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CANADIAN COALS, THE ENVIRONMENT AND NEW COAL TECHNOLOGIES

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ABSTRACT

Canadian energy forecasts indicate that electricity growth will increase at 2.3% per annum between 1988 and 2020 and that coal will continue to supply about 17% of the total annual electricity demand over this period. Emissions of acid rain precursors from utility coal combustion will be effectively curtailed over the next decade in response to provincial regulations and federal management plans. Advanced clean coal technologies offer the promise of more efficient electricity generation with corresponding reductions in CO_2 and power costs.

LES CHARBONS CANADIENS, L'ENVIRONNEMENT ET LES NOUVELLES TECHNOLOGIES DU CHARBON

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RÉSUMÉ

Les prévisions énergétiques canadiennes indiquent que la demande d'électricité augmentera au rythme de 2,3% par année entre 1988 et 2020 et que 17% environ de la demande annuelle totale d'électricité continueront d'être produits au charbon au cours de la même période. Les émissions de précurseurs de pluies acides par la combustion de charbon dans les centrales seront réduites avec efficacité dans la prochaine décennie par suite de l'adoption de réglementations par les provinces et de plans de gestion par le gouvernement fédéral. Des technologies de pointe de combustion propre du charbon promettent d'accroitre le rendement de la production de l'électricité et de réduire en proportion les émissions de CO_2 de même que les coûts de l'énergie.

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INTRODUCTION

Canadian utilities, in partnership with government, have a major responsibility in responding to the rapidly evolving environmental issues associated with electricity production in the 1990's. The necessity to use coal for electricity well into the next century will require decisive action by all concerned to effectively integrate energy planning, environmental improvement options and fiscal policies for optimal social benefit. Concerns specific to coal utilization that must be constructively addressed include global warming, acid rain fallout and waste management. In addition, the technical risks and economic uncertainties in accelerating the incorporation of unproven clean coal technologies into operational systems must be better delineated.

This paper reviews the current and forecast role of coal in Canada's electricity mix, the emission control strategies being implemented or contemplated, and the main advanced coal-to-electricity processes of potential interest to Canadian utilities.

COAL-FIRED ELECTRICITY GENERATION

Coal Supplies

In 1988 nearly 38 Mt of Canadian coal and over 8 Mt of imported coal were burned by Canadian utilities. Forecasts indicate that the total utility coal demand will escalate to 82 Mt and 110 Mt by 2005 and 2020 respectively.

Between 1988 and 2020 the domestic production of thermal coal is projected to grow at about 2.1% per annum with exports increasing from 4 Mt tonnes in 1988 to about 17 Mt in 2020. The future domestic coal supply is forecast to be slightly less than the anticipated electrical demand for coal indicating a need for new, more efficient processes for the conversion of coal to electricity as well as a gradual increase in tonnages of imported coal from 1988 levels to 18 Mt in 2020. Except Ontario, which receives all of its coal from either the United States or Western Canada, almost all of the coal currently consumed in each province is produced regionally. The range of coal properties and the amounts of coal consumed in each province in 1989 are given in Tables 1 and 2 respectively.

In general lower rank coals containing 0.2 to 0.7% sulphur - lignite in Manitoba and Saskatchewan and subbituminous in Alberta - are burned in Western Canada. Bituminous coals with sulphur contents ranging from 0.8 to 2.0% in Ontario from 2.0 to 5.0% in Nova Scotia and from 3.0 to 8.0% in New Brunswick are the norm for eastern Canada. Ontario and

Alberta also consume minor quantities of lignite and bituminous coal respectively. All of the coals burned in Canada typically contain 0.8% to 1.8% nitrogen.

Electricity Demand

Canada's electrical generating capacity is expected to increase at 2.3% per annum, from 109 to 226 GW, between 1988 and 2020. Coal's share of this capacity will remain relatively constant at about 17% as shown in Table 3, whereas electricity production from all sources is projected to increase at 2.7% per annum from 485 to 1137 TWh over the same period. These forecasts indicate that coal-fired stations will be operated more intensively resulting in a decrease in surplus capacity.

Ontario, Alberta, Saskatchewan and Nova Scotia plan to rely on coal for a significant portion of their electricity production for the foreseeable future as shown in Table 4. In addition, new coal-fired generating stations are being considered in New Brunswick and British Columbia. Table 5 lists the major coal-fired generating stations in each province as well as the new capacity that has been committed or projected since 1989.

EMISSIONS ABATEMENT

Although the provinces have jurisdiction over emission controls for stationary sources, Saskatchewan, Alberta and British Columbia either have adopted or are considering the adoption of the National Emissions Guidelines for Utility Boilers advocated by Environment Canada. East of Saskatchewan, the provincial governments have set emissions caps on utility systems to achieve overall regional SO_2 reductions of 50% by 1994 using 1980 as the base year. The cap allocated to Ontario Hydro includes both NO_x and SO_2 and allows the utility the option of reducing either pollutant or both pollutants to meet its acid gas emissions target for each year.

The utility source SO_2 and NO_x emissions, nearly all of which are attributable to coal, accounted for about 22% of the SO_2 and 13% of the NO_x emitted in Canada in 1984. Tables 6 and 7 show these emissions for 1984, the 1980 base year and the projected emissions for 1994 and 2010.

SO_2 Emissions

Reductions in SO_2 emissions east of Saskatchewan are forecast to decrease by over 50% between 1980 and 2010, primarily due to control measures in Ontario. Increased coal consumption in Saskatchewan and Alberta SO_2 emissions will steadily increase over the same period, and partially offset the SO_2 reductions in Ontario and the Maritimes.

