COAL: AMERICA'S ENERGY FUTURE

VOLUME II: A TECHNICAL OVERVIEW

The National Coal Council

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Coal: America's Energy Future

VOLUME II

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A TECHNICAL OVERVIEW

ELECTRICITY GENERATION

Commercial Combustion-Based Technologies

Combustion technology choices available today for utility scale power generation include circulating fluidized bed (CFB) steam generators and pulverized coal (PC) steam generators utilizing air for combustion. Circulating fluidized beds are capable of burning a wide range of low-quality and low-cost fuels. The largest operating CFB today is 340 Megawatts (MW), although units up to 600 MW are being proposed as commercial offers. Pulverized coal-fired boilers are available in capacities over 1000 MW and typically require better quality fuels.

Advanced Pulverized Coal Combustion (PC) Technology

Pulverized Coal Process Description

In a pulverized coal-fueled boiler, coal is dried and ground in grinding mills to face-powder fineness (less than 50 microns). It is transported pneumatically by air and injected through burners (fuel-air mixing devices) into the combustor. Coal particles burn in suspension and release heat, which is transferred to water tubes in the combustor walls and convective heating surfaces. This generates high temperature steam that is fed into a turbine generator set to produce electricity.

In pulverized coal firing, the residence time of the fuel in the combustor is relatively short, and fuel particles are not recirculated. Therefore, the design of the burners and of the combustor must accomplish the burnout of coal particles during about a two-second residence time, while maintaining a stable flame. Burner systems are also designed to minimize the formation of nitrogen oxides (NO_X) within the combustor.

The principal combustible constituent in coal is carbon, with small amounts of hydrogen. In the combustion process, carbon and hydrogen compounds are burned to carbon dioxide (CO_2) and water, releasing heat energy. Sulfur in coal is also combustible and contributes slightly to the heating value of the fuel; however, the product of burning sulfur is sulfur oxides, which must be captured before leaving the power plant. Noncombustible portions of coal create ash; a portion of the ash falls to the bottom of the furnace (termed bottom ash), while the majority (80 to 90%) leaves the furnace entrained in the flue gas.

Pulverized coal combustion is adaptable to a wide range of fuels and operating requirements and has proved to be highly reliable and cost-effective for power generation. Over 2 million MW of pulverized coal power plants have been operated globally.

After accomplishing transfer of heat energy to the steam cycle, exhaust flue gases from the PC combustor are cleaned in a combination of post combustion environmental controls. These environmental controls are described in detail in further sections. A schematic of a PC power plant is shown in Figure 1.1.

Schematic Illustration of a Pulverized Coal-Fired Utility Boiler

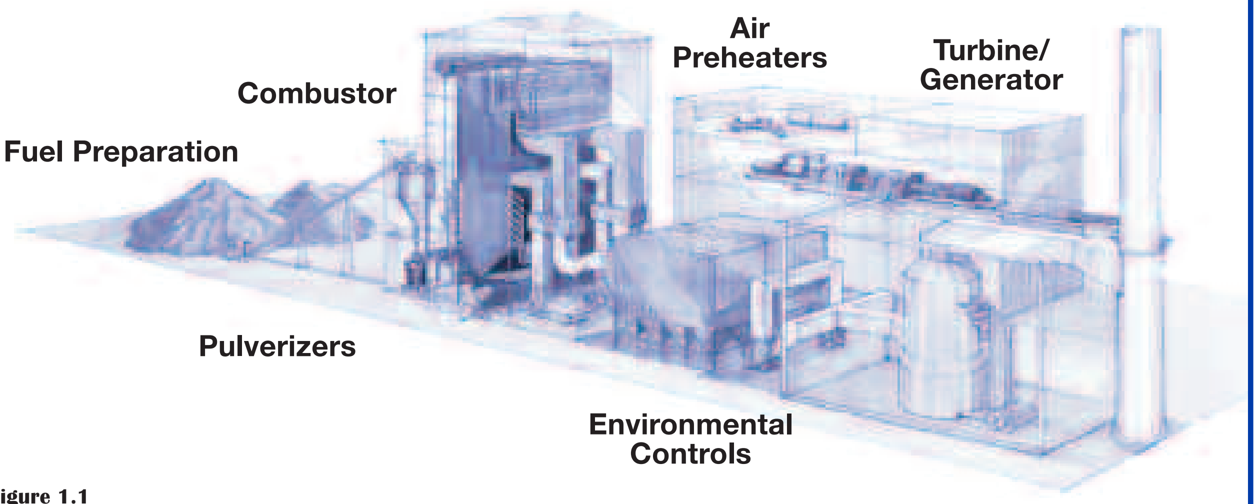

Figure 1.1

Fluidized Bed Combustion

Fluidized Bed Combustion Process Description

In a fluidized bed power plant, coal is crushed (rather than pulverized) to a small particle size and injected into a combustor, where combustion takes place in a strongly agitated bed of fine fluidized solid particles. The term "fluidized bed" refers to the fact that coal (and typically a sorbent for sulfur capture) is held in suspension (fluidized) by an upward flow of primary air blown into the bottom of the furnace through nozzles and strongly agitated and mixed by secondary air injected through numerous ports on the furnace walls. Partially burned coal and sorbent is carried out of the top of the combustor by the air flow. At the outlet of the combustor, high-efficiency cyclones use centrifugal force to separate the solids from the hot air stream and recirculate them to the lower combustor.

This recirculation provides long particle residence times in the CFB combustor and allows combustion to take place at a lower temperature. The longer residence times increase the ability to efficiently burn high moisture, high ash, low-reactivity, and other hard-to-burn fuel such as anthracite, lignite, and waste coals and to burn a range of fuels with a given design.

CFB technology incorporates primary control of NO_X and sulfur dioxide (SO_2) emissions within the combustor. At CFB combustion temperatures, which are about half that of conventional boilers, thermal NO_X is close to zero. The addition of fuel/air staging provides maximum total NO_X emissions reduction. For sulfur control, a sorbent is fed into the combustor in combination with the fuel. The sorbent is fine-grained limestone, which is calcined in the combustor to form calcium oxide. This calcium oxide reacts with sulfur dioxide gas to form a solid, calcium sulfate. Depending on the fuel and site requirements, additional NO_X and SO_2 environmental controls can be added to the exhaust gases. With this combination of environmental controls, CFB technology provides an excellent option for low emissions and very fuel-flexible power generations.

CFB technology has been an active player in the power market for the last two decades. Today, over 50,000 MW of CFB plants are in operation worldwide.

Advanced Steam Cycles for Clean Coal Combustion

Improving power plant thermal efficiency will reduce CO_2 emissions and conventional emissions such as SO_2, NO_X and particulate by an amount directly proportional to the efficiency improvement. Efficiency improvements have been achieved by operation at higher temperature and pressure steam conditions and by employing improved materials and plant designs. The efficiency of a power plant is the product of the efficiencies of its component parts. The historical evolutionary improvement of combustion-based plants is traced in Figure 1.2. As shown, steam cycle efficiency has an important effect upon the overall efficiency of the power plant.

Current Coal-Fired Power Plant Improvements

Rankine cycle efficiency improvement from 34% to 58% (LHV)

Due to:
- Regenerative feedwater preheating
- Increase of steam pressure and temperature
- Reheat

Steam turbine efficiency improvement from 60% to 92%

Due to:
- Blade design
- Reheat
- Increase in steam pressure and temperature
- Shaft and inter-stage seals
- Increase in rating

Generator efficiency improvement from 91% to 98.7%

Due to:
- Increase in rating
- Improved cooling (hydrogen/water)

Boiler efficiency improvement from 83% to 92% (LHV)

Due to:
- Pulverized coal combustion with low excess air
- Air preheat
- Reheat
- Size increase

Auxiliary efficiency improvement from 97% to 98%

Due to:
- Increase in component efficiencies
- Size increase

Auxiliary efficiency decrease from 98% to 93%

Due to:
- More boiler feed pump power
- Power and heat for emission-reduction systems

Power plant net efficiencies:

η Power Plant = η Rankine Cycle x η Turbine x η Generator x η Boiler x η Auxiliaries

η Early Power Plant = 34% x 60% x 91% x 83% x 97% = 15%

η Today's Power Plant = 58% x 92% x 98.7% x 92% x 93% = 45% (LHV)

Note: Efficiency is usually expressed in percentages. The fuel energy input can be entered into the efficiency calculation either by the higher (HHV) or the lower (LHV) heating value of the fuel. However, when comparing the efficiency of different energy conversion systems, it is essential that the same type of heating value is used. In U.S. engineering practice, HHV is generally used for steam cycle plants and LHV for gas turbine cycles. In European practice efficiency calculations are uniformly LHV-based. The difference between HHV and LHV for a bituminous coal is about 5%, but for a high-moisture low-rank coal, it could be 8% or more.

Figure 1.2 Source: Termuehlen and Empsperger 2003

As steam pressure and superheat temperature are increased above 225 atm (3308 psi) and 374.5°C (706°F), respectively, the steam becomes supercritical (SC); it does not produce a two phase mixture of water and steam but rather undergoes a gradual transition from water to vapor with corresponding changes in physical properties. In order to avoid unacceptably high moisture content of the expanding steam in the low pressure stages of the steam turbine, the steam, after partial expansion in the turbine, is taken back to the boiler to be reheated. Reheat, single or double, also serves to increase the cycle efficiency.

Pulverized coal fired supercritical steam cycles (PC/SC) have been in use since the1930s, but material developments during the last 20 years, and increased interest in the role of improved efficiency as a cost-effective means to reduce pollutant emission, resulted in an increased number of new PC/SC plants built around the world. After more than 40 years of operation, supercritical technology has evolved to designs that optimize the use of high temperatures and pressures and incorporate advancements such as sliding pressure operation. Over 275,000 MW of supercritical PC boilers are in operation worldwide.

Supercritical steam parameters of 250 bar 540°C (3526psi/1055°F) single or double reheat with efficiencies that can reach 43 to 44 % (LHV) (39 to 40% HHV) represent mature technology. These SC units have efficiencies two to four points higher than subcritical steam plants representing a relative 8 to 10% improvement in efficiency. Today, the first fleet of units with Ultra Supercritical (USC) steam parameters of 270 to 300 bar and 600/600°C (4350 psi, 1110°/1110°F) are successfully operating, resulting in efficiencies of >45% (LHV) (40 to 42% HHV), for bituminous coal-fired power plants. These “600°C” plants have been in service more than seven years, with excellent availability. USC steam plants in service or under construction during the last five years are listed in Figure 1.3.

USC Steam Plants in Service or Under Construction Globally

Power Station	Cap. MW	Steam Parameters	Fuel	Year of Comm.	Eff% LHV
Matsuura 2	1000	255bar/598°C/596°C	PC	1997	
Skaerbaek 2	400	290bar/580°C/580°C/580°C	NG	1997	49
Haramachi 2	1000	259bar/604°C/602°C	PC	1998	
Nordjyland 3	400	290bar/580°C/580°C/580°C	PC	1998	47
Nanaoota 2	700	255bar/597°C/595°C	PC	1998	
Misumi 1	1000	259bar/604°C/602°C	PC	1998	
Lippendorf	934	267bar/554°C/583°C	Lignite	1999	42.3
Boxberg	915	267bar/555°C/578°C	Lignite	2000	41.7
Tsuruga 2	700	255bar/597°C/595°C	PC	2000	
Tachibanawan 2	1050	264bar/605°C/613°C	PC	2001	
Avedere 2	400	300bar/580°C/600°C	NG	2001	49.7
Niederaussen	975	290bar/580°C/600°C	Lignite	2002	>43
Isogo 1	600	280bar/605°C/613°C	PC	2002	
Neurath	1120	295bar/600°C/605°C	Lignite	2008	>43%

Figure 1.3 Source: Blum and Hald and others

Looking forward, advancements in materials are important to the continued evolution of steam cycles and higher efficiency units. Development programs are under way in the United States, Japan and Europe, including the THERMIE project in Europe and the Department of Energy/Ohio Cooperative Development Center project in the United States, which are expected to result in combustion plants that operate at efficiencies approaching 48% (HHV) (Figure 1.4). Advanced materials development will be critical to the success of this program.

Ongoing Development for USC Steam Plants

	Japan – NIMS Materials Development	**U.S. – DOE Vision 21**	**Europe – THERMIE AD700**
	1997–2007	**2002–2007**	**1998–2013**
Development Requirements	Ferritic steel for 650°C	Materials development and qualification Target: 350 bar, 760°C, (870°C)	Materials development and qualification Componentdesign and demonstration Plant demonstration Target: 400 –1000 MW, 350 bar, 700°C, 720°C

Figure 1.4 Source: Blum and Hald

Figure 1.5 summarizes the evolution of efficiency for supercritical PC units. It should be noted that commercial offerings for supercritical CFBs have been made in the last two years and that the first SCCFB units will be commissioned in the next 2 to 3 years.

Estimated Plant Efficiencies for Various Steam Cycles

Description	Cycle	Reported at European Location (LHV)	Converted to U.S. Practice(2) (HHV)
Subcritical–commercial	16.8 MPa/558°C/538°C		37
Supercritical–mature	24.5 MPa/565°C/565°C/565°C(1)		39–40
ELSAM (Nordjyland 3)	28.9 MPa/580°C/580°C/580°C	47/44	41
State of the Art Supercritical–commercial	31.5 MPa/593°C/593°C/593°C(1)		40–42
THERMIE–future	38 MPa/700°C/720°C/720°C	50.2/47.7	46/43
EPRI/Parson–future	37.8 MPa/700°C/700°C/700°C		44
DOE/OCDO	38.5 MPa/760°C/760°C		46.5
USC Project–future	38.5 MPa/760°C/760°C/760°C		47.5–48

1. Eastern bituminous Ohio coal. Lower heating value, LHV, boiler fuel efficiency is higher than higher heating value, HHV, boiler fuel efficiency. For example, an LHV net plant heat rate at 6205.27 Btu/kWh with the LHV net plant efficiency of 55% compares to the HHV net plant heat rate at 6494 Btu/kWh and HHV net plant efficiency of 52.55%.
2. Reported European efficiencies are generally higher compared to those in the United States due to differences in reporting practice (LHV vs. HHV), coal quality, auxiliary power needs, condenser pressure and ambient temperature, and many other variables. Numbers in this column for European project numbers are adjusted for U.S. conditions to facilitate comparison.

Figure 1.5 Source: P. Weitzel, and M. Palkes

The effect of plant efficiency upon CO_2 emissions reduction is shown in Figure 1.6.

It is estimated that during the present decade 250 gigawatts (GW) of new coal-based capacity will be constructed. If more efficient SC technology is utilized instead of subcritical steam, CO_2 emissions would be about 3.5 gigaton (Gt) less during the lifetime of those plants, even without installing a system to capture CO_2 from the exhaust gases.

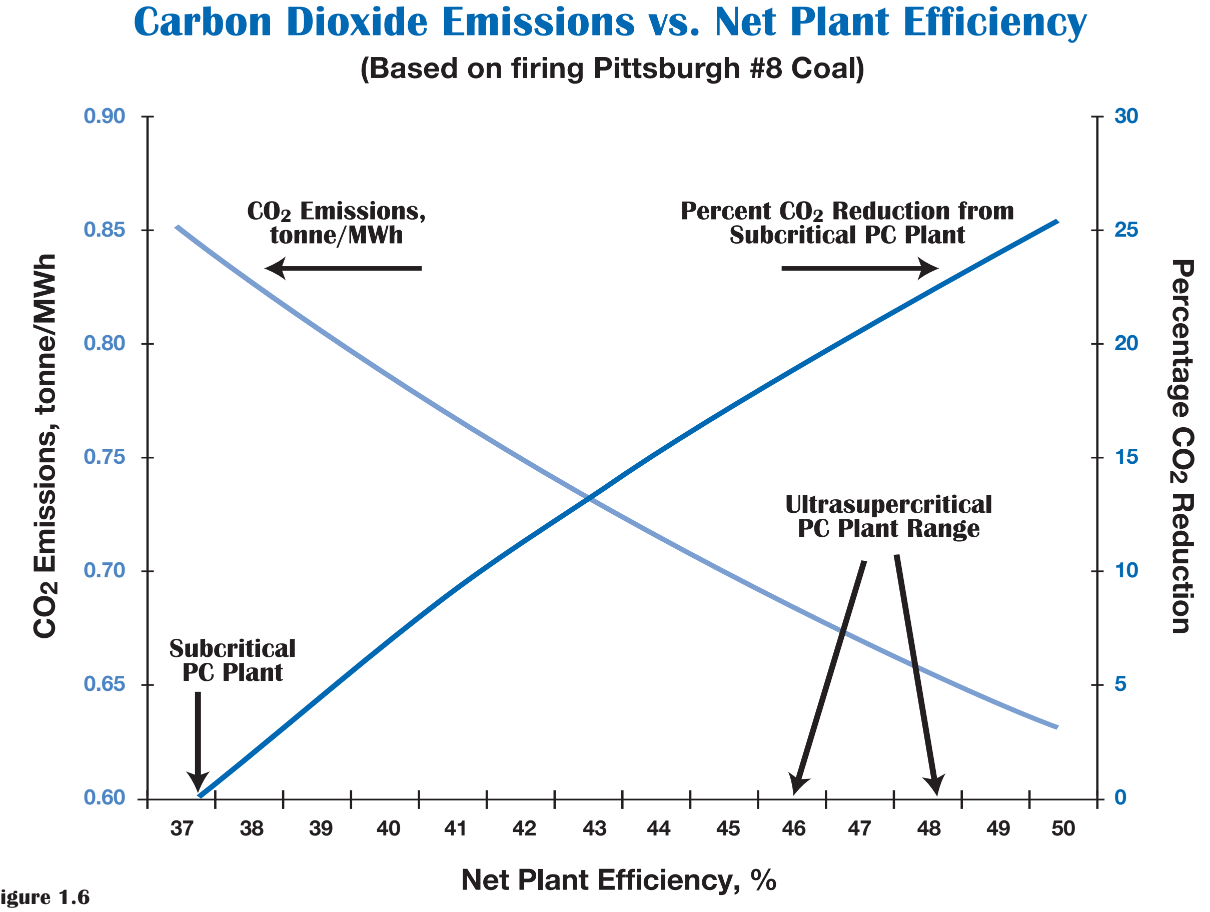

Figure 1.6

Environmental Control Systems for Combustion-Based Technologies

In all clean-coal technologies, whether combustion- or gasification-based, entrained ash and trace contaminants and acid gases must be removed from either the flue gas or syngas. Different processes are used to match the chemistry of the emissions and the pressure/temperature and nature of the gas stream.

PC/CFB plants can comply with tight environmental standards. A range of environmental controls are integrated into the combustion process (low NO_X burners for PC, sorbent injection for CFB) or employed post combustion to clean flue gas. The following sections describe the state of the art for emissions controls for combustion technologies. In general, these environmental processes can be applied as retrofit to older units and designed into new units. In some cases, performance will be better on a new unit since the design can be optimized with the new plant.

Figure 1.7 illustrates the comprehensive manner in which combustion and post-combustion controls combine to minimize formation and maximize capture of emissions from clean-coal combustion.

Recent Air Permit Limits

POLLUTANT	CONTROL TECHNOLOGY	EMISSIONS LIMIT	AVERAGING TIME	PERMITTED FACILITIES
Carbon Monoxide (CO)	Good Combustion Practices	.10 lb/MBtu	3-day rolling average, excluding start up (SU)/ shut down (SD)	Thoroughbred, Trimble County II, others
Nitrogen Oxides (NO_x)	Low NO_X Burners and Selective Catalytic Reduction	.05 lb/MBtu <2 ppmdv Ammonia	30-day rolling average, excluding SU/SD	CPS San Antonio, Trimble County II
Particulate Matter (PM)	Fabric Filter Baghouse, Flue Gas Desulfurization, Wet ESP	.018 lb/MBtu 20% Opacity	Based on a 3-hour block average limit, includes condensables	Thoroughbred, Elm Road
Particulate matter <10 microns ($PM_{<10}$)	Fabric Filter Baghouse, Flue Gas Desulfurization, Wet ESP	.018 lb/MBtu 20% Opacity	Based on a 3-hour block average limit, includes condensables	Trimble County II
Sulfur Dioxide (SO_2)	Washed Coal and Wet Flue Gas Desulfurization	.1 lb/MBtu 98% Removal	30-hour rolling average, including SU/SD	Trimble County II
Volatile Organic Compounds (VOC)	Low NO_X Burners and Good Combustion Practices	.0032/lb MBtu	24-hour rolling average excluding SU/SD	Trimble County II
Lead (Pb)	Fabric Filter Baghouse, Flue Gas Desulfurization	3.9 lb/TBtu	Based on a 3-hour block average limit	Thoroughbred
Mercury (Hg)	Fabric Filter Baghouse, Flue Gas Desulfurization	1.12 lb/TBtu (Based on 90% Removal, Final Limit is Operational Permit)	Stack testing, coal sampling & analysis	Elm Road
Beryllium (Be)	Fabric Filter Baghouse, Flue Gas Desulfurization	$9.44x10^{-7}$ lb/MBtu	Stack testing, coal sampling & analysis	Thoroughbred
Fluorides (F)	Fabric Filter Baghouse, Flue Gas Desulfurization	0.000159 lb/MBtu	Stack testing, coal sampling & analysis	Thoroughbred
Hydrogen Chloride (HCl)	Flue Gas Desulfurization	6.14 lb/hr	Stack testing based on a 24-hour rolling average	Thoroughbred
Sulfuric Acid Mist (H_2SO_4)	Flue Gas Desulfurization and Wet ESP	.004 lb/MBtu	.004 lb/MBtu	Trimble County II

Figure 1.7

Overview of Nitrogen Oxides

Nitrogen oxides are byproducts of the combustion of virtually all fossil fuels. The formation of NO_X in the combustion process is a function of two reactions/sources—thermal NO_X originates from the nitrogen found in the air used for combustion, and fuel NO_X originates from organically bound nitrogen found at varied levels in all coals. Control of NO_X emissions is accomplished in PC/CFB units through a combination of in-furnace control of the combustion process and post-combustion reduction systems.

Combustion NO_X Control

Advanced low NO_X PC combustion systems, widely used today in utility and industrial boilers, provide dramatic reductions in NO_X emissions in a safe, efficient manner. These systems have been retrofitted to many existing units and are reducing NO_X emissions to levels that in some cases rival the most modern units. The challenges are considerable, given that the older units were not built with any thought of adding low NO_X systems in the future. Low NO_X combustion systems can reduce NO_X emissions by up to 80% from uncontrolled levels, with minimal impact on boiler operation, and they do so while regularly exceeding 99% efficiency in fuel utilization. Low NO_X firing systems are standard equipment on new PC units.

Advanced low NO_X systems start with fuel preparation that consistently provides the necessary coal fineness while providing uniform fuel flow to the multiple burners. Low NO_X burners form the centerpiece of the system, and are designed and arranged to safely initiate combustion and control the process to minimize NO_X. An overfire air (OFA) system supplies the remaining air to complete combustion while minimizing emissions of NO_X and unburned combustibles. Distributed control systems (DCS) manage all aspects of fuel preparation, air flow measurement and distribution, and flame safety and also monitor emissions. Cutting-edge diagnostic and control techniques, using neural networks and chaos theory, assist operators in maintaining performance at peak levels.

For pulverized coal units, uncontrolled NO_X emissions from older conventional combustion systems typically range from 0.4 to 1.6 lb/106 Btu, dependent on the original system designs. Retrofitting of low NO_X PC combustion systems is capable of reducing NOx down to 0.15 to 0.5 lb/106 Btu exiting the combustor; the performance is highly dependent on the fuel and the ability to modify the existing boiler design. The goal of the DOE's low NO_X burner program is to develop technologies for existing plants with a NO_X emission rate of 0.15 lb/10^6 Btu by 2007 and 0.10 lb/10^6 Btu by 2010, while achieving a levelized cost savings of at least 25% compared to state-of-the-art selective catalytic reduction (SCR) control technology.

New plants which can be designed for optimized reduction of NO_X in the firing systems which will achieve combustor outlet levels at the lower end of this range and designs are in demonstration to drive combustor outlet NO_X levels to 0.1 lb/MMBtu.

Combustion NO_X Control Costs

The installed cost of a low NO_X combustion system retrofit on a coal-fired unit is in the range of $7 to $15/kW to achieve NO_X reductions of 20 to 70%. Installation of low NO_X firing systems is standard procedure on new units, and the cost is embedded in the firing system cost of the new unit design.

The industry continues to aggressively develop improvements to low NO_X burner technology to lessen the NO_X reduction requirements of the post-combustion NO_X control equipment (selective catalytic reduction), which can significantly reduce capital and operating costs.

