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COAL GASIFICATION - COMBINED CYCLES FOR ELECTRICITY PRODUCTION

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by

T.D. Brown*

ABSTRACT

This introductory review summarizes a series of specific areas of technology which must contribute to the development of a coal gasification-combined cycle power plant. The optional combinations of the gas and steam turbines are each seen to pose different technical problems. The paramount importance of the development of a high temperature (>1200°C) turbine inlet temperature and the subsidiary role of high temperature gas cleaning and water requirements are discussed; the prospective reliability of gasifier/boiler couplings are largely unknown.

The cost of electricity from the combined-cycle process has been shown to be most attractive in regions of high cost coal. It is considered likely that combined cycle power production will be implemented where conditions of high coal cost, low water availability and strict emission regulations coexist.

The commentary is framed in the perspective of Canadian coal resources, however most comments apply to all coal gasification combined cycle power plants and examples are drawn from all sources.

I did all the background & library search for this report - NO Credit.
G.M.B. - [illegible] had the kindness to send me a copy of the final report.

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INTRODUCTION

The majority of electric power generating stations operated by central utilities use generators driven by either independent steam turbines or independent gas turbines. These two units have been developed separately and are used independently to fill different components of the electricity load pattern.

In most Western European countries and in North America coal-fired boilers and steam turbines have fulfilled a base-load role. Oil and gas have been used with greater flexibility. Recently the nuclear power sector of the industry has supported the fossil fuels used in base-load power production. In these applications steam turbine sizes have reached 1200 MW with common installation at the 300, 600, and 800 MW level.

The role of the gas turbine, on the other hand, has been directed towards a "load topping" role in power production where maximum advantage has been taken of its fast response characteristics and remote control capability. In these instances the fuel used has almost invariably been natural gas or distillate oil to permit maximum flexibility in selecting the size and site of the units. The remote units range in size up to 25 MW; in other applications a size of 75 MW is rarely exceeded.

The combination of gas and steam turbines into a single power production operation has been developed systematically during the past two decades in several applications. The input to these combined cycles has usually been a gaseous or liquid fuel. This coupling offers the potential of conversion efficiency (fuel to electricity) higher than either of the individual parent systems and has therefore attracted attention as a route to energy conservation.

The successful development of combined cycle technology using natural gas or distillate oil has led to thoughts of its use with a coal-derived fuel. Advantages relative to the conventional steam cycle using a pulverised coal-fired boiler and condensing turbines are seen to lie in improved emission control and lower water demand as well as in improved conversion efficiency. The commonest system postulated has been the gasification of coal to produce carbon monoxide and hydrogen which can be used as the primary combined cycle fuel. The use of other coal-derived gases or liquids is possible with limitations only being placed by process economics.

The gains in conversion efficiency are, in many cases, considered to be sufficient to offset the inherent process losses incurred in the coal gasification stage. Even when the coal-gasification combined cycle plant is less efficient than the simple coal-fired steam boiler plus steam turbine, it may still offer an improvement in plant efficiency when the thermal and efficiency penalty due to emission contol by flue-gas-desulphurization must be considered.

This article described the technical and economic advantages and disadvantages of the coal-gasification combined-cycle power generation option. It is framed in the perspective of Canadian coal resources; however, most of the commentary will apply to all combined cycle developments, and examples are drawn from all sources.

POWER PRODUCTION FROM GAS TURBINES

Two single gas turbine power generating schemes are shown in Figure 1 and their energy flow distributions in Table.[1]. The gas turbine without an air preheater converts approximately 29% of its input to power; this conversion is increased to 36% by introduction of an air preheater. The expensive air preheater increases the system's efficiency, but introduces a major pressure restriction in the system. Power output can therefore only be maintained by increasing the turbine size. The cost of achieving this increase in efficiency could be more easily justified if the power output could be simultaneously increased. Utilization of the waste heat in the gas turbine exhaust to produce steam for the production of useful electrical energy is one method by which this can be done. Table 1 shows comparable data for the simplest incorporation of a waste-heat recovery boiler into the gas turbine exhaust to create a combined steam and gas turbine power generating plant. The gas turbine with air preheater represents an additional cost and a higher efficiency without the benefit of increased generating capacity; the gas turbine with a waste heat boiler and steam turbine represents an additional cost <u>and</u> a higher efficiency with the added benefit of an increase in generating capacity.

An additional advantage of the combined cycle relative to a conventional steam turbine of the same capacity is the decrease in water requirements per unit of electrical output.

Table 1 - Energy balances for gas turbines and combined steam plus gas turbine cycles (Reference 1)

	Simple Gas turbine	Gas turbine with air preheat	Gas turbine with waste heat boiler and steam turbine
Gas turbine inlet temperature, °C	800	880	880
Heat supplied by fuel, MW	238	168	238
Output of gas turbine, MW	68	60	65.8
Output of steam turbine, MW	-	-	25.8
Stack temperature, °C	443	280	160
Thermal efficiency, %	28.5	35.7	38.5

TYPES OF COMBINED CYCLE POWER PLANTS

UNFIRED COMBINED CYCLES

The Direct Cycle

This cycle, illustrated as Figure 2a is alternatively known as the "waste heat recovery combined cycle". Exhaust heat from the gas turbine is fed directly to the waste heat boiler where steam is generated to drive a steam turbine.[3] No radiant heat transfer occurs in the boiler where, because of the clean character of the hot combustion products, a finned-tube design is possible. This lends itself to compact design and factory construction as package units.

Alternative arrangements can exist for waste heat recovery in independent steam circuits to integrate the combined-cycle into a co-generation scheme.

The Indirect Cycle

In this cycle, illustrated in Figure 2b, no combustion products pass through the expansion turbine. The turbine working fluid is air. This is heated in an independent gas-to-air heat exchanger within a steam boiler which simultaneously feeds a steam turbine. The clear advantage of this indirect cycle lies in the fact that no gas cleaning is required upstream of the gas turbine.

This system involves the construction of a costly heat exchanger which is requred to work at both high pressure and high temperature. The cycle efficiency is limited by the air temperature which can be achieved in the heat exchanger. It is unlikely that improvements in heat exchanger performance will parallel the projected increases in gas turbine inlet temperature predicted for the immediate future to allow this cycle to achieve high efficiencies.

This cycle is unlikely to see major use in coal gasification (or other) combined cycle development.

FIRED COMBINED CYCLES

In those combined-cycles which use secondary firing, advantage is taken of the fact that when dilution has been used to control turbine inlet temperatures the exhaust gases from the gas-turbine can contain over 16%

oxygen. The turbine exhaust can therefore be used a a source of preheated air to the combustion system in the steam boiler.

Supplementary-Fired Cycles

In the cycle illustrated in Figure 2c the turbine exhaust gas is used as oxidant with controlled amounts of a supplementary fuel to produce hot gas for steam boiler use at a predetermined boiler inlet temperature. This type of cycle finds particular application where the gas turbine inlet temperatures are low and outlet temperatures are consequently too low to generate a high quality steam. The controlled amount of supplementary firing with a clean fuel allows use of current finned-tube designs in a compact waste heat recovery boiler and the system therefore lends itself to factory constructed units.

Fully-Fired Combined Cycles

In these cycles the exhaust product from the gas turbine serves as an air supply to the combustion chamber of a steam boiler of conventional design as shown in Figure 2c. No limitation is placed on boiler inlet temperatures; a major requirement is for a large combustion chamber.

This type of cycle allows the greatest flexibility of fuel use of those discussed so far in that the steam boiler can be fired by any of the conventional fossil fuels.

The Fully-Fired Supercharged Cycle

In this cycle, as is shown in Figure 2d, the normal downstreeam location of the boiler relative to the gas turbine is reversed. A supercharged (pressurized) boiler fired by the primary fuel supplies steam to a steam turbine; the hot combustion products exhaust through a gas turbine. A second (waste heat) boiler is the final heat recovery unit before the combustion products are exhausted to atmosphere. Both boilers are normally integrated into the same steam circuits with economizers and other convective surfaces being located in the final waste heat boiler: superheaters, radiant surfaces as well as some convective surfaces are located in the supercharged boiler.

This system provides a measure of control of turbine inlet temperatures and is capable of producing a high quality of superheated steam - and reheated steam - independently of the gas turbine inlet temperatures.

It is not, however, easy to arrange for independent operation of the supercharged boiler and gas turbine. This represents, to some degree, a reduction in flexibility of the system. This may be compensated for by the small physical dimensions of the supercharged boiler which facilitates factory construction for units of large capacity.

COMBINED CYCLE PERFORMANCE

It is appropriate at this point to define the performance characteristics of combined cycle technology as it is currently applied. The development of installed capacity of combined cycle plants in the western world has followed the pattern shown in Figure 3.[3] Fuels have been natural gas or a distillate oil; more rarely, residual fuel oils have been used. The installations represented by Figure 3 are widely different. For example, in some instances the gas turbine output may amount to two-thirds of the total output of the plant, whereas in others the turbine may only fulfill the function of an air delivery system to a boiler, thus replacing the boiler fan and air preheater. In the majority of cases, however, the units employ heat recovery boilers either with or without supplementary firing and steam turbines. The figures after 1971 are considered to include a single coal gasification combined cycle plant. (Lunen, West Germany, commissioned 1970).

ATTAINABLE OUTPUTS AND EFFICIENCIES

The attainable efficiency of the combined plant depends on the performance of the gas turbine and the steam boiler/steam turbine. The major factors influencing combined cycle efficiency have been described in detail by Wunsch, who illustrated the effect of a series of parameters on efficiency.

Gas turbine efficiency is strongly dependent on inlet gas temperature as illustrated in Figure 4; the range shown for proven modern designs indicates that current units are capable of achieving an efficiency of about 30%.[3] Higher inlet temperatures than 1000°C are in use in aviation turbines but have not yet been demonstrated for long-term use in stationary turbines.

Figure 5 illustrates the role of steam pressure, temperature and reheat temperature on the performance of a steam boiler and steam turbine. The figure shows that the major gain in steam turbine performance is a consequence of the improvement in steam quality introduced by steam reheat.

The steam cycle components of current combined cycle installations rarely use reheat; the efficiency of these non-reheat systems is illustrated in Figure 6. The factors which influence the operating conditions of the gas turbine are clearly more important than those influencing the steam turbine operating conditions in their effect on combined cycle efficiency.

The dominant factor barring the way to improved combined cycle efficiencies is the ability to increase turbine inlet temperatures above 1000°C. The effective incorporation of reheat into the steam cycle (without supplementary firing) is dependent on achieving these inlet temperatures which will inevitably result in turbine outlet temperatures essential for the reheat steam cycle.

Current gas turbine practice (using inlet temperatures between 900 and 1000°C) allows the achievement of combined cycle efficiencies up to 46% compared to a steam cycle efficiency limit of 40%. Postulated system efficiencies to 50% (or higher) rely on projected development of super-alloys or cooling technique which will allow continued operation at inlet temperatures of 1100 to 1200°C. The development becomes, of course, even more important when it is considered that the system may be fueled by gas from a coal gasification plant with a probable thermal efficiency of 85%. Current technology suggests that the coal-gasification combined-cycle plant cannot achieve an efficiency significantly above 39%. If turbine technology allows operation at an inlet temperature(s) of 1100°C or 1200°C this type of plant could achieve an efficiency as high as 47%. The time scale of this development, as postulated by one turbine manufacturer, is shown in Figure 7.[4]

The Role of Supplementary Firing

In systems which use supplementary firing the gas turbine exhaust is used as the oxidant supply in the combustion of a supplementary fuel in the boiler. The resultant upgrading of steam quality produced in the boiler is a major advantage when the turbine system produces a low temperature exhaust. In this case the efficiency and output of the system increase. However, at higher turbine outlet temperatures, as is shown in Figure 8, the effect of supplementary firing may be to reduce the efficiency of the combined cycle whilst increasing the output from the steam turbine.[3] In the extreme, when the gas turbine produces a negligibly small part of the total output, the efficiency of this type of combined cycle approaches the efficiency of a conventional steam cycle.

Part-load efficiency of combined cycle plant

When the cycle plant consists of one turbine exhausting through one boiler the part load performance of the cycle is usually poor. However, the problem can be overcome by coupling more than one gas turbine with a single steam turboset.

Figure 9 illustrates the case of four gas turbines operating in conjuction with one steam turbine. In this arrangement the efficiency of the combined cycle can be held close to its maximum level across a wide range of load factors. At all load levels the efficiency of the combined cycle arrangement is higher than that of the conventional system; the conventional cycle, however, shows less sensitivity to load fluctuations at all load factors above 60%.[3,5] A multi-turbine installation will necessarily be more expensive than a single turbine system.

THE LURGI-STEAG COMBINED CYCLE POWER PLANT, LUNEN

This power generating unit is the only example of a load-carrying coal-gasification combined cycle power plant in the world. It was constructed during 1970/72 as a consequence of a development decision made in 1969. Major factors influencing this decision are reported to be the improved coal-to-electricity conversion efficiency, the prospective reduction in particulate, NO_x and SO_2 emissions and the ability to use a local coal.[6]

The basic plant is a 170-MW_e unit incorporating pressurized coal gasification, a supercharged boiler exhausting into a gas turbine and secondary waste heat boiler. The plant arrangement is shown in Figure 10. The cycle was designed to use conventional technology at the design date. It has a design efficiency (coal to electricity) of 37% at full load. The gas turbine output is 74 MW, the steam turbine output is 96 MW and the auxiliary power consumption is 7 MW.

One of the most impressive features of this plant is the small size. This will certainly provide increased flexibility in site selection and also in construction since components in the scheme can be factory con- structed; this can also be done for proposed second generation plant of 400 MW_e.

OPERATING EXPERIENCE

Problems encountered during commissioning of the gasifier and gas cleaning system led to the boiler and turbine acceptance trials being carried out with a light oil fired system.[6]

These problems were identified as being:

(a) excessive gasifier outlet temperatures,

(b) low quality (cv) gas,

(c) excessive tar, dust and water carry-over in the product gas,

(d) poor tar removal performance.

The high outlet temperatures led to a metal failure at the junction of the gas generator and quench separator.

This experience led to a major reconstruction of the gas generators, gas quench and gas cleaning systems.[7,8]

The plant has accumulated 10,000 hrs of operation in the intervening years since reconstruction. It has not been required to fulfil a base load function and has achieved a maximum load of 140/150 MW (or 80% of design full load). At the achieved load the conversion efficiency is low compared to adjacent steam cycle stations and the plant was "mothballed" prior to May 1979. During the operating lifetime of the plant it was demonstrated that the dust emission could be reduced to 10% of local standards, that NO_x emissions were less than 30% of conventional coal fired stations, and that sulphur removal to the extent of 90% of the input could be achieved.

CONTINUED DEVELOPMENT OF THE STEAG-LURGI CYCLE

A "second generation" 400 MW_e cycle has been designed to incorporate a 125 MW gas turbine and 375 MW steam turbine. This cycle (summarized in Table 2) was supported by a development program which had these objectives:

(a) enlarging the coal spectrum to permit the use of coal containing excessive fines by developing a pregasification briquetting process, and .....

(b) improving the load response characteristics of the gasifiers by internal redesign, and .....

(c) developing an improved gas cleaning process with a reduced cycle penalty, and .....

(d) reducing the specific energy consumption of the desulphurization process.

The 400 MW_e cycle design incorporates conservative increases in gas turbine inlet temperature and pressure ratio; 850°C and 10:1 respectively. The postulated cycle efficiency is 45%. Further increases in inlet temperature and pressure ratio to 930°C and 15:1 will give a cycle efficiency of 45.5%. The cycle efficiency reflects a simultaneous improvement in steam quality incorporated into the new design. Steam conditions of 530°C/190 bar, reheat to 530°C/42 bar replace the 525°C/130 bar, no reheat used in the original plant.

Table 2 - Development of the Lurgi-Steag combined cycle power plant
(after Meyer-Kahrweg; reference 6)

Design Size	Turbine Conditions and Output				Steam Conditions				Steam Turbine Output MW	Cycle Efficiency (Coal-electricity)	
	Inlet	Out	Pressure Ratio	MW	S'Heat		Reheat			full load	half load
	°C	°C			T °C	P bar	T °C	P bar			
170 MW	800	400	10:1	74	520	130	-	-	96	37	28
400 MW	850	400	10:1	125	530	190	530	42	275	>45	-
400 MW	930		15:1							>45	

THE COMBUSTION ENGINEERING COMBINED CYCLE

This postulated combined cycle is based on the entrained-bed atmospheric pressure gasifier under development by Combustion Engineering Co. of Windsor, Connecticut.[9,10] The gasifier is illustrated in Figure 11.

The gasifier builds on the historic expertise of the company in pulverized coal combustion and incorporates feed systems characteristic of the boiler applications. The vertical reactor is a steam tube wall construction with a refractory surface; steam generated in this unit is integrated into the overall cycle. Gasification is operated in an air-blown mode in what is essentially a two-stage reactor:

Stage 1: Stoichiometric Combustion.

Stage 2: Diffusion Gasification.

Two separate coal feeds are employed. The first goes to the stoichiometric combustion zone; the second feeds coal directly into the hot (1800°C) products from this zone where the coal is entrained upwards into the diffusion zone of the gasifier.

The high temperatures of the system ensure rapid devolatilization and low tar production; molten ash is removed from the base of the vertical tubular reactor. Carbon particulate carry-over amounts to approximately 25% of the input fuel and demands that a fines recycle loop be incorporated. The effluent gas is quenched in a heat exchanger which is also integrated into the steam cycle. Conventional gas cleaning can be employed at the resultant low temperatures for sulphur removal and the gas recompressed for combustion turbine use.

A "current technology" exhaust fired combined cycle has been developed for use with this gasifier.[11] Figure 12 shows that it incorporates a twin gas-turbine system with an exhaust-fired boiler feeding a single steam turbine. The novel feature of the cycle is the subdivision of the turbine exhaust gas stream. Part of the exhaust stream goes directly to the rear passes (steam generating, economiser, air preheating) of the waste heat boiler. The second turbine exhaust stream is used as combustion air in the combustion chamber of the same boiler. The supplementary firing with a partial exhaust stream allows the achievement of high superheat (and reheat) without the need to handle the total exhaust stream. The combustion chamber, superheater and reheater are therefore reduced in size allowing construction of a smaller boiler. Gas compressors, which are an essential feature of all atmospheric-pressure gasifier combined-cycles, are driven by the gas turbines.

In a development of this combined cycle which is classified as "near future" and incorporates turbine inlet temperatures of 1100°C, a series of four heat recovery boilers are coupled into an undivided gas turbine exhaust stream.[11,12] This alternative cycle is illustrated in Figure 13.

THE SHELL-KOPPERS COMBINED CYCLE

Joint activities of Shell International and Krupp-Koppers have led to the construction of a 150 ton/day entrained bed gasifier in the Harburg refinery of Deutsche Shell. The gasifier is a development of the Koppers-Totzek entrained bed system and is capable of operation at pressures up to 30 atm with normal operation being postulated for 20 atm.[13]

The gasifier operates in a slagging mode. In order that no molten slag particles shall be carried over with the product gas a proprietary quench cyclone and scrubber system is incorporated into the raw gas stream to give a product containing 1 mg/Nm^3 solid; this level is below the level currently required for gas turbines operating on blast furnace gas. Sulphur removal follows the particulate cleaning system.