Committed reductions of SO_2 by Ontario Hydro will be achieved by electricity imports, more nuclear generation, switching to low-sulphur coal, and installation of wet scrubbers on selected units at Lambton and Nanticoke. These scrubbers will produce usable gypsum as a byproduct. New Brunswick Power will also control SO_2 emissions from the new Belledune Generating Station with a wet scrubber that will produce usable gypsum. Other SO_2 control options being studied by N.B. Power are the replacement of No. 6 oil with imported low-sulphur coal at Coleson Cove Generating Station, and the addition of an integrated gasification combined cycle plant (IGCC) at Grand Lake. Nuclear expansion and electricity imports are also being considered.

Nova Scotia plans to control SO_2 emissions through the construction of a circulating fluidized bed unit at Point Aconi which will be fuelled with high-sulphur (2.0-5.0%) coal, and by the replacement of high-sulphur coals at other stations with lower-sulphur coals. Future coal-fired plants will incorporate control strategies to meet provincial SO_2 targets.

In Western Canada the National Emissions Guidelines for SO_2 now apply only to new plants. Under these guidelines, new plants burning coals with 0.23% sulphur or less would require no SO_2 control, whereas those burning coals with higher sulphur coals would require up to 70% SO_2 removal.

NO_x Emissions

NO_x emissions in Eastern Canada are projected to decline slightly between 1984 and 1994 due to the retrofitting of low-NO_x burners at Ontario Hydro's Nanticoke Generating Station, the commissioning of the new circulating fluidized bed boiler at Port Aconi, Nova Scotia and the planned construction of an IGCC plant in New Brunswick. After 1994 the NO_x emissions are forecast to increase gradually as more coal is burned in existing and planned plants in Ontario, Nova Scotia and New Brunswick.

In Western Canada NO_x emissions will track coal consumption and increase by almost 60% from 101 kt/a to 157 kt/a between 1984 and 1994. These emissions are currently regulated in Saskatchewan and Alberta by ground-level concentration limits, although all planned and many existing plants meet the National Emissions Guidelines for NO_x.

In anticipation of more stringent NO_x emission targets by 1994 and beyond, the utility industry is actively conducting research and assessing available technology for further reducing NO_x emissions during both base load and peaking operations from installed capacity. Some of the processes under study include selective and non-selective catalytic reduction, amidogen injection, fuel reburning, staged combustion and external flue gas recirculation.

Greenhouse Gases

The major greenhouse gases attributed to coal-fired utility boilers are carbon dioxide (CO_2) and nitrous oxide (N_2O). Nitrous oxide emissions, being less than 10 ppm from existing conventional coal-fired plants in Canada, are not deemed to be a problem. However, CO_2 emissions are proportional to the carbon in coal and cannot at present be easily or economically abated.

Utility CO_2 emissions from coal, currently about 82 Mt, will steadily increase to 168 Mt by 2005 unless coal demand decreases, fuel conversion to electricity increases and inexpensive processes can be found for CO_2 removal. Although these emissions levels correspond to 20% in 1988 and 28% in 2005 respectively of the Canadian total (Table 7), they comprise less than 0.6% of the world's anthropogenic CO_2 burden. Clearly, even a major reduction in Canadian CO_2 emissions will have little impact on the global build-up of greenhouse gases because of the rapid escalation of coal consumption in the centrally controlled economies and the third world over the next 25 years.

One solution would be for the industrialized countries to provide the less developed nations with expertise and technology to reduce inefficiencies in both fuel conversion and energy use. Another would be to accelerate the commercialization of advanced renewable energy sources for use in remote and tropical areas where electricity is essential but in low demand. For example, inexpensive solar or wind generators could replace small inefficient fossil-fuelled units and provide for new electricity demand.

EMERGING TECHNOLOGIES FOR COMBINED NO_x/SO_2 CONTROL

Three emerging technologies that simultaneously reduce NO_x and SO_2 emissions - fluidized bed combustion, slagging combustion and post-flame chemical injection - are being actively fostered by Canadian utilities.

Fluidized Bed Combustion (FBC)

FBC systems using either bubbling or circulating beds are on the verge of commercialization. The use of limestone as a bed material neutralizes most of the sulphur and the low combustion temperatures inherently produce low NO_x. The systems are relatively insensitive to fuel quality and have been demonstrated in small utility applications.

In Canada, the 22 MWe circulating FBC at Chatham has been successfully commissioned using 6% sulphur coal. Sulphur capture has exceeded 90% and NO_x emissions have been consistently less than 100 ppm at 3% 0_2. As mentioned previously Nova Scotia Power has selected a 165 MWe circulating FBC for their new plant at Port Aconi.

Slagging Combustion

Demonstrations of the TransAlta and TRW slagging burners in a utility environment are being funded under the US Clean Coal Technology Program. Both burner designs can be economically retrofitted to existing oil and coal-fired boilers, and are ideal for firing low-ash fusion coals.

The TransAlta burner is an entrained flow reactor that fires a pulverized mixture of coal and limestone. Sulphur is captured in the slag and NO_x is controlled by multiple staging ports. Pilot-scale tests have achieved NO_x emissions of less than 100 ppm on a range of coals and sulphur captures of 70% and 80% on low-rank and bituminous coals respectively. An industrial demonstration is being conducted at Cold Lake, Alberta on a 15 MWt steam generator and engineering has started on retrofitting a 33 MWe cyclone-fired boiler at Marion Illinois with two 60 MWt LNS burners.