Post Combustion NO_X Control — SCR and SNCR

Advanced PC/CFB plants utilize a combination of combustion and/or post-combustion control for high levels of NO_X reduction. PC plants generally combine low NO_X firing with selective catalytic reduction (SCR) to reduce NO_X emissions, while CFB units utilize selective non-catalytic reduction (SNCR).

SCR systems use a catalyst and a reductant (typically ammonia) to dissociate NO_X to harmless nitrogen and water. The SCR catalytic-reactor chamber is located at the outlet of the combustor, prior to the air heater inlet. Ammonia is injected upstream of the SCR; the ammonia/flue gas mixture enters the reactor, where the catalyst reaction is completed. SCR technology is capable of reducing NO_X emissions entering the system by 80 to 90%. SCR technology has been applied to coal-fired boilers since the 1970s; installations are successfully in operation in Japan, Europe and the United States.

Depending on the fuel, CFB units may also incorporate post combustion NO_X control. Typically CFB would utilize a chemical process called selective non-catalytic reduction (SNCR) to reduce NO_X. In SNCR, a reagent (either ammonia or urea) is injected in the flue gas and reacts with the NO_X to form nitrogen and ammonia. No catalyst is used, and it is necessary to design the injection to provide for adequate residence time, good mixing of the reagent with the flue gas and temperature, and a suitable temperature window (1600°–2100°F) to drive the reaction. SNCR is capable of reducing NO_X emissions entering the system by 70 to 90% and is a proven and reliable technology that was first applied commercially in 1974.

SO_X Overview

All coals contain sulfur (S), which, during combustion, is released and reacts with oxygen (O_2) to form sulfur dioxide, SO_2. A small fraction, 0.5 to 1.5%, of the SO_2 will react further with O_2 to form sulfur trioxide (SO_3). If an SCR is installed for NO_x control, the catalyst may result in an additional 0.5 to 1.0% oxidation of SO_2 to SO_3. Both SO_2 and SO_3 are precursors to acid rain.

The most prevalent technologies for SO_2 reduction in the U.S. power generation market are wet scrubbing, or wet flue gas desulfurization (WFGD) and spray dryer absorption (SDA). Wet scrubbers can easily achieve 98% to over 99% SO_2 removal efficiency on any type of coal. Other technologies that have been employed to a minor extent include dry sorbent injection and dry fluidized-bed scrubbers.

All recent, new coal-fired generating plants include either WFGD or SDA technologies for SO_X emissions control. The technology selection is dependent on the coal characteristics, the emission limit requirements, and site-specific factors, which may include restrictions on water availability and space limitations. WFGD is typically used when the expected range of coal sulfur content will exceed approximately 1.5%. However, SDA technology has been applied across the full range of coal ranks.

The U.S. utility industry is experiencing a surge of WFGD system retrofits at existing generating stations in response to Clean Air Interstate Rule (CAIR) and other state or federal legislation. Approximately 38,000 MW of WFGD systems are currently in various stages of design and construction. WFGD systems dominate the coal-fired utility industry with approximately 80 to 85% of the total installed SO_2 emissions control systems.

SDA technology has been selected for emissions control on more than 3,500 MW of new coal-fired generators completed in the last five years or currently under construction, as well as more than 1,500 MW of retrofit installations. The SDA technology consumes significantly less water than WFGD and is often a choice where water usage is restricted.

Technical Description: Wet Scrubbers (WFGD)

Wet scrubbers are large vessels in which the flue gas from the combustion process is contacted with a reagent. The reagent is typically limestone or lime mixed with water to form a slurry. The reagent is added to the scrubber in a reaction tank located at the bottom of the scrubber. Slurry from the reaction tank is pumped to a spray zone and sprayed into the gas inside the scrubber. This slurry is a combination of reaction products, fresh reagent and inert material. The SO_2 is absorbed into the slurry, reacts with the reagent, and forms a solid reaction product. A portion of the recirculated slurry is pumped to a dewatering system where the slurry is concentrated to 50 to 90% solids. The water is returned to the scrubber. The most common reagent for wet scrubbing is limestone, although there are a number of units that use lime or magnesium-enriched lime.

Peformance: WFGD

Wet scrubbers can easily achieve 98% to over 99% SO_2 removal efficiency on any type of coal.

Direction of Technology Development: WFGD

The development of wet scrubbers is in the optimization stage to drive incremental removal to more than 99% and to reduce capital and operating cost. This includes developing methods for reduction in power and reagent consumption. Also, better methods for reducing moisture carryover and lowering the filterable particulate leaving the scrubber are important.

There is work in developing multi-emissions control systems that optimize the design of post-combustion controls and integrate the capture processes for NO_X, particulate, SO_2 and mercury. In addition, innovations in wet scrubbing include a design that uses the air stream used for forced oxidation to develop the recirculated flow of slurry in the scrubber. Also, work is being done on high-velocity designs to reduce the size of WFGD.

Technical Description: Spray Dryer Absorption (SDA)

SDA differs from WFGD in that it does not completely quench and saturate the flue gas. A reagent slurry is sprayed into the reaction chamber at a controlled flow rate that quenches the gas to about 30°F above the saturation temperature. An atomizer is used to break up the reagent slurry into fine drops to enhance SO_2 removal and drying of the slurry. The water carrying the reagent slurry is evaporated leaving a dry product. The gas then flows to a fabric filter (FF) or electrostatic precipitators (ESP) for removal of the reaction products and fly ash. There is also significant SO_2 and other acid gas removal in the fabric filter due to the reaction of SO_2 with the alkaline cake on the filter bags. Fresh lime slurry is mixed with a portion of the fly ash and reaction products captured in the particulate collector downstream of the SDA to form the reagent slurry.

SDA is considered best available control technology (BACT) for sub-bituminous coal-fired generating stations. State-of-the-art application of the technology involves one or more SDA modules each with a single, high-capacity atomizer to introduce the reagent slurry to the flue gas followed by a pulse-jet fabric filter for collection of the solid byproduct. Demonstrated long-term availability and reliability of the system have eliminated the need for including spare-module capacity in the design.

SDA technology has also been applied as a polishing scrubber following CFBs to achieve overall SO_2 emissions reduction of 98 to 99%. Retrofit of SDA/FF systems on existing boilers is a cost-effective means to achieve significant emissions reduction.

Performance: SDA

Performance guarantees for SDA systems are typically in the range of 93 to 95% SO_2 removal for coals with up to 1.5% sulfur content. Higher removal efficiencies have been guaranteed and demonstrated in practice. An SDA/FF system with a fabric filter can typically achieve >95% removal of H_2SO_4 with 0.004 lb/MMBtu as a typical emission limit. Emission limits for the acid gases HCl and HF as well as trace metals are also typically provided.

Direction of Technology Development: SDA

SDA is also a mature technology for SO_2 emissions control. Technology development efforts are focused on integrating operating experiences from existing installations to:

- extend maintenance intervals by introducing new wear materials and process design features;
- reduce reagent consumption by enhancing process monitoring and optimizing lime slaking;
- enhance operating flexibility to respond to process upsets;
- enhance maintenance access; and
- optimize trace element and acid gas emission control performance.

Development efforts are also in progress to extend the capacity of the SDA modules and reagent slurry atomizers to treat higher flue gas flows in single spray chambers. Expansion of beneficial byproduct use applications is another ongoing development need.

H_2SO_4 Emission Control

The catalyst used in the selective catalytic reduction (SCR) technology for nitrogen oxides control oxidizes a small fraction of sulfur dioxide in the flue gas to SO_3. The extent of this oxidation depends on the catalyst formulation and SCR operating conditions. Gas-phase SO_3 and sulfuric acid, upon being quenched in plant equipment (e.g., air preheater and wet scrubber), turn into fine acidic mist, which can cause increased plume opacity and undesirable emissions.

An SDA followed by fabric filter provides for high-efficiency H_2SO_4 emissions control (+95% typically). H_2SO_4 removal in wet scrubbers typically falls in the range of 30 to 60%; however, removal efficiencies as low as 15% and as high as 75% have been achieved. R&D efforts are under way to gain a better understanding of the parameters for H_2SO_4 removal in wet scrubbers.

There are a number of emerging technologies that involve injection of dry reagent or slurry containing reagents into the gas path from the economizer inlet to the inlet of the wet scrubber. Reagent is typically injected in two or more locations. Typical reagents are sodium- or magnesium-based. Testing indicates that the acid removal increases when using slurry vs. using dry reagent feed. Some users report nearly 90% reduction of SO_3/H_2SO_4. The technology is not developed to the point where it is commercially bid and backed by performance guarantees.

Performance: WFGD

Wet scrubbers can easily achieve 98% to over 99% SO_2 removal efficiency on any type of coal.

Direction of Technology Development: H_2SO_4 Emission Control

A variety of technologies are now being investigated to control SO_3 and H_2SO_4 cost effectively. Reagent injection for control of SO_3 and H_2SO_4 emissions is an area in which significant R&D efforts are under way. Work is being done to develop a better understanding of H_2SO_4 removal in the wet scrubber.

Particulate Control

Particulate Overview

All coals contain ash, and during the combustion process various forms of particulate, including vaporous products, are formed. The solid particulate is removed from the flue gas using either electrostatic precipitators or high-efficiency fabric filters. Many of the vaporous products can be removed by pretreatment methods that convert the vaporous products into solid particulate upstream of the particulate control. Mercury, for example, is removed using this pretreatment method by the addition of activated carbon.

Electrostatic Precipitators

Overview

Wet and dry electrostatic precipitators (ESPs) are effective devices for the removal of solid or condensed particulate matter and are proven, reliable subsystems for the utility customer.

In an ESP, particulate-laden flue gas enters the ESP, where electrons discharged by the discharge electrode system electrostatically charge the particulate. The charged particles are attracted to the positive grounded collecting surfaces of the ESP. The main difference in the wet ESP and the dry ESP is the method of removing the trapped particle out of the system for disposal. In the dry ESP, the trapped particle is dislodged by mechanical rapping and drops in the ESP hoppers and is removed by using an ash removal system. In a wet ESP, the trapped particle is water-washed, and then the wash water and particulate is routed to the WFGD system and neutralized.

Performance: Wet ESP

The current particulate issue of interest is limiting fine particulate emission (under 2.5 microns) from coal-fired utility stacks. Plants that burn medium- to high-sulfur coals will be adding wet flue gas desulfurization systems on units with existing selective catalytic reduction systems. This will add to the particulate issue, as the mist formed in the scrubber contributes both to fine particulate emissions and stack appearance. Several plants have already experienced visible plumes from these emissions. Fine particulate emissions are also perceived as a health issue. Other hazardous air pollutants may become regulated, and the removal of these pollutants will become a major issue. Wet electrostatic precipitators (wet ESPs) are now being proposed on new boiler projects burning medium- to high-sulfur fuels to mitigate poor stack appearance, to limit acid mist emissions, and to limit fine particulate emissions.

Wet ESPs have successfully served industrial processes for almost 100 years. Cumulative experience gained over the past century is being employed to lower all particulate emissions from modern utility boilers.

As the wet ESP is designed to capture submicron particles, it can be designed to achieve 90 to 95% reduction in PM2.5 (particulate matter). The wet ESP has an added benefit of removing the same or a slightly higher percentage of other fine particulates. It is an excellent polishing device for collection of both solid PM2.5 and condensed particulate formed in the wet FGD system. The wet ESP is also an excellent collector of any remaining PM10 particulate.

Direction of Technology Development: Wet ESP

Wet ESP performance based on requirements for the near future is not an issue. Wet ESP technology development will be cost-centered. Savings on capital investment may be realized by minimizing use of expensive alloys (since alloy costs are unpredictable in today's market) and novel arrangements. Parasitic power may be minimized by additional efforts to mitigate space charge either by redesign or alternate arrangements, and processes could substantially reduce unit size and cost on today's projects.

Performance: Dry ESP

Dry electrostatic precipitators (dry ESPs) have been the workhorse of the utility industry for removal of solid particulate since the 1950s. Dry ESP development came from utility customer requirements to reduce emissions on existing installations, while keeping capital costs at a minimum. The dry ESP is an excellent device for removal of PM10 particulate from the boiler flue gases. It is a relatively good device for removal of solid PM2.5 particulate on some coals.

Future employment of this technology on retrofit projects will depend on utilities evaluation of capital cost versus operating costs of competing technologies. However, new testing methodologies need to be developed to attain repeatable results for the emission levels being required in today's air permits.

Direction of Technology Development: Dry ESP

Today, the technology has evolved by work related to performance enhancements such as wider plate spacing, better discharge electrodes, digital controls and newly developed power supplies. Integration of ESPs with other technologies such as the particle agglomerator is also under consideration. Studies of the effects of unburned carbon on removal efficiency are under way to help this technology perform at its maximum level. The evolution of key dry ESP components such as collecting electrodes, discharge electrodes, wider plate spacing and more effective rapping systems has also improved the reliability of this technology. New technologies or improved technologies such as agglomerators and new power supplies could further enhance dry ESP performance. These enhancements appear to be more cost-competitive than replacement with a new particulate collector. On new projects, careful evaluation of the complete air quality system requirements will be necessary when selecting the primary particulate collector.

Fabric Filters

Technical Description

Fabric filters are particulate collectors that treat combustion flue gas by directing the gas through the filter media. The fabric filter is installed after the air heater as a particulate removal device. The fabric filter may be installed after a dry scrubber or pretreatment device and serves as a multi-pollutant removal device. Solid particulate is captured on the surface of the filter media. The collected particulate is dislodged from the filter media during the cleaning cycle. The dislodged particulate drops into the fabric filter hoppers for removal using the ash removal system. Some applications reuse the collected particulate as a recycled product to enhance the dry scrubber lime utilization.

The U.S. utility industry is favoring pulsejet technology today over reverse gas fabric filters in most coal-fired applications. Worldwide pulsejet has been the preferred fabric filter technology for more than a decade. Advancements in fabric filter cleaning capabilities have resulted in smaller fabric filters that are being used in new and retrofit applications. In fact, there is a growing trend in the industry to convert the older undersized precipitators into high-efficiency fabric filters.

Performance

Fabric filters are the particulate collector of choice for most coal-fired applications. On low-sulfur coals, the fabric filter is coupled with dry scrubber technology and serves as a multi-pollutant control device. On medium- to high-sulfur applications fabric filters are being applied on new units as the primary particulate control device. Only on medium- to high-sulfur coals is the fabric filter less cost-effective than an electrostatic precipitator. Many utilities are choosing the fabric filter over the electrostatic precipitators to ensure fuel flexibility and to keep down mercury-removal costs. The fabric filter is an excellent collector for both PM10 and PM2.5 filterable particulate relative to comparably sized precipitators.

Direction of Technology Development

The power industry is moving from the electrostatic precipitator particulate collector to fabric filter collectors for the majority of new installations. Air quality monitoring and opacity concerns are becoming a public issue, and the industry is responding to these issues with high-efficiency fabric filters.

This shift from precipitators to fabric filters has created a new research focus in the industry for advancements of filter media. Filter media development concentrates on restructuring, blending and coating of existing materials. Membrane-coated filter media are being developed by suppliers worldwide. Specialty filters supplied in cartridge form are commercially available, but much more development is needed. Alternative materials are being developed to improve temperature resistance and increase efficiency. Advancements in cleaning techniques are allowing for more efficient use of filter media including longer bags, which translates into fewer plan area requirements. Electrically enhanced pretreatment of filter media is one of the many advances under development.

Mercury Control

Mercury Overview

Current studies of mercury deposition in the United States indicate that 70% comes from natural sources and non-U.S. manmade emissions. Those non-U.S. anthropogenic emissions originate primarily from China and the rest of Asia. Before March 2005, coal-fired power plants were the largest unregulated anthropogenic source of domestic mercury emissions. However, they still account for less than 1% of global mercury emissions.

In 2005, the Environmental Protection Agency (EPA) proposed to reduce emissions of mercury from U.S. plants through the Clean Air Mercury Rule (CAMR), a two-phase cap-and-trade program. This program is integrated closely with other recent regulations requiring stricter sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emission reductions called Clean Air Interstate Rule (CAIR). The CAMR establishes a nationwide cap-and-trade program that will be implemented in two phases and applies to both existing and new plants. The first phase of control begins in 2010 with a 38-ton mercury emissions cap based on "co-benefit" reductions achieved through stricter SO_2 and NO_X removals. The second phase of control requires a 15-ton mercury emissions cap beginning in 2018. It has been estimated that U.S. coal-fired power plants currently emit approximately 48 tons of mercury per year. As a result, the CAMR requires an overall average reduction in mercury emissions of approximately 69% to meet the Phase II emissions cap.

In the following discussion, the term "co-benefit capture" is defined as utilizing existing environmental equipment, or equipment to be installed for future non-mercury regulation, to capture mercury. The term "active capture" is defined as installation of new equipment for the express purpose of capturing mercury.

Co-Benefit Mercury Control

Due to the large capital investments required of CAIR plants, it makes sense to take full advantage of co-benefit mercury control. Previous testing has demonstrated that various degrees of mercury co-benefit control are achieved by existing conventional air pollution control devices (APCD) installed for removing NO_X, SO_2 and particulate matter (PM) from coal-fired power plant combustion flue gas. The capture of mercury across existing APCDs can vary significantly based on coal properties, flyash properties (including unburned carbon), specific APCD configurations, and other factors, with the level of control ranging from 0% to more than 90%. The most favorable conditions occur in plants firing bituminous coal, with installed selective catalytic reduction (SCR) and wet flue gas desulfurization (WFGD), which may capture as much as 80% with no additional operations and maintenance (O&M) cost. Further R&D investments will be required to fully understand, and be able to accurately predict, co-benefit capture of mercury.

Other co-benefit mercury control technologies are being tested to enhance mercury capture for plants equipped with wet FGD systems. These FGD-related technologies include: 1) coal and flue gas chemical additives and fixed-bed catalysts to increase levels of oxidized mercury in the combustion flue gas; and 2) wet FGD chemical additives to promote mercury capture and prevent re-emission of previously captured mercury from the FGD absorber vessel. The DOE is funding additional research on all of these promising mercury control technologies so that coal-fired power plant operators eventually have a suite of control options available in order to cost effectively comply with the CAMR.

Active Capture Mercury Control

To date, use of activated carbon injection (ACI) has been the most effective near-term mercury control technology. Normally, powdered activated carbon (PAC) is injected directly upstream of the particulate control device (either an ESP or FF) which then captures the adsorbed mercury/PAC and other particulates from the combustion flue gas. Short-term field testing of ACI has been relatively successful, but additional longer-term results will be required before it can be considered to be a commercial technology for coal-fired power plants. There are issues such as the erosion/corrosion effect of long-term use of PAC (or any other injected sorbent or additive) as well as an increase in carbon content for plants that sell their fly ash or gypsum that might adversely affect its sale and lead to increased disposal costs.

Field testing has begun on a number of promising approaches to enhance ACI mercury capture performance for low-rank coal applications, including: 1) the use of chemically treated PACs that compensate for low chlorine concentrations in the combustion flue gas, and 2) coal and flue gas chemical additives that promote mercury oxidation. In order to secure the long-range operability of the existing power generation fleet, it is necessary to continue development of these advanced technologies.

Coal Combustion Products

The production of concrete and cement-like building materials is among the many beneficial reuses of coal combustion products. The use of Coal Combustion Products (CCPs) provides a direct economic benefit to the United States of more than $2.2 billion annually and a total economic value of nearly $4.5 billion each year. These findings are from a recent study published by the American Coal Council (ACC) and authored by Andy Stewart (Power Products Engineering). “The Value of CCPs: An Economic Assessment of CCP Utilization for the U.S. Economy,” details the economic value of CCPs, including:

- avoided cost of disposal
- direct income to utilities
- offsets to raw material production
- revenues to marketing companies
- transportation income
- support industries
- research
- federal and state tax revenues

CCPs, created when coal is burned in the generation of electricity, are the third-largest mineral resource produced in the United States.

Annual CCP Production

CCP	2001	2002	2003
Fly Ash	76,013,930	68,869,740	77,239,710
Bottom Ash	21,846,100	22,107,060	26,658,240
FGD Sludge	16,686,700	17,045,140	14,311,500
Gypsum	9,326,100	9,550,700	8,599,400
Other	1,164,900	957,000	1,986,780
TOTAL	**125,037,730**	**118,529,640**	**128,795,630**

Figure 1.8 Source: Federal Energy Regulatory Commission (FERC), EIA Form 767

In 2003, more than 128 million tons (mt) of CCPs were produced in the United States, predominantly fly ash, which accounted for nearly 60% of CCP production. Of the 128 mt of CCPs produced in 2003, 34 mt were utilized in value-added applications, such as cement and concrete products, highway pavement, soil stabilization and construction bedding, manufactured products and agriculture, among others. The production of CCPs has consistently outpaced utilization for the past 35 years, representing significant untapped market potential.

Future Economic Opportunity

The 94 mt of CCPs that were not utilized in 2003 were disposed of or deposited in landfills—a costly and inefficient use of land. According to the ACC study, in 2003 industry spent more than $560 million to dispose of CCPs. The cost savings of beneficial reuse—in other words, the avoided cost of disposal—totaled nearly $200 million in 2003. In addition to providing significant cost savings over landfill deposits, beneficial reuse programs produce better, more durable products and help lower the cost of electricity. This, in turn, leads to greater economic growth and prosperity, which enhances our nation's ability to steward the environment.

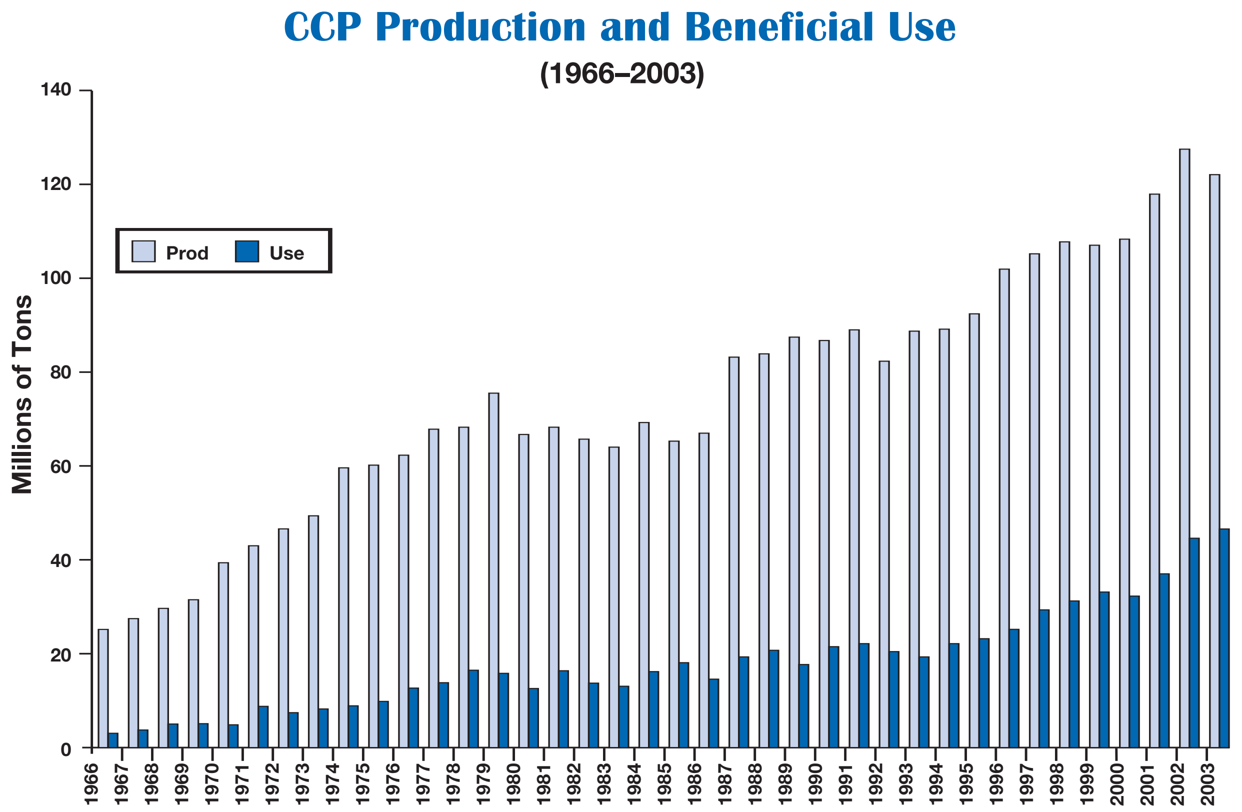

Figure 1.9 Source: American Coal Ash Association Annual Coal Combustion Product Production and Use Survey

Integrated Gasification Combined Cycle (IGCC)

Gasification of coal is a process that occurs when coal is reacted with an oxidizer to produce a fuel-rich product. Principal reactants are coal, oxygen, steam, carbon dioxide and hydrogen, while desired products are usually carbon monoxide, hydrogen and methane.