The gasifier in both the oxygen and air blown modes can be integrated into a waste heat boiler combined-cycle power generation scheme as shown in Figure 14. The postulated cycle efficiency is between 42 and 45% with a gas turbine inlet temperature of 1200°C and live steam condition of 160 bar, 540°C. A lower steam pressure (90 bar) reduces station efficiency by 2% and also reduces capital investment.

COAL QUALITY AND CYCLE EFFICIENCY

The calculated cycle efficiencies for four different coals used in the Shell-Koppers combined cycle are shown in Figure 15. The cycle efficiency is clearly dependent on the ash content of the coal fed to the gasifier at the moisture contents specified.

The comparative assessment of the oxygen-blown and air-blown combined cycles carried out for this proposed scheme is shown in Table 3.[14] A major reduction in gasification efficiency occurs in the case of airblown operation; this results in a reduction in station efficiency of less than 1% at a 1200°C gas turbine inlet temperature. If turbine inlet temperatures increase past this level, it may become difficult to achieve adiabatic flame temperatures and sustain easy turbine applications when using the low calorie gas produced by air blown gasification. Figure 16 shows that the developers of the Shell process feel that the oxygen blown system offers the prospect of cheaper electricity than does the air blown gasifier. It remains to be seen if the power utilities will accept oxygen plant in the course of accepting the new combined-cycle technology.

Table 3 - Comparison of oxygen and air-blown gasification
Shell-Koppers combined cycle: 500 MWe

	Low Ash Bituminous Coals		High Ash Bituminous Coals	
	Oxygen Blown	Air Blown	Oxygen Blown	Air Blown
Coal feed: Mt/d	3630	3575	4915	4900
Gasification Eff., %	83	67	80	61
Fuel gas, MJ/kg	13.6	3.7	13.5	3.2
Gas turbine power	300	240	300	230
Steam turbine power	265	290	270	300
Station efficiency	43.5	44.2	42.4	42.7

The air-blown combined cycle is quoted as having the potential for a further 3% increase in efficiency by incorporating blast preheat. This introduces an additional level of integration between the gasifier and the generating systems.

THE UNITED TECHNOLOGIES MOLTEN SALT GASIFICATION COMBINED CYCLE

This developing process has been incorporated into a conceptual combined cycle to take advantage of the desulphurisation occurring when coal is gasified in a hot sodium carbonate bath. The calorific value of the product gas can be as high as 150 Btu/ft^3 without the need for an oxygen blown system.[15,16]

The control of the gasifier demands that temperatures are sufficient to maintain a liquid salt bath but insufficient to permit significant evaporation of the sodium carbonate. Reaction occurs at about 950°C and 20 atmospheres. The coal feed and sodium carbonate are premixed and fed to the gasifiers via lock hoppers.

In the fully integrated combined cycle shown in Figure 17 the recovery and regeneration of sodium sulphate are a charge against the cycle and the mechanics of integrating the gasifier and steam cycle are critical. The product gas is cooled in a fluid bed cooler where vapourized sodium condenses on particle surfaces; it is further cooled in a waste heat boiler prior to carbon dioxide removal and water washing. Finally it enters to the gas turbine combustion chamber.

Efficient steam cycle integration requires that the fluid bed cooler functions as a superheater and that the waste-heat boiler functions as a reheater. These steam circuits are integrated with other superheater and generator circuits in the gas turbine exhaust stream to give a complex circuit design. Using available technologies in the steam and gas turbine circuits the cycle efficiency is estimated to be just over 38%. This complex integration in a largely unproven gasification process demands the advent of high gas turbine inlet temperatures so that the return for complexity is enhanced. Problems of corrosivity of the melt; gasifier availability and prospective load factors are not estimable for this process. Gasification takes place at a sufficiently high temperature where coal reactivity is unlikely to affect reaction rates; however, the process is affected by the ash content of the coal. Ash removal and separation penalises the combined cycle efficiency by approximately 1% per 2½% ash content:

At 15% Ash: Cycle efficiency is 36%
At 5% Ash: Cycle efficiency is 40%

GENERAL ELECTRIC COMBINED CYCLE

The combined cycle study carried out by General Electric as part of the "Energy Conversion Alternatives Study" (ECAS) is based on a conventional[17,18] waste heat recovery cycle incorporating an advanced fixed bed gasifier based on current G.E. developments. The primary gaseous fuel is used in a postulated gas turbine with an inlet temperature of 2400°F and a pressure ratio of 12:1. The turbine incorporates air-cooled blades and has an exhaust temperature of 1100°C. These conditions allow the waste heat recovery boiler to form part of an 1850°F, 950/950 psi steam cycle as illustrated in Figure 18.

Turbine compressed air is used in the gasifier blast; steam for gasification is generated in the gasifier alone. The scheme originally postulated had a high heat rejection from a cooling tower in the gas cleaning system and developed a modest cycle efficiency of 39.6% as a consequence of the irrecoverable losses in gas cleaning.[19].

In an analysis of this cycle presented by NASA, the importance of the mechanics of coupling the gasifier and gas cleaning subsystems into the cycle was emphasized. The proposed changes made a significant difference to the overall cycle efficiency. The suggested integration modifications can be summarized:

- gasifier process steam to be supplied from steam power cycle;
- gasifier air to be supplied by turbine compressor;
- sensible heat of low Btu-gas to be used in the steam power cycle;
- gasifier auxiliary requirements to be supplied by the steam power cycle.

The modifications proposed by NASA indicated that the G.E. scheme offered a potential cycle efficiency of 42%.

Table 4 - Combined cycle efficiencies developed in the Energy Conversion Alternatives Study (ECAS)

Cycle	Efficiency, %
General Electric Fixed Bed (ECAS)	39.6
NASA fixed bed 1 (modified G.E.) GT = 1090°C	37.0
NASA fixed bed 2 (modified G.E.) GT = 1315°C	42.0
NASA fixed bed 3 (modified G.E.) GT = 1370°C	42.2
Westinghouse Fluid Bed (ECAS)	46.8

THE WESTINGHOUSE COMBINED CYCLE

This combined cycle - which also forms part of the ECAS study - is based on a multi-stage fluidized bed gasification system under development by the sponsor organisation.[20].

Coal is successively dried, devolatilized/desulphurized and gasified in a series of fluid beds which may be interlinked. The gasifier is schematically illustrated in Figure 19. Dolomite is introduced into the devolatilizer with the dried coal. At the temperature of this reactor dolomite decomposes to produce CO_2 and CaO; in turn the CaO reacts with H_2S to give a removable sulphide and a measure of desulphurization within the gasifier. The process developers indicate that removal in the desulphurizer bed will amount to over 80% of the input sulphur and the product gas will leave the desulphurizer at a temperature of about 870°C. The desulphurizer will also ensure that tars generated in devolatilization do not persist into the product gas stream.

The proposed waste heat recovery combined cycle, Figure 20, incorporates four gasifiers, a gas turbine with an inlet temperature of 2500°F and an advanced steam cycle of 2400 psig 1000°F/1000°F.[21] This results in a cycle efficiency of 46.8%. The high efficiency postulated for this cycle reflects the adoption of conceptual designs as if they were commercially mature technologies. Similar cycle efficiencies could be generated for other proposed cycle arrangements if the availability of a high temperature gas cleaning process, high temperature gas turbine inlet temperatures, and an advanced steam cycle are postulated.

THE N.C.B. FLUID-BED COMBINED CYCLE

The possibility of alternative fluid-bed routes to combined cycle power exists. The characteristic low bed temperatures of pressurized fluid bed reactors operating at 20 atmospheres has revitalized talk in some circles of the direct coal fired gas turbine. This concept, however, is not likely to be compatible with high cycle efficiencies since the product gas temperature will not exceed 1000°C if alkali metal volatilization is to be controlled.

The more realistic fluid-bed gasification process proposed by the NCB is faced with the problem - as are all fluid bed processes - of extracting ash from a bed in which the fuel carbon is uniformly dispersed. The N.C.B. proposal links the fluid bed gasifier and combustor;[22,23] the combustor serves as the combustion chamber in a direct fired gas turbine and is fed by the discharge from a partial gasifier. This combination allows the fluid bed combustor to form part of an advanced gas turbine combined cycle. A flow diagram of the proposed scheme appears as Figure 21.

GAS CLEANING

For use in a gas turbine the raw gas from any coal gasification process must be cleaned of both particulate material and sulphur gases to:

(a) prevent erosion, fouling, and corrosion of downstream surfaces, particularly the gas turbine blades, and

(b) to minimize solids and sulphur dioxide emissions to the atmosphere after use of the product gas as a fuel, and

(c) to prevent solid particles interfering with H_2S recovery.

The nature and concentration of the contaminants depends very much on the gasifiers and gasification conditions used. Specific data for the various gasifiers is missing and makes the specification of gas cleaning equipment difficult. Similarly the standards required to protect advanced gas turbines (T>1000°C) are not well defined.

The problems anticipated in these turbines follow the pattern that was recorded when residual fuel oil was first used in gas turbines. Erosion by large particles, condensation of vaporized species, and corrosion of metal surfaces at elevated temperatures are all potential problems. Erosion is a function of particle aerodynamic diameter and flow velocity; impaction is not anticipated to occur with particles below 1/4 μm and will not be severe for low particle concentrations. Condensation is dependent on the partial pressure of the components in the gas stream and their vapour pressure at blade temperatures. Condensed phases may produce corrosion by an oxidative, sulphatic or sulphidic mechanism or by alternate periods of each. Sub-micron particles in the gas stream, which would not normally reach blade surfaces, can act as condensation nuclei during passage through the turbine to give rise to particles of sufficient size to impact and adhere. The literature describing these corrosion and deposition mechanisms is extensive.[24,25] Currently turbine manufacturers are developing stringent inlet gas specifications in an effort to avoid recurrence of the blade problems of the 1960's.

The closest operating analogy to the coal-gasification combined-cycle is the use of the gas turbine with blast furnace gas.[25] This has been a common practice since the late 1940's for both power production and air compression in the steel industry. In this turbine application inlet temperatures have been held below 750°C with turbine efficiencies approaching 28%. Experience with suitable blade materials indicates that when dust loadings are held below 2 $\mu g/m^3$ the erosion and corrosion of blades in a base-loaded turbine can be minimal. Current specifications for this use limit the particle concentration to 1 $\mu g/Nm^3$ with not more than 30% of the particles being greater than 2μ diameter. This standard has been achieved with electrostatic precipitators working at temperatures below 250°C.[27]

For turbine inlet temperatures above 950°C a particle concentration of 0.5 g/Nm^3 must be envisaged.[26] For turbines with inlet velocities above 300 m/sec <u>no</u> material above 5 μm should be admitted. This specification will demand gas cleaning efficiencies well in excess of 99.5%. The performance of several types of candidate particulate removal systems are listed in Table 6.[28]

Hydrogen sulphide processes for use at low temperature are well developed. The Stretford process, the amine-based processes, the solvent processes, the carbonate process and the eventual sulphur recovery from the Claus process all have possible application in combined cycle schemes.

The choice of process depends on the presence of impurities. For example, COS and CS_2 are not normally accepted in the Stretford process, which is also adversely affected by high carbon dioxide concentrations. The amine processes can be highly selective but must be operated at temperatures below 50°C; amine loss by evaporation can be significant; irreversible reaction between the amine compounds and COS, CS_2, RCOOH occurs and gives rise to sludge.

The comments above indicate that many low temperature gas cleaning processes currently available will meet the sulphur removal requirements of the gas turbine. However, they all create a cycle penalty because they demand that the product gas be cooled to a low temperature for cleaning. The energy benefit to a combined cycle plant that could be obtained by use of a high temperature gas cleaning process is variously reported between 3 and 8 percent. The range reflects the different efficiencies that are assumed for heat exchanger performance and the complexity of integration of these heat exchangers into the cycle.

The prospect of hot gas clean-up with its ability to eliminate some heat exchangers and simplify the integrated design has led to a major research and development effort. Summaries of the desulphurization efforts and the particulate removal systems are shown in Table 5 and 6 respectively.

The high temperature desulphurization processes are generally based on the iron oxide or calcium carbonate reactions:-

$$Fe_2O_3 + 2H_2S + H_2 \qquad 2FeS + 3H_2O$$
$$Fe_2O_3 + 4H_2S \qquad 2FeS_2 + 3H_2O + H_2$$
$$CaCO_3 + M_2S \qquad CaO + CO_2 + H_2S$$
$$CaO + CO_2 + H_2S \qquad CaS + CO_2 + H_2O$$

Reaction and dissociation in the calcium based processes is slower than in the iron based systems and will therefore require larger equipment with corresponding increases in material handling during regeneration.

The development of high temperature particulate removal systems is being pursued by extension of the common low temperature gas cleaning technologies into higher temperature operation by use of new materials.

Comparative station efficiencies for high and low temperature gas clean-up were developed for the ECAS case of an advanced fixed-bed coal-gasification combined cycle. The results, shown in Figure 22, indicate a potential improvement in plant efficiency of two percent.

Table 5 - Hot gas desulphurization development
(after Morrison; reference 28)

Developer	Active Ingredient	Operating Conditions		Recovery % (H_2S)
		T °C	P atm	
Appleby-Frodingham	Fe_2O_3		1	99.9
I.M.M.R.*	Fe_2O_3	800	1-2	90-95
U.S.B.M.** (Morgantown)	Fe_2O_3	800	1-11	95
Babcock & Wilcox	Fe_2O_3	650	1	95-98
Batelle-Columbus	Fe_2O_3	800	1	99
Conoco	CaO; MgO	870	15	95
Batelle***	$CaCO_3$	925	1	95
Kennecott	CuO	500	1	90

*Institute for Mining and Minerals Research, University of Kentucky.

**United States Bureau of Mines.

***Pacific North West Laboratories.

Table 6 - Hot gas particulate removal development
(after Morrison; reference 28)

	Operating Conditions T °C	Operating Conditions P atm	Removal Efficiency*
Cyclone systems	650	5	99.5% (+40μm) and 23% (0-2.5μm)
Multi-cyclone systems	650	50 5	99.9% (+18μm) and 50% (+2μm) 98% (+10μm) and 50% (-10μm)
Metal filters	815	50	100% (1μm) 100% (+1μm) and 98% (+2μm)
Fibre filters	650 - 1200	1	- - - -
Fabric filters	1370	1	99.5% (at ambient temps)
Ceramic filters	760	1	100% (+1μm)
Bed filters	870	2	97.5% of +5μm but may generate sub-micron particles
Electrostatic precipitators	800 - 1090	20	99% (+8μm) and 98.9 (.75 to 1.5μm)

*Where more than one efficiency is quoted, the information derives from different manufacturers.

LOW AND MEDIUM-JOULE GAS IN GAS TURBINES

The majority of existing gas turbine applications use distillate oils or natural gas; the exception to this, which again provides guidance to the prospects for coal gasification combined cycle systems, is the blast-furnace-gas fired turbine. The major operational problems that have been encountered with these units have been ascribed to variations in fuel quality. Turbine designs can be produced to cater adequately for specific fuels of constant composition; turbine inlet temperature control is difficult to achieve with varying fuel composition.

Blast-furnace-gas and low/medium joule gas must be fed at higher mass flows than natural gas to maintain the same turbine inlet temperature. The post-combustion dilution factors however mean that the combustion chamber volume need not change. (See Table 7). The combustion rates and flame temperatures of the low quality gases are low and it therefore becomes vitally important to ensure an adequate residence time for completion of the combustion reactions. For the same reason an auxiliary fuel may be mandatory during start-up or low load operation.

Combustion chamber wall temperatures are low and nitric oxide emissions are also low; concentrations of 5 ppm are reported with blast-furnace-gas.

It should be noted that the comments above are framed in terms of the waste heat combined cycle. In the case of the supercharged Steag-Lurgi cycle, the comments apply to the pressurized shop-constructed boiler rather than the gas-turbine.

Operating experience has shown that a gaseous fuel with a calorific value as low as 3200 kJ/kg can be burnt satisfactorily in a conventional gas turbine combustion chamber.[26] If it is required to operate with lower calorific value gases or gases with a high CO_2 content then a support flame or preheat may be necessary to ensure flame stability.

Table 7 - The properties of blast furnace gas and methane in a gas turbine

	Blast Furnace Gas	Natural Gas (Methane)
Calorific value, kJ/kg	3280	50050
Turbine inlet temperature, °C	1000	1000
Stoichiometric air, kg/kg	0.82	17.4
<u>Mass flow rates per 100 kg/s exhaust gas</u>		
Fuel, kg/s	24.5	1.6
Stoichiometric air, kg/s	20.2	27.8
Dilution air, kg/s	55.3	70.6
Exhaust mass flow, kg/s	100.0	100.0
Gas volume in combustion space	98%	100%
Adiabatic flame temperature ($\lambda = 1$)	1700°C	2160°

THE COST OF ELECTRICITY

THE ECAS STUDY

The best known study of combined-cycle techno-economics is the Energy Conversion Alternatives Study (ECAS) carried out in the mid 70's on behalf of the American National Science Foundation. The study developed conceptual designs for several advanced coal-to-electricity conversion systems which were capable of meeting the following environmental emission standards.[16-21]

Table 8 - Target emission standards for E.C.A.S.
(Expressed in U.S. regulatory units)

SO_x	Solid fuel	1.2 lb/MMBtu
	Liquid fuel	0.8 "
	Gaseous fuel	0.2 "
NO_x	Solid fuel	0.7 "
	Liquid fuel	0.3 "
	Gaseous fuel	0.2 "
Particulates	All fuels	0.1 "

The plants were conceived for a consistent set of site specific conditions for water supply and waste disposal. All costs were developed for the same financial constraints and operating costs were based on the same load pattern to a mid 1975 base (U.S. dollars).

The seven systems studied included atmospheric and pressurized fluid bed boilers with advanced steam cycles, open cycle combined cycle systems using liquid and gaseous coal derived fuels. Other systems studied but not reported in this review were topping and bottoming cycles using potassium and organic fluid respectively and an open-cycle MHD scheme. An advanced pulverised-fired steam plant was chosen as the reference plant. This was designed as a 3500 psig 1000°F/1000°F steam cycle; the boiler being equipped with a wet lime scrubbing and stack reheat system. The reference cycle was calculated to have a conversion efficiency of 32% and a cost-of-electricity of 39.8 mills/kwh.

All the systems studied bettered the apparently conservative 32% conversion efficiency of the reference system.

Figure 23 shows the comparative cost-of-electricity and conversion efficiency; the target area is the lower right hand quadrant of the diagram. The combined-cycle options and the pressurized-fluid-bed steam cycle were considered to be medium term options from the 1975 viewpoint. It is interesting to note that in December 1976 (the report date) the atmospheric fluid bed was seen as being a demonstrable technology generating electricity in a plant which included all the elements of a "mature commercial unit" by a December 1982 start-up date. The open combined cycle turbine was seen as requiring a longer time to demonstrate despite the fact that a 175 MW_e unit was already being operated using a supercharged cycle. Both technologies were seen as having a "good" probability of success.

The two low Btu gasification cycles developed in the ECAS study differed markedly in the operating conditions assumed to represent "state-of-the-art": the levels of integration incorporated into the designs were also different. Performance differences presented in Table 9 are therefore ascribed to differing design approaches, gasifier systems and turbine blade cooling technology.

In the NASA re-appraisal of the ECAS study[19] one of the low BTU gasification cycles (the G.E. design) was substantially modified to consider more advanced turbine conditions and more extensive integration of the gasifier and steam cycle.

