scaling techniques are discussed below, and are not as accurate as would be liked.

Scaling from tests on an overall pipeline

Better than just going from experience, is to take a sample of the material to be conveyed, blow this around a test pipeline in a laboratory and record the relationships between flow rates of solids and air, and pressure drop, then use this test data as a basis for design. This method has the advantage that the data used covers a variety of conditions, allowing a degree of optimisation, and relates to the actual material which is to be conveyed. The rig used at The Wolfson Centre for this approach has a pipeline loop of 2, 3 or 4 inch bore, 50-200m long, and about one to three tonnes of coal is used in trials.

This method is fairly reliable, and is used by a number of reputable suppliers of pneumatic conveying systems. Its biggest drawback, however, still lies in the difficulty of scaling up from the test pipeline to the plant pipeline, which is usually a good deal bigger. Scaling for the pipe bore is quite reliable, but scaling for the length, and number and position of bends, are especially difficult.

The insuperable difficulty with a technique based around "scaling" from one complete pipeline to another arises because the air velocity increases along the pipeline, as pressure falls. The bends, then, all have different air velocities through them and so each gives a different pressure drop, making it difficult to scale accurately for the effects of bends. Because the bends are often major contributors to the overall pressure drop, the effect of the number of bends on the system pressure drop cannot be predicted accurately.

Design from mathematical models

Design from mathematical formulae is not reliable. Many papers have been published on the subject, but there is still no agreement on any reliable mathematical models to predict either the pressure drop or limits of conveyability of products of industrial interest. The use of Computer Fluid Dynamics (CFD) has also received quite a lot of attention, but has not yet been shown to be capable of making useful predictions.

DEVELOPMENT OF A NEW METHOD

A consideration of the problems with the above-mentioned techniques of making pressure drop predictions led The Wolfson Centre, several years ago, to embark upon a programme to develop a better method. This method would still involve testing the material to be conveyed on the plant, but should eliminate the need to scale for the number of bends between test and plant pipelines.

Description

The method developed by The Wolfson Centre still involves conveying trials, but using a specially instrumented pipeline and taking separate data on pressure drop in straight pipes and bend losses. The test pipeline used is shown in figure 2; 2in, 3in, and 4in nominal bore test pipelines are available, in an identical layout. There are pressure transducers along the long straight sections before and after the test bend, monitored by a data logging system, and the receiving hopper is mounted on load cells so that flow rate of solid can be measured. Flow rate of air is set using choked flow nozzles.

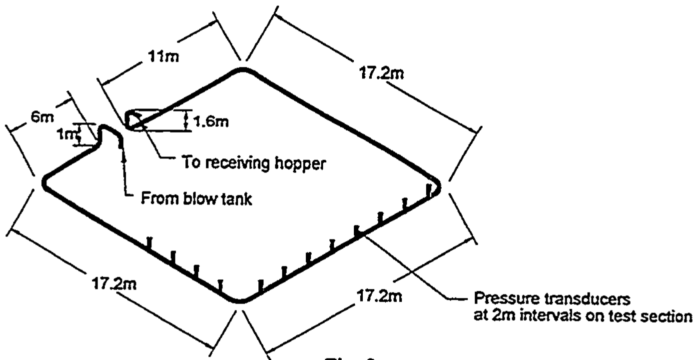

Fig. 2
The instrumented test pipeline used

A sample (between about 200 to 2000 kg) of the material to be conveyed is loaded into the test rig, and a number of conveying tests are undertaken, the conveying conditions and the pressure drops being measured in each.

The use of the pressure transducers on the straight sections allows the pressure gradients along these sections, and also the pressure drop caused by the test bend, to be measured accurately. A more detailed description of the method can be found in reference 2, and a full description of the test plant in reference 3.

Making pressure drop predictions

The data from the tests are stored, in the form of graphs and/or equations. To make a prediction of pressure drop in any proposed plant pipeline, a computer program is used which calls upon this data. It works along the proposed pipeline finding pressure drop and conveying conditions in each bend and straight in turn, and summing these pressure drops as it goes along. It should be emphasised that this information is found from correlations of the data which was generated in the conveying trials, so that the design is based on conditions which have been achieved and measured in the test line, and not on theoretical equations.

The flow chart for the computer program is shown in figure 3. This is shown in the format used for dealing with positive pressure pipelines, for which it begins at the end of the pipeline where the pressure is known to be atmospheric and works backwards along the line to find the pressure at inlet. For dealing with vacuum pipelines, the procedure is reversed, the program beginning with atmospheric pressure at pipeline inlet and working forwards along the line to find the outlet vacuum.

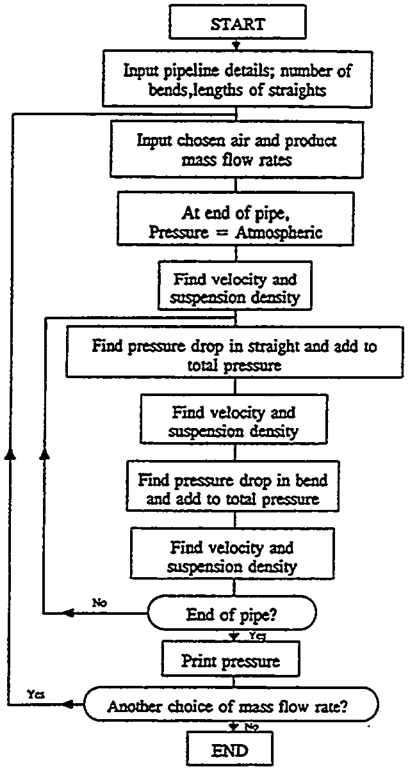

Fig. 3
Flow diagram of the computer program used to predict pipeline pressure drop

EXPERIENCE WITH THE NEW METHOD

The new method described above has now been in regular use at The Wolfson Centre for pneumatic conveying system design, for about five years. During this time a number of advantages have become apparent, as follows.

Use for Stepped Bore Pipelines

One advantage of the new method, which was apparent from an early stage, is that it can be used easily to predict pressure drop in pipelines which have an increase in bore size at some point along the length. These had been difficult to deal with using a "scaling" type of approach.

Principle of stepped bore pipelines

Since air is compressible, it expands as it travels along a pipeline, because of the reduction in pressure from inlet to outlet. Thus the volume of air increases along the pipe and if the pipe is of constant bore, so the air velocity will also be increasing all the way along the pipe.