In its simplest form, coal is gasified with either oxygen or air. The resulting synthesis gas, or syngas, consisting primarily of hydrogen and carbon monoxide, is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators. By removing the emission-forming constituents from the syngas under pressure prior to combustion in the power block, an IGCC power plant can meet stringent emission standards.

There are many variations on this basic IGCC framework, especially in the degree of integration. The general consensus among IGCC plant designers is that the preferred design is one in which the air separation unit derives part of its air supply from the gas turbine compressor and a part from a separate air compressor. Since prior studies have generally concluded that 25 to 50% air integration is an optimum range, the case study in this section has been developed on that basis.

Three major types of gasification systems are used today: moving bed, fluidized bed and entrained flow. Pressurized gasification is preferred to avoid large auxiliary power losses for compression of the syngas. Most gasification processes currently in use or planned for IGCC applications are oxygen-blown instead of air-blown technology. This results in the production of a higher heating value syngas. In addition, since the nitrogen has been removed from the gas stream in an oxygen-blown gasifier, a lower volume of syngas is produced, which results in a reduction in the size of the equipment. High-pressure, oxygen-blown gasification also provides advantages when CO_2 capture is considered.

Only oxygen-blown gasification has been successfully demonstrated for IGCC. Oxygen-blown gasification avoids the large gas (nitrogen) flows and very large downstream equipment sizes and costs that air-blown gasification would otherwise impose. However, the tradeoff is that an expensive cryogenic oxygen plant is required. Pressurized oxygen-blown gasification reduces equipment sizes and enables the delivery of syngas at the specified fuel pressure required by cooling towers (CTs). Commercially, gasification pressures in IGCC range from about 400 psi to 1,000 psi depending on the process. Current entrained-flow gasification reactors have capacities of about 2000 to 2500 standard tons per day (st/d) of good quality coal. Larger coal sizes are required as coal quality decreases. While somewhat larger gasifier capacities may be possible, two gasifiers might be required for a very low-quality coal to match the syngas energy output of a single gasifier with a high-quality coal.

The gasification process also includes downstream cooling of the raw syngas in a waste heat boiler or by a water quench step. Saturated steam generated in the waste heat boiler is routed to the heat recovery steam generator of the combined cycle where it is superheated and used to augment steam turbine power generation. The steam required for gasification is also supplied from the steam circuit. Cyclones and/or ceramic, sintered metal hot filter and water scrubbing are employed for particulates removal. Water scrubbing also removes ammonia (NH_3), hydrogen cyanide (HCN) and hydrogen chloride (HCl) from the syngas. Following cooling and particulates removal, the sulfur constituents of the syngas are removed in a gas treating plant.

The overall IGCC plant efficiency is also partly determined by the gasification process and configuration selected (heat recovery and quench). The recovery of heat from the hot raw syngas in a waste heat boiler enables a higher efficiency than water quenching of the raw syngas. However, syngas cooling adds significantly to the capital cost of gasification. Syngas heat recovery is an option for all of the gasification processes.

The predominant and preferred gasification processes for good quality solid feedstocks are Shell, General Electric (GE) and ConocoPhillips. Gas entrained-flow processes, as they operate at high temperatures, achieve good carbon conversion and enable higher mass throughputs than other processes. Some entrained-flow gasification processes are also suitable for low-rank fuels, such as lignites.

Entrained-flow gasifiers that operate in the higher-temperature slagging regions have been selected for the majority of IGCC project applications. These include the coal/water-slurry–fed processes of GE. A major advantage of the high-temperature entrained-flow gasifiers is that they avoid tar formation and its related problems. The high reaction rate also allows single gasifiers to be built with large gas outputs sufficient to fuel large commercial gas turbines. Recent studies have shown that a spare gasifier can significantly improve the availability of an IGCC plant.

Coal for Gasifiers

Oxygen-blown gasifiers typically operate better with bituminous and lower volatile coal. In most gasification systems, sulfur content of the coal is only a design consideration for the sulfur-removal system and not an operating limitation on the gasifier.

The composition of coal and some of its physical properties have important influences on the gasification process. Young coals such as lignite and sub-bituminous coal generally contain a high percentage of moisture and oxygen, while old coal, such as bituminous coals and anthracite, tend to become sticky as they are heated. As a result, in the entrained flow gasifier the coal must be dried, because if the water enters the gasifier, some of it will react with CO to form hydrogen and CO_2. Moisture content has no effect on the gasification process in the fixed bed gasifier because the hot gas leaving the gasifier dries the coal as it enters the gasifier.

Since oxygen is present in the gasification process, coals containing more oxygen will need less oxygen or air to be added. For example, an E-gas gasifier system requires 2,220 tons per day of oxygen for sub-bituminous coal, 2,330 tons per day of oxygen for bituminous coal, and 2,540 tons per day for pet coke. The oxygen in coals is particularly important in air-blown gasification as any oxygen in the coal will reduce the amount of air required for the gasification reaction and thereby reduce the resulting nitrogen in the syngas.

Mercury Control with Gasification

Mercury control from coal gasification is applied to the syngas before it is burned, resulting in a significant volumetric reduction from handling flue gas.

For entrained flow systems, essentially all of the mercury in the coal will be present in the syngas. Since syngas volume is considerably less than flue gas, mercury removal systems greater than 90% can be relatively easily applied to the syngas stream.

IGCC OPERATIONS

Owner	Location	Gasification Technology	Syngas Output (MWth)*	Online Year	Feedstock	Products
Sasol-II	South Africa	Lurgi Dry Ash	4,130	1977	Subbit. coal	FT liquids
Sasol-III	South Africa	Lurgi Dry Ash	4,130	1982	Subbit. coal	FT liquids
Repsol/Iberdrola	Spain	GE Energy	1,654	2004a	Vac. residue	Electricity
Dakota Gasification Co.	U.S.	Lurgi Dry Ash	1,545	1984	Lignite res & ref	Syngas
SARLUX srl	Italy	GE Energy	1,067	2000b	Visbreaker res	Electricity & H_2
Shell MDS	Malaysia	Shell	1,032	1993	Natural gas	Mid-distallates
Linde AG	Germany	Shell	984	1997	Visbreaker res	H_2 & methanol
ISAB Energy	Italy	GE Energy	982	1999b	Asphalt	Electricity & H_2
Sasol-I	South Africa	Lurgi Dry Ash	911	1955	Subbit coal	FT liquids
Total France/ edf / GE Energy	France	GE Energy	895	2003a	Fuel oil	Electricity & H_2
Shell Nederland	Netherlands	Shell	637	1997	Visbreaker res	H_2 & electricity
SUV/EGT	Czech Republic	Lurgi Dry Ash	636	1996	Coal	Elec. & steam
Chinese Pet Corp	Taiwan	GE Energy	621	1984	Bitumen	H_2 & CO
Hydro Agri Brunsbuttel	Germany	Shell	615	1978	Hvy Vac res	Ammonia
Global Energy	U.S.	E-gas	591	1995	Bit. coal/ pet coke	Electricity
VEBA Chemie AG	Germany	Shell	588	1973	Vac residue	Ammonia & methanol
Elcogas SA	Spain	PRENFLO	588	1997	Coal & pet coke	Electricity
Motiva Enterprises	U.S.	GE Energy	558	1999b	Fluid pet coke	Electricity
API Raffineria	Italy	GE Energy	496	1999b	Visbreaker res	Electricity
Chemopetrol	Czech Republic	Shell	492	1971	Vac. residue	Methanol & ammonia
NUON	Netherlands	Shell	466	1994	Bit. coal	Electricity
Tampa Electric	U.S.	GE Energy	455	1996	Coal	Electricity
Ultrafertil	Brazil	Shell	451	1979	Asphalt res	Ammonia
Shanghai Pacific	China	GE Energy	439	1995	Anthracite coal	Methanol & town gas
Exxon USA	U.S.	GE Energy	436	2000b	Pet coke	Electricity & syngas
Shanghai Pacific Chemical Corp	China	IGT U-Gas	410	1994	Bit. coal	Fuel gas & town gas
Gujarat National Fertilizer	India	GE Energy	405	1982	Ref. residue	Ammonia & methanol
Esso Singapore	Singapore	GE Energy	364	2000	Residual oil	Electricity & H_2
Quimigal Adubos	Portugal	Shell	328	1984	Vac residue	Ammonia

Figure 1.10

Integrated Gasification Fuel Cell Systems

Fuel cells make it possible to generate electric power with high-efficiency, environmentally benign conversion of fuel to electric energy. If the fuel cells are fueled on syngas from coal, the United States can achieve energy security by using an indigenous fuel source and producing clean-high-efficiency power. Many countries globally, including the United Kingdom, Italy, Germany and Japan, are promoting the development of high-temperature fuel cells for distributed generation and central power.

Fuel cells are electrochemical devices that convert chemical energy in fuels into electrical energy directly. This technology generates electric power with high thermal efficiency and low environmental impact. Unlike conventional power generation technologies (e.g., boilers and heat engines), fuel cells do not produce heat and mechanical work and are not constrained by thermodynamic limitations. Since there is no combustion in fuel cells, power is produced with minimal pollutants. Operation of fuel cells on syngas from gasified coal is the ultimate goal of the U.S. Department of Energy's Solid State Energy Conversion Alliance (SECA) program. This program extends coal-based solid oxide fuel cell technology for central power stations to produce affordable, efficient, environmentally friendly electricity from coal.

In general fuel cells are capable of processing a variety of fuels. The Department of Energy in August 2005 selected the first two projects under the Department's new Fuel Cell Coal-Based Systems program. The projects will be conducted by General Electric Hybrid Power Generations Systems and Siemens Westinghouse Power Corporation. Each team will develop the fuel cell technology required for central power stations to produce affordable, efficient, environmentally friendly electricity from coal. This coal-based solid oxide fuel cell technology will be applied to large central power generation stations.

Planar SOFC Cell Configuration

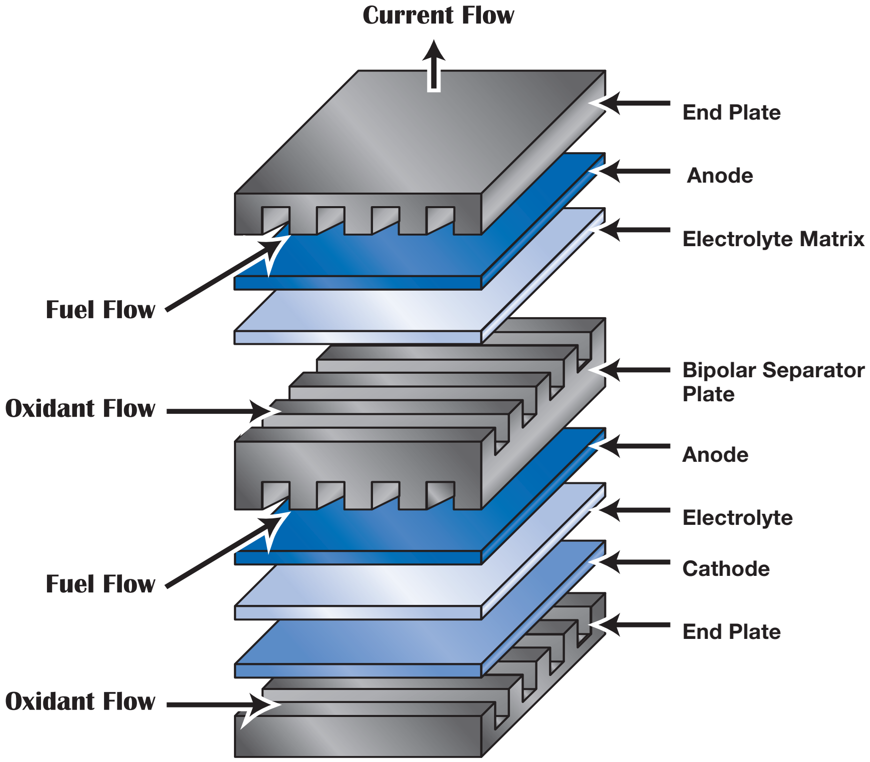

Figure 1.11

The Fuel Cell Coal-Based Systems program is expected to become a key enabling technology for FutureGen. The two teams will demonstrate fuel cell technologies that can support power generation systems larger than 100 MW capacity. Key system requirements to be achieved include:

- 50% plus overall efficiency;
- capturing 90% or more of the carbon dioxide emissions; and
- a cost of $400 per kilowatt, exclusive of the coal gasification unit and carbon dioxide separation subsystems.

Projects will be conducted in three phases. During Phase I, the teams will focus on the design, cost analysis, fabrication and testing of large-scale fuel cell stacks fueled by coal synthesis gas. The Phase I effort is to resolve technical barriers with respect to the manufacture and performance of larger-sized fuel cells. To conduct Phase I, each team is awarded $7.5 million. The duration of Phase I is 36 months.

Phases II and III will focus on the fabrication of aggregate fuel cell systems and will culminate in proof-of-concept systems to be field-tested for a minimum of 25,000 hours. These systems will be sited at existing or planned coal gasification units, potentially at the DOE's FutureGen facility.

SOFC Fuel Cell-Gas Turbine Hybrids

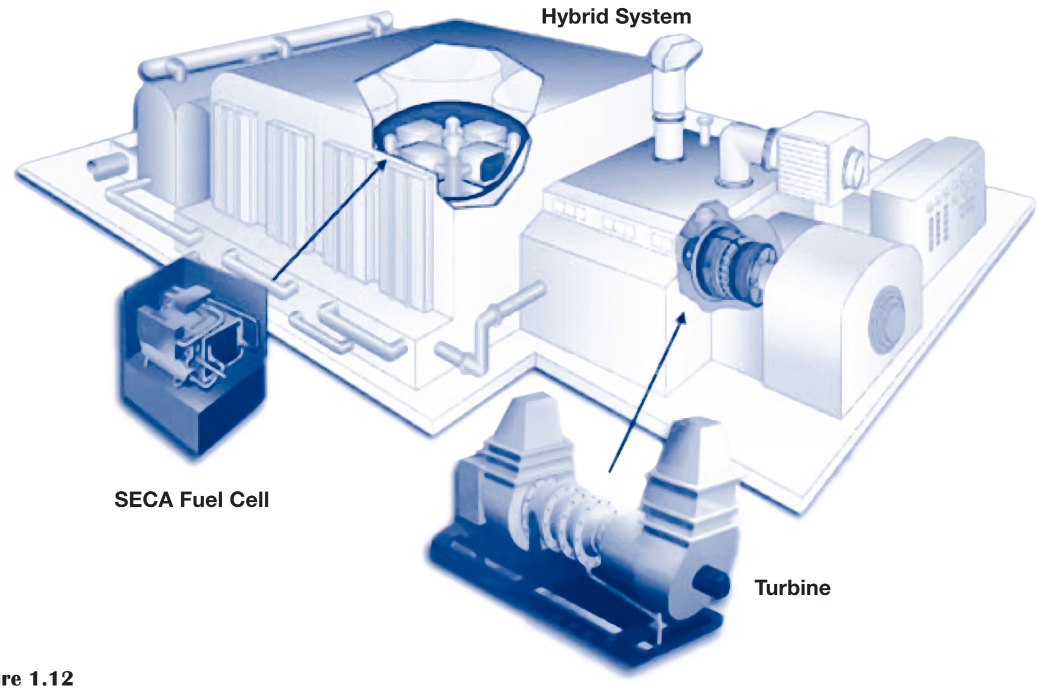

Figure 1.12

Solid Oxide Fuel Cell Coal-Based Power Systems

General Electric Hybrid Power Generation Systems will partner with GE Energy, GE Global Research, the Pacific Northwest National Laboratory and the University of South Carolina to develop an integrated gasification fuel cell system that merges GE's SECA-based solid oxide fuel cell, gas turbine and coal gasification technologies. The system design incorporates a fuel cell/turbine hybrid as the main power generation unit.

Siemens Westinghouse Power Corporation is partnering with ConocoPhillips and Air Products and Chemicals Inc. to develop large-scale fuel cell systems based on their in-house gas turbine and SECA-modified tubular solid oxide fuel cell technology. ConocoPhillips will provide gasifier expertise, while the baseline design will incorporate an ion transport membrane (ITM) oxygen separation unit from Air Products.

CO_2 Overview

Over the last three decades, utilities have implemented emission control equipment to control NO_X, SO_2 and particulate emissions on a large number of coal-fired boilers resulting in significantly improved air quality. Additionally, great progress is being made toward development of low-cost controls for mercury emissions. Public policy dictating reduction of greenhouse gas (GHG) emissions will pose the next major environmental challenge.

Oxyfuel

Of the 325,000 MW of coal-fired power capacity currently in the U.S. generation, which is just over half of the power generated annually, about 90% is provided by pulverized coal combustion. Technologies that can be retrofitted into some of the plants of the existing fleet will have the potential for greater impact on GHG reduction than those requiring construction of new plants. If public policies require GHG emission reductions, oxyfuel combustion is expected to be applicable to the existing pulverized coal plants as well as new pulverized coal plants. For new plants, optimization is anticipated to result in significant improvements in efficiency and reduction in cost.

Technical Description

In a conventional coal-fueled power plant, coal is combusted with air to produce heat and generate steam that is converted to electricity by a turbine-generator. As a result, the flue gas streams are diluted with large quantities of nitrogen from the combustion air. Air contains 78% nitrogen; only the oxygen in the air is used to convert the fuel to heat energy.

In the oxyfuel power plant, combustion air is replaced with relatively pure oxygen. The oxygen is supplied by an on-site air separation unit, with nitrogen and argon being produced as byproducts of the oxygen production. In the oxyfuel plant, a portion of the flue gas is recycled back to the burners and the nitrogen that would normally be conveyed with the air through conventional air-fuel firing is essentially replaced by carbon dioxide by recycling the carbon dioxide. This results in the creation of a flue gas that is a concentrated stream of carbon dioxide and other products of coal combustion, but no nitrogen. This concentrated stream of carbon dioxide is then compressed for transportation and storage in geologic formations.

Advanced processes are also being developed that would reduce the amount of flue gas recycled in an effort to reduce parasitic power. Optimization of the process is also under development, such as integration of the power required by the CO_2 compression train and perhaps the air separation equipment. Process integration has the potential to increase efficiency and reduce cost.

Performance

Current designs suffer considerable degradation in heat rate (i.e., fuel consumption), due to the high power requirement of the cryogenic air separation unit and for compression of the concentrated CO_2 stream to transport for storage. To satisfy these additional parasitic power requirements, the power plant heat rate is estimated to increase to about 12,000 Btu/kWh, resulting in a reduction in net plant efficiency to about 28%. However, potential reductions through development of membrane oxygen separation technologies and increased steam temperature boilers offer potential to decrease heat rate to perhaps 9,800 Btu/kWh HHV (35% net efficiency) or better, which would be about the same as the average coal-fired fleet efficiency in the U.S. today.

Cost

The production of a concentrated stream of CO_2 is a key to enabling storage from fossil power plants. Many technologies are being investigated to facilitate the production of a concentrated CO_2 stream from coal-fired power plants including advanced amine flue gas scrubbing, and oxyfuel combustion. The quality and quantity of economic analyses for these technologies is quite limited. All capture technologies are significantly more costly than conventional pulverized coal combustion and no clear economic winner has yet emerged. Of the options, amine scrubbing and oxygen combustion also provide the opportunity for retrofit onto the existing fleet as well as for new green-field or brown-field plants.

In an oxyfuel plant, the impact on the boiler island is minimal. In fact, as the quantity of flue gas recycled is reduced, the boiler island cost reduces as well. By far, the largest costs are in the air separation unit and CO_2 cleaning and compression train.

Direction of Technology Development

Several engineering studies of both retrofit and new oxyfuel designs have been made and limited pilot scale testing has been completed. Many major equipment manufacturers have completed a significant amount of pilot testing. The next logical step is a small-scale demonstration under utility conditions. Such a demonstration would aid in identifying technology areas for further development and reveal the means of integration and opportunities for significant cost reduction.

Several studies are still needed. These include: plant optimization incorporating an ultra-supercritical boiler, reduction of the quantity of recycle gas, integration of the power requirements for the compression train and lower cost, lower power oxygen production methods.

Proposed Solution Pathways

Reducing or offsetting CO_2 emissions from fossil fuel use is the primary purpose of the new suite of technologies called carbon dioxide capture and storage (CCS). Carbon dioxide can be captured directly from the industrial source, then concentrated into a nearly pure form and stored in geological formations far below the ground surface. Carbon dioxide capture and storage is a four-step process. After the CO_2 is separated from the flue gas, it is compressed to about 100 bars, where it is in a liquid phase. Next, it is put into a pipeline and transported to the location where it is to be stored. Pipelines transporting CO_2 for hundreds of kilometers exist today. The last step is to inject it into the medium in which it will be stored.

CO_2 can be injected into deep underground formations such as depleted oil and gas reservoirs, brine-filled formations or deep unmineable coal beds. This option is in practice today at three industrial scale projects and many smaller pilot tests. At appropriately selected storage sites, retention rates are expected to be very high, with CO_2 remaining securely stored for geologic time periods that will be sufficient for managing emissions from combustion of fossil fuels. The potential storage capacity in geological formations is somewhat uncertain, but estimates of worldwide storage capacity in oil and gas fields range from 900 to 1,200 billion tonnes of CO_2 and the estimated capacity in brine-filled formations is expected to be much greater. The U.S. is estimated to have a very large capacity to store CO_2 in oil fields, gas fields and saline formations, sufficient for the foreseeable future.

Three industrial-scale CCS projects are operating today. Two of them are associated with natural gas production. Natural gas containing greater than several percent CO_2 must be “cleaned up” to pipeline and purchase agreement specifications. The first of these projects, the Sleipner Saline Aquifer Storage Project, began nearly 10 years ago. Annually, 1 million tonnes of CO_2 are separated from natural gas and stored in a deep sub-sea brine-filled sandstone formation. The In Salah Gas Project in Algeria began in 2004 and is storing 1 million tonnes of CO_2 annually in the flanks of a depleting gas field. The third industrial-scale CCS project, located in Saskatchewan, Canada, uses CO_2 from the Dakota Gasification Plant in North Dakota to simultaneously enhance oil production and store CO_2 in the Weyburn Canadian Oil Field. Depending on the generation technology, 1,000 MW coal-fired power plants may emit from 6 million tonnes to 10 million tonnes/year of CO_2. These are a greater volume than the existing capture and storage projects, but experience suggests that capture and storage of this magnitude should be possible.

Cost of CO_2 Capture and Storage Is a Significant Barrier to Deployment

Estimated additional costs for generating electricity from a coal-fired power plant with CCS range from $20 to $70/tonne of CO_2 avoided, depending mainly on the capture technology and concentration of CO_2 in the stream from which it is captured. While this metric may be useful for comparing the cost of CCS with other methods of reducing CO_2 emissions, the increase in costs of electrical generation may be a more meaningful metric. Costs would increase from $0.02/kWh to $0.05/kWh, depending on the generation technology and baseline.

Capture and compression typically account for over 75% of the costs of CCS, with the remaining costs attributed to transportation and underground storage. Pipeline transportation costs are highly site-specific, depending strongly upon economy of scale and pipeline length.

In addition to the high cost of CCS, the loss of efficiency associated with capture and compression is high. The post-combustion, “end-of-pipe” capture technologies use up to 30% of the total energy produced, thus dramatically decreasing the overall efficiency of the power plant. Oxy-combustion has a similarly high energy penalty, although eventually, new materials may lower the energy penalty by allowing for higher temperature and consequently more efficient combustion. Pre-combustion technologies are estimated to require from 10 to 15% of energy output, leading to higher overall efficiency and lower capture costs.

Public and privately sponsored research and development programs are aggressively working to lower the costs of CO_2 capture. The U.S. Department of Energy has a cost goal of $10/tonne CO_2. This challenging target is likely to be hard to meet without significant advances in separations technology, including membrane separators and new absorbents. Recent outreach efforts by the Department of Energy and the National Academy of Sciences are tying to engage academic researchers with new ideas in these areas.

At first glance, CO_2 capture and storage in geological formations may appear to be a radical idea that would be difficult and perhaps risky to employ. Closer analysis, however, reveals that many of the component technologies are mature. A great deal of experience with gasification, CO_2 capture and underground injection of gases and liquids provides the foundation for future CCS operations.

No doubt, challenges lie ahead for CCS. The high cost of capture, the large scale on which geological storage may be employed, and adapting our energy infrastructure to accommodate CCS are significant hurdles to overcome. But none of these seem to be insurmountable, and progress continues through continued deployment of industrial-scale projects, research and development, and growing public awareness of this promising option for lowering CO_2 emissions.