The cycles considered in the ECAS and ECAS/NASA studies are not mature. The advanced fixed and fluid-bed gasifiers are unproven systems, the turbine cooling blade designs are equally unproven for utility availability requirements. The levels of integration proposed are highly optimized and heat recovery is installed on every minor energy flow where this is technically possible. Experience with existing gasification units indicates that such vigorous optimization may not be practical. An example is the development effort that has been expended on the air-blown Lurgi gasifier to achieve satisfactory tar re-cycle. The contribution of tar losses to cycle efficiency dominates effects due to rigorous integration.

Table 9 - Cycle performance and time to demonstration
(ECAS; Dec. 1976)

Conversion System	Cycle Performance			Time to start-up of Demonstration Plant (years)
	Conversion Efficiency (%)	Cost of Electricity* (mills/kwh)	Relative Cost of Electricity	
Reference P-F + Steam Cycle	320	39.8	1	
Atmospheric Fluid Bed	35.8	31.7	0.80	6
Pressurized Fluid Bed	39.2	34.1	0.86	12
Combined Cycle: Liquid	37.8	29.5	0.74	14
Combined Cycle:				
General Electric Case	39.6	35.1	0.88	11
Westinghouse Case	46.8	29.1	0.73	11

*Mid 1975 U.S. dollars

Table 10 - Combined cycle performance economics: NASA/ECAS

	Westinghouse E.C.A.S	G.E. E.C.A.S.	G.E. E.C.A.S. NASA I	G.E. E.C.A.S. NASA II	G.E E.C.A.S. NASA III
Steam cycle (psig)	2400	1800	1800		
T°C/T°C	535/535	510/510	510/510		
Gas cleanup	hot	cold	cold	cold	cold
Turbine:					
Inlet, T°C	1370	1320	1100	1200	1370
Pressure ratio	16	12	8	10	12
Cycle Efficiency, % ...	46.8	39.6	37.0	39.3	42.0
Capital Charges , $\$/kW_e$*	613.8	770.8	809.1	762.1	741.2
Cost of Electricity*					
Capital	19.4	24.4	25.6	24.1	23.4
Fuel	7.3	8.6	9.2	8.7	8.1
O + M	2.4	2.1	2.7	2.5	2.2
TOTAL	29.1	35.1	37.5	35.3	33.7

*Mid 1975 U.S. dollars

CANADIAN STUDIES

Shaunavon

A further development, comparable to the ECAS study, has been carried out to relate the combined cycle technologies to Canadian lignite deposits in the Shaunavon area of Saskatchewan.

This study considered a small (300 MW_e) installation using the Shaunavon lignite as opposed to the Illinois No. 6 bituminous coal which was considered to be the feedstock in the ECAS study. The important technical and economic consequences of this change are shown below:

Table 11 - The effect of feedstock on cycle performance: Shaunavon Phase I

	Cycle Efficiency, %		Cost of Electricity* mils/kwh
	Illinois No. 6	Shaunavon Lignite	Shaunavon Lignite
Base Case			35.2
Westinghouse: ECAS ...	46.8		36.2
G.E.: ECAS	39.6	34.3	41.9
G.E.: ECAS/NASA I	37.0	32.4	39.7
G.E.: ECAS/NASA II ...	39.3	-	
G.E.: ECAS/NASA III ..	42.0	36.7	38.5

*Mid 1988 Canadian dollars; reflecting differences due to both coal quality and price

Later phases of the Shaunavon study compared the relative economics of fully-fired supercharged boiler cycles with unfired waste-heat recovery cycles and a pulverized coal fired steam cycle.[29] The gasifiers considered were Lurgi and Shell-Koppers. Both gasifiers were preceded by coal-drying facilities and, in the case of Lurgi, by a briquetting plant. The eventual moisture content of the Lurgi feedstock was 15% whereas that of the Shell-Koppers unit, which incorporated a nitrogen swept pulverizer, was 2%.

The most viable of the coal gasification-combined cycle options studied was Lurgi gasification with the regenerative combined cycle, followed by the Steag pressurized boiler cycle with reheat. Table 12 shows a comparative direct capital cost breakdown excluding administration and engineering and the levelized cost of electricity expressed in mid 1979 dollars, over the economic life of the plants, for the 150 MW Lurgi-regenerative combined cycle plant and the conventional plant with flue gas desulphurization. It shows that the conventional plant equipment costs about 30 percent less, but is only 14% less costly in terms of the relative cost of electricity (COE). This is due to the efficiency advantage of the Lurgi-regenerative combined cycle plant, its efficiency being 37% versus 28.2% for the conventional plant. Thus there is a substantial fuel conservation (of about 28%) aspect to the combined cycle scheme. Approximately 16% differential in the levelized cost of electricity on a plant lifetime basis of 30 years is favourable to the conventional power plant in relation to the regenerative combined cycle plant with Lurgi gasification process. A larger differential exists for the other alternatives considered, the maximum being 30%. See Table 13.

For the two most economic cases a sensitivity analysis based on the cost of coal showed that, with all other costs remaining the same, these two plants of the 150 MW nominal size become equal in cost of electricity with the coal cost increased by 127% (174% for the 300 MW size). Any further increase, therefore, would show an advantage to the gasification-combined cycle plant. These results are summarized in Figure 24.

This economic comparison indicates that, for the schemes considered for this site, the best combined cycle gasifier plant becomes closely competitive with conventional plant only when all contributing cost factors and assumptions remain constant except that the cost of coal increases. Thus this type of plant may be more suitable for locations where the cost of coal is already high or transportation costs added to the mining costs would bring the total cost of Shaunavon lignite up to $19.56 per tonne in mid 1979 dollars ($42 per tonne in 1988 dollars) for the 150 MW plant.

It is therefore apparent that a mine mouth plant located near Shaunavon favours the conventional power plant. The gasification-combined cycle plant is more attractive when plants are at other locations where the coal transportation cost is significant.

This study also suggests that a reduction in overal capital costs could be achieved through a phased development. For an ultimate 300 MW capacity plant, the initial installation could consist of a 115 MW gas turbine with full waste heat boiler (i.e. capable of operation on two gas turbines), together with a 70 MW steam turbine operating at half load. Subsequent extension of the plant would therefore be limited to addition of a second similar gas turbine. If provision were made for directly firing the boiler, this would have the additional benefit of permitting the steam turbine to be used in the event of a gas turbine failure.

Any combined cycle plant will be a new development based on the latest available technology, no savings can be anticipated in design and construction time. In fact, it would be wise to be cautious and allow a full five years for these activities, a conventional plant can be designed and constructed in four years.

Table 12 - Comparative cost assessment of Lurgi-regenerative combined combined cycle vs conventional plant flue gas desulphurization

	Capital Cost, Mid 1979 $\$x10^6$	
	Lurgi-Combined Cycle	Conventional
Site, Buildings, Foundations, Heating	2.5	11.75
Combustion Systems	98.88 (2)	38.0 (1)
Desulphurication	9.2 (3)	23.0 (4)
Generation systems	44.26 (5)	24.0 (6)
Electrical	2.33	4.03
Instrumentation and Controls	0.63	3.64
Miscellaneous	0.72	0.92
Cost of Electricity	155.52	105.34
The levelized COE (in 1979 mills/kWh)	27.3	23.6

NOTES:

(1) Includes boiler, pulverizers, precipitator, coal and ash handling, stack, water treatment.

(2) Includes gasifiers, waste heat boiler, coal and ash handling, cooler-saturator, waste and water treatment.

(3) Stretford process to produce elemental sulphur from H_2S in the product gas with over 99 percent sulphur removal. The sulphur produced is of commercial grade, but no value has been attributed to it in the economic analysis.

(4) Alkaline fly ash scrubbing system with 89 percent sulphur removal efficiency.

(5) Includes steam and gas turbines, steam condenser, wet/dry cooling towers, feedheating, expander-compressor.

(6) Includes steam turbine, air cooled condenser, feedheating.

Table 13- Cost summary: Combined cycle schemes Shaunavon Phase II

COSTS IN MILLIONS CANADIAN DOLLARS MID 1979 BASIS

SYSTEM	NOMINAL SIZE 150 MW					NOMINAL SIZE 300 MW		
	REGENERA-TIVE C.C. - LURGI GASIFI-CATION	REGENERA-TIVE C.C. - SHELL - KOPPERS GASIFI-CATION	STEAG-LURGI REHEAT	STEAG-LURGI NON REHEAT	150 MW PF	REGENERA-TIVE C.C. - LURGI GASIFI-CATION	REGENERA-TIVE C.C. - SHELL - KOPPERS GASIFI-CATION	300 MW PF
Nominal Site Output at MCR	148	141	159	148	133	297	281	269
Output GWhr/yr	1044	951	1021	916	809	2088	1901	1627
CAPITAL COSTS								
Total Power Plant Excluding IDC	74	80	117	106		136	141	
Total Gasifier Excluding IDC	106	120	91	91		175	190	
TOTAL CAPITAL COST (EXCLUDING IDC)	180	201	208	198	118	312	332	200
$/kW Net Capital Cost	1212	1427	1309	1.327	882	1000	1179	751
ANNUAL COSTS								
Annual Levelized Fuel Cost	9.46	7.49	8.79	8.85	8.37	15.93	12.08	13.31
Power Plant O&M Gas Turbine	1.91	1.40	1.25	1.25		3.82	2.80	
O&M Steam System	1.04	1.10	1.40	1.35	1.88	1.30	1.66	2.97
Gasifier Maintenance (FGD or PF Plants)	4.28	4.68	4.28	4.28	1.86	7.13	7.40	3.07
Gasifier Operation	1.57	1.75	1.57	1.57		2.28	2.45	
Water Supply Maintenance	0.03	0.02	0.04	0.04	0.01	0.06	0.04	0.02
Cooling System Maintenance	0.07	0.11	0.14	0.14	0.16	0.13	0.22	0.32
Levelized COE in mid 1979 Mills/kWh	27.3	29.4	28.7	31.2	23.6	23.1	23.9	19.3

FGD for conventional P.F. plants based on the alkaline fly ash system with SO_2 emission level of 0.52 kg/GJ

Note: Cost of briquetting is included in each alternative that uses Lurgi gasification process.

Hat Creek

A further study of combined cycle power generation utilizing a Canadian coal deposit examined the Hat Creek Deposit in British Columbia as primary source for power generation.[30] This 400 million ton deposit was compared as the feedstock for conventional p-f combustion, p-f combustion with scrubbers, fluid-bed combustion and combined cycle power schemes.

The coal itself is lignitic (with a mean ash content of 25% and a low fines content); the ash has extremely high fusion characteristics which make it suitable for dry bottom utilisation techniques.

The combined cycles have been compared with a reference 2000 MW_e power plant using conventional technology of mid-1975 vintage. The summary data is shown in Table 14. It should be noted that the G.E. cycle considered in this study was not identical with that considered in the ECAS study; it considered a (relatively) low steam quality at 1250 psig/900°F and did not incorporate reheat.

Table 14 - Comparison of power generating schemes
(Hat Creek Coal)

	Pulverized Coal		Combined Cycles		
	No Flue gas Cleaning	With SO_2 Scrubbers	Steag (Supercharged Boiler)	G.E. Cycle (Lurgi)	Advanced Cycle
Cycle Efficiency %	36.3	35.0	40.3	33.1	45.0
Relative Cost of Electricity	1	1.22	1.22	1.19	0.87

The developed costs were based on a coal cost of $3.00 (Canadian) per ton. As the price of coal increases, the advanced cycles assume a progressively more competitive position in regard to the cost of the electricity. This effect is illustrated for this deposit in Figure 25.

This conclusion re-emphasizes that although the degree of optimization affects cycle efficiency, the cost of coal can play a dominantly important role in establishing the cost of electricity. The highly optimized cycle may not be a practical choice for a first generation combined cycle power plant using a cheap western Canadian coal unless the reductions in emissions and water consumption are of paramount importance in arid prairie locations where trans-boundary pollutant transport is a matter of political concern.

COMBINED CYCLE AVAILABILITY

The implementation of a new technology in any industry inevitably raises questions of equipment availability. In the power generating industry four availability criteria are in common use.

<u>Availability</u>: the percentage of a year that a unit was - or could have been - generating electricity.

<u>Operating Reliability</u>: Availability plus scheduled <u>unforced</u> outages

<u>Starting Reliability</u>: The ratio of successful start-ups to attempted start-ups

<u>Mean Time Between Failures</u>: the average number of operating hours between <u>forced</u> outgas.

The existing operations of combustion turbines and combined cycle plant using liquid or gaseous fuels have been analyzed to identify experience and targets in these areas.[31]

Table 15 - Combined cycle plant reliability
(Average data; twin gas turbine, single steam turbine plant)

	Utility Experience	EPRI Analysis		EPRI Targets	
	MBTF hrs	MBTF hrs	Availability %	MBTF hrs	Availability %
Combustion Turbine alone	2690	5560	94.7	9000	System Dependent
Combustion Turbine system	593	980	92.2	6000	95
Steam Turbine + balance of plant	545	663	91.1	System Dependent	System Dependent
Total Plant	184	281	77.5	3000	90

The North American requirement is for at least 1500 hrs between failures to be comparable to steam boiler-turbine cycles.[32] The EPRI target indicates that a ten-fold increase in between failure outages is necessary. The target availability of 90% is not high. It is not apparent from the data in Table 15 that the combustion turbine is the major culprit in outage time. Table 16 makes this clear.

Table 16 - Outage profiles in combined cycle plant

	Outage % of total number	Outage % of total downtime	Duration (Relative, per failure)
Combustion Turbine			
Turbine	7	45	65
Auxiliaries	41	19	5
Generator	12	16	13
Steam Turbine			
Steam Generator	26	2	1
Auxiliaries	8	6	8
Turbine Generator	5	7	14
Electric			
Transformers and Switch Generator	1	5	50

The combustion turbine itself is not the most frequent cause of outages. Nevertheless, because of the complexity of design and inaccessibility of the component parts the outages are generally of long duration. The accessibility of the auxiliary equipment makes their frequent downtime less important in terms of overall plant availability.

The use of combustion turbines alone has decreased during the past few years in the United States. Uncertainty about fuel supply is partially responsible but a secondary reason is "dissatisfaction with perceived combustion turbine reliability".[31] The finding of the EPRI study also indicated the important influence of plant maturity on failure rate. Reliability creates a learning curve for operational and maintenance personnel; the initial combined cycle plants will certainly be at the lowest point on such a curve.

The study also indicated that, for mature combined cycle plants in the 100 to 200 MW range, the gas turbine itself is more reliable than its controls and auxiliaries. This indicates that a major availability improvement could be introduced by increasing equipment redundancy levels. It is also clear from other studies that the repair policy following fault or breakdown affects availability.

DEMONSTRATION OF COAL GASIFICATION COMBINED-CYCLE TECHNOLOGY

The coal gasification combined cycle plant at Lunen is the only plant of this type with any operational history. There is necessarily considerable doubt attached to the cost estimates for projected schemes elsewhere and a lack of information about system and component reliability. These uncertainties have led to a plan for a 100 MW demonstration plant which is now at the engineering design stage at the Cool Water Generating Station of Southern California Edison.[33,34]

The plant is based on the Texaco gasification process in a waste-heat recovery cycle. California environmental permits have been obtained for the 1000 ton/day gasifier. The committed participants in the demonstration project at the time writing are Southern California Edison, Texaco, Bechtel and E.P.R.I. The objectives of the demonstration effort are:

- construction of an integrated coal gasification combined cycle electric generating facility on a commercial scale
- demonstration of
  - a) compliance with environmental regulations
  - b) operatonal flexibility and reliability
  - c) coal feedstock flexibility
  - d) integrated system controls
  - e) alternative plant and process components
- establishing operating, maintenance safety and training procedures
- developement of precise economic criteria.

The demonstration facility is budgeted to cost \$300 x 10^6 with funding shared between the major participants and other sponsors. A schematic illustration of the proposed cycle is shown in Figure 26.

THE CANADIAN PROSPECT

A consideration of the prospects for an electricity generating station based on coal gasification combined cycle technologies such as those outlined in this review must be approached from different viewpoints. Amongst the technical options which must be assessed are:

- the need for increased generating capacity in specific areas
- the quality of the local coal resource
- the gasification potential of the coal
- the cost of the coal
- local environmental constraints for air and water pollution
- local water availability
- technical capabilities within the generating authority and the local labour force
- capacity requirements of the generating authority during years 1 and 2 of operation.

ELECTRIC POWER PRODUCTION AND PLANS

In Canada the 1980 coal-fired generating capacity was approximately 14000 MW_e with the bulk of this being located in Ontario (9000 MW_e), Alberta (3000 MW_e) and Saskatchewan (1200 MW_e). The two western provinces both feature mine-mouth power stations whereas all the coal used in Ontario is imported from either western Canada or from mines in the United States. Those utilities with traditional expertise in the operation of major coal handling, preparation and utilisation facilities appear to be candidates for advanced coal technologies. Other utilities which use coal or own major coal deposits e.g., the Maritime Provinces and British Columbia are also candidates.

Canadian utilities have expansion plans for the next two decades which suggest the need for generating capacity increases ranging between 4% annually in central and eastern Canada to 6% in western Canada.[35]

Coal quality, method of mining and coal cost varies widely across the country. In the east the coal is generally a high sulphur bituminous coal produced in underground undersea mines. The sulphur may be finely disseminated throughout the coal structure.[36]

In the central prairies the coal is exclusively lignitic with high ash and high moisture content. It is currently in use in mine mouth power plants adjacent to the strip mine operations.

In the western prairies the coal is a low sulphur bituminous coal, strip mined and in use at mine mouth power stations. Foothills and mountain coals are generally low sulphur, moderate ash bituminous coals which are currently exported to metallurgical industries in the Pacific Rim market. In the mountains the mining operations are both open pit and deep mining. One major, unexploited lignite deposit occurs in the Western Mountains at Hat Creek. This coal is projected to be an open pit mine with a mine mouth pulverised coal fired power station.

Coal costs are highest in the deep mine operations of the maritime provinces and lowest in the strip mines of the Alberta and Saskatchewan sub-bituminous and lignite fields.

All of these deposits can be gasified to produce a low or medium calorie fuel gas using appropriate technologies with modifications to accomodate specific coal characteristics.

Environmental constraints vary across the country. To date no Canadian coal-fired power station is equiped with Flue-Gas Desulphurisation although provision has been made for the equipment in stations close to the U.S. border and a retrofit program is currently in the design stage in Ontario. Atmospheric emission considerations may limit the expansion of existing conventional plants where trans-boundary flow of plumes is possible. Water availability is matter of serious concern at many prairie and foothills sites in particular where heavy-oil and tar-sands plants create an immense processing demand for both water and electric power.

Other local factors which must be considered are the expertise that has developed in nuclear technology in Ontario and in hydro-electric technology that has developed in Quebec. Projected expansion in these two provinces is dominated by the technology in which the generating authority has its principal existing expertise. Ontario currently generates 5600 MW_e in its nuclear stations and projects an expansion of 10 000 MW_e in the next decade.[35] Quebec currently generates 17 000 MW_e in hydro-electric plants and its expansion plan in the next decade postulates a further 13 000 MW_e of hydro power.[35]

COMBINED CYCLES IN CANADA

The studies conducted to date in Canada do not support the case for a close-coupled mine mouth coal gasification combined cycle power plant based on either the sub-bituminous coals of Alberta or the lignites of Saskatchewan. In both instances the plant is technically feasible but the cost of electricity is unlikely to be competitive with conventional pulverized coal fired power stations equipped with flue gas desulphurisation equipment. Costs have been defined for Saskatchewan and British Columbia lignites. Sub-bituminous coals can be expected to offer lower gasification costs because of their higher rank and lower ash content. (This is also advantageous to the conventional plant). They will offer a higher combined cycle conversion efficiency than lignites. However, the sub-bituminous coal has a lower cost than lignite per thermal unit (and per carbon unit) which will not be offset by the improved cycle efficiency.

