

Coal for Peak Power

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In the ensuing debate about new forms of coal utilisation for power generation the attention has - often wrongly - been focused on mid load and base load plant but, it is most important also to look carefully at the problem of using coal for the generation of peak power.

Large variations in demand between night and day produce problems that the generating industry will always have to live with. This means that a lot of plant must be capable of stopping and starting once or twice in every day - with the associated need for changing the load of the installed capacity over large areas very rapidly. The giant-size base-load steam plants now being installed do not have these essentially flexible characteristics, and yet they will be required to meet such exacting duties if they - in the traditional way - are shifted down in the merit order as they get old. The alternatives are either to dissipate - during the night - some of the generated electricity as heat (seriously being put forward in some circles as the only practical, low-cost, method of dealing with the problem) or to tackle the overall question of reconciling generation method with load pattern.

One most effective course that can be adopted fills up the night time troughs in the demand curves by the introduction of power storage. Hydro-pumped power storage is an established technique that will soon reach the end of its limited exploitation potential and, quite naturally, it becomes more expensive as the less and less obvious sites are taken over and developed. An alternative method uses the storage of air under pressure, a technique that has not yet been exploited but which, because it will develop from known and tried techniques, shows excellent promise. Air storage power as such does not require large forward strides or jumps in technology, it is only a matter of marrying two known, experienced, branches of engineering: building and operating large industrial gas-turbines and the techniques of forming large underground caverns by mining, tunnelling, or leaching.

Up to 20% of the installed capacity of some power systems could in the future be air storage power and it is therefore necessary, already now, to look at the various possibilities for using coal as the primary fuel for such plant.

Fig. 1 shows by way of an example what can be achieved by employing a substantial amount of air storage power. Fig. 1a shows the 24 hour variation in electricity demand for a U.S. utility. The horizontal lines indicate the contribution of the various generating units on the system: several big units have to be turned down very severely every night and a large number of units have to be stopped and started every day.

By contrast has been shown on Fig. 1b the load pattern which the conventional plants would have to follow - the bold line - if 20% of the installed capacity was provided by six air storage units. These units would generate, on average, 8 hours per day. Assuming that our total installed capacity will increase fivefold between 1970 and year 2000, we see that air storage plants in year 2000 could represent as much capacity as we had installed in total in 1970 and the electrical energy generated by these plants could be well over half of our total 1970 production.

The principle of air storage power requires the use of gas-turbine equipment where the compressor(s) can be separately driven by an electric motor at such times as surplus, and therefore cheap, electricity supplies are available. Excess electricity production at night from ultra-large generating sets which must be run continuously and cannot be shut down or controlled on a divided-day basis is becoming very freely available and will become a serious "disposal problem" as nuclear plants proliferate. Air storage provides a use for this surplus production and a most economic method of using gas-turbines to cater for peak demands in day time.

During the day compressed air from storage is taken to the combustion chambers where it is heated up and then expanded through the turbine component to produce peak power. With this arrangement approximately three times as much day time output is available from an equal-capacity gas turbine installation than in the normal way - when two-thirds of the turbine output is needed to drive the compressor. Today, gas-turbines having 70 to 80 MW output are in routine production and use. It is a simple and straightforward matter to extend this to the construction of air storage units of 200 to 300 MW.

It is not the intention of this paper to draw comparisons between hydro-pumped storage power and air-storage power; such comparisons can only be made in specific cases where the authority concerned is fortunate enough to have a choice available in a given power system area.

This is an examination of air-storage power compared with conventional gas-turbines with and without steam turbines in combined-cycle installations. For these two main considerations there are the added

alternatives of fuelling by High-Btu gas and Low-Btu gas derived from coal. As a major consideration, these two fuels are compared with the direct combustion of coal in a fluidised-bed air heater operating in conjunction with air-storage plant.

The need to improve the efficiency of open cycle gas-turbines and combined cycle units is forcing designers of gas-turbines to strive for inlet temperatures of well over 2000 °F. In turn, this demands a clean fuel and we see how - with coal as the main fossil fuel - this has led to all the interest in coal gasification and low-Btu gas in particular.

