Glossary of Technical Terms and Abbreviations

ARD&D
Analysis, Research, Development, and Demonstration

ASU
Air Separation Unit

BACT
Best Available Control Technology

BAU
Business As Usual

CAIR
Clean Air Interstate Rule

CAMR
Clean Air Mercury Rule

CCS
Carbon Capture and Storage

CFB
Circulating Fluid Bed

CGE
Computable General Equilibrium

COE
Cost of Electricity, ¢/kW_e-h

CSLF
Carbon Sequestration Leadership Forum

EOR
Enhanced Oil Recovery

EPPA
Emissions Prediction and Policy Analysis Model (MIT)

EPRI
Electric Power Research Institute

ESP
Electrostatic Precipitator or Precipitation

FGD
Flue Gas Desulfurization

F-T
Fischer-Tropsch

GHG
Greenhouse Gas

HHV
Higher Heating Value, kJ/kg

HRSG
Heat Recovery Steam Generator

ICE
Injectivity, Capacity and Effectiveness

IECM
Integrated Environmental Control Model (Carnegie Mellon University)

IGCC
Integrated Gasification Combined Cycle

LAER
Lowest Achievable Emissions Rate

LLV
Lower Heating Value, kJ/kg

LNG
Liquified Natural Gas

LPG
Liquified Petroleum Gas

MDEA
Methyl-Diethanol Amine

MEA
Mono Ethanol Amine

MMV
Measurement, Monitoring, and Verification

NAAQS
National Ambient Air Quality Standards

NG
Natural Gas

NGCC
Natural Gas Combined Cycle

NPV
Net Present Value

O&M
Operating and Maintenance Costs, ¢/kW_e-h

PC
Pulverized Coal

PDF
Probability-Density Function

PDU
Process Demonstration Unit

PM
Particulate Matter

PRB
Powder River Basin

RD&D
Research, Development, and Demonstration

SC
Supercritical

SCPC
Supercritical Pulverized Coal

SCR
Selective Catalytic Reduction

SFC
Synthetic Fuel Corporation

SIP
State Implementation Plan

SNCR
Selective Non-Catalytic Reduction

SNG
Synthetic Natural Gas

SUBC
Subcritical

TCR
Total Capital Required, $/$kW_e$

TPC
Total Plant Cost, $/$kW_e$

UIC
Underground Injection Control

USC
Ultra-Supercritical

USGS
US Geological Survey

Chapter 3 Appendices

Appendix 3.A — Coal Quality

Coal type and quality can have a major impact on power plant heat rate, capital cost, generating efficiency, and emissions performance, as well as on the cost of electricity (COE). The carbon, moisture, ash, sulfur and energy contents, and the ash characteristics are all important in determining the value of the coal, its use in power generation, the choice of the technology employed, and its transportation and geographical extent of use.

Coal Reserves and Usage The estimated total recoverable coal reserves in the world are a little over 900 billion tonnes (long or metric tons), sufficient to meet current demand for almost 200 years [1]. The U.S. has about 255 billion tonnes of recoverable coal reserves or about 27% of the world total, more than any other country (See Figure 2.1, Chapter 2) [2]. Our coal reserves consist of about 48% anthracite and bituminous coal, about 37% subbituminous coal, and about 15% lignite. The distribution of coal reserves in the U.S. is shown in Figure A-3.A.1 [3]. Table A-3.A.1 gives the U.S. coal production by coal region for 2004.

Figure A-3.A.1 Distribution of Coal Reserves by Type in the U.S.

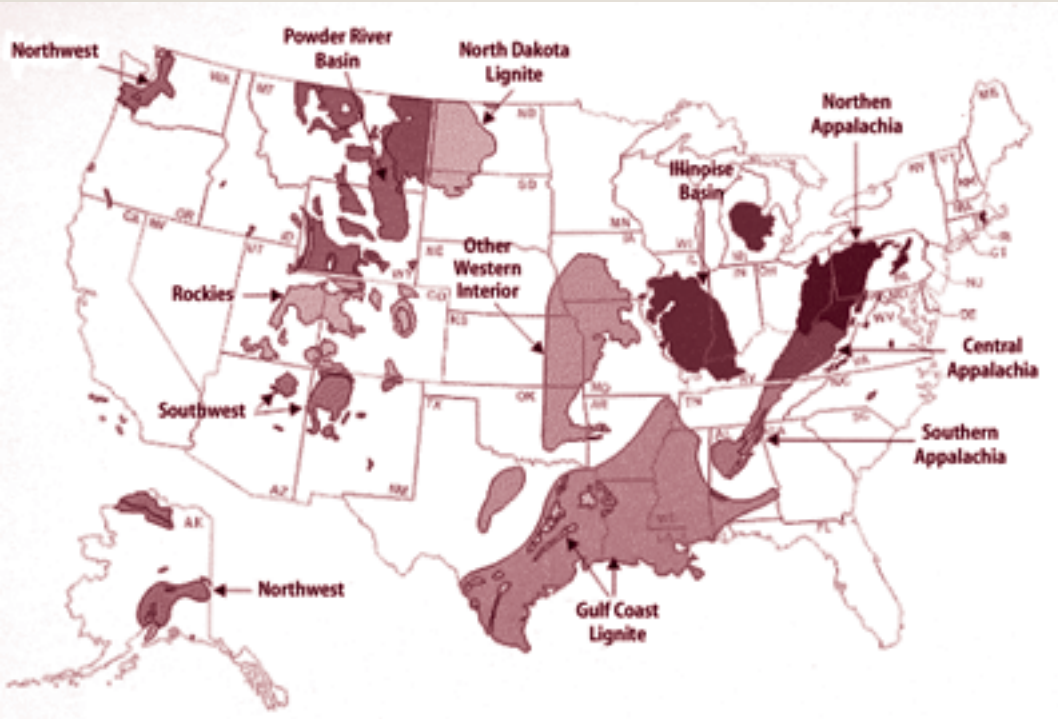


Table A-3.A.1 U.S. 2004 Coal Production by Coal Region

REGION	NORTHWEST	SOUTHWEST	ROCKIES	POWER RIVER BASIN (PRB)	N. DAKODA LIGNITE	OTHER WESTERN INTERIOR	GULF COAST LIGNITE	ILLINOIS BASIN (ILLIN #6)	NORTHERN APPALACHIAN (PITTS #8)	SOUTHERN APPALACHIAN	CENTRAL APPALACHIAN
2004 Coal Production, thousand tonnes	6.6	36.3	56	397	27.2	2.2	48.5	82	121.2	22.9	200

In 2004, total global coal consumption was over 5,400 million tonnes [2]. Of this, ~1,500 million tonnes (28%) were used by China, 985 million tonnes (18%) by the U.S., and 446 million tonnes (8%) by India. Western Europe and the Eastern Europe/Former Soviet Union states used 652 and 670 million tonnes, respectively (12% each)[2]. Our Emissions Prediction and Policy Analysis (EPPA) model [4] projects 2030 world coal consumption at about 10,340 million tonnes, with 2,360 million tonnes (23%) being used in China, 1,550 million tonnes (15%) in the U.S., and 970 million tonnes (9.4%) in India.

COAL TYPES AND CHARACTERISTICS Figure A-3.A.2 provides a general overview of coal properties by type for the U.S., China, and India. Coal types range from anthracite, with a heating value (HHV) upwards of 30,000 kJ/kg (13,000 Btu/lb) to lignite with a heating value around 14,000 kJ/kg (6,000 Btu/lb). Heating value and mine-mouth cost typically vary directly with carbon content, whereas sulfur and ash content vary widely and depend primarily on site-specific geologic conditions. Moisture content normally increases from bituminous coal to lignite.

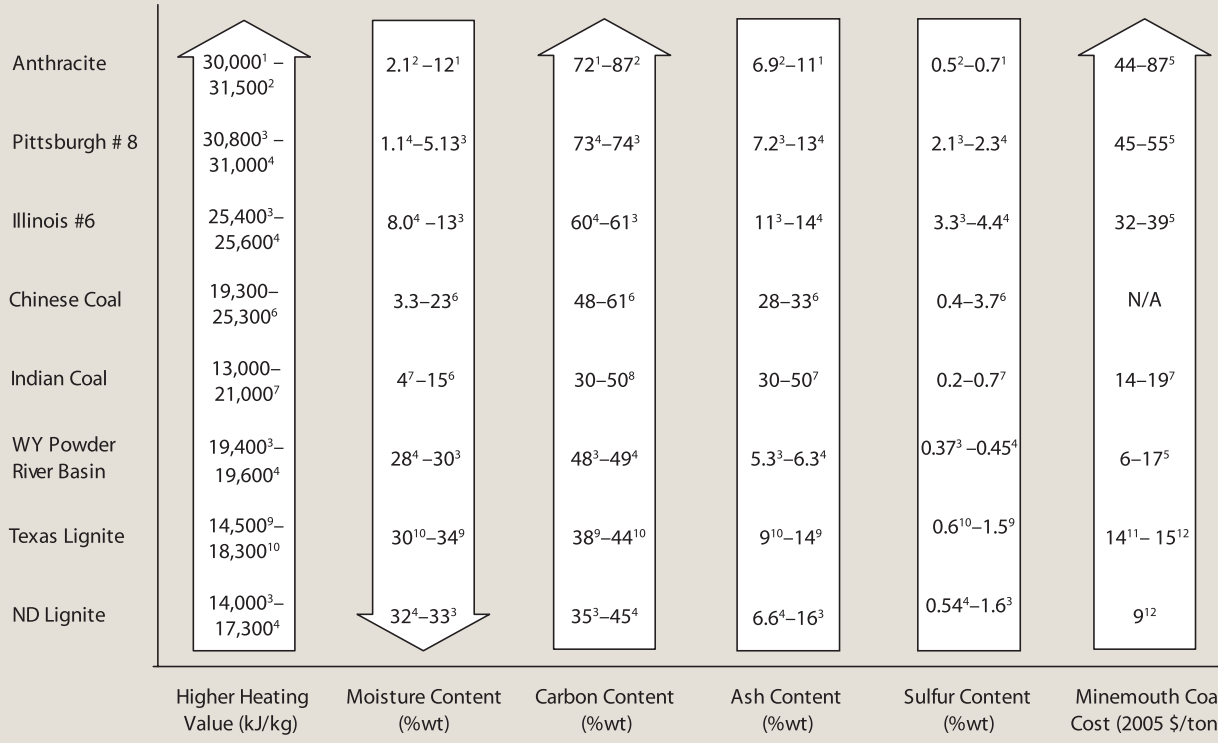
Coals that are typically used for electric power production in the U.S. include high-and medium-sulfur bituminous coals from the Appalachian regions and the Illinois Basin, and low-sulfur subbituminous coals and lignites from the Northern Plains, the Powder River Basin (PRB), and the Gulf Coast regions. Anthracite is generally used only for metallurgical applications. Chinese coals are typically bituminous varieties with relatively high ash content and varying sulfur content, and Indian coals are generally low-sulfur bituminous varieties with unusually high ash content.

COMPONENT IMPACTS Most of the energy content in coal is associated with the carbon present. Higher-carbon coals normally have high energy content, are more valued in the market place, and are more suited for PC and IGCC power generation.

Generating plants designed for high carbon content fuels have a higher generating efficiency and lower capital cost, and could be more effectively designed for CO_2 capture.

Sulfur, on the other hand, tends to decrease PC boiler efficiency, because of the need to maintain higher boiler outlet temperature to avoid condensation of sulfuric acid and resultant corrosion problems in downstream equipment. The higher outlet temperature carries thermal energy out of the boiler rather than converting it into steam to drive the steam turbine. High-sulfur content also increases FGD power requirements and operating costs. For IGCC, sulfur content impacts the size of the clean-up process but has little effect on cost or efficiency[5]. Sulfur's biggest impact to date has been to drive a shift from eastern high-sulfur coals to western low-sulfur subbituminous coals to avoid installing FGD units on operating PC plants or to minimize FGD operating costs on new plants. For CO_2 capture, high-sulfur coals may cause increased complications with the capture technologies.

Figure A-3.A.2 Coal Characteristics by Coal Type



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2. Edward Aul & Associates, Inc., & E.H. Pechan & Associates, Inc., "Emission Factor Documentation for AP-42 Section 1.2 Anthracite Coal Combustion," U.S. EPA, Research Triangle Park, NC, 1993.

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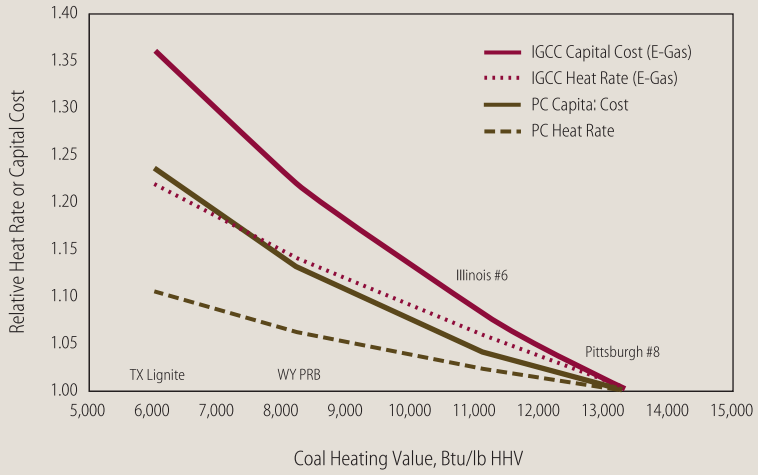
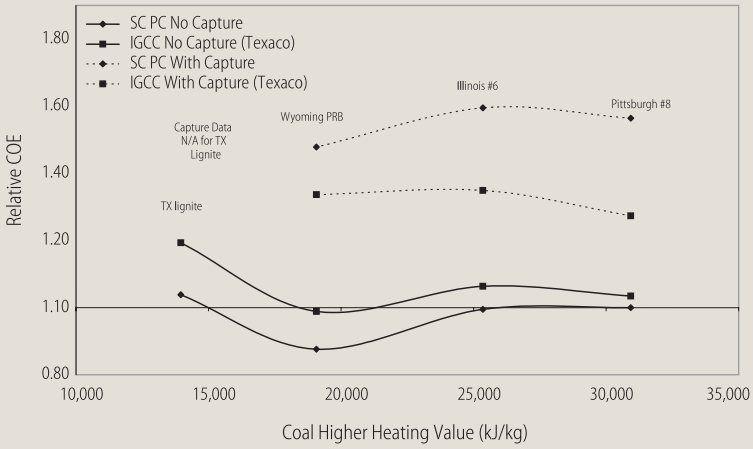
Coal ash content and properties affect boiler design and operation. High-ash coals cause increased erosion and reduce efficiency, and may be more effectively handled in circulating fluid-bed boilers. Boilers are designed for the ash to exit the boiler either as a molten slag (wet bottom boilers), particularly for low fusion temperature ash, or as a fly ash (dry bottom boilers). Most boilers are dry ash designs. For IGCC plants, coal ash consumes heat energy to melt it, requires more water per unit carbon in the slurry, increases the size of the ASU, increases the cost per kW_e, and reduces the overall generating efficiency. This has a larger effect with slurry-feed gasifiers, and as such, high-ash coals are more suited to dry-feed systems (Shell), fluid-bed gasifiers (BHEL), or moving-bed gasifiers (Lurgi)[5].

Figure A-3.A.3 PC And IGCC Relative Heat Rate And Capital Cost



Adapted from National Coal Council[5], heat rate is 3414 Btu/kW$_e$-h divided by plant generating efficiency.

Figure A-3.A.4 Effect of Coal Quality on COE for Generation with and without CO_2 Capture



**Based on minemouth coal cost (not including transportation costs).*

Higher moisture content coals reduce generating efficiency in PC combustion plants and reduce gasifier efficiency in IGCC plants, increasing cost/kW$_e$ [6, 7]. CFB boiler size and cost also increases with higher moisture coals, but the effect is less pronounced than for PC systems. Slurry-fed gasifiers have the same problems with high-moisture coals as with high-ash coals. They both decrease the energy density of the slurry, increase the oxygen demand for evaporation of the excess moisture, increase cost per kW$_e$, and decrease generating efficiency.

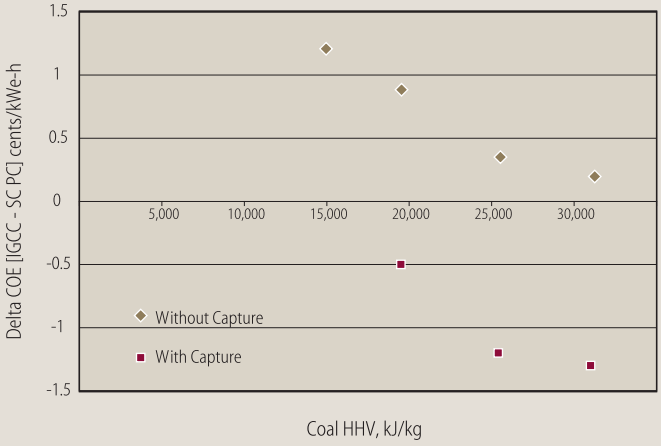
IMPACT ON GENERATING EFFICIENCY, CAPITAL COST, AND COE Generating efficiency is affected by coal quality, as is capital cost. The high moisture and ash content of low-quality coals reduce generating efficiency, and increase capital cost. Figure A-3.A.3 shows how generating efficiency, expressed as heat rate [8], and capital cost change for both PC and slurry feed IGCC plants with coal quality [5]. Relative CO_2 emissions follow heat rate, and therefore the curve for relative heat rate in Figure A-3.A.3 also represents the relative CO_2 emissions per kW$_e$-h.

However, the cost of electricity (COE) need not necessarily increase as coal quality decreases, as would be suggested by Figure A-3.A.3. This is because mine-mouth coal cost decreases with coal quality, and to a different extent than heat rate (generating efficiency) and capital cost increase. Actual COE will be highly dependent on coal cost and coal transportation cost, which can vary with coal type, time, and geographic location. Figure A-3.A.4 indicates how COE can vary with coal quality at average 2004 minemouth costs.

Although many assumptions are involved, these relative COE numbers show directionally the technology dependence of COE difference as a function of coal heating value. Figure A-3.A.5 shows the relative trend in the COE difference between IGCC and supercritical PC combustion as a function of coal type using 2004 mine mouth coal prices. Without CO_2 capture, the COE for SC PC is less than the COE for IGCC, and the gap widens for lower heating value coals. With CO_2 capture, the COE for IGCC is lower than that for SC PC, and the delta is therefore negative. However, the delta is projected to decrease with decreas-

ing coal heating value, as shown in Figure A-3.A.5. This is for a water-slurry feed gasifier, and estimates are based on limited data. A dry-feed gasifier should show better performance, although the impact on the cost deltas is unclear because of its higher cost. Figure A-3.A.5 suggests that an ultra-supercritical PC with a reduced-energy capture system could potentially be competitive with IGCC for low rank coals such as lignite.

Figure A-3.A.5 Projected Relative COE Performance (IGCC Vs. SC PC) as a Function of Coal Rank Using 2004 Mine Mouth Coal Cost



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5. NCC, *Opportunities to Expedite the Construction of New Coal-Based Power Plants*. 2004, National Coal Council.
6. Holt, N., *Gasification and IGCC - Status, Challenges, Design Issues & Opportunities*, in *Reaction Engineering International*. 2005.
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8. Heat rate is the thermal energy input to the generating plant per kWe-h of net electricity generated. Heat rate is 3414 Btu/kWe-h divided by the efficiency.

Appendix 3.B — Electricity Generation Primer

INTRODUCTION

This primer provides the next higher level of detail on coal-based electric power generation beyond that included in Chapter 3. To explore the subject further, we suggest the following references [1-4].

The electricity generating efficiency is the energy in the net electricity generated divided by the energy in the fuel used to generate that electricity on an all-in basis. Higher efficiency means less coal consumed and reduced emissions per unit of electricity. The chemical energy in the fuel can be expressed as either its Lower Heating Value (LHV) or its Higher Heating Value (HHV) [5]. In U. S. engineering practice, HHV is generally used for steam cycle plants; whereas in European practice, efficiency calculations are uniformly LHV based. The difference in efficiency between HHV and LHV for bituminous coal is about 2 percentage points absolute (5% relative), but for high-moisture subbituminous coals and lignites the difference is 3 to 4 percentage points. The efficiency of gas turbines is on an LHV basis in the U. S. and Europe. The thermal efficiency of an electricity generating plant may also be expressed as the "heat rate", the fuel thermal energy consumption per unit of electricity produced, in kJ/kW_e-h or Btu/kW_e-h [6].

For the technology comparisons in this report, each of the generating technologies considered was a green-field unit, and each unit contained all the emissions control equipment required and was designed to achieve emissions levels somewhat lower than the current, best-demonstrated low criteria emissions performance. The design performance and operating parameters for these generating technologies was based on the Carnegie Mellon Integrated Environmental Control Model (IECM), version 5.0 [7] which is specific to coal-based power generation. The IECM model was used to achieve numbers with a consistent basis for comparison of the individual technologies. Other models would each give a somewhat different set operating parameters, such as overall generating efficiency, because of the myriad of design and parameter choices, and engineering approximations used. Thus, the numbers in this report will not exactly match other numbers found in the literature, because of these different design and operating bases and assumptions. Mature commercial technology, such as subcritical PC boiler and generator technology, was estimated based on current performance. Commercial technologies that are undergoing significant evolution, such as more efficient emissions control and IGCC technologies, were estimated based on the n^{th} plant, where n is a small number such as 5 or 6, in 2005 $.

Coal type and properties are important in the design, operation, and performance of a power generating unit. The units all burn Illinois # 6 bituminous coal, a high-sulfur, Eastern U.S. coal with a moderately high heating value. Detailed analysis is given in Table A-3.B.1 [7].

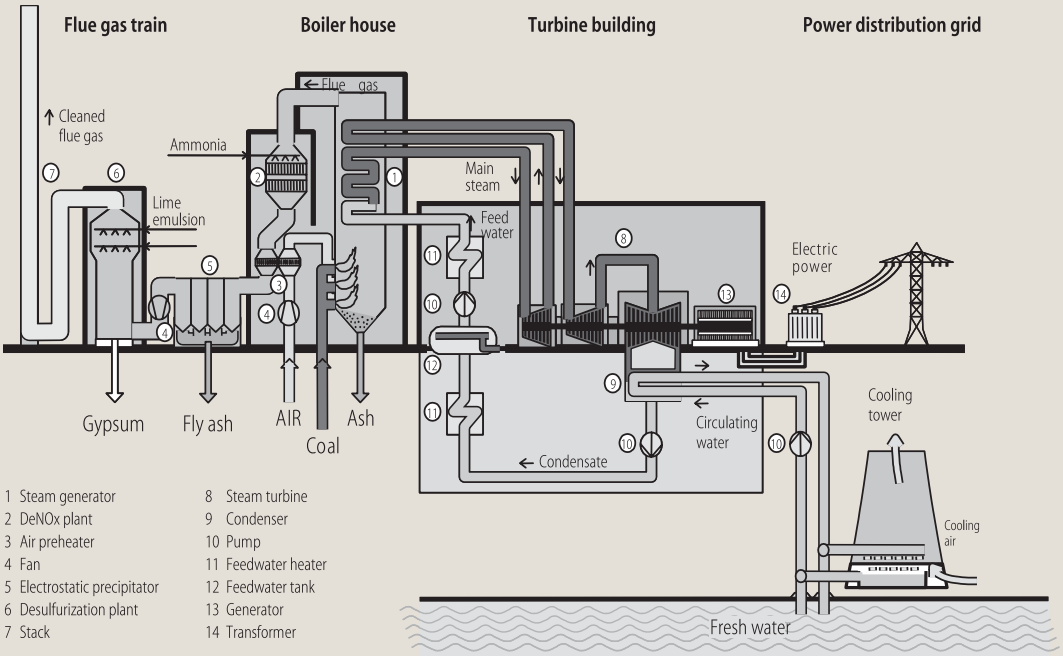
Table A-3.B.1 Analysis of Illinois #6 Bituminous Coal Used in the Design Base of Each of the Green-Field Generating Technologies

ILLINOIS #6 BITUMINOUS COAL FUEL ANALYSIS — AS RECEIVED		COMPONENT	% WT
		Carbon	61.20
		Hydrogen	4.20
		Oxygen	6.02
		Chlorine	0.17
HIGH HEATING VALUE	25,350 kJ/kg (10,900 Btu/lb)	Sulfur	3.25
		Nitrogen	1.16
		Ash	11.00
LOW HEATING VALUE	24,433 kJ/kg (10,506 Btu/lb)	Moisture	13.00
		Mercury	1.04E-05

AIR-BLOWN PULVERIZED COAL COMBUSTION

Figure A-3.B.1 shows an advanced, pulverized coal (PC) unit that meets today's low, permitted emissions levels [8]. The three main components of a PC unit are: (1) the boiler block where coal is burned to generate steam in the boiler tubes; (2) the generator block, which contains the steam turbine/electric generator set and manages the steam, condenser, and cooling water; and (3) the flue gas clean-up train, which removes particulates and criteria pollutants from the flue gas. The flue gas clean-up section contains Selective Catalytic Reduction (SCR) for NO_x removal, followed by electrostatic precipitation (ESP) to remove particulate matter, and wet flue gas desulfurization (FGD) to remove SO_x. The choice of coal, and the design and operation of the flue gas units is to assure that emissions are below the permitted levels.