The TRW burner is a cyclonic combustor with staged air for NO_x control and sorbent injection at the combustor exit for SO_2 control. A 4000 h demonstration in an industrial boiler at Cleveland, Ohio yielded NO_x values of about 250 ppm with 90% sulphur capture on a 2.5% sulphur coal. Engineering for retrofitting a 70 MWe corner-fired boiler at Orange and Rockland, New York is almost complete. Trials are scheduled for 1991.

Post-Furnace Chemical Injection

The injection of an aqueous slurry containing a calcium-based sorbent to neutralize sulphur and an amidogen compound to destroy NO_x has been under investigation by Ontario Hydro. This process, called SONOX, involves injection of the slurry into flue gases from 900°C to 1200°C. In pilot plant tests, sulphur captures of up to 90% and NO_x reductions of 75-85% were achieved.

Ontario Hydro is currently seeking to commercialize the process and to develop hardware for a large-scale demonstration. Major advantages of the process are low capital cost, ease in retrofitting and applicability to all fuels.

ADVANCED CLEAN COAL UTILIZATION

Current utility combustion practice focuses on burning at atmospheric pressure. However, theoretical considerations indicate that reductions of more than 50% in CO_2 and up to 90% in acid rain precursors can be achieved by combustion at elevated pressures. These pressurized processes also allow the application of innovative combined power generation cycles that produce 16 to 45% more electricity for a given fuel input. Coupled with co-generation overall energy savings and CO_2 reductions can reach 54%.

Six advanced processes that are being developed in response to increasingly stringent emission limits for electricity generation are described below. The first two are either being demonstrated or are candidates for near-term demonstrations. The last four are still undergoing pilot-scale or large-scale component evaluations and will unlikely be demonstrated as integrated systems before 2005.

Integrated Gasification Combined Cycle (IGCC)

In this process coal is pyrolyzed with an oxidant under reducing conditions to produce a synthesis gas. Depending on the oxidant, the calorific value of this gas can vary from 3.75 to 12 MJ/m^3. As shown in Fig. 1, the hot off-gas, after being cooled prior to solvent treatment to remove gaseous and particulate contaminants, is fired in a gas turbine with steam injection for NO_x control. The turbine exhaust gas then passes through a boiler which feeds steam to a second turbine. Overall cycle efficiencies can exceed 44%.

Gasification processes using fixed-bed, fluidized bed and entrained-flow reactors have been demonstrated. However, most of the recent IGCC activities, notably the Texaco 100 MWe Cool Water Plant, the Shell 250 MWe Buggenum Plant and the Dow facility in Louisiana employ entrained flow reactors. Additional technology developments are needed to raise the efficiencies of these plants above the 38 to 41% range by increasing gas turbine inlet temperatures by 100 to 200°C, employing hot gas clean-up, raising steam temperatures by 50 to 60°C, and using air instead of oxygen as an oxidant.

IGCC processes have several features that make them particularly attractive to utilities. These include modular construction, shop fabrication of many components, phased expansion to meet capacity, reduced water demand and co-production of chemicals.

Successful commissioning of the Shell Buggenum plant will likely accelerate interest in using IGCC systems for meeting electricity growth in the late 1990's.

Pressurized Fluidized Bed Combustion (PFBC)

By pressurizing either a circulating or a bubbling fluidized bed combustor and incorporating it into a combined cycle as shown in Fig. 2, overall cycle efficiencies can be raised from 34 to 40%. Other advantages are modular construction, a 75% reduction in bed area, a 4 fourfold increase in convective heat transfer, and better sorbent utilization. In essence, a PFBC unit operating at 12-16 bar replaces the gasifier and combustor in an IGCC process. The hot combustion gases produced are low in SO_x and NO_x, but must be filtered to ensure that the limiting ash loading to the gas turbine is not exceeded.

Three utility scale bubbling PFBC plants are scheduled for commissioning in 1990 by ASEA/Brown-Boveri. The Tidd Plant (70 MWe) and the Escratron Plant (80 MWe) in Spain produce electricity whereas the Vartan Plant (130 MWe + 224 MWt) in Sweden is a combined heat and power station.

Areas of technology risk include in-bed tube erosion, ash removal from hot combustion gases, high inlet temperatures, gas turbines and dry coal feeding.

Circulating PFBC is not as far advanced but small demonstration-scale plants are being considered in Finland and West Germany.

Topping Cycle

The British Coal Corporation is promoting a topping cycle based on partial gasification of coal with combustion of the burnable gasifier residue in a pressurized fluidized bed. As shown in Fig. 3 the hot gaseous products from both the gasifier and the PFBC are burned in a gas turbine with steam from the PFBC being used to drive a steam turbine. Owing to higher inlet gas turbine temperatures overall cycle efficiencies are in the 45% range.

This combined cycle arrangement incorporates all of the advantages and requires resolution of all of the technology risks associated with both IGCC and PFBC processes. Critical to this development is the availability of a gas turbine capable of accepting partially cleaned combustion gases at 1300°C or above.

Pressurized Flame Combustion

A number of pressurized slagging combustion concepts have been developed in conjunction with coal-fired MHD programs. Some of these including the Avco, TRW and Rockwell-TransAlta designs have been modified to perform as low NO_x/SO_x burners on conventional oil- and coal-designed boilers and could be readily adapted for use on combined cycles.