Consequently, if the air velocity is sufficient to transport the product reliably at inlet, it will be excessive further along the pipe. Excessive air velocity means excessive power consumption, excessive pipeline wear and unnecessary particle breakdown. But if the bore size is increased along the line, the expansion will be compensated for, keeping air velocities down to reasonable levels, giving reliable operation but avoiding these problems.

Although well understood for many years, this principle had been difficult to apply using a "scaling" approach because it had not been possible to decide accurately where to place the steps, or how to predict pressure drop, bearing in mind that scaling techniques were developed to deal with pipes of constant bore size.

Design of stepped bore pipelines

The improved method, however, could deal with stepped pipelines readily, simply by changing the pipe size in the calculations at a point somewhere along the pipeline. Several different points could be tried out and the most appropriate determined by calculating the air velocities after the step, which should not fall below the inlet air velocity of the pipeline. Note that the minimum air velocity required for successful conveying is determined as part of the conveying trials.

Case study of a stepped bore pipeline

The following example shows the benefits of employing a stepped bore pipeline for a specific duty. In this example the requirement was to convey a material at 60 tonne/hour through a pipeline 60m long having 15 x 90° bends equi-spaced. In this particular case, the pipeline was feeding into a reactor at 1.3 bar gauge rather than the usual case of a silo at atmospheric pressure, but this makes little difference to the analysis. The minimum conveying air velocity to transport the product reliably was taken as 11.8m/s, both at pipe inlet and immediately after steps.

The product was abrasive, so the use of blind tee bends[1] was proposed; this does not affect the analysis, except insofar as this was the type of bend used in the test work. The material was conveyed in the instrumented pipeline using this type of bend, to produce data on bend and straight pipe pressure losses. This data was then fed into the computer program which was used to predict the performance of both constant-bore and stepped-bore lines for the given duty.

Profiles of air pressure and air velocity against distance have been produced for both stepped and constant bore pipelines, to show the effect of the steps on the air velocities and pressure drop. Figure 4 shows the pressure along the pipeline whilst figure 5 shows how air velocity varies.

Looking first at air velocity, figure 5, it is evident that in the single bore pipeline the air velocities at the end of the line are extremely excessive, at 47m/s as compared with the 11.8m/s which is the minimum necessary to transport the product reliably. Such a high air velocity will result in very rapid wear of pipeline bends and other components. Also there would be a good deal of production of fines from particle attrition, leading to dust problems.

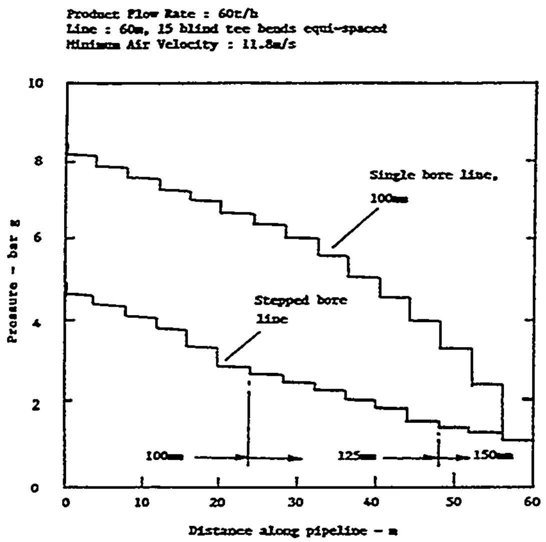

Fig. 4
Pressure-distance diagrams for the
pipelines with constant and stepped bore sizes

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[1]Note that a blind tee bend is a bend made up from a tee piece, with the flow entering along the run of the tee, which is capped at the far end, and discharging through the branch. This type of bend has the advantage of a much greater service life than radiused bends when handling abrasive materials, although they cause greater pressure drop.

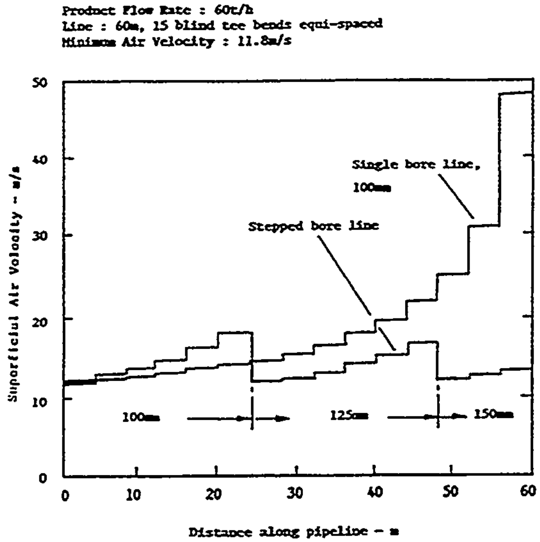

Fig. 5
Velocity-distance diagrams for the
pipelines with constant and stepped bore sizes

When using the stepped line, however, the air velocity is kept under control by increasing pipe bore at two points, so that the maximum air velocity is just 18m/s. The reduction in wear would be very significant, especially in view of the general agreement that wear rates increase in a power law manner with velocity, much greater than in direct proportion. Consequently, the lives of system components would be extended many times by employing the steps in bore size.

Turning to the pressure drop, figure 4 shows that the much lower air velocities in the stepped bore line cause much less pressure drop. Consequently, because the inlet pressure is much lower, the free air flow rate needed to achieve the same inlet air velocity is also much lower, so the saving in power consumption is very significant, coming down from 490 to 180kW. This allows a saving of some £38,000 sterling per annum based on 312 days per year and an electricity cost of £0.05 Sterling per kWh.

From this simple case study it is evident that the benefits of using a stepped pipeline can be very noticeable in terms of running costs as well as reduced maintenance and kindness to the product. Clearly it is necessary to position the steps correctly if benefits are to be realised, but this can be done easily using the improved design method advocated above.

Dealing with non-horizontal pipelines

Most test pipeline loops tend to be installed with the pipes lying in an horizontal plane, for convenience. Some test loops have vertical sections, but usually they have both risers and downcomers, so there is little nett elevation around the loop; few have routes on a steady incline or decline. Occasionally, though, it is necessary to design plant pipelines with these features.

Predominantly vertical pipelines

One of the test loops at The Wolfson Centre has vertical sections, running both down and up, now instrumented with pressure transducers at 2m intervals. When dealing with a plant system which is predominantly vertical, the material sample is conveyed through this loop and the data on pressure drop in the riser or downcomer is recorded, for use in predicting the operation of the plant pipeline. Such work has been undertaken a number of times, and it has proved to be particularly valuable where steps in bore size have been required to keep air velocities in check.