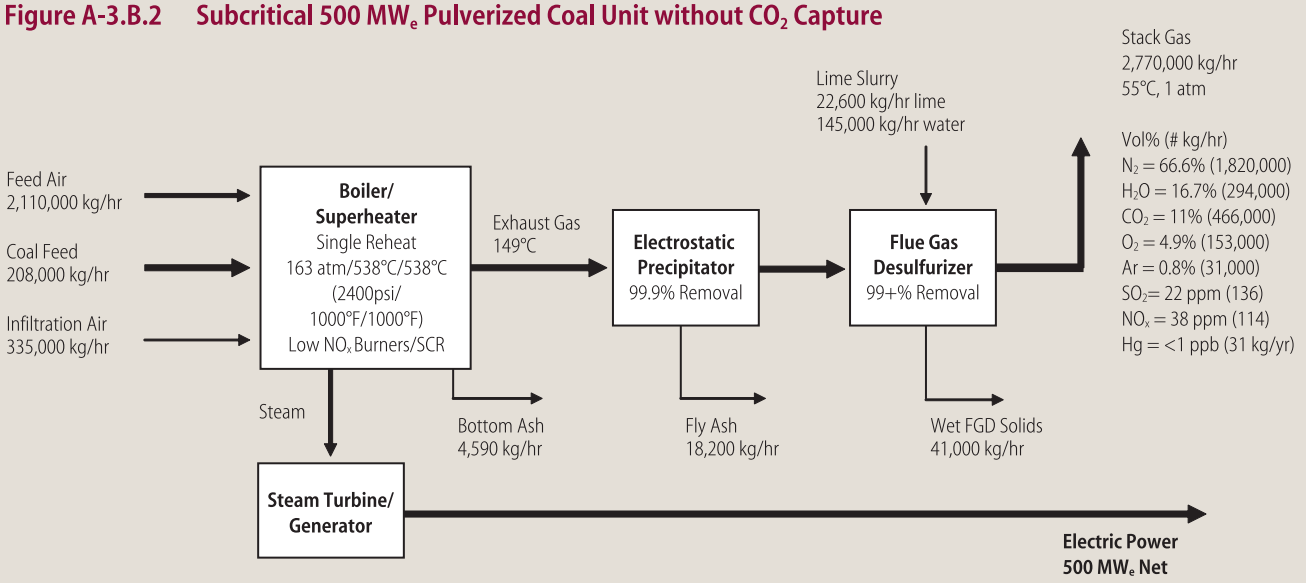
Figure A-3.B.1 Schematic of an Advanced, Low-Emissions, Pulverized Coal Unit



Courtesy ASME.

PC GENERATION: WITHOUT CO_2 CAPTURE Figure A-3.B.2 is a detailed schematic of a subcritical PC unit with the important stream flows and conditions given [7, 9][10]. Air infiltrates into the boiler because it operates at below-atmospheric pressure so that hot, untreated combustion gases do not escape into the environment. Total particulate material removal is 99.9%, most of it being removed as fly ash by the electrostatic precipitator. Particulate emissions to the air are 11 kg/hr. NO_x emissions is reduced to 114 kg/hr by a combination of low-NO_x combustion management and SCR. The flue gas desulfurization unit removes 99+% of the SO_2 reducing SO_2 emissions to 136 kg/hr. For Illinois #6 coal, the mercury removal with the fly ash and in the FGD unit should be 70-80% or higher. For these operating conditions, the IECM projects a generating efficiency of 34.3% for Illinois #6 coal. For Pittsburgh #8 (bituminous coal) at comparable SO_x and NO_x emissions, IECM projects a generating efficiency of 35.4% [7]. For Powder River Basin (subbituminous coal) and North Dakota Lignite at comparable emissions IECM projects generating efficiencies of 33.1% and 31.9% respectively.

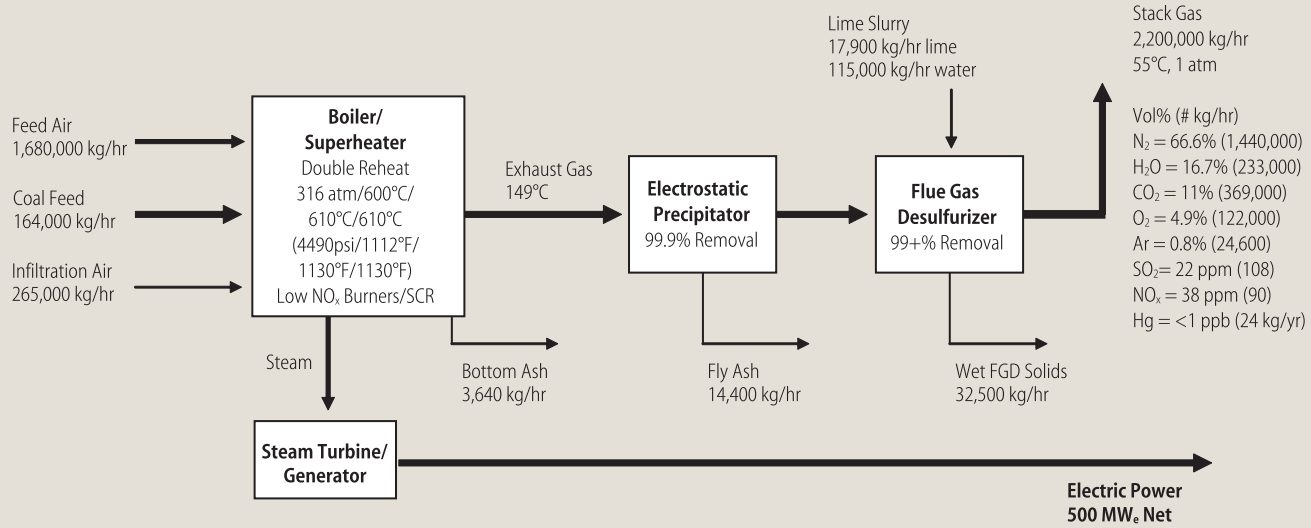
Figure A-3.B.2 Subcritical 500 MW_e Pulverized Coal Unit without CO_2 Capture



Booras and Holt [11], using an EPRI electricity generating unit design model, project 35.6% generating efficiency for Illinois #6 coal, at 95% sulfur removal and <0.1 lb NO_x/million Btu. Under the same operating and emissions control conditions, they calculated a generating efficiency of 36.7% for Pittsburgh # 8 coal, which is similar to the efficiency reported by the NCC study [12]. The difference between Illinois # 6 and Pittsburgh # 8 is due to coal quality and is the same for both models, about 1 percentage point. We attribute the IECM and EPRI model differences to the higher levels of SO_x and NO_x removal that we used and to differences in model parameter assumptions. For Illinois # 6 coal, increasing SO_x and NO_x removal from the levels used by Booras and Holt to those used in this study reduces the generating efficiency by about 0.5 percentage point. The rest of the difference is almost certainly due to model parameter assumptions. For example, cooling water temperature, which has a large effect, could be one.

Figure A-3.B.3 is the schematic of an ultra-supercritical PC unit with the stream flows and operating conditions given. Flue gas emissions control efficiencies are the same. The main

Figure A-3.B.3 Ultra-Supercritical 500 MW_e Pulverized Coal Unit without CO_2 Capture



differences, compared to the subcritical PC unit, are: the generating efficiency, which is 43.3% vs. 34.3%; and the coal feed rate which is 21% lower, as is the CO_2 emissions rate. Other pollutant generation rates are lower also, but their emission rate is determined by the level of flue gas emissions control.

CFB POWER GENERATION: The most commonly used fluid-bed technology today is the circulating fluid bed combustor, of which one version is shown in Figure A-3.B.4. Coal and coal char are burned while the coal, coal char, coal ash, and sorbent are carried up through the furnace by combustion air. The solid materials are separated from the flue gas in the cyclone and pass though a convective section where heat is transferred to boiler tubes generating high-pressure steam. Additional steam is generated by removing heat from the hot solids in the fluid bed heat exchange section before they are returned to the furnace. There are no boiler tubes in the furnace because the rapidly moving solids cause excessive erosion. NO_x is managed through low combustion temperature and staged injection of the combustion air. SO_x emission is controlled via the lime sorbent in the bed. This saves significant capital for flue gas clean-up, but low SO_x emissions require low-sulfur coal, and NO_x emissions are limited by combustion chemistry. Extremely low emissions levels would require the addition of flue gas clean-up units with the attendant cost increase. The largest CFB unit is 320 MW_e in Japan, and 600 MW_e units have been designed, but no unit this size has been built. CFB units are best suited to low-value feedstocks such as high-ash coals or coal waste. They are very feed flexible and can also burn biomass. Figure A-3.B.5 shows the schematic for a CFB power generating unit burning lignite with the flows and operating conditions given.

Figure A-3.B.4 Example Design Configuration of a Circulating Fluid-Bed Boiler

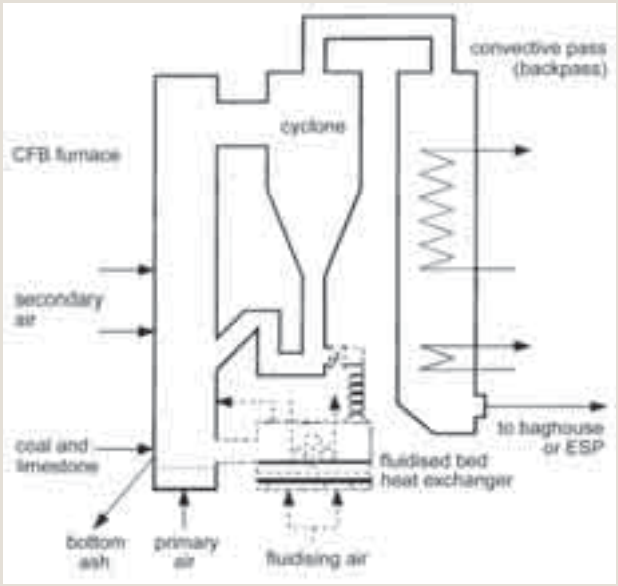


Figure A-3.B.5 500 MW_e Circulating Fluid-Bed Electricity Generating Unit Burning Lignite

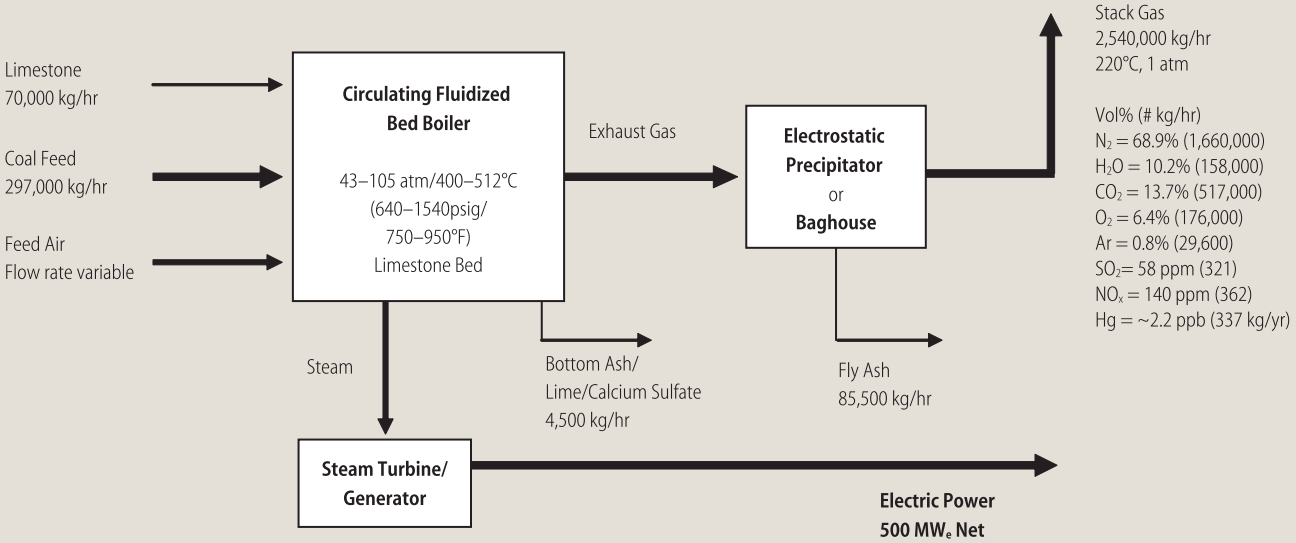
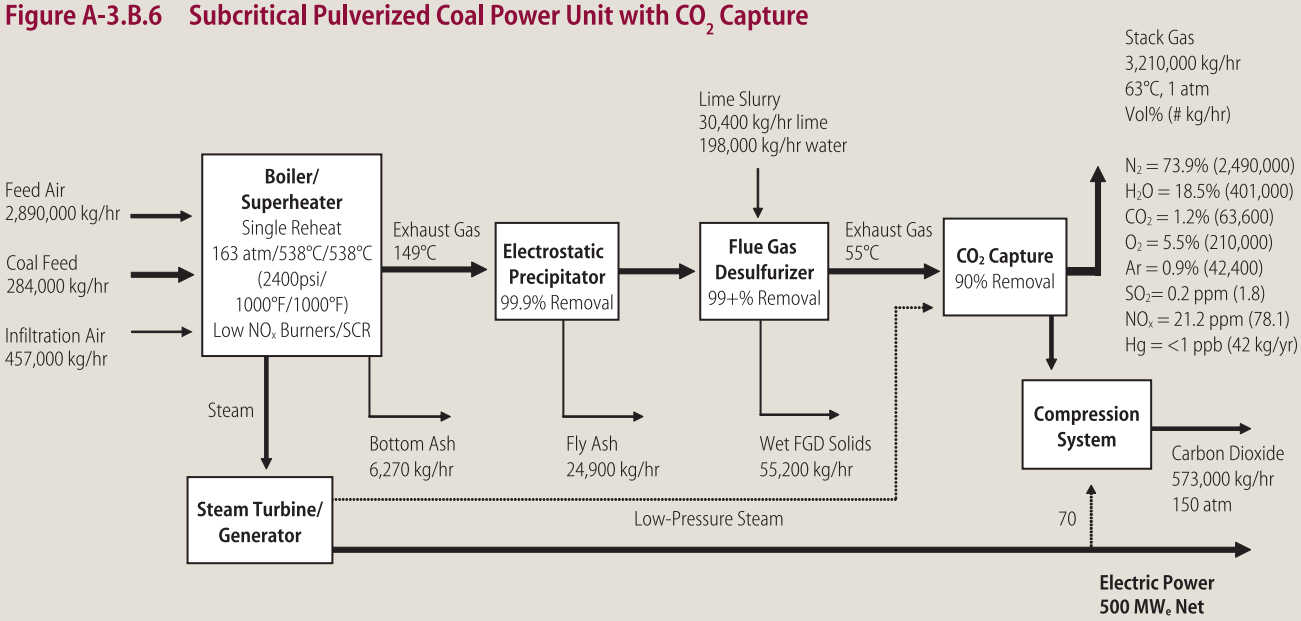


Figure A-3.B.6 Subcritical Pulverized Coal Power Unit with CO_2 Capture



PC GENERATION: WITH CO_2 CAPTURE Figure A-3.B.6 is a detailed schematic of a subcritical PC unit with amine-based CO_2 capture to reduce CO_2 emissions by 90%. The internal power requirement for CO_2 capture and recovery is equivalent to almost 130 MW_e, most of which is in the form of the low-pressure steam required to recover the absorbed CO_2 from the amine solution. Compression of the CO_2 consumes 70 MW_e. This additional internal energy consumption requires 76,000 kg/hr additional coal, a 37% increase, over the no-capture case to produce the same net electricity. All associated equipment is also effectively 37% larger. Design and operating experience, and optimization could be expected to reduce this somewhat; as could new technology.

The process technology added for the capture and recovery of CO_2 effectively removes most of the SO_2 and PM that are not removed earlier in the flue-gas train so that their emissions are now extremely low, an added benefit of CO_2 capture.

Figure A-3.B.7 illustrates the effect of adding amine-based CO_2 capture to an ultra-supercritical unit. For 90% CO_2 capture, the internal energy consumption for capture and compression per unit of coal feed (or CO_2 captured) is the same for all the PC combustion technologies. However, for increasing technology efficiency, the coal consumtion per net kW_e-h produced, decreases leading to a reduced impact of CO_2 capture on the overall energy balance for the system. For ultra-supercritical PC, the efficiency reduction for CO_2 capture is 21% vs. 27% for subcritical PC.

OXYGEN-BLOWN POWER GENERATION

The major cost associated with CO_2 capture from air-blown PC combustion is the low CO_2 concentration in the flue gas due to nitrogen dilution. Oxygen-blown combustion can avoid this and allow the direct compression of the flue gas which is then primarily composed of CO_2 and water. This should reduce the cost associated with the capture of CO_2 in coal combustion based power generation.

Figure A-3.B.7 Ultra-Supercritical Pulverized Coal Unit with CO_2 Capture

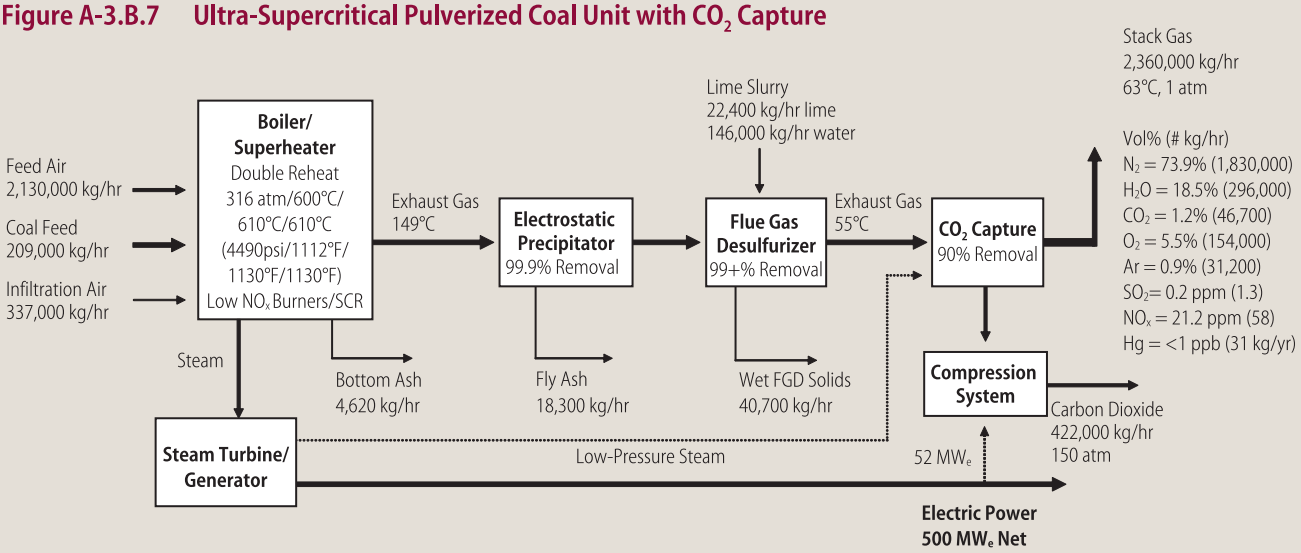
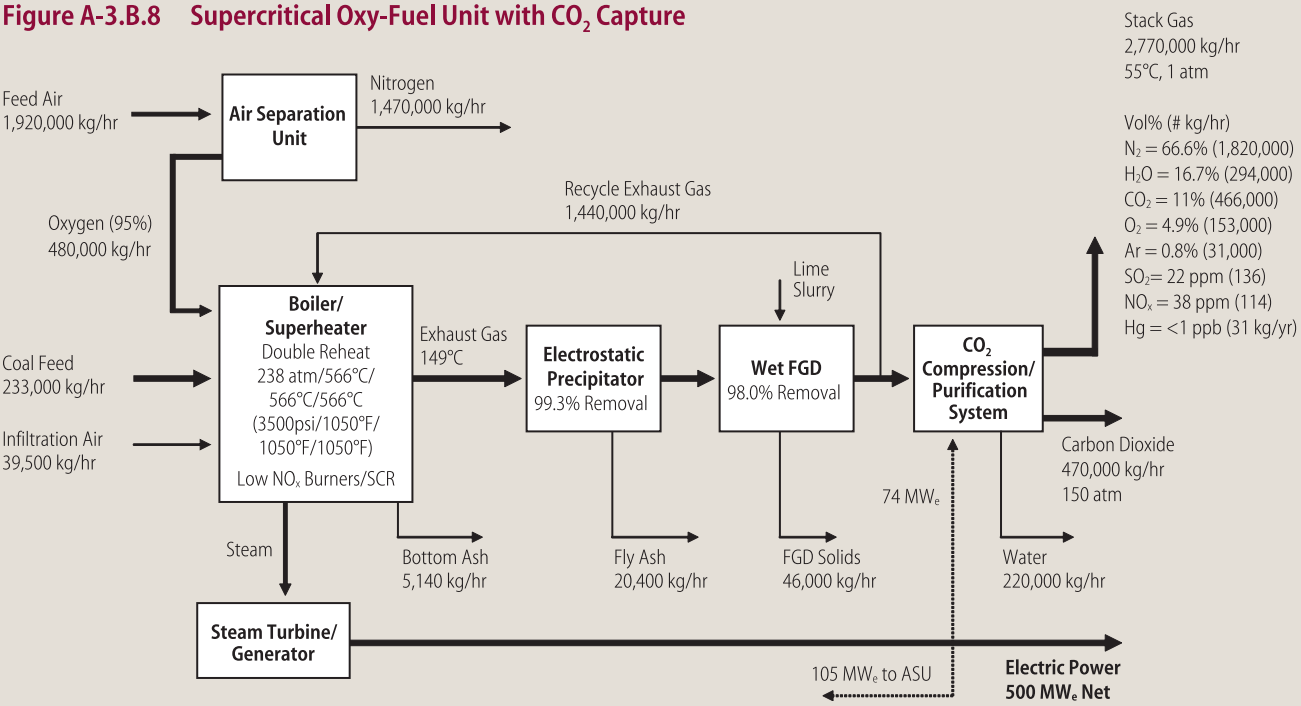


Figure A-3.B.8 gives a detailed schematic for a 500 MW_e Supercritical Oxy-Fuel Power unit. In this design version of oxy-fuel PC, the flue gas is cleaned to achieve a high purity CO_2 stream after compression. The stack gas is decreased by almost 95% and criteria pollutant emissions would readily meet today's low permit levels. ASU and the CO_2 compression-purification consume about 180 MWe of internal power, which is what drives the increased coal feed rate. The separate wet FGD step may be eliminated for low-sulfur coal and/or with upgraded metallurgy in the boiler and combustion gas handling system. Further, with a newly designed unit it may be possible to eliminate the recycle entirely. These changes could reduce capital and operating costs significantly. If the CO_2 stream does not need to be high purity for sequestration, it may be possible to reduce the degree of CO_2 clean-up and the attendant cost. If air infiltration is sufficiently low, it may even be possible to eliminate the stack gas stream. These issues need further design clarification and experimental PDU verification since they represent potentially significant cost reductions.

Figure A-3.B.8 Supercritical Oxy-Fuel Unit with CO_2 Capture



INTEGRATED COAL GASIFICATION COMBINED CYCLE (IGCC) TECHNOLOGY

GASIFIER TYPES A number of gasifier technologies have been developed. They are classified and summarized in Table A-3.B.2. Operating temperature for different gasifiers is largely dictated by the ash properties of the coal. Depending on the gasifier, it is desirable either to remove the ash dry at lower temperatures (non-slagging gasifiers) or as a low-viscosity liquid at high temperatures (slagging gasifiers). For all gasifiers it is essential to avoid soft ash particles, which stick together and stick to process equipment, terminating operation.