Mine mouth combined cycle power plant using the high rank, high cost Maritime coals appear more attractive. A high efficiency cycle makes maximum use of the carbon content in the coal and the high sulphur content represents a marginal cycle penalty. In this way the cost of electricity will be held down. Alternative technologies appear to be

a) Conventional pulverised coal with flue gas desulphurisation
   Steam Cycle limited. 36% Conversion (max)

b) Fluid-Bed Combustion
   Steam Cycle limited. 40% Conversion (max)

c) Combined Cycle
   40% Conversion, current technology
   44% Conversion, future technology

It should be noted that, in all cases, conversion efficiencies can be increased if co-generation options are added to the steam cycle.

Where coal shipment charges are a major feature of power generation coast then the coal gasification combined cycle can offer competitive costs of electricity and other factors must considered. The plan s for Ontario and Quebec indicate that existing expertise and costs of nuclear or hydro generated electricity dominate the expansion plans for the future. However, in Saskatchewan, where the power corporation is responsible for provision of fuel gas as well as electricity to homes and industry, the expansion plans will not accomodate a 600 MW_e (minimum size) nuclear power station and the availability of exploitable hydro sites is limited. The prospects for integrating an industrial gaseous fuel supply with a combined cycle power plant at sites distant from the mine mouth must be reviewed in the light of diminishing provincial natural gas reserves.

HEAVY OIL RECOVERY AND UPGRADING

The heavy oil recovery processes can use steam, electricity and in some instances carbon dioxide; the processing and upgrading can use major quantities of hydrogen. At the moment clear economic advantages occur by generating hydrogen by reforming natural gas. However, it is possible to define a coal utilisation/heavy oil recovery and upgrading scheme in which combined cycle power production/cogeneration is coupled with hydrogen production for upgrading purposes in order that the maximum liquid yield from the heavy oil can be realised. Other options include combined-cycle power production in conjunction with methanol production.

RETROSPECT

Current plans do not include the development of a coal gasification combined cycle power plant in Canada during the next decade. Continued increases in the cost of thermal coal demand that this plan be kept under continuous scrutiny for specific locations within the country.

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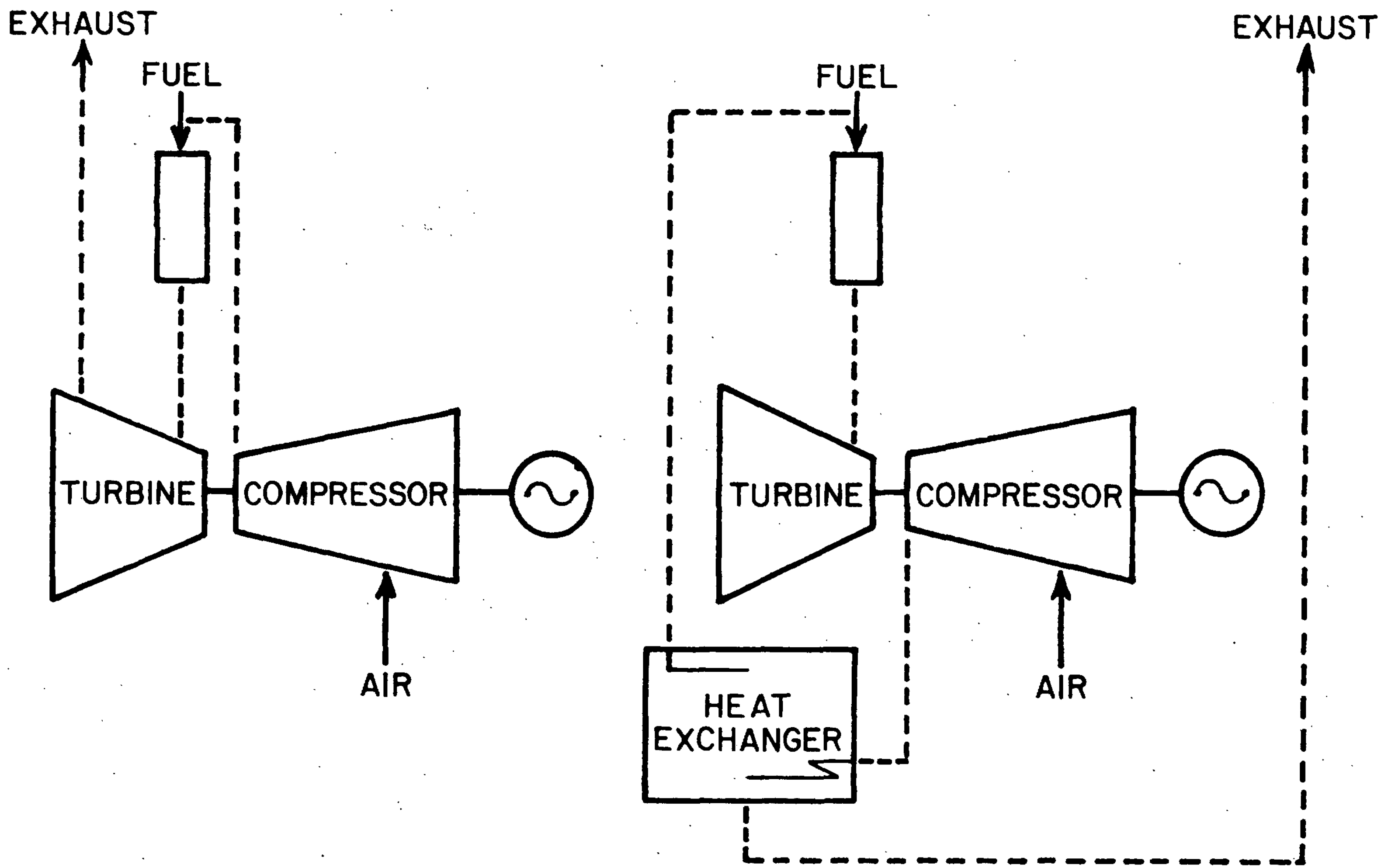


Fig. 1 - Power generation by gas turbines

(a) No preheat

(b) With preheat

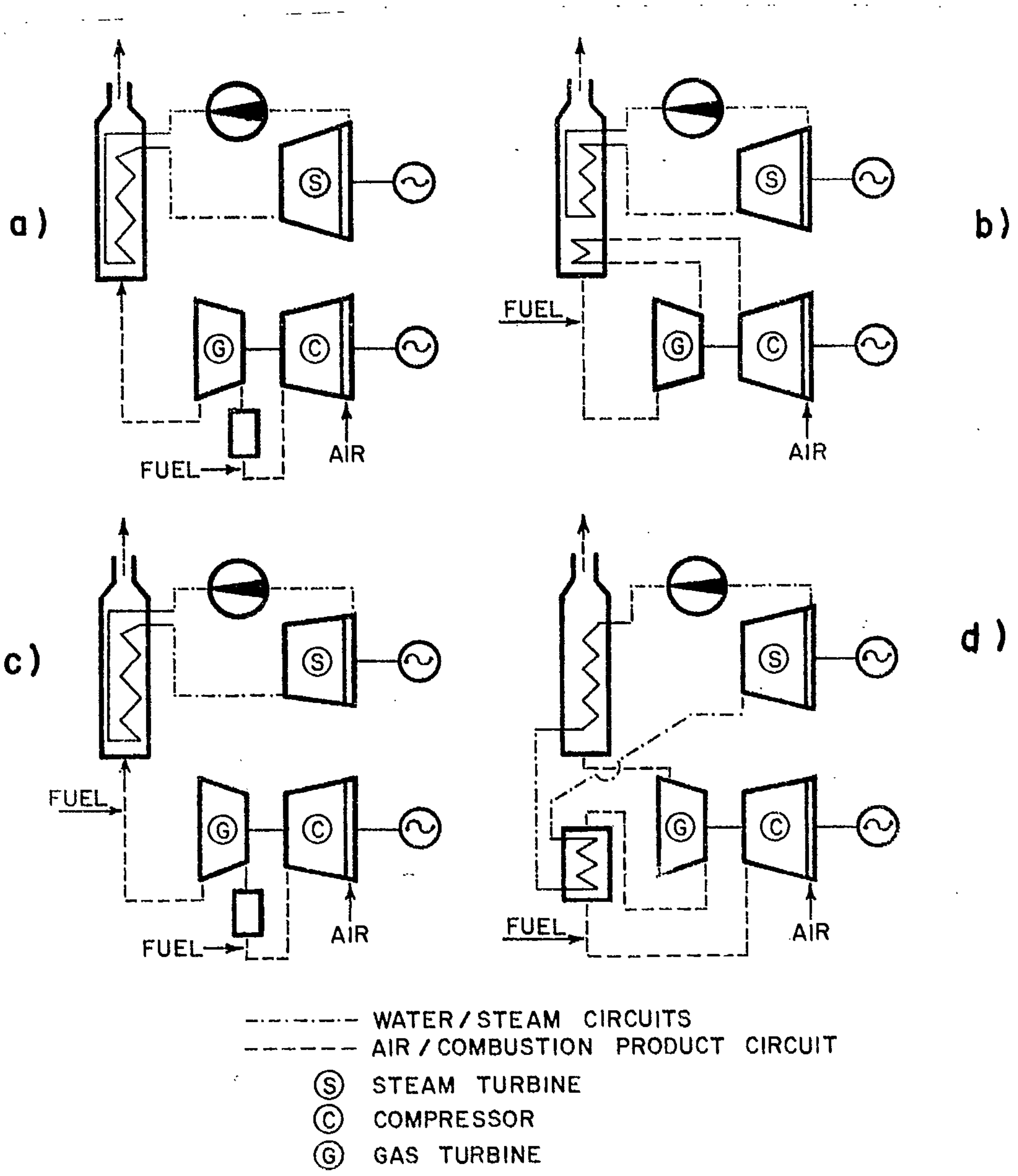


Fig. 2. Types of combined cycles

(a) Direct or waste heat recovery cycle

(b) Indirect cycle

(c) Fully fired cycle
A partially fired cycle differs only in the amount of fuel that is injected into the gas turbine exhaust.

(d) Supercharged Cycle

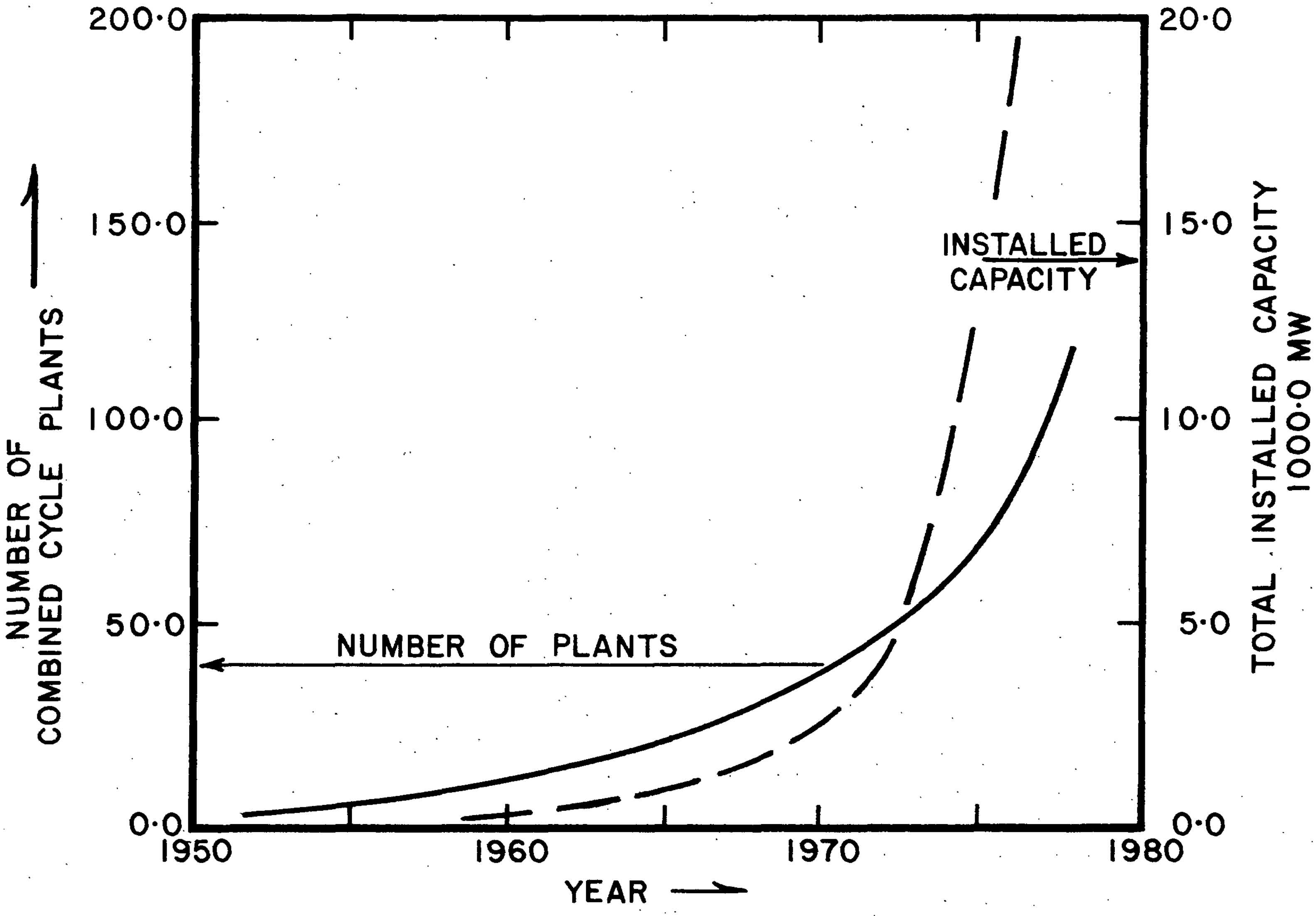


Fig. 3 - The development of installed capacity of combined cycle plant in the Western world