Although an air-storage plant is basically a gas-turbine - albeit used in a very special way - there is not the same demand for very high turbine inlet temperatures. An economical analysis - which is not gone into here - shows that it is more rewarding to go to high storage pressures. Since a very high turbine inlet temperature is not a prerequisite for a good air-storage plant it has been natural to study the possibility of using coal fired fluidised bed air heaters instead of going the detour around coal gasification.

The simplest form of gas-turbine combined with a fluidised-bed heater is seen in Fig. 2. The air from the compressor is divided into two streams: primary combustion air, about 30 per cent of the total, goes through the bed, providing 10 to 20 per cent excess air for the combustion. This leaves the bed at 1600 °F (870 °C) after which it passes through two stages of cyclone separation.

Secondary air is passed through a closed-tube bundle immersed in the bed and is heated to 1427 °F. (775 °C); this bed-cooling air is mixed with the cyclone-separated air before entering the turbine at an average temperature of 1472 °F (800 °C).

By today's standard 1472 °F is a very conservative inlet temperature, but at a bed temperature of 1600 °F fluidised bed combustors have optimum performance: maximum sulphur removal by absorption into limestone or dolomite fuel additives, low vapour pressure of the alkali component in the ash and no melting of the ash. At this temperature the formation of nitrous oxides is low and particularly so when the combustion takes place under pressure as in this proposal.

This concept of a coal burning gas turbine is radically different from previous attempts to burn coal in gas-turbines. Firstly the feed consists of crushed coal in pea-sized lumps of which only a small amount is inadvertently reduced to dust. Previously, all the fuel was pulverised specially and expensively. There is now, therefore, a much smaller amount of airborne particles to be separated from

the exhaust gases before these are passed to the turbine. It is also of importance that these particles have not been sintered whereas, previously, all fuel passed through the intensely hot high-temperature combustion zone, where all the ash was sintered and became highly abrasive, before being cooled by dilution air. Thirdly there is not now a corrosion problem superimposed on the erosion problem since, due to the lower temperature, the vapour pressure of the alkali component of coal ash in a fluidised bed is only a small fraction of that in conventional combustion systems. The cyclones, finally, have to deal with only one third of the mass flow compared with previous systems.

For air storage plant, where the air compression is done separately during the night, the specific fuel consumption during the day is barely influenced by the turbine inlet temperature - with reasonable preheating of the air from the storage cavern it will be around 4600 Btu/kWh.

A proposal for an air storage plant incorporating a pressurised fluidised bed air heater is shown on Fig. 3. If a storage pressure as high as 50 atmosphere is used it is natural to introduce reheat and let the actual combustion take place at about 10-12 atmosphere pressure. All the cold air from the storage cavern is preheated in an exhaust heat recuperator, it then passes through a high pressure tube bundle in one section of the fluidised bed where it is heated and subsequently expanded through a high-pressure air turbine. After the H.P. turbine the air is divided in two flows, as in the simple gas-turbine arrangement, with one stream going through cooling tubes to be reheated before joining the exhaust gases and expanded through the low-pressure turbine.

The air mass flow of this proposed 260 MW reheat air storage plant corresponds to the mass flow of a 70 MW conventional gas-turbine now in production. This gives an idea of how much more the hardware is utilised in an air storage arrangement.

In the following, very coarse, comparison of the cost of an air-storage-fluidised bed-air-heater with other alternatives is made a number of assumptions and the results are shown in a diagram, Fig. 4 :

- capital cost of gas turbines	\$ 100/kW
- capital cost of combined cycle	\$ 135/kW
- capital cost of air storage plant:	
"above ground"	\$ 75/kW
storage cavern: "0" hour/day	\$ 25/kW
12 " /day	\$ 65/kW