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COAL-TO-LIQUIDS

Background

Processes for producing liquid fuels from coal can be grouped into categories of pyrolysis, solvent extraction, catalytic liquefaction and indirect liquefaction. Pyrolysis involves the heating of the coal feedstock to high temperatures to convert the coal into gases, liquids and char. Carbon is removed from the process, increasing the content of hydrogen in the gaseous product, while light and heavy liquids contain less hydrogen than crude oil. Solvent extraction uses a coal-derived liquid that transfers hydrogen to the coal, increasing the yield of liquid hydrocarbons. Catalytic liquefaction adds hydrogen to coal with the aid of a suitable catalyst operating in the liquid phase. Indirect liquefaction first reacts coal with oxygen and steam to produce carbon monoxide and hydrogen. These gases are purified to remove sulfur, nitrogen and ash and are then reacted in the presence of a catalyst to produce liquid products.

These liquefaction products have been used as transportation fuels for over 50 years. This process is an increasingly attractive alternative as conventional, petroleum-derived fuels become less available and more expensive.

Indirect Liquefaction for Transportation Fuels

The Fischer-Tropsch (FT) from coal is well-understood chemistry, discovered in 1923 by the German scientists Hans Fischer and Franz Tropsch. Today it is commercially used by Sasol South Africa, whose facilities produce over 160,000 barrels per day of transportation fuels, including diesel, gasoline and jet fuels. With changing petroleum and energy economics there are several projects under development in the United States. The projected first to be on line will be the Rentech conversion of the Royster-Clark facility in East Dubuque, Illinois. This facility will be on-stream in early 2009, producing about 250,000 gallons of ultra-clean FT diesel fuel per day, some of which could be sold to the Department of Defense for testing in jet engines and ground vehicles. The remainder will go to transit fleets, agriculture cooperatives and Mississippi River transport. Coal-to-transportation fuels is proven technology with a long history, and the fuels that are produced have favorable characteristics and high value. The fuels are ultra-low sulfur, ultra-low aromatics, high-cetane and biodegradable and are very stable, with a shelf life of over eight years.

History of Commercial Indirect Liquefaction

Germany began the commercialization of indirect liquefaction in the 1930s as a means to produce fuel for the German military in World War II. After WWII the technology was further developed by the U.S. government and Texaco, who together built and operated a plant in Texas until the early 1950s. It was eventually shut down due to the relative economics with petroleum products.

In the 1960s, South Africa was facing restrictions on imported oil due to apartheid, and they turned to a national energy policy that would push for energy independence by using domestic resources of coal. They committed large government resources to build coal gasification and high-temperature Fischer-Tropsch facilities that continue to operate today, producing nearly 200,000 barrels per day. These facilities were provided to Sasol, which develops and operates projects based on their technology and experience throughout the world. In 1981, a small start-up company in Denver called Rentech, Inc., was formed and began research and development of a low-temperature Fischer-Tropsch technology. Rentech, Inc., is leading the deployment of the low-temperature, high-efficiency technology in the United States today and has plans for their first commercial plant to come online in 2009.

In summary, Fisher-Tropsch chemistry has been understood since 1923. The first commercial facilities were built in the 1930s, and Sasol has operated commercially since the early 1960s. Commercial facilities with high-efficiency, low-temperature FT technology are being planned for start up in the United States in 2009.

Review of Coal-to-Liquids Technologies

Coal-to-liquids (CTL) is the process of converting solid coal into liquid fuels and/or chemicals. This section of this report focuses on the conversion of coal-into-liquid transportation fuels. The key to converting coal-into-liquid fuels is hydrogen. Coal typically contains only 5% hydrogen, while distillable liquid fuels typically contain 14% hydrogen. The hydrogen deficit can be made up in two different ways. In the direct route, hydrogen is forced into the coal under high pressure and temperature often in the presence of a catalyst. In the indirect route, coal is gasified with oxygen and steam to produce a synthesis gas (syngas) containing hydrogen and carbon monoxide that is then passed over a catalyst to form hydrocarbons.

There are several additional routes to making transportation fuels from coal. Direct and indirect coal liquefaction can be integrated into a hybrid plant. Direct coal liquefaction can be combined with heavy oil upgrading in a coal and oil co-processing plant. Finally, coal can be partially converted into liquid fuels by mild pyrolysis.

Direct Coal Liquefaction

In the direct coal liquefaction process, pulverized coal is slurried with a recycled oil and heated under high pressure to produce a synthetic crude oil that can be further refined into ultra-clean transportation fuels. The hydrogen required for this process can be produced by gasifying coal and residual carbon or reforming natural gas.

Historical Development

Direct coal liquefaction originated in Germany in 1913, based on work by Friedrich Bergius. It was used extensively by the Germans in World War II to produce high octane aviation fuel. Since that time, tremendous advancements have been made in product yields, purity and ease of product upgrading.

Following the petroleum price and supply disruptions in 1973, the U.S. government began a substantial program to fund the development of alternative fuels, particularly direct coal liquefaction. From 1976 to 2000, the U.S. government invested approximately $3.6 billion (1999 dollars) on improving and scaling up direct coal liquefaction. Early direct liquefaction processes used single-stage reactor configurations. This was replaced by two-stage configurations to achieve higher efficiency of hydrogen utilization. Process equipment and operating conditions were optimized, online hydrotreating and solvent de-ashing were added, and improved catalysts were developed. Pilot and demonstration facilities ranging up to 600 tons per day of coal (1800 bbl/d of fuel oil) were built and operated in the United States.

Following is a partial list of direct coal liquefaction technologies developed during the last half of the twentieth century. Most of these technologies are no longer under development.

Single-Stage Direct Coal Liquefaction Processes

Process	Developer, Country
Kohloel	RAG/Veba Oel, Germany
NEDOL	NEDO, Japan
H-Coal	HRI (predecessor of HTI) USA
Solvent Refined Coal (SRC-I and SRC-II)	Gulf Oil, USA
Conoco Zinc Chloride	Conoco, USA

Figure 2.1

Two-Stage Direct Coal Liquefaction Processes

Process	**Developer**
HTI Coal Process or Catalytic Multi-Stage Liquefaction (CMSL)	DOE and HTI (subsidiary of Headwaters, Inc.), USA
Catalytic Two-Stage Liquefaction (CTSL)	DOE and HRI (predecessor of HTI), USA
Liquid Solvent Extraction (LSE)	British Coal Corp., UK
Brown Coal Liquefaction (BCL)	NEDO, Japan
Lummus Integrated Two-Stage Liquefaction (ITSL)	Lummus, USA
Chevron Coal Liquefaction (CCLP)	Chevron, USA
Kerr-McGee ITSL	Kerr-McGee, USA
Consol Synthetic Fuel (CSF)	Consol, USA
Mitsubishi Solvolysis	MHI, Japan
Pyrosol	Saarberwerke, Germany
Close-Coupled Two-Stage Liquefaction (CC-TSL)	Amoco, USA
Supercritical Gas Extraction (SCE)	British Coal Corp., UK

Figure 2.2

A report was issued in July 2001 by the U.S. Department of Energy summarizing the results of its direct coal liquefaction development program. Following are excerpts from the conclusion of that report:

> *"The DOE direct liquefaction program produced a surprisingly mature technology. The intensive effort between 1976 and 1982 (Phase I), when 90% of the program funds were expended, resulted in a demonstration of the technical feasibility of the major process components. The Phase I processes, however, were deficient in terms of product yield and quality. This stimulated further research and development work between 1983 and 1999 (Phase II). The Phase II work was significantly less costly than earlier demonstration projects, but resulted in substantial improvements in process performance and economics. It now is possible to produce liquids of high quality at high yields that approach the theoretical maximum. At the same time, the cost for a barrel of product dropped by 50% because of process optimization and increased yields. Economics and engineering studies conducted throughout Phase II have reduced the uncertainty, and therefore, the risk associated with commercial deployment of the technology.*
>
> *"The current technology is well defined in terms of cost and performance. It represents a technically available option for the production of liquid fuels. It can be used domestically in the United States to limit our exposure to oil price increases in the international market or to offset supply reductions. It also can be used by other nations who choose to use domestic coal to meet their transportation fuel needs, thus reducing demands on conventional petroleum sources. It can be used with coal alone, or to co-process a variety of lower value feedstocks. The results of the DOE program allow direct coal liquefaction to be accurately assessed in context to the costs and risks associated with other options for securing liquid fuel supplies should the need arise."*

Current Commercial Activity

In 1996, the DOE received an inquiry from the Chinese government asking for information on the most advanced direct coal liquefaction available in the United States. The DOE recommended the HTI Coal Process and introduced HTI to the Chinese in December of that year. The Chinese government put direct coal liquefaction into its five-year plan and commissioned Shenhua Group (the largest coal company in China) to develop a direct coal liquefaction project in Inner Mongolia, China.

Shenhua Group studied all of the commercially available direct coal liquefaction technologies from the United States, Japan and Germany and in June 2002 signed a license agreement with HTI to apply HTI's technology for the first stage of a 50,000 bbl/d project. A process design package was supplied by HTI and engineering was proceeding; however, Shenhua Group wanted to make some modifications to the technology contrary to the advice of HTI. After further negotiation, a new agreement was drafted and signed that allowed Shenhua to use and modify HTI's technology for the first-stage of the 50,000 bbl/d project. Shenhua paid HTI the full license fee for the technology applied to the first-stage and released HTI from any process performance guarantees.

In October 2004, HTI signed an agreement with Oil India Ltd. (OIL) to conduct testing and a feasibility study for a commercial plant in the Assam state of India. The Assam coal is some of the best coal for direct coal liquefaction because of its high reactivity and yield. Lab-scale tests have been completed and pilot plant testing commenced in late 2005.

In February 2005, HTI signed a memorandum of understanding with the Philippines Department of Energy to evaluate applying direct and/or indirect coal liquefaction in the Philippines. The Philippines' government has placed high priority on coal liquefaction and desires to make that country the hub for the coal liquefaction industry in Southeast Asia. The first stage of the feasibility study was completed in September 2005.

Process Description

Coal is a solid organic material made up of large, complex molecules containing mostly carbon, plus small amounts of hydrogen, sulfur, nitrogen and oxygen. Raw coal also contains moisture and solid particles of mineral matter (ash). The aim of direct coal liquefaction is to break coal down into smaller component molecules, then to add hydrogen, creating lighter and more stable oil molecules. The process simultaneously removes sulfur, nitrogen and ash, resulting in a clean liquid fuel product.

Typical Direct Coal Liquefaction Process

In a typical direct coal liquefaction process, pulverized coal is dissolved in recycled coal-derived heavy process liquid at about 170 bar and 425°C while hydrogen is added. Most of the coal structure is broken down in the first-stage reactor. Liquefaction is completed in the second-stage reactor, at a slightly higher temperature and lower pressure. A proprietary catalyst is dispersed in the slurry for both stages. A hydrotreater is incorporated in the process to remove sulfur and nitrogen and open up the aromatic structure to achieve higher cetane levels, thereby facilitating the downstream refining process. The bottom-of-the-barrel residue (material boiling above 455°C) is de-ashed and recycled as heavy process liquid. The ash reject, containing residual carbon, can be fed to the gasifier for use in production of hydrogen.

Indirect Coal Liquefaction

Indirect coal liquefaction involves first the gasification of coal to produce synthesis gas, followed by purification to remove CO_2 and other contaminants, and then the conversion of the synthesis gas to liquid products using the Fischer-Trospch synthesis process and associated product upgrading.

Historical Development

Indirect coal liquefaction was developed in Germany in 1923 based on work by Dr. Franz Fischer and Dr. Hans Tropsch. During World War II, the technology was used by Germany to produce 17,000 bbl/d of liquid fuels from coal.

After the war, the Fischer-Tropsch synthesis technology was used by HRI (predecessor of HTI) to construct a 7,000 bbl/d gas-to-liquids plant in Brownsville, Texas, in 1949. The plant was operated by Cathage Hydrocol from 1950 to 1953 before shutting down due to declining oil prices. The partial oxidation unit, used to convert the natural gas into synthesis gas to feed the fixed-bed FT reactors at this plant, was the basis for what eventually became the Texaco coal gasification process currently owned by GE Energy.

During this same time period (1950–53), Koelbel tested a 1.5 meter diameter slurry-phase FT reactor in Rheinpreussen, Germany. By the mid-1950s, all of the German FT plants were shut down due to declining world oil prices with discovery of abundant oil deposits in the Middle East.

While other countries were shutting down their FT plants, South Africa began commissioning its first indirect coal liquefaction plant. Sasol was established in 1950 with the prime objective to convert low-grade coal into petroleum chemicals and feedstocks. Sasol One was built in Sasolburg and produced its first liquid product in 1955. In 1969 the Natref crude oil refinery was commissioned, and in 1980 and 1982, Sasol Two and Sasol Three respectively began production in Secunda. Today, Sasol produces the equivalent of 150,000 bbl/d of fuels and petrochemicals from coal via the indirect liquefaction process. The process produces in excess of 40% of South Africa's liquid fuel requirements. Sasol manufactures more than 200 fuel and chemical products in Sasolburg and Secunda in South Africa, as well as at several global locations.

The FT reactors installed in 1995 at Sasol One consisted of five tubular fixed-bed reactors with a capacity of 500 bbl/d each, and three circulating fluidized-bed reactors having a capacity of 2,000 bbl/d each. In 1980/1982, Sasol installed 16 x 6,500 bbl/d circulating fluidized-bed reactors at Secunda. From this engineering effort, it became clear that the circulating fluidized-bed technology had reached its maximum scale-up potential. A new generation 3,500 bbl/d (5-m diameter) fluidized-bed reactor was installed at Sasolburg in 1989. This led to the further scale-up to an 11,000 bbl/d (8-m diameter) reactor in 1995 and the 20,000 bbl/d (10.7-m diameter) reactor in 1998. Between 1995 and 1998, the 16 original circulating-fluidized-bed reactors at Secunda were replaced with 4 x 11,000 bbl/d and 4 x 20,000 bbl/d fluidized-bed reactors. Sasol's total capital investment for indirect coal liquefaction from 1955 to 2000 exceeded $6 billion.

Interest in gas-to-liquids for monetizing stranded natural gas reserves has influenced most major oil companies to invest billions of dollars (combined) in developing their own FT technology. Following is a list of FT technologies that have reached at least the process development unit (PDU or large pilot-plant scale).

FT Technologies

Licensor	Reactor	Catalyst	Scale-Up Status
Sasol, South Africa	Fluidized Bed and Slurry	Fe & Co	150,000 bbl/d CTL plants 30,000 bbl/d GTL plant
Shell, Netherlands	Fixed Bed	Co	12,500 bbl/d GTL plant
Statoil, Norway	Slurry	Co	1000 bbl/d GTL plant
ConocoPhillips, USA	Slurry	Co	400 bbl/d GTL demo
BP, UK	Fixed Bed	Co	300 bbl/d GTL demo
ExxonMobil, USA	Slurry	Co	300 bbl/d GTL demo
Rentech, USA	Slurry	Fe	235 bbl/d GTL demo
Syntroleum, USA	Fixed Bed	Co	70 bbl/d GTL PDU
Axens/ENI, France/Italy	Slurry	Co	20 bbl/d GTL PDU
Institute of Coal Chemistry, China	Slurry	Fe	20 bbl/d CTL PDU

Figure 2.3

Most of the above companies are focused only on gas-to-liquids (GTL) rather than coal-to-liquids (CTL). The noticeable exceptions are Sasol, Rentech Incorporated and the Institute of Coal Chemistry, which are active in CTL. Shell is constructing a biomass-to-liquids (BTL) pilot plant in Freiberg, Germany. Iron or cobalt catalyst can be used for indirect coal liquefaction, but iron catalyst offers an advantage in that it can operate with a lower H_2/CO ratio typically found in coal-derived syngas.

Current Commercial Activity

Major oil companies are currently spending, or planning to spend, in excess of $25 billion on gas-to-liquids facilities in remote areas such as Qatar, Iran, Nigeria, Bolivia and Australia. Commercial activity on indirect coal liquefaction projects has been less dramatic but is gaining momentum.

In 2004, Sasol reached agreement with the government of China to conduct a feasibility study on two 70,000 bbl/d indirect coal liquefaction projects in China sponsored by Shenhua Group, Luneng Coal Chemicals, Ningxia Coal Group and Sinopec. In July 2004, Yankuang Group started up a 480 bbl/d demo plant. The Institute of Coal Chemistry announced that it is planning to set up a 3,900 bbl/d demo plant in China. And in August 2005, HTI announced signing a license with UK RACE Investment Limited for setting up a 700 bbl/d demo plant in China.

Indirect coal liquefaction projects are also being studied in Australia, Indonesia, India, Pakistan and the Philippines. The United States has several indirect coal liquefaction projects under consideration. Following is a list of those that have been discussed publicly.

U.S. Indirect Coal Liquefaction Projects

State	Developers	Coal Type	Capacity (bbl/d)
AZ	Hopi Tribe, Headwaters	Bituminous	10,000–50,000
MT	State of Montana	Sub-bit./Lignite	10,000–150,000
ND	GRE, NACC, Falkirk, Headwaters	Lignite	10,000–50,000
WY	DKRW Energy	Bituminous	33,000
WY	Rentech Sub-bit./Pet Coke	Mississippi	10,000–50,000
IL	Rentech	Bituminous	2,000
PA	WMPI	Anthracite	5,000
WV	Mingo County	Bituminous	10,000

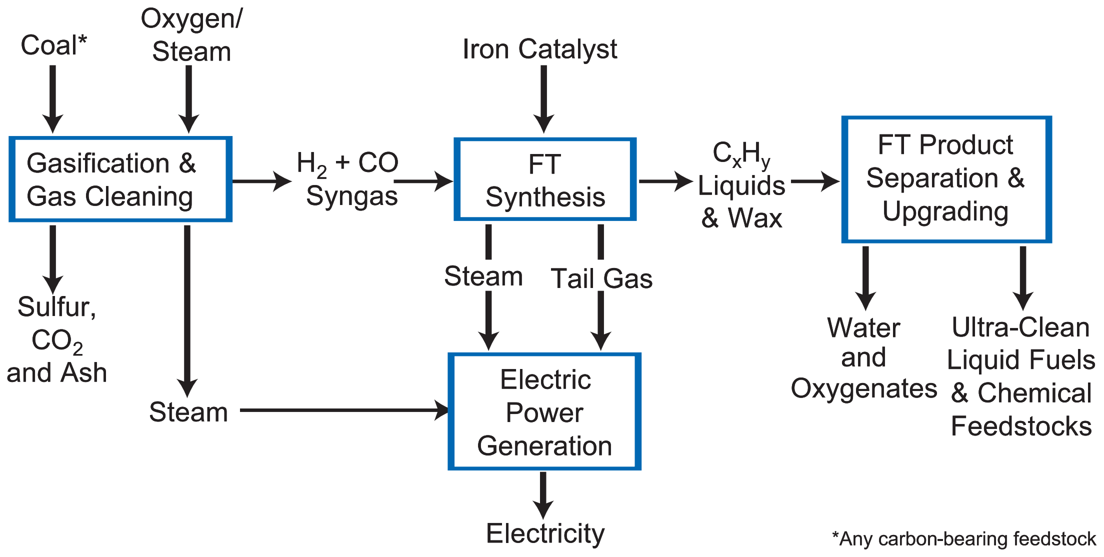
Figure 2.4

The Rentech projects in Illinois and Ohio involve coal-based integrated FT fuel and ammonia production. A preliminary feasibility study has been completed on the Illinois project, and the first phase of front end engineering and design (FEED) has begun. Most of the projects will involve production of some electricity as well as FT diesel and FT naphtha.

Process Description

Indirect coal liquefaction can operate on nearly any coal feedstock as long as the proper gasification and gas cleaning technology are selected. Selection of the proper coal gasification technology is critical because it has perhaps the biggest impact on the overall project cost.

Typical Indirect Coal Liquefaction Process



*Any carbon-bearing feedstock

Figure 2.5 Source: NCC Working Group, September 2005

In the gasification process, coal is partially oxidized with oxygen and steam to form carbon monoxide and hydrogen rich syngas. The raw syngas is cooled and cleaned of carbon dioxide and other impurities such as hydrogen sulfide, ammonia, halogens, cyanide and mercury. The H_2/CO ratio of the syngas may be adjusted for optimum FT performance. As the clean syngas passes through the FT reactor, it comes in contact with a proprietary catalyst and forms long-chain paraffin hydrocarbons ranging from C1 to C100+ along with some oxygenates such as water and alcohols. The tail gas can be recycled or sent to a gas turbine to generate electricity. The oxygenates and distillable liquids are separated through fractionation. The wax and catalyst are separated through settling and filtration. The wax is sent to a hydrocracker, where it is converted into distillable liquids using a catalyst and hydrogen. The distillable liquids are hydrotreated and separated by fractionation into finished products such as FT diesel and FT naphtha. The oxygenates can be used as feedstock for the gasifier or combusted to produce electricity. The steam generated from cooling the syngas and from cooling the exothermic reactions in the FT reactor can be sent to a steam turbine to generate additional electric power.

Comparison of Direct and Indirect Coal Liquefaction

Figure 2.6 compares typical product characteristics for direct and indirect coal liquefaction products. One of the biggest differences between the two coal liquefaction technologies is that direct coal liquefaction makes high-octane gasoline and low-cetane diesel, while indirect coal liquefaction produces high-cetane diesel and low-octane gasoline. One other difference is that direct coal liquefaction products are denser and therefore tend to have more Btus per gallon than indirect coal liquefaction products.

Final Product* Comparison

Type of Coal Liquefaction	Direct	Indirect
Distillable product mix	65% diesel/35% naphtha	82% diesel/18% naphtha
Diesel cetane index	42–47	70–75
Diesel sulfur	<5 ppm	<1 ppm
Diesel aromatics	4.8 wt%	<4 wt %
Diesel specific gravity	0.865	0.780
Naphtha octane (RON)	>100	45–75
Naphtha sulfur	<0.5 ppm	nil
Naphtha aromatics	5 wt %	2 wt %
Naphtha specific gravity	0.764	0.673

Figure 2.6

*After hydrotreating

Hybrid Coal Liquefaction

Hybrid coal liquefaction integrates direct and indirect coal liquefaction into a single plant. This concept takes advantage of the complementary characteristics of the two processes. As mentioned above, direct coal liquefaction makes high-octane gasoline and low-cetane diesel, while indirect coal liquefaction produces high-cetane diesel and low-octane gasoline. Blending the products in an integrated plant allows production of premium quality gasoline and diesel with minimal refining.

Historical Development

The concept of a hybrid DCL/ICL plant has been discussed for many years. The U.S. Department of Energy commissioned MITRE Corporation to study the concept between 1990 and 1991. Initial studies indicated that production costs were slightly lower for a hybrid plant compared to standalone direct or indirect plants. No testing has been done on this concept to date.

Current Commercial Activity

HTI signed two license agreements in August 2005 with UK RACE Investment Limited for two 700 bbl/d plants to be built in China. The first plant will be an indirect coal liquefaction plant, and the second plant will be a direct coal liquefaction plant and will be integrated into the first plant to demonstrate the hybrid concept.

A feasibility study for a 60,000 bbl/d hybrid plant is currently being conducted in the Philippines by HTI in cooperation with private and government entities.

Process Description

The synergy between the direct and indirect processes improves overall thermal efficiency of an integrated hybrid plant. Higher-quality coal can be fed as feedstock to the direct coal liquefaction reactors, and lower-quality coal can be fed to the gasifier to provide syngas for FT synthesis. The hydrogen-rich FT tail gas can be used to provide hydrogen for product upgrading and for direct coal liquefaction.

Typical Hybrid Coal Liquefaction Process

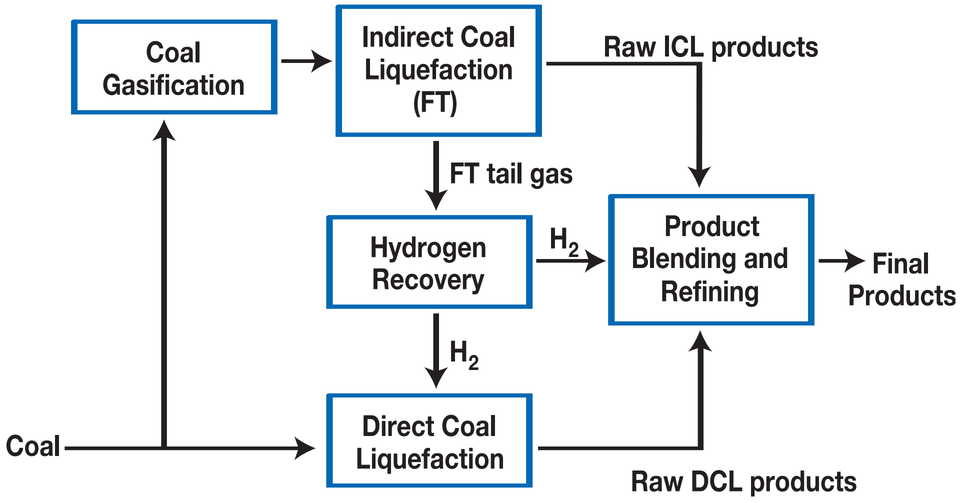


Figure 2.7

Blending the raw distillable products prior to refining takes advantage of their complementary characteristics. High-octane naphtha from direct coal liquefaction is blended with low-octane naphtha from indirect coal liquefaction and high-cetane diesel from indirect coal liquefaction is blended with low-cetane diesel from direct coal liquefaction. The blended liquids require less refining to meet premium product specifications than if they were refined separately.