Inclined or declined pipelines

These are usually best avoided if possible, but in some cases are inevitable, for example if conveying a long distance down a mountainside. To design a pipeline on an incline or decline requires data from a test section operating at the appropriate angle. In such cases, the longest straight run in the test loop has been angled to the same inclination or declination as proposed for the plant line (e.g. figure 6), and data taken from this section in operation. This data has then been used for design of the plant pipeline.

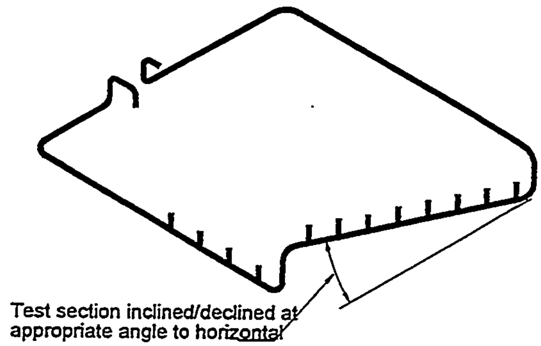

Fig. 6
The instrumented pipeline with the test section set to
a decline equal to that to be expected on the plant pipeline

An interesting and unexpected phenomenon which has been noted when using declined pipelines, has been the amount of pressure gradient reduction observed along the test section. Under some conditions, the difference between the pressure gradient down the declined section and that in the horizontal sections, has exceeded the effective static head of air/solid mixture in the declined section. It would of course be expected that the pressure gradient would be lower when going downhill; elementary mechanics would suggest:-

Pressure drop in declined section length l, falling a vertical distance h	=	pressure drop in horizontal section length l	-	ρ.g.h

Where ρ = effective density of air and solids in the section, g = acceleration due to gravity.

In fact, measurements have shown that the reduction can be anywhere up to six times the magnitude of the (ρ.g.h) term, even with a relatively modest gradient of 1 in 3. This work has been reported more fully in reference 4.

CONCLUDING REMARKS

The improved design technique described above offers significant advantages over what went before. It uses actual data from the product to be conveyed to predict pipeline performance, and it is very quick, flexible and convenient in use. It has been applied successfully for design of both lean and dense phase pipelines.

Perhaps its most important advantage is that it enables stepped pipelines to be designed properly. These have been shown to offer very significant benefits in terms of energy-efficiency, as well as reduction of pipeline wear and product damage. In virtually any case where the overall pressure drop is above about 0.6 bar, stepping the bore gives very significant savings in energy cost, maintenance and product damage.

The advantage of being able to use the technique to design long vertical pipelines, or inclined or declined pipelines, is also significant. Although such cases are not very common, they can now be dealt with in a much more satisfactory way than previously.

The Wolfson Centre is currently using this technique on a commercial basis, with success. Experience from this shows that many of the problems currently experienced by users of pneumatic conveyors can be cured, or better still can be prevented by good design practices in the early stages of plant design.

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This paper was unavailable at the time of publication and may be obtained directly from the author.

RESULTS OF ON-LINE MASS FLOW RATE MEASUREMENT TESTS IN A PILOT PNEUMATIC COAL INJECTION SYSTEM USING AN ELECTROSTATIC MEASUREMENT TECHNIQUE

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ABSTRACT

It has been widely accepted for some years that combustion efficiency of coal fired electricity generating plant could be significantly improved by the use of a control system which had the ability to operate the boilers in a balanced way at optimum stoichiometric ratio. One of the requirements of such a control system is the ability to measure the flow rate of pulverised coal (PF) within the pneumatic PF injection system, which feeds the PF to the boilers. In recent years, The Wolfson Centre at the University of Greenwich has undertaken a programme of work aimed at the development and evaluation of such a measurement system.

This paper details the operating principle of a measurement system based on a non-intrusive electrostatic sensing technique. Results of evaluation trials on a pilot scale PF injection system will also be presented, along with discussion of the presented data.

INTRODUCTION

The pneumatic injection of pulverised coal (PF) into combustion processes is widespread in both the electrical power generation and cement manufacturing industries as the primary means of firing boilers and kilns. In order to allow optimum operation of such combustion processes, it is important that the feed rate of PF is closely matched to the feed rate of air at each burner, providing correct stoichiometric combustion. Recent increases in the awareness of the environmental issues have lead to significant worldwide initiatives to reduce emissions from such plants, thus placing a renewed emphasis on optimal operation.

In order to effect control of the fuel-air ratio at the burners of such systems, it is necessary to measure the mass flow rate of PF in the respective injection duct. Techniques for such measurements have been under investigation for a number of years (McVeigh and Craig 1971, Beck et al. 1982, Klinzing et al. 1987, Boeck 1989 and Gajewski 1994), a review of much of this work having been published elsewhere

(Woodhead et al. 1990). It is however apparent that none of these techniques have found wide application in industry.

The work reported in this paper concerns the testing of a mass flow rate measurement system based on non-intrusive electrostatic sensing technology and using cross correlation signal processing techniques. It is essential that any such technique is inherently of a non-intrusive nature, due to the highly aggressive environment present inside the injection duct.

The technique detailed in this paper requires the measurement of two independent variables; namely the average particle velocity and the average density of the flowing gas-solid suspension. These two values, along with a knowledge of the pipeline cross sectional area can be combined to give solid phase mass flow rate.

MEASUREMENT EQUIPMENT

Sensor Arrangement

A block diagram of the electrostatic sensor arrangement is shown in Figure 1. Two steel ring type probes are incorporated into the wall of the test pipeline, each being separated from the steel pipeline by insulating nylon rings. An earthed guard ring is also incorporated between the two ring probes.