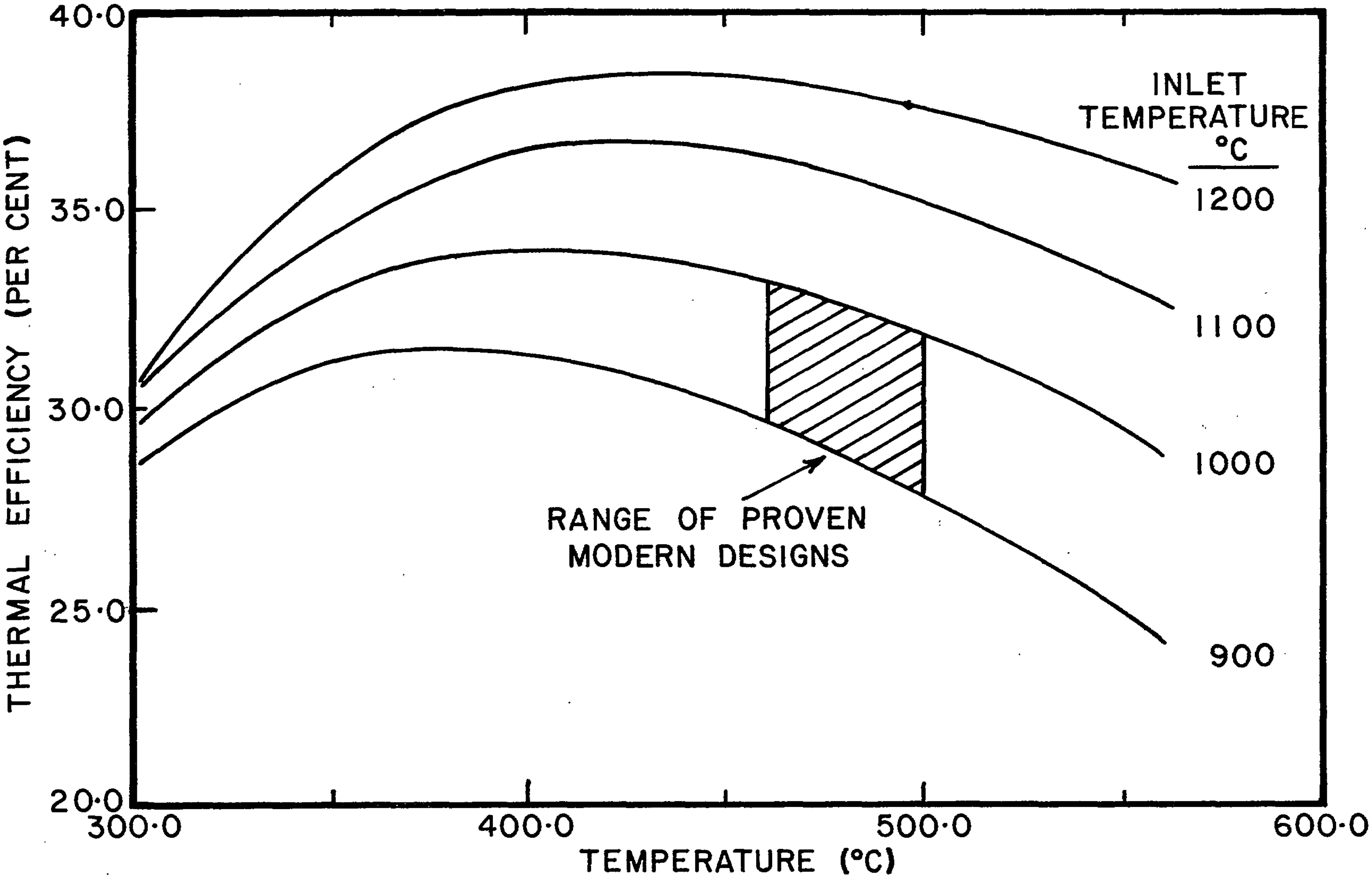


Fig. 4 - The effect of gas turbine inlet temperature on gas turbine efficiency

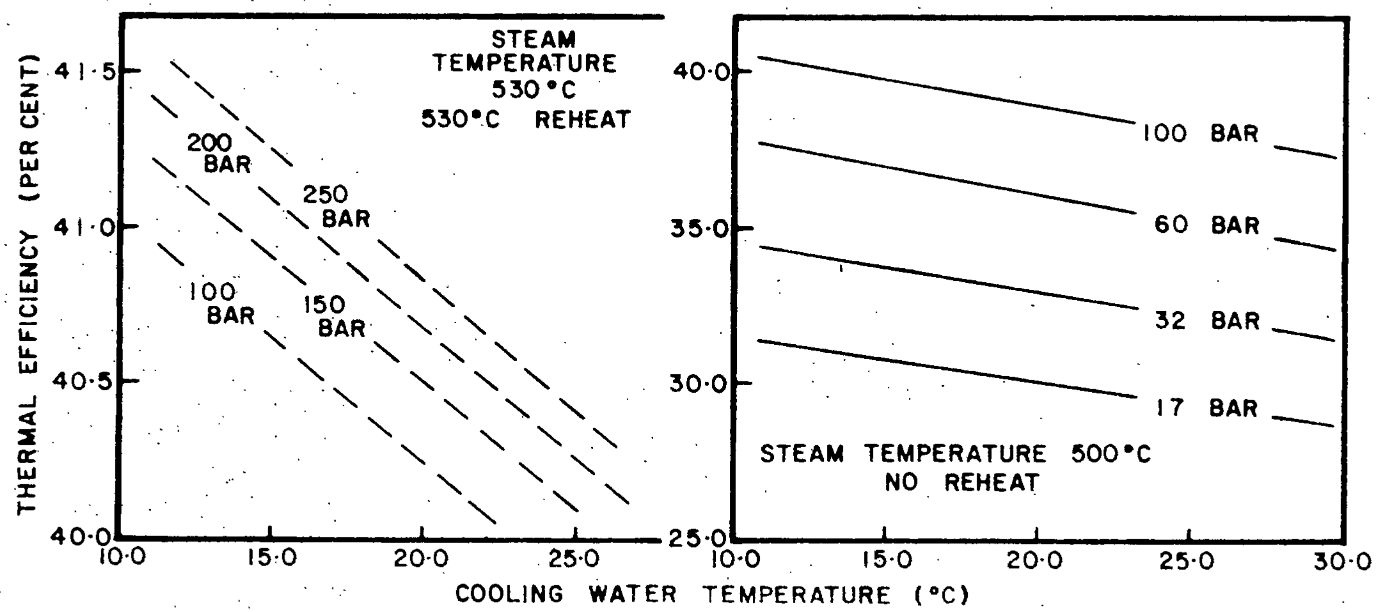


Fig. 5 - The efficiency of steam turbines

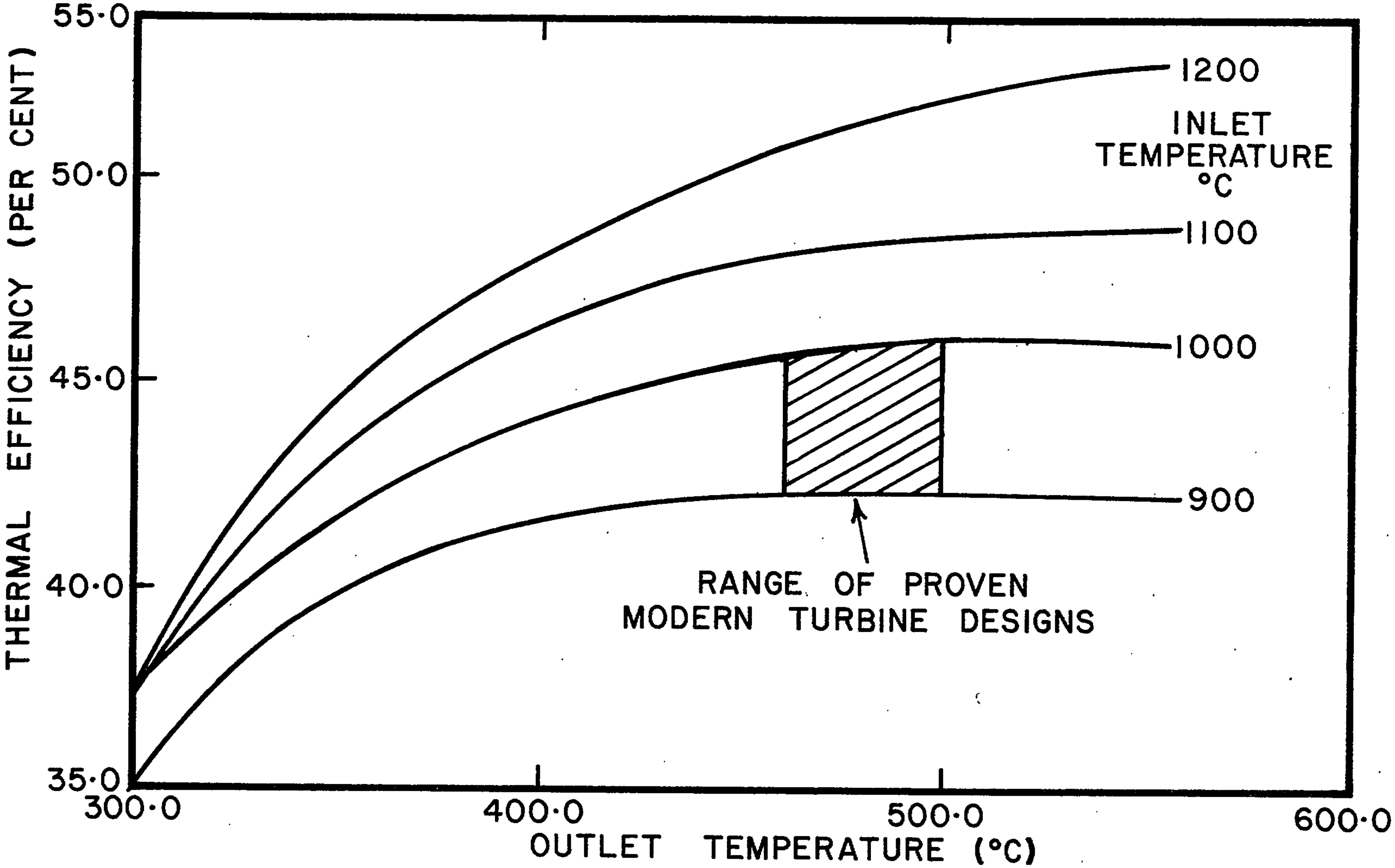


Fig. 6 - The efficiency of combined cycle (gas and steam turbine) power generating systems

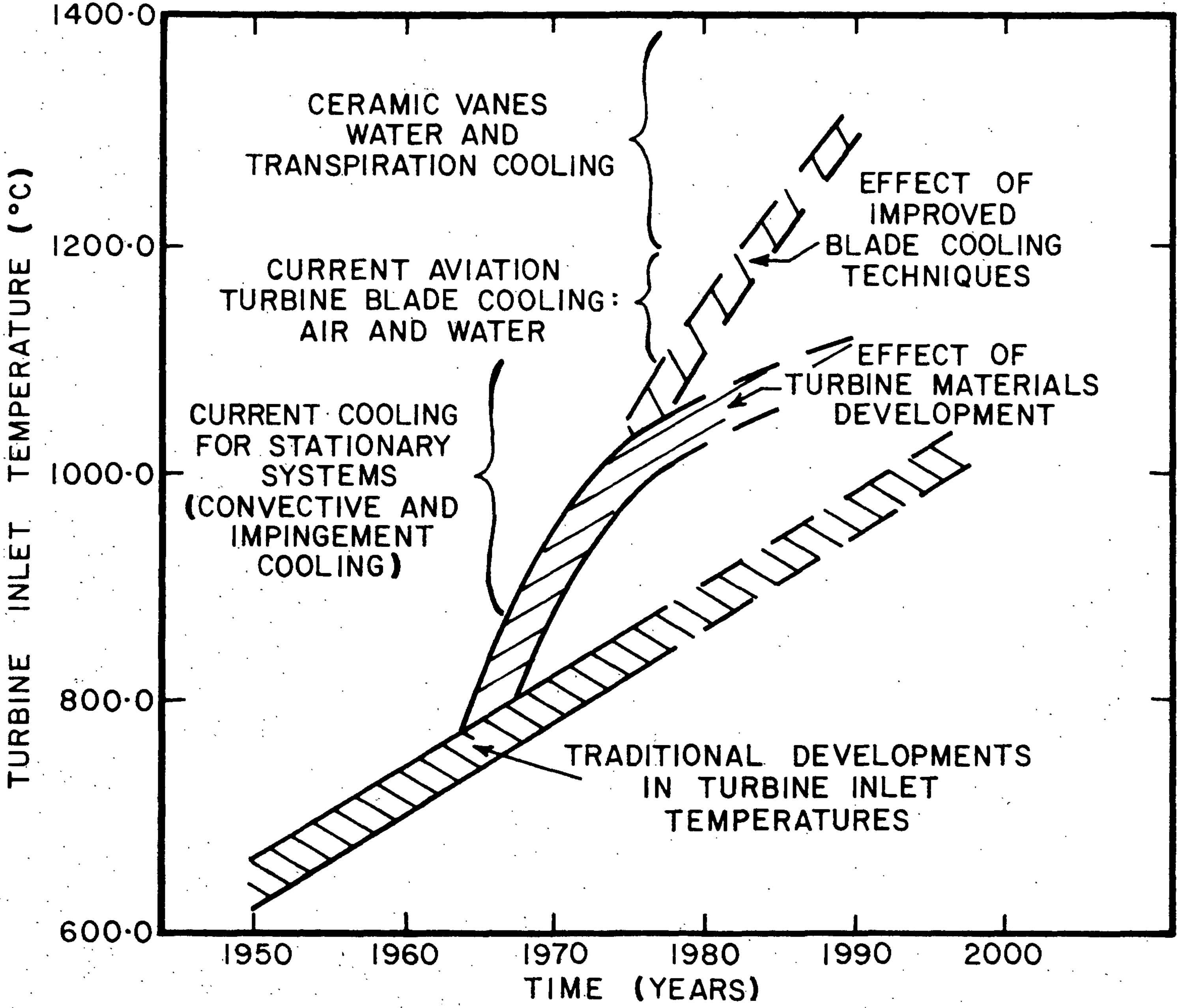


Fig. 7 - Future development in gas turbine inlet temperatures

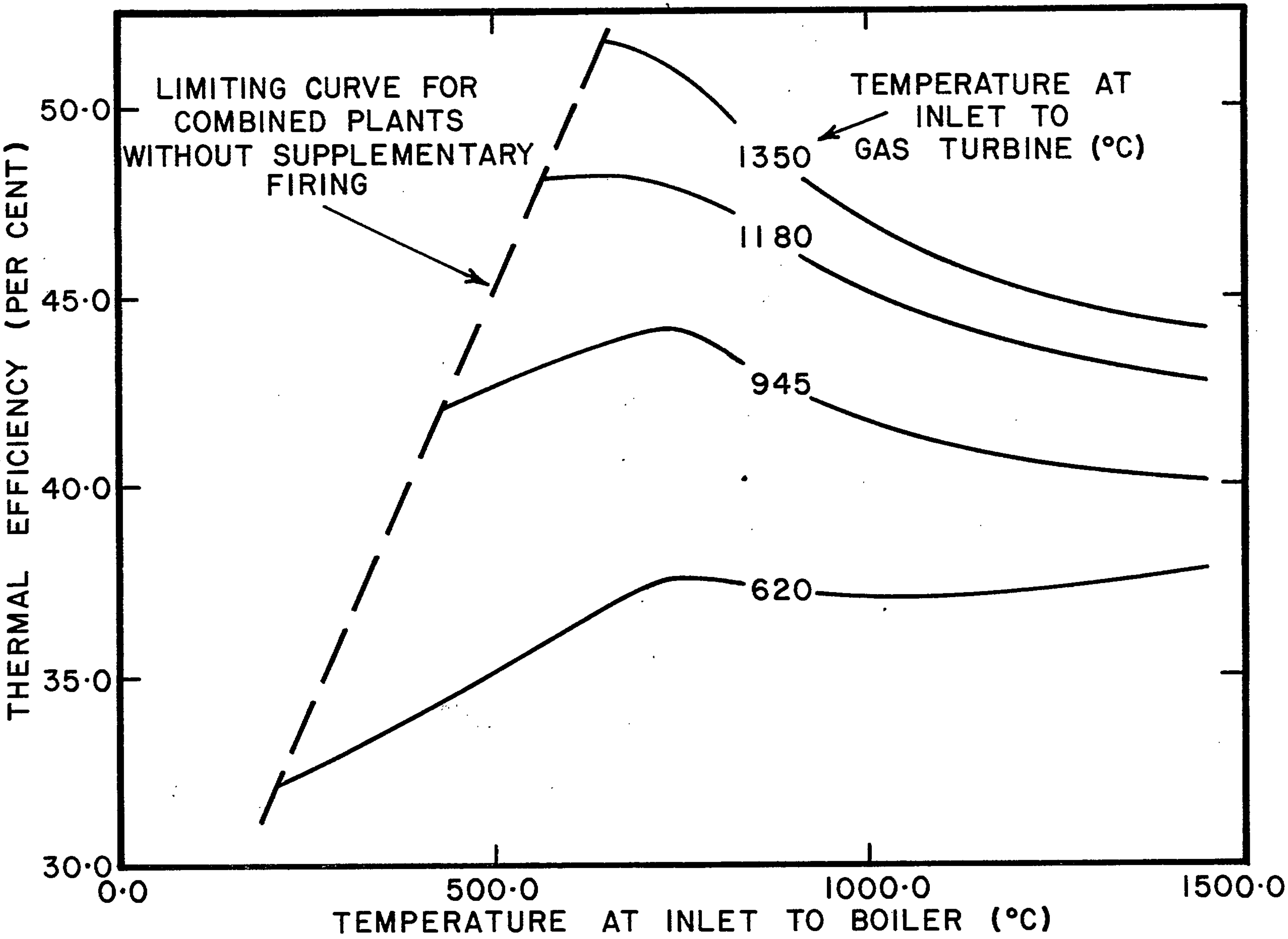


Fig. 8 - Combined cycle efficiency; cycles with supplementary firing

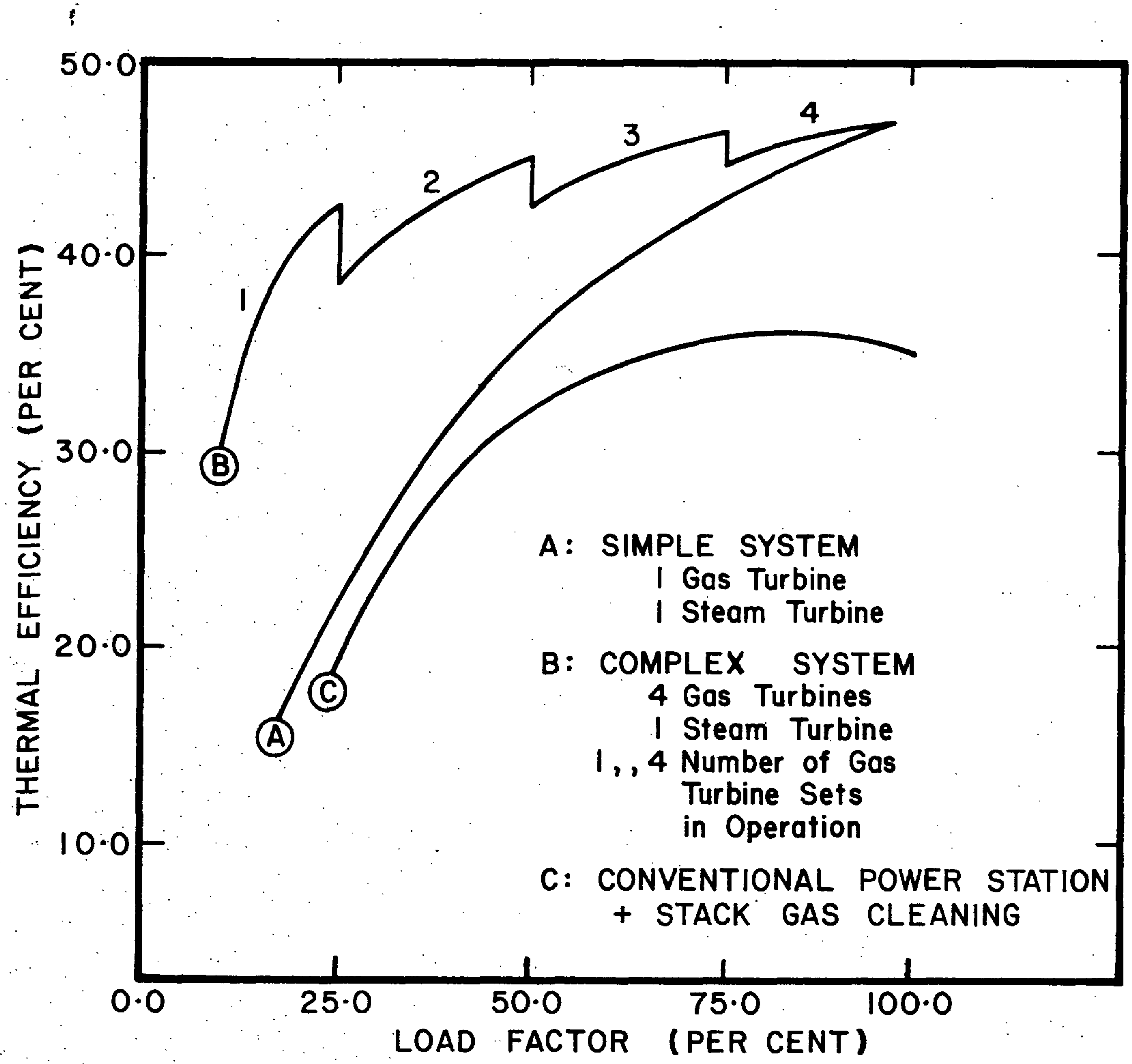


Fig. 9 - Part load performance characteristics of two combined cycle power schemes