Co-Processing Coal and Heavy Oil

Co-processing of coal and heavy oil is worth considering if there is a low-cost source of heavy oil such as bottom-of-the-barrel resid from a local refinery. The aim of co-processing coal and heavy oil is to simultaneously break down the complex coal and heavy petroleum molecules into smaller distillable molecules, which can be further refined into clean liquid fuel products.

Co-processing can be technically and economically more appealing than direct coal liquefaction because it eliminates the need for recirculating a large stream of internally generated process-derived liquids and lowers the required capital and operating cost. However, co-processing production costs may be higher than direct coal liquefaction production costs if the resid is significantly more expensive than coal on an energy basis.

Historical Development

Co-processing was first tested in 1974 at HRI (now HTI) test facilities in Lawrenceville, New Jersey. Bench-scale tests were conducted on a wide range of materials in the early to mid-1980s. In 1989, tests were run on Ohio coal and Cold Lake resid in the 30 bbl/d process development unit. In the 1990s, co-processing tests were run for customers in Nova Scotia, China, India and Indonesia. A co-processing pilot plant was built in Duliajan, Assam, India, in 1994.

Process Description

In co-processing, a preheated mixture of pulverized coal, catalyst, resid (may also contain a small amount of recycle liquid) and hydrogen is fed into the first of two reactors at a temperature of 435°–460°F and pressure of 170 bars. Most of the coal and resid structure is broken down in the first-stage reactor. Hydrocracking of the intermediate coal and resid products is completed in the second-stage reactor. The distillable products pass through a mild hydrotreater and then further upgraded using conventional refining techniques to produce gasoline, as well as jet and diesel fuels that will meet or exceed existing and planned fuel specifications.

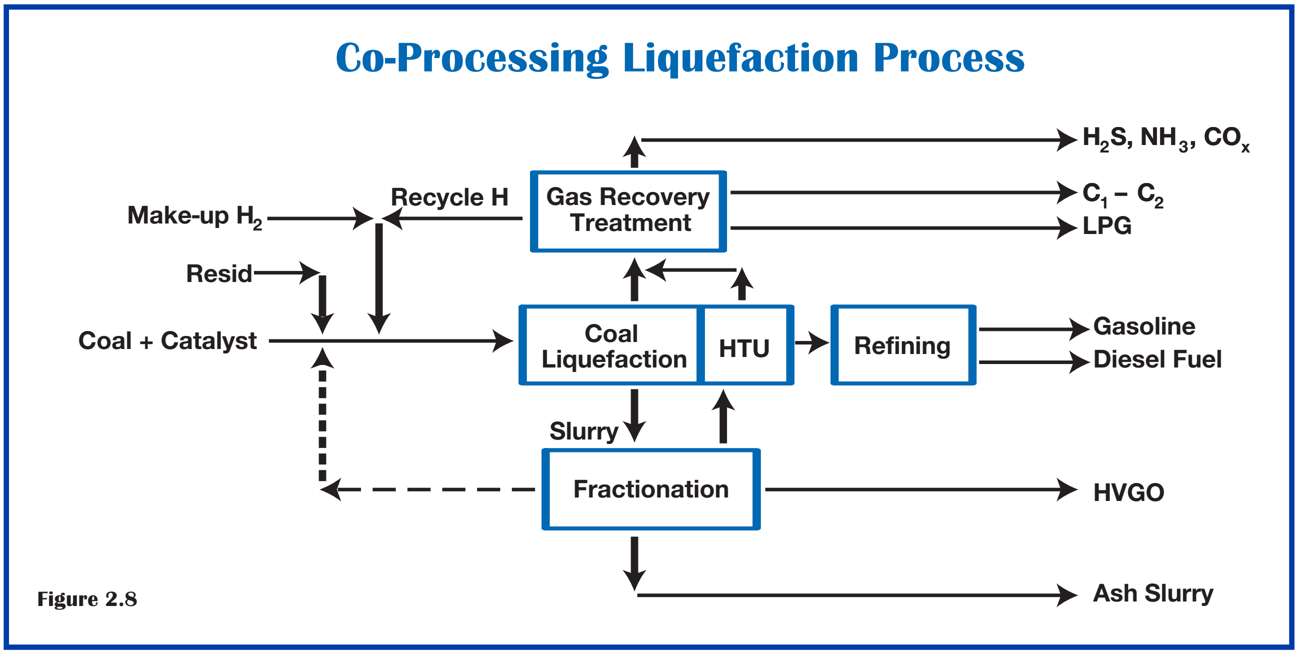

Co-Processing Liquefaction Process

Figure 2.8

Mild Pyrolysis

Mild pyrolysis is a method of obtaining liquid fuels from coal by heating the coal in an oxygen-free atmosphere, vaporizing the volatile material, and then condensing out the hydrocarbon liquids from the product vapors. This technique is perhaps the oldest method of extracting liquid fuels from coal, but yields and product quality are very low.

Historical Development

At least three mild pyrolysis technologies were developed to pilot-plant scale in the United States in the 1980s. The processes differed mainly in the design of the pyrolyzing reactor. One process, the liquids from coal (LFC) process, was scaled up to a 1,000 stpd demo plant in 1992. The LCF process was developed by SGI International. The demo plant was built in Gillette, Wyoming and owned by Encoal Corporation. Funding was provided by the U.S. Department of Energy Clean-Coal Technology Demonstration Program. The plant operated up and down for a few years before shutting down. The plant has changed ownership several times since starting up.

Process Description

Mild pyrolysis favors use of high-volatile coals. It consists of heating coal to a temperature in the range of 450°–650°C in an oxygen-free atmosphere, driving off volatile matter from the coal, generating other volatile organic compounds, and condensing out the distillable liquids. Liquid yield is typically less than 20%. The main product is char with a reduced hydrogen, sulfur and nitrogen content.

Typical Mild Pyrolysis Process

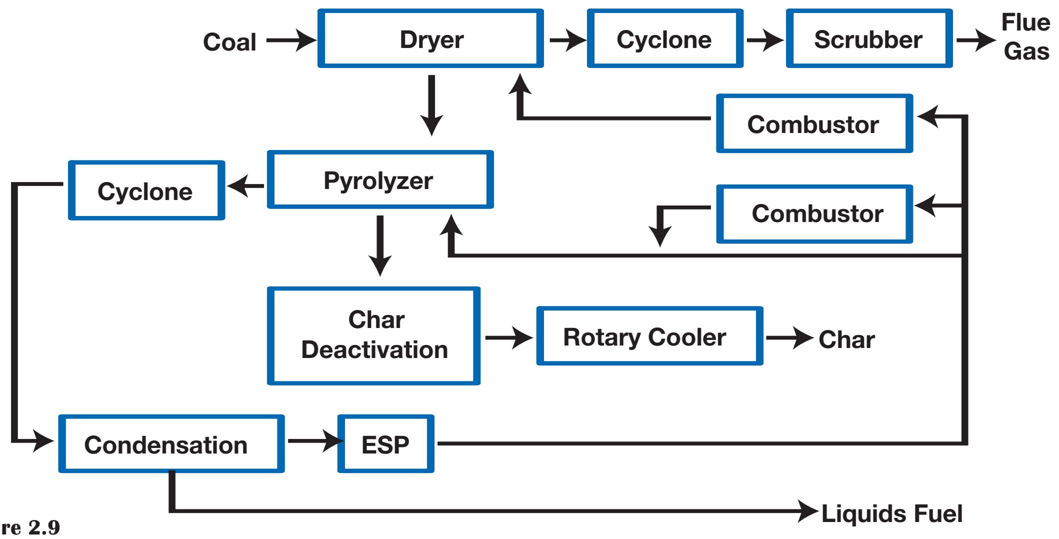


Figure 2.9

In a typical mild pyrolysis process, coal is crushed and screened and then heated by a hot gas stream in a rotary-grate dryer. The dried coal is then fed into the main rotary-grate pyrolyzer, where it is heated to about 540°C by a hot recycle gas stream. Upon discharge from the pyrolyzer, the solids are passed to a deactivation step and are then cooled in an indirect rotary drum cooler. The gas from the pyrolyzer is cooled in a quench tower condensing out the distillable liquids. The gases are then recycled to provide fuel for the process. The liquid fuel produced in this process is roughly equivalent to a No. 6 fuel oil.

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AN OVERVIEW OF THE
NATURAL GAS SITUATION

Conventional natural gas (NG) production in the United States is in significant decline, leading to supply and deliverability issues, higher prices and increasing dependence on foreign sources. These problems will become far more serious as domestic supplies continue to decline and NG demand increases. LNG presents the same economic cost and national security problems as imported oil. Using coal to produce NG and as replacement for NG in chemical processes would ease supply pressures by providing an alternative to at least 15% of America's annual NG consumption, or the equivalent of 4 trillion cubic feet (Tcf) per year. This additional supply would moderate NG prices and use an additional **340 million tons** of coal per year. The NG made available could be used for residential, commercial, industrial and any other application that uses NG. The amount is roughly equal to EIA's projection of LNG imports in 2025.

World Consumption and Competition

Natural gas is projected to be the world's most rapidly growing primary energy source over the next several decades. The EIA has estimated that NG consumption will increase over 75% from 2000 to 2025. These data show the steady rise in NG consumption:

Actual and Projected World NG Consumption
(1980–2025)

Year	Tcf
1980	53
2000	88
2010	111
2025	156

In short, the global demand for NG is a steady drumbeat growing louder with each passing year. Further, this demand will not be evenly distributed. The emerging and transitional economies of the world will steadily increase their demand for NG in direct competition with the United States (see Figure 3.1).

Examples of Demand Growth in Emerging Economies (Tcf)

Region/Country	2000	2025	% increase
China	0.9	6.5	600
India	0.8	2.8	250
South Korea	0.7	1.9	171
Mexico	0.9	3.0	233
Middle East	6.8	16.6	144

Figure 3.1 Source: EIA International Energy Outlook 2004 and 2005

For the United States, this international competition for NG will mean a new era in energy geopolitics. Not long ago, the United States and the former Soviet Union (FSU) more or less stood alone on the NG stage, but the world is changing:

Consumption of the World's NG (%)

Year	United States	FSU	Rest of World
1980	38	25	37
2000	26	25	49
2010	23	23	54
2015	22	23	55
2025	19	21	60

Figure 3.2 Source: Compiled from EIA/DOE Reports; International Energy Outlook 2005

Thus, the estimated global reserve of six thousand Tcf not withstanding, it is clear that the demand for NG will stimulate international competition for a diminishing resource. In fact, this competition is already under way as offshore drilling rigs leave the Gulf of Mexico in response to higher dayrates in foreign markets—the Far East, Saudi Arabia and West Africa—prompting the CEO of Rowan Drilling to comment on the Gulf situation: "rigs are going to get pulled out of here…I mean, people are bidding all over the world." As of November 2005, at least eight jackups were scheduled to leave the Gulf in 2006—out of a fleet of only 103. Clearly, a new day is dawning for the international competition for NG.

Strong U.S. Demand for NG

For decades, NG has been an important source of energy in the United States, consistently meeting over one-fifth of demand, from 23% in 1985 to 24% in 2000 to a projected 21% in 2025. But although overall NG use is expected to remain steady on a relative basis, the manner of that use is changing dramatically. Figure 3.3 shows how consumption of NG is changing by sector, especially in regard to electric power generation.

Projected Growth in Demand (Tcf)

	Year		
Consumption by Sector	**2004**	**2015**	**2025**
Residential	4.88	5.36	5.57
Commercial	3.00	3.36	3.77
Industrial	7.41	8.08	8.51
Electric Power	5.32	7.14	7.05
Lease/Pipe/Other	1.78	1.89	1.97
TOTAL	**22.39**	**25.83**	**26.87**

Figure 3.3 Source: EIA Annual Energy Outlook 2006, Reference Case

In fact, the role of NG in producing electricity is going through a major transition. In 1990, NG provided 13% of generation in the United States, but by 2015 NG is expected to provide 22%.

Electric Generation Provided by NG

Year	NG as Source of Electric Generation (%)
1990	13
2000	16
2004	21
2015	22
2025	20

Figure 3.4 Source: Compiled from EIA Annual Reports; Annual Energy Outlook 2006

Buildout of Demand Infrastructure

During the current decade, a confluence of overly optimistic supply and price projections, modified environmental regulations, changing regulatory conditions and simple convenience has led to an unprecedented buildout of NG-based power plants. For example, it is estimated that from 2000 to 2009, over 300 GW of new electric generation capacity will be constructed in the United States, of which more than 88% will be NG-based. While over 70 GW of coal-fired units are planned, most will not come on line for over a decade, forcing NG units to meet a large share of incremental electricity demand for the next 10 to15 years.

Moreover, the demand for electricity is projected to increase steadily for the foreseeable future. The EIA has projected that electricity use will grow from 3,729 billion kWh in 2004 to 5,208 billion kWh in 2025—an increase of 40%.

Clearly, despite the questions about price and supply of NG, we continue to increase our dependency on our most volatile and costly source of supply. In fact, some states are rapidly developing an overwhelming dependence on NG-fired generation during periods of greatest demand.

Figure 3.5 details states that are increasingly dependent on NG for generation at peak periods. Each of these states—representing a population of over 108 million—had to rely on NG for at least 40% of electricity during the July 2005 heat wave, despite record prices.

States Particularly Dependent on NG During Peak

State	Net Generation (Thousand MWH)	Generation (Thousand MWH)	Net NG-based % NG-Fired July, 2005	State Populations (Millions)
TX	41,502	23,340	56	22.5
CA	21,001	11,265	54	35.5
MA	4,975	2,648	53	6.4
LA	9,243	4,917	53	4.5
OK	7,801	4,181	53	3.5
NV	4,016	2,057	51	2.2
MS	5,844	2,735	47	2.9
FL	23,739	9,916	42	17.0
AZ	10,874	4,507	41	5.6
NJ	7,018	2,800	40	8.7
USA	**403,702**	**100,577**	**25**	**108**

Figure 3.5 Source: Compiled from EIA reports on electricity generation

In general, these states and a number of others have few options but to turn to NG during periods of peak load. Coal and nuclear are generally at full capacity as baseload facilities, hydro is geographically limited and oil capacity has been greatly reduced over the past several decades.

The Vulnerabilities of NG Policy and Supply

Given the importance of electricity in American society, the ever-growing dependence on NG for generation raises special concern that supply be adequate and prices remain stable. By 2005, it had become apparent that there were significant flaws in the U.S. NG supply system:

- By August 2005, the wellhead price of NG had reached $7.65, which was a 43% increase over August 2004.
- Year-over-year production through August had **decreased** by 1.5%, despite a near-record number of drilling rigs in the field.
- September/October required a Henry Hub price of over $12.00 to assure adequate storage for the upcoming winter.

While there may be a tendency to blame our NG problems solely on the hurricanes of 2004 and 2005, it is clear that there were problems in price and production long before Hurricanes Ivan, Rita and Katrina hit shore. Over the past decade the United States has greatly suffered from our general inability to more accurately predict production and, to an even greater extent, price. Much of the problem emerges from the ever-optimistic view on NG production that has prevailed in governmental and industry circles for over a decade.

Reversing course from the 1970s and 1980s, by the late 1990s energy analysts were convinced that the United States had enough NG to fuel the economy for decades to come. The National Petroleum Council's report on natural gas summed up the consensus view:

> *"…the resource base exists to support the indicated levels of future demand [26.5 Tcf in 2005] and…the additional supply required can be brought to market at competitive prices…"*
> (NPC, 1999)

In the Annual Energy Outlook (AEO) for 1996, the EIA projected a steady increase in the growth of domestic NG production. In reality, however, the EIA projected production has been below actual production in every single year, and the discrepancy has increased over time. In fact, for the first six years of this decade, during which over 200,000 MW of NG power plants were being constructed, the 1996 EIA report overestimated production by a total of 7.29 Tcf, or 7,290 bcf.

Furthermore, the EIA was not an outlier in these optimistic projections. Other industry experts made even loftier predictions of NG production. Optimistic statements were regularly made by the American Gas Association, National Petroleum Council, Gas Research Institute and *Oil and Gas Journal.* This optimism relating to NG production prevailed at EIA through 2002 when the AEO projected:

> *"Growing numbers of new wells (will) increase natural gas production…Conventional onshore natural gas production is projected to grow rapidly in the last 20 years of the forecast."*

By 2004, however, geological reality had set in. Since then, optimistic production estimates have given way to acceptance of the grim facts of depletion:

> *"With increasing rates of production decline… A significant increase in conventional natural gas production is no longer expected."* (EIA, AEO, 2004)

In fact, it is now generally accepted that first-year decline rates in conventional NG wells in North America has approached 30%, necessitating the drilling of thousands of wells each year merely to maintain existing production. The problem of depletion is exemplified in three key areas of traditional NG supply for the United States: the Gulf of Mexico, Texas and Canada.

Declining Production in the Gulf of Mexico

In 2000, the Gulf of Mexico (GOM) accounted for 24% of NG production in the United States. Depletion and the exodus of major oil companies, however, have taken a toll:

Declining Production in Gulf of Mexico

Year	GOM Production (bcf)	Y/Y Decline %
2001	5,028	—
2002	4,511	10
2003	4,406	2
2004	3,979	10

Figure 3.6 Source: Compiled from EIA Annual Reports

As the data in Figure 3.6 indicate, production in the GOM declined steadily over 2001 to 2004 by 1,049 bcf, or 21%. By 2004 the GOM accounted for only 20% of U.S. production. Further, data from January 2005 indicate this decline is continuing as a further 17 bcf (5%) that Ivan-adjusted drop occurred relative to January 2004. Given the recent drilling patterns in the GOM, it is likely this decline will continue. In 2001 there were 153 rigs drilling in the GOM, and by 2003 that number had decreased to 108. By November 2005, it had slipped to 73.

Stagnation in Texas

Texas has been a mainstay of NG production in the United States and in 2004 accounted for 27% of output, but there are significant indications that depletion is beginning to take a toll on Texas production. NG fields in Texas are susceptible to significant decline rates. EOG, Inc., has pegged the overall first-year decline rate for new wells at 30%. Actual production data from Texas starkly indicate the treadmill facing the NG industry:

NG Production in Texas vs. Producing Wells

Year	NG Production (bcf)	Producing Wells	Production per Well (bcf)
1970	9,450	23,417	.403
1980	6,998	37,345	.187
1990	5,533	49,989	.111
2000	5,645	60,486	.093
2002	5,611	65,686	.085
2004	5,874	69,964 (e)	.084 (e)

Figure 3.7 Source: Compiled from EIA Annual Reports and the Texas Railroad Commission

In other words, it took three times as many wells in 2004 to produce 62% of the NG produced in Texas in 1970. These data give real meaning to the oft-repeated maxims "treadmill" and "the lowest fruit has already been picked." The downtrend continues; preliminary data from the Texas Railroad Commission indicate that 71,440 wells as of February 2005 could not stem a production decline of over 12% when compared to February 2004 rates.

Canada Has Its Own NG Problems

Canada is unlikely to alleviate NG supply problems in the United States, since Canada faces the same supply issues that plague the United States—namely, depletion. In terms of depletion, First Energy (2004) has estimated annual decline rates for western Canadian NG fields:

Western Canadian NG Decline Rate

Year	Decline Rate for Underlying Production (%)
1991	7
1995	14
1998	18
2001	19
2004	21

Figure 3.8 Source: First Energy, 2005

Actual production data provide strong evidence of these decline dates. In 2002, there were 9,061 NG wells drilled in Canada and production was 17.4 bcf/d. In 2004, there were 16,000 wells drilled and production was also 17.4 bcf/d. In other words, an increase of 6,939 (77%) wells from 2002 to 2004 was only able to keep production flat. In examining the NG situation, Canada's National Energy Board (2005) concluded:

- Despite robust drilling, Canadian NG production is expected to remain flat.
- While NG production has flattened, demand has increased, largely due to oil sands operation where demand could soon reach over one bcf per day.
- Demand from NG-fired generation in Canada is also increasing and may accelerate even further due to closure of coal-fired generation in Ontario.

This situation is especially important since Canada has been the overwhelming source of NG imports to the United States. In 1993, for instance, Canada accounted for 86% of U.S. NG imports, and by 2003 that figure was 87%. The Canadian safety net has been crucial as our own NG production declined and demand ramped up.

Unfortunately, based on EIA forecasts, the days of increasing NG imports from Canada appear to be over:

NG Imports from Canada (Tcf)

Year	Imports from Canada
1990	1.4
1995	2.8
2000	3.5
2004	3.6
2010	2.3
2025	1.2

Figure 3.9 Source: EIA Annual Reports: Annual Energy Outlook 2006, Reference Case

In essence, the rise in Canadian imports in the 1990s appears to have peaked, and reduced imports are projected, with a decline of 2.3 Tcf (65%) from 2000 to 2025 and beyond.

Economic Impacts of Rising NG Prices

Increased demand from the electric power sector, coupled with decreased NG production, has led to competition for NG within the U.S. economy. Residential, commercial, industrial and electrical demand has created an internecine competition for NG resulting in steadily higher NG prices. Wellhead prices per mcf have increased from $2.95 in 2002 to $5.49 in 2004 to over $8.00 in January 2006.

Higher NG prices have several major effects on the economy. First, escalating prices directly increase home heating bills, which acts as a tax on consumers and crowds out expenditures on other items in the consumers' budget, such as consumer durables and other forms of discretionary spending.

The second major impact involves inflation. Higher natural gas prices increase the costs of production electricity and other natural gas intensive commodities, such as fertilizers, glass and metals. These price increases then set off a round of cost-push inflation that reverberates through other sectors of the economy. Higher price inflation leads to higher interest rates, which diminish investment in plants and equipment. With lower real income and higher costs, employers reduce their demand for labor and employment drops.

Moreover, additional output and employment losses may occur if higher natural gas prices reduce the international competitiveness of the industrial base. Such an outcome has severe consequences for the manufacturing base of the United States, where over 3.1 million jobs were lost from 2000 to 2005 alone. Figure 3.10 shows the price increases in NG since 2000 to industrial consumers:

Industrial NG Prices

Year	Cost to Industrial Users (per mcf)
1999	3.12
2000	4.45
2001	5.24
2002	4.02
2003	5.81
2004	6.43
2005	7.92 *

* through October 2005

Figure 3.10 Source: EIA Annual Reports and Short-Term Energy Outlooks

Thus, the increase for price to industrial customers from 1999 to 2005 price was $4.80 per mcf, or 154%. These increases have had a steadily expanding adverse impact on the manufacturing sector and have removed both **competitiveness** and **stability** from the industrial planning process regarding the commodity.

The U.S. Department of Commerce Economics and Statistics Administration (ESA) recently estimated the magnitude of these economic impacts from rising natural gas prices. Using an inter-industry model of the U.S. economy, the ESA simulated how the economy would have performed if natural gas had not increased so dramatically from 2000 to 2004. Specifically, they conducted a simulation of the economy with natural gas prices only 60% of actual natural gas prices for each year from 2000 through 2004.

During the first two years, ESA found the growth in real gross domestic product is 0.2 percentage points lower in each year, representing a cumulative loss in economic output of roughly $40 billion. According to the ESA study, on average between 2000 and 2004, annual total civilian employment was 489,000 lower due to higher natural gas prices. Manufacturing jobs comprised about 16% of that loss, or about 79,000 jobs per year. These output and employment losses are compounded with the additional natural gas price increase during 2005.

Another concern with higher natural gas prices is that manufacturers would decide to shift production and investment capital to foreign countries with lower natural gas prices. The evidence for this activity, however, is more difficult to establish. What is known is that U.S. manufacturing firms invested about $28 billion abroad in 2003, representing 17% of capital spending in this sector. The impact of higher natural gas prices on these decisions must be examined on a case-by-case basis. Apart from these macroeconomic investment data, the case for a loss in competitiveness of U.S. chemical industries to Middle Eastern producers with very cheap natural gas is compelling, especially since most new chemical production capacity is going into that part of the world.