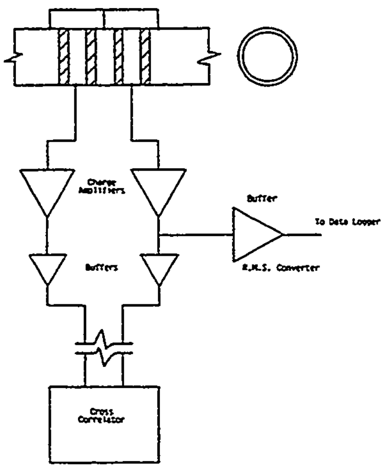

Figure 1 Block Diagram of Electrostatic Sensor Arrangement

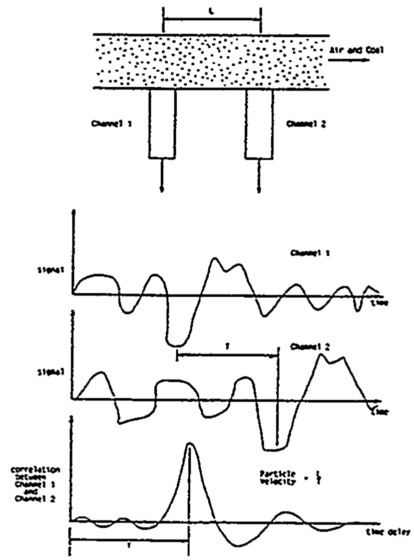

Figure 2 Principle of Cross Correlation Velocity Measurement.

It is important to realise that the principle of operation of the sensors is that of charge induction and not charge transfer by contact. No contact is required between the solid particles and the sensing electrode since the electrodes operate by sensing the disturbance to the electrostatic field caused by the passage of charged particles. The principle of operation of these sensors is further explored in a separate paper currently in press (Murnane et al 1995).

Signal Processing

Each of the two axially spaced electrodes is connected to the input of their own charge amplifier. The output of each charge amplifier is then connected to an input channel of the cross correlator via buffer amplifiers and cabling. The output of one charge amplifier is also processed to produce a signal proportional to the RMS value of the derivative of the charge on the respective sensor, this being used to indicate suspension density.

The principle of the cross correlation velocity measurement technique is shown in Figure 2. Disturbances to the electrostatic field in the vicinity of each sensor are sensed by the charge amplifiers. Since these sensors are spaced axially along the pipeline in close proximity to one another, the disturbances sensed by the first sensor will be very similar to those sensed by the second sensor, there being very little opportunity for the charge pattern to change in the intervening distance. This allows accurate cross correlations to be obtained.

Details of the cross correlation equipment used for this work have been reported elsewhere (Coulthard and Keech 1981), and so will not be detailed here. The transit time of inhomogeneous elements of the flow between the sensors, T, is determined from the cross correlation function. This is then used, with a knowledge of the sensor spacing to calculate a value for the average particle velocity.

The Pilot Test Plant

A pilot scale test facility was used to provide the gas/solids flow. This test facility is illustrated in Figure 3. Clean dry compressed air is supplied to the facility from the main laboratory air supply. The flow rate of air to the test pipeline is then controlled by a pressure regulator and a bank of choked flow nozzles. Air is fed in accurately metered amounts to the PF feeder, as well as directly to the conveying pipeline, thus allowing a wide range of operating conditions to be achieved. The PF/air suspension then passes along the test pipeline, which is of 53mm bore steel tube to the electrostatic sensing system, situated 7m from the PF feeder.

The PF/air suspension then passes via a return pipeline section, also of steel, to a receiving hopper, where the suspension is separated by a cloth bag filter, the air passing to atmosphere, and the PF being retained for re-use. The receiving hopper is mounted on load cells, thus facilitating the measurement of mass flow rate of PF within the system. The flow rate of air and PF are monitored at all times by a computerised data logging system, which also records the values of average particle velocity and suspension density determined by the electrostatic sensing system.

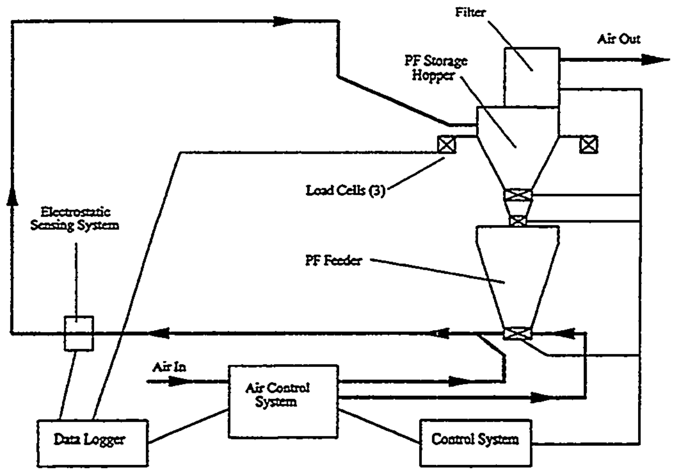

Figure 3 The Pilot Scale Test Facility.

TESTING OF THE MEASUREMENT SYSTEM

Testing of the system was undertaken for a range of average air velocities between 20 and 45m/s, and for a range of suspension densities from 0.1kg to 10.0kg of solids per cubic metre of air. The mean particle size of the solid particles used was approximately 60 microns. All of the tests were carried out using PF. Data from the two measurement systems, namely that to determine average particle velocity and that to determine suspension density were recorded for each test condition.

For each test condition, both the velocity and suspension density measurements were averaged over a period of approximately 30s whilst the test rig was operating in a steady state condition.

TEST DATA

Velocity Measurement Test Data

For the purposes of evaluating of the accuracy of this component of the measurement system, the average particle velocity readings obtained from the cross correlation system were compared with the average air velocity in the pipeline. Data previously obtained using laser doppler velocimetry (Woodhead et al 1995, in press) indicates that over much of the range of relevant test conditions, the average particle velocity is within $\pm 2\%$ of the average air velocity. It should be noted however that the combined accuracy of the sensors used to evaluate the average air velocity is of the order of $\pm 1\%$. The comparative data is presented in Figure 4.

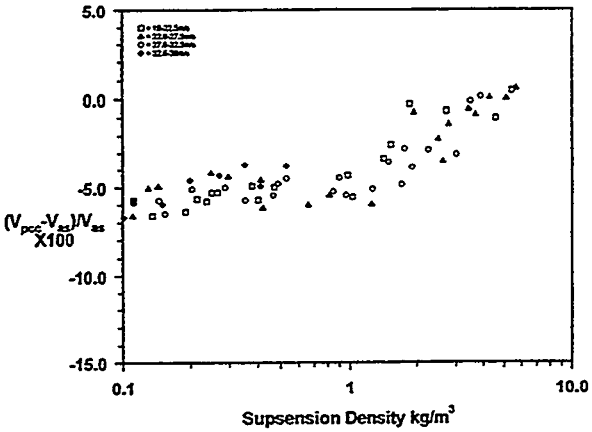

Figure 4 Graph of Percentage Difference Between Pipeline Air Velocity and Average particle Velocity Determined by Cross Correlation Against Suspension Density for a Range of Conveying Air Velocities.