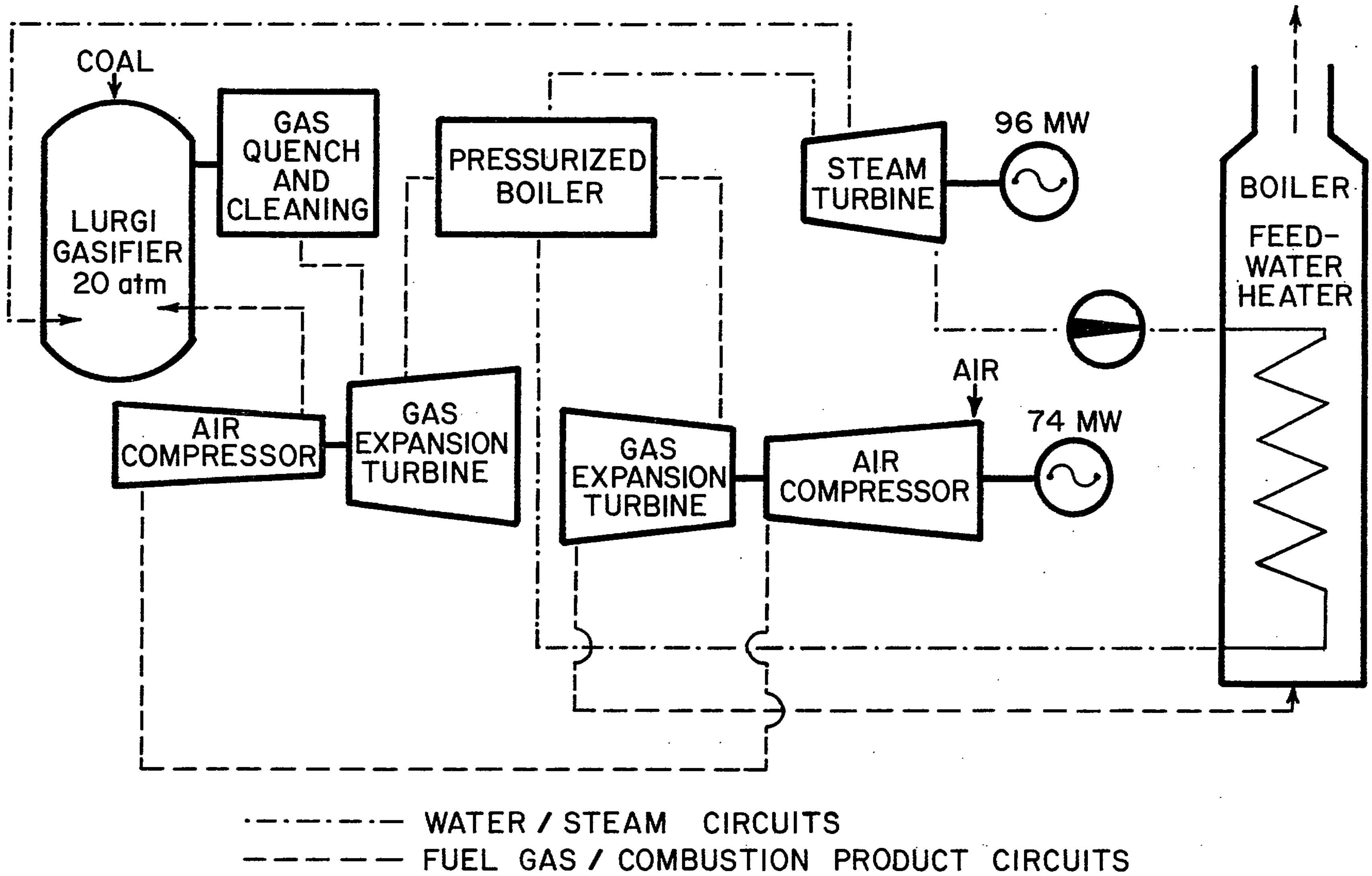


Fig. 10 - The Lurgi-Steag combined cycle plant

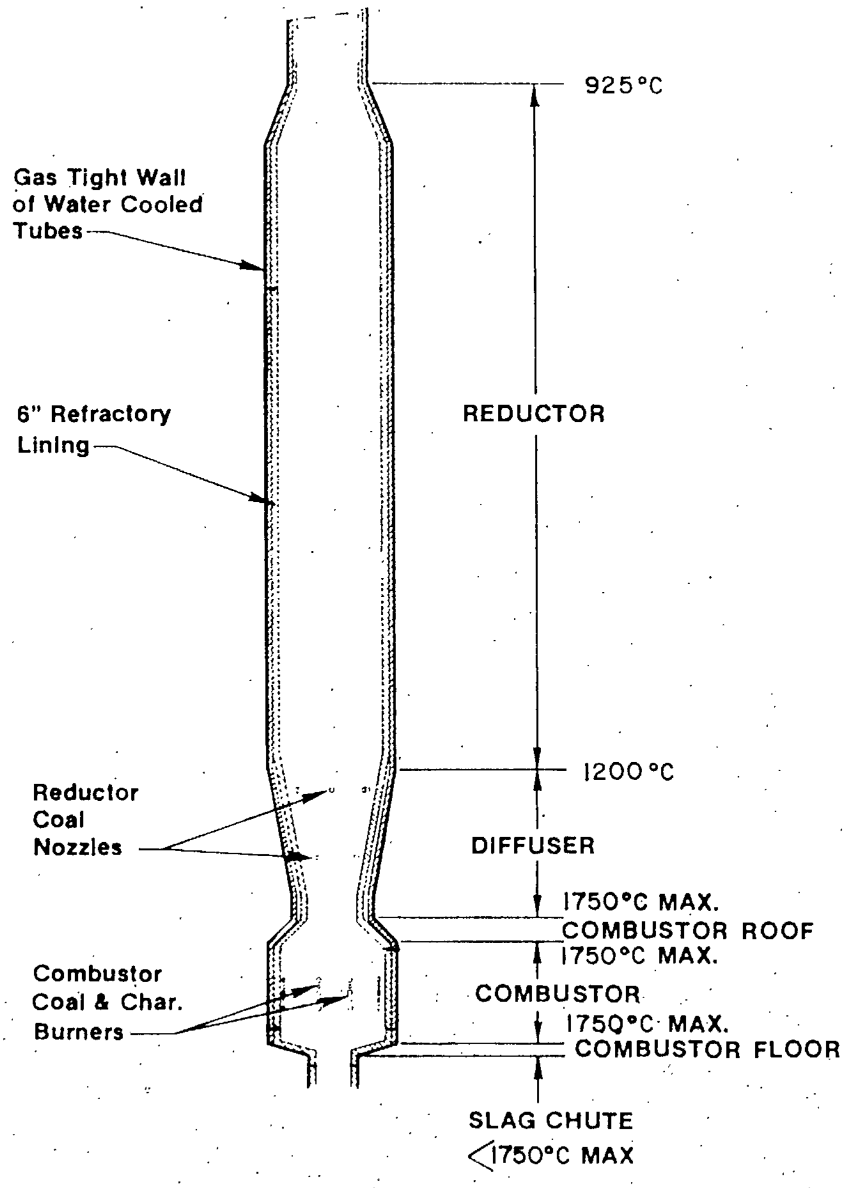


Fig. 11 - The Combustion Engineering gasifier

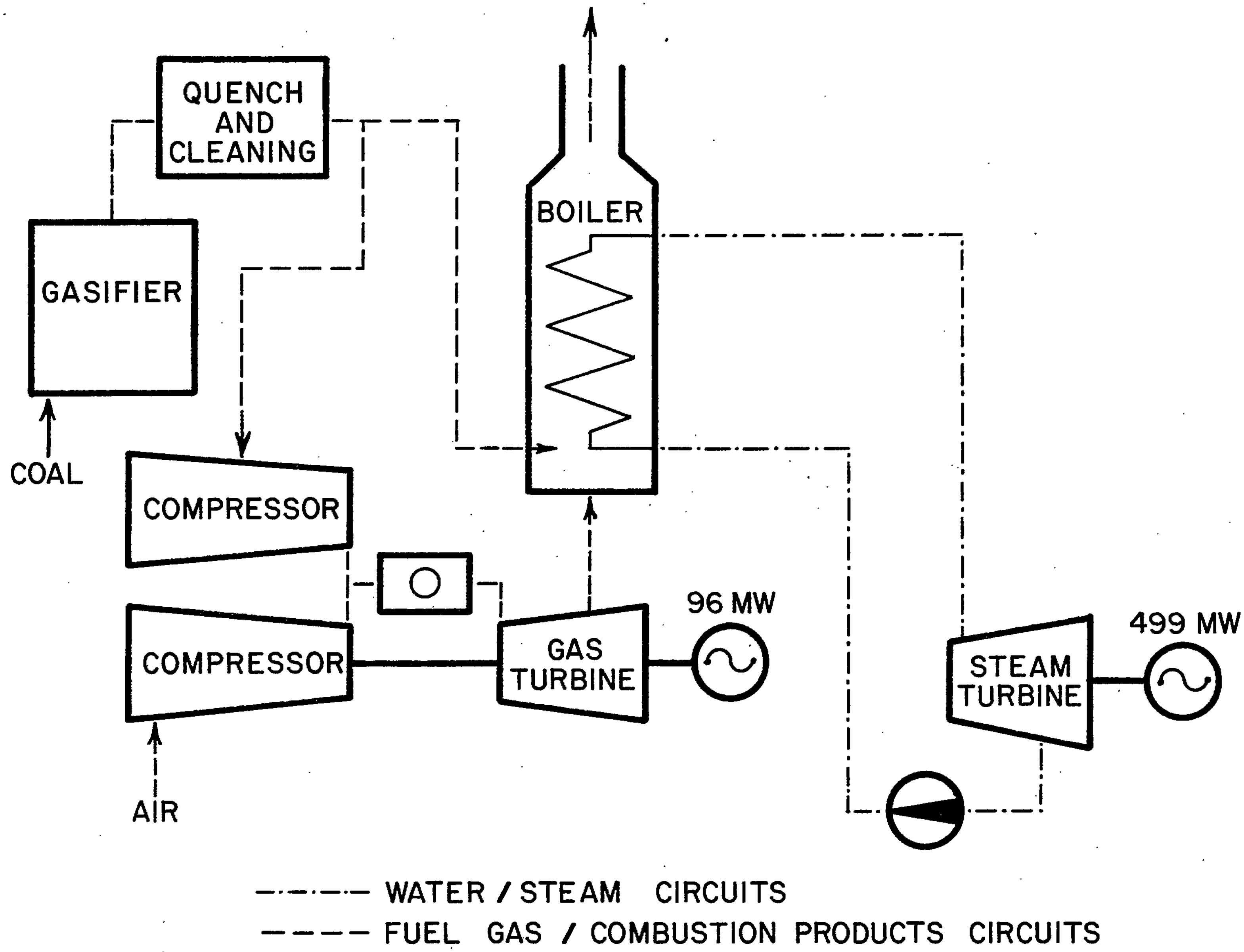
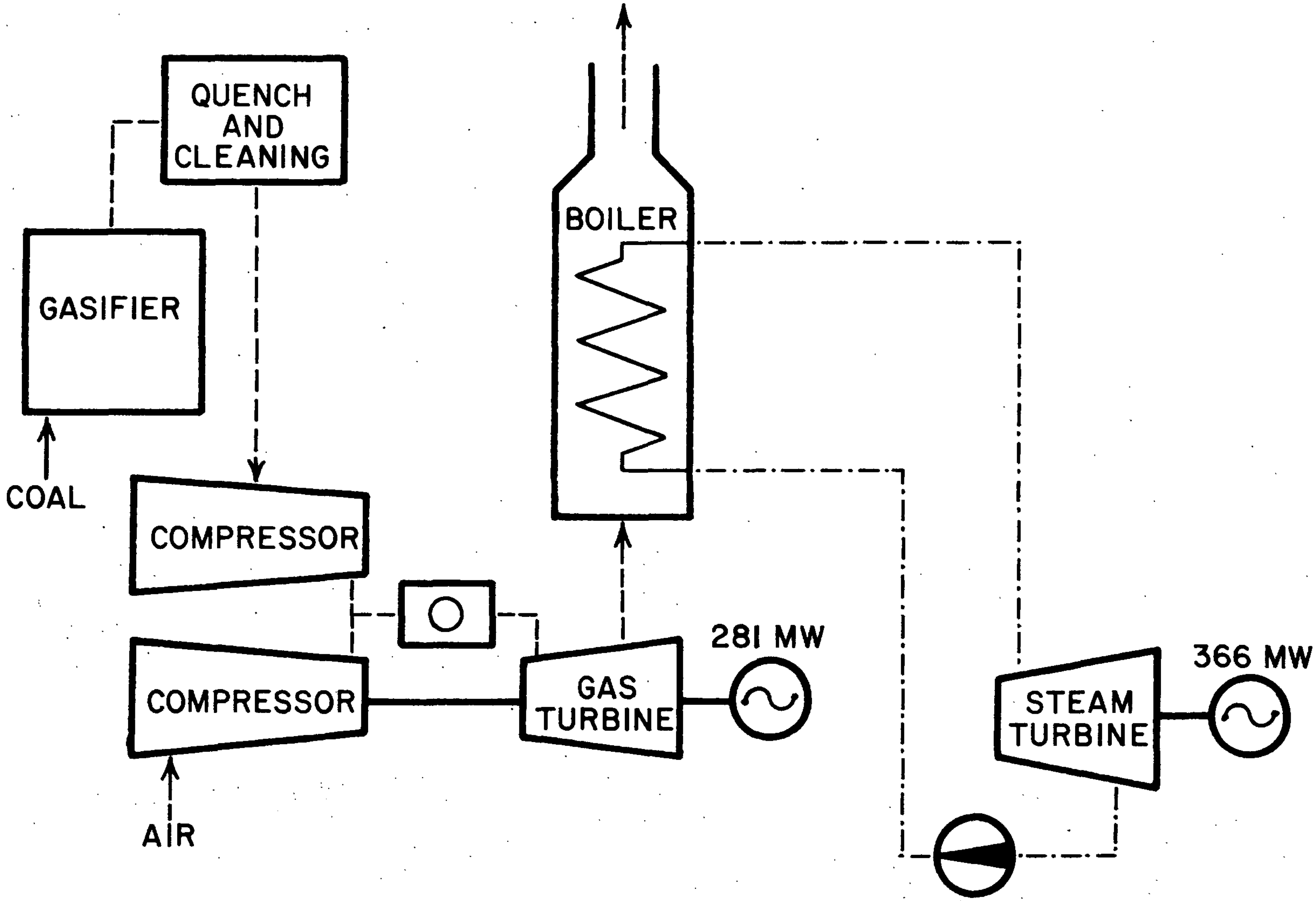