Impacts on Industry

The economic activity of the U.S. industrial sector is critical to the success of the entire U.S. economy. This sector provides the goods and materials that are used throughout the remainder of the economy to provide the quality of life that Americans have come to expect.

The industrial sector as a whole used approximately 25 Quads (quadrillion Btu) of energy in 2001 (neglecting energy losses experienced in energy generation and transmission). The source of this energy is shown in Figure 3.11.

Net Industrial Energy Use

Energy Source	Quads Used	% of Total
Gaseous Fuels	8.75	35
Petroleum	8.75	35
Electricity	3.50	14
Coal-Derived	2.25	9
Renewables	1.75	7
TOTALS	**25.00**	**100**

Figure 3.11

Energy in the industrial sector is used in two ways. The bulk of the energy, approximately 70% (17.5 Quads), is electricity or fuels burned to generate the heat and power needed in industrial processes. The remainder of the energy is used as a raw material to produce products such as polymers, petrochemicals, agricultural chemicals and fertilizers and lubricants and waxes.

Industrial Technology Program “Industries of the Future”

In the early 1990s, the U.S. DOE designated the nine most energy-intensive industry sectors as “Industries of the Future” (IOF). Since then, this concept has been incorporated under a broader Industrial Technologies Program (ITP), but the IOF classification is useful for discussing industrial energy use. The nine industries included in the IOF designation—agriculture, aluminum, chemicals, forest products, glass, metal casting, mining, petroleum refining and steel—account for approximately 67% of industrial energy consumption. Under this effort, a number of specific programs were established to support research, development, demonstration projects and best-practice adoption within these sectors in an attempt to reduce the energy intensity of production and improve the bottom line of companies operating in these industry sectors. According to the ITP website, recent tracking results indicate that the ITP’s projects have cumulatively saved over 1.6 quadrillion (10^{15}) Btu—valued at about $6.5 billion.

The profile of energy consumption within the IOF sectors is shown in Figure 3.12. The IOF sectors represent the materials and basic manufacturing portion of the U.S. industry.

IOF Energy Use

Sector	Residual Fuels	Distillate Fuels	Natural Gas	LPG, NGL	Coal-Derived	Net Electric	Other	Total Net Use
Agriculture	0	339	77	221	0	221	14	1,072
Mining (Including Oil and Gas)	5	262	1,268	0	77	355	631	2,598
Aluminum	0	1	189	1	1	246	3	441
Chemicals	50	9	1,984	51	284	602	749	3,729
Forest Products	152	21	659	9	279	327	1,825	3,272
Glass	3	0	194	1	0	54	2	254
Steel	29	5	456	0	48	163	971	1,672
Petroleum Refining	70	4	948	33	0	123	2,300	3,478
Metal Casting	0	1	136	2	0	63	31	233
TOTALS	**309**	**642**	**5,911**	**318**	**689**	**2,154**	**6,526**	**16,749**

Figure 3.12 Source: Taken from "Profile of Total Energy Use for U.S. Industry," Energetics, Inc. for the U.S. DOE, 12/04. LPG/NGL = Liquefied Petroleum Gas/Natural Gas Liquids. Table does not include energy sources used as raw materials.

Even in the absence of the data in the table, it could be expected that the energy use patterns between these industry sectors would vary dramatically, given the wide range of manufacturing operations represented. For example, electrical consumption varies from a low of ~3.5% to nearly 56% among these sectors, and other fuels vary from less than one percent to over 66%. However, gaseous fuel consumption (represented by natural gas, LPG and NGL) is the one energy source that finds consistently significant use across all the IOF Sectors, as shown in Figure 3.13.

Gaseous Fuel Intensity

Percent of Total Energy Consumption

All IOF Sectors	Agr.	Mining	Alum.	Chem.	F.P.	Glass	Steel	Pet. Ref.	M.C.
37.1	27.7	48.8	43.1	54.6	20.4	76.8	27.3	28.2	61.9

Figure 3.13 Source: Taken from "Profile of Total Energy Use for U.S. Industry," Energetics, Inc. for the U.S. DOE, 12/04.

It should be remembered, however, that energy consumption as fuels represents only 70% of industrial energy use. The use of "energy" (natural gas, petroleum) as a raw material represents 30% of the industrial energy use, and nearly all of this energy use occurs in chemical and petroleum refining sectors. A first approximation is that the chemical sector uses gaseous raw materials and the petroleum sector liquid-based raw materials. Using this assumption, approximately 40% of the raw material "energy" used in the industrial sector is in the form of natural gas-like materials, or 12% of the total energy use. As a result, it is safe to assert that nearly 50% of the energy used in IOF sectors is represented by gaseous fuels and, consequently, nearly 50% of industrial energy consumption might be derived from coal-generated synthesis gas that could be burned as fuel or converted to hydrocarbon raw material streams through various catalytic processes.

The nine IOF industries account for approximately 67% of this energy use. Fifty percent of the energy used in these sectors is estimated to be from gaseous sources, such as natural gas, liquefied petroleum gas (LPG) and natural gas liquids (NGL).

Two Industries at Risk: Chemical and Glass

Based on data from the "Energy Use, Loss and Opportunities" report prepared by Energetics and E3M, Inc., two primary conclusions can be drawn:

- The chemical sector usage of gaseous materials accounts for 74% of its energy.
- In the glass sector, more than 76% of the energy consumed is in the form of natural gas.
- A brief discussion of these two industries provides insights into the problems they encounter with escalating NG prices.

The Chemical Industry

It has been well documented that increasing NG prices have hit the chemical industry particularly hard. Chemical manufacturers use about 12% of the NG in the United States in a full range of processes from heating to power to feedstock.

Further, the chemical industry is an important component of the nation's economy, since, in addition to using 12% of United States' NG, the industry:

- directly employs almost 900,000 people;
- generates more than $500 billion for the economy;
- is the leading American export industry;
- is America's second largest rail shipper; and
- accounts for one of 8 new patents.

With substantial increases in the price of NG, however, chemical companies have been forced to make significant changes in their operation to compete on a global basis. Dow Chemical has been forthright about the steps it has taken to adjust to the increase in NG prices. Since 2002, Dow has:

- shifted some production to such countries as Kuwait, Argentina, Malaysia and the Netherlands, where energy prices are more competitive;
- eliminated 6,500 jobs;
- announced plans to build major new production facilities in Oman (2004), Kuwait (2005) and China (2005); and
- closed production facilities throughout the United States including Texas (four), Michigan, West Virginia (two), New Hampshire, New Jersey (two), and Kentucky.

Dow's actions are representative of the trend in the industry. An analysis by *Business Week* revealed that of 120 large-scale chemical plants being built throughout the world, only **one** is being built in the United States. The U.S. Department of Labor has summarized the vulnerability of the chemical industry in the United States:

> *"Foreign competition has been intensifying [in] the chemical industry…rapidly expanding foreign production capabilities should intensify competition…shifting operations to locations in which the costs are lowest. U.S. companies are expected to move some production activities to developing countries—three in East Asia and Latin America, for example…"*

Accordingly, the Department of Labor projects that the chemical industry will lose as many as 200,000 jobs by 2012.

The Glass Industry

Although each of these nine IOF sectors is under severe competitive pressures, none is under more stress from escalating energy prices than the glass industry, where more than 75% of the energy input is in the form of NG. Even at $3.50 per mcf, the industry was paying 15% of its total manufacturing costs for energy. With January 2006 NG prices over $8.00 per mcf, energy costs may exceed 20% of manufacturing costs. Before these rapidly increasing energy costs, job losses resulting from decisions with at least a partial energy component were estimated to be 10% of the glass workforce nationwide. The current costs of NG are almost certain to spur an additional round of energy-related plant closures in the glass industry.

The glass industry is divided into four sectors. Container glass, the largest sector in tons, includes all glass packaging products. The flat glass sector is principally made up of window glass, but also includes architectural and decorative glass panels. The glass fiber sector produces fine strands of glass for textile and glass wool insulation applications. The specialty material sector includes glass applications including lighting, tableware, optics, optical wave guides, stepper cameras for integrated circuits and others.

According to the U.S. Census Bureau, the cumulative sales of the glass industry in the United States were about $27 billion in 2003. The industry employed approximately 126,000 in 2003, with an overall payroll of approximately $5 billion. This nearly $40,000 per year salary is above average for U.S. industry. The nature of the glass industry in the United States has changed in recent years. Originally, the vast majority of domestic glass facilities were owned by U.S. companies. A growing trend now is foreign ownership of U.S. glass facilities. Saint Gobain, the largest glass manufacturer in the world, is now a major player in U.S. container and fiberglass manufacture; Pilkington has purchased Libby Owens Ford glass facilities; ARC is a French tableware producer and AFG float glass is owned by Asahi.

In addition to the presence of significant foreign ownership of domestic glass production, there has been shrinkage in domestic company participation in all sectors. Corning, Inc. employment was reduced from 41,000 to 20,000 between 2001 and 2004. About 8,000 of the 21,000 jobs were in the traditional glass areas, such as the lighting products plant in Greenville, Ohio; the electrical products CTV plant in State College, Pennsylvania; the Corning, New York CTV tube plant; and the Martinsburg, West Virginia, consumer products plant that had previously been sold by Corning to World Kitchen. Other companies experiencing closures were Thomson Consumer Electronics in Circleville, Ohio; Techneglas' Columbus, Ohio, and Pittston, Pennsylvania plants; and two Anchor plants. Most of these closures were solely related to product obsolescence and lower labor/benefit costs in overseas locations.

A number, however, had direct links to increased energy costs including plants at Corning, Thomson, Techneglas, Anchor, Gallo and Libby Glass. Estimated employment losses with a partial energy cost cause are approximately 15,000—or slightly more than 10% of total employment.

North American Glass Furnaces

Sector	2000	2003
Container	210	180
Flat	45	48
Fiber	110	100
Specialty	234	225
TOTALS	**599**	**553**

Figure 3.14

Figure 3.14 shows the decrease in glass furnaces in North America in just three years. Most closures have been in the United States.

Information developed in DOE-funded studies by Energetics indicate that natural gas represents over 75% of the energy used in the domestic glass industry. Until 2000 NG prices were relatively steady, but significant increases in recent years have taken the average cost of this critical energy source to over $8.00 per mcf. Recent experiences graphically illustrate the volatility of the natural gas markets in the United States as spot prices exceeded $13.00 in the fall of 2005.

With gas prices at $3.50 per MMBtu, energy costs to the glass industry were about 15% of total costs for specialty products, flat and textile fiber and 10% for container and wool insulation. Batch costs and more energy per ton for other products raise the proportional cost of energy. If the prices being approached by the January Futures contract are maintained, energy costs for the glass industry may well reach and possibly exceed 25% of total costs. In this scenario, the glass industry will experience a continual downward pressure on already marginal profits, leading to a point of marginal viability. Further plant closings and employment reductions in the glass industry will result. The other eight IOF sectors will face similar pressures, but perhaps not to the same degree.

One Solution: Coal Gasification and Glass Manufacture

The increased cost of natural gas is of growing concern to the domestic glass industry, hence the industry's desire to investigate the possibility of alternative gaseous combustible energy sources. Coal gasification presents one option for accomplishing this end. In gasification, solid coal is converted into a stream containing CO and H_2 commonly called "synthesis gas" or "syngas" for short. Syngas streams can be used as produced as a fuel or can be manipulated catalytically into methanol or hydrocarbons of varying molecular weights. Preliminary work has already been done in planning design characteristics for coal gasification plants for the industry.

Examples of industrial applications of coal gasification include the following applications identified in a cursory search by Oak Ridge National Laboratory (ORNL) personnel:

- Gasification of Kraft liquor is used to produce process heat (and/or power) for the pulp and paper industry. Ongoing research on this process and on the related materials issues is funded by the DOE Office of Energy Efficiency and Renewable Energy.
- Gasification of coal is used to produce gas for domestic and industrial heating and lighting ("Town Gas"), widely practiced in Europe during and after WWII.
- Gasification of agricultural waste and biomass on a small, local scale is used for domestic and industrial consumption, which is fairly widely practiced in Europe.
- Domestic and South African facilities produce methanol and hydrocarbons through catalytic conversion of synthesis gases generated from coal.

Glass plants vary enormously in plant size and energy use. Commercial plants range from 80 million to 300 million Btu per hour. While this may seem like a lot of energy, it would require as many as eight Gallo wine bottle plants (the largest container glass plant under one roof in the United States) to consume the output of one Tampa Electric Company-sized coal gasification demonstration plant.

This being the case, three scenarios can be discussed which would make it practical to use coal gasification in the glass industry (and likely for most other industrial facilities as well):

- smaller gasification plants would have to be developed and proven viable;
- a number of industrial users in a single area would be assembled to consume the output of a large gasification plant; or
- one or more industrial facilities would share a portion of the output of a gasification plant built for electrical generation.

In any of these cases, a number of critical technical, environmental and economic concerns would have to be addressed in order to make the wholesale substitution of coal-derived syngas for natural gas a reality. These issues include:

- development of the necessary materials of construction, process equipment and process design for a gasification plant with a high degree of on-stream time and high-process reliability;
- development of an environmentally acceptable coal-based gasification system; and
- demonstration of commercially viable, small-scale gasification plants.

Even though there are established facilities generating fuels and raw materials from gasified coal and biomass, there are a number of issues associated with the gasification process that are still being addressed through research programs. The ORNL has provided the following list as an example of the types of projects being undertaken:

- **Degradation of the refractory linings of the gasification vessels —** This is being addressed by ongoing research under the DOE Office of Fossil Energy's Advanced Research Materials (ARM) program.
- **Premature loss of control sensors (e.g., thermocouples) in the gasification vessel due to high-temperature corrosion/sulfidation —** Some research in this area is being conducted under the DOE's ARM program.
- **Degradation of the burner nozzle tips due to high-temperature oxidation/sulfidation —** Ongoing trials at the ORNL using iron aluminide tips are showing promise.
- **High-temperature corrosion of the components of the hot gas cooler —** This has been researched extensively in the past, resulting in the use of higher-grade alloys than initially planned for the heat exchanger and, in power generation applications, having a replacement hot gas cooler available on-site for rapid replacement.
- **Hot gas filtration (where used): plugging, breakage and corrosion of ceramic and metallic filters —** Recent experience in power generation IGCC plants has been that certain metallic filters give acceptable, predictable performance where good control measures are practiced.
- **Aqueous corrosion from recycled water ("grey water"), depending on the fuels used —** Where water quenching/scrubbing of the gas is employed, there may be issues with this phenomenon.
- **Combustion of the product gas: differences in combustion characteristics compared to natural gas can bring some control issues —** Depending on the degree of gas cleaning, there can be issues of deposition, corrosion or erosion of components touched by the flame.

Combustion practices in the glass industry have been tending toward oxy-fuel installations. These installations should be able to use synthesis gas without too many problems. A simple change in the oxygen/fuel ratio from 2:1 to 1:1 would compensate for the $CO{:}H_2$ mixture in the syngas. Nevertheless, traditional air-fired regenerative furnaces may find that the lower Btu value of syngas would result in greater generation of NO_x than would be allowed under EPA regulations.

These issues and others represent the barriers to the use of gasification broadly for industrial fuel applications. Solving these issues will require a substantial investment of high-caliber technical resources; the expenditure of substantial sums of money for research, development and demonstration projects; and project management and coordination talent. The effort is of a scale such that only the federal government would have the resources and abilities to bring it to a successful conclusion. We urge the Department of Energy to consider developing and securing funding for a program that would use the vast coal resources of this nation to increase the availability of gaseous fuels and reduce the pressure on natural gas prices for industrial, commercial and residential markets.

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AN INDEPENDENT ECONOMIC ANALYSIS CONDUCTED BY TIM CONSIDINE,
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ECONOMIC BENEFITS OF COAL CONVERSION INVESTMENTS

Economic Analysis

The development of coal-based energy conversion plants at the scale envisioned in this report will increase U.S. domestic energy supply by more than 10% and lower domestic energy prices by more than 33% from where they would be without coal conversion. Higher domestic energy production, lower energy prices, and the economic stimulus from coal British thermal units (Btu) energy conversion plant construction contribute to cumulative gains in real gross domestic product (GDP) of more than \$3 trillion in discounted present value terms. Further, if some of the CO_2 from these plants is used to enhance oil recovery, domestic oil production could increase more than 3 million barrels per day (bbl/d). This additional energy production would expand the cumulative discounted GDP gains to over \$4 trillion. This section describes the methods used to obtain these estimates.

Methodological Overview

Estimating the economic impacts from coal Btu energy conversion may at first seem a daunting task. The breadth of the conversion scenarios discussed above affect all segments of the energy industry, from natural gas, crude oil and petroleum, and electricity. Representation of how equilibrium energy prices and quantities adjust in each of these markets and their interactions in response to coal-based energy manufacturing is impossible given the resources and timeframe for this project. As a result, an aggregate energy supply and demand framework is adopted for this study.

This approach greatly simplifies the analysis, distilling the effects down to a few key parameters, such as:

- the price elasticity of aggregate energy demand;
- the elasticity of gross domestic product to energy price changes; and
- the output multipliers associated with energy output and plant construction.

This study does not estimate these parameters from primary data but instead uses estimates that appear in the economic literature.

Given the simple approach employed in this study, the scenarios discussed are aggregated into one key variable: the quantity of Btus delivered to energy consumers. This involves making assumptions about the size of Btu conversion plants and the thermal efficiencies of the conversion processes.

Another key assumption involves timing. The actual adoption of these technologies in the marketplace depends upon how energy prices and energy conversion plant costs evolve over time. We avoid making assumptions about such specific factors and instead use a smooth extrapolation technique that attempts to model a process of steady and accelerating adoption of Btu energy conversion technologies over to the year 2025.

Scenario Development

The first step in the economic analysis is to establish the goal for the production of Btu from the coal conversion technologies discussed above. These targets are presented in Figure 4.1. The first four scenarios listed are driven by an assumed, targeted amount of coal production to the year 2025. In essence, these scenarios assume that the additional units of energy supply from these coal technologies will be consumed by the energy consumers.

Driving Assumptions and Total Coal Use in 2025

Technologies	Driving Assumption	Total Coal Use (Mtpy)
Coal-to-gas	340 Mtpy coal	340
Coal-to-liquids	475 Mtpy coal	475
Coal-to-electricity	375 Mtpy coal	375
Coal-to-hydrogen	70 Mtpy coal	70
Coal to produce ethanol	10% of 2030 U.S. gasoline	40
Million tons per year (Mtpy)		**1,300**

Figure 4.1

The scenario for coal to product ethanol is driven by a target of 10% of the vehicle fleet supplied from ethanol. Coal is used as a fuel to convert biomass into ethanol. This scenario is not included in the economic analysis below because the net energy contribution from coal is not clear and because it is a relatively minor part of the overall Btu energy conversion vision presented above.

Time Path of Plant Construction

The next step in the analysis is to determine a path for annual production of Btus from coal to reach these targets. First, the number of plants is determined by taking the total amount of coal in the first four scenarios and dividing by an assumed 6 million tons of annual coal consumption per Btu conversion plant. This coal consumption amount per plant implies roughly 212 coal Btu energy conversion plants in the year 2025.

Given this target number of plants, a plant construction schedule is then developed. For this, we assume construction of two plants beginning in the year 2007. In subsequent years, an additional 1.5 plants on average are started. The next key assumption is that it takes four years to build these plants. This means, for example, that the two plants begun in 2007 do not begin producing Btus until 2010. The plants started in 2008 then go into production in 2011 and augment the production from the plants started in the previous year. Defining N_t as the number of Btu conversion plants operating in year t and NC_t as the number of plants under construction in year t, the number of plants operating in any given year after 2010 is given by the following formula:

$$N_t = N_{t-1}+NC_{t-3}$$

This formulation allows an easy adjustment of the average number of new plant starts to reach the target number of plants in 2025. Coal consumption in each year is simply computed by multiplying the number of plants by the 6 million ton per year average coal use per plant.

The incremental Btus of marketable energy product from coal energy conversion in quadrillion Btus, ΔQ_t, is obtained by the following equation:

$$\Delta Q_t = N_t * \left[\frac{6\ \textit{million tons}}{\textit{plant}}\right] * \left[\frac{20.5\ \textit{million BTUs}}{\textit{ton}}\right] * CE \Big/ 1{,}000$$

where *CE* is the average conversion efficiency, which is calculated as a weighted average of the individual thermal efficiencies presented with the weights computed from the coal quantities in Figure 4.1. These thermal efficiencies and weights are presented in Figure 4.2:

Assumed Thermal Efficiencies of Coal Conversion Technologies

Technologies	Thermal Efficiencies	Weights
Coal-to-gas	50%	0.2698
Coal-to-liquids	60%	0.3770
Coal-to-electricity	33%	0.2976
Coal-to-hydrogen	50%	0.0556
Conversion efficiency	48.71%	1.0000

Figure 4.2

The number of new construction starts and plants operating each year are presented in Figure 4.3. Notice that plant starts cease in 2022. Incremental coal use in million tons and in quadrillion Btus appears in columns four and five of Figure 4.3. Total energy output from coal conversion in 2025 amounts to 12.7 quadrillion Btus. This energy production is achieved by the gradual ramping up of the number of operating coal conversion plants that results from the construction of these plants over time and the assumed four-year construction period. These plants include electric power generation facilities, coal methane production plants, coal-to-liquids plants and plants that produce hydrogen. In reality, Btu coal energy conversion plants will produce multiple product streams, with most producing electric power along with either methane or, most likely, a slate of liquid products, including methanol, gasoline, diesel fuel and jet fuel. Delineating these plant configurations with a greater degree of specificity is a topic for additional research.

New Plant Starts, Operating Plants

	PLANTS		INCREMENTAL COAL	
Year	Starts	Operating	Input in Million Tons	Energy Output in Quadrillion Btus
2007	2			
2008	4			
2009	5			
2010	7	2	12	0.12
2011	8	6	33	0.33
2012	10	11	63	0.63
2013	11	17	102	1.02
2014	13	25	150	1.50
2015	14	35	207	2.07
2016	16	46	273	2.73
2017	17	58	348	3.47
2018	19	72	432	4.31
2019	20	88	525	5.24
2020	22	105	627	6.26
2021	23	123	738	7.37
2022	25	143	858	8.57
2023		165	987	9.86
2024		188	1125	11.23
2025		212	1272	12.70

Figure 4.3

To assess the margin of error from our aggregate approach, a more detailed analysis was undertaken that allows the amount of coal consumed per plant and the implied plant size to differ by each coal conversion scenario. Figure 4.4 presents a more detailed set of calculations. For each of the scenarios, coal use, output and capital cost per plant are presented. The estimated number of plants is higher because the scale of the hydrogen plants is smaller than the plant size assumed above. Nevertheless, the total amount of energy produced is very close, within 5%, of the estimate presented above. Hence, the aggregate methodology adopted here provides a reasonable estimate of the total amount of energy production from coal Btu conversion plants.

Also included in Figure 4.4 is the coal to produce ethanol scenario. This scenario involves 40 million tons of coal consumed in 383 plants that in total will produce about 10% of U.S. gasoline consumption in 2030. The hydrogen scenario would supply between 40 and 50 million fuel cell vehicles, which falls between 10 to 20% of transportation needs.

Disaggregate Calculations of Energy Production from Coal Btu Energy Conversion

		PLANT PARAMETERS			**OUTPUT/CAPACITY**				
	Total Coal Use (Mtpy)	**Coal Use (Mtpy)**	**Output**	**Capital Cost in Billions $**	**Quantity**	**Units**	**Number of Plants**	**Total Capital Cost in Billions $**	**Energy Output, Quads**
Coal-to-gas	340	2.98	35 BCF/yr	1.0	4	Tcf	114	115	4.11
Coal-to-liquids	475	14.39	80,000 bbl/day	6.4	2.6	MMbd	33	211	5.08
Coal-to-electricity	375	5.63	3.7 million MWh/yr	2.3	100	GW	67	150	2.53
Coal-to-hydrogen	70	1.10	153 million scf H_2/day	0.4	3553.8	BSCF	64	27	1.21
TOTALS	1260						278	503	12.93
Coal to produce ethanol	40	0.11	50 million gallons/yr	$0.03	1.25	MMbd	383	12	

Figure 4.4

* Note: Economic Impact calculations are based on production of an additional 1,260 million short tons of coal per year

Capital Outlays and Direct Employment Impacts

Significant capital expenditures will be required to build these plants. Construction and operation also will generate employment gains. The time path for these direct impacts is calibrated to the time path of plant construction discussed in the previous section.

Annual capital expenditures are estimated by multiplying the stock of plants under construction by an average annual capital outlay, which is computed as a weighted average of capital costs for the four technologies. Coal-to-gas and coal-to-hydrogen plants are assumed to cost $1 billion, again assuming 6 million tons per year of coal consumption. The coal-to-liquids plant cost is assumed to be $3.6 billion for this plant size. Coal-to-electricity plants are assumed to cost $2.25 billion. Given a four-year plant life, the average annual capital outlay per plant is $590 million.