Suspension Density Test Data

The suspension density data obtained from the electrostatic sensing system was compared with values of actual suspension density derived from solids and gaseous phase flow rate measurements obtained at the inlets and outlets of the test rig. The combined accuracy of the method used to evaluate actual suspension density was of the order of $\pm 2\%$. This comparative data is plotted in Figure 5.

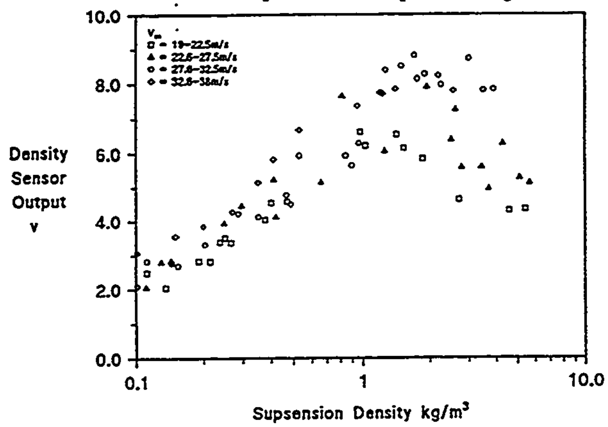

Figure 5 Graph of Suspension Density Sensor Output Voltage Against Actual Flow Suspension Density for a Range of Conveying Air Velocities.

DISCUSSION

Average Particle Velocity Measurements

It is apparent that the data presented in Figure 4 has some scatter, however, much of this can be accounted for by the combined accuracy of the sensors used to evaluate the average air velocity in the pipeline. It is further apparent that over much of the range of test conditions, the value of velocity obtained by cross correlation is approximately 5% below that of the corresponding average air velocity. Furthermore, this error is not consistent; the error reducing as suspension density increases.

The discrepancy between the velocity values is almost certainly due to a combination of the presence of a velocity profile within the pipeline, giving rise to lower particle velocities close to the pipeline wall, and the relative sensitivity of the electrostatic sensors to the passage of particles in the region close to the pipeline wall. Furthermore, there is evidence to suggest that the velocity profile may change as a result of the presence of particles within the flow at suspension densities around 0.5-1.0kg/m^3 (Prandtl 1952, Kolansky et al 1976 and Woodhead et al 1992), this leading to a flattening of the velocity profile, and therefore the presence of higher velocity particles close to the pipeline walls. The presence of such phenomena would account for the improvement in accuracy of the cross correlation method with increasing suspension density.

Suspension Density Measurements

This data may be usefully divided into two sections; that for suspension densities above 0.5kg/m^3, and that for suspension densities below 0.5kg/m^3. For the lower range of suspension densities, there is a small amount of scatter on the data. There is also a discernable sensitivity to conveying air velocity. If the output voltage dependency on conveying air velocity is disregarded on the basis that it is possible to compensate for it in the PF mass flow rate calculation, then from visual inspection, the scatter on the points is in the region of $\pm$ 0.3v, which represents $\pm$3% of the full scale sensor output. In view of the likely accuracy of the values of actual suspension density used, this is considered to be encouraging.

For the higher range of suspension densities above 0.5kg/m^3 the performance of the sensor is very different. The scatter, even for a fixed value of air velocity, increases markedly, as does the sensitivity to velocity and above a suspension density of approximately 2.0kg/m^3, the sensor has negative sensitivity. The performance of the sensor under such conditions is a cause for concern and clearly cannot be utilised in its present form.

CONCLUSIONS

The results of the test work undertaken clearly demonstrate the feasibility of the technique described, although areas of weakness in the measurement system have also been identified. Further research work is currently under way to improve the understanding of the fundamental operating principles of such sensors, as well as the electrostatic charging and discharging mechanisms of fine particles under conditions of pneumatic injection.

It is hoped that the results of such research will allow the measurement system described to undergo further development, aimed at reducing the relative sensitivity of the sensors to particles close to the pipeline wall, and increasing the range of conditions over which a linear response can be obtained from a suspension density sensor.

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THE SENSING OF UNBALANCED PULVERISED FUEL FEED RATES AT THE EXIT OF RIFFLE BOXES IN COAL FIRED POWER STATION FUEL DISTRIBUTION SYSTEMS

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ABSTRACT

Considerable energy is lost in large coal fired boiler furnaces due to the poor distribution of pulverised fuel (PF) to the burners. The main cause of this problem lies in the deficiencies of the splitting of pneumatically conveyed PF at the various pipe bifurcations due to roping and also wear of the riffle boxes. The losses occur because the majority of the combustion air is supplied separately to the furnace and is equally divided between the burners, consequently stoichiometric conditions will not be met at each burner if the fuel feeds are unbalanced. Improvements in efficiency will be possible by the individual control of the secondary air to the burners if the relative mass flow rates of the fuel at the burners are known.

This paper reports on the techniques being developed at the Wolfson Centre for Bulk Solids Handling Technology at the University of Greenwich, London, UK which will have application to the measurement of the relative mass flow rates at the exit ports of the final stage riffles in a PF distribution system. Information is also given as to how the measurement process may be incorporated into existing riffle box designs of boiler furnaces and feed lines.

INTRODUCTION

Coal fired power stations are generally regarded as the type of power station producing the most harmful emissions when compared to other power generation stations, such as gas fired stations and those based on renewable resources. By-products of the combustion of coal include sulphur dioxide, nitrogen oxides, carbon monoxide and carbon dioxide, all gases regarded as harmful to the Earth's atmosphere. Clearly it is important to keep production of these compounds to a minimum, and increasingly stringent regulations are forcing power generation companies to reduce their emissions to conform to approved levels.

In spite of recent advances in combustion technology many fossil fuel fired power stations still suffer from producing relatively high levels of emissions, and one factor of prime importance is that the generation of power should be as efficient as possible. Any loss of efficiency, not only entails an economic penalty, but also means that more emissions than necessary are produced for the same power output. The first aim of this paper is to present information as to the possible loss in efficiency that can result from the unequal distribution of pulverised fuel to the burners in large boilers, and a second aim is to outline possible methods of measuring the distribution of pulverised fuel flow rate and to use this information to adjust the secondary so as to achieve stoichiometric conditions at each burner.

