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COPRODUCTION OF ELECTRICITY AND FERTILIZER: A KEY ENVIRONMENTAL/ENERGY CONCEPT FOR THE TWENTY-FIRST CENTURY

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As the 21st century approaches, we must focus on innovative concepts in the industrial sector of the world's economic market to decrease negative impacts of industrial growth on the environment in an economically-sound manner. In the United States, the Tennessee Valley Authority (TVA), a Federal Government corporation committed to a mission of natural resource management, power generation, regional economic development, support of national defense, and national responsibility for fertilizer research, development, and introduction, has accepted this challenge in continuation of its fifty-nine years of economic and environmental leadership. In one such activity toward meeting this challenge, TVA is proposing to develop and commercially demonstrate the coproduction of electricity and fertilizer using integrated gasification/combined cycle (IGCC) technology. The coal-based Coproduction Demonstration Project will show that coproduction of chemicals with electricity can economically and environmentally enhance the production of electric power from coal.

As conceptually envisioned and shown in Table 1, the proposed facility of the Coproduction Demonstration Project will be designed for a nominal electrical capacity of about 250 megawatts (MW). During normal operation, the system will produce about 150 MW of base-load electrical capacity and 1,000 tons urea per day. The sulfur in the coal is recovered either as a sulfuric acid or elemental sulfur by-product. During peak power demand, the fertilizer capacity can be turned down or bypassed and the full 250 MW of electrical capacity can be produced. This production scheme allows the continuous operation at 100-percent capacity of the capital intensive gasification-related process units, while varying the amount of electricity produced from 60 percent to 100 percent of rated capacity. Coproduction also will further reduce the annual revenue requirements for power generation by the coproduction of the higher-valued fertilizer coproduct.

As subsequent milestones in the dynamic development of the initial phases of this project occur, e.g. more detailed engineering estimates and consideration of alternative operating schemes, this cyclic-operation configuration of the project may vary. The overall schedule for the project is given later in this paper.

TECHNICAL

IGCC/F Coproduction Process

As shown in Figure 1, the coproduction concept is based on the integrated operation of air separation, coal gasification, acid gas removal, combined cycle (steam and combustion turbines), ammonia, urea, and by-product recovery units of modular single-train design.

- Air separation unit: Elevated-pressure separation of air into oxygen (for the coal gasification unit) and nitrogen (for the ammonia and combined cycle units).

- Coal gasification unit: Dry-feed, oxygen-blown, entrained-flow, slagging-type gasification to produce clean medium-Btu synthesis gas (for the ammonia plant and the gas turbine) and nonleachable slag.

- Acid gas removal unit: Selective solvent recovery of acid gases (primarily CO_2 and H_2S with traces of COS and HCN) for CO_2 feed to the urea unit and H_2S feed to either a sulfuric acid unit or a Claus sulfur production unit.

- Combined cycle unit: High-temperature (2350°F) combustion of clean medium-Btu synthesis gas in a gas turbine (for electricity generation) followed by a heat-recovery steam generator and steam turbine (for additional electricity generation and steam feed to the chemical units).

- Ammonia unit: Hydrogen enhancement and catalytic gas-phase reaction of hydrogen and nitrogen (from the air separation unit) to produce ammonia.

- Urea unit: Two-stage reaction of ammonia and carbon dioxide (from the acid gas removal unit), from acid gas removal, to produce urea.

- Sulfur recovery unit: Conversion of H_2S directly into sulfuric acid or partial oxidation of H_2S into elemental sulfur with tail gas cleanup (SCOT process) to produce marketable by-products.

COMPETITIVE TECHNOLOGIES

It has been recently stated that, for many utilities, coal is and will continue to be the preferred fuel alternative; however, achieving the simultaneous goals of using coal as the primary fuel source and meeting more stringent environmental and technical requirements is becoming more difficult and costly. The competing coal-based technologies to integrated gasification combined cycle for base-load capacity are considered to be pulverized coal (PC) combustion with flue gas desulfurization (FGD) and combined cycle (combustion and steam turbines). Other new coal-based power generating technologies include the fluidized-bed combustion (FBC) plants, both atmospheric and pressurized. From an overall technical and economic perspective, atmospheric FBC is considered for the purpose of this comparison to be equivalent to PC. Pressurized FBC has not been commercially demonstrated and at this time is not considered a competitive technology for new coal-based generating capacity.