Construction jobs are estimated assuming 976 jobs per plant year based upon a study of the economic impact analysis of the Peabody Energy Park in Illinois. The operation of the mines and plants generates 414 jobs per plant per year. Total direct employment is determined by multiplying each of these estimates by the number of plants under construction and operating, respectively. The total number of plants under construction, annual capital outlays and employment are presented in Figure 4.5.

Capital Outlays and Direct Employment

Year	Plants Under Construction	Capital Billion $	EMPLOYMENT Construction	EMPLOYMENT Operation
2007	2	1.2	1,951	
2008	6	3.2	5,365	
2009	11	6.2	10,243	
2010	17	10.0	16,584	827
2011	23	13.6	22,437	2,276
2012	29	17.1	28,290	4,344
2013	35	20.6	34,143	7,033
2014	41	24.2	39,996	10,343
2015	47	27.7	45,849	14,274
2016	53	31.3	51,702	18,825
2017	59	34.8	57,555	23,997
2018	65	38.3	63,408	29,789
2019	71	41.9	69,261	36,202
2020	77	45.4	75,114	43,235
2021	83	49.0	80,967	50,889
2022	89	52.5	86,820	59,164
2023	69	40.7	67,310	68,059
2024	48	28.0	46,336	77,575
2025	25	14.5	23,900	87,711

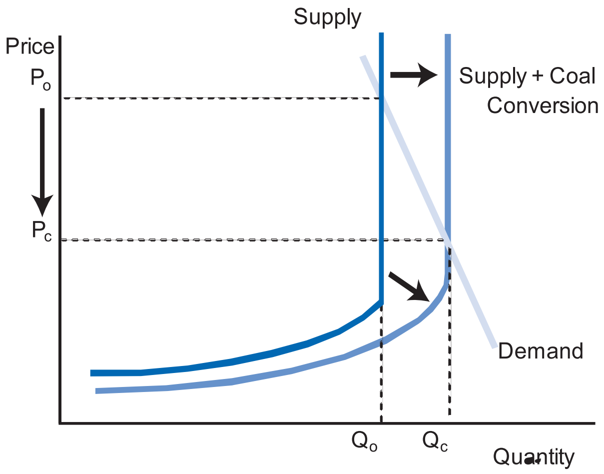
Figure 4.5

Impacts on Energy Markets

The additional energy production from coal conversion will lower equilibrium energy prices. Assuming energy producers in the United States are operating at full production, the extent of the price reduction from additional energy production from coal would depend upon the slope of the demand curve as illustrated in Figure 4.6. Economists characterize demand-and-supply relationships using elasticities. An own-price elasticity of demand is defined as the percentage change in quantity for a given percentage change in price, and its solution for the percentage change in price is as follows:

$$\varepsilon = \frac{\%\Delta Q}{\%\Delta P} \Rightarrow \%\Delta P = \frac{\%\Delta Q}{\varepsilon}\,.$$

The above equation provides a simple model for estimating the impacts of coal energy conversion on aggregate energy prices.



Impacts of Coal Conversion on Energy Supply and Prices

Figure 4.6 Source: Economic Analysis Conducted at Penn State University, 2006

The annual changes in quantities, which are the incremental supplies of energy products from coal conversion plants, are presented in Figure 4.7. To compute the percentage change in quantity, we use the long-term forecast of aggregate primary energy consumption produced by the EIA. Own-price elasticities of energy demand vary considerably by product depending upon the degree of substitution possibilities and between the short-run—when energy-consuming capital is for the most part fixed—and the long-run, when investment allows much greater flexibility to respond to changing relative energy prices. For example, the short-run own price elasticity of demand for gasoline is about -0.2, while the long-run elasticity is at least -0.7. For this study, we adopt an intermediate value of -0.3, which can be interpreted as an intermediate-run elasticity.

The resulting energy price reductions from coal conversion appear in Figure 4.7. Notice that by the end of the forecast horizon, aggregate energy prices would be more than 30% lower than the EIA base case forecast. This implies lower prices for electricity, natural gas, petroleum products and many other energy products. This is significant given that coal conversion augments the nation's energy supply by more than 10% in 2025.

A smaller own-price elasticity of demand in absolute terms or a steeper demand schedule in Figure 4.7 would imply even sharper reductions in energy prices from coal energy conversion. Likewise, a larger absolute value on the own-price elasticity would imply a smaller impact on energy prices. Our elasticity of -0.3 can be viewed as a reasonable compromise between these two extremes.

Impacts of Coal Energy Conversion on Aggregate Energy Prices

	EIA LONG-TERM FORECAST		IMPACTS OF COAL ENERGY CONVERSION	
Year	Total Quantity Primary Energy	Price Primary Energy ($/MMBtu)	Incremental Quad Btus	Percentage Change in Price
2007	103.35	12.59	0	0.00%
2008	104.93	12.32	0	0.00%
2009	106.36	11.90	0	0.00%
2010	107.87	11.52	0.12	-0.37%
2011	109.16	11.52	0.33	-1.01%
2012	110.67	11.46	0.63	-1.89%
2013	111.75	11.48	1.02	-3.04%
2014	112.87	11.40	1.50	-4.42%
2015	114.18	11.40	2.07	-6.03%
2016	115.58	11.46	2.73	-7.86%
2017	116.83	11.51	3.47	-9.91%
2018	118.14	11.67	4.31	-12.17%
2019	119.36	11.79	5.24	-14.64%
2020	120.63	11.89	6.26	-17.30%
2021	121.80	12.00	7.37	-20.17%
2022	123.05	12.08	8.57	-23.21%
2023	124.29	12.17	9.86	-26.43%
2024	125.75	12.25	11.23	-29.78%
2025	126.99	12.35	12.70	-33.34%

Figure 4.7

Macroeconomics Impacts

These energy price reductions act like a tax cut for the economy, reducing the outflows of funds from energy consumers to foreign energy producers. In addition, the supply-side push from additional domestic energy production will directly increase the nation's economic output. Finally, the plant construction will stimulate the economy at local, regional, and national levels.

To estimate these impacts, specifically the changes in Gross Domestic Product (GDP) resulting from coal conversion, published estimates of output multipliers are used. In this study, we use an output multiplier of 2.6

reported by Shields, et al. in 1996 which means that total output increases $2.60 for every dollar spent on coal energy conversion plant construction and every dollar generated from the resulting energy output. The elasticity of GDP with respect to energy prices is -0.048, which is the average of the range reported by S.A. Brown and M.K. Yucel in 1999, based upon an Energy Modeling Forum study by B.G. Hickman, et al. in 1987.[1] Estimates of these three avenues of impacts of GDP are presented below in Figure 4.8. Total real 2004 dollar GDP gains by the year 2025 exceed $600 billion. The discounted present value of these gains, assuming a real discount of 3%, exceeds $3 trillion.

Impacts of Coal Energy Conversion of GDP in Billions of Dollars ($2004)

Year	Energy Price Reductions	Plant Construction	Energy Output	Total GDP Gains
2006	0	0	0	0
2007	0	3.1	0	3.1
2008	0	8.5	0	8.5
2009	0	16.2	0	16.2
2010	2.3	26.2	3.6	32.1
2011	6.5	35.4	9.8	51.7
2012	12.5	44.7	18.5	75.7
2013	20.7	53.9	29.6	104.2
2014	31.0	63.2	42.6	136.8
2015	43.7	72.4	57.8	173.9
2016	58.8	81.6	75.1	215.5
2017	76.6	90.9	94.1	261.5
2018	97.0	100.1	115.5	312.6
2019	119.9	109.4	137.7	367.0
2020	145.7	118.6	160.8	425.1
2021	174.5	127.8	184.2	486.5
2022	206.3	137.1	207.4	550.8
2023	241.4	106.3	230.4	578.1
2024	279.6	73.2	252.4	605.2
2025	322.0	37.7	273.0	632.8

Figure 4.8

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[1] An earlier version of this study used the GDP electricity price elasticity of -0.14 used by A. Rose and B. Yang, which increases the present value of GDP gains to over $6 trillion. This elasticity apparently came from a study completed over 20 years ago by National Economic Research Associates. We were unable to verify the methods used to obtain this estimate and instead relied upon published estimates from the peer-reviewed literature.

The employment multiplier used to estimate the indirect and induced job gains from direct employment in construction and operation of energy conversions plants is 3.23, which is also drawn from the 1996 study by Shields, et al. For the response of employment to energy prices, we use the study by S.A. Brown and J.K. Hill from 1988 that surveyed the major economic forecasting services and found an elasticity between national employment and oil prices of -0.0193.

The employment impacts of the coal energy conversion scenario considered here are also significant.
By the end of the forecast period, employment is more than 1.4 million higher than the base case (see Figure 4.9). Employment gains arise primarily from the impacts of lower energy prices. In this case, service sector employment is stimulated by the higher level of discretionary income available to consumers made possible by the lower energy prices from the additional production from the coal energy conversion complex.

Employment Impacts of Coal Energy Conversion

Year	Energy Price Reductions	Plant Construction	Energy Output	Total Jobs
2006	0	0	0	0
2007	0	6,296	0	6,296
2008	0	17,314	0	17,314
2009	0	33,054	0	33,054
2010	10,153	53,517	2,670	66,339
2011	27,766	72,405	7,343	107,514
2012	52,619	91,293	14,019	157,931
2013	85,005	110,181	22,698	217,884
2014	124,833	129,069	33,379	287,281
2015	171,876	147,958	46,063	365,897
2016	226,251	166,846	60,750	453,846
2017	288,964	185,734	77,439	552,137
2018	359,390	204,622	96,131	660,144
2019	437,068	223,511	116,826	777,405
2020	521,584	242,399	139,524	903,507
2021	613,753	261,287	164,225	1,039,264
2022	713,273	280,175	190,928	1,184,376
2023	820,519	217,214	219,634	1,257,368
2024	934,010	149,532	250,342	1,333,884
2025	1,056,719	77,127	283,054	1,416,900

Figure 4.9

These estimates should be considered only order of magnitude estimates given the wide range of uncertainty surrounding the coal energy conversion technology. In addition, such large-scale coal utilization could increase equilibrium prices for basic materials and services used to produce Btus from coal. To estimate these impacts, a general equilibrium model of energy markets and the economy is needed. Indeed, another possible area to explore is the impact of additional coal production on world energy markets. In fact, our analysis implicitly assumes that the coal energy conversion would affect world energy prices. Analysis of these economic relationships awaits further research.

Impacts of Enhanced Oil Recovery

The adoption of large-scale coal conversion would generate significant amounts of carbon dioxide (CO_2) that could be either sequestered or used to enhance oil production. Enhanced oil recovery using CO_2 already produces more than 200,000 barrels of oil per day, primarily in west Texas, which is supplied with CO_2 via pipeline. Given the large pipeline network that overlays oil- and coal-producing regions, there is considerable potential to find low cost methods to deliver this CO_2 to enhance oil production.

To estimate the enhanced oil production from coal conversion, we assume that 14,844 supercritical fluids (scf) CO_2 is produced per ton of coal consumed, 187.5 barrels are produced per million scf of CO_2 injected, and 30% of the total CO_2 is utilized to enhance oil production. These assumptions yield additional oil production of nearly 3 million barrels per day. As a result, energy prices are nearly 50% lower than the EIA base case. The present value of cumulative GDP gains increases to more than $4 trillion. This rough analysis suggests that coal energy conversion coupled with CO_2 recovery and enhanced oil recovery could yield very substantial economic benefits.

Impacts of Coal Energy Conversion with CO_2 Capture and Enhanced Oil Recovery

Year	Incremental Oil Production MMbd	Energy Price Reductions (5)	GDP Gains in Billions $
2006	0	0	0
2007	0	0	3
2008	0	0	8
2009	0	0	16
2010	0	-0.5	35
2011	0.1	-1.5	60
2012	0.1	-2.8	90
2013	0.2	-4.5	128
2014	0.3	-6.6	171
2015	0.5	-9.0	220
2016	0.6	-11.7	276
2017	0.8	-14.7	337
2018	1.0	-18.1	404
2019	1.2	-21.7	475
2020	1.4	-25.7	549
2021	1.7	-29.9	627
2022	2.0	-34.5	706
2023	2.3	-39.3	747
2024	2.6	-44.2	786
2025	2.9	-49.5	823

Figure 4.10

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APPENDICES

APPENDIX 2.1

Description of The National Coal Council

In the fall of 1984, The National Coal Council was chartered and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which could, in turn, lead to decreased dependence on other, less abundant, more costly and less secure sources of energy.

The Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of The National Coal Council is solely to advise, inform and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

Members of The National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The National Coal Council is headed by a chairman and vice-chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members. To wit, it receives no funds whatsoever from the federal government. In reality, by conducting studies at no cost, which might otherwise have to be done by the department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry nor the views of any one particular part of the country. It is instead to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by The National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the startup of the Council.

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APPENDIX 2.3

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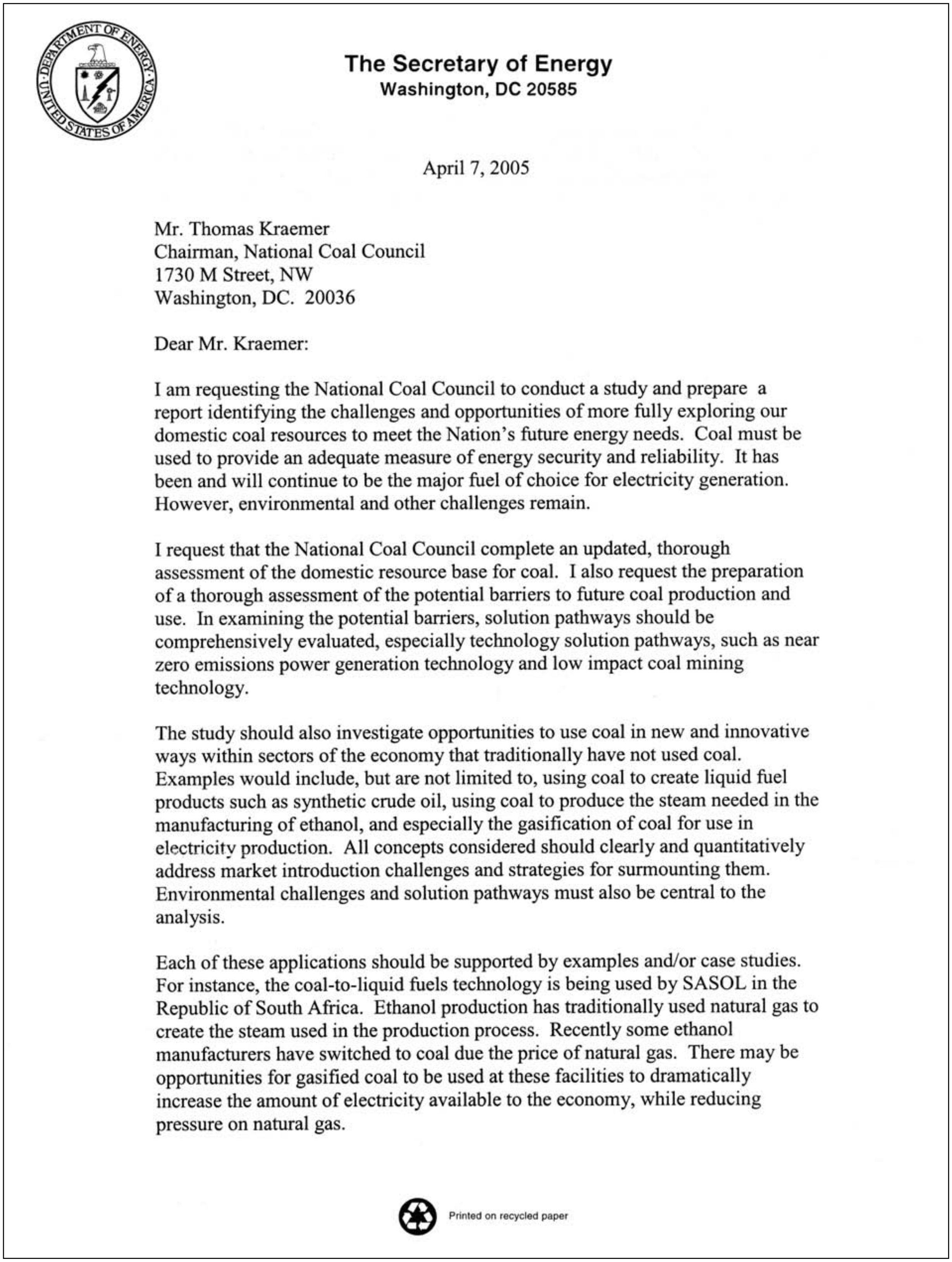
APPENDIX 2.5
Correspondence Between The National Coal Council and the U.S. Department of Energy



The Secretary of Energy
Washington, DC 20585

April 7, 2005

Mr. Thomas Kraemer
Chairman, National Coal Council
1730 M Street, NW
Washington, DC. 20036

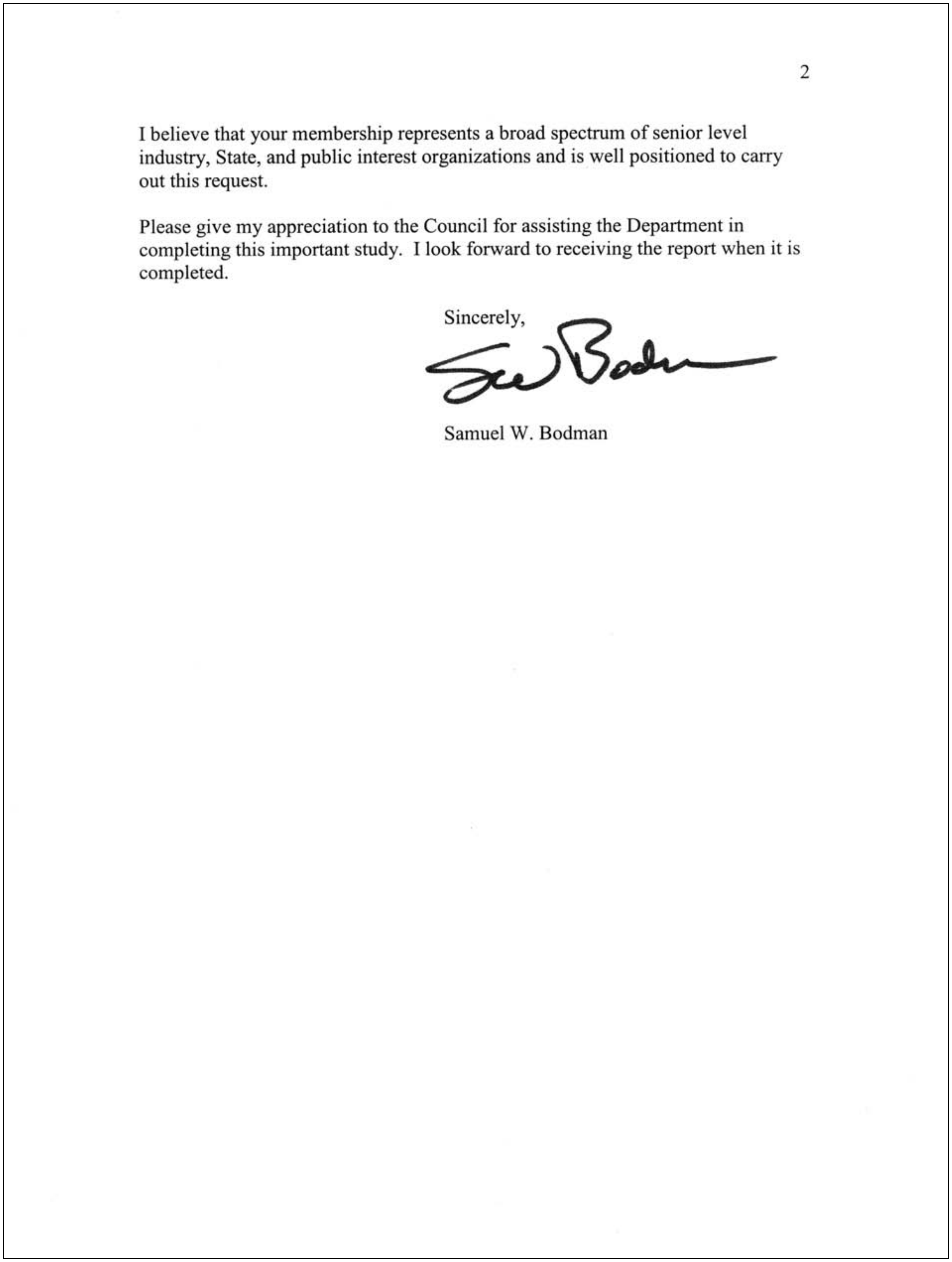
Dear Mr. Kraemer:

I am requesting the National Coal Council to conduct a study and prepare a report identifying the challenges and opportunities of more fully exploring our domestic coal resources to meet the Nation's future energy needs. Coal must be used to provide an adequate measure of energy security and reliability. It has been and will continue to be the major fuel of choice for electricity generation. However, environmental and other challenges remain.

I request that the National Coal Council complete an updated, thorough assessment of the domestic resource base for coal. I also request the preparation of a thorough assessment of the potential barriers to future coal production and use. In examining the potential barriers, solution pathways should be comprehensively evaluated, especially technology solution pathways, such as near zero emissions power generation technology and low impact coal mining technology.

The study should also investigate opportunities to use coal in new and innovative ways within sectors of the economy that traditionally have not used coal. Examples would include, but are not limited to, using coal to create liquid fuel products such as synthetic crude oil, using coal to produce the steam needed in the manufacturing of ethanol, and especially the gasification of coal for use in electricity production. All concepts considered should clearly and quantitatively address market introduction challenges and strategies for surmounting them. Environmental challenges and solution pathways must also be central to the analysis.

Each of these applications should be supported by examples and/or case studies. For instance, the coal-to-liquid fuels technology is being used by SASOL in the Republic of South Africa. Ethanol production has traditionally used natural gas to create the steam used in the production process. Recently some ethanol manufacturers have switched to coal due the price of natural gas. There may be opportunities for gasified coal to be used at these facilities to dramatically increase the amount of electricity available to the economy, while reducing pressure on natural gas.

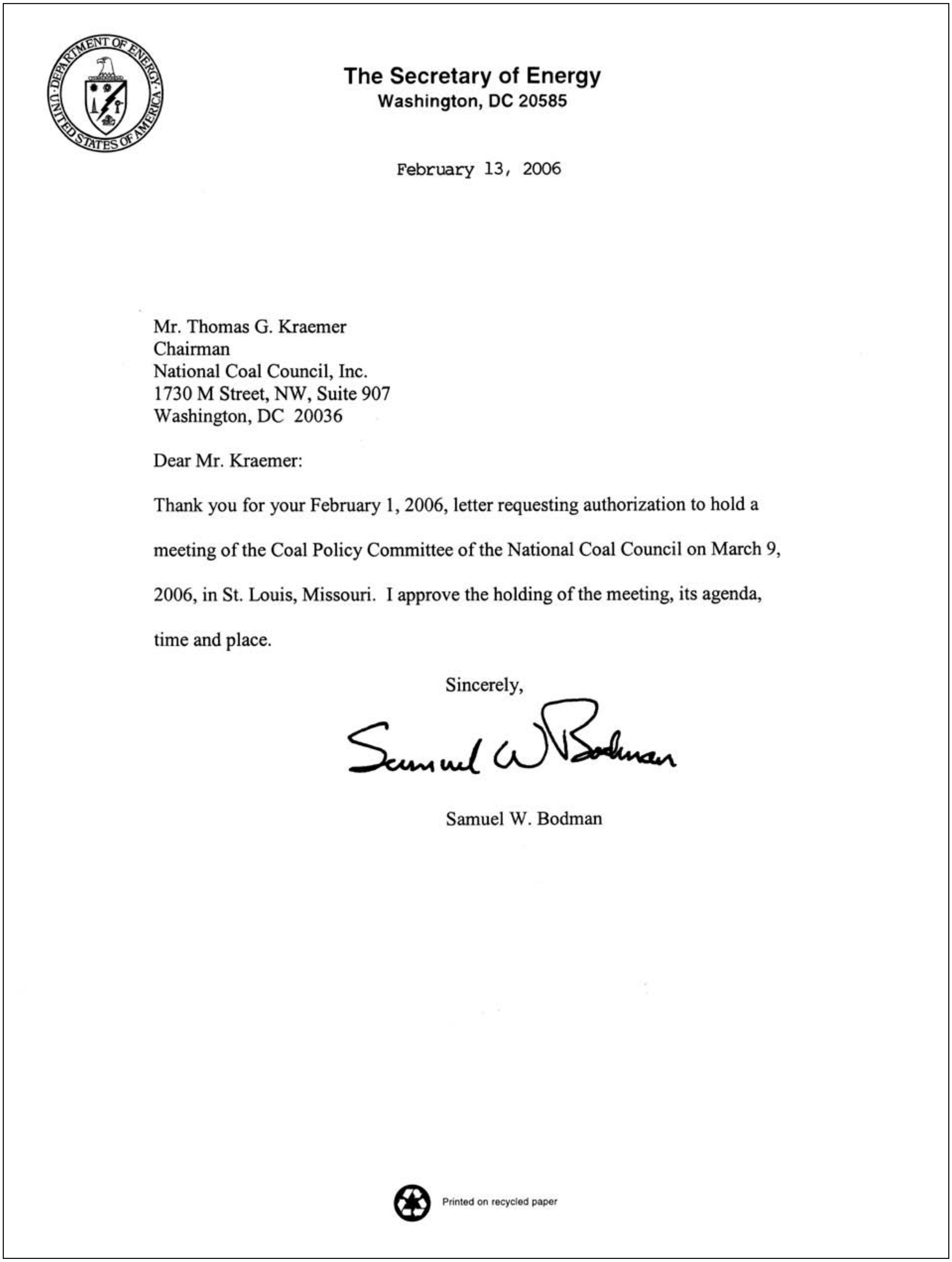


I believe that your membership represents a broad spectrum of senior level industry, State, and public interest organizations and is well positioned to carry out this request.