- capital cost of high-Btu gas plant supplying a generating station which uses 10,000 Btu/kWh \$ 250/kW
- capital cost of low-Btu gas plant supplying a generating station which uses 10,000 Btu/kWh \$ 125/kW
- The capital cost of fluidised bed air heaters have been studied in some depth and the best estimate now is that a fluidised bed air heater with all coal and ash handling facilities will add \$ 40/kW to the cost of a 260 MW reheat air storage plant.
- gas turbine efficiency (for late 1970's) 35%
- combined cycle efficiency 46%
- efficiency of high-Btu gas plant 70%
- efficiency of low-Btu gas plant 85%
- cost of coal 40 cent/MBtu
- capital charges 15%
- Operating costs for air storage plant can be divided into two parts:-
 - (a) The cost of night time energy supplies. With a night/day energy ratio of 0.66 (i.e. 0.66 kWh spent for compression of air for each 1 kWh generated during the day), and an assumed marginal fuel consumption for base load plants during the night of 9000 Btu /kWh, the cost for night night energy is 6000 Btu/kWh x the specific fuel cost. For simplicity it is considered that night time supplies of energy would at present come from coal-fired stations. Eventually, when night time energy is provided by nuclear plants, operating costs will be reduced still further - and make air storage even more competitive.
 - (b) The cost of fuel used during the day. The direct day time fuel consumption - also called the in situ fuel consumption - can be 4600 Btu/kWh.

Therefore, $a + b = 6000 + 4600 = 10,600$ Btu/kWh, which is the total primary fuel consumption needed by an air storage plant using a fluidised-bed air heater. This is the fuel consumption which is used here as the reference value for all comparisons.

- variations in fuel consumption for different alternatives are converted to capital cost equivalent so that all comparisons can be done on capital cost diagrams alone. This is possible when the same initial fuel is used throughout.
- high-Btu gas will be produced on a continuous basis in large plants and stored for use intermittently by peak power plants. Therefore the capital cost for gas making plant is taken in proportion to the number of hours per day - out of 24 - which the peak load plant is intended to operate.
- low-Btu gas will be produced at power station site when needed, partly because it is "bulky" and partly to avoid the losses in cooling it down for storage. Designers of low-Btu gas plants should note that such plant will be required to stop and start every day!

The specific capital cost figures used in Fig. 4 to correct for variations in primary (i.e. coal) fuel consumption has been worked out in the following tables: I, II and III. 12 hours per day is used as reference time (12 hours per day during 11 month corresponds to 4000 hours per year). At zero hours per day there is of course no adjustment.

Table I

Air Storage

	Fluidised Bed *	High-Btu Gas	Low-Btu Gas
Indirect night fuel, Btu/kWh	6000	6000	6000
Primary day fuel, - " -	4600	6600	5400
Total			
Btu/kWh	10600	12600	11400
Variation	- " - Datum	+2000	+ 800
\$/kW at			
4000 h/year (12h/day)	Datum	+ 21	+ 9

* Or natural gas or oil as fuel in conventional combustion chambers.

Table IIGas Turbine (Secondary fuel consumption 9750 Btu/kWh)

	Primary fuel consumption Btu/kWh	Compared with Air Storage Btu/kWh	\$/kW at 4000 h/year
High-Btu gas :	13,900	+ 3300	+ 35
Low-Btu gas :	11,500	+ 900	+ 10

Table IIICombined-Cycle Plant (Secondary fuel consumption 7400 Btu/kWh)

	Primary fuel consumption Btu/kWh	Compared with Air Storage Btu/kWh	\$/kW at 4000 h/year
High-Btu gas :	10,600	\pm 0	\pm 0
Low-Btu gas :	8,750	- 1850	- 20

Looking now at Fig. 4 one sees in alternative "a" that an air storage plant for less than 6 hours operation per day should burn high-Btu gas if this can be produced on a large scale in a plant which operates continuously. But, for longer operating hours it pays to employ fluidised bed air heaters. For the demand curve shown on Fig. 1 this would mean three units gas fired and three units with fluidised bed air heaters - these last three units generating three times as much electricity as the first three.