Table A-3.B.2 Characteristics of Different Gasifier Types (adapted from [3])

	MOVING BED	FLUID BED	ENTRAINED FLOW
Outlet temperature	Low (425–600 °C)	Moderate (900–1050 °C)	High (1250–1600 °C)
Oxidant demand	Low	Moderate	High
Ash conditions	Dry ash or slagging	Dry ash or agglomerating	Slagging
Size of coal feed	6–50 mm	6–10 mm	< 100 μm
Acceptability of fines	Limited	Good	Unlimited
Other characteristics	Methane, tars and oils present in syngas	Low carbon conversion	Pure syngas, high carbon conversion

The four major commercial gasification technologies are (in order of decreasing installed capacity):

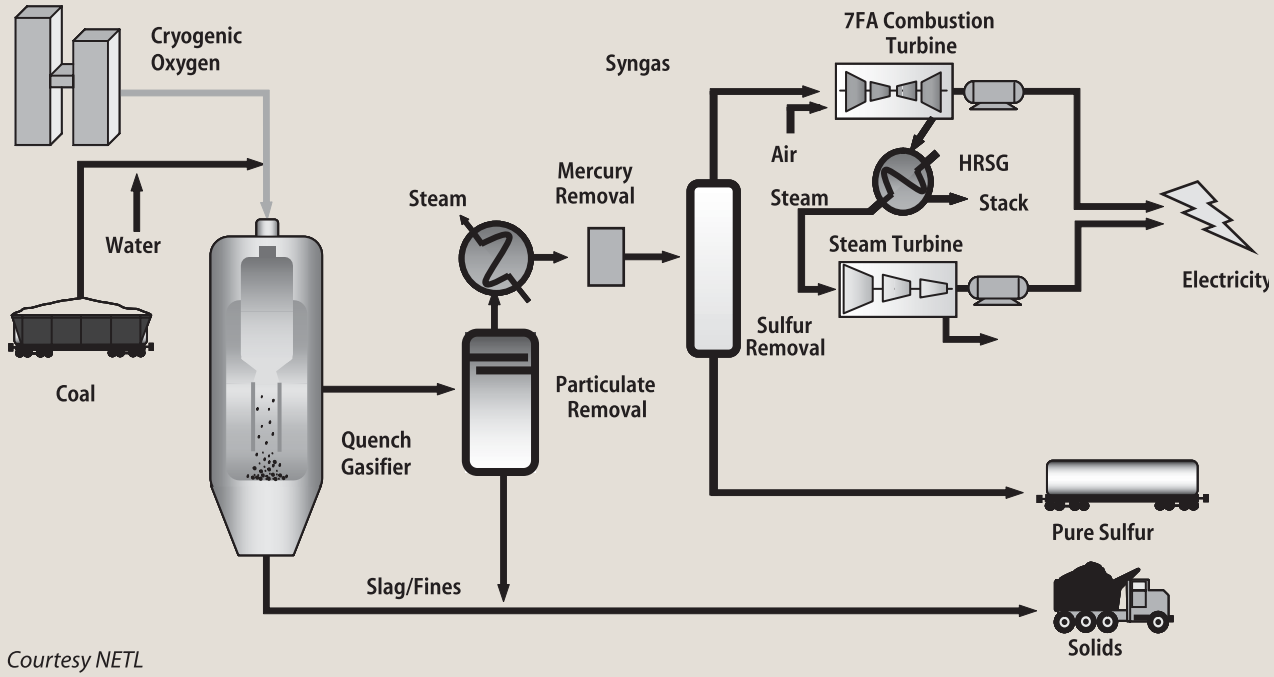
1. Sasol-Lurgi: dry ash, moving bed (developed by Lurgi, improved by Sasol)
2. GE: slagging, entrained flow, slurry feed, single stage (developed by Texaco)
3. Shell: slagging, entrained flow, dry feed, single stage
4. ConocoPhillips E-Gas: slagging, entrained flow, slurry feed, two-stage (developed by Dow Chemical)

The Sasol-Lurgi gasifier has extensive commercial experience at Sasol's synfuel plants in South-Africa. It is a moving-bed, non-slagging gasifier. The other three are entrained-flow, slagging gasifiers. The GE/Texaco and Shell gasifiers have significant commercial experience, whereas ConocoPhillips E-Gas technology has less commercial experience. Proposed IGCC projects are focusing on entrained-flow, slagging gasifiers. These gasifiers are all oxygen blown. A 250 MW_e air-blown IGCC demonstration plant is under construction for a 2007 start-up in Japan [13]. The gasifier is a two-stage, entrained-flow, dry-feed, medium-pressure, air-blown design.

Fluid-bed gasifiers are less developed than the two other gasifier types. Operating flexibility is more limited because they are typically performing several functions (e.g. fluidization, gasification, sulfur removal by limestone) at the same time [3]. The Southern Company is developing in Orlando, with DOE support, a 285 MW_e IGCC project which is based on the air-blown, KBR transport reactor[14, 15]. This fluid-bed gasifier has been developed at smaller scale and is potentially suited for low-rank coals with high moisture and ash contents [16].

GASIFIER DESIGN CONSIDERATIONS FOR IGCC Integration of gasification into the total IGCC plant imposes additional considerations on the technology [17]. Moving-bed gasification technology cannot deal with a significant fraction of coal fines, which means that 20–30%

Figure A-3.B.9 GE Full-Quench Gasifier Incorporated into an IGCC Unit



Courtesy NETL

of the processed coal cannot be fed to it. It also produces significant amounts of tars, etc. which cause downstream fouling problems. High-temperature, entrained-flow gasifiers do not have these issues and are thus more readily integrated into an IGCC system. High-pressure operation is favored for these units. The introduction of coal into a pressurized gasifier can be done either as dry coal feed through lock hoppers, or by slurrying the finely ground coal with water and spraying it into the gasifier. The latter introduces about 30 wt% liquid water, which is desirable for the gasification reactions if the coal has low moisture content. However, for high-moisture coals the gasifier feed can approach 50% water which increases the oxygen required to gasify the coal and vaporize the water, and reduces the operating efficiency. For high-moisture coals, a dry-feed gasifier is more desirable [18]. High-ash coals have somewhat the same issues as high-moisture coals, in that heating and melting the ash consumes considerable energy, decreasing the overall operating efficiency.

The gas temperature leaving entrained flow gasifiers is about 1500 °C and must be cooled for the gas clean-up operations. This can be accomplished downstream of the gasifier by direct quench with water as in the GE full-quench configuration shown in Figure A-3.B.9. This configuration has the lowest capital cost and the lowest efficiency [17, 19, 20].

The GE-type gasifier is lined with firebrick and does not accommodate heat removal. However, a radiant syngas cooler can be added to recover heat as high-pressure steam, as shown in Figure A-3.B.10, which is used to generate electricity in the steam turbine. In the Shell gasifier, gasification and radient heat removal are integrated into a single vessel. The membrane wall of the Shell gasifier, which becomes coated with a stable slag layer, recovers radiant heat energy via water filled boiler tubes. With the E-Gas gasifier, high-pressure steam is generated via radiant cooling in the second stage of the gasifier. This radiant heat recovery typically raises the overall generating efficiency by 3 percentage points [17]. Additional energy can be recovered, producing steam, by addition of convective syngas coolers, as also

shown in Figure A-3.B.10. This raises the overall efficiency by another 1 to 1.5 percentage points. These efficiency improvements require additional capital, but the added capital charge is essentially offset by decreased fuel cost.

Pressure is another factor in gasifier design. The simplest vessel shape and design along with slurry feed allow operation at higher pressures. Thus, the GE/Texaco gasifier can operate to 6.9 MPa (1000 psi); whereas E-Gas, because of vessel constraints, and Shell, because of dry-feed addition, are limited to about 3.3 to 4.1 MPa (500 to 600 psi). Pressure becomes more important when IGCC with CO_2 capture is considered [21].

Figure A-3.B.10 Gasifier Heat Recovery Options: Radiant Syngas Cooler And Convective Syngas Coolers Illustrated

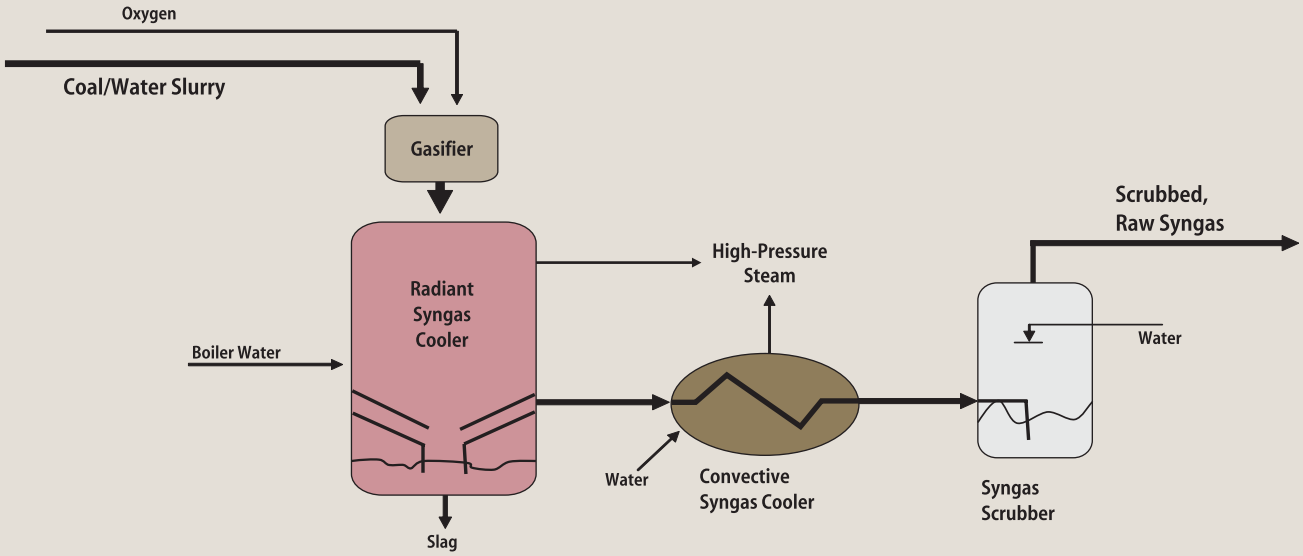
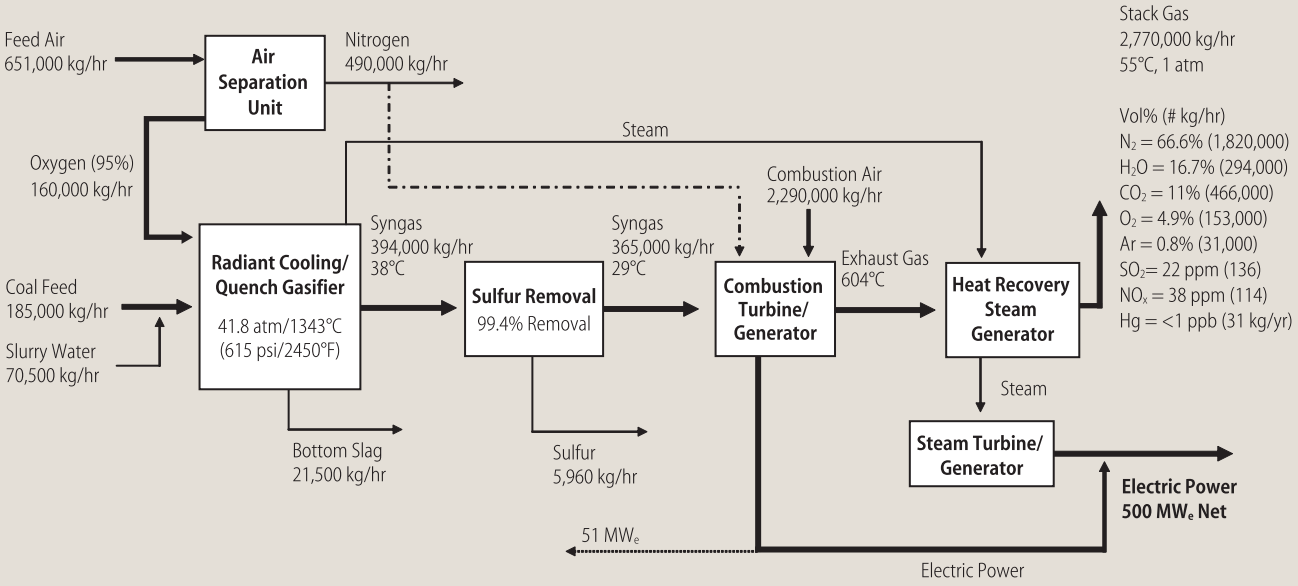


Figure A-3.B.11 is a detailed schematic of an oxygen-blown IGCC unit without CO_2 capture showing typical stream flows and conditions. In this case, a lower-pressure (4.2 MPa) GE radiant-cooling gasifier is used, producing high-pressure steam for electricity generation. Nitrogen from the ASU is fed to the combustion turbine to produce increased power and reduce NO_x formation. Internal power consumption is about 90 MW_e, and the net efficiency is 38.4%. MDEA can achieve 99.4% sulfur removal from the syngas for 0.033 lb SO_2/million Btu, as low or lower than for recently permitted PC units. Selexol can achieve 99.8% sulfur removal for an emission rate of 0.009 lb SO_2/million Btu. Rectisol, which is more expensive, can achieve 99.91% sulfur removal for an emissions rate of 0.004 lb SO_2/million Btu [22]. NO_x emission control is strictly a combustion turbine issue and is achieved by nitrogen dilution prior to combustion to reduce combustion temperature. Addition of SCR would result in NO_x reduction to very low levels.

Figure A-3.B.12 shows the impact of adding CO_2 capture to a 500 MW_e IGCC unit. The added units are a pair of shift reactors with inter-stage cooling to convert CO to hydrogen and CO_2 by reaction with steam. Because the shift reaction requires a lot of steam to drive it, an IGCC unit with CO_2 capture uses a direct-quench gasifier to maximize the steam in the syngas from the gasifier. CO_2 capture requires the addition of second Selexol unit, similar to the one used for sulfur removal. The CO_2 is desorbed from the capture solution by pressure reduction. The desorbed CO_2, already at an intermediate pressure, is compressed to a supercritical liquid. Internal power consumption for the capture unit is about 130 MW_e and

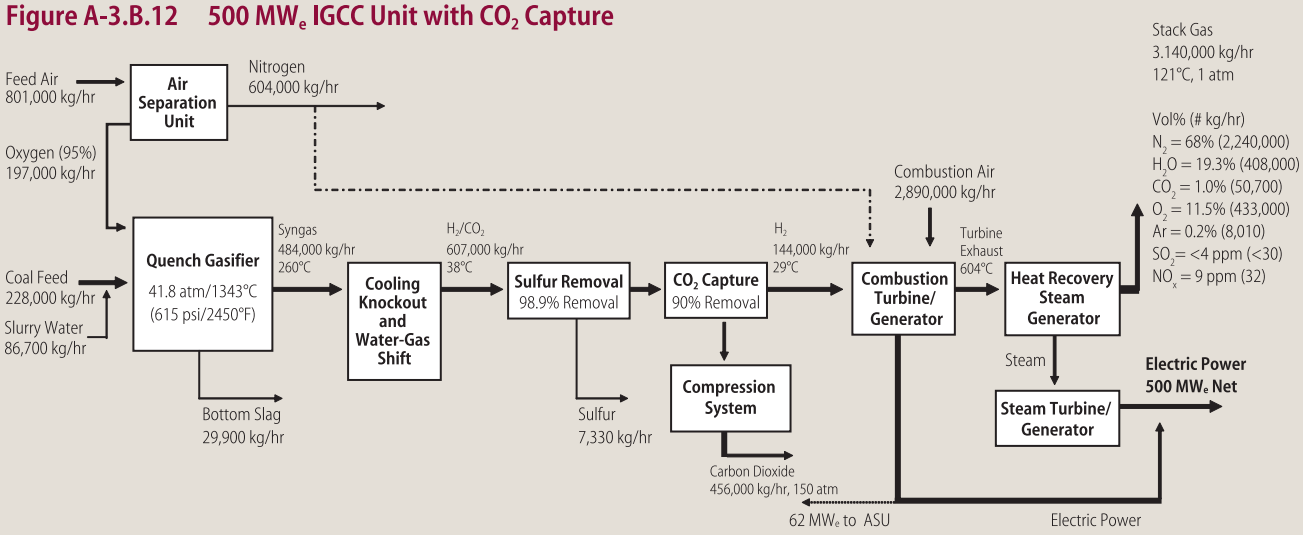
Figure A-3.B.11 500 MW_e IGCC Unit without CO_2 Capture



coal consumption is about 23% higher. The overall efficiency is 31.2%. CO_2 separation and compression is favored by higher unit operating pressure, which requires higher pressure gasifier operation.

IGCC OPERATIONAL PERFORMANCE The promise of IGCC has been the potential of a smaller environmental footprint, including order-of-magnitude lower criteria emissions, of highly-efficient CO_2 capture, and of high generating efficiency. As discussed in Appendix 3-D, IGCC can provide a significantly smaller environmental footprint, and can also achieve close to order-of-magnitude lower criteria emissions, and very high levels of mercury removal. Available design studies do not clearly define the incremental cost to achieve these markedly lower criteria emissions. Recent studies suggest that adding SCR to the gas turbine exhaust and upgrading the upstream sulfur removal to accommodate it results in an incremental cost for the additional NO_x removal of about $13,000 to $20,000 per ton NO_x [22, 23].

Figure A-3.B.12 500 MW_e IGCC Unit with CO_2 Capture



From design studies using high heating value coals, IGCC shows a distinct cost advantage for CO_2 capture over other coal-based electricity generating technologies with CO_2 capture. This advantage is expected to be demonstrated in commercial scale operation. However, this IGCC cost advantage will probably be significantly less for lower heating value coals, such as bituminous coals (e.g., PRB) and lignite. Data in this area are limited or lacking.

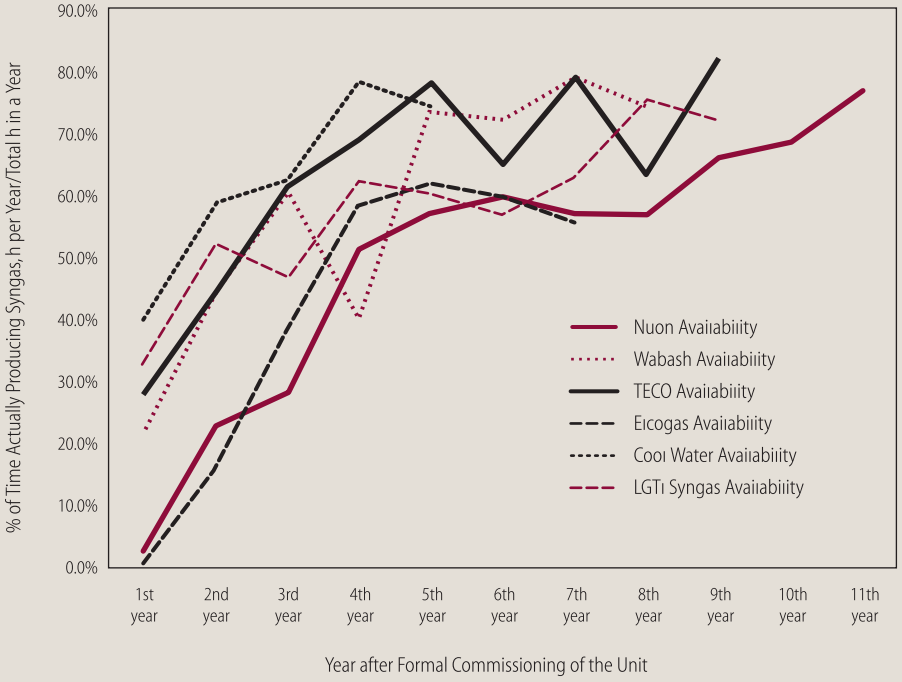
The electricity generating efficiencies demonstrated to date do not live up to earlier projections due to the many engineering design compromises that have been made to achieve acceptable operability and cost. The current IGCC units have and next-generation IGCC units are expected to have electricity generating efficiencies that are less than or comparable to those of supercritical PC generating units. Current units typically gasify high-heating value, high-carbon fuels. Polk IGCC with a Texaco-GE water-slurry gasifier, radiant and convective syngas cooling but no combustion turbine-air separation unit integration operates at 35.4% (HHV) generating efficiency. The Wabash River IGCC with a water-slurry fed E-Gas gasifier, radiant and convective syngas cooling and no integration operates at about 40% generating efficiency. The IGCC in Puertollano Spain with a dry-feed Shell type gasifier, radiant and convective and combustion turbine-air separation unit integration has a generating efficiency of about 40.5% (HHV). Supercritical PC units operate in the 38 to 40% efficiency range, and ultra-supercritical PC units in Europe and Japan are achieving 42 to 46% (HHV) generating efficiency.

IGCC system and gasifier availability remains an important issue. Figure A-3.B.13 shows the availability history for the IGCC demonstration plants. These represent learning curves for the operation of a complex process with many component parts. No single process unit or component part of the total system was responsible for the majority of the unplanned shutdowns that reduced IGCC unit availability, although the gasification complex or block represents the largest factor in reduced availability and operability. For example, for Polk Power Station, the performance in terms of availability (for 1992, for 1993, and expected performance) was: for the air separation block (96%, 95%, & 96-98%); for the gasification block (77%, 78%, & 80-90%); and for the power block (94%, 80%, & 94-96%). A detailed analysis of the operating history of the Polk Power Station over the last few years suggests that it is very similar to operating a petroleum refinery, requiring continuous attention to avert, solve, and prevent mechanical, equipment and process problems that arise. In this sense, IGCC unit operation is significantly different than the operation of a PC unit, and requires a different operational philosophy and strategy.

Figure A-3.B.13 shows that most of the plants were able to reach the 70-80% availability after 4 to 6 years, and data on these units beyond this "learning curve" period show that they have been able to maintain availabilities in the 80% range (excluding planned shutdowns). By adding a spare gasifier, IGCC units should be able to exhibit availabilities near those of NGCC units. At the Eastman Chemical Gasification Plant, which has a full-quench Texaco gasifier and a backup gasifier (a spare), the gasification/syngas supply system has had less than a 2% forced outage over almost 20 years. Recent performance has been in excess of 98% including planned outages. Areas in the gasification block that require attention are gasifier refractory wear and replacement, coal-slurry pump and injector nozzles, and downstream syngas stream fouling.

Refinery-based IGCC units gasifying petroleum residua, tars and other wastes have experienced much better start-up histories and generally better operating statistics. Bechtel projects

Figure A-3.B.13 History of IGCC Availability for the Start-up of Coal-based Units
(excluding operation on back-up fuel)



Graph provided by Jeff Phillips, EPRI

that future coal-based IGCC plants should achieve around 85% availability without back-up fuel or a spare gasifier [25].

IGCC units are primarily base-load units because there turndown is limited and somewhat complex. There is little information on turndown, but easy turndown to 50% is unlikely. The Negishi Japan IGCC unit is routinely turned down by 25% over a 30 minute period, so that it is operating at 75% of full capacity, to accommodate lower electric power demand at night and on weekends [26]. It is ramped up to full capacity operation over a 30 minute period when electricity demand increases again. Buggenum IGCC reports turndown to 57% of peak load at off-peak periods.

Integration between the ASU and the combustion turbine lowers total unit cost and NO_x emissions, and increases efficiency and power output. Part or all of the ASU air may be supplied from the gas turbine compressor outlet to reduce or eliminate the need for a less-efficient ASU compressor. The degree of integration is defined as the fraction of the ASU air supplied from the combustion turbine. In general, 100% integration gives highest efficiency, but partial integration gives maximum power output and improved operability with shorter start-up times. The nitrogen from the ASU is typically used for NO_x reduction and power augmentation to the extent compatible with the combustion turbine operating characteristics. The use of nitrogen instead of water injection is favored for NO_x reduction because it results in higher operating efficiency. Current designs typically use partial air integration to achieve partial efficiency gain without sacrificing too much operability.

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5. The LHV of a fuel is the heat released upon combustion of the fuel with oxygen to form carbon dioxide and water at standard initial and end states with the water produced in the combustion remaining in the vapor state. For the HHV, the water produced in the combustion is condensed to liquid in the end state, releasing additional energy`; the difference between the two heating values is the latent heat of condensation of the water from the fuel moisture and from the combustion of hydrogen in the fuel.
6. Generating efficiency is simply 3600 (kJ/kW_e-h) divided by the "heat rate"in kJ/kW_e-h or 3414 (Btu/kW_e-h) divided by the "heat rate" in Btu/kW_e-h.
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Appendix 3.C — Electricity Generation Economics: Bases and Assumptions

LEVELIZED COST OF ELECTRICITY

The levelized cost of electricity (COE) is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors. Levelized COE is comprised of three components: capital charge, operation and maintenance costs, and fuel costs. Capital cost is generally the largest component of COE. This study calculated the capital cost component of COE by applying a carrying charge factor of 15.1% to the total plant cost (TPC) which could also be called the total unit cost. This procedure is in accordance with the EPRI Technology Assessment Guide (TAG) [1], and is based on the financial assumptions presented in Table A-3.C.1.

Table A-3.C.1 Key Financial Assumptions Applied in Capital Cost Evaluation

ASSUMPTION	VALUE
Fraction debt	55%
Cost of debt	6.5%
Cost of equity	11.5%
Tax rate	39.2%
Inflation rate	2%
Construction period	3 years
Book life	20 years

CRITICAL EVALUATION OF DESIGN AND COST STUDIES

Seven coal technology design and cost studies were reviewed and critically analyzed for this report. These studies, published since 2000, typically estimate the required capital cost and levelized cost of electricity (COE) for current coal-based generating technologies. Most of these studies also estimated the cost of electricity for these technologies with CO_2 capture. The capital costs for each study were developed independently and thus exhibited considerable variation. Further, the financial and operating assumptions that were used to calculate the COE varied from study to study which also added variability to the COE. Several studies that were on a substantially different basis or fell well outside the range expected were not included in the analysis because there was no adequate way to effectively evaluate them. For example, several IEA GHG reports that we reviewed appeared to underestimate systematically capital costs, had generating efficiencies that typically would not be achieved under U.S. conditions, and were not used[2, 3]. Table A-3.C.2 lists these studies, and Table A-3.C.3 summarizes the key technical, operational, and financial parameters for the cases evaluated for PC generation, including oxy-fuel and CFB generation. Table A-3.C.4 provides a similar summary for the IGCC cases.