Please give my appreciation to the Council for assisting the Department in completing this important study. I look forward to receiving the report when it is completed.

Sincerely,

Samuel W. Bodman



The Secretary of Energy
Washington, DC 20585

February 13, 2006

Mr. Thomas G. Kraemer
Chairman
National Coal Council, Inc.
1730 M Street, NW, Suite 907
Washington, DC 20036

Dear Mr. Kraemer:

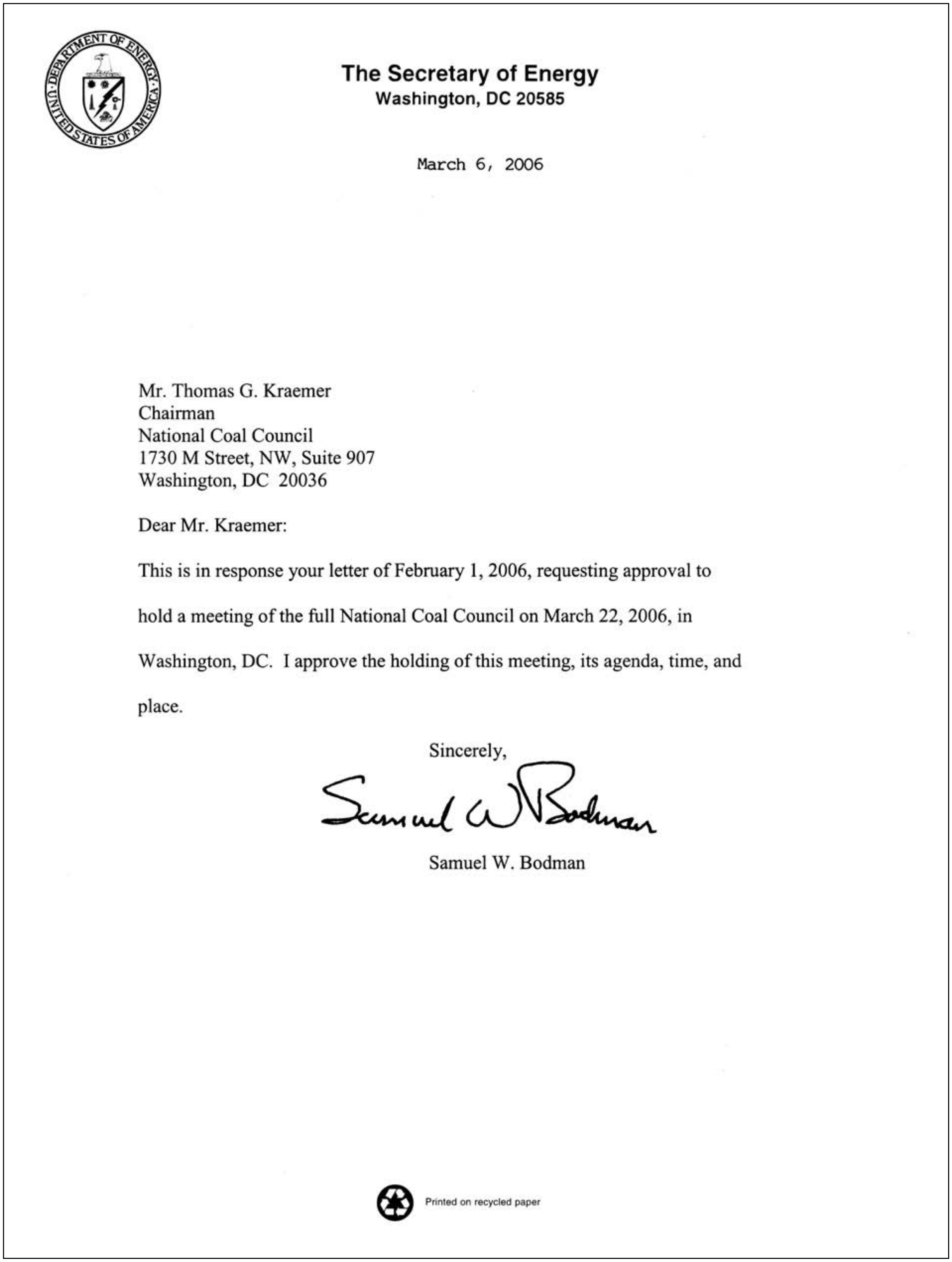
Thank you for your February 1, 2006, letter requesting authorization to hold a meeting of the Coal Policy Committee of the National Coal Council on March 9, 2006, in St. Louis, Missouri. I approve the holding of the meeting, its agenda, time and place.

Sincerely,

Samuel W Bodman

Samuel W. Bodman

Printed on recycled paper



The Secretary of Energy
Washington, DC 20585

March 6, 2006

Mr. Thomas G. Kraemer
Chairman
National Coal Council
1730 M Street, NW, Suite 907
Washington, DC 20036

Dear Mr. Kraemer:

This is in response your letter of February 1, 2006, requesting approval to hold a meeting of the full National Coal Council on March 22, 2006, in Washington, DC. I approve the holding of this meeting, its agenda, time, and place.

Sincerely,

Samuel W Bodman

Samuel W. Bodman

APPENDIX 2.6

Correspondence from Industry Experts

As submitted by Clark D. Harrison, CQ, Inc.

Coal Cleaning for Control of Mercury Emissions

Because mercury is generally associated with mineral matter to a large degree, it can be partially removed by conventional physical coal cleaning technologies. Figure 2.6.1 contains reduction data for mercury from 26 commercial or commercial-scale tests using conventional coal cleaning technologies[1]. Because they may become important in the future, data is also provided for arsenic, chromium and selenium. The goal of the cleaning was to reduce ash and sulfur in the clean-coal, and no special effort was made to remove trace elements in any of these tests.

In spite of the fact that no effort was made to reduce mercury content, mercury was reduced by as much as 78%. However, some reductions were also very low. The degree of mercury removal is dependent on several mechanisms, including the degree of liberation of the mercury-bearing mineral, the intensity of cleaning, the mode of occurrence of the trace element, and the method of cleaning[2,3,4].

Trace Element Reductions via Conventional Physical Cleaning

(%)

Seam	Location	Arsenic	Chromium	Mercury	Selenium
	Central Appalachia	58	82	22	42
	Central Appalachia	49	78	39	58
Illinois No. 6	Illinois	62	80	60	41
Pittsburgh	Pennsylvania	68	47	33	9
Pittsburgh	Pennsylvania	74	74	50	53
Pittsburgh	Pennsylvania	75	72	30	59
Pittsburgh	Pennsylvania	83	74	12	51
Pittsburgh	Pennsylvania	63	79	41	37
Pittsburgh	Pennsylvania	81	79	42	—
Upper Freeport	Pennsylvania	40	13	—	—
Lower Kittanning	Pennsylvania	73	55	38	66
Sewickley	Pennsylvania	51	59	26	39
Pittsburgh	Pennsylvania	61	64	27	37
Pittsburgh	Pennsylvania	30	27	14	12
Illinois No. 6	Illinois	20	36	12	33
Kentucky No. 9 & 11	Kentucky	46	37	24	21
Pratt & Utley	Alabama	43	53	39	46
Pratt	Alabama	42	58	22	57
Utley	Alabama	29	23	26	33
Pratt	Alabama	28	64	45	28
Upper Freeport	Pennsylvania	83	70	78	- 5
Upper Freeport	Pennsylvania	85	67	76	39
Illinois No. 2, 3 & 5	Illinois	39	51	28	33
Illinois No. 2, 3 & 5	Illinois	54	53	50	28
Kentucky No. 11	Kentucky	66	72	—	80
Kentucky No. 11	Kentucky	43	79	48	62
AVERAGE		**56**	**59**	**37**	**40**

Figure 2.6.1

The Role of Liberation

Mineral matter occurs in coal in a variety of forms. For example, pyrite, the most studied coal-associated mineral, can occur as anything from a massive fracture-filling form several centimeters in size to discrete euhedral crystals a few microns in size. Comminution processes such as crushing and grinding can be used to liberate ash- and sulfur-bearing minerals from the raw coal to allow more effective cleaning. Similarly, crushing can also be used to increase the degree of liberation of the trace element-bearing mineral matter so that additional quantities may be removed during coal cleaning without adversely affecting energy recovery.

Laboratory washability data can be used to measure the impact of the use of liberation during cleaning. If an uncrushed Northern Appalachian coal is cleaned (or "washed") using a density fractionation process, the level of mercury reduction that can be attained while recovering 90% of the energy value of the as-mined coal is about 35%. However, by cleaning this coal after it has been crushed to minus 100 mesh, mercury reduction may be increased to about 50% for the same level of energy recovery. If only the marginal quality, or middling, fractions of this coal are crushed prior to cleaning, the level of mercury reduction at 90% energy recovery can be about 45%. Thus, the amount of mercury reduction that may be attained during cleaning is directly affected by the degree of liberation of the trace element-bearing mineral matter in the coal.

The Effect of Intensity of Cleaning

Typically, coal cleaning is used to remove ash-forming mineral matter from as-mined coal to reduce the cost of transportation; lower the costs of ash collection, handling and disposal; and increase the combustion efficiency of a boiler. Not surprisingly, increasing the intensity of cleaning to increase the reduction of ash and, in some cases, sulfur, also tends to yield an increase in the reduction of trace elements associated with mineral matter.

Mode of Occurrence

Mode of occurrence is the form, association and distribution of a trace element within the coal. Trace elements in coal that are contained in large-sized minerals, such as fracture-filling pyrite, can be removed readily using conventional physical cleaning techniques. In some cases, trace elements contained in fine-sized minerals can also be removed by conventional cleaning. In most cases, however, crushing for liberation prior to cleaning may be required to attain high removals of trace elements that occur in very small mineral grains. If the trace element is bound organically, it cannot be removed by physical processes; however, chemical or biological processes may be a removal option.

In recent years, the U.S. Geological Survey (USGS) and various coal research and industry associates have studied the geochemical and washability characteristics of numerous coals from the major coal-producing areas of the U.S.[2,5]. The USGS determined the modes of occurrence of many of the trace elements found in these coals using an inventive process that involves a series of leaching steps followed by analysis of residues and leachates[6]. Scanning electron microscopy, microprobe analysis and x-ray diffraction studies complement the leaching studies.

In the case of mercury, a strong association with the sulfide minerals such as pyrite was noted. Therefore, cleaning technologies that remove sulfide minerals will remove mercury.

The Impact of the Method of Cleaning

The method of cleaning and the types of equipment used to remove ash-forming and sulfur-bearing mineral matter from coal can also affect the reduction of trace elements[2,3,4]. For example, cleaning coal using a density-based process provides higher levels of mercury reduction at all levels of energy recovery than does the use of froth flotation.

The primary reason for this difference in cleaning response is that pyrite is a very dense mineral that can be removed using a density-based process. By way of comparison, fine-sized coal and pyrite sometimes have similar surface characteristics, which make the removal of pyrite and pyrite-associated trace elements via surface-based processes such as froth flotation difficult and inefficient. Moreover, since mode of occurrence and textural relation evidence suggest that mercury occurs predominantly in association with the pyrite in many coals, an interplay exists between the method of cleaning and the form, association, and distribution of the mercury.

The selection of an effective removal method, therefore, will require knowledge of both the mode of occurrence of a trace element and the way in which this mode will cause the element to behave during a particular cleaning process. By coupling mineralogical information such as trace element mode of occurrence and textural relationship with mineral processing information and knowledge, engineers can identify the most efficient and economical coal cleaning methods to remove elements of concern from a specific coal.

Increasing Trace Element Removal During Cleaning

As stated previously, the most direct method of increasing the removal of a trace element in the cleaning process is to clean more intensely. However, results can vary widely depending on an element's mode of occurrence and a host mineral's textural characteristics. In some cases, more intense cleaning provides a proportional removal of a specific trace element and in other cases it does not. Also, more intense cleaning often reduces yield, increasing the cost of cleaning on a tonnage basis.

Several options exist to reduce the loss of clean coal yield caused by more intense cleaning. In some cases, crushing to increase the liberation of the trace-element bearing mineral may be effective; however, the benefit of increased liberation must meet or exceed the cost of increased loading on the fines circuit and the increase in moisture associated with cleaning finer-sized coal. In other cases, utilization of more efficient cleaning equipment or improved circuitry, possibly in combination with crushing, may be cost-effective.

Figure 2.6.2 gives the results of a series of commercial-scale tests at CQ Inc. on four different Northern Appalachian coals[2,4]. A heavy-media cyclone (HMC) circuit was used to clean the plus 0.5-mm fraction of each coal, a two-stage water-only cyclone/concentrating spiral circuit (WOC-Spiral) was used to clean the 0.5 mm by 150 micron size fraction, and the flotation circuit was used to upgrade the minus 150 micron size fraction.

For the first three coals, the cleaning in the WOC-Spiral circuit yielded a higher mercury reduction than did the cleaning in the HMC or flotation circuits even though the ash reduction achieved by the WOC-Spiral circuit was the lowest of the three circuits in all cases. For the fourth coal, the cleaning in the WOC-Spiral circuit resulted in the lowest mercury reduction of the three circuits. However, this result is somewhat misleading because the intensity of cleaning (as indicated by the ash reduction) in the WOC-Spiral circuit was also the lowest of all that were attained during testing. If the impact of the intensity of cleaning is buffered by creating a ratio of the levels of mercury reduction to the levels of ash reduction for each test result, the results show that the use of the two-stage, water-only cyclone/concentrating spiral circuit provided the best results in all cases.

The major mercury-bearing minerals in these coals are large-grained, fracture-filling pyrites that tend to liberate easily[4]. In these tests, the superior performance of the WOC-Spiral circuit over that of the HMC circuit is attributable to the liberation and subsequent removal of this mercury-bearing pyrite. The WOC-Spiral circuit cleaned a smaller size fraction than did the HMC circuit, one which is more likely to contain liberated mercury-bearing minerals. However, in cleaning even finer-sized particles, froth flotation rejected less mercury than did the WOC-Spiral circuit because the surface-based process removed pyrite less efficiently than did the density-based process.

In general, increasing the amount of mercury reduction during the cleaning of coals like these can probably be best effected by crushing the coal before cleaning and by using, in combination, a density-based cleaning process such as a Falcon Concentrator to remove liberated pyrite and froth flotation to remove clays and other less-dense ash-forming minerals from the finest-sized fraction of the coal.

Mercury and Ash Reduction During the Cleaning of Northern Appalachian Coals

Coal	Circuit	Ash Reduction (%, Heat Unit Basis)	Mercury Reduction (%, Heat Unit Basis)	Ratio of Mercury/Ash Reductions
1	HMC †	45.7	9.3	0.20
	WOC-Spiral ‡	20.2	24.2	1.20
	Flotation	38.5	7.6	0.20
2	HMC	79.0	28.4	0.36
	WOC-Spiral	33.2	62.1	1.87
	Flotation	56.7	38.5	0.68
3	HMC	76.4	28.1	0.37
	WOC-Spiral	25.1	51.8	2.06
	Flotation	56.2	22.1	0.39
4	HMC	57.7	33.9	0.59
	WOC-Spiral	17.7	18.0	1.02
	Flotation	47.0	24.2	0.51

† Heavy-media cyclone
‡ Water-only cyclone/concentrating spiral (two-stage circuit)

Figure 2.6.2

Another option for increasing trace element removal beyond what can be achieved by physical cleaning processes is to develop chemical processes that specifically target trace elements. While chemical cleaning technologies have been developed that can remove ash and sulfur from coal and would likely remove trace elements, these processes require rather extreme conditions and have not yet proved to be economical. However, the geochemistry of trace elements is different than that of ash- and sulfur-bearing minerals and the lack of success with the one does not prove that the other can't be done. For example, CQ Inc. and Howard University have developed a process for removing large amounts of mercury from coal using mild chemical conditions, and further work in this area is warranted[7].

Ultimately, the success of using cleaning to reduce the trace element content of coals will depend on the percentage of the element that is bound organically, the mode of occurrence and the textural characteristics of the host minerals, the potential for liberation of the host minerals, the method of cleaning and the economics of cleaning more intensely.

Changes In Combustion Characteristics With Cleaning*

(%)

Seam Name	Illinois No. 6	Kentucky No. 11	Lower Kittanning	Robinson	Stockton Lewiston	Upper & Lower Freeport	Upper Kittanning
Location (county, state)	Perry, IL	Union, KY	Cambria, PA	Bighorn, MT	Kanawha, WV	Clearfield, PA	Nicholas, WV
Ash Loading (lb/MBtu)	16.3–6.6	48.4–5.1	21.6–3.9	9.4–5.3	48.7–14.4	9.1–3.8	11.9–3.7
Potential SO_2 Emmissions (lb/MBtu)	6.82–4.50	9.80–4.80	2.43–1.04	1.64–0.67	1.50–1.20	2.46–0.94	1.84–1.62
Volatile Matter (wt%, dry basis)	36.4–41.9	29.9–42.0	17.2–19.9	37.4–37.8	24.2–31.9	24.8–27.9	32.3–37.2
Fouling Index	0.59–0.07	0.28–0.82	0.04–0.08	2.1–4.8	0.04–0.04	0.10–0.05	0.11–0.29
Silica Percentage	66–73	73–61	85–76	58–53	91–92	74–88	88–77
Slagging Index	1.65–0.86	1.30–1.60	0.21–0.12	2,008–2,172	0.07–0.07	0.43–0.09	0.15–0.24
EPRI Report Number	CS-3666	CS-4434	CS-4548	CS-081	CS-4433	CS-3808	CS-4866

Figure 2.6.3

*First value shown is for raw coal. Second value is for clean coal.

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APPENDIX 2.7

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Global Energy Decisions

The Coal Policy Committee

APPENDIX 2.8

Abbreviations

AAR	American Association of Railroads
ACC	American Coal Council
ACI	activated carbon injection
AEO	Annual Energy Outlook
AEP	American Electric Power
AJCAct2004	American Job Creations Act of 2004
AMT	Alternative Minimum Tax
APCD	air pollution control devices
ARI	Advanced Resources International
ARM	Advanced Research Materials
B&W	Babcock and Wilcox
BACT	best available control technology
bbl	barrel(s)
bbl/d	barrels per day
bcf	billion cubic feet
bcf/d	billion cubic feet per day
BRAC	Base Realignment And Closure
Btu	British thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAR	Cooperative Automotive Research
CCP	Coal Combustion Products
CCP2	CO_2 Capture project – Phase 2
CCPC	Canadian Clean Power Consortium
CCPI	Clean Coal Power Initiative
CCS	CO_2 capture and storage
CERA	Cambridge Energy Research Associates
CFB	circulating fluidized bed
CHP	combined heat and power
CNOOC	Chinese crude oil and natural gas developer (no English translation for acronym)
CNPC	China National Petroleum Council

CO_2	carbon dioxide
CO_2CRC	Cooperative Research Centre for Greenhouse Gas Technologies
COE	cost of electricity
CS	carbon sequestration
CSLF	Carbon Sequestration Leadership Forum
CSM/IFP	Colorado School of Mines/Instituit Français du Petrole
CT	cooling tower
CTG	coal to gas
CTL	coal to liquid
DCL	direct coal to liquids
DCS	distributed control systems
DDGS	distillers dried grains with solubles
DKRW	Doyle Kelly Ramm & White Energy, LLC
DOE	Department of Energy
DRB	demonstrated reserve base
EIA	Energy Information Administration
EOR	enhanced oil recovery
EPA	Environmental Protection Agency
EPAct2005	Energy Policy Act of 2005
EPIC	Econo-Power International Corporation
ESA	Economics and Statistics Administration
ESP	electrostatic precipitators
FEED	front end engineering and design
FERC	Federal Energy Regulatory Commission
FF	fabric filter
FGD	flue gas desulfurization
FT	Fischer-Tropsch
GCCC	Gulf Coast Carbon Center
GCCI	Global Climate Change Initiative
GDP	Gross Domestic Product
GE	General Electric
GHG	greenhouse gas
GOM	Gulf of Mexico

GRE	Great River Energy
Gt	gigaton
GVW	Gross Vehicle Weight
GW	gigawatt
GW_E	gigawatt of electricity
H_2	hydrogen
H_2SO_4	sulfuric acid
HCl	hydrogen chloride
HCN	hydrogen cyanide
HF	hydrogen fluoride
HFCS	high fructose corn syrup
HHV	high heating value
HRI	Hydrocarbon Research, Inc.
HTF	Highway Trust Fund
HTI	Hydrocarbon Technologies, Inc.
ICL	indirect coal to liquids
ICM	intracytoplasmic membranes
ITP	Industrial Technologies Program
IEA	International Energy Authority
IGCC	integrated gasification combined cycle
IOF	Industries of the Future
IPCC	Intergovernmental Panel on Climate Change
ITM	ion transport membrane
kWh	kilowatt-hour
LFC	liquids from coal
LHV	lower heating value
LNG	liquefied natural gas
LPG	liquefied petroleum gas
M85	85% methanol, 15% gasoline
Mcf	thousand cubic feet
MEA	monoethanolamine
MEPI	Midwest Ethanol Producers
MITRE	company name, not an acronym

MMbbl/d	million barrels per day
MMBtu	million British thermal units
mt	million tons
MTBE	methyl tertiary-butyl ether
MW	megawatt
MW/HR	megawatt per hour
NAAQS	National Ambient Air Quality Standards
NACC	North American Coal Corporation
NASA	National Aeronautics and Space Administration
NATCARB	National Carbon Sequestration Database and Geographical Information System
NCC	National Coal Council
NETL	National Energy Technology Laboratory
NG	natural gas
NGL	natural gas liquids
NGCC	natural gas combined cycle
NH_3	ammonia
NIOSH	National Institute for Occupational Safety and Health
NMA	National Mining Association
NO_X	nitrogen oxide
NPC	National Petroleum Council
NSPS	New Source Performance Standards
NSR	New Source Review
O&M	operations and maintenance
OCDC	Ohio Cooperative Development Center
OIL	Oil India Ltd.
OPEC	Organization of the Petroleum Exporting Countries
ORNL	Oak Ridge National Laboratory
OSM	Office of Surface Mining
PAC	powdered activated carbon
PC	pulverized coal
PCC	pulverized coal combustion
PC/CFB	pulverized coal/circulating fluidized bed
PC/SC	pulverized coal-fired supercritical steam cycles

PEM	polymer electrolyte membrane
PM	particulate matter
PRB	Powder River Basin
psi	pounds per square inch
R&D	research and development
RD&D	research, development and demonstration
RFS	renewable fuels standard
SAFETEA-LU	Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users
SCPC	supercritical pulverized coal
SCR	selective catalytic reduction
SDA	spray dryer absorption
SECA	Solid State Energy Conversion Alliance
SMCRA	Surface Mining Control and Reclamation Act of 1977
SMR	steam methane reforming
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
st/d	standard tons per day
SU/SD	start up/shut down
Tcf	trillion cubic feet
tpy	tons per year
USACE	United States Army Corps of Engineers
USC	Ultra Supercritical
USCPCC	Ultra Supercritical Pulverized Coal Combustion
USGS	United States Geological Survey
VEETC	Volumetric Ethanol Excise Tax Credit
VOC	volatile organic compounds
WFGD	wet flue gas desulfurization (wet scrubbing)
WMPI	Waste Management & Processors, Inc.

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