In the United States, IGCC has been commercially demonstrated at Southern California Edison's Cool Water plant during a five-year program sponsored by a consortium led by the Electric Power Research Institute (EPRI). A 100-MW Texaco gasification system and a conventional 2000°F combustion turbine (CT) were used in this facility. Dow Chemical (DOW) has operated a 160-MW IGCC plant since 1987 on subbituminous coal in Louisiana. The DOW gasification process is used to fuel existing CTs. Shell Oil operated a 30-MW-equivalent gasification demonstration project near Houston, Texas, from 1987 to 1991 and gasified different feedstocks. In Europe a consortium of Dutch utilities is building a 250-MW IGCC plant using the Shell gasification process and a conventional CT. The heat rate of the latter system is approximately 8300 Btu/kWh (higher heat value basis). Newly developed IGCC designs, using CTs which operate at higher temperatures (2350°F) and a high degree of steam integration, show heat rates of about 8000 Btu/kWh.

ENVIRONMENTAL EVALUATION

Gaseous Emissions

General: The SO_2 and NOx emissions from IGCC are significantly less than those from PC with conventional SO_2 and NOx control technologies. In gasification, the coal's sulfur and nitrogen are converted to reduced forms of sulfur and nitrogen. The reduced sulfur is more concentrated in the synthesis gas without the N_2 diluent from the air, and H_2S can be more easily recovered as a by-product as compared with the dilute concentration of SO_2 in the flue gas of the PC combustion system. The reduced nitrogen compounds (NH_3 and HCN) are more easily removed than NOx and are decomposed in wastewater treatment. In addition, the higher efficiency of IGCC as compared to that of a PC results in lower CO_2 emissions; the IGCC/F coproduction process will further decrease CO_2 emissions at the site by the production of urea.

Sulfur dioxide (SO_2): Conventional SO_2 control for PC is through flue gas desulfurization. Typical FGD units using wet absorption removes 90-95% of the SO_2 in the flue gas. Conventional reduced-sulfur removal from IGCC's synthesis gas is by acid gas removal (AGR) and total reduced sulfur removal for high-sulfur coal has typically been 95-98% for power generation applications.

The expected IGCC and IGCC/F SO_2 emissions are shown in Table 2 to be less than 0.06 lb SO_2 per MBtu (greater than 99% overall sulfur removal). FGD at 95% SO_2 removal would have an SO_2 emission of 0.3 lb SO_2 per MBtu for a 3.5% sulfur coal as compared with the New Source Performance Standard (NSPS) of 1.2 lb SO_2 per MBtu. The ammonia catalyst used for fertilizer production can be poisoned by reduced sulfur compounds, one of the several trace compounds in the coal-derived synthesis gas. Therefore, the total reduced sulfur in the synthesis gas must be below 2 ppmv from the AGR unit and must be decreased to less than 0.1 ppmv before entering the ammonia synthesis loop to avoid poisoning the ammonia catalyst.

Coal gasification plants used for ammonia production in Japan by Ube Industries and for methanol production in the United States by Tennessee Eastman meet this stringent level of sulfur removal. The sulfur compounds are removed in the commercially-available absorption AGR processes at these plants to below 1ppmv of sulfur in the clean synthesis gas.

Nitrogen oxides: Typical uncontrolled NOx emissions from PC units range from 0.6 to 1.0 lb NOx per MBtu. For the NSPS NOx standard of 0.5 to 0.6 lb NOx per MBtu, low-NOx burners are required with good control of both air and coal to each burner in the register. Additional NOx control can be achieved by selective catalytic or noncatalytic reduction (SCR and SNCR). For SCR/SNCR, either ammonia or an ammonia-type compound (e.g. urea) is injected into the flue gas and used to reduce the NOx to elemental N_2. The SCR could reduce NOx to approximately 0.1-0.2 lb NOx per MBtu for controlled and uncontrolled combustion, respectively. Although SCR has shown 80-90% NOx reduction, it has not been commercially demonstrated on high-sulfur coals.

In conventional CTs, NOx emissions are controlled to about 0.1 lb per MBtu. The use of water/steam (wet) and/or nitrogen (dry) injection into the synthesis gas provides a diluent (heat sink) to reduce thermal NOx emissions. The diluent reduces the heating value of the synthesis gas from about 280-300 Btu per standard cubic feet (SCF) to 130-150 Btu per SCF. In the IGCC plant at Cool Water, NOx emissions were less than 0.08 lb per MBtu using water-saturated fuel gas in a conventional CT (operating at 2000°F). The synthesis gas at Cool Water had a heating value of about 180 Btu per SCF. The NOx emissions for IGCC or IGCC/F are expected to be about 0.1 lb per MBtu.