Table A-3.C.2 Primary Design Studies Reviewed in Developing Coal-Based Power Generation Economics

STUDY/YEAR	PULVERIZED COAL	IGCC	CAPTURE
EPRI/ Parsons 2002 [4]	Supercritical & Ultra-Supercritical PC	E-gas	Yes
NETL 2002 [5]	Subcritical & Oxy-fuel PC	E-gas & Shell	Yes
Simbeck 2002 [6]	Ultra-Supercritical PC	GE/Texaco	Yes
Rubin 2004 [7]	Supercritical PC	GE/Texaco	Yes
NCC 2004 [8]	Subcritical & Supercritical PC	E-gas	No
NCC 2004 [8]	Circulating Fluidized Bed (CFB)		No
Dillon 2004 [9]	Supercritical & Oxy-fuel PC	—	Yes
Andersson 2003 [10]	Supercritical & Oxy-fuel PC	—	Yes

Table A-3.C.3 Summary of Design Studies of PC And CFB Generation — As Reported

STUDY	NETL 2002[5]	NETL 2002[5]	NCC 2004	EPRI 2002[4]	NCC [11]	RUBIN [7]	EPRI 2002 [4]	SIM-BECK [6]	DILLON [9]	ANDERSSON [10]	NCC [8]
Technology	subC	subC	SubC	SC	SC	SC	USC	USC	SC	SC	CFB
Cost year basis	2002	2002	2003	2000	2003	2004	2000	2000	2004	2004	2003
Baseline											
Efficiency (%, HHV)	37.4		36.7	40.5	39.3	39.3	42.8	43.1	42.5	38.3	34.8%
TPC ($/kW$_e$)	1114		1230	1143	1290	1076	1161	1290	1260	1271	1290
TCR ($/kW$_e$)	1267		1430	1281	1490	1205	1301	1445	1411	1424	1490
Annual CC (% on TPC)	16.8		14.3	15.5	14.2	16.6	15.5	15.0			15.1%
Fuel price ($/MMBtu)	0.95		1.5	1.24	1.5	1.27	1.24	1.00			1.00
Capacity Factor (%)	85		80	65	80	75	65	80			85%
Electricity cost											
Capital charge (cents/kWh$_e$-h)	2.52		2.51	3.10	2.62	2.71	3.15	2.77			2.61
O&M (cents/kWh$_e$-h)	0.8		0.75	1	0.75	0.79	0.95	0.74		0.42	1.01
Fuel (cents/kWh$_e$-h)	0.87		1.39	1.04	1.30	1.10	0.99	0.79			0.98
COE (¢/kWh$_e$-h)	**4.19**		**4.65**	**5.15**	**4.67**	**4.61**	**5.09**	**4.30**	**4.4**		**4.60**
Capture	MEA	Oxy-fuel		MEA		MEA	MEA	MEA	Oxy-fuel	Oxy-fuel	
Efficiency (%, HHV)	26.6	29.3		28.9		29.9	31.0	33.8	34.0	30.2	
TPC($/kW$_e$)	2086	1996		1981		1729	1943	2244	1857	2408	
TCR ($/kW$_e$)	2373	2259		2219		1936	2175	2513	2080	2697	
Annual carrying charge (%)	16.8	16.8		15.5		16.6	15.4	15.0			
Fuel price ($/MMBtu)	0.95	0.95		1.24		1.27	1.24	1			
Capacity Factor	85	85		65		75	65	80			
Electricity cost											
Capital charge (cents/kWh$_e$-h)	4.72	4.49		5.38		4.36	5.27	4.80			
O&M (cents/kWh$_e$-h)	1.67	1.23		1.71		1.6	1.61	1.28			
Fuel (cents/kWh$_e$-h)	1.22	1.11		1.46		1.45	1.36	1.01		0.86	
COE (¢/kWh$_e$-h)	**7.61**	**6.83**		**8.55**		**7.41**	**8.25**	**7.09**	**6.1**		

Note: For Rubin, TCR assumed 12% higher than TPC as per EPRI TAG

To allow comparison of capital costs, O&M costs, and the COE among these studies, each was reevaluated using a common set of operating and economic parameters. In addition to the economic parameters in Table A-3.C.1, a capacity factor of 85%, and a fuel cost of $1.50/million Btu (HHV) for the PC and IGCC cases, and $1.00/million Btu (HHV) for the CFB case. The rationale for the lower fuel price for the CFB case is that CFB technology is ideally suited for low-quality coals such as coal waste, and low heating value coals such as lignite, both of which are typically lower cost.

Each study was adjusted to a 2005 year cost basis. Adjustment factors for inflation, taken from the U.S. Department of Labor consumer price index, were used to normalize the studies to a constant 2005 cost year basis. These are given in Table A-3.C.5. The results of the re-evaluation using the normalized economic and operating parameters are presented in Tables A-3.C.6 and A-3.C.7 for the PC and CFB, and the IGCC cases, respectively. Two studies (Andersson [10] and Dillon [9]) did not provide sufficient information to normalize and are not included in these tables.

Table A-3.C.4 Summary of Design Studies of IGCC Generation — As Reported

STUDY	EPRI 2002[4]	RUBIN[7]	SIMBECK[6]	NCC[11]	NETL 2002[5]
Technology	E-Gas	Texaco	Texaco	E-Gas	E-Gas
Cost year basis	2000	2004	2000	2003	2002
Baseline					
Efficiency (%, HHV)	43.1	37.5	43.1	39.6	44.90
TPC ($/kW$_e$)	1111	1171	1293	1350	1167
TCR ($/kW$_e$)	1251	1311	1448	1610	1374
Fuel price ($/MMBtu)	1.24	1.27	1	1.5	0.95
Capacity Factor (%)	65	75.0	80	80	85
Electricity cost					
Capital charge (¢/kWh$_e$-h)	3.03	2.95	2.77	2.80	2.73
O&M (¢/kWh$_e$-h)	0.76	0.72	0.74	0.89	0.61
Fuel (¢/kWh$_e$-h)	0.98	1.16	0.79	1.29	0.72
COE (¢/kWh$_e$-h)	**4.77**	**4.83**	**4.30**	**4.99**	**4.06**
Capture					
Efficiency (%, HHV)	37.0	32.4	37.7		38.6
TPC($/kW$_e$)	1642	1561	1796		1616
TCR ($/kW$_e$)	1844	1748	2012		1897
Annual carrying charge (%)	15.5	16.6	15.0		17.4
Fuel price ($/MMBtu)	1.24	1.27	1		1
Capacity Factor	65	75	80		85
Electricity cost					
Capital charge (¢/kW$_e$-h)	4.47	3.94	3.85		3.77
O&M (¢/kW$_e$-h)	0.96	0.98	1.03		0.79
Fuel (¢/kW$_e$-h)	1.14	1.34	0.91		0.88
COE (¢/kW$_e$-h)	**6.57**	**6.26**	**5.78**		**5.44**

Note: For Rubin and Simbeck, TCR assumed 12% higher than TPC as per EPRI TAG

Table A-3.C.5 Inflation Adjustment Factor to Year 2005 Dollars

YEAR	ADJUSTMENT FACTOR
2000	1.11
2001	1.08
2002	1.07
2003	1.05
2004	1.03

Table A-3.C.6 Results of Design Study Normalization to Consistent Economic and Operational Parameters — PC and CFB

STUDY	NETL 2002	NETL 2002	NCC 2004	EPRI 2002	NCC	RUBIN	EPRI 2002	SIMBECK	NCC
Technology	SubC	SubC	SubC	SC	SC	SC	USC	USC	CFB
Baseline									
TPC ($/kW$_e$)	1192		1292	1269	1355	1108	1289	1432	1329
TCR ($/kW$_e$)	1356		1502	1422	1565	1241	1444	1604	1535
Capital charge (¢/kW$_e$-h)	2.42		2.62	2.57	2.75	2.25	2.61	2.90	2.69
O&M (¢/kW$_e$-h)	0.86		0.79	1.11	0.79	0.81	1.05	0.82	1.04
Fuel (¢/kW$_e$-h)	1.37		1.39	1.26	1.30	1.30	1.20	1.19	0.98
COE (¢/kW$_e$-h)	**4.64**		**4.80**	**4.95**	**4.84**	**4.36**	**4.86**	**4.91**	**4.72**
Capture	MEA	Oxy-fuel		MEA		MEA	MEA	MEA	
TPC ($/kW$_e$)	2232	2136		2199		1780	2157	2491	
TCR ($/kW$_e$)	2539	2417		2463		1994	2414	2790	
Capital charge (¢/kW$_e$-h)	4.53	4.33		4.46		3.61	4.37	5.05	
O&M (¢/kW$_e$-h)	1.79	1.32		1.90		1.65	1.79	1.42	
Fuel (¢/kW$_e$-h)	1.92	1.75		1.77		1.71	1.65	1.51	
COE (¢/kW$_e$-h)	**8.24**	**7.39**		**8.13**		**6.97**	**7.81**	**7.99**	

Table A-3.C.7 Results of Design Study Normalization to Consistent Economic and Operational Parameters — IGCC

STUDY	EPRI 2002	RUBIN	SIMBECK	NCC	NETL 2002
Technology	E-Gas	Texaco	Texaco	E-Gas	E-Gas
Baseline					
TPC ($/kW$_e$)	1233	1206	1435	1418	1249
TCR ($/kW$_e$)	1389	1350	1607	1691	1470
Capital charge (¢/kWh)	2.50	2.44	2.91	2.87	2.53
O&M (¢/kW$_e$-h)	0.84	0.74	0.82	0.93	0.65
Fuel (¢/kW$_e$-h)	1.19	1.36	1.19	1.29	1.14
COE (¢/kW$_e$-h)	**4.53**	**4.55**	**4.92**	**5.10**	**4.32**
Capture					
TPC ($/kW$_e$)	1823	1608	1994		1729
TCR ($/kW$_e$)	2047	1800	2233		2030
Capital charge (¢/kW$_e$-h)	3.70	3.26	4.04		3.51
O&M (¢/kW$_e$-h)	1.07	1.01	1.14		0.85
Fuel (¢/kW$_e$-h)	1.38	1.58	1.36		1.33
COE (¢/kW$_e$-h)	**6.14**	**5.85**	**6.54**		**5.68**

Figure A-3.C.1 Total Plant Cost from Design Studies of Air-Blown Generating Technologies (2005 Dollars)

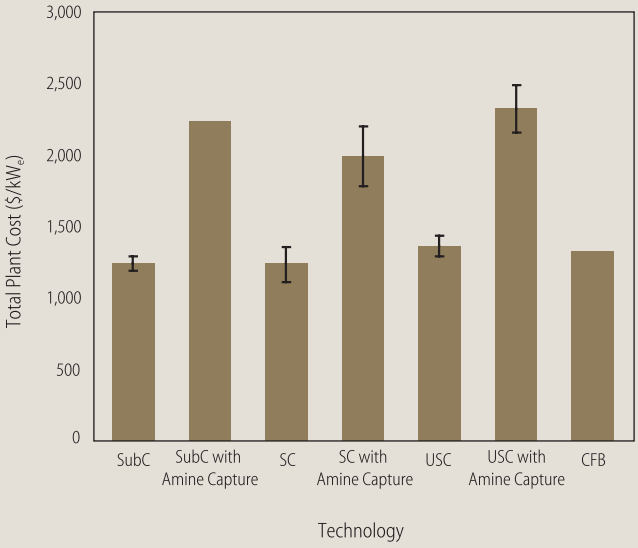


Figure A-3.C.2 Total Plant Cost from Design Studies of Oxygen-Blown Generating Technologies (2005 Dollars)

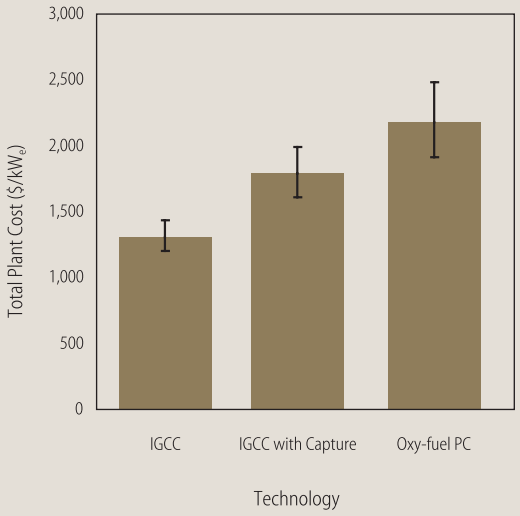


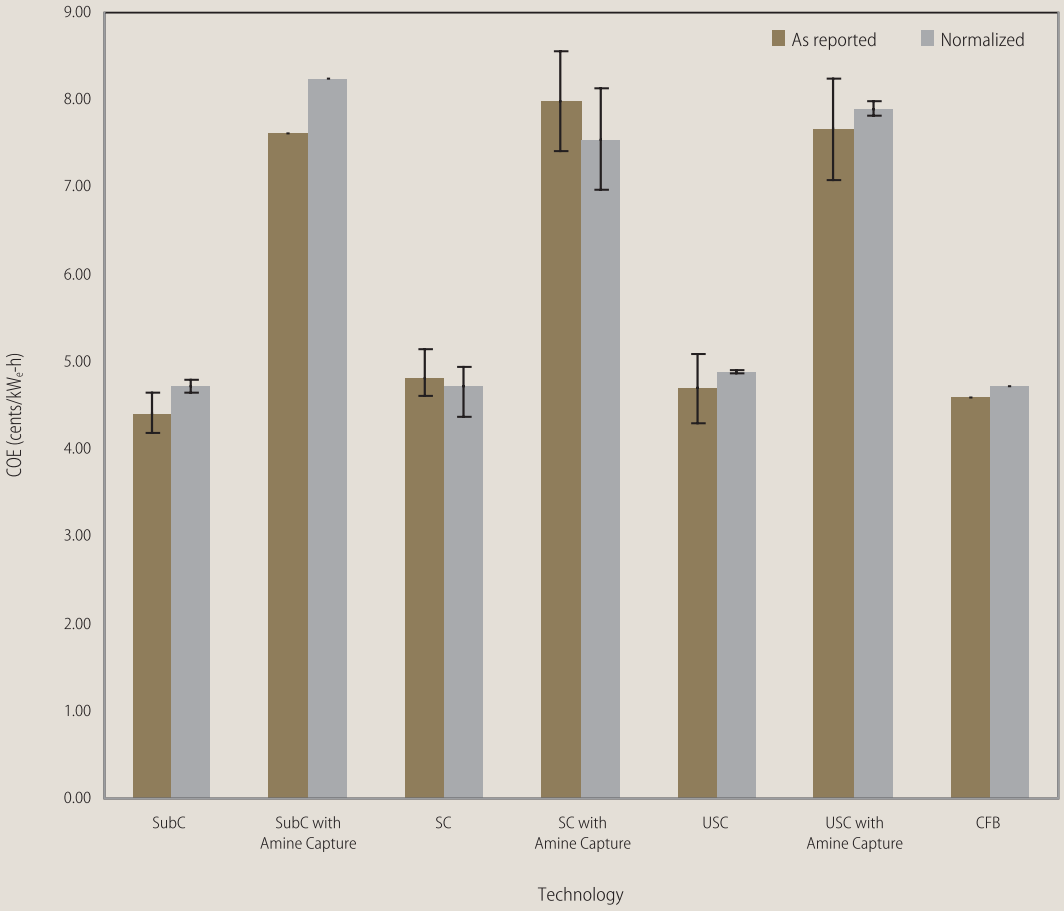
Figure A-3.C.1 shows the min, max, and mean for the TPC for each of the air-blown generating technologies from the design studies, expressed in 2005 dollars. Figure A-3.C.2 shows the same information for each of the oxygen-blown generating technologies. Figure A-3.C.3 and Figure A-3.C.4 show the min, max, and mean for the COE from these same studies both "as-reported" and as recalculated in 2005 dollars using the normalized set of economic and operating parameters summarized in Table 3.5.

ADDRESSING UNCERTAINTY AND FORWARD SIMULATION

Our economic analyses of total and marginal COE are for a single point set of conditions, and do not take into account the considerable uncertainty in many of the variables upon which these point COE values are based. Plant capital cost (TPC) is one of the major contributors to COE. The capital cost basis used here was developed in the 2000 to 2004 time period, which was a period of relative price and cost stability. These costs were all put on a 2005$ basis using CPI inflation. Recent global economic growth, including China's rapid growth, have driven up commodity prices, engineering costs, and construction costs much more than the CPI increase in the last three years. These construction cost related increases have driven increases in the capital cost (TPC) of from 25 to 35 % from 2004 levels. This is reflected in a capital cost range recently reported by Dalton [12] of $1290 to $1790 /$kW_e$ for a SCPC unit, considerably above earlier projections[13] (see also Figure A-3.C.1). If world economic growth were to substantially slow, these costs would reduce significantly. Because we have no firm information on how these cost increases would affect the other generating technologies involved, including those with CO_2 capture, and because our main interest is in comparing the full range of technologies, we have based our discussion on the design estimates referenced here and not escalated them to capture today's construction cost environment.

Because electricity prices from forward market quotes are generally not available, the cost of generation is the proxy for the market. As such, forward projected cost of generation

Figure A-3.C.3 COE from Design Studies of Air-Driven Generating Technologies — "As-Reported" and for Normalized Economic and Operating Parameters



(NPV cost) and the effect of uncertainty in key variables on this cost is the most relevant approach to comparing technologies for future construction.

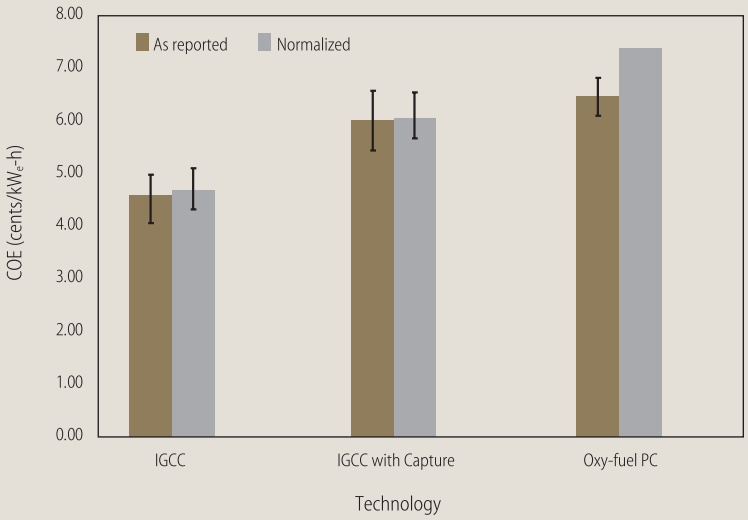
Major variables affecting NPV cost include:

- Plant capital cost (TPC) (discussed above)
- Coal price and fuel flexibility
- O&M cost
- Capacity factor and plant dispatch
- Air pollutant regulations and costs, including SO_x, NO_x, and mercury
- Future greenhouse gas policy and CO_2 costs
- Marketable by-products

Each of these variables have significant uncertainties associated with cost, technology, performance, and timing. One way to evaluate the impact of these variables is to perform a numerical simulation. For example, a Monte Carlo-type simulation produces a sensitivity analysis that shows how changes in any one of these variables affects the economics of

a given generating technology or plant [14]. Simulation requires building a set of forward assumptions of the value, of the bounds, and of associated probability distribution function for each of the variables. A simulation is then performed producing a probability distribution function for the results of the analysis. From this, the probability of the NPV cost for the plant can be projected for a given set of conditions for each generating technology.

Figure A-3.C.4 COE from Design Studies of Oxygen-Blown Generating Technologies — "As-Reported" and for Normalized Economic and Operating Parameters



An example of how an uncertainty simulation can be used is with regulations of criteria air contaminants. At today's environmental costs and with no CO_2 policy, PC generation has a lower COE and is favored in terms of having the lowest NPV cost. However, as allowed future pollutant emissions levels are reduced and the cost of emissions control increases, the NPV gap between PC and IGCC will narrow; and at some point, increased emissions control can be expected to lead to IGCC having the lower NPV. This, of course, depends on when and the extent to which these changes occur and on how emissions control technology costs change with time and increasing reduction requirements.

In the case of CO_2, uncertainty surrounds the timing, the form (tax or cap) and level of CO_2 controls. Assuming a carbon tax, variables would include:

- Year of introduction of tax
- Initial tax rate
- Annual increase in the tax rate.

The introduction of a CO_2 tax at a future date (dependent on date, CO_2 tax rate, and rate of increase) will drive IGCC to be the lowest NPV cost alternative at some reasonable set of assumptions, and assuming today's technology performance. Substantial technology innovation could change the outcome, as could changing the coal feed from bituminous coal to lignite.

This type of analysis is widely used in evaluating the commercial economics of large capital projects, but is outside the scope of this report. Nevertheless, its importance in forward planning relative to coal-based generating technology needs to be acknowledged. AEP decided to build two IGCC plants, using analysis of this type to help make the decision internally and to support the decision externally [15].

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Appendix 3.D — U.S. Emissions Regulations and Emissions Performance

EMISSIONS REGULATIONS

The Clean Air Act requires the U.S. EPA to establish nationally applicable National Ambient Air Quality Standards (NAAQS) for each air pollutant which, in the EPA Administrator's judgment, causes or contributes to the endangerment of public health and welfare, and which results from domestic mobile or stationary sources. The EPA to date has issued seven such standards, for ozone, carbon monoxide, sulfur dioxide, lead, nitrogen dioxide, coarse particulates (PM_{10}), and fine particulates ($PM_{2.5}$). The Act further requires that these standards be reviewed and updated every five years. Most recently, the Agency issued revised ozone and particulate matter standards in 1997 [1], as well as an entirely new standard for small particulates. Once the standards are issued, areas are designated as in "attainment" or "non-attainment" of each standard. For example, EPA in December 2004 finalized regional compliance designations for the new NAAQS standards for fine particulates [1].

The NAAQS form the basis for the federal ambient air quality program, also known as Title I, which is administered by the states and the federal government cooperatively. Under this program, each state must submit, and EPA must approve, a State Implementation Plan (SIP). Each state's SIP must describe, among other things, how the state plans to come into compliance, and/or stay in compliance with each NAAQS, through various mobile and stationary source programs, , and must include provisions related to the review and approval of required air quality permits for new and modified stationary sources. A SIP may include provisions that are more, but not less, stringent than Federal requirements.

Another section of Title I authorizes EPA to retract or "call in" state SIPs, if it finds that pollution emissions in one state or several states are causing or contributing to downwind non-attainment or difficulty attaining the NAAQS in other states. This is referred to as a SIP Call, and EPA has issued such a rule (the NO_x SIP Call) for NO_x emissions in the eastern half of the US, which cause and contribute to downwind non-attainment of the ozone NAAQS.

Additionally, other provisions of the Clean Air Act authorize federal programs for air pollution control, which are implemented through the SIPs. For example, Title IV of the Act authorizes the Acid Rain Program [2], which was enacted by Congress in 1990. Title IV sets up a cap and trade system for sulfur dioxide (SO_2) and emissions of nitrogen oxides (NO_x). The SO_2 program was initially limited to the 440 largest utility units, and now covers all affected sources nationwide (over 2000 units). NO_x emissions control has been phased in, by setting limits on the amount of NO_x that can be emitted per unit of fuel consumed, based on the goal of reducing NO_x by 2 million tons per year below a BAU number.

Local air quality issues are very important in establishing permitted emission levels for new coal plants and other new stationary sources. In the permitting of each new coal unit under "new source review," emissions levels are set based on federal New Source Performance Standards requirements, and based on the local area's air quality designation for each criteria pollutant. In areas that are in attainment for a criteria pollutant, a new facility must meet an emissions limit based on the Best Available Control Technology (BACT), determined through a federally-directed "top-down" process. In non-attainment areas, the source must meet the Lowest Achievable Emissions Rate (LAER). The Clean Air Act states that BACT

determinations can include consideration of the costs of achieving lower emissions levels; whereas LAER determinations must be strictly based on the most stringent emissions rate achieved by the same class or category of source. In addition, new units permitted in non-attainment areas are required to purchase emissions offsets equal to their emissions.

In March 2005, EPA enacted the Clean Air Interstate Rule (CAIR) [3], under the same legal authority as the NO_x SIP Call, to reduce atmospheric interstate transport of fine particulate matter and ozone. CAIR sets up a cap-and-trade program allocating emission "allowances" of the PM and ozone precursors SO_2 and NO_x to each state. The program is to be administered through the affected states' SIPs. Figure A-3.D.1 shows EPA's projection of NO_x and SO_2 emissions with the final rule's CAIR caps [4, 5]. The figure also shows the projection for electricity generation using coal as fuel. CAIR applies to 28 eastern states and the District of Columbia. While CAIR does not require emissions reductions from any particular industrial sector, but leaves it to the states to decide how the caps will be achieved, it is widely accepted that the power sector will be the most cost-effective place to achieve the required reductions. Power plants may (a) install control equipment, (b) switch fuels, or (c) buy excess allowances from other sources that have achieved greater reductions, to satisfy state requirements under the CAIR.

This context complicates the permitting of new coal power plants under "new source review". Permitting a new plant in an attainment area involves negotiations with state and local agencies. The plant is federally mandated to meet BACT, for which there is some flexibility in interpretation and cost considerations. However, negotiations usually start at emissions levels lower than this and often lower than the levels of the latest permits. Permitted levels for a give plant are the result of these negotiations and continue to be reduced with each permit cycle. A new coal plant located in a non-attainment area will have to meet a lower emissions rate for the non-attainment pollutant. In addition to having to meet the LAER emissions rate, local and state authorities are typically under pressure to meet their SIP requirements with additional gains wherever they can achieve them. Thus, the coal plant in a non-attainment area will typically incur higher total emissions control costs which include the capital and operating costs for the enhanced emissions control equipment, the cost of the potential purchases of emissions allowances, and the cost of emissions offset purchases for that pollutant.