The main advantages of these combustors are compact size, modular construction, suitability for new or retrofit installations, and partial removal of ash as an inert slag. More research is needed to develop reliable systems for slag removal, hot gas clean-up and dry coal feeding.

Fuel Cells

Fuel cells have the potential for direct conversion of fuel gas to electricity via electrochemical reactions at efficiencies of up to 55%.

As illustrated in Fig. 4, a fuel cell generates electricity from a continuous supply of fuel gas to an anode and of oxidant to a cathode. The fuel ionizes at the cathode to co-produce a steady stream of electrons which generate direct current electricity to a load and a steady stream of hydrogen ions which pass through an electrolyte to a cathode where they react with an oxidant to form waste water. Waste heat, which represents the difference between the chemical energy input and the electrical energy output, must also be removed. Utilization of this waste heat by co-generation can increase the overall cycle efficiency to above 80%.

Three of the fuel cell concepts now being developed employ phosphoric acid, molten carbonate, and solid oxides as electrolytes with operating pressures up to 8 atmo. The phosphoric acid cell which operates at about 200°C is the most technically advanced and has been demonstrated on cycling duty at 4.5 MWe with 40% thermal efficiency. The other two, which operate at higher temperatures, have been tested at 3 to 5 kW. Advantages of this technology are high efficiency at both full and part load, modular construction, production of hydrogen and oxygen from off-peak power for use on demand, and fast response times for peaking. More research is required to provide coal-derived gases suitable for fuel cells, to develop high reactivity electrodes for rapid, reliable fuel ionization and to increase operational life.

Magnetohydrodynamics

In magnetohydrodynamic (MHD) processes, thermal energy is converted directly to electricity by injecting electrically-conductive, high-velocity combustion gases from 2500°C to 2800°C through a magnetic field constrained in a channel as illustrated in Fig. 5. The hot gases exiting the channel pass through a radiant boiler to generate steam for bottoming the cycle and to remove slagged ash. Prior to entering the stack, the alkali seed, which is added at the combustor to render the hot gases conductive, is removed for regeneration and reuse. Overall cycle efficiencies of more than 50% are claimed for large MHD units on base load. As the unit size and the load factor decrease, the cycle efficiency decreases rapidly.

Although a gas-fired MHD topping cycle rated at 270 MWe is due for commissioning in the USSR next year, the use of coal as a feedstock has yet to be demonstrated. The US Department of Energy has funded coal-fired test facilities rated at 50 MWt to validate designs of MHD modules and at 28 MWe to evaluate seed recovery and emissions. Interest in Japan and Europe appears to be reviving after a decade of inactivity. Research breakthroughs are needed in a number of critical areas before coal-fired MHD can be demonstrated at a commercial scale. These include:

(a) high temperature air preheating
(b) seed recovery and regeneration
(c) MHD channel scale-up
(d) superconductive magnet design
(e) control of NO_x emissions and
(f) electrode reliability.

In view of the current status of MHD developments, utility applications are not anticipated before the early part of the next century.

CONCLUSIONS

In response to the forecast demand for electricity, utility coal consumption in Canada is expected to double over the next 20 years. Major environmental issues, primarily acid rain and greenhouse gas emissions, are being addressed through joint government/industry programs to demonstrate innovative control processes for use on existing units, and to accelerate the development of advanced clean coal technologies for new units.

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   - SONOX Process

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9. The Coal Association of Canada
   - Coal Production and Demand
   - Electricity from Coal

Table 1 - Properties of Canadian utility coals

Rank	Moisture %	Volatile matter	Ash %	Sulphur %	Nitrogen %	HHV MJ/kg*
Lignite	26-29	18-25	7-18	0.4-0.6	1.0-1.2	15-18
Subbit	18-25	25-31	6-14	0.2-0.7	1.0-1.5	18-21
Bituminous						
- Eastern	1-10	23-37	7-26	2-8	0.8-1.7	24-34
- Western	3-9	20-35	8-12	0.2-0.4	1.1-1.3	24-36
- U.S.	1-8	28-39	4-10	1-3	1.3-2.0	26-33

* Moisture basis

Table 2 - Utility coal consumption 1989, kt

Province	Total	Domestic	Imported
Nova Scotia	2 141		
- bituminous			2 141-
New Brunswick	705		
- bituminous		614	91
Ontario	12 809		
- bituminous		2 833	8 386
- lignite		1 590	-
Manitoba	327		
- lignite		327	-
Saskatchewan	8 534		
- lignite		8 523	
- subbituminous		11	-
Alberta	21 410		
- bituminous		577	-
- subbituminous		20 833	-
Canada	45 926	37 449	8 477

Table 3 - Coal-fired generating capacity, MW

Province	1988	2005	2020
Nova Scotia	1 052	1 952	3 152
New Brunswick	311	1 389	1 940
Ontario	9 601	11 923	16 423
Manitoba	369	369	-
Saskatchewan	1 764	2 364	2 664
Alberta	4 589	6 972	12 222
British Columbia	-	2 120	2 120
Canada	17 686	27 089	38 521

Table 4 - Electricity from coal-1988

Province	TWH from coal	Percentage of Total Electricity Generated
Nova Scotia	6.1	67.8
New Brunswick	1.9	11.7
Ontario	35.0	24.5
Manitoba	0.9	5.7
Saskatchewan	9.9	76.2
Alberta	33.7	83.7
Canada - Coal	87.5	17.9
Canada - All sources	489.0	100