PULVERISED FUEL DISTRIBUTION SYSTEMS IN LARGE FURNACES

Large coal fired boilers are generally fed from a series of mills running on line that pulverise the coal being fed to the boiler into a fine dust known as pulverised fuel (PF). The pneumatic conveying pipeline from the output of a single mill will typically have a diameter of the order of 1m and will be bifurcated, three times, to produce individual feeds to 8 individual burners. A very large furnace of above, say 1000 Mw of thermal input power, may well have 4 or 5 mills providing the feeds for up to 40 individual burners.

A schematic of the fuel supply system for a typical large PF fed boiler furnace is shown in Fig.1. Each of the 4 mills feeds 8 burners, and the air used to convey the pulverised fuel from the mills (termed the primary air) is usually about 20% of the air required for total combustion. This fraction is employed so as to produce a conveying velocity of around 25 $m.s^{-1}$ which is high enough to maintain the PF in suspension. The additional air required for complete combustion (termed the secondary air) is supplied separately and is mixed with the pneumatically conveyed PF at, or just prior to, the individual burners.

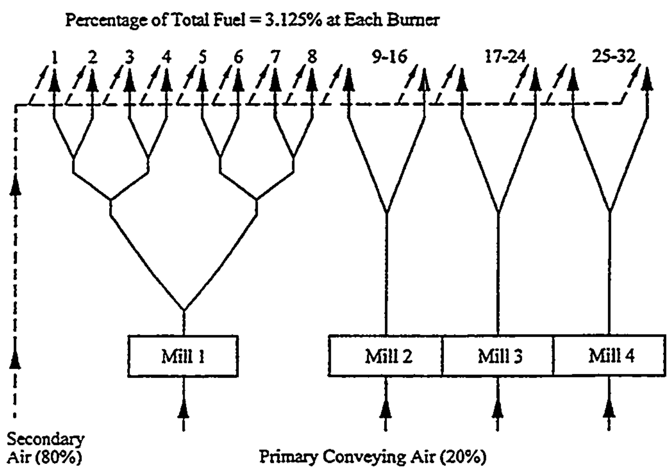

Figure 1 Schematic of a Furnace Fuel Feed System Using 4 PF Mills

Such an arrangement of primary and secondary air is adopted for two reasons. Firstly, if all of the air required for complete combustion were to be used to convey the PF, all of the PF in transit from the mill to the furnace would constitute a highly explosive mixture and would be an unacceptable hazard. Secondly, the velocity would be much higher than needed to obtain satisfactory conveying conditions which would result in excessive erosion of the pipework.

The secondary air supplied to the burners is arranged so as to provide a group of burners associated with a given mill with the necessary air for the complete combustion of the PF and is split equally between the burners within the group.

The ideal situation for such a furnace is for each burner to receive the same quantity of fuel per unit time and to also receive equal quantities of air in the correct ratio to the fuel so as to produce complete combustion. The fuel and air percentages shown on Fig.1. constitute the ideal.

The main operational problem with the PF distribution systems outlined above is that the fuel does not necessarily split evenly at the pipe bifurcations. The flow of particulate material in pneumatic conveying lines is complex and the distribution of the particles over a pipe cross section is generally not uniform. Such patterns of uneven distribution, known as roping, can be stable and can cause severe unbalance in the split ratio at a pipe bifurcation. The uneven split may be minimised by fitting a riffle box at the bifurcation and a sketch of a simplified riffle box is shown in Fig.2. The upward inlet flow to the riffle is divided into 8 equal area slots and the PF flowing into adjacent slots is alternately directed to the left and right outlet ports, ie the flow into input slots 1, 3, 5, and 7 is directed to the left hand output port, and the flow into input slots 2,4,6 and 8 is directed to the right hand output port.

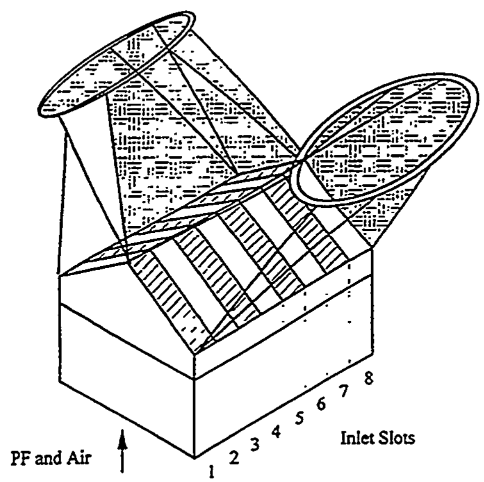

Figure 2 The Principle of Operation of a Riffle Box

The use of riffle boxes considerably improves the split ratio at pipe bifurcations but over a period of time they become eroded and their efficiency is gradually reduced.

CAUSES OF EXCESS LOSSES IN PF FURNACES

The combustion of PF in a furnace requires a given quantity of air per unit mass of the fuel. The quantity of air depends upon the precise chemical composition of the fuel and is termed the theoretical air. In all combustion processes it is necessary to provide more air than this theoretical quantity to achieve as near complete combustion as possible. In the case of PF burners the air required for complete combustion is around 123% of the theoretical air.

If the quantity of air is less than this value incomplete combustion will occur with the result that some of the carbon burns to form carbon monoxide (CO) rather than carbon dioxide (CO_2), and some carbon in ash loss also occurs. These two factors represent a loss in efficiency as not all of the thermal energy is recovered from the fuel.

If the combustion air is greater than 123% of the theoretical air, then excess air is needlessly heated up in the combustion process and not all of the heat will be recovered in the boiler heat transfer process. A further loss associated with the excess air results from the additional auxiliary power needed to pass it through the boiler.

As a consequence any deviation of the combustion air above or below the optimum value of 123% of the theoretical air produces excess losses. The graph of Fig.3 shows the excess loss as a function of the combustion air and has been derived from data given by Gill (Gill 1984). The actual loss at the minimum point of Fig.3 is about 9%.