Fig. 12 - The Combustion Engineering combined cycle



-·-·-·- WATER / STEAM CIRCUITS

------ FUEL GAS / COMBUSTION PRODUCTS CIRCUIT

Fig. 13 - The Combustion Engineering "near future" combined cycle

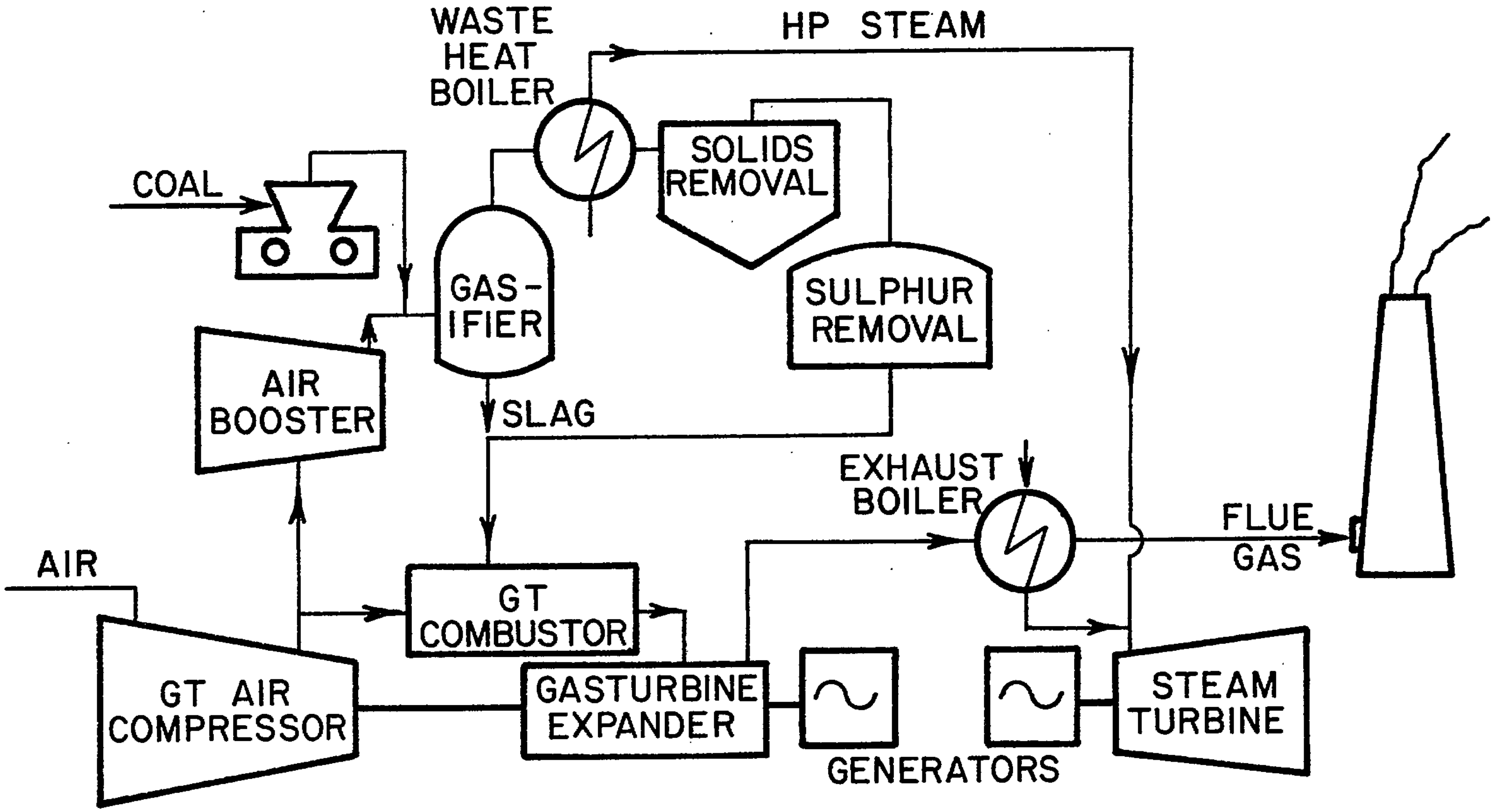


Fig. 14 - The Shell-Koppers combined cycle

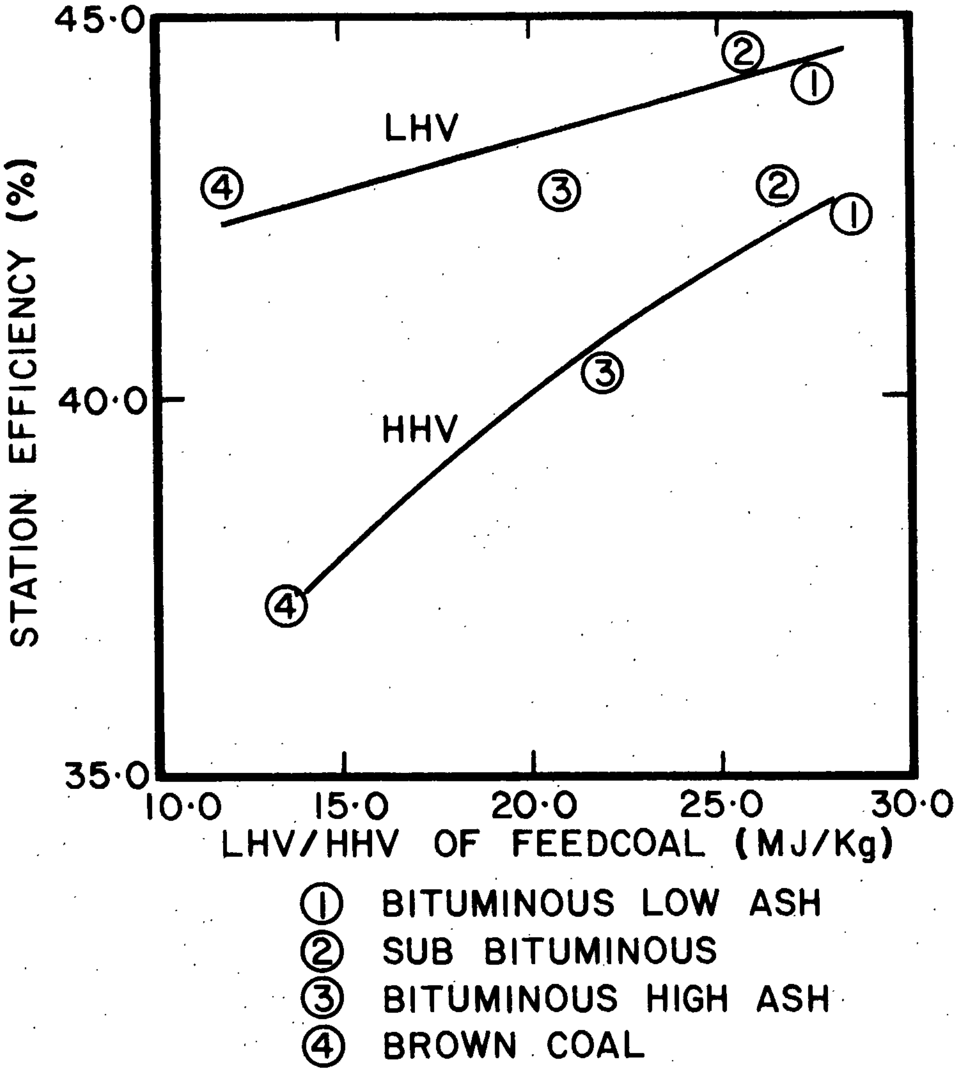


Fig. 15 - Efficiency of the Shell-Koppers cycle for different coals

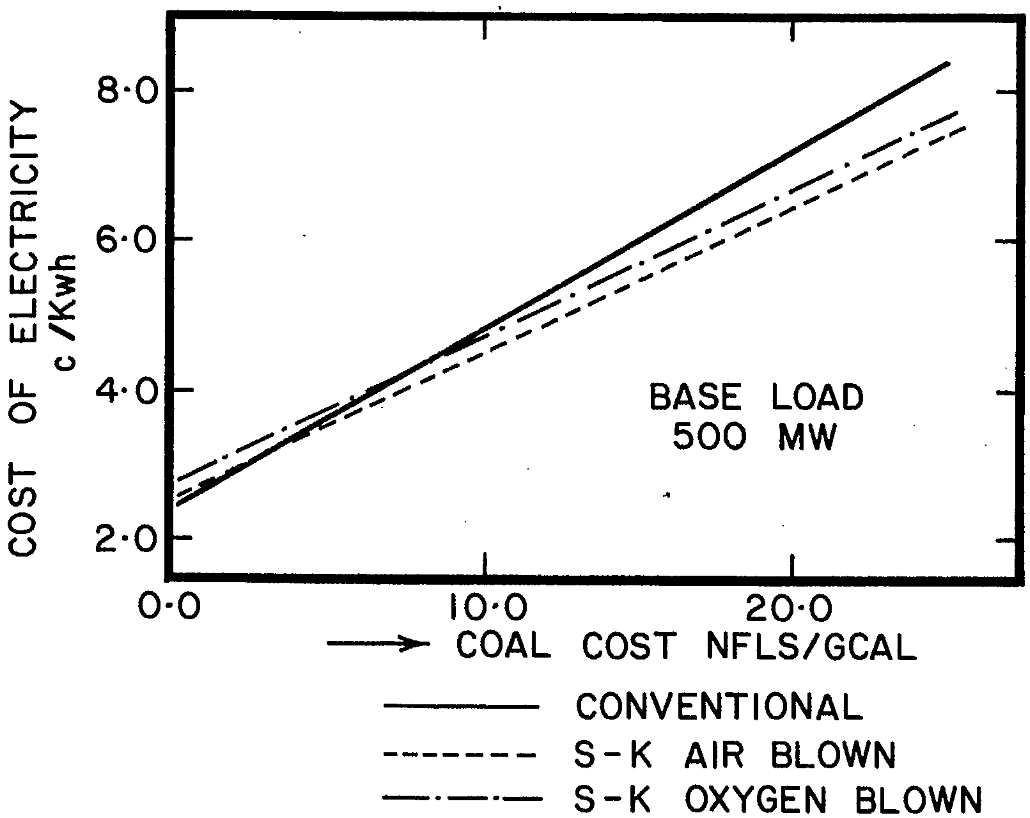
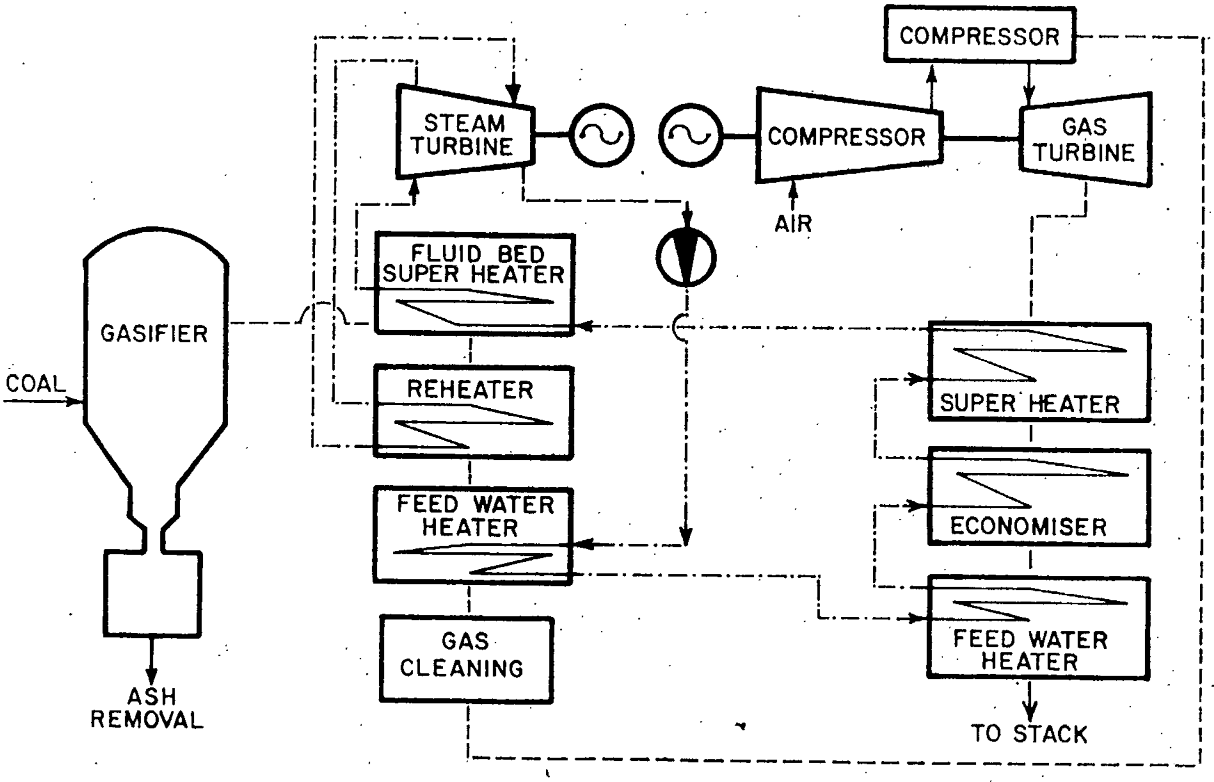


Fig. 16 - The Shell-Koppers cycle; the effect of oxygen and air gasification on the cost of electricity



—·—·—·— STEAM / WATER CIRCUITS. THE CIRCUITS ILLUSTRATED FORM PART OF A SINGLE STEAM GENERATING BOILER.

– – – – – GAS / COMBUSTION PRODUCTS CIRCUITS.