Table 5 - Major coal-fired generating stations

Province	MW	In Service
Nova Scotia:		
- Trenton	190	Existing
- Lingan	600	Existing
- Glace Bay	88	Existing
- Point Tupper	150	Existing
- Trenton 6	150	1991
- Port Aconi	165	1993
- New	600	2000
New Brunswick:		
- Dalhousie	200	Existing
- Grand Lake	89	Existing
- Belledune 1	450	1993
- Grand Lake 9	200	1994
- New	450	2000
Ontario:		
- Lambton	2010	Existing
- Lakeview	2285	Existing
- Nanticoke	4335	Existing
- Atikokan	215	Existing
- Thunder Bay	320	Existing
- New	2322	1995-2014
Manitoba:		
- Brandon	237	Existing
- Selkirk	132	Existing
Saskatchewan:		
- Boundary Dam	882	Existing
- Poplar River	600	Existing
- Estevan	50	Existing
- Shand 1	300	1992
- Shand 2	300	1992
- Poplar River 3	300	2010
Alberta:		
- Battle River	722	Existing
- Genessee	386	Existing
- Keephills	766	Existing
- Milner	145	Existing
- Sheerness	380	Existing
- Sundance	1990	Existing
- Wabamun	548	Existing
- Genessee 1	386	1991
- Sheerness 2	366	1990
- New	5250	1994-2010
British Columbia		
- New	2120	2005

Table 6 - Utility SO_2 emissions, kt

Year	Eastern	Western	Total	% Utility in Canada
1980	669	98	767	17
1984	720	149	869	27
1994	394	225	619	21
2010	314	287	601	21

Table 7 - Utility NO_x emissions, kt

Year	Eastern	Western	Total	% Utility in Canada
1980	158	77	235	12
1984	151	101	252	13
1994	153	157	290	15
2010	154	180	334	16

Table 8 - Utility CO_2 emissions, Mt

Year	Eastern	Western	Total	% Utility in Canada
1988	38	47	85	21
2005	79	94	173	28