Also in March 2005, EPA issued the Clean Air Mercury Rule (CAMR) [6], which establishes a cap-and-trade system for mercury emissions from power plants. This rule applies to 50 states, the District of Columbia, and certain Tribal governments. Each is allocated an emissions "budget" for mercury, although states can opt out of the cap and trade program and administer a more stringent emissions reduction program than is required by CAMR. In the early years of the rule, EPA projects that states will be able to meet their budgets solely on the basis of the "co-benefits" of CAIR emissions reductions. This rule was issued as an alternative to the Clean Air Act's requirement that maximum achievable control technology (MACT) standards must be applied to all industrial sources of hazardous air pollutants. MACT standards would require much lower emissions of mercury, and in the nearer term.

Table A-3.D.1 gives EPA's projections for NO_x, SO_2, and mercury emissions for both rules [3, 6]. Of 75 tons of mercury in the coal that is burned annually in the U.S. today, about 50 tons are emitted to the air [7]. The roughly 25 ton reduction is achieved through existing pollution control equipment, primarily fly ash removal by electrostatic precipitators and fabric filters, and wet FGD scrubbers for SO_x removal. The first phase of mercury reduction

is designed to be achieved through the actions taken in the first phase of CAIR.

Table A-3.D.2 projects the NO_x, SO_2, and mercury emissions for both rules to 2020. In addition to the early mercury reductions being credited to CAIR implementation, the emissions without CAIR include all the reductions that would occur due to the Title IV Acid Rain Program, the NO_x SIP Call, and state rules finalized before March, 2004. The projections are higher than the cap limits because of the banking of excess emissions reductions under the Acid Rain Program and their use later.

EMISSIONS CONTROL FOR PULVERIZED COAL COMBUSTION

Typical flue gas cleaning configurations for PC power plants are shown in Figure A-3.D.2.

PARTICULATE CONTROL Particulate control is typically accomplished with electrostatic precipitators (ESP) or fabric filters. Either hot-side or cold-side ESPs or fabric filters are installed on all U.S. PC plants and routinely achieve >99% particulate removal. The level of control is affected by coal type, sulfur content, and ash properties. Greater particulate control is possible with enhanced performance units or with the addition of wet ESP after FGD [8] (b above). Wet ESP is beginning to be added to new coal units to control condensable PM and to further reduce particulates. Option b) should achieve less than 0.005 lb PM/million Btu or less than 5 mg/Nm³ at 6% O_2, which is what new units in Japan are achieving [9]. Typical PM emission from modern, efficient, U.S. PC units is less than ~0.015 lb/million Btu or less than 15 mg/Nm³. CFB units are permitted at slightly higher levels.

ESP capital costs range from $30 to $80/$kW_e$. Standard ESP costs are at the lower end of this range; retrofits, or a combina-

Figure A-3.D.1 Achieved and Projected SO_2 and NO_x Emissions Reductions and Growth in U.S. Electricity Generation

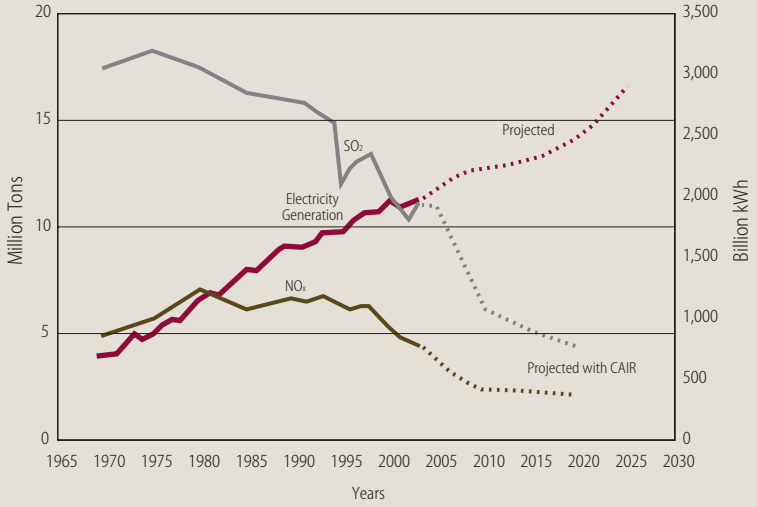


Table A-3.D.1 NO_x and SO_2 Caps for CAIR Region and National Mercury Targets under CAMR

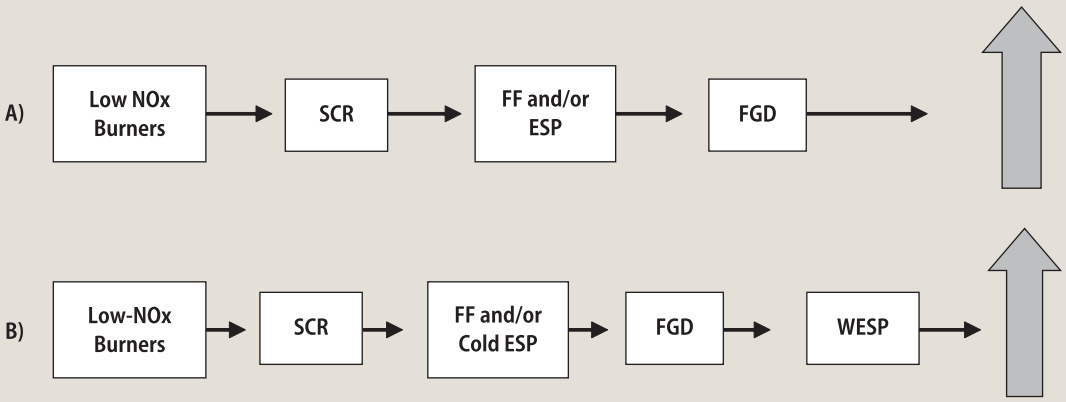
	2009	2010	2015	2018
NO_x [million tons] CAIR Region	1.5	1.5	1.3	1.3
SO_2 [million tons] CAIR Region	—	3.6	2.5	2.5
Mercury [tons]	—	38	38	15

Table A-3.D.2 Projected Emissions from Fossil Fuel Based Electric Generators*

		2003	2009	2015	2020
NO_x Emissions without CAIR (million tons)	CAIR Region	3.2	2.7	2.8	2.8
	Nationwide	4.2	3.6	3.7	3.7
NO_x Emissions with CAIR (million tons)	CAIR Region	—	1.5	1.3	1.3
	Nationwide	—	2.4	2.2	2.2
SO_x Emissions without CAIR (million tons)	CAIR Region	9.4	8.8	8.0	7.7
	Nationwide	10.6	9.7	8.9	8.6
SO_x Emissions with CAIR (million tons)	CAIR Region	—	5.1	4.0	3.3
	Nationwide	—	6.1	5.0	4.3
Mercury Emissions Nationwide (tons)	Without CAIR and CAMR	48	46.6	45	46.2
	With CAIR	—	38.0	34.4	34.0
	With CAIR and CAMR	—	31.1	27.9	24.3

** Fossil fuel generators greater than 25 MW that sell one-third or more of their generated electricity to the grid.*

Figure A-3.D.2 Emissions Control Options For Coal-Fired Power Generation



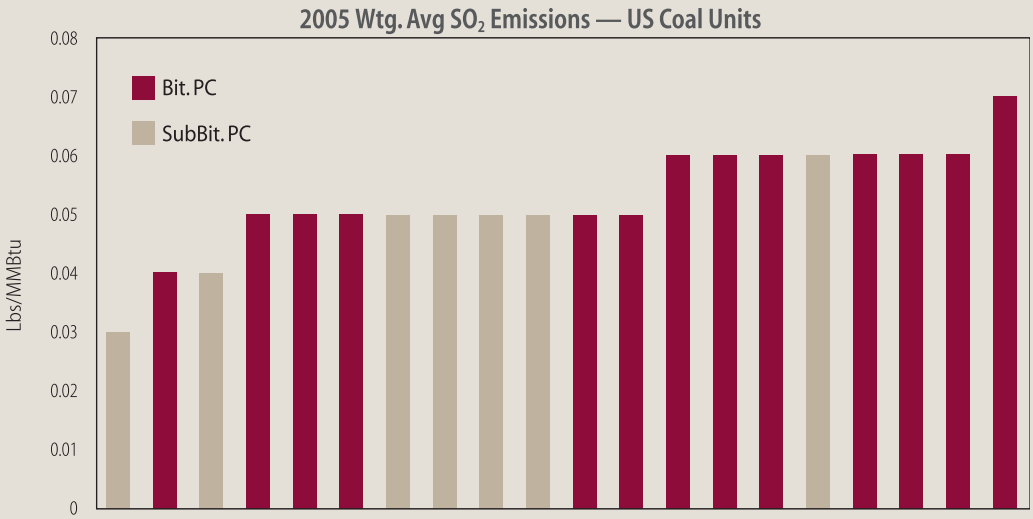
tion of dry ESP and wet ESP (~$40/kW$_e$) are at the upper end of this range. Operating costs are 0.15 to 0.3 cents/kW$_e$-h [8]. Achieving efficiencies of about 99.8% could increase the capital by $5 to $20/kW$_e$ [10]. If a wet ESP is required to achieve these or higher levels of PM emissions reductions, the cost would be appropriately higher. Since an ESP is standard on all PC units, it is typically considered part of the base system cost. The coal ash contained in flue gas is removed as fly ash, which should be disposed of safely to prevent toxic metals from leaching at the disposal site and returning to the environment.

SO_X CONTROL Partial flue gas desulfurization (FGD) can be accomplished by dry injection of limestone into the duct work just behind the air preheater (50-70% removal), with recovery of the solids in the ESP. For fluidized-bed combustion units, the fluidized-bed is primarily limestone, which directly captures most of the SO_x formed. On PC units wet flue gas desulfurization (FGD) (wet lime scrubbing), can achieve 95% SO_x removal without additives and 99+% SO_x removal with additives [8, 11]. Wet FGD has the greatest share of the market in the U.S. (when applied), is proven technology, and is commercially well established. The capital cost for wet scrubbers is from $100 to $200/kW$_e$, and the parasitic power for operation is from 1.0 to 3.0% depending on coal sulfur level and removal level. Operating costs are from 0.20 to 0.30 ¢/kW$_e$-h, dependent on sulfur level.

Typical U. S. PC unit commercial emissions performance is 0.21 to 0.23 lb SO_2/million Btu [12], which meets the level to which these units were permitted. Recently permitted units have lower limits, ranging from 0.08 to about 0.12 lb SO_2/million Btu for low-sulfur coal to 0.15 to 0.20 lb SO_2/million Btu for high-sulfur coal. Lower emissions levels can be expected as permit levels are further reduced. FGD technology has not reached its limit of control and can be expected to improve further. Figure A-3.D.3 shows the twenty lowest SO_x emitting coal-fired PC units in the U. S. as reported in the EPA CEMS Database [13]. Coal sulfur level impacts the SO_x emissions level achievable.

The best PC unit in the U.S. burning high-sulfur coal, such as Illinois #6, in 2005 had demonstrated emissions performance of 0.074 lb SO_2/million Btu [11]. For low-sulfur coals, the best performance was 0.03 lb SO_2/million Btu. The best units in Japan operate below 0.10 lb SO_2/million Btu [9]. The design developed for the PC units in this report achieved greater than 99% sulfur removal and had an emissions level of about 0.06 lb SO_2/million Btu, independent of generating efficiency [14]. Emissions per MW$_e$-h decrease with increasing unit generating efficiency. The wet sludge from the FGD unit should be disposed of safely and

Figure A-3.D.3 Demonstrated SO_2 Emissions from the 20 Lowest Emitting U. S. Pulverized Coal Power Plants in 2005



in a manner that does not reintroduce the toxic materials such as mercury and other toxic metals back into the environment.

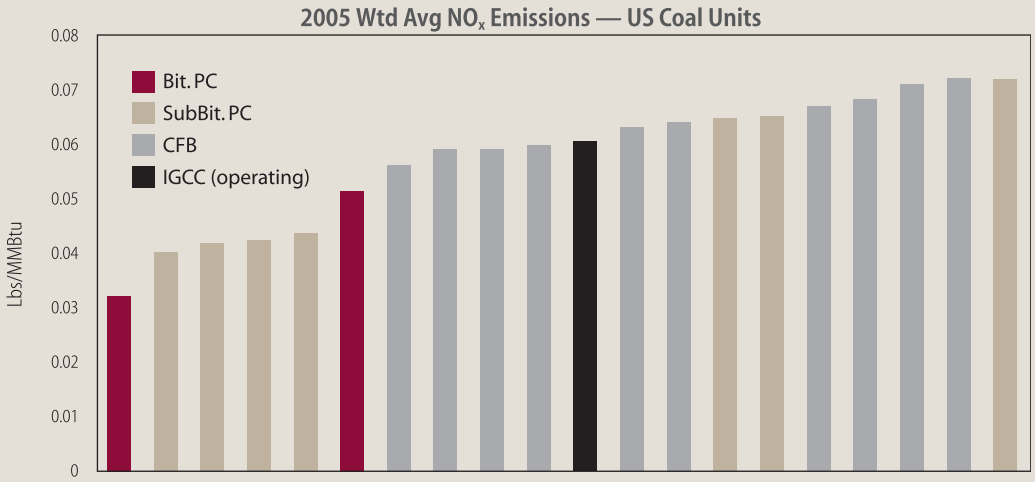
NO_X CONTROL Low-NO_x combustion technologies, which are very low cost, are always applied and achieve up to a 50% reduction in NOx emissions compared to uncontrolled combustion. The most effective, but also, the most expensive, technology is Selective Catalytic Reduction (SCR), which can achieve 90% NO_x reduction over inlet concentration. Selective non-catalytic reduction falls between these two in effectiveness and cost. Today, SCR is the technology of choice to meet very low NO_x levels. Capital cost for SCR is about $20 to $40/$kW_e$ for installation in a typical new unit. For a retrofit the capital cost ranges from $50 to $90/$kW_e$. Operating cost is in the range of 0.05 to 0.15 cents/kW_e-h [8, 15].

Typical U.S. PC unit commercial emissions performance is 0.09 lb NO_x/million Btu to 0.13 lb NO_x/million Btu, which meets their permit levels. Figure A-3.D.4 shows the NO_x emissions performance of the 20 lowest NO_x emitting PC power plants in the U. S. in 2005 [16]. Again the level of NO_x reduction depends on coal sulfur level.

Recently permitted U.S. units are in the range of 0.07 to 0.12 lb NO_x /million Btu. The best PC units in the U.S. are achieving demonstrated performance of about 0.04 lbs NO_x/million Btu on sub-bituminous coal, and about 0.065 lb NO_x/million Btu on high-sulfur (3.3%) bituminous coal. The Parish plant, burning Powder River Basin coal, is achieving 0.03 lbs NO_x/million Btu [11]. The best PC units in Japan are achieving somewhat higher NO_x emissions levels. The design developed for the PC units in this report achieved 0.05 lb NO_x/million Btu [17].

MERCURY CONTROL Mercury in the flue gas is in the elemental and oxidized forms, both in the vapor, and as mercury that has reacted with the fly ash. This third form is removed with the fly ash, resulting in 10 to 30% removal for bituminous coals but less than 10% for sub-bituminous coals and lignite. The oxidized form of mercury is effectively removed by wet FGD scrubbing, resulting in 40-60% total mercury removal for bituminous coals and less than 30–40% total mercury removal for sub-bituminous coals and lignite. For low-sul-

Figure A-3.D.4 Demonstrated NO_x Emissions from the 20 Lowest Emitting U. S. Pulverized Coal Plants in 2005



fur sub-bituminous coals and particularly lignite, most of the mercury is in the elemental form, which is not removed by wet FGD scrubbing. In most tests of bituminous coals, SCR, for NO_x control converted 85-95% of the elemental mercury to the oxidized form, which is then removed by FGD [18, 19]. With sub-bituminous coals, the amount of oxidized mercury remained low even with addition of an SCR. Additional mercury removal can be achieved by activated carbon injection and an added fiber filter to collect the carbon. This can achieve up to 85-95% removal of the mercury. Commercial short-duration tests with powdered, activated carbon injection have shown removal rates around 90% for bituminous coals but lower for sub-bituminous coals [19]. For sub-bituminous coals, the injection of brominated, activated carbon has been shown to be highly effective in emissions tests at 3 plants lasting 10 to 30 days. Brominated, activated carbon in these tests showed the potential to reduce mercury by 90% in conjunction with a CS-ESP [15]. Costs are projected at 0.05 to no more than 0.2 ¢/kW_e-h (Table A-3.D.4).

R&D programs are evaluating improved technology that is expected to reduce costs and improve effectiveness. The general consensus in the industry is that this picture will change significantly within the next few years. EPA states that they believe that PAC injection and enhanced multi-pollutant controls will be available after 2010 for commercial application on most, if not all, key combinations of coal type and control technology to provide mercury removal levels between 60 and 90%. Optimization of this commercial multi-pollutant control technology in the 2015 timeframe should permit achieving mercury removal levels between 90 and 95% on most if not all coals [15], but the technology remains to be commercially demonstrated.

SOLID WASTE MANAGEMENT Coal combustion waste consists primarily of fly ash, along with boiler bottom ash, scrubber sludge, and various liquid wastes. This waste contains such contaminants as arsenic, mercury, chromium, lead, selenium, cadmium, and boron. These toxic contaminants can leach from the waste into groundwater and surface water when the waste is not properly disposed. There are no federal regulations governing the disposal of coal combustion waste, and state regulation of the waste is inconsistent or non-existent. The U.S. EPA determined in 2000 [20] that federal regulation of coal combustion wastes was necessary to protect water resources but has not yet promulgated such regulations. Safe dis-

posal of coal combustion waste requires placement in an engineered landfill with sufficient safeguards, including a liner, leachate collection system, groundwater monitoring system and adequate daily cover.

COSTS The estimated costs for a supercritical PC power plant to meet today's best demonstrated emissions performance and the projected impact on the COE are summarized in Table A-3.D.3 and Table A-3.D.4.

To meet future CAIR and CAMR emissions targets, and driven by local air quality needs to meet NAAQS and/or other local specifications, power plants will have to add or improve their pollution control capabilities. This will increase the capital as well as the O&M costs for new and existing power plants. Table A-3.D.4 summarizes the estimated incremental costs to meet CAIR and CAMR requirements [21, 22]. This includes estimated increased capital and operating costs for mercury control and for decreasing the PM, SO_x and NO_x emissions levels by about a factor of two from current best demonstrated emissions performance levels. This increases the projected COE by about 0.22 ¢/kW_e-h. If wet ESP is required, this could add approximately 0.1 ¢/kW_e-h to this amount.

Table A-3.D.3. Incremental Costs for Advanced Pulverized Coal Power Plant to Meet Today's Best Demonstrated Criteria Emissions Performance

	CAPITAL COST[A] [$/$KW_e$]	O&M[B] [¢/KW_e-h]	COE [¢/KW_e-h]
No Control[c]	1155 (TPC)	0.43	4.11
NO_x	25 (50 – 90)[d]	0.10 (0.05 – 0.15)	0.15 (0.15 – 0.33)
SO_2	150 (100 – 200)[d]	0.22 (0.20 – 0.30)	0.52 (0.40 – 0.65)
Today's Unit	1330 (TPC)	0.75	4.78

a. Capital costs are for a new-build plant, except where indicated, and are for a typical plant to meet today's low emissions levels; costs for low heating value coals will be somewhat higher

b. O&M costs are for typical plant meeting today's low emissions levels; costs will be somewhat higher for high sulfur coal and low heating value coals.

c. Particulate control by ESP or fabric filter included in base unit

d. Range is for retrofits and depends on coal type, properties, control level and local factors

Table A-3.D.4. Estimated Incremental Costs for an Advanced Pulverized Coal Plant to Meet Future CAIR and CAMR Requirements

	CAPITAL COST [$/$KW_e$]	O&M [¢/KW_e-h]	COE [¢/KW_e-h]
Today's Best Units	1330 (TPC)	0.75	4.78
NO_x	5	0.01	0.02
SO_2	15	0.04	0.07
Mercury[a]	20 (6 – 56)[b]	0.08 (0.05 – 0.1)[b]	0.13 (0.06 – 0.16)[b]
Future Plant[c]	1370 (TPC)	0.89 (0.80 – 0.85)	5.00

a. Projected costs for commercially demonstrated technology; new and improved technologies are expected to reduce this significantly, but requires demonstration

b. Range in projected cost increase, dependent on technology, coal type, emission level and local conditions

c. If wet ESP is required, added capital and COE increases could be $40/$kW_e$ and ~0.1 cent/kW_e-h.

EMISSIONS CONTROL FOR IGCC

IGCC has inherent advantages for emissions control because most clean-up occurs in the syngas which is contained at high pressure, and contaminants have high partial pressures. Thus, removal can be more effective and economical than cleaning up large volumes of low-pressure flue gas.

PARTICULATE CONTROL The coal ash is primarily converted to a fused slag which is about 50% less in volume and is less leachable compared to fly ash, and as such can be more easily disposed of safely. Particulate emissions from existing IGCC units vary from 0.4 to 0.01 lb PM/million Btu. Most of these emissions come from the cooling towers and not from the turbine exhaust and as such are characteristic of any generating unit with large cooling towers. This means that particulate emissions in the stack gas are below 0.001 lb PM/million Btu or about 1 mg/Nm^3.

SO_X CONTROL Commercial processes such as MDEA and Selexol can remove more than 99% of the sulfur so that the syngas has a concentration of sulfur compounds that is less than 5 ppmv. MDEA can achieve about 99.4% sulfur removal and should produce an emission rate in the range of 0.045 lb SO_2/million Btu for high-sulfur coal. Selexol can remove more sulfur to about 99.8% of the sulfur and produce an emissions rate of about 0.015 lb SO_2/million Btu. The Rectisol process, which is more expensive, can remove 99.9% of the sulfur and reduce the emission rate to about 0.006 lb SO_2/million Btu (less than 0.1 ppmv) [23, 24].

SO_2 emissions of 0.015 lb SO_2/million Btu (0.15 lb/MW_e-h) or ~5.7 mg/Nm^3 has been demonstrated at the ELCOGAS IGCC plant in Puertollano, Spain [25] and at the new IGCC plant in Japan. The Polk IGCC is permitted for 97.5% sulfur removal, which is an emissions rate of about 0.08 lb SO_2/million Btu [26, 27]. Current IGCC permit applications have sulfur emissions rates of between 0.02 and 0.03 lb SO_2/million Btu [24]. Recovered sulfur can be converted to elemental sulfur or sulfuric acid and sold as by-product.

NO_X CONTROL NO_x emissions from IGCC are similar to those from a natural gas-fired combined-cycle plant. Dilution of syngas with nitrogen and water is used to reduce flame temperature and to lower NO_x formation to below 15 ppm, which is about 0.06 lb NO_x/million Btu. Further reduction to single digit levels can be achieved with SCR, to an estimated 0.01 lb NO_x/million Btu. NO_x emissions of about 0.01 lb NO_x/million Btu or about 4.2 mg/Nm^3 NO_x (at 15%O_2) has been demonstrated commercially in the new IGCC unit in Japan, which uses SCR. The Polk IGCC is permitted for 15 ppmv in the stack gas, but is typically achieving 10 ppmv, which is about 0.09 lb NO_x/million Btu. Current IGCC permit applications are at the 0.06 to 0.09 lb NO_x/million Btu.

MERCURY CONTROL Commercial technology for mercury removal in carbon beds is available. For natural gas processing, 99.9% removal has been demonstrated, as has 95% removal from syngas[25]. Mercury and other toxics which are also captured in both the syngas clean-up system (partial capture) and carbon beds produces a small volume of material, which must be handled as a hazardous waste. It is a small enough volume of material that these wastes could be managed to permanently sequester mercury from the environment. This is not a current regulatory requirement. The cost of mercury removal has been estimated to $ 3,412/lb for IGCC, which translates into an estimated cost increase for IGCC of 0.025 ¢/kW_e-h [28].

SOLID WASTE MANAGEMENT IGCC process differences result in significantly different solid waste streams than are produced by a PC. For the same coal feed an IGCC produces 40% to 50% less solid waste than a PC. An IGCC plant produces three types of solid waste: a) ash typically as a dense slag, b) elemental sulfur (as a solid or a liquid), and c) small volumes of solid captured by process equipment.

The vitreous slag is dense and ties up most of the toxic components so that they are not easily leachable. However, limited field data on long-term leaching of coal gasification slag show that some leaching of contaminates can occur [29]. Therefore, proper engineering controls should be applied to coal gasification solid residue disposal sites to ensure that ground water concentrations of certain contaminants do not exceed acceptable limits [29].

Sulfur, as H_2S in the syngas, can be recovered as either elemental sulfur (solid or liquid) or as sulfuric acid which can be sold as a by-product. If IGCC technology is extensively deployed, it is not clear that all the associated elemental sulfur will be able to find a market.

The metallic toxics that are not tied up in the vitreous slag are volatized into the syngas and are removed as small volumes of waste at various parts of the gas clean-up system, including a carbon bed that will be used for mercury control.

The current legal status of IGCC solid wastes is less clear than is the case for PC solid waste, because the Congressional language exempting coal combustion wastes from RCRA is ambiguous regarding IGCC wastes.

WATER USAGE PC and IGCC technologies both use significant quantities of water, and treatment and recycle are increasingly important issues. IGCC uses 20 to 35% less water than supercritical PC plants [30]. Proven wastewater treatment technology is available and has been demonstrated to handle the water effluents for both technologies.