Fig. 17 - The United Technologies molten salt gasification combined cycle

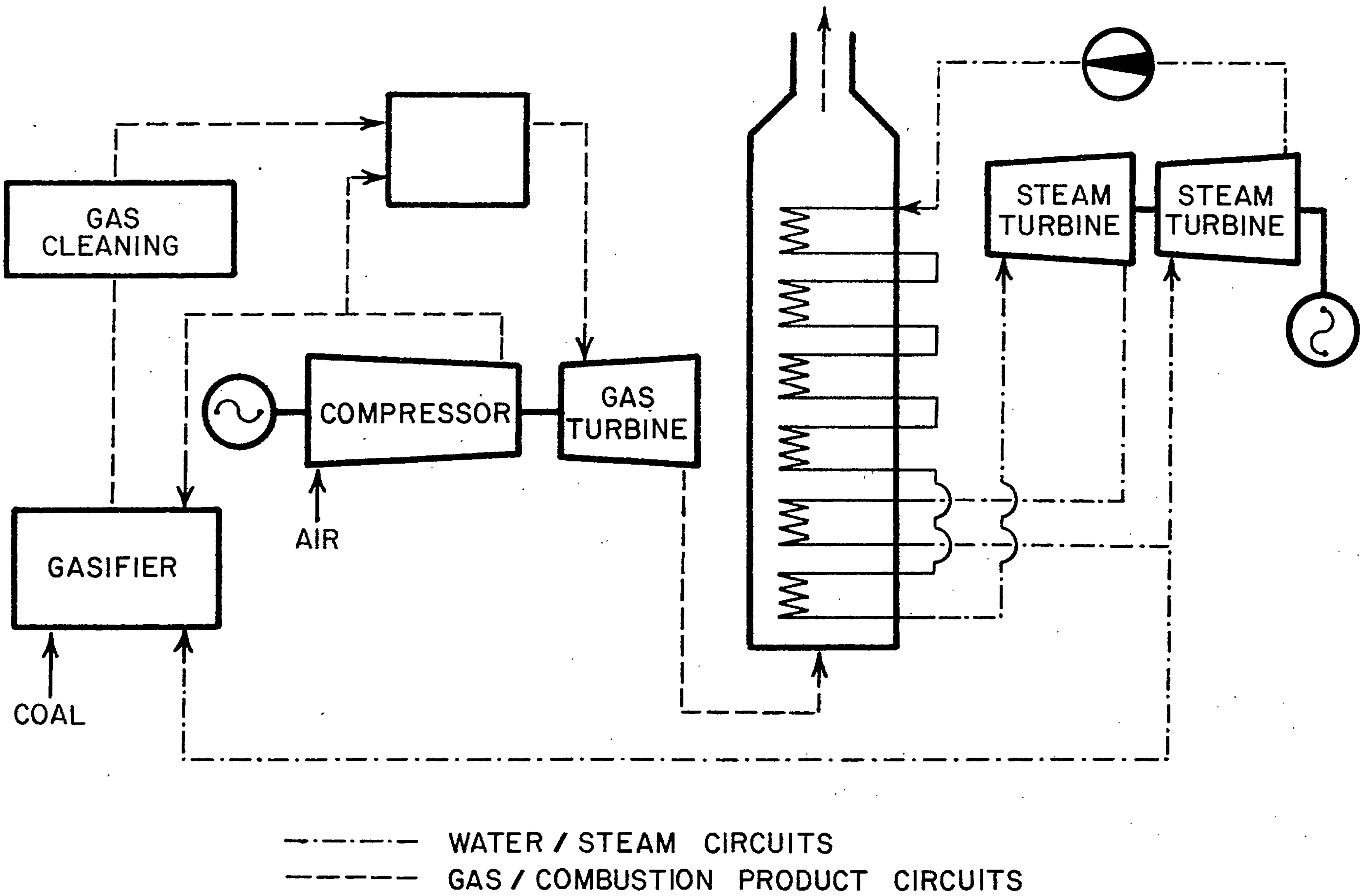


Fig. 18 - The General Electric combined cycle

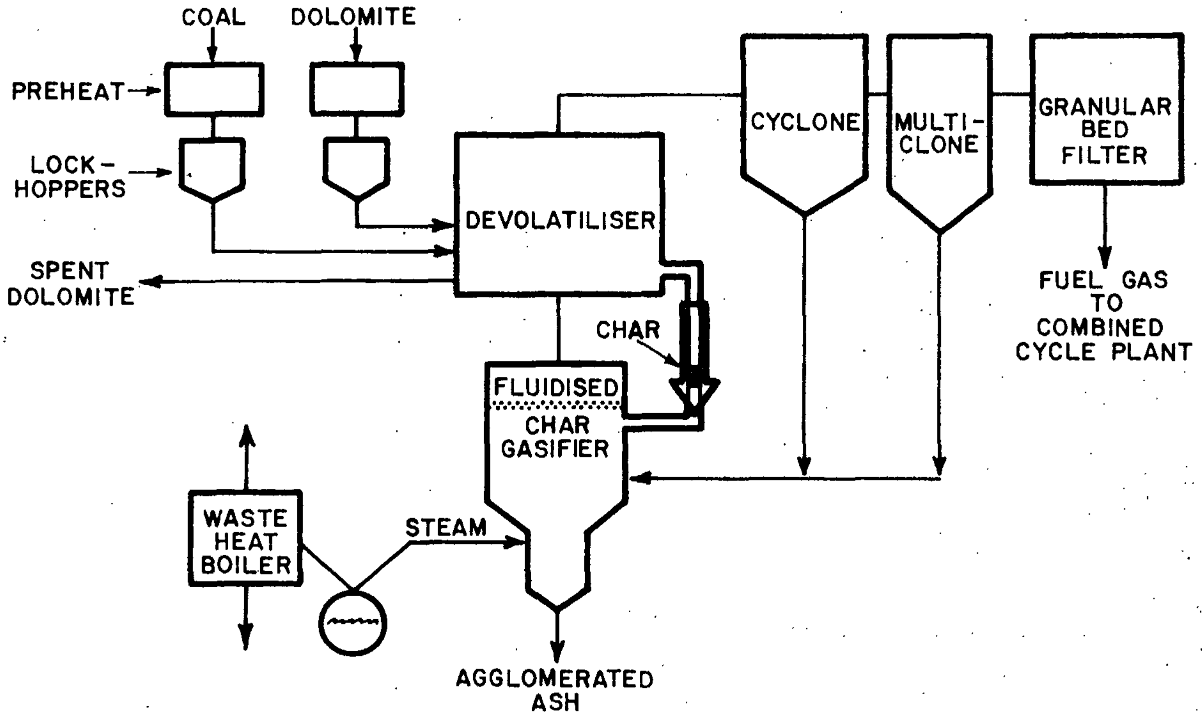


Fig. 19 - The Westinghouse gasification reactors

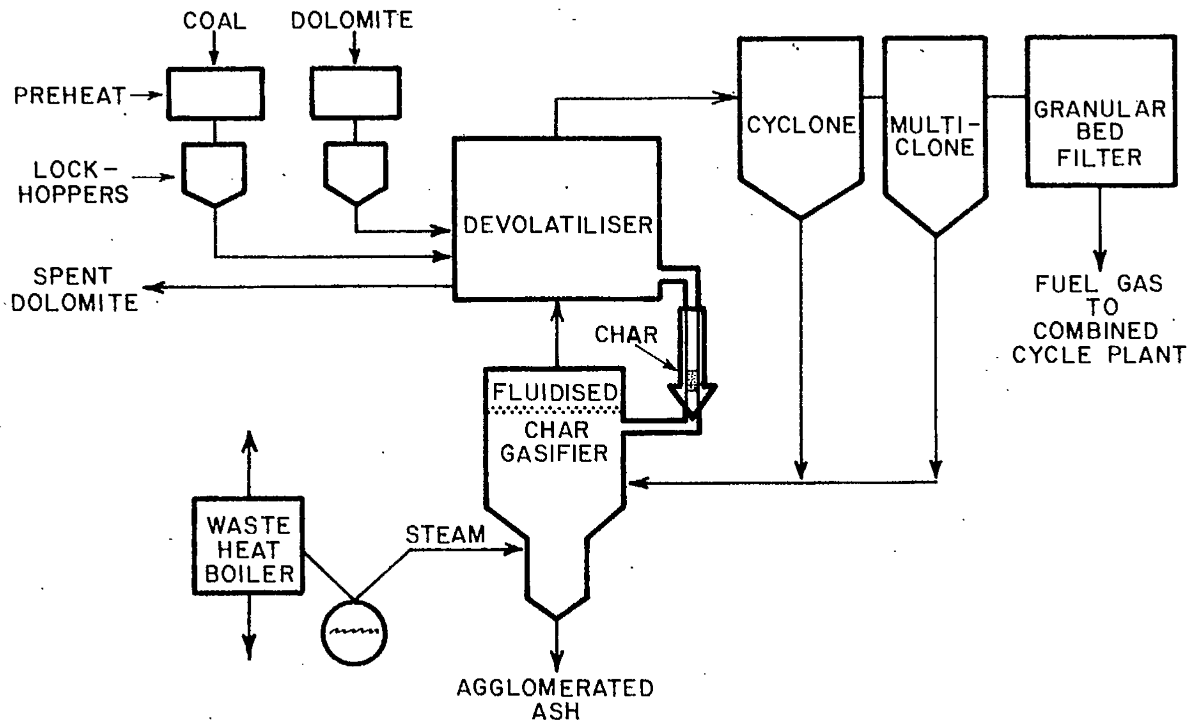


Fig. 20 - The Westinghouse combined cycle

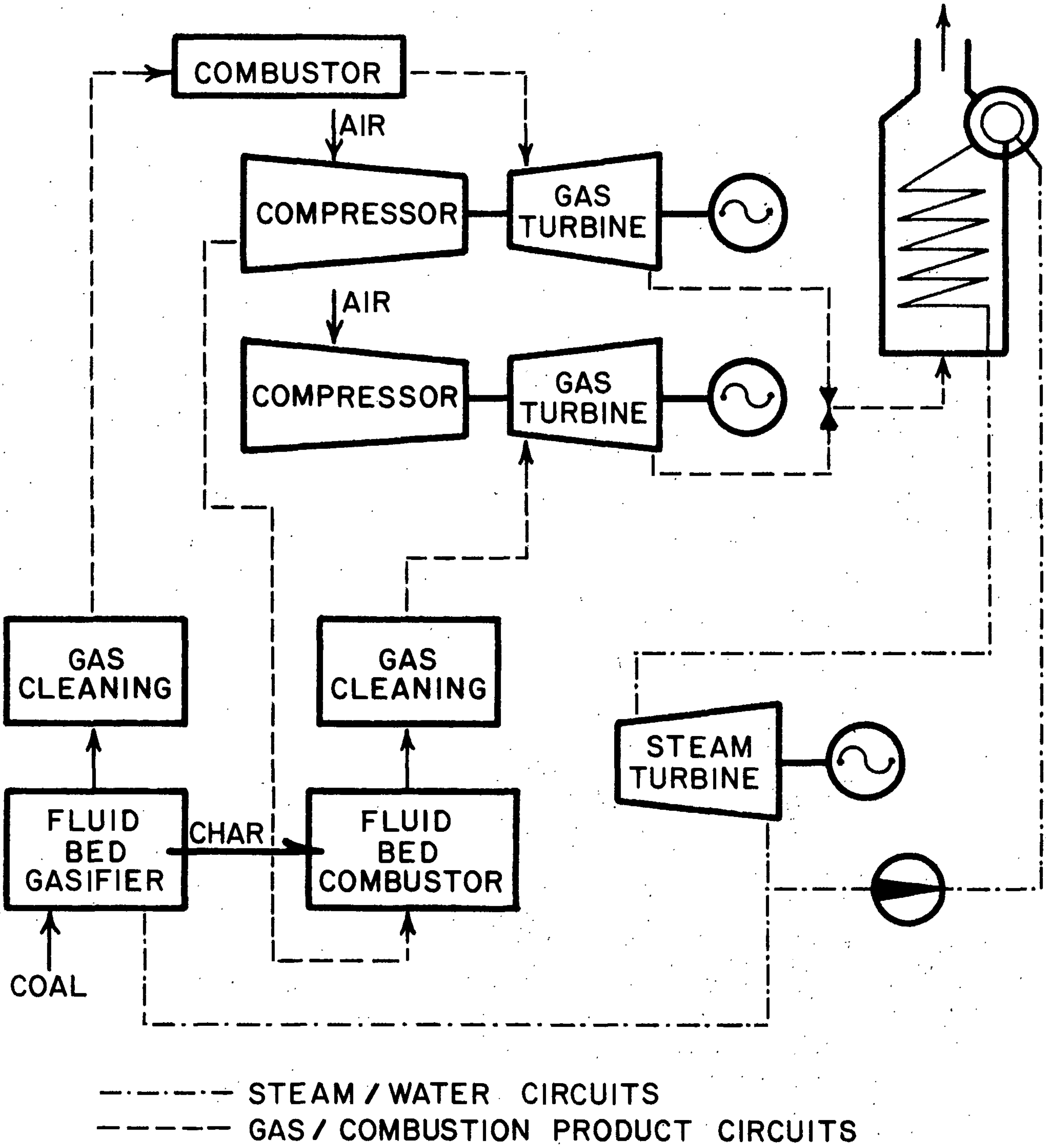


Fig. 21 - The National Coal Board combined cycle

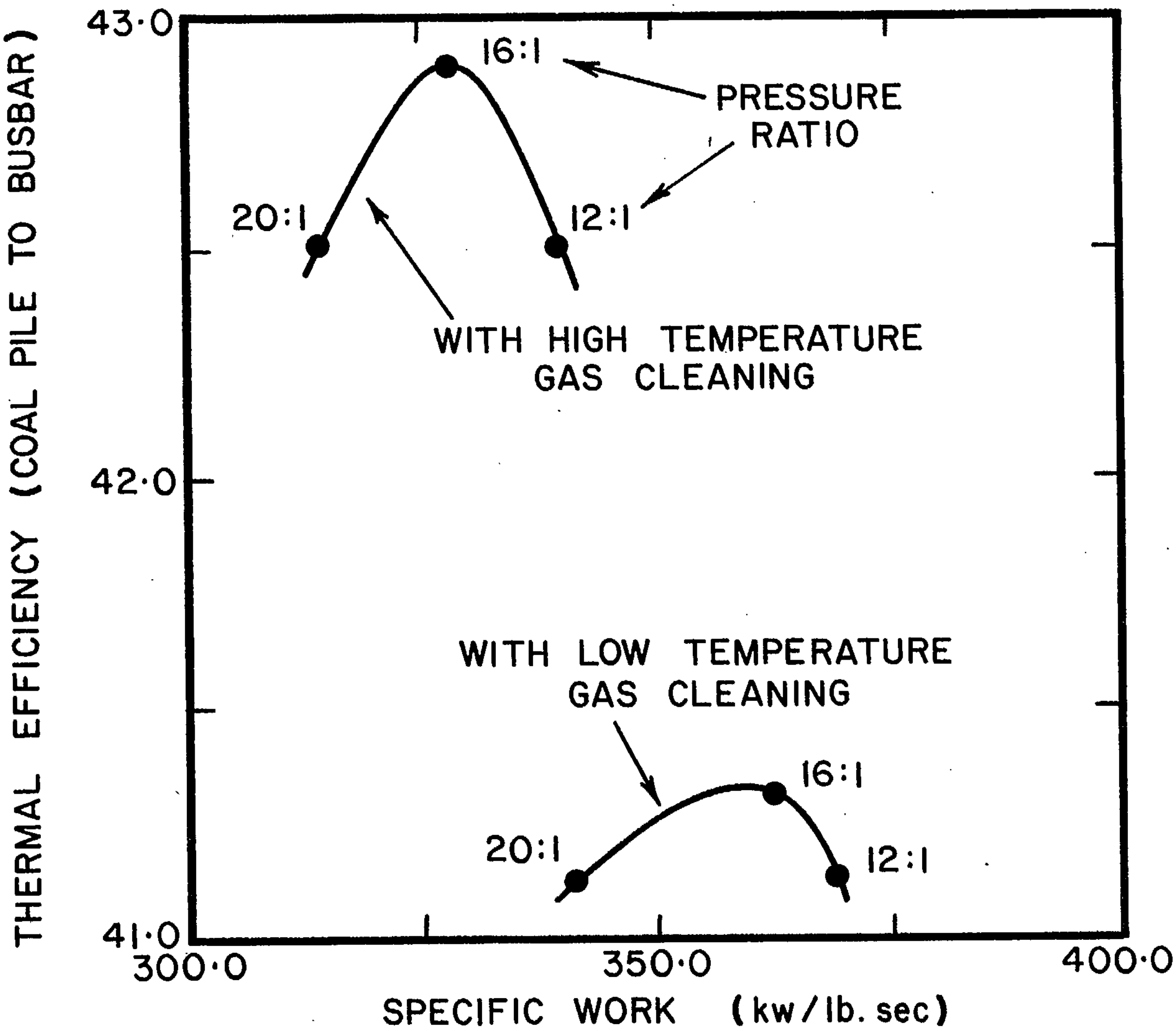


Fig. 22 - The effect of high temperature gas cleaning on combined cycle efficiency

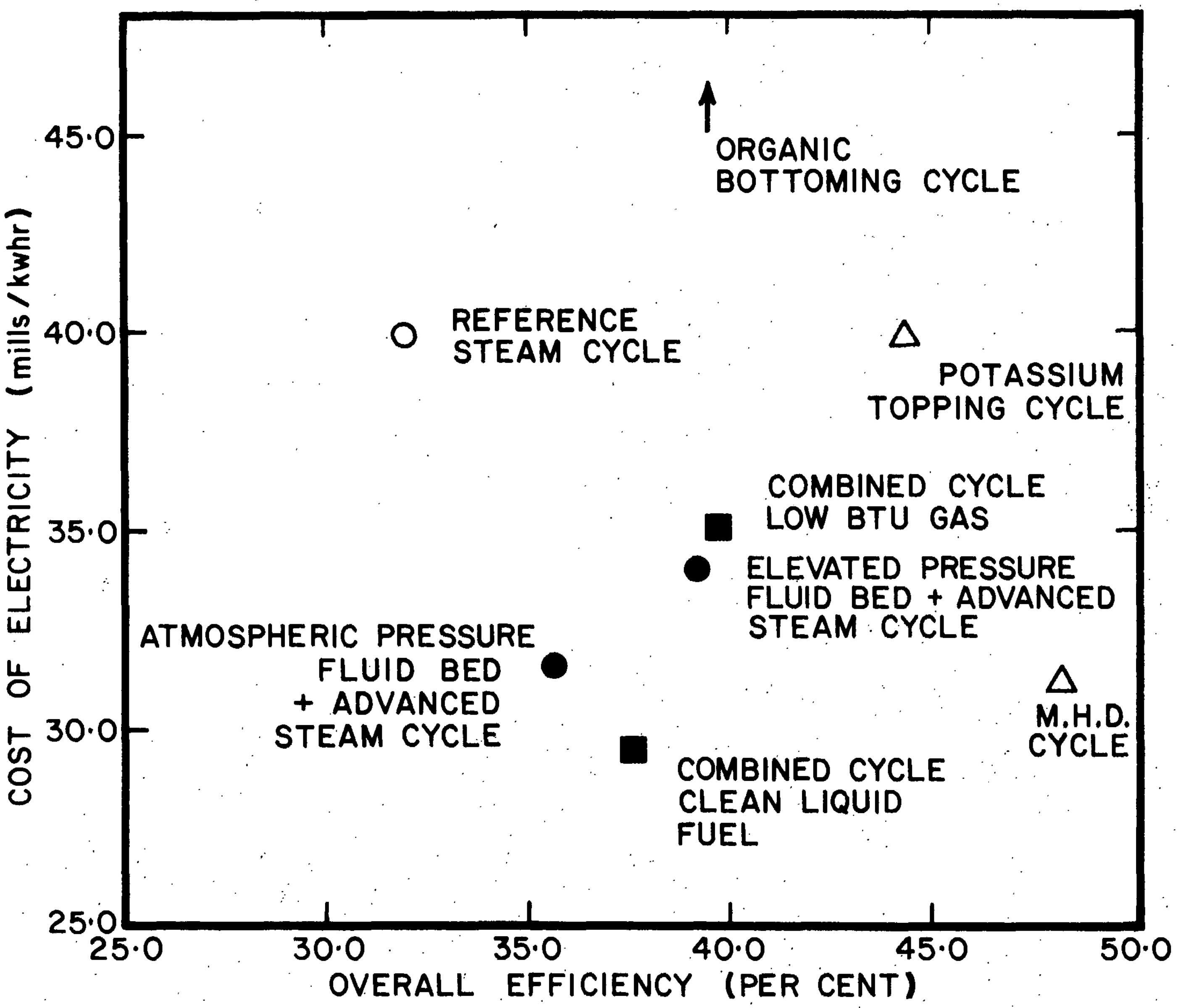


Fig. 23 - The cost of electricity and conversion efficiences developed in the Energy Conversion Alternatives Study

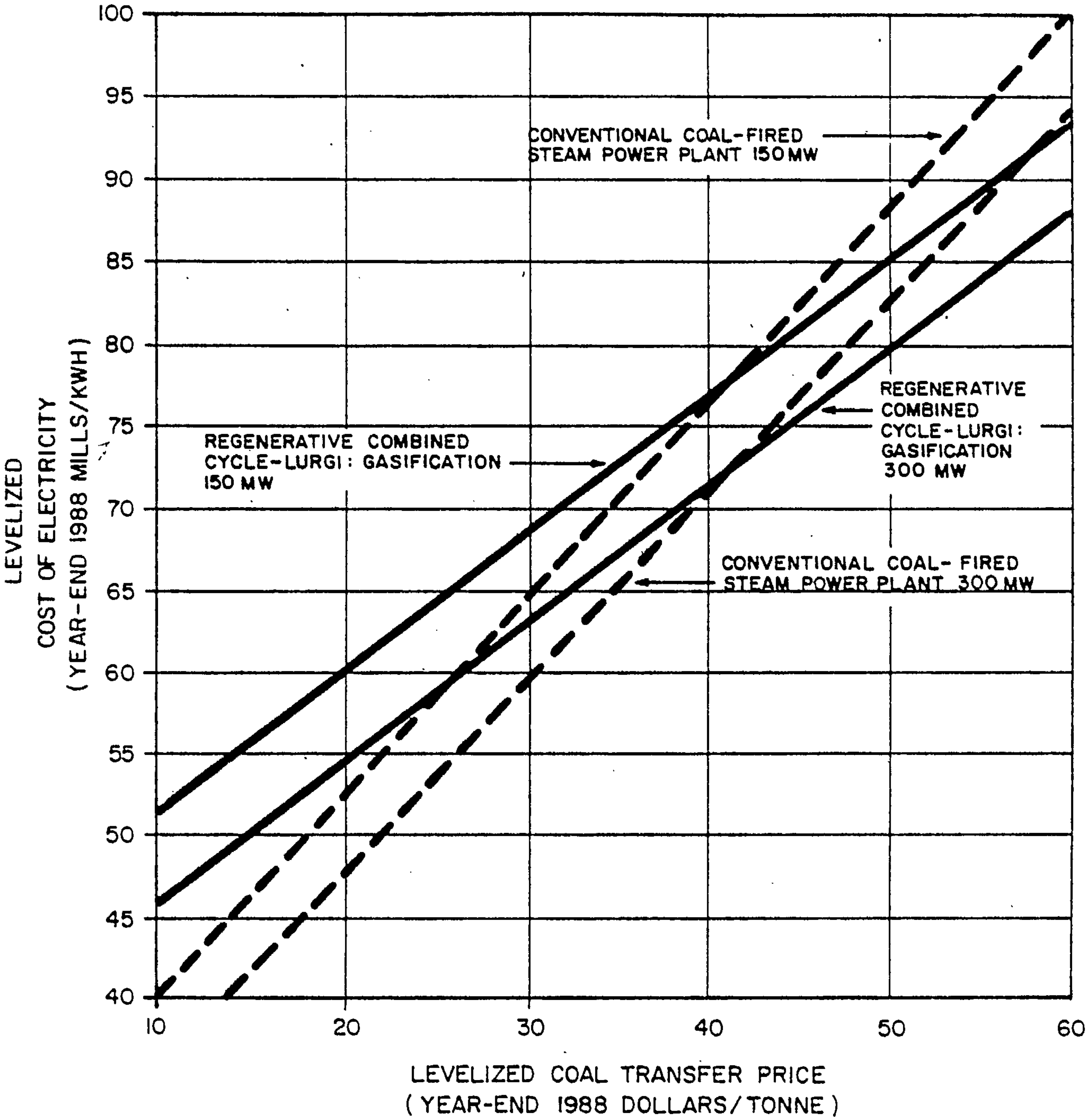


Fig. 24 - The effect of coal price on the cost of electricity developed in the Shaunavon study

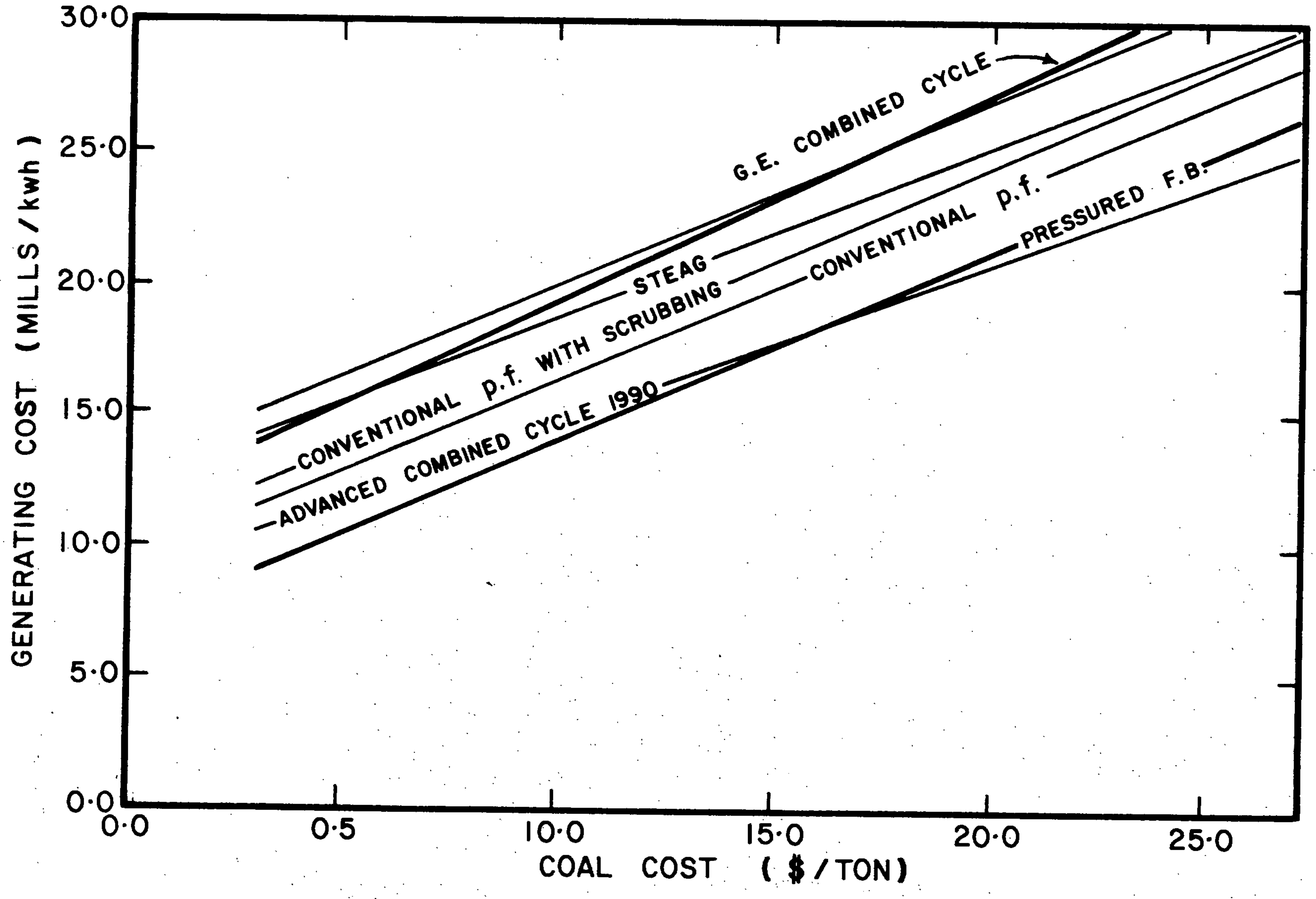


Fig. 25 - The effect of coal price on the cost of electricity developed in the Hat Creek study

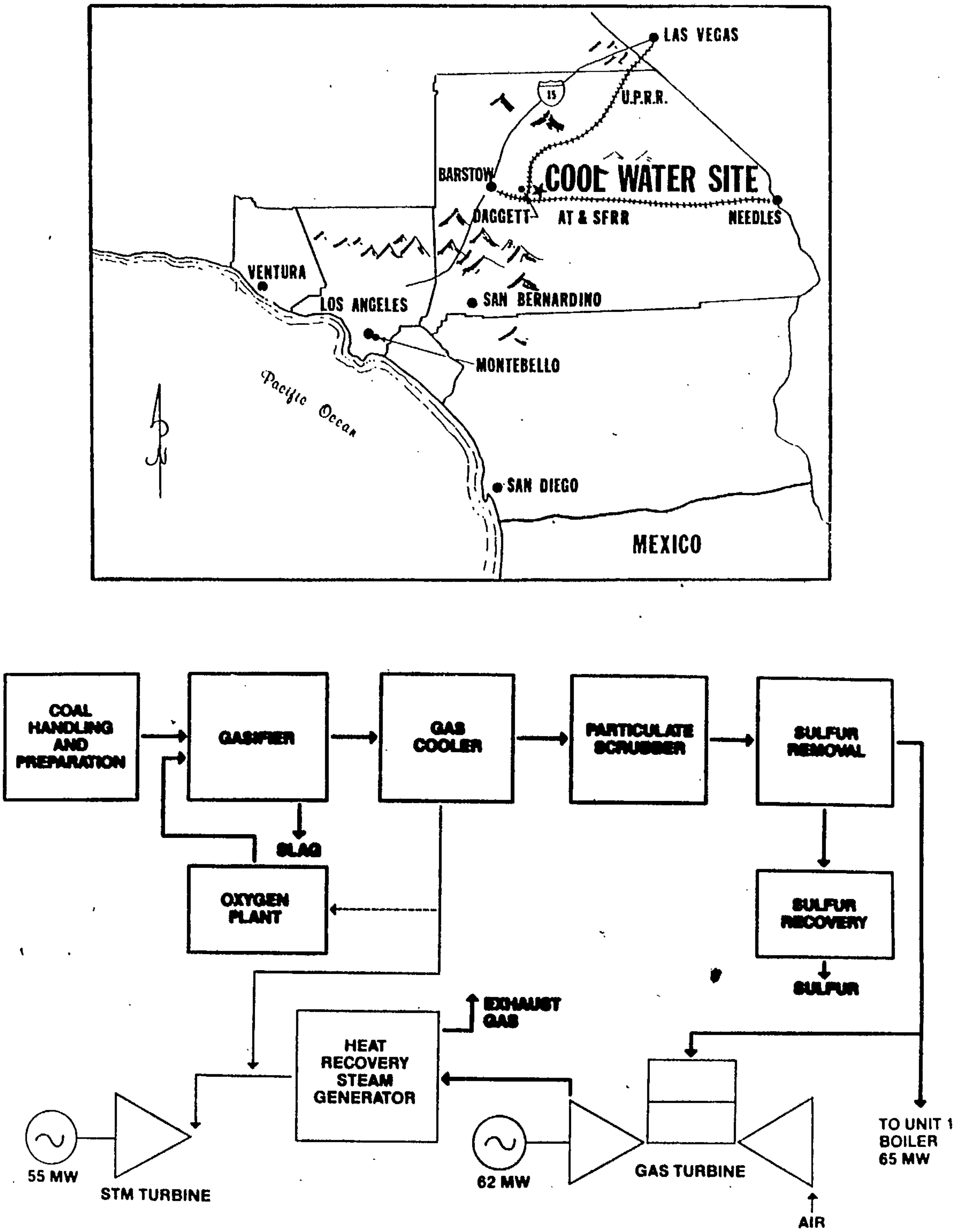


Fig. 26 - The Cool Water demonstration project; cycle schematic