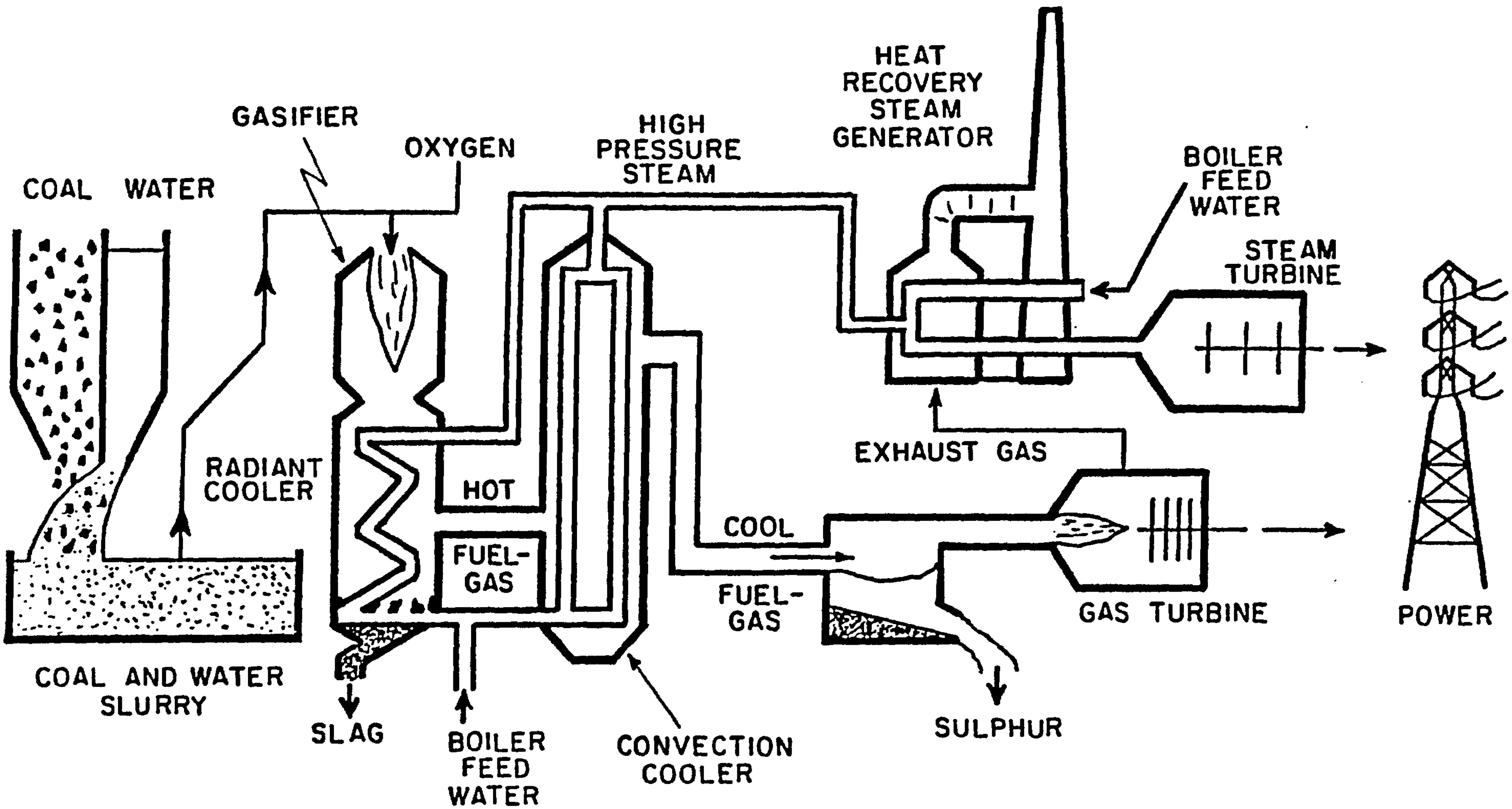

FIG. 1 - INTEGRATED COAL GASIFICATION COMBINED-CYCLE SYSTEM

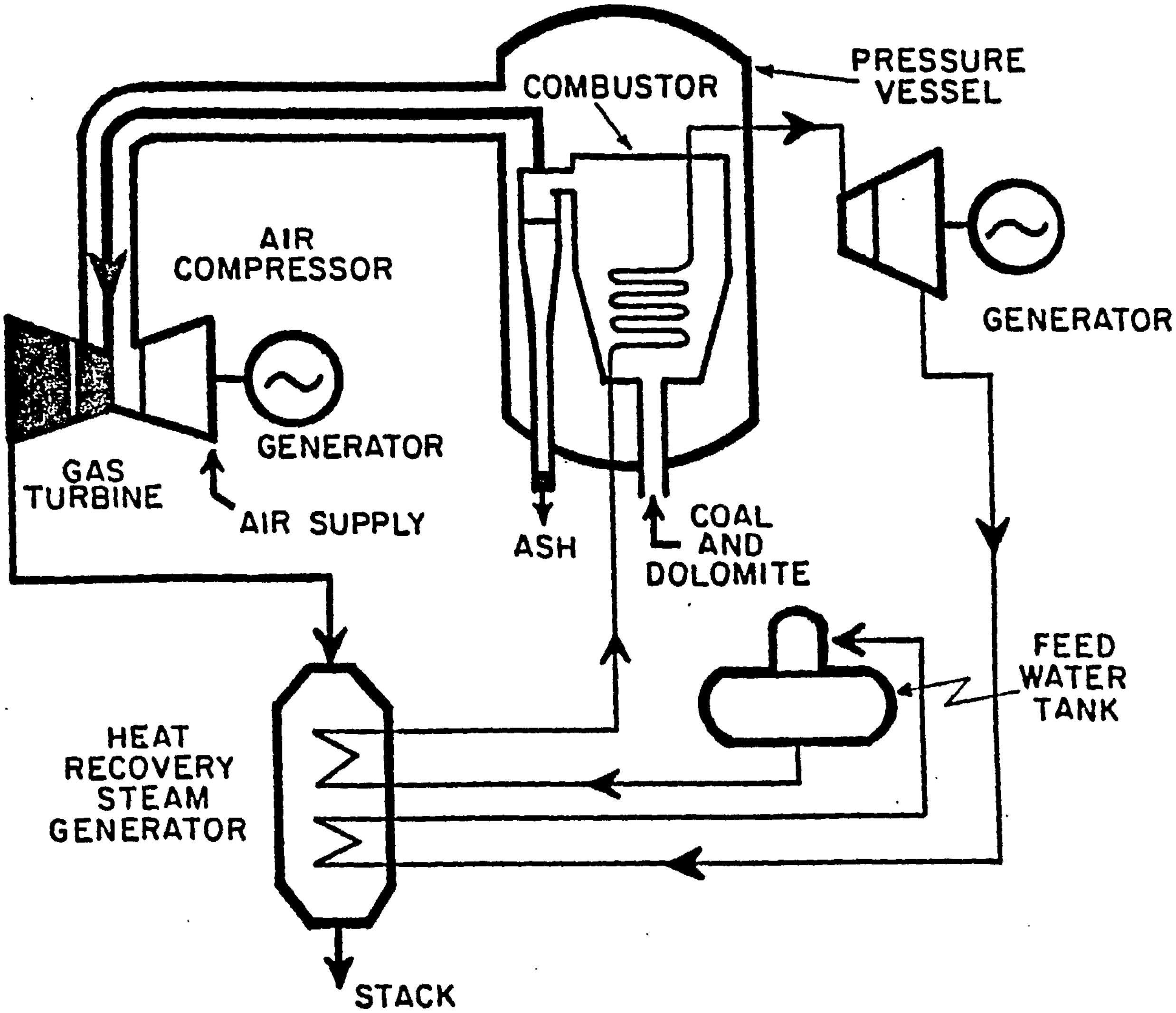