Liquid Effluents

The primary liquid effluent from a conventional PC power plant is the cooling tower blowdown. Since only one-third of IGCC's power is produced by the steam turbine, the amount of IGCC heat rejection (consequently, the cooling tower blowdown) is estimated to be about one-half of the heat rejection in the PC plant.

IGCC produces a wastewater stream which contains ammonia, sulfides, cyanides, BOD, and COD, in addition to the normal power plant's general wastewater (demineralizer regenerant, boiler blowdown, etc.). All U.S. gasification projects have demonstrated the use of commercially-available process units to treat the process wastewater to meet National Pollutant Discharge Elimination System (NPDES) effluent limits or to recycle the process wastewater.

Slag and Sulfur By-products

The ash and sulfur contents of coal produce potential solid wastes. The ash in U.S. bituminous coals ranges from 8 to 20%, with a typical content of about 12% ash, or about 10 lb ash per MBtu. Typical PC (dry bottom) furnaces produce about a 4:1 weight ratio of flyash to bottom ash. Although most U.S. PC plants can sell a portion of the bottom ash and all of the slag from cyclone furnaces, the flyash usually requires landfill disposal. Entrained-bed gasification produces a vitrified, granular ash (slag) due to the high temperatures and reducing atmosphere in the gasifier. The trace metals are encapsulated in the resulting slag from the gasifier. Recent tests have shown that gasification's slag is nonleachable and classified as nonhazardous under the U.S. Resource Conservation and Recovery Act (RCRA). The bulk of the gasification slag is, therefore, considered a marketable by-product.

The sulfur content in U.S. bituminous coals ranges from 1.0 to 5.0%; 3.5% sulfur is typical for the high-sulfur coals (5.6 lb $S0_2$ per MBtu with 97.5% of the sulfur in the coal being evolved as $S0_2$). For bituminous coals containing 2-5% S, FGD solid wastes from conventional PC combustion units range from 8 to 22 lb solid waste per MBtu. In the operation of fludized-bed combustion system, with a much higher stoichiometry of Ca0 to $S0_2$ (2.5 moles Ca0 per mole $S0_2$) for equivalent $S0_2$ removal, the FGD waste would be significantly increased. In the IGCC processes, particularly those used for coproduction of ammonia, sulfur removal is highly efficient and either elemental sulfur or sulfuric acid is produced as a marketable by-product.

A comparison of the environmental impact of the competing technologies is shown in Table 2. The use of the IGCC and IGCC/F results in the lowest environmental impact of the coal-based technologies.

ECONOMIC EVALUATIONS

Fuel Prices

The impact of escalation on fuel prices is an important key in the economics of the coproduction concept. Since nitrogen fertilizers are typically made in the U.S. from natural gas, trends in natural gas prices should reflect long-range effects on the market price of these products.
A real escalation in fertilizer prices are expected, while electricity prices based on coal remain relatively stable. An additional factor is that the operating costs for natural gas-based fertilizers in 1990 are based on the use of fully-depreciated plants and older natural gas contracts, which are expected to be a low price as compared to a contractible market price in the future. Any new fertilizer plant built in the late 1990s or beyond will require depreciation (financing) of the new investment and a higher-priced natural gas feedstock. An evaluation of energy price projections in 1990 by DOE showed the following real escalation for natural gas and coal prices:

Real price escalation, %

Time period	Natural gas	Coal
1990-2000	5.9	1.1
1990-2010	4.5	1.1
1990-2020	3.7	1.1
1990-2030	3.1	1.0

Therefore, the coproduction concept using less expensive coal, instead of the higher-priced natural gas, as a feedstock becomes more attractive to produce fertilizers when new fertilizer capacity is needed.

COMPETITIVE TECHNOLOGIES¶

The economic advantage of an optimized (fully integrated sub-units) IGCC/F coproduction system as compared to the following power generating plants is shown in Table 3. A natural-gas-based case for a combined cycle (CC) unit, which consists of combustion and steam turbines, is also shown in this comparison since it is expected to be a common base-load dispatch option within the U.S. utility industry.