In alternatives "b" and "c" is shown - in heavy broken line - for comparison the most economical air storage cost called "datum". Only combined cycle plant ("c") operating for more than 15 hours

per day will be competitive with air storage plant - and then one is out of the peak load regime, but not necessarily out of the two-shift regime.

In summing up one can highlight a number of important features of air storage plant:

- it allows base load plant to be operated in a true base load mode by filling up the night trough in the demand.
- when built near load centres - as it should be - it then causes less air pollution than any other alternative: 4600 Btu/kWh in situ fuel consumption.
- its maximum output is not reduced at high ambient temperature - a problem with conventional gas turbines and combined cycle plant.
- it does not require excessive turbine inlet temperatures and is therefore well suited to its invariable duty of daily stops and starts.
- the relatively low turbine inlet temperature allows the use of fluidised bed air heater, which in turn makes it possible to use coal of very low and varying quality.
- the combination with fluidised bed air heaters does not alter the ability to stop and start every day: when air and fuel is cut off the bed will stay warm for days.
- it should be operated at nearly constant turbine inlet temperature - by throttling fuel and air simultaneously - and therefore shows very good part load efficiency.

In planning the development of new generating plant, using coal as the primary fuel, it is important to remember that none of the new ideas now being discussed will make an effective impact until we are well into the 1980's. In the mean time we see lots of large base load plant being put on stream - plant which will have to remain in a near base load mode of operation throughout its life. Nuclear power in particular will want to stay in the base load area - and towards year 2000 may account for 50% of all installed capacity. Altogether this makes it exceedingly important to guide the coal-power developments in such a direction that it allows these new breed of plant to operate in peak load and intermittent modes and air storage plant may prove very competitive in our endeavours to provide clean power from dirty fuel.

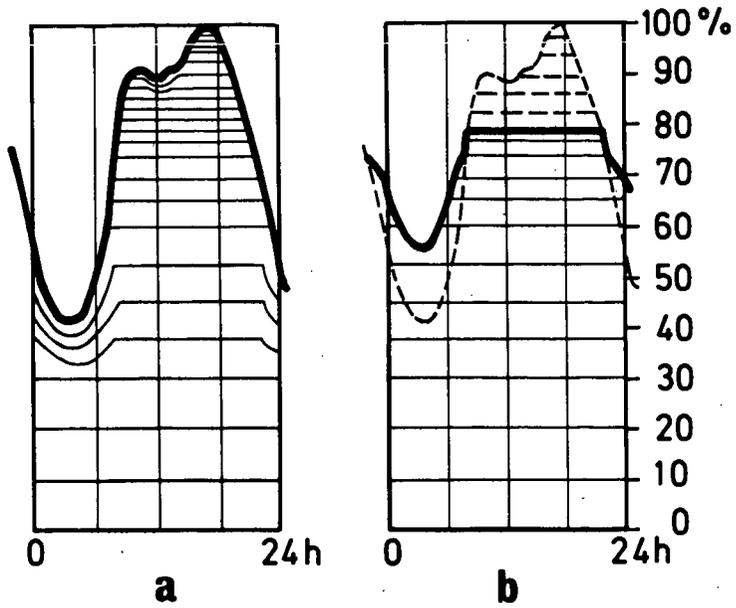


Fig. 1. Example of a daily load curve in an electricity supply system (a) and the effect of introducing 20% air storage power (b).