Table A-3.D.5 compares the estimated incremental cost for a PC plant and for an IGCC plant, to comply with projected future emission caps, built off the base of this report. The incremental difference between IGCC-Future and IGCC-Today is primarily due to the cost of additional mercury removal capabilities [30]. Other emissions are already within the range expected for future control. These estimates are based on reasonable further reductions in emissions using existing technologies with limited learning curves for the PC technology and for IGCC. Moving new PC units to lower emission levels that are consistent with the Federal standards projected through 2015-2018 (mainly mercury with some further SO_x and NO_x reductions) does not make PC COE as costly as the COE from IGCC.

Table A-3.D.5 Estimated Incremental Cost for Pulverized Coal and IGCC to Meet Projected Future Emissions Requirements

	CAPITAL COST [$/kW$_e$]	O&M [¢/kW$_e$-h]	COE [¢/kW$_e$-h]
Advanced PC	1330 (TPC)	0.75	4.78
Future PC	1370 (TPC)	0.89	5.00
IGCC-Today	1429 (TPC)	0.90	5.13
IGCC-Future	1440 (TPC)	0.92	5.16

Although an IGCC can achieve significantly lower emissions than the projected PC levels, there will be an added cost to do so. For example, changing from Selexol to Rectisol involves an increase in capital and operating costs, which could make the cost of removal of the incremental tonnes of SO_2 ($/tonne) much higher [24] than the allowance costs for SO_2, which have recently been less than $1000/tonne. This would eliminate the economic incentive to design units for the extremely low levels that IGCC can achieve. Permitting a unit in an attainment area does not require such heroic efforts, but non-attainment areas may present a different opportunity for IGCC. There is neither sufficient design data nor commercial operating information available to quantitatively assess this situation today.

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Appendix 3.E — Retrofitting Existing Units for CO_2 Capture

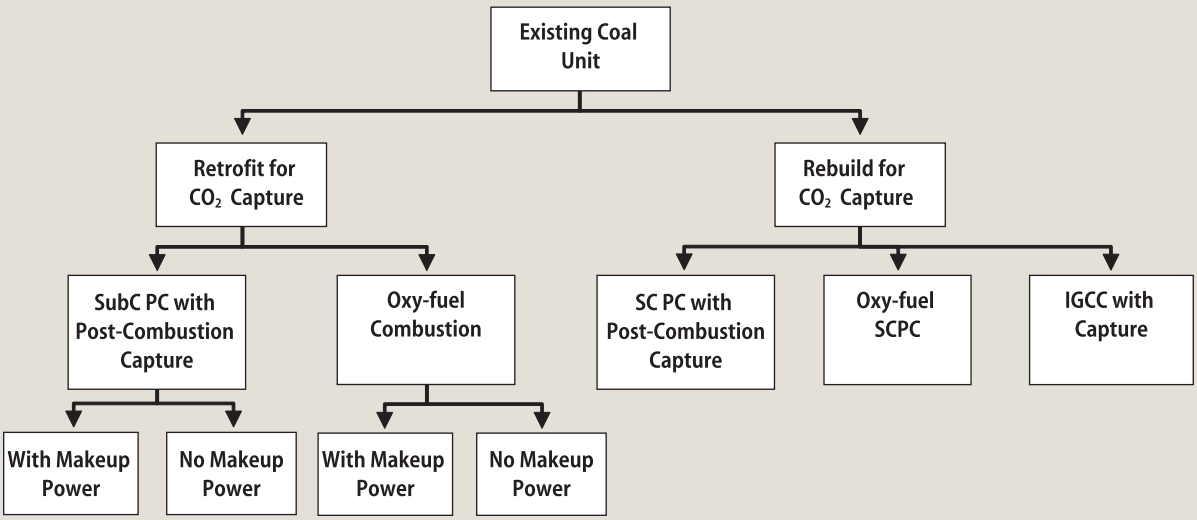
The U.S. coal-based generating capacity is about 330 GW, which is 33% of the total, but because it is primarily base load, it generated 51% of the electricity produced in the U.S. (1980 TW_e-h) in 2003. Although the average age of the coal fleet is greater then 35 years (number average age), 50% of the coal is consumed in units that are less than 30 years old [1, 2]. Of the over 1000 boilers in the U.S. about 100 are supercritical, the remainder being subcritical units. There are currently over 100 coal-based power plants at various stages of consideration/approval in the U.S. of which about 20 GW of new coal based capacity are expected to be built by 2015. Of these new units, a significant fraction will be supercritical units.

The issue of what to do with this coal fleet base in a carbon-constrained environment is critical if the U.S. is to manage its CO_2 emissions from coal generation. The options include: (a) substantially improve unit generating efficiency, (b) continue to operate them and achieve additional carbon reductions from other areas, (c) retire and replace the units with new capacity equipped with carbon capture for sequestration, (d) retrofit existing units to capture CO_2 for sequestration, or (e) operate the units and pay the carbon tax. Here we consider the issues associated with retrofitting existing coal-fired generating units for CO_2 capture.

Adding CO_2 capture technology to an existing PC unit is complicated by the range of options that exist and the number of issues associated with each. These can typically not be generalized because they are determined by the specific details of each unit. The physical issues include space constraints associated with the unit, and its proximity to a CO_2 sequestration site. The technical issues include: technology choice, technology maturity, operability and reliability, impact on efficiency, and retrofit complexity. The economic issues are the investment required (total and $/$kW_e$), net output reduction, and change in dispatch order.

A decision tree illustrating a number of the options that need to be considered is shown in Figure A-3.E.1. These include a standard retrofit of the existing unit to capture CO_2 either

Figure A-3.E.1 Decision Tree of Possible First-Level Options for Retrofitting an Existing Subcritical Pulverized Coal Electricity Generating Unit



by post-combustion capture with one of several technologies or by addition of oxy-fuel combustion with CO_2 capture by compression. Because of the derating that occurs upon adding capture technology, additional capital can be spent to make up for the lost power by adding an additional boiler with each of the options.

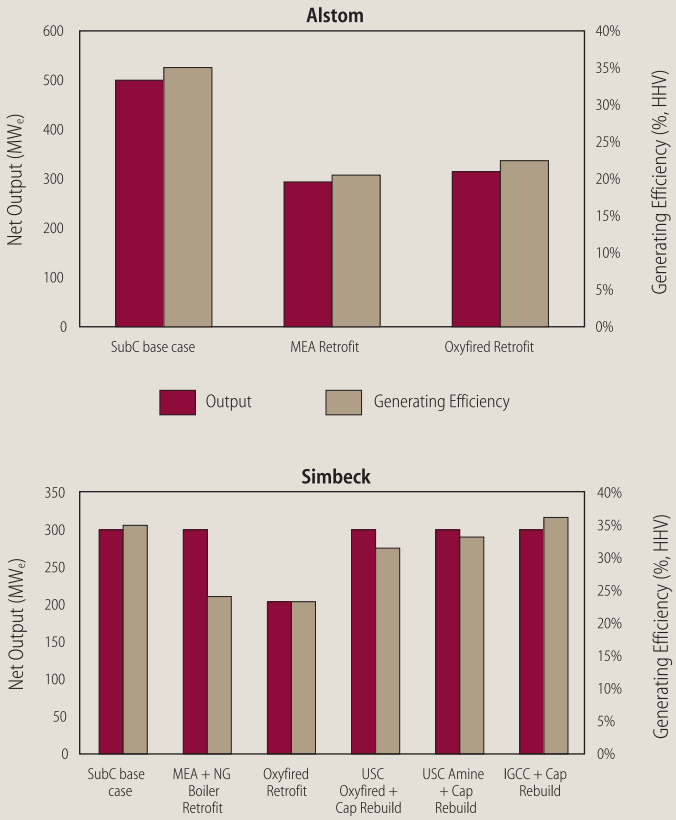
A more aggressive approach would be to rebuild the existing unit to include CO_2 capture and improve the overall technology on the site, resulting in an optimally sized and balanced unit. This could be done by upgrading to a supercritical PC or an ulta-supercritical PC with post-combustion CO_2 capture, by upgrading to oxy-fuel supercritical technology, or by installing IGCC with CO_2 capture.

RETROFIT AND REBUILD FOR CO_2 CAPTURE FOR PULVERIZED COAL UNITS

Recent studies by Alstom Power, Inc. [3, 4] and by Simbeck [5, 6]) provide a basis for estimating the economics of retrofitting and rebuilding existing units for CO_2 capture. These studies involved subcritical boilers only. The base unit size was 500 MW_e for the Alstom evaluation and 300 MW_e for Simbeck.

EFFICIENCY AND NET OUTPUT The impact on net electrical output and unit efficiency of retrofitting a subcritical PC unit for CO_2 capture by adding amine adsorption and by adding oxy-firing is shown in Figure A-3.E.2. Cases involving rebuilds of key components were also evaluated by Simbeck [5].

Figure A-3.E.2 Impact of Retrofitting or Rebuilding a Subcritical Pulverized Coal Unit



Adding MEA (monoethanolamine) flue gas scrubbing to the unit decreased the net generating capacity from 500 MW_e to 294 MW_e, a 41% derating. For this retrofit, the reduction in efficiency is from 35% to 20.5% (HHV), or 14.5 percentage points. The efficiency reduction for purpose-built units from this study in going from no-capture to capture is 34.3% to 25.1% (HHV) or 9.2 percentage points (Figure 3.5). The roughly additional 5 percentage point efficiency reduction is due to the non-optimum size mismatch of the components in the retrofit case.

For an oxy-fuel retrofit the net output is derated by 35.9% (500 MW_e to 315 MW_e) [3] and 33.3% (300 MW_e to 204 MW_e) [5] (Figure A-3.E.2). This corresponds to efficiencies of 22.5% and 23.3% (HHV) respectively. These are efficiency reductions of 12.5 and 11.7 percentage points, vs. an 8 to 9 percentage point reduction estimated for a purpose-built oxy-fuel PC unit.

We estimated the capital costs, and the impacts on performance and COE of retrofitting a supercritical PC unit based on information from the subcritical PC evaluations and our greenfield supercritical unit information. An amine scrubbing retrofit of a

Table A-3.E.1 Summary of Greenfield and Retrofit Efficiencies and Deratings for Pulverized Coal Units

TECHNOLOGY	GREENFIELD SUBC PC	GREENFIELD SC PC	RETROFIT SUBC PC	RETROFIT SC PC
Baseline Efficiency (%, HHV)	35.0	39.2	35.0	39.2
MEA Derating (%)	28.1	25.2	41.5	36
MEA Efficiency (%, HHV)	25.1	29.3	20.5	25
Oxy-fuel Derating (%)	n/a	23.0	35.9	31
Oxy-fuel Efficiency (%, HHV)	n/a	30.2	22.4	27

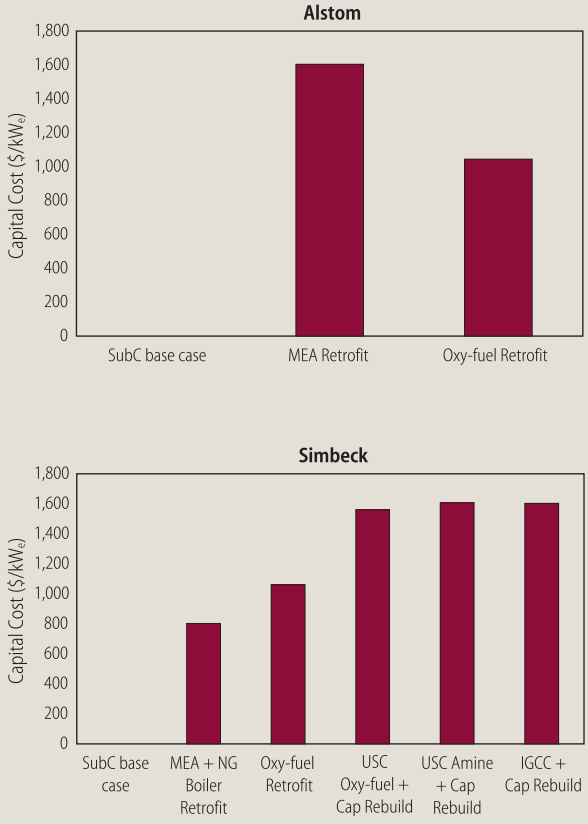
supercritical PC (39.2% efficiency (HHV)) reduces the efficiency by about 36% (to 25% (HHV)), vs. a 41% derating for the subcritical unit retrofit due to the higher initial efficiency of the supercritical base unit. The net power output is 320 MW_e, a 36% derating. Oxy-fuel retrofit reduces the efficiency to about 27% vs. 30.2% (HHV) for a purpose-build oxy-fuel supercritical PC unit. Table A-3.E.1 summarizes the results for subcritical and supercritical PC retrofits.

Simbeck [5] also evaluated rebuild cases designed to maintain the same electrical output as the base case and also to upgrade the unit with an ultra-supercritical steam cycle. The USCPC rebuild unit with MEA CO_2 capture had a generating efficiency that was only 3.5 percentage points below the subcritical base case unit without CO_2 capture. An ultra-supercritical oxy-fuel rebuild for CO_2 capture had a generating efficiency only 1.8 percentage points lower than the subcritical base case without CO_2 capture. Rebuilding with an IGCC unit with CO_2 capture resulted in a generating efficiency that was 1.2 percentage points higher that the original base case subcritical unit without CO_2 capture. The rebuild efficiencies are similar to those for new, purpose-built USC capture units. This is as expected because rebuilding a unit allows the optimum sizing of major pieces of equipment.

CAPITAL COSTS The capital cost associated with these retrofits/rebuilds varies significantly, depending on the approach taken. Figure A-3.E.3 summarizes the incremental capital costs, in $/$kW_e$, for each of the cases. The subcritical PC base case unit was assumed to be fully paid off and thus to have zero value. The capital cost for the supercritical retrofits was scaled from the subcritical cases based on the increased efficiency and reduced CO_2 production per kW_e-h output.

The capital cost per net kW_e output for the straight MEA retrofit [3] is high ($1604/$kW_e$) because of the severe output reduction that occurs. If a simple natural gas boiler is added to the MEA retrofit to provide make-up stripping steam for CO_2 recovery so that net electrical output is not reduced [5], the cost is lowered to $800/$kW_e$. The oxy-fuel retrofit cost for the two studies is similar ($1044/$kW_e$ [3] and 1060/kW_e [5]) and is

Figure A-3.E.3 Capital Cost for Subcritical Pulverized Coal Retrofits and Rebuilds



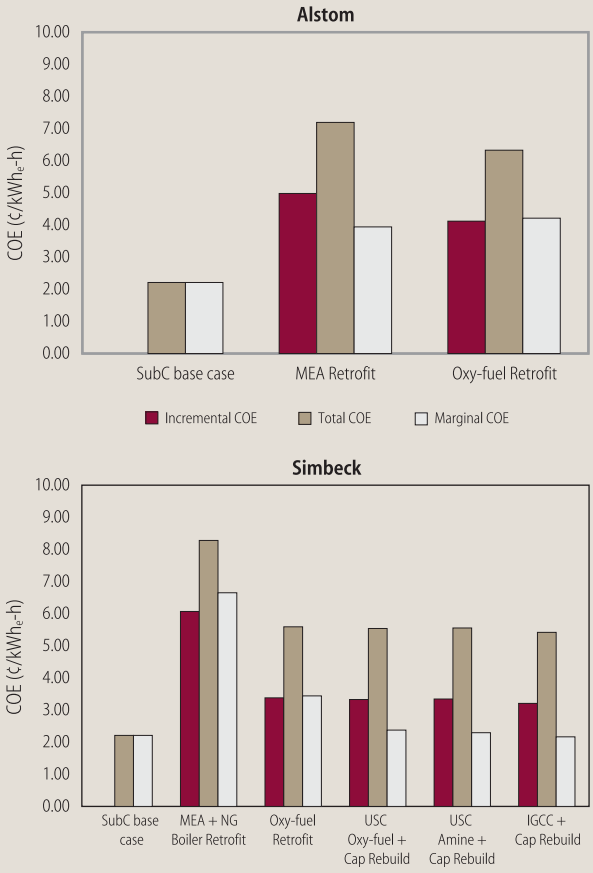
significantly lower than the other options evaluated. The rebuild cases each have a capital cost in the range of \$1550 to \$1600/kW_e.

COST OF ELECTRICITY To calculate the COE for these cases, we applied the same normalization parameters that were used in analyzing new generating units (Table 3.4, summarized in Table A-3.E.2). A key assumption in this analysis is that the existing units are fully paid off and thus carry no capital charge other than the added retrofit or rebuilding capital. The results of this analysis are presented in Figure A-3.E.4 For details see [7].

Table A-3.E.2 Economic and Operational Normalization Parameters

PARAMETER	VALUE
Annual carrying charge rate (applied to TPC)	15.1%
Capacity factor	85%
Fuel cost, coal ($/MMBtu, (HHV))	$1.50
Fuel cost, natural gas ($/MMBtu, (HHV))	$9.00

Figure A-3.E.4 Incremental, Total and Marginal Cost of Electricity for Subcritical Pulverized Coal Unit Retrofits and Rebuilds



For the retrofit options, oxy-fuel is the most attractive because it has lower total and incremental COE costs than the MEA retrofit and similar marginal COE costs. It is slightly more costly than the rebuild cases. The MEA retrofit with the natural gas boiler is the least attractive of all the retrofit cases based on total, incremental and marginal COE costs. The primary cause of this is the significant natural gas input requirement, which significantly increases the fuel cost component of COE. Compared with the oxy-fuel retrofit, the rebuild options have lower marginal COE and similar incremental and total COE costs. If natural gas is assumed to be \$6.00 per million Btu, these conclusions do not change, although the Total, Incremental and Marginal COE for the MEA with natural gas boiler case decrease by 1.3 ¢/kW_e-h.

ECONOMICS FOR PC RETROFITS Table A-3.E.3 summarizes the economics of the primary retrofit and rebuild cases on the same bases as used throughout this report. The O&M costs for the retrofit options were estimated by scaling O&M costs for greenfield capture units by the decreased generating efficiency of the retrofit options.

The CO_2 avoidance and capture costs (in \$/tonne) were calculated for the retrofit and rebuild cases using a CO_2 capture efficiency of 90% for each case. The results of this analysis are presented in Table A-3.E.4 [8].

IMPACT OF CAPITAL WRITE-OFF ASSUMPTION ON COE This analysis assumed that the capital associated with the original unit has been fully written off. This may not be the case when retrofits of newer units are considered, or where there is market value for the non-retrofitted unit. To accommodate this factor, a sensitivity to different levels of residual value in the original unit was performed for the two SCPC cases (see Table A-3.E.5).

The assumption of residual value can have a significant impact on the economics of retrofitting, and should be considered in the analysis of retrofit cases, although it may not be a key retrofit determinant because that capital is already sunk.

Table A-3.E.3 Total Cost of Electricity for Pulverized Coal Retrofit and Rebuild Cases

	BASELINE CASES		RETROFITS – SUBC PC		RETROFITS – SC PC		REBUILDS – USC PC	
TECHNOLOGY	SUBC PC	SC PC	MEA	OXY-FUEL	MEA	OXY-FUEL	MEA	OXY-FUEL
Efficiency (HHV)	35%	39.2%	20.5%	22.4%	25%	27%	34.1%	31.5%
Retrofit/Rebuild Capital Cost ($/$kW_e$)	0	0	1604	1043	1314	867	1880*	1848*
Capital Cost (¢/kW_e-h)**	0.00	0.00	3.25	2.12	2.66	1.76	3.81	3.75
O&M (¢/kW_e-h)	0.75	0.75	1.96	2.36	1.88	1.96	1.60	1.75
Fuel Cost (¢/kW_e-h)	1.46	1.31	2.50	2.29	2.05	1.90	1.50	1.63
Total COE (¢/kW_e-h)	2.21	2.06	7.71	6.76	6.59	5.61	6.91	7.12

* *Assumes capital required was 90% of that of the corresponding Greenfield plant*

** *Calculation of total COE assumes that the capital of the original plant was fully paid off*

Table A-3.E.4 CO_2 Emission Rates, Capture Cost and Avoidance Costs for Pulverized Coal Cases

	BASELINE CASES		RETROFITS – SUBC PC		RETROFITS – SC PC		REBUILDS – USC PC	
TECHNOLOGY	SUBC PC	SC PC	MEA	OXY-FUEL	MEA	OXY-FUEL	MEA	OXY-FUEL
CO_2 Produced (tonnes/MW_e-h)	0.93	0.83	1.59	1.45	1.30	1.20	0.95	1.03
CO_2 Captured (tonnes/MW_e-h)	0.00	0.00	1.43	1.31	1.17	1.08	0.86	0.93
CO_2 Emitted (tonnes/MW_e-h)	0.93	0.83	0.16	0.15	0.13	0.12	0.10	0.10
CO_2 Capture cost[a] ($/tonne)	n/a	n/a	38.5	34.8	38.7	32.8	54.8*	52.9*
CO_2 Avoidance cost[b] ($/tonne)	n/a	n/a	71.4	58.0	62.6	48.0	56.4*	59.5*

a. CO_2 capture cost = (total COE with capture – base-case total COE)/(captured CO_2)

b. CO_2 avoidance cost = (total COE with capture – total COE without capture)/(CO_2 emitted without capture –CO_2 emitted with capture)

c. Relative to the SubC PC baseline case

Table A-3.E.5 Impact of Residual Unit Capital Value on Incremental and Total Cost of Electricity (¢/kW_e-h)

REMAINING CAPITAL ASSUMPTION	SC PC WITH MEA RETROFIT (¢/kW_e-h)	OXY-FUEL SC PC RETROFIT (¢/kW_e-h)
10%	0.43	0.40
25%	1.07	0.99
50%	2.14	1.98

RETROFIT OF IGCC FOR CO_2 CAPTURE

Retrofitting IGCC for CO_2 capture involves changes in the core of the gasification/combustion/ power generation train that are different from the type of changes that need to be made upon retrofitting a PC unit for capture, i.e., adding a separate unit to the flue-gas train. The choice of gasifier and of gasifier configuration and design are different for an optimum IGCC design without CO_2 capture and an IGCC design with CO_2 capture. The available data contain insufficient design and cost information to quantitatively evaluate most of the options and configurations available.

Designs without CO_2 capture tend to favor lower pressure, 2.8 to 4.2 MPa (400 to 600 psi) and increased heat recovery from the gasifier train, including radiant syngas cooling and convective syngas cooling to raise more steam for the steam turbine and increase the net generating efficiency (See Appendix 3-B, Figure A-3.B.2.). Dry-feed gasifiers, e.g. Shell, provide the highest efficiency and are favored for coals with lower heating values, primarily because of their already-higher moisture content. However, today, such gasifiers have higher capital cost. The higher capital cost charge to COE is partially offset by higher generating efficiency, reduced coal feed rate and cost, and may be totally offset by lower coal cost in the case of low-quality coals.

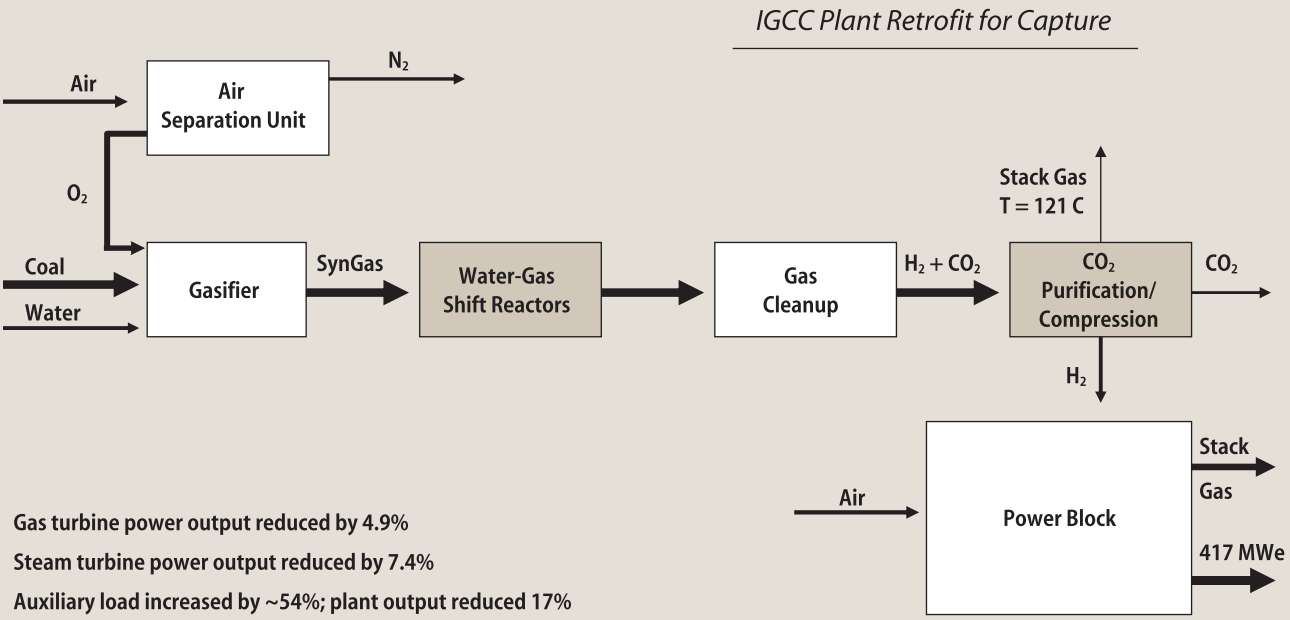
On the other hand, designs with CO_2 capture favor higher-pressure (1000 psi) operation, slurry-feed, and full-quench mode [9]. Full-quench mode is the most effective method of adding sufficient steam to the raw syngas for the water gas shift reaction without additional, expensive steam raising equipment and/or robbing steam from the steam cycle. Higher pressure reduces the cost of CO_2 capture and recovery, and of CO_2 compression. The following examples illustrate these points and the differences between retrofitting a PC and an IGCC unit.