- Pulverized coal combustion unit with wet flue gas desulfurization (PC/FGD)

- Pulverized coal combustion unit with wet flue gas desulfurization and selective catalytic reduction of NOx (PC/FGD/SCR)

- Combined cycle unit fired with natural gas (CC)

- Conventional IGCC (sub-units not optimally integrated)

- Optimized IGCC

These comparisons are based on data given in EPRI's Technical Assessment Guide - Volume 1: Revision 6, September 1989 (TAG). As stated in the TAG, an important part of an evaluation of technologies within a utility system is a production cost analysis since utility planning is based on economic dispatch, the commitment and operation of generating units or load control activities so as to meet demand with minimum total system operating cost. Capital costs are considered sunk costs, and their associated carrying charges are not included in production cost analysis. As a result, a comparison of technology alternatives must consider each technology's operating cost in terms of the utility's order of economic dispatch. Start-up costs and variable operating costs, including fuel, determine the order for bringing a power plant on line and dispatching its level of output. Typically, conversion efficiency improves as the output of a power plant increases. Thus the order of economic dispatch actually depends on the incremental efficiency, which is the ratio of the change inoperating costs to the change in resulting output of a power plant. Other factors that affect dispatch decision include transmission consideration, minimum load level of each generating unit, and the ability of each unit to rapidly follow load changes.

It should be noted that the load factor shown in Table 3, and subsequently used in calculating the results shown, is the "equivalent availability" from the EPRI TAG or the maximum load factor for a technology. The actual load factor for a specific unit is primarily dependent on its dispatch priority within the utility system. Generally, electric utility units are dispatched to generate power in sequential order, based on their lowest incremental operating cost. Since the optimized IGCC/F unit has the lowest incremental operating cost (actually a revenue income of 14.3 mills per kWh) and is followed by the IGCC-only units, the PC units, and the CC unit, the order of dispatch and the order of highest actual load factor will probably ~~occur in this~~ sequence.

OVERALL SCHEDULE

The sequence of activities from evaluation and demonstration of the coproduction concept until commencement of commercial operation of the Coproduction Demonstration facility is shown in Figure 2. Major activities in the development of this concept are:

- TVA-EPRI IGCC/F Coproduction Study. This conceptual design study of both dry- and wet-feed alternative gasification technologies being considered in the IGCC/F concept, as well as a market analysis of the impact of coproducts and byproducts from a demonstration-scale unit in the Tennessee Valley region, began in January 1991 and will be concluded by October 1992.

- DOE Clean Coal Technology (CCT) V Proposal. TVA is preparing a response to the U.S. Department of Energy's Clean Coal V Program Opportunity Notice, which was issued on July 6, 1992 and will close on December 7, 1992. The proposal, being prepared jointly with select U.S. vendors of the gasification and combined cycle units, will encompass a plan to design, construct, and operate an IGCC/Fertilizer demonstration unit within the Tennessee Valley region.

- Demo Site Selection and Environmental Planning/Permitting. Site selection procedures began in January 1992 for the Coproduction Demonstration Project for potential sites for a facility within the Tennessee Valley region. Additional tasks of (1) fulfilling the requirements of the National Environmental Policy Act regulations, (2) completing the regulatory site permitting procedures, and (3) developing an Environmental Monitoring Plan will be completed in September 1995.

- Optimized-concept Preliminary Design and Engineering Studies. TVA has contracted, as of October 1992, with an A&E firm to assist TVA in defining an optimally-integrated IGCC/F process configuration and to prepare (1) more-detailed capital and operating and maintenance cost estimates, (2) revised project schedule, and (3) preliminary equipment specifications for the demonstration facility. Completion of this activity is expected to be in April 1994.

- Design, Construction, and Operation of the Demonstration Unit. Subtasks, including final detailed design, equipment procurement, site preparation, construction, startup, demonstration operation, and associated environmental monitoring of the unit, will begin in April 1994 and will conclude in October 2000, after which the facility will be operated as a commercial unit in the TVA system.

CONCLUSIONS

Preliminary engineering and economic studies to date of the Integrated Gasification Combined Cycle/Fertilizer Coproduction concept show the following:

- Process units for the IGCC/Fertilizer coproduction process are commercially available.

- Compatible process streams, which are frequently considered waste streams in stand-alone units, allow synergistic operation among the process units to achieve optimization of the coproduction concept.

- The IGCC/Fertilizer coproduction concept offers the lowest SO2 and NOx emissions and solid waste disposal requirements as compared to competitive coal-based power generating technologies.