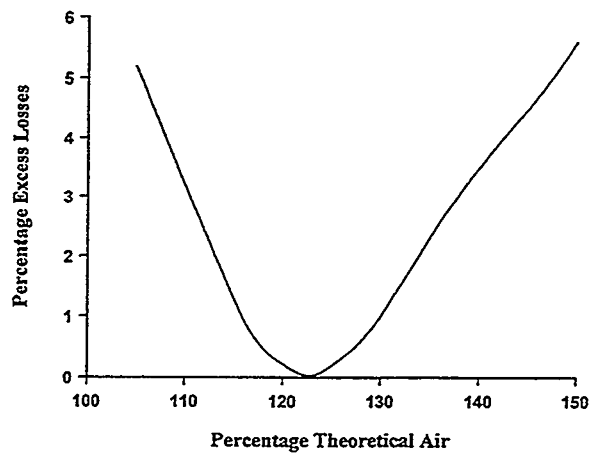

Figure 3 Graph of Excess Losses (Above Minimum) Against Excess Air from Gill 1984

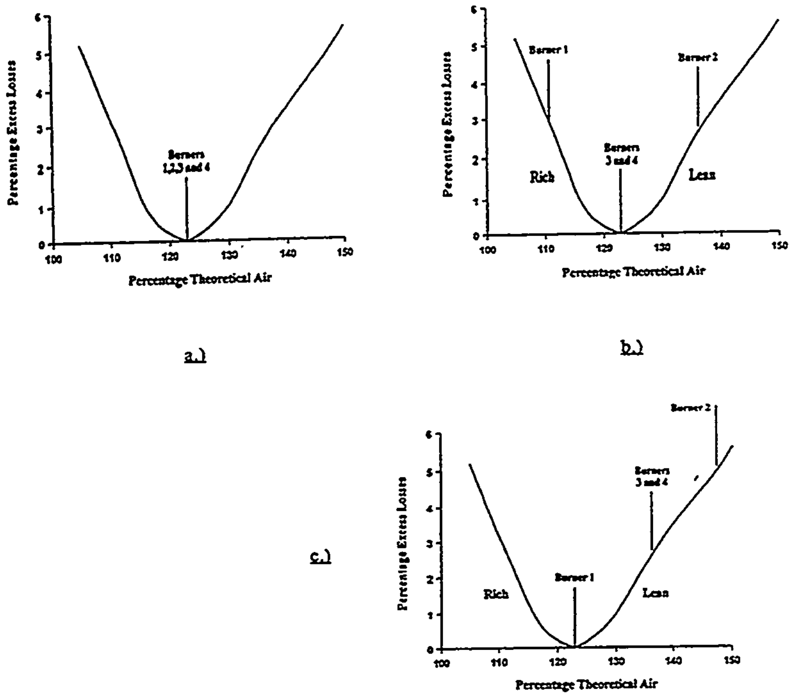

Figure 4 Operating Points of Burners For the Balanced and Unbalanced Condition

TABLE 1

	Power loss Mw	Efficiency loss %	Coal Tonnes per day
Unchanged air conditions	8.96	0.72	35.2
Additional air to boiler to eliminate CO	32	2.56	125.6

The results given in Table 1 are calculated losses and are based on a power station unit having a fuel distribution system as shown in Fig.1, and having the following parameters.

It is clear that for the maximum efficiency to be achieved in a multi burner boiler, the air to fuel ratio at each individual burner should ideally be 123%, but if the PF is not split evenly at each pipe bifurcation, then ideal conditions will not be maintained at each burner. Some burners will run rich and some will run lean but both will produce losses for the reasons given above. It is important to appreciate that the excess air at one burner may not necessarily be available for combustion at a burner that is running rich.

The main problem is that at present the actual fuel flow to each burner is not known; it is merely assumed that the riffle boxes achieve equal splitting of the fuel flow and the total combustion air is provided in proportion to the mass flow rate of coal into the mills. Therefore if one burner is running rich and another lean, due to an uneven split ratio in the distribution system, CO will be present in the flue gasses which would be detected by the appropriate monitors and this will result in the secondary air being increased until the CO falls to an acceptably low level. This will occur when the burner that was running rich now has an adequate supply of combustion air.

Unfortunately this means that many of the burners will be over provided with air and be running lean, which will result in unnecessary losses.

EXAMPLE OF LOSSES DUE TO UNBALANCED SPLITTING IN PF FEED LINES

Before examining the possible losses in a large scale boiler in some detail, let us consider a simple example to illustrate the effect of unbalanced fuel supply. Suppose we consider a boiler with 4 burners fed from a single mill as shown in Fig.4. If the fuel flow rate to each burner were equal, and the total air supply were such as to provide 123% theoretical air at each burner, each burner would run correctly and the operating point for each burner would be at the minimum point of the curve as indicated in Fig.4(a).

Suppose that the split ratio at the pipe bifurcation was now 45% : 55% instead of 50% : 50% so as to cause burner 1 to run rich and burner 2 to run lean and with burners 3 and 4 running correctly. The combustion conditions for the individual burners would now be as shown in Fig.4(b) with burner 1 running rich and producing CO, and with burner 2 running lean so both of these would produce excess losses.. Burners 3 & 4 will still be running correctly.

If the secondary air were then to be increased to the whole boiler so as to eliminate CO from burner 1, conditions would be as shown in Fig.4(c). Burner 1 now runs correctly but burners 3 & 4 which were running correctly now run lean, and burner 2 which was running lean now runs even more lean. Under these circumstances the overall excess losses will be greater than would have occurred if the secondary air had not been increased and burner 1 were allowed to produce CO.

In a very large boiler with a large number of burners it only requires one burner to run rich and produce CO to cause all of the secondary air to increase. When the air has been increased to eliminate the CO then every other burner which was running correctly runs lean and produces excess losses. The sum of these losses can be very high indeed as shown in Table 1 below.

Furnace Power	1250 Mw
Electrical output power	500 Mw
Number of mills	4
Number of burners	32

It is assumed that there is an unbalanced split ratio of 45% : 55% at the first stage bifurcation of the distribution system of mill 1 so that burners 1-4 run rich and burners 5-8 run lean, all other burners have equal fuel flow rates. The air fuel ratios are then calculated for every burner and the losses for each burner is found from the graph shown in Fig.2.

The first row gives the losses for the correct overall air and the second row gives the results assuming that the air supply has been increased so as to eliminate the CO that has been produced by the burners that run rich.

It is clear from the table above that considerable losses can occur if the correct air fuel ratios are not maintained at each burner. It would also appear that if the PF mass flow rate to each burner could be ascertained it would then be possible to individually adjust the secondary air supplied to each burner so as to achieve stoichiometric conditions across the whole furnace.

ELECTROSTATIC MASS FLOW RATE SENSING METHODS

Electrostatic methods of sensing flow rate of solids in pneumatic conveying pipelines has been investigated by a number of workers over several years (Klinzing 1987, Gajewski 1994 and Woodhead 1990 and 1992). The passage of particulate material through pneumatic conveying systems inevitably results in the particles picking up electrostatic charges due to particle-particle and particle-wall collisions involving the triboelectric effect. Electrodes placed in the walls of the pipeline can then sense the passage of these charges by the charge induction effect, and the amount of induced charge will be a function of the mass flow rate of the particulate material flowing through the pipe. A significant advantage of this method of sensing flow is that it is non-intrusive. However there are several problems associated with this method of flow sensing. The induced charge sensed by the electrodes depends upon several parameters and these are listed below.