For a GE full-quench, (1000 psi) design without CO_2 capture, the overall generating efficiency is about 35.5 % [10]. The capital cost for retrofitting this IGCC unit for CO_2 capture was estimated to be about \$180/kW_e [10], which is significantly lower than that for retrofitting a PC unit on an absolute basis and on a \$/kW_e basis. This retrofit results in an overall unit derating (efficiency reduction) of about 17 % (see Figure A-3.E.5). Furthermore, the additional derating over a purpose-built IGCC unit with CO_2 capture is projected to be less than 1 percentage point efficiency reduction, vs. the additional 4+ percentage point efficiency reduction estimated for an MEA retrofit of a subcritical PC unit. Thus, the impact on COE is also less.

Figure A-3.E.5 illustrates the impact of the retrofit on the net electrical output. With no increase in coal feed rate, the gas turbine for the capture case is producing 4.9% less power then for the baseline, no CO_2 capture case; and the steam turbine is producing 7.4% less. Thus, these turbines are close to their optimum operating efficiencies. The gas turbine was retrofitted to burn hydrogen-rich syngas at a cost of about \$6 million, which is in the retrofit cost. The reduced net electrical output for the unit is about 17% because the auxiliary power requirements are up considerably in the CO_2 capture case. The overall efficiency decreased from 35.3% to 29.5% upon retrofitting for CO_2 capture.

EPRI also evaluated the impact of pre-investment for CO_2 capture for this case, including over-sizing the gasifier and ASU, and optimizing the unit layout for the addition of CO_2 capture equipment at a later date [10]. Incremental capital required for pre-investment was estimated to be about \$60/kW_e, which would add about 0.12 ¢/kW_e-h to the cost of electricity produced by the IGCC unit without CO_2 capture suggesting the preinvestment was not justified [11]. Furthermore, the impact of pre-investment on retrofit cost was relatively small, about 5% less than for a straight retrofit on a \$/kW_e basis. Pre-investment can effectively eliminate the derating in net unit output upon adding CO_2-capture capability vs. the output of a purpose-built IGCC unit with CO_2 capture. The study projects that the retrofit unit will produce electricity within 0.15 ¢/kW_e-h of a purpose-built IGCC capture unit. We therefore expect that the COE will be in line with that in Table 3.5.

Figure A-3.E.5 Impact of Retrofitting a GE Full-Quench IGCC Unit for CO_2 Capture



In the case of a lower-pressure E-Gas gasifier-based IGCC unit operating at 3.5 MPa (500 psi) with radiant cooling and convective syngas coolers to maximize the heat recovery and HP steam delivery to the steam turbine, the overall unit generating efficiency without CO_2 capture is 39.5 % [10]. With the addition of CO_2 capture and at constant coal feed rate, the gas turbine undergoes an 8.7 % derating. However, the major impact is on the steam turbine. Because the syngas has a lower water to (CO + H_2) ratio than for the GE full-quench unit, steam must be added to the gas stream prior to the water gas shift reactors to achieve adequate CO conversion. This steam is taken from the stream turbine system reducing the stream turbine output by 19 %. Total auxiliaries are similar for the two cases. Retrofitting reduced the overall efficiency from 39.5% to 30.5%, a 23% reduction. Lower-pressure operation also contributes of this larger efficiency decrease, through both increased CO_2 separation and compression costs. A unit built with a GE gasifier with radiant and convective syngas coolers would have a similar efficiency reduction upon retrofit.

The retrofit costs were estimated at \$225/kW_e, significantly greater than for the GE full-quench retrofit because of the need for several additional pieces of equipment beyond the adds and upgrades that are required for both. Overall, the changes were more significant for the E-gas case. Further, the additional heat recovery of the original gasifier design which adds significant cost is not effectively used in the CO_2 capture mode. The optimum design would not contain the same gasifier/heat recovery system for a CO_2 capture unit as for a no-capture unit, and retrofitting a no-capture unit to a CO_2 capture configuration does not involve the optimum use of capital.

IMPACT OF NEW TECHNOLOGIES ON CAPTURE

The above analyses are based on existing, commercially-demonstrated technologies. As occurred with PC emissions control technologies, such as flue gas desulfurization technology, when commercial application of CO_2 capture becomes relatively close and certain, it can be

expected that new and improved technologies that are both more effective and less expensive for CO_2 capture will evolve and be improved-upon as commercial experience is gained. Thus, although we expect the cost differences discussed above to remain directionally correct, we expect that the deltas could change significantly.

Alternative technologies, in addition to MEA post-combustion capture and oxy-firing are currently being investigated for CO_2 capture from pulverized coal units. These include, among others: chemical looping, CO_2 frosting, CO_2 adsorber wheels, and chilled aqueous ammonia scrubbing[3, 12, 13]. Chapter 6 addresses this area further.

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7. For this analysis: (a) the capital of the existing plant is assumed to be entirely written off, (b) marginal COE is defined as the variable cost of production, which consists of fuel cost and variable O&M, (c) Incremental COE is defined as the increase in Total COE for a capture case with respect to the baseline, no-capture plant, and (d) Total COE is defined as the sum of all costs associated with electricity production [fuel cost, capital charge, and all O&M].
8. *CO_2* capture cost = (total COE with capture - basecase total COE)/ captured CO_2. CO_2 avoidance cost = (total COE with capture - total COE without capture)/ (*CO_2* emitted without capture - CO_2 emitted with capture)
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Appendix 3.F — Coal to Fuels And Chemicals

As the price petroleum and natural gas increases relative to unconventional hydrocarbon resources, there will be increasing interest in exploring the commercial potential of producing synthetic liquid fuels, chemicals, and synthetic natural gas (SNG) from coal and also oil shale. This trend is already apparent in the increasingly large investments to produce and upgrade heavy oils in Venezuela, and oil sands in Canada. If it appears that crude oil and natural gas prices will fluctuate in a range near their recent historically-high values rather than return to previously lower levels, commercial projects to produce synthetic liquids, chemicals, and SNG from coal will receive increasing attention.

Unfortunately, the conversion of coal to synthetic fuels and chemicals requires large energy inputs which in turn result in greater production of CO_2. The initial step in the production of methane or (SNG), of chemicals, or of liquids, such as methanol, diesel or gasoline, from coal is the gasification of coal to produce syngas, just as carried out in IGCC for electricity generation. This syngas, which is a mixture of predominately carbon monoxide and hydrogen is cleaned of impurities; and the hydrogen to carbon monoxide ratio is increased by the water gas shift reaction to the value required by the specific synthesis reaction to be carried out. After the water gas shift reaction, CO_2 is removed from the synthesis gas. For liquids production, this route is referred to as indirect liquefaction, and this is the route analyzed here.

Coal can also be converted directly to liquid products by reaction at high temperature and high hydrogen pressure. This route is referred to as direct liquefaction. However, the direct liquefaction route is very costly because of severity of the conditions and the cost of the capital equipment required to operate at these conditions. The direct route generally produces low-quality liquid products that are expensive to upgrade and do not easily fit current product quality constraints. Direct liquefaction will not be considered further here except in an historical context.

The reactions for indirect conversion of coal to fuels and chemicals are illustrated below and include:

Combustion to increase temperature and provide heat for the remaining reactions. Here, coal is represented by C-H, an approximate formula for many coals.

$$2\ C\text{-}H + 3/2\ O_2 \rightarrow 2CO + H_2O$$

Gasification reactions include reaction of water with coal char and reaction between water and carbon monoxide.

$$C + H_2O \rightarrow H_2 + CO$$

$$CO + H_2O \rightarrow H_2 + CO_2$$

At typical gasification conditions, this syngas is an equilibrium mixture which is about 63% CO, 34% H_2 and 3% CO_2, on a molecular basis

Water gas shift reaction is used to adjust the H_2 to CO ratio to the value required by the synthesis reaction to follow.

$$CO + H_2O \text{-}\rightarrow CO_2 + H_2$$

Synthesis reactions produce the desired products from the synthesis gas.

For **methane formation**, the synthesis gas needs to have a H_2 to CO ratio of 3 to 1.

$$CO + 3H_2 \rightarrow CH_4 + H_2O$$

For **Fischer-Tropsch** reaction to form diesel fuel, the synthesis gas needs to have a H_2 to CO ratio of about 2 to 1.

$$CO + 2H_2 \rightarrow -(CH_2)_n- + H_2O$$

An ideal overall stoichiometry for the conversion of coal to methane can be illustrated by the following reaction, where coal is represented by C-H (a typical approximate composition of coal).

$$4C\text{-}H + O_2 + 2H_2O \rightarrow 2CH_4 + 2CO_2$$

For Fischer-Tropsch (F-T) conversion to diesel fuel the ideal overall stoichiometry can be illustrated by:

$$2\ C\text{-}H + O_2 \rightarrow (-CH_2-) + CO_2$$

As these reactions show, under completely ideal conditions, one CO_2 molecule is produced for each CH_4 molecule produced and for each carbon atom incorporated into F-T product.

If coal is assumed to be pure carbon, then the overall reactions would be:

$$8\ C + 6\ H_2O + 2\ O_2 \rightarrow 3\ CH_4 + 5\ CO_2 \quad \textbf{(for methane)}$$

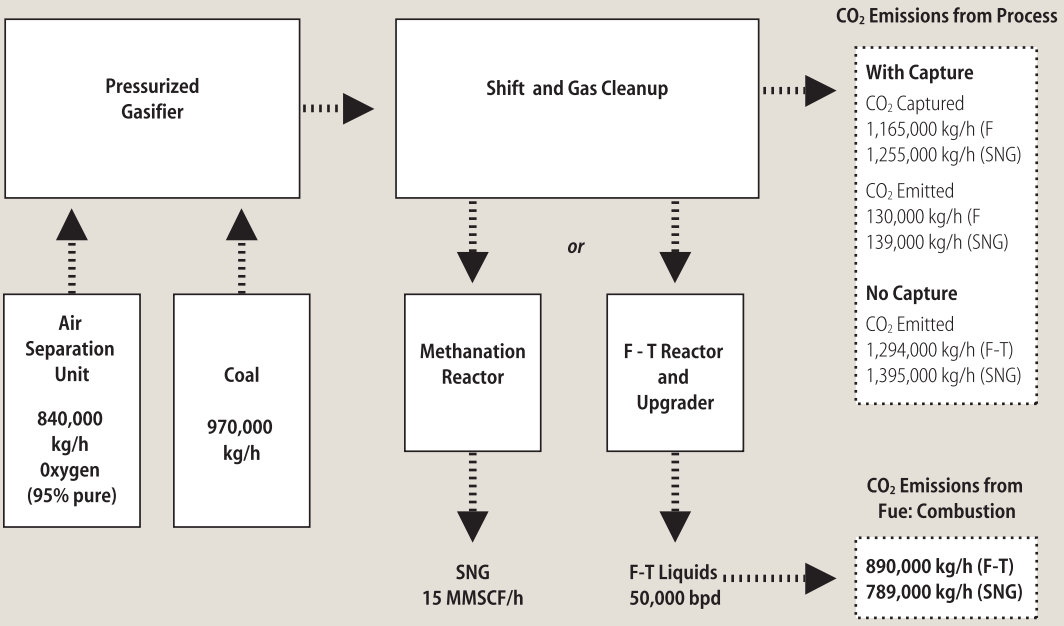
$$4\ C + 4\ H_2O + O_2 \rightarrow 3(-CH_2-) + 3\ CO_2 \quad \textbf{(for F-T)}$$

These reactions suggest that 1 2/3 CO_2 molecules are produced for every CH_4 molecule produced and one CO_2 molecule produced for each carbon atom incorporated into F-T product.

However, because of the need to heat the system to high temperatures, and because of process and system irreversibilities and other inefficiencies, the amount of CO_2 formed is significantly larger. Thus, synthetic fuels derived from coal will produce a total of 2.5 to 3.5 times the amount of CO_2 produced by burning conventional hydrocarbons. Since this study is concerned with understanding how coal is best utilized in a carbon constrained world, we must anticipate combining CCS with synfuels and chemicals production. Requiring CCS will make synfuels more expensive. On the other hand, CO_2 capture and separation is a required, integral part of the synfuels production process. It is also cheaper and easier because "indirect" synthetic fuels production uses oxygen rather than air, and the cost of the air separation unit (ASU), CO_2 separation, and high operating pressure are "sunk" costs of synfuels production process.

As an illustration, Figure A-3.F.1 presents a process flow diagram for the production of 50,000 bpd of Fischer-Tropsch liquids or the production of 15 million SCF/h of SNG from coal. Scale is an important issue in synfuels production because of the large size of our fuels consumption. A 50,000 bpd plant consumes over 5 times as much coal, and emits over 3 times as much CO_2 as does a 500 MW_e IGCC plant. As noted above, the total fuel cycle

Figure A-3.F.1 Process Flow Diagram for Coal-to-Fuels Production



emission of CO_2 from the coal to fuels process is markedly larger than that for just burning the fuel if carbon capture and sequestration (CCS) are not employed. Without CCS, FT-synthesis of liquid fuels emits about 150% more CO_2 as compared with the use of crude oil derived products. For comparison, refining petroleum emits about 8 % more CO_2 than the amount that is emitted upon consuming the fuel. For SNG, up to 175% more CO_2 is emitted than if regular natural gas were burned [1]. With CCS, the full fuel-cycle CO_2 emissions for both liquid fuel and SNG can be comparable with the total CO_2 emissions from these fuels when derived from traditional sources. However for synfuels, CCS does not require major changes to the process or significant energy penalties as is the case for electric power generation since the CO_2 is a process byproduct in an almost pure stream and at intermediate pressure.

PRACTICAL EXPERIENCE WITH SYNFUELS

Technology to convert coal to liquid and gaseous fuels has been available in various forms since the 1920's, but the high capital and operating costs have kept it uncompetitive, except in situations of extreme shortage. SASOL , in South Africa, has been producing 195,000 barrels per day of liquid fuel using Fischer-Tropsch technology for several decades.

Today, the largest commodity chemical produced from syngas is ammonia. Most U.S. ammonia plants were designed to get their hydrogen for ammonia synthesis by reforming natural gas and shifting the resultant syngas mixture to pure hydrogen. Today, many of these plants are closed and/or exploring coal gasification as a source of syngas because of high natural gas prices [2]. World-wide there are a significant number of ammonia plants that use syngas from coal gasification. China (e.g., the Shenhau Group) is embarking on a number of large plants to convert coal to methanol, then to ethylene and propylene, for polyethylene and polypropylene production [3]. Dow is involved in one of these plants, where the plan is to sequester CO_2 [4].

Eastman Chemical in Kingsport Tennessee has operated a coal to chemicals plant for over 20 years, at 98% availability, without government assistance. The plant produces synthesis gas from coal (1,250 tons of coal/day fed to Chevron/Texaco gasifier) and then converts the synthesis gas to acetic anhydride and other acetyl chemicals. These routes to chemicals can be carried out individually or are easily integrated together. The possibility of production of liquid fuels and chemicals from coal raises an image of a coal refinery. Such a refinery, producing a slate of chemical and fuel products could also generate electricity as well. This is referred to as polygeneration.

In 1979, the United States, anticipating increases in the price of oil to $100 per barrel, embarked on a major synthetic fuels program intended to produce up to 2 million barrels of oil equivalent per day of natural gas from coal and synthetic liquids from oil shale and coal. A quasi-independent government corporation, "The Synthetic Fuels Corporation" (SFC), was formed for this purpose. The SFC undertook to finance approximately six synfuels projects using a combination of indirect incentives, for example, loan guarantees and guaranteed purchase. The price of oil fell in the early 1980s to a level of about $20 per barrel, making all coal to fuels technologies economically unattractive, and thus obviating the need for a government supported synfuels program, and the SFC was terminated in 1985. The lesson of the SFC is that it is dangerous to build a government support program on assumptions about future world oil prices.

ECONOMICS OF COAL TO FUELS PRODUCTION

CAPITAL COSTS Several recent studies have evaluated the economics of both F-T synthesis fuels, and SNG production [5-8]. For F-T synthesis fuels, reported capital costs (TPC) range from $42,000 to $63,000 per bpd capacity, of which the F-T reactor section and associated equipment accounted for $15,000 to $35,000 of the costs. This compares to a typical capital cost of $15,000 per bpd capacity for a traditional crude oil refinery. For SNG facilities, the reported capital cost for the methanation equipment range from $22,000 to $24,000 per million Btu/hr.

It is difficult to estimate the cost of synfuels plants; and historically, estimates have proven to be wildly optimistic. There are several reasons for this: First, few synfuels plants are in operation; and therefore, there are few data upon which to estimate the cost of a "first of a kind" or "Nth" plant. Second, plant cost will vary with location, capacity, construction climate, product slate, and coal type. Third, there are differing economic assumptions about interest rates, equity/debt ratio, and capacity factor. Fourth, the engineering estimates are usually performed by development organizations that do not have the perspective of a plant owner and/or are frequently attempting to promote business opportunities. With these reservation about the uncertainties in cost estimates, we report the results of our analysis in Table A-3.F.1 [9], compiled using the same economic assumptions that were used in Chapter 3.

Table A-3.F.1 Total Plant Cost for Synthetic Fuels Production Facilities*

TECHNOLOGY	NO CO_2 CAPTURE	WITH CO_2 CAPTURE
F-T Synthesis ($/bpd)	53,000	56,000
SNG Production ($/MM SCF/h)	182,000	191,000

**Based on cost estimates made in the 2000 to 2004 period converted to 2005 $ using CPI; recent increases in materials, engineering and construction costs will increase these significantly (of order 25%).*

We have also estimated the finished production costs for both coal to F-T fuels and coal to SNG, with and without CO_2 capture. To maintain consistency with the analysis of electricity generation in Chapter 3, we adopted a 20-year plant life, a three-year plant construction period and a 15.1% capital carrying charge factor on the total plant cost. We assumed 50% thermal efficiency for the F-T plant and 65% for the SNG plant [10]. Both plants were assumed to have a 95% capacity factor. The results of this analysis are shown in Table A-3.F.2.

Using the economic and operating parameters outlined above, the F-T fuel production cost is estimated at $50/bbl without CCS and $55/bbl with CCS. Approximately half of this cost is capital recovery charges due to the high plant cost. The CO_2 avoidance cost is $9.6 per tonne for these conditions. The production cost of SNG is estimated to be $6.7 /million Btu without CO_2 capture and $7.5 /million Btu with CO_2 capture. The CO_2 avoided cost in this case is $8.4 per tonne. The CO_2 avoidance cost is primarily due to the compression and drying costs (capital and O&M) of the CO_2, which is already separated from the synthesis gas as an integral part of the fuel production process.

Table A-3.F.2. Production Cost for Fischer-Tropsch Liquid Fuels and Synthetic Natural Gas

COSTS	F-T PLANT, $/bbl/day		SNG PLANT, $/MM SCF/h	
Total Plant Cost	w/o CC	w/ CC	W/O CC	w/ CC
	53,000	56,000	173,000	182,000
	F-T LIQUIDS $/bbl		SNG, $/MM SCF	
Inv. Charge @ 15.1%	23.1	24.3	3.0	3.2
Fuel @ $1.50/MM Btu	16.8	16.8	2.3	2.3
O&M	10.0	14.2	1.4	1.9
Production Cost	**49.9**	**55.3**	**6.7**	**7.5**
CO_2 Avoidance Cost ($/tonne CO_2)	**9.6**		**8.4**	

Today, the U.S. consumes about 13 million barrels per day of liquid transportation fuels. To replace 10% of this fuels consumption with liquids from coal would require over $70 billion in capital investment and about 250 million tons of coal per year. This would effectively require a 25% increase in our current coal production which would come with its own set of challenges.

SUMMARY COMMENTS

Under the economic assumptions of Table A-3.F.2, coal conversion to fuels becomes compititive when crude prices are greater than about $45/bbl and when natural gas is greater than about $7.00/million Btu.

Without CCS, such synfuels production would more than double CO_2 emissions per unit of fuel used because of the emissions from the coal conversion plant. CCS will increase the cost of coal-to-liquid fuels by about 10%. This relatively low additional cost is due to the fact that synthetic fuel plants are designed to use oxygen, operate at high pressure, and separate the CO_2 from the synthesis gas as an integral part of the fuels production process.

For IGCC plants designed to produce electricity, the production of fuels or chemicals (polygeneration) will usually be unattractive for a power producer. However, for synthesis gas plants designed to produce fuels and/or chemicals, power production for internal plant use (almost always) and for the merchant market (sometimes) will be attractive.

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Chapter 4 Appendices

Appendix 4.A — Unconventional CO_2 Storage Targets

Chapter 4 focused on sequestration opportunities in saline formations and depleted hydrocarbon fields. What follows is a brief description of the opportunities and challenges associated with other potential geologic storage formations.

UNMINEABLE COAL SEAMS

Definition of what coal is unmineable is limited by technological and economic constraints. For the purposes of this discussion, we will only consider seams deeper than 2500 feet (the deepest coal mine in the world today). The primary storage mechanism is well understood (gas adsorption) and serves as the basis for current volume assessments.[1] There is strong interest in this mechanism as it releases methane which might be profitably produced. This process, enhanced coal bed methane production, may offset the costs of capture and storage, increasing market penetration of sequestration and providing more flexibility in storage options.

Currently, many issues surround coal storage and ECBM. A major concern is that coals swell in the presence of CO_2, which reduces their effective permeability and injectivity. In addition, many coal bodies have extremely low matrix permeability, and almost all flow is in the fractures (cleats) of the system. Cleat structures are extremely difficult to map, and their response to pressure transients from injection is poorly understood. In addition, coals plasticize and alter their physical properties in the presence of CO_2, raising questions about long-term injectivity. From an effectiveness standpoint, it is unclear how to rank coals in terms of leakage risk; many targets underlie large permeable fresh water aquifers and could present a groundwater contamination and leakage risk. There was one large commercial CO_2-ECMB pilot in northern New Mexico (the Allison Project)[2]; however, this project was deemed uneconomic by the operators and shut in 2004.

In short, these concerns limit the immediate attractiveness of unmineable coal seams for commercial CO_2 storage. However, many of these topics are the focus of intensive study throughout the world and might be partially resolved within a fairly short period of time.

BASALTS

Basalts are crystalline and glassy rocks with abundant iron, calcium, and magnesium rich silicate minerals. When these minerals are exposed to carbonic acid over time, they prefer-

entially form new carbonate minerals, releasing silica but permanently binding CO_2. In addition, large basaltic rock accumulations underlie locations where other geological storage options are scared (e.g., the Deccan Traps, Japan). These features make basaltic rock bodies interesting potential targets.[3]

Many of the concerns present in coals are present in basalts. Their hydrology is notoriously difficult to constrain, and almost all the injectivity and transmissivity is related to fractures. This feature, however, raises several issues. It raises immediate questions of leakage risk. While there is evidence that some basaltic reservoirs are chemically segregated, there is no commercial database or industrial experience in predicting the sealing potential of fractured basalts or their response to injection pressure. The rates of the chemical reactions that bind CO_2 remain poorly defined, and prior studies of basaltic minerals estimated very slow kinetics for reactions.[4] Finally, there is no tested or established monitoring technology for basaltic formations, and due to the high velocity and low porosity of many basaltic units it is not clear of conventional seismic methods could detect a CO_2 plume or mineralization. Again, while many of these questions might be addressed through research, it appears that early commercial CO_2 storage in basaltic formation is unlikely.

DIRECT MINERALIZATION

Similar to basaltic storage, carbonic acid will react with iron- and magnesium-rich silicate minerals to form carbonates, effectively binding the CO_2 permanently.[5] The kinetics for these reactions are extremely slow. However, one may engineer systems to accelerate reaction rates through increased acidity, elevated temperatures, and comminution of grains. These approaches suffer from high operational costs, and are currently not economic. However, they benefit from the sureness and permanence of CO_2 stored, and would require very little transport and monitoring. Continued research in this area may yet create new opportunities for storage.

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Appendix 4.B — Well Abandonment Practices Relevant to CO_2 Sequestration

CO_2 injected into any geological targets may encounter man-made well bores. For most sites of interest, CO_2 will form a supercritical fluid that is less dense than brine. If the rock above the formation is impermeable, it will physically trap the buoyant CO_2, which will spread laterally in a plume. As long as the integrity of the cap rock is not compromised by permeable conduits like wells or faults, the cap rock will prevent the escape of mobile CO_2 phase. However, as a result of active hydrocarbon exploration and production during the last century, many of the sites under consideration for CCS projects may have wells that penetrate the cap rock. Wells that do penetrate the cap rock are potential sites through which mobile CO_2 phase might escape. Under typical circumstances, such wells would be properly cemented and plugged at depth, preventing upward migration of CO_2. However, these wells may not have a proper plug in place to prevent the flow of CO_2 to the surface, and cement might fail either mechanically or due to corrosion.[1,2] If well integrity is compromised, it may act as a high-permeability conduit through which CO_2 could escape.