- The estimated first-year revenue requirements for an IGCC/Fertilizer coproduction unit are more economical (about 15 percent less) than those for a conventional pulverized-coal combustion power generating unit with high-efficiency flue gas desulfurization and selective catalytic NOx removal.

- Conceptual-level comparative economics among competitive base-load fossil-fuel power generating technologies show the IGCC/Fertilizer coproduction process to be the primary option under "economic dispatch" planning used by the electric utility industry.

As evidenced by these conclusions from the initial phases in the development and demonstration of the concept of an Integrated Gasification Combined Cycle/Fertilizer coproduction system, TVA's power-generation research and development organizations and National Fertilizer and Environmental Research Center are focused on innovate concepts which provide economically- and environmentally-sound process alternatives for consideration by the industrial sector of the world's economic market.

Table 1

APPROXIMATE CAPACITIES OF PROCESS UNITS
IN THE PROPOSED COPRODUCTION DEMONSTRATION FACILITY

Process unit	Operational mode	
	Coproduction	Power production only[a]
Combined cycle, MW (net)	150	250
Gasification, tons of coal/day	2,200	2,200
Air separation, tons of O_2/day	1,600	1,600
Ammonia, tons/day	600	0
Urea, tons/day	1,000	0
Sulfur recovery, tons/day		
Elemental sulfur	80	80
or		
Sulfuric acid	300	300

a. Seasonal peaking-load operation - typical for periods of about two-three consecutive weeks in midwinter and midsummer.

Table 2

ENVIRONMENTAL COMPARISON[a] OF COMPETITIVE COAL-BASED POWER GENERATING TECHNOLOGIES WITH THE IGCC/FERTILIZER COPRODUCTION CONCEPT (COMMERCIAL SIZE)

	PC			Optimized	
	/FGD	/FGD/SCR	FBC	IGCC	IGCC/F
Size, MW	500	500	500	500	500
Avg. annual heat rate, Btu/kWh	9,830	10,400	7,740	8,500	9,500
Load factor, %	80.6	80.6	90.5	85.7	85.7
Coal feed rate, TPH	214.1	214.1	217.4	184.8	206.5
Gaseous emissions					
SO_2					
% removal	90	95	90	97.5	99
lb/MBtu	0.59	0.30	0.59	0.15	0.06
lb/MWh	5.8	2.9	5.9	1.3	0.6
NO_x					
lb/MBtu	0.5	0.1	0.3	0.1	0.1
lb/MWh	4.9	1.0	3.0	0.8	0.9
Solid wastes					
Leachable wastes, TPH					
Bottom ash and flyash	25.7	25.7	26.1	NA	NA
FGD wastes	34.0	37.4	72.0	NA	NA
Nonleachable slag, TPH	NA	NA	NA	22.2	24.8
Total solid wastes					
TPH	59.7	62.1	98.1	22.2	24.8
lb/MBtu	24.4	25.2	39.4	10.4	10.4
lb/MWh	240	248	394	88	99

a. Based on data from EPRI's Technical Assessment Guide - Volume 1: Revision 6, September 1989.

Table 3

ECONOMIC COMPARISON[a] OF COMPETITIVE FOSSIL-FUEL POWER GENERATING TECHNOLOGIES
WITH THE IGCC/FERTILIZER COPRODUCTION CONCEPT
(COMMERCIAL SIZE)

	PC			Conventional	Optimized	
	/FGD	/FGD/SCR	CC	IGCC	IGCC	IGCC/F
Size, MW	500	500	120	500	500	500
Feed stock						
Type	Coal	Coal	NG	Coal	Coal	Coal
Cost, $/MBtu	1.50	1.50	2.50	1.50	1.50	1.50
Load factor, %	80.6	80.6	90.5	85.7	85.7	85.7
Avgerage annual heat rate, Btu/kWh	9,830	10,400	7,740	9,220	8,500	9,500
Capital requirements, $M	641	684	109	729	695	840
First-year revenue requirements, m/kWh						
Subtotal before urea credit	50.3	53.7	31.7	50.3	47.7	84.7
Urea credit ($170/ton)	NA	NA	NA	NA	NA	(39.4)
Total	50.3	53.7	31.7	50.3	47.7	45.3
Incremental operating cost[b], m/kWh						
Subtotal before urea credit	20.0	21.5	23.1	16.2	15.2	25.1
Urea credit ($170/ton)	NA	NA	NA	NA	NA	(39.4)
Total	20.0	21.5	23.1	16.2	15.2	(14.3)

a. Power generating data and economic evaluation are based on EPRI's Technical Assessment Guide - Volume 1: Revision 6, September 1989.
b. Dispatch priority.