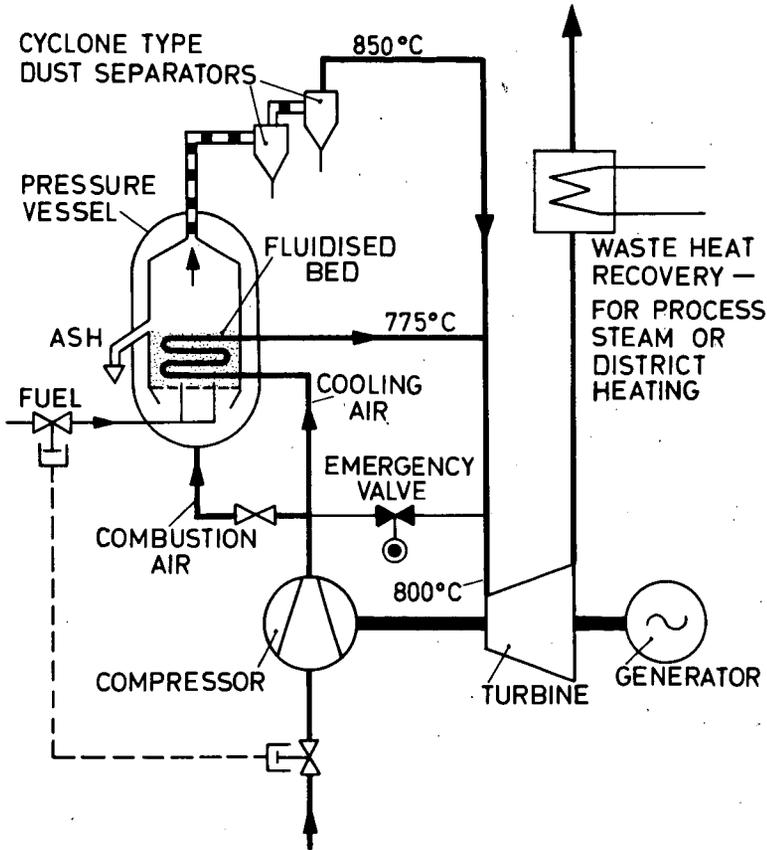
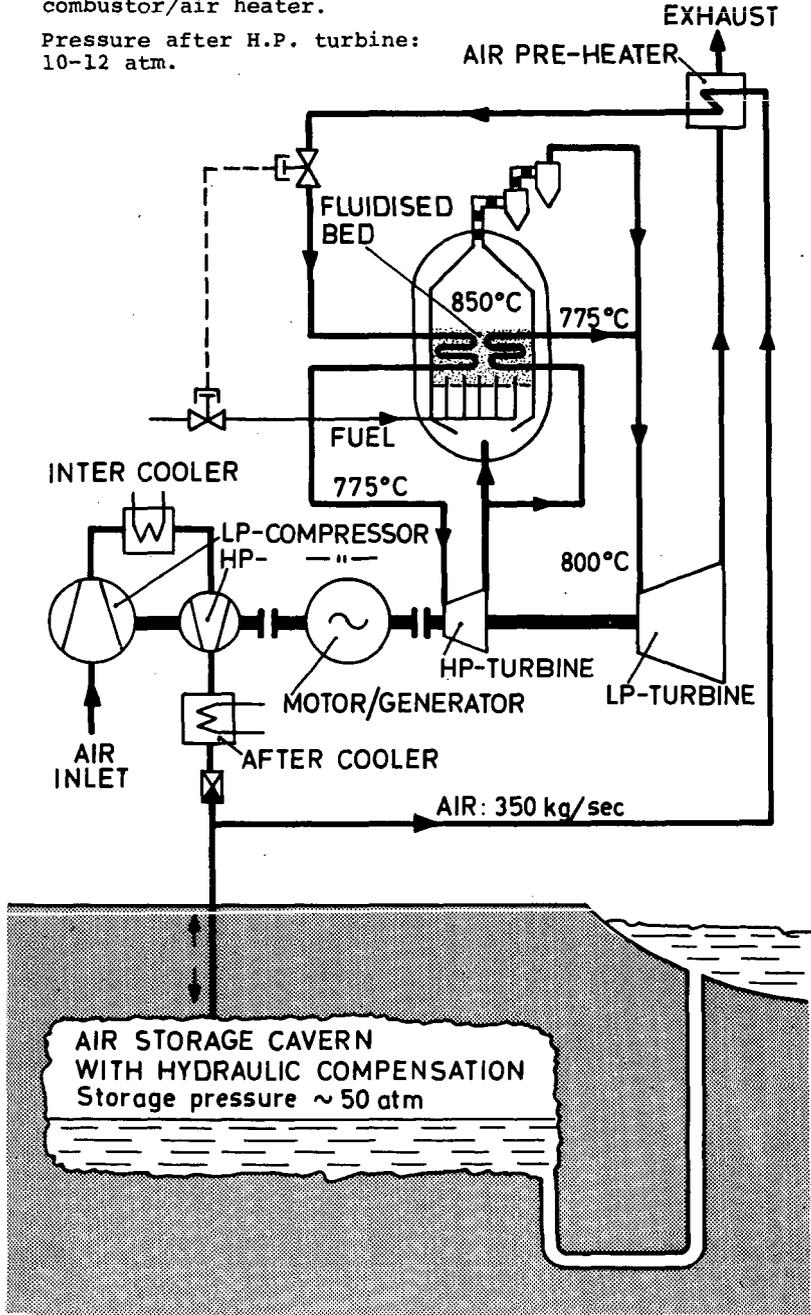