1. Type of material
2. Particle size
3. Moisture content
4. Flow history
5. Velocity
6. Distance between particle and electrode

All of these factors make it difficult to calibrate an electrostatic flow sensor, and for the calibration to remain valid since several of the parameters mentioned above may well change with time.

One approach whereby these problems may be minimised, in PF distribution systems, follows from the realisation that if the relative flow from the riffle boxes at the pipe bifurcations is measured, rather than the absolute flow, then the relative distribution of PF flow at the burners can be ascertained. It further follows that if the relative PF flow is known at the burners then the relative flow rates of the secondary air can be set accordingly. All that then needs to be done to ensure that stoichiometric conditions apply to each burner is to ensure that the gross air supply matches the coal flow rate into the pulverising mill.

Sensing the relative flow rate at the output of a pipe bifurcation means that the parameters 1 to 5 above will be the same for both exit pipelines, and will therefore have no effect on the split ratio measurement.

The problem then remains as to the effect of parameter 6 above (the distance of particles from the electrode). Since there is a possibility of rope flow conditions at the approach to riffle boxes, the position of PF flow at the exit of the riffle boxes relative to the pipe walls may well be different at each exhaust.

The distance of the particulate material from the sensing electrode is a serious problem when using electrodes mounted directly in the pipe walls of pneumatic conveying systems particularly if the pipes are of a large diameter. The charge induced in the sensing electrodes by moving particles depends upon the inverse square of the distance of the particle from the electrode, consequently the induced signals are more sensitive to the flow near to the pipe wall than the flow in the pipe centre. This problem may be minimised, in the case of sensing the flow at the output of riffle boxes, by arranging for the sensing electrodes to interrogate the flow across the exit slots of the riffles. In a typical case this means that instead of having to sense the flow across a pipe of say 350mm in diameter, the flow is sensed across rectangular slots of only 50mm width. One possible arrangement is shown in the diagram of Fig.5 Each electrode has it's own signal processing electronics and the outputs from each side are summed together to produce a composite left and right signals.

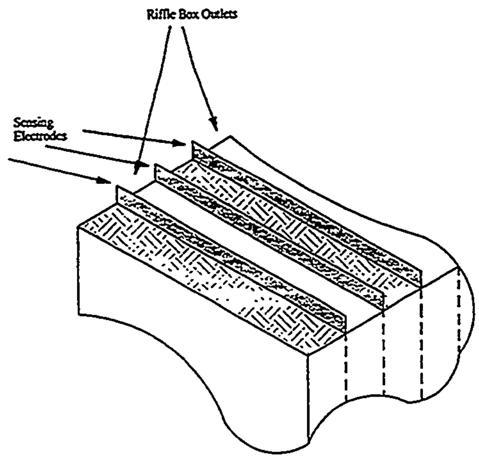

Figure 5 Installation of Electrostatic Sensing Electrodes on a Riffle Box Exit

A further development of such sensors, as shown in Figs. 6 and 7 involves the embedding of the sensing electrodes in a solid insulating material, such as fused alumina, which is particularly resistant to erosive wear. By so doing, the electrode is made remote from the riffle box exhaust, thus reducing the difference between the sensitivity of the electrodes to particles close to the pipeline wall, and those in the centre of the pipeline. This effect is greatly enhanced by the relative permittivity of the insulating material, which in the case of fused alumina will be in the region of 10, thus making the effective distance of the electrode from the slot bore 10 times the actual value. So that if a sensing electrode is embedded behind 5mm of fused alumina insulating material, the effective distance of the electrode from the slot wall will be 50mm. Thus the difference between the sensitivity of the electrode to a particle close to the slot wall and that to a particle at the centre of the slot will be the difference in sensitivity to a particle 50mm away, compared to that to a particle 75mm away. Clearly, this arrangement will reduce the sensitivity of the sensing electrodes to particle position.

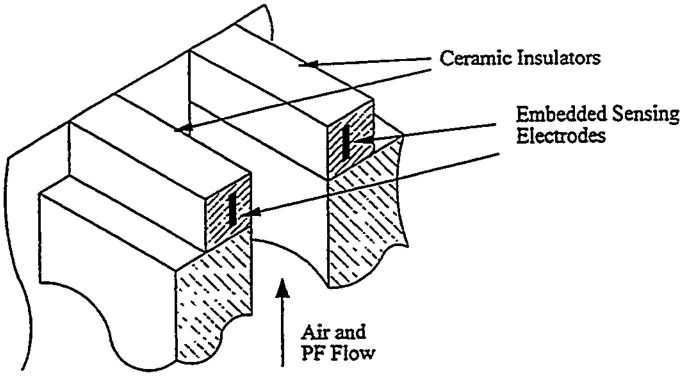

Figure 6 Embedding of Electrodes in Ceramic Insulators

CONCLUSIONS

From the above, it may be clearly appreciated that maldistribution of PF in fuel feed systems can lead to significant problems, both in terms of overall plant efficiency and plant emissions which are harmful to the environment. The benefits to be accrued from addressing the problem of maldistribution are therefore numerous. A possible method by which this problem may be addressed has been described in this paper, which relies only on the measurement of relative PF flow rates, thus eliminating many problems described by other authors of sensitivity to coal type, moisture, particle size, coal history, etc. which are inherent in the measurement of absolute mass flow rate.

Feasibility work aimed at proving the principle of the method described is currently under way at The University of Greenwich, London, UK.

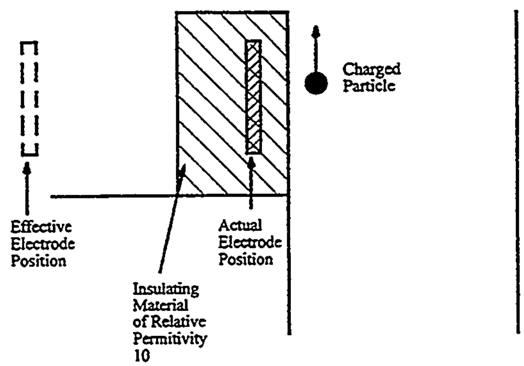

Figure 7 The Effect of the Relative Permittivity of the Ceramic Material on the Effective Position of the Sensing Electrode

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