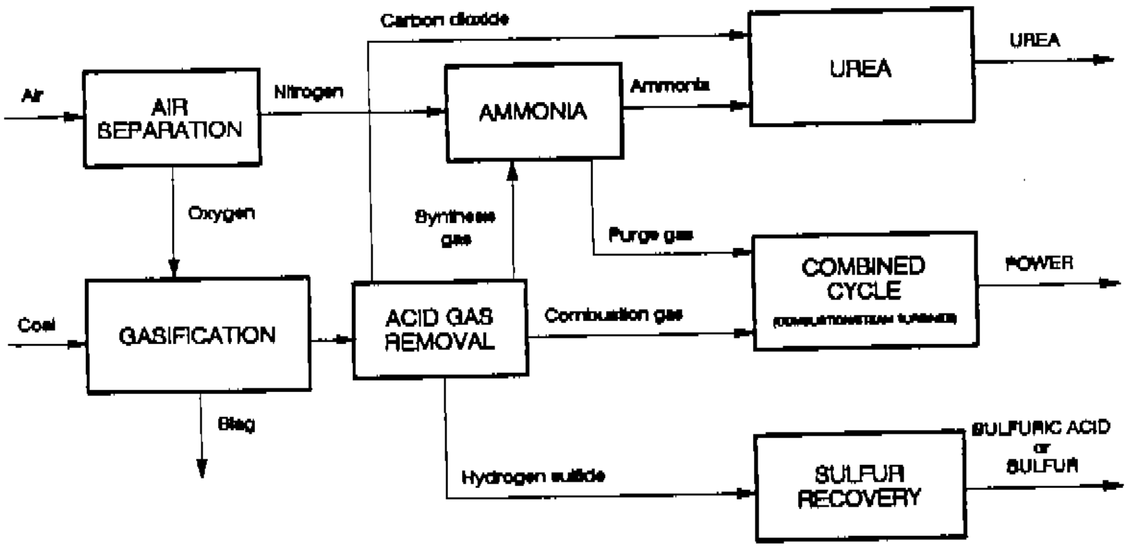

Figure 1

IGCC/FERTILIZER COPRODUCTION PROCESS CONCEPT

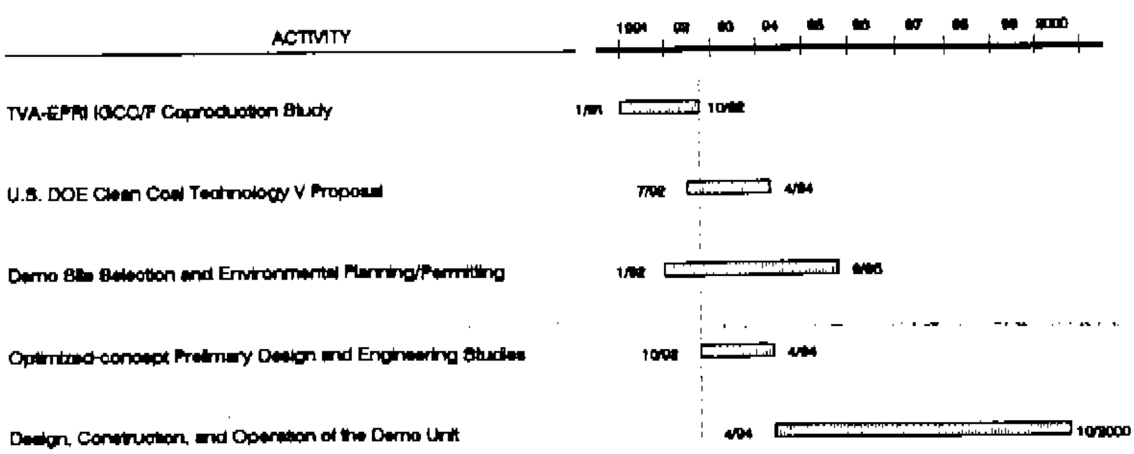

Figure 2

SCHEDULE FOR EVALUATION & DEMONSTRATION OF IGCC/FERTILIZER COPRODUCTION CONCEPT