FIG. 2 - PFBC COMBINED CYCLE

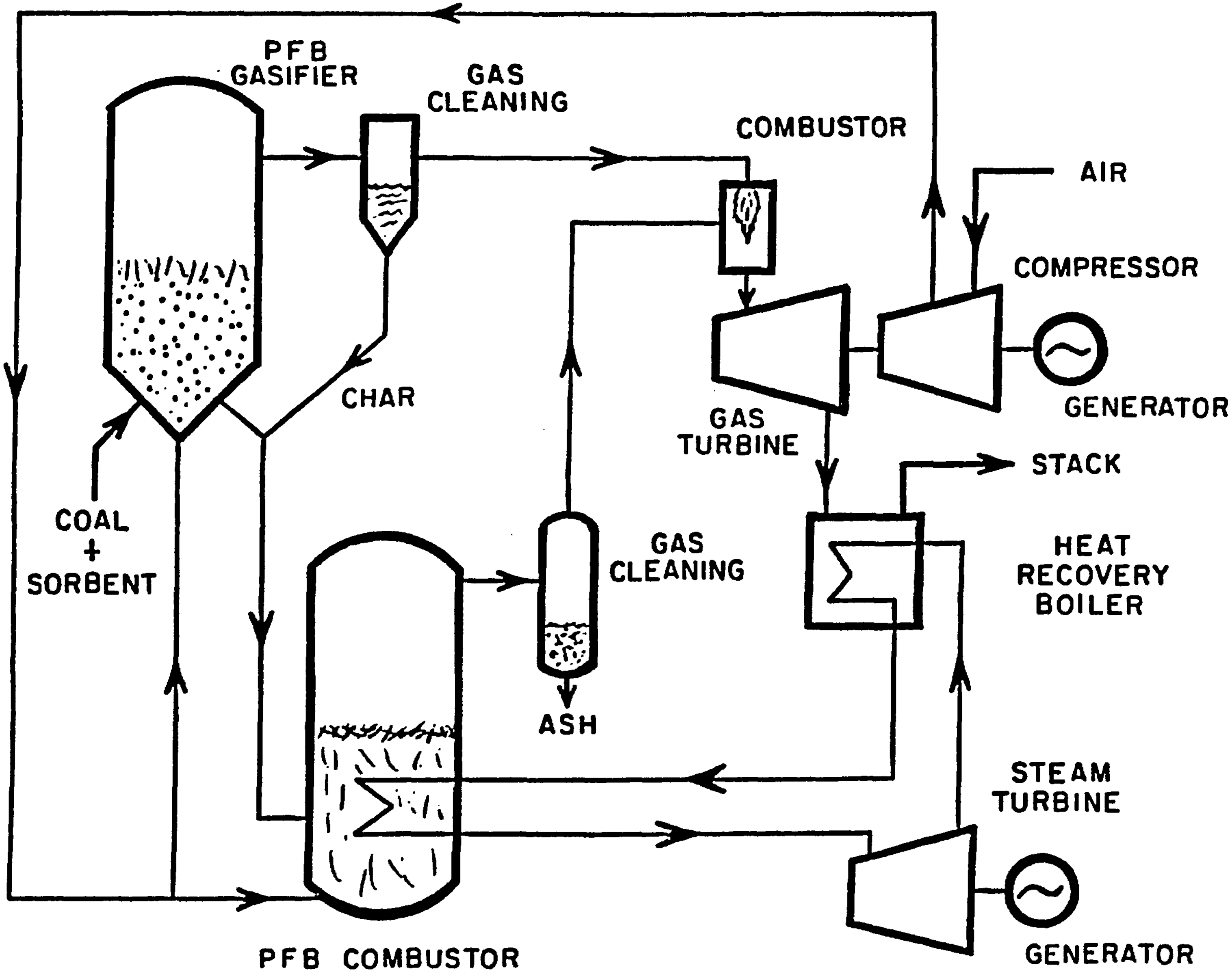

FIG. 3 - TOPPING CYCLE BASED ON PFBC

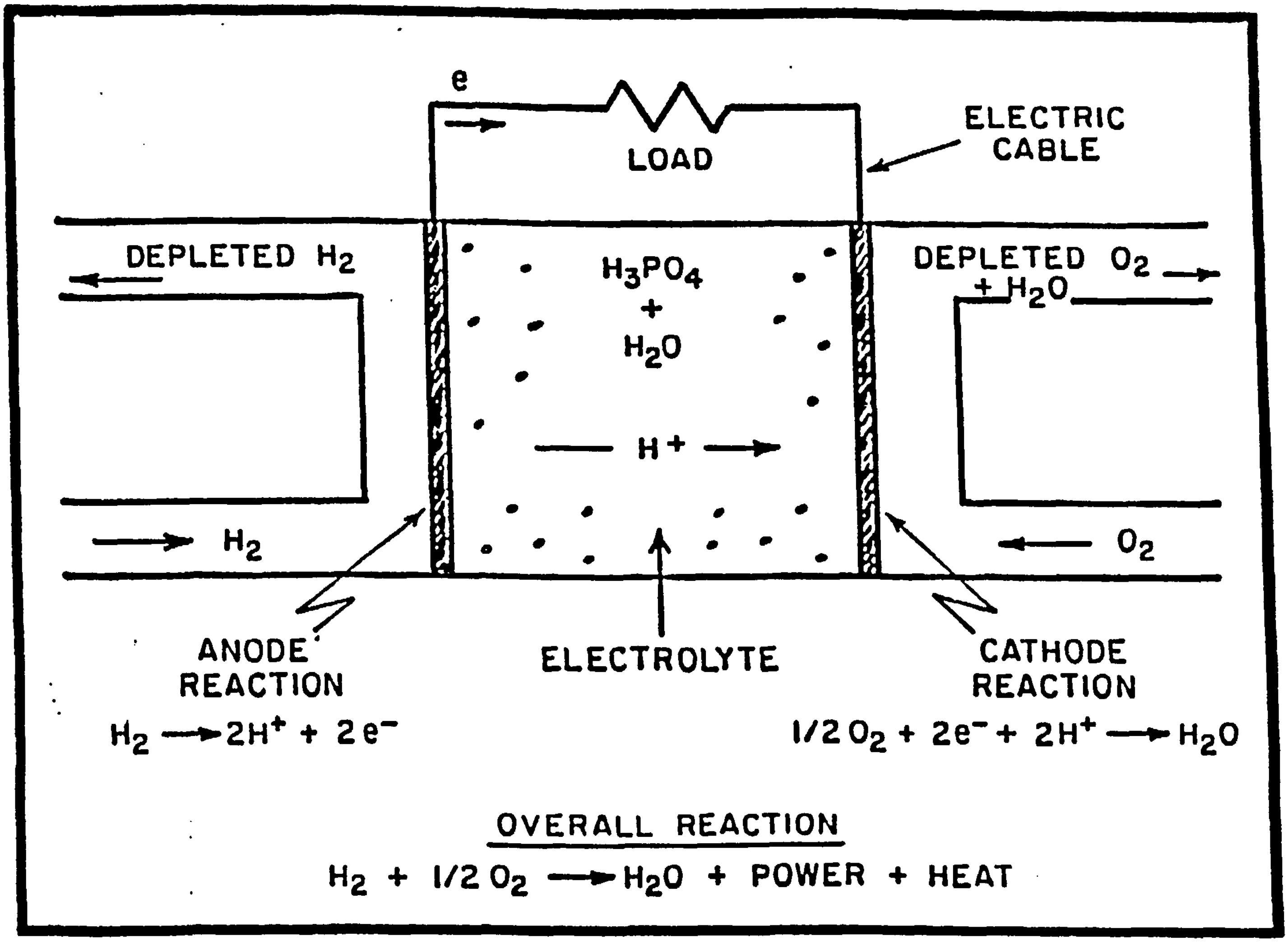