Fig. 2. Open cycle gas turbine with pressurised fluidised bed combustor/air heater.

Fig. 3.

260 MW reheat air storage plant
with pressurised fluidised bed
combustor/air heater.

Pressure after H.P. turbine:
10-12 atm.



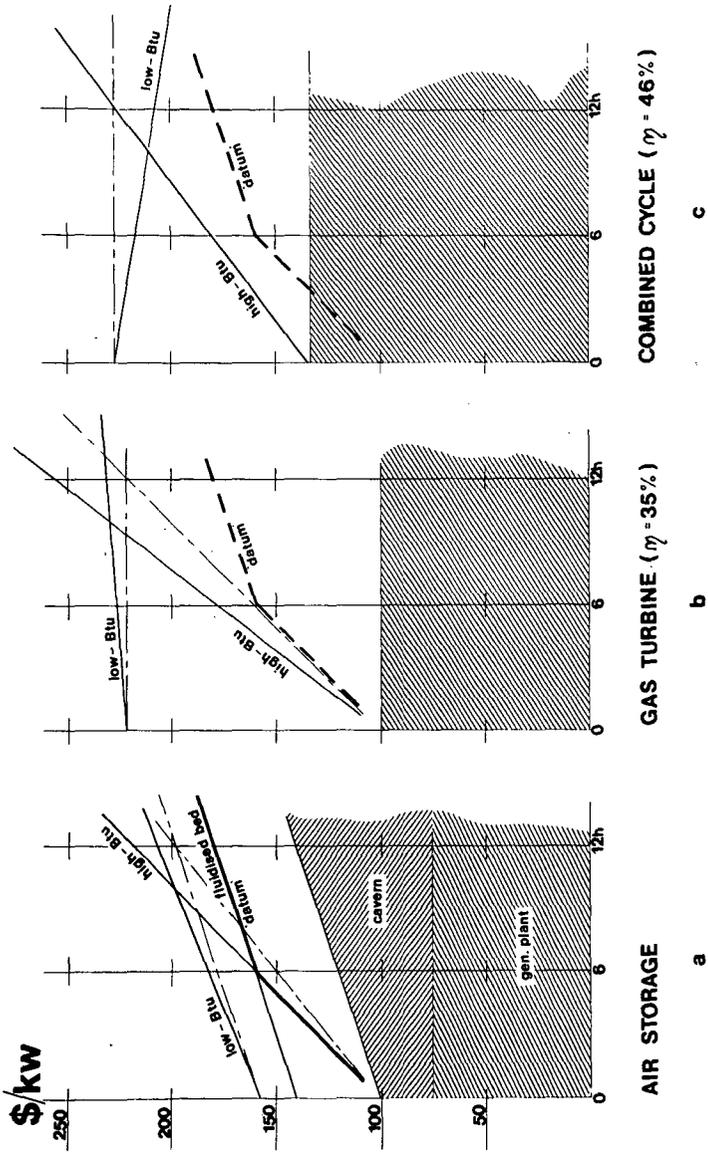


Fig. 4. Capital cost comparison of different types of peak power plant as function of operating hours per day. All using coal as primary fuel and all normalised to 10,600 Btu/kWh primary fuel consumption.