FIG. 4- HYDROGEN-OXYGEN FUEL CELL PROCESS

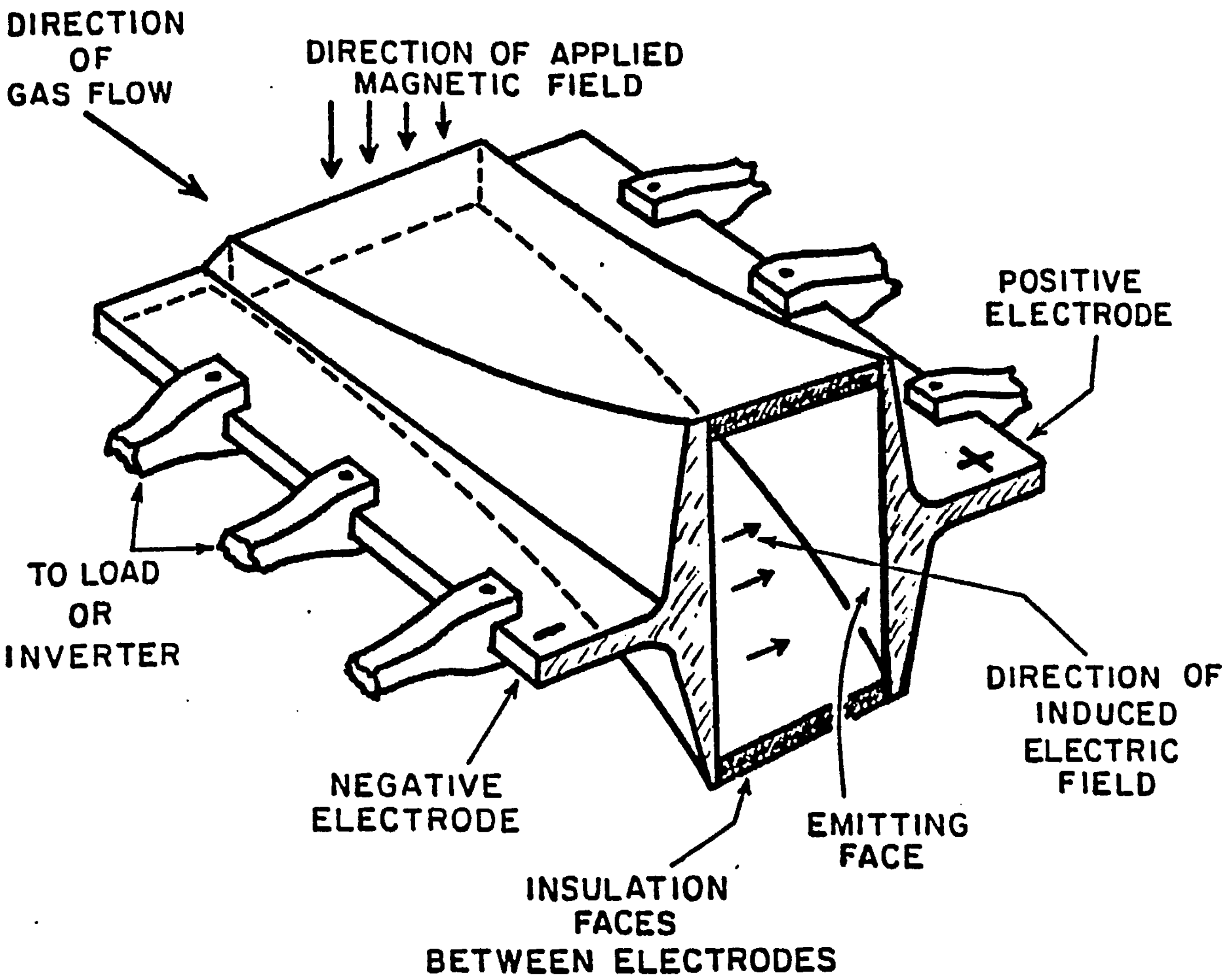

FIG. 5 - MHD GENERATOR
WITH CONTINUOUS ELECTRODES