Recent research has shown that CO_2 could leak even from wells that are properly plugged. This occurs when carbonic acid forms due to dissolution of CO_2 into brines. When this acid comes in contact with hydrated cements, corrosion can occur.[3] The rate at which this degradation occurs depends primarily on temperature, but also on cement, brine, and rock composition. Currently, there is little chemical kinetic data or equations of state to use in modeling this problem.

The evolution of plugging techniques has been well documented in numerous oil and gas publications.[4] Most of the changes have occurred in plug lengths and additives that alter the properties of basic cement. While the modern objectives of plugging—protection of potable water source and the isolation of hydrocarbon zones—are the same in all states, minor details such as plugging material and plug length vary from state to state. To obtain detailed up-to-date plugging techniques and regulations, one should contact the Oil and Gas Divisions (or its equivalent agency) of each hydrocarbon producing state.

Cement was introduced to the petroleum industry as early as 1903,[5] and different techniques of cementing were soon patented in California but did not spread quickly to other states. As a result, many hydrocarbon states independently developed unique cementing techniques. Commonly, cement was used to bolster the production of hydrocarbons (i.e. cement lining, prevention of water flow into well), but was seldom used for plugging purposes. For example, in California, plugging with cement was not practiced until it became mandatory under the regulations of California Oil and Gas Division, established in 1915.[6] During this time, plugs were likely to be inadequate for prevention of CO_2 leakage from CCS projects—plugs discovered from the early days of hydrocarbon production include tree stumps, logs, animal carcasses, and mud. Even after many state regulatory bodies were established in the 30's and 40's, effective cement plugs were often not installed.[4] This lack of efficacy can be attributed to the fact that cement was poorly understood. Additives are chemical compounds that are added to basic cement components in order to tailor the cement to specific down-hole temperature and pressure conditions. Without these additives, basic cement often failed to harden and form an effective plug and the cement could become contaminated with the surrounding drilling mud. Most improvements in well cements developed between 1937 and 1950.[4] Notable differences in plugging procedures since 1953 are in plug lengths and the increase in the number of plugs in a single well[7] and are mainly the result of the Safe

Drinking Water Act of 1974.[8] The new standard technique, which is still the most common method of plugging used today, minimizes the mud contamination of cement.[9]

In the United States, the Safe Drinking Water Act of 1974 created the Underground Injection Control Program (UIC), requiring all underground injections to be authorized by permit and prohibiting certain types of injection that may present an imminent and substantial danger to public health.[9] The primary objective of UIC is to prevent the movement of contaminants into potential sources of drinking water due to injection activities. There are no federal requirements under UIC to track the migration of injected fluids within the injection zone or to the surface.[10] Under UIC, a state is permitted to assume primary responsibility for the implementation and enforcement of its underground injection control program upon the timely showing that the state program meets the requirements of EPA's UIC regulations.

A key regulation in the UIC program aimed to prevent leakages of injected fluids through wells is the Area of Review (AOR) requirement. Under this requirement, injection operators must survey the area around the proposed injection wells before any injection projects can commence. This area is determined through either an analytical method or a fixed radius method, usually a radius no less than a ¼ mile. [11] The radius used can vary among hydrocarbon producing states, as each state has a different approach for determining the appropriate area to be reviewed. Once the area has been determined, each operator must review the available well records that penetrate the injection zone within the AOR and plug all inadequately plugged wells.

Unowned and inactive wells subject to replugging are often termed *orphan wells*. Many orphan wells lie outside of the AOR for a given site, and these may become leakage pathways, as injected fluid can migrate outside of the anticipated area. Although states are generally not legally responsible for these orphan wells, they nevertheless frequently monitor them.[5] If significant leakage that endangers the environment or public health is detected from these wells, the state will use available funds to plug the well. Funds to plug these wells are often collected through production tax, fees, and other payments related to the oil and gas industry.

The main reason why states do not plug all of their orphan wells is due to the lack of available funds[12] and only those deemed highly hazardous are plugged immediately. State regulators have tried to alleviate the occurrence of these orphan wells by requiring well operators to demonstrate financial ability to plug wells before and during well operation.[13]

Unlike orphan wells, wells that were properly abandoned under the existing regulations at the time of plugging are not monitored by the state. These wells are termed *abandoned wells*. States are not mandated to monitor for leakage or other failures at these properly abandoned sites. The lack of monitoring is based on the assumption that once a well plug is set, the plug will not fail.[4]

Wells lacking a cement plug are most likely to be shallow wells that were drilled prior to 1930's. By 1930, many major hydrocarbon producing states had begun to monitor plugging operations. Thus wells abandoned after the 1930's are likely to have some form of a cement plug, although they may be of poor quality. Many wells were left unplugged after the 1986 oil bust as many companies became insolvent, and these deeper wells are of primary concern. Wells that were plugged with cement prior to 1952 may prevent CO_2 leakages

better than wells that were left unplugged or plugged with ad-hoc materials; however, their integrity cannot be assured and thus still remain to be major leakage sources. The cement plug deformation shows poor setting of the cement plug, which was corrected with the introduction of appropriate additives after 1952. Wells plugged after 1952 are the least likely to leak, due to modern methods and the due diligence required by regulation. However, the possibility of cement degradation by CO_2-brine mixture remains.[2] It is important to note, however, that cement degradation has not been a serious issue in enhanced oil recovery activities with CO_2 flooding over the past 30 years.[14] There is little kinetic data on cement corrosion rates under a range of common conditions of pressure, temperature, and brine-rock composition. As such, it could take tens to thousands of years for CO_2 to corrode enough cement to reach the surface. In addition, it is not clear that even substantial degradation of the cement or casing would result in large volume escape of CO_2. More laboratory and field research is needed to understand and quantify these effects for both scientific and regulatory purposes.

To reduce these risks, a revision of existing regulations may be needed to address liability issues that could arise due to surface leakage. Revisions should address issues such as how abandoned wells should be assessed before and after CO_2 injection, how CO_2 concentrations might be monitored at the surface, the process of designating a responsible party for a long-term monitoring of abandoned injection sites, and how to allocate funds to replug high-risk wells.

Lastly, CO_2 sequestered underground could surpass the ¼ to ½ mile radius that is typically used to assess the wells in the area around and injection well. As the AOR increases for sequestration projects, the number of wells that fall within this area may increase significantly. In order to ensure proper injection-site integrity, it may be necessary to alter regulations to cover the likely footprint for injection. Regulators may need to concern themselves with the determination of the CO_2 injection footprint, the requirements for operators to treat abandoned and orphan wells, and the liability associated with leakage within and without the predetermined footprint.

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Appendix 4.C — Description and Cost Assumptions for CO_2 Storage Projects

In considering large CO_2 storage experiments, the first concerns must be injectivity, capacity, and effectiveness. In planning a set of experiments for a country or the world, the next consideration must be to accurately reflect the richness of the key geological settings for successful large-scale deployment. To consider the global context of commercial deployment, the variance should include the following aspects:

- Critical plays defined by density of coal-fired power generation and other large point sources.
- A range of reservoir character (homogeneous and heterogeneous, Siliciclastic and carbonate, high- and low-injectivity)
- A range of physical seals (mudstones, evaporites)
- A range of potential leakage mechanisms (faults, wells)

Thankfully, it is not necessary to test the entire matrix of possible parameters suggested by this list. The most important and representative cases can be represented by a handful of geological settings, and the number of critical plays is not enormous even on a global basis.[1] Nonetheless, to represent a large-scale deployment accurately, an experimental project must be large itself.

To estimate the likely costs of a large-scale experiment, the following assumptions were used:

1. No CO_2 capture is needed: the available experimental source is a pure supply and sold at prices comparable to CO_2-EOR commodity prices.
2. Annual injection volumes would range from 500,000 to 1 million tons CO_2
3. The project would run for 8 years, with two years of scoping and preparation, five years of injection and 1 year post mortem
4. The project would proceed on land
5. There is no consideration of capital depreciation or discount rate

With this basis, Table A-4.C.1 lays out the range of estimated costs for various stages of a broad experimental program.

These assumptions, conditions, and estimated costs are not unreasonable. The incremental costs of the Sleipner program are comparable to the above projections.[2] In this context and in 1996 dollars, the comparable costs total to 152 million. The costs of well and monitoring are higher for the Sleipner case, but these costs did not include a broad monitoring suite, an aggressive science program, or post-injection validation.

Table A-4.C.1 Estimated Costs of a Large-Scale CO_2 Injection Experiment

PROGRAM ELEMENT	EST. COST ($M)
Detailed pre-drill assessment	$2 - 4
Wells, injection (1-2) and monitoring (3-8)	$3 - 8
CO_2 (5 years injection)	$1.5 – 10 / yr
Compression (5 years)	$3 – 6 / yr
Monitoring (5 years)	$ .2 – 6.4 /yr
Analysis and simulation	$5 - 7
Post injection sampling and re-completion	$3 - 8
Total Sum	$107 - 255
Average Annual Sum	$13 - 28

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Appendix 5.A — India

INTRODUCTION

India is the world's second most populated country, after China, with 1.1 billion people.[1] With its higher population growth rate, India is projected to equal China's predicted population of 1.45 billion people in 2030. India's economy, with a real growth rate of 7.8%, lags that of China, which has a real growth rate of 9.2%.[2] India also lags China in terms of electricity consumption with an average per capita consumption of 600 kW_e-h/yr, compared with China's 1700 kW_e-h/yr and about 14,000 kW_e-h/yr in the U.S..[3] India is also plagued by chronic electricity shortages. To address these problems, India has put in place policies to speed up generating capacity additions and growth in the power sector. The Indian central government plays a large role in electric sector development, presenting an opportunity for an effective single source of leadership. All factors suggest significantly increased coal consumption

POWER GENERATION

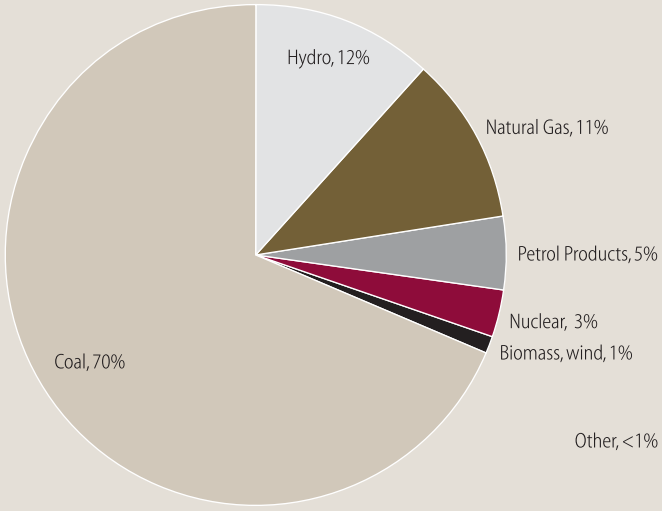
BACKGROUND Until recently, India maintained a relatively closed economy and focused on indigenous or indigenized technologies. In the electricity sector the key players were the National Thermal Power Corporation (NTPC), the central government's power generation company, and Bharat Heavy Electricals Limited (BHEL), the primary boiler and steam turbine manufacturer and turn-key plant constructor. The central government owned nuclear and hydroelectric plants and large thermal plants (NTPC) that supplied substantial electricity across state boundaries. The remainder of the Indian electricity sector was historically under the control of vertically-integrated State Electricity Boards (SEBs) which built, owned and operated the local electricity infrastructure (generation and distribution), and set rates and collected tariffs. In an effort to promote food production and increase the rate of agricultural growth in the late 1970's, farmers were given free electricity for irrigation. The state-controlled SEBs used this and other related programs as a political instrument whereby the state governments could introduce subsidies for political gain. As a result of this and the lack of effective control over illegal connections to the grid, by the mid-1990s about 30% of the electricity produced was un-metered or not paid for. Even for the metered portion low tariffs were set for many poorer consumers and largely cross-subsidized by higher tariffs charged to commercial and industrial users. The gross subsidy per unit of electricity generated increased from 0.75 Rupees/kW_e-h (2 ¢/kW_e-h) in 1997 to 1.27 Rupees/kW_e-h (2.6 ¢/kW_e-h) in 2002.

The result was that many SEBs were effectively bankrupt, deeply indebted to the central government financing institution, and unable to honor payments to generators or to fi-

nance new capacity. This has been a primary root-cause of depressed growth in new generating capacity additions over the last 15 years and the resulting power shortages. Today, the unmet electricity demand is 7.6%, and the peak demand deficit is 10%.[4] This does not take into account the fact that 40% of Indian households are not yet electrified or connected to the grid and rely primarily on biomass for their energy needs.[5]

In the mid-90s the Indian economy began to be opened up. To address the increasing electricity shortages the Indian government encouraged independent power production (IPPs). However, because of the poor financial state of the SEBs and their inability to pay for power purchased, most IPPs either failed or never materialized.

Figure A-5.1 Electricity Generation *(share of annual kW_e-h)*



IEA data from 2003

TODAY India's installed generating capacity in the public or utility sector was 115,550 MW_e in 2005.[4] Of this, coal generating capacity was 67,200 MW_e or 58% of total installed capacity. These plants accounted for almost 70% of India's electricity generation (Figure A-5.1). India's coal consumption was about 360 million tons in 2000 and increased to 460 million tons per annum in 2005 or an increase of about 5.5%/yr. Recently, total electricity generating capacity growth has averaged about 3.3% per year, whereas the economy has been growing at over twice that rate; thus, the increasingly severe electricity shortages.

In addition to the public or utility generating capacity, Indian companies have resorted to captive power to ensure the availability of consistent, quality power. Captive power generation is within-the-fence generation that provides the primary power needs of the facility and is not connected to the local grid. Indian captive power grew from 8.6 GW_e installed capacity in 1991 to 18.7 GW_e installed capacity in 2004.[6,7] At this level it represents almost 25% of the public or utility thermal generating capacity in India. The fuel mix for captive power is about 45% coal, 40% diesel and 15% gas.

The Indian government, recognizing the problems inhibiting growth, began addressing them through policy reforms in the 1990s, culminating in the Electricity Act of 2003. This legislation mandated the establishment of electricity regulatory commissions at the state and central levels, and the development of a National Electricity Policy. Emphasis was placed on financial reforms and on unbundling the SEBs into separate generating, transmission, and distribution companies. To date, eight of 28 states have unbundled.[8] The legislation opened the electricity sector to private generating and private distribution companies, gave increased flexibility to captive power generators, and gave open access to the grid.

The ability to meet electricity demand and to increase electricity supply will depend on the success of structural, financial, and economic reforms in the power sector. The payment structure to generators was reformed to create incentives for generating companies to improve plant efficiencies and to increase operating load factors. This, combined with the restructuring of the SEBs, had the purpose of improving the financial health of the sector to

ensure payments to the generating companies and improve payment collection from consumers. This would attract more private sector development, particularly by IPPs.

During the 1990s the central sector, particularly NTPC, began to play a larger role. It developed an engineering center that successfully improved plant operating factors and efficiency and began to offer engineering services to the SEB-operated plants. These activities helped improve plant performance and during this period the all-India average plant operating load factor increased from 64% in 1997 to almost 75% in 2005. This load factor improvement has been responsible for about half of the power generation growth that India achieved during this period. Economic incentives to improve plant efficiency are sufficiently recent that the all-India effect is still small. Operating efficiency improvements are harder to achieve than improvements in plant load factor.

The Electricity Act of 2003 mandated the development of a National Electricity Policy and a Plan for achieving it. These were developed by mid-2005. The National Electricity Policy calls for (a) eliminating general and peak shortages by 2012 so that demand is fully met, (b) achieving a per capita electricity consumption increase to over 1000 kW_e-h by 2012, (c) providing access to electricity for all households, (d) strengthening the national grid and distribution systems, and (e) metering and appropriately charging for all electricity generated.

The Plan for achieving these goals calls for doubling installed generating capacity from 100,000 MW_e in 2002 to 200,000 MW_e by 2012. The goal is to meet all demand and create a spinning reserve of at least 5%. The Planning Commission's Expert Committee on Integrated Energy Policy has recommended an energy growth rate of 8%/yr to ensure continuing economic development. This would require that installed capacity increase from 115 GW_e in 2005 to 780 GW_e in 2030 and that coal consumption increase from 460 million tons/yr in 2005 to about 2,000 million tons/yr in 2030.[9] The Plan also calls for: (a) gas-based generation to be sited near major load centers, (b) new coal plants to be sited either at the pit-head of opencast mines or at major port locations which can easily import coal, (c) thermal plant size to be increased to the 800-1000 MW_e size and (d) a shift to supercritical generating technology.

India's new capacity additions are primarily the joint responsibility of the central and state sectors, and to a lesser degree, the private sector. The process of capacity addition begins with the Central Electricity Agency (CEA), which collects and analyzes historical and annual operating data, makes forward projections of demand (both national and local) and develops recommendations of new capacity additions including fuel mix, size, and location of plants to meet these needs. These recommendations form the basis for discussions among the various players of how to meet the increased demand.

It is clear that NTPC is playing a larger role than it has in the past because it has met its capacity addition commitments and improved plant performance effectively, whereas the SEBs have routinely fallen far short of meeting their capacity addition commitments and have frequently had the lowest operating efficiency plants in the system. The worst of these plants have been handed over to NTPC to operate. Currently over 90 % of the installed coal capacity in India is under 250 MW_e per unit, and all units are subcritical. NTPC has built and operates most of the 500 MW_e plants in India. NTPC currently has an effective in-house technology capability which it is further strengthening, and it is greatly expanding its technology center. It has the lead on the introduction of supercritical generating technology into India and has the financial resources to build 800–1000 MW_e plants. It currently owns and operates about 32% of installed coal capacity, [10] but is destined to play a larger role in the future.

Our assessment of the Electrification Plan is that it adequately addresses the most important problems in the Indian electricity sector. However, the most critical question is, "Can it be successfully implemented?" This is more problematic, in that the Indian bureaucracy offers many roadblocks. Coal supply is one of the most important issues, and the rate of coal industry reform will be critical. Coal India Limited (CIL) may be able to produce only about 1/3 of the projected 2030 coal demand; the rest would have to be imported. [9,11]

The view from the state of Andre Pradesh (AP) offers some insight into these issues. AP unbundled its SEB about two years ago and is well into the new structure. Our discussions with the AP Environmental Protection Department, the AP Electricity Regulatory Commission, the AP GenCo, and the AP distribution company all provided a consistent understanding of the National Electrification Plan and how AP was addressing it. Such a high level of alignment is encouraging. CIL did not show high alignment.

AP is involved in planning a couple of large generating plants, one potentially at mine mouth and one in the port city of Chennai. Negotiations are between APGenCo and NTPC. The distribution company has reduced the extent of un-metered electricity to about 20% (confirmed by the AP Electricity Commission) and has plans to further reduce it. They are installing meters at a rapid pace with the target of being fully metered by 2012. AP also has a couple of IPPs which are being paid for all the electricity they produce. In a state with a SEB in worse financial shape, the story would not be as positive.

COAL-GENERATING TECHNOLOGY AND CO_2

As already noted, India's PC power generation sector employs only subcritical technology. Coal is India's largest indigenous fuel resource, and it has a reserves-to-production ratio of about 230 years at today's production level. To use this resource most wisely and to reduce CO_2 emissions, higher generating efficiency technology is important. NTPC is now constructing the first supercritical pulverized coal power plant in India and has plans for several additional units. The technology is being supplied by a foreign equipment manufacturer. To remain competitive the national equipment manufacturer, BHEL, has entered into an agreement to license supercritical technology from a different international equipment manufacturer. This competition should serve to reduce the costs and make it more feasible politically for Indian generating companies to build supercritical plants in the future. Ultimately, by constructing only supercritical PC power plants, CO_2 emissions could be reduced by one billion tons between 2005 to 2025 based on projected capacity adds.[12]

Integrated gasification combined cycle (IGCC) technology is a more distant option that requires development for India's high-ash coal. NTPC, in coordination with the Ministry of Power India, is planning to build a 100 MW_e demonstration plant either with a foreign technology or with BHEL-developed technology. One issue is that the more-proven foreign entrained-bed gasifier technology is not optimum for high-ash Indian coal. BHEL's fluid-bed gasifier is better suited to handle high-ash Indian coal but needs further development. BHEL has a 6 MW pilot plant which it has used for research. This represents an opportunity to develop a gasifier applicable to high ash coals that adds to the range of IGCC gasifier technology options.

CONCLUSION

India's economic development lags that of China, and its power development lags even further. However, India's economic growth is likely to continue and further accelerate over time. This will require rapid growth in electricity generation, and a large fraction of this will be coal-based. Growth in coal-based power generation is indicated by central government and NTPC plans for and recent governmental approval of 11 coal-based IPP power plants to be built by industry leaders such as Reliance Energy and Tata Power, with a total capacity of 42,000 MW_e.[13] The fact that rapid growth is just beginning in India offers opportunities in that there is time to institutionalize cleaner, more efficient generating technologies before the greatest growth in the Indian power sector occurs.

The central sector company (NTPC) has successfully met its expanded capacity addition targets, has opened a power plant efficiency center, developed technology capabilities to improve plant operating factor and efficiency, is pursuing IGCC technology, and is markedly expanding its research and technology center capabilities. The strength and breadth of these activities suggest the potential for an Indian power generation sector company to develop and disseminate technology, create generating standards and practices, and be a factor in the rational development and deployment of the needed generating capacity.

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Appendix 8.A — Government Assistance to IGCC Plants Without Capture

Because of the current interest in gasification technology for coal electricity generation and the prominence given to gasification technology in the 2005 Energy Act, we discuss the factors that federal or state policy makers should consider in deciding if incentives should be offered for projects to build IGCC *without* CO_2 capture.

To recap the discussion in chapter 3 of our report, our assessment is that there is sufficient practical experience with IGCC *without* capture so that technical readiness should not be used as a justification for governmental support. Since a new IGCC plant is likely to operate as designed (after a start-up period) additional IGCC "demonstration" plants without CCS are not needed. The reason that new IGCC electricity generating plants are not being ordered today, in the absence of a subsidy and/or favorable regulatory treatment, is because of the cost difference reported in Chapter 3 between IGCC and SCPC in the absence of a carbon charge, together with the vastly greater experience base for operating PC power plants reliably.

Our base line estimate of the cost of electricity is that SCPC is today and for the foreseeable future cheaper than IGCC for plants without capture. We also estimate that the cost to retrofit an IGCC plant for capture is less than the cost to retrofit a comparable SCPC plant for capture. These conclusions are based on point estimates with a number of operating and economic assumptions, e.g. capacity factor, discount rate, investment cost, etc. We have not performed sensitivity analysis although this evidently would be helpful in defining the range of possible outcomes.

Two arguments are advanced for government assistance for building IGCC plants without capture in addition to technical readiness. The first argument is that IGCC is more flexible for adapting to possible new federal regulations. This is true for CO_2 capture under our base line estimate with presently available technology and may be true for future regulations of criteria pollutants or mercury capture. The argument here is that there is a public interest to encourage investment today in the technology that is judged to be more flexible for responding to tighter emissions restrictions that may be applied at some uncertain future date. The second argument is that the public will be better off if the new power plants that are built are IGCC plants because these plants are cheaper to retrofit and thus the adjustment to a possible imposed carbon charge in the future will be less costly compared to a PC plant.

Our analysis of these arguments depends upon the nature of market regulation.

In an unregulated market private investors will make their decision to build IGCC or SCPC based on their evaluation of many uncertain variables that affect the future profitability of their investments: these variables include the future trajectory of electricity prices, the cost and performance of alternative generating technologies, and the evolution and cost of complying with future environmental regulations, including the magnitude and timing of a carbon charge. We see no reason to interfere in this decentralized investment evaluation process and believe that the decisions of private investors are as good a way to deal with future uncertainty as any government guesses about the relevant variables. If the government wishes to influence the decision of the private investors toward taking the need for CCS into account, the proper way to do so is to adopt an explicit policy of carbon constraints, not to offer subsidies to IGCC technology without capture. The subsidy would permit the private investor to capture the increase in market electricity price that will accompany a future carbon charge without paying anything for this benefit or taking any risk.

In a regulated, cost of service, market the situation is different. A state utility regulatory body might decide that it is desirable to encourage new IGCC power plants even though they are more expensive to build, because of an anticipated imposition of a carbon charge. Because the regulatory body determines the return to the utility investor, if the carbon charge is imposed, the future rate of return for the utility can be adjusted so, in principle, there is no windfall for the investor. So in a state where there is regulated cost of service generation, incentives arising from the willingness of state regulators to approve construction and costs recovery for IGCC without capture today is a plausible regulatory response to uncertainties about future environmental policies. Indeed, in a regulated environment, cost-based regulation may undermine private investor incentives to evaluate properly the future costs and benefits of investments in alternative generating technologies. Of course, this assumes that the state PUC's reasoning is indeed based on consideration of adapting to possible future CO_2 emission regulation and not other extraneous factors such as creating a concealed subsidy for coal mined in the state.

There remains, however, a policy problem that is only now becoming recognized. Prospective investors in new SCPC or IGCC plants today may believe as a practical political matter, that they will be "grandfathered" from any future CO_2 emission restrictions, either partially or totally for their remaining life, by tax abatement or by the allocation to them of free CO_2 emission rights in the context of a cap and trade program. If true, grandfathering would, at the very least, insulate private investors from the future costs of CO_2 charges, leading them to ignore these potential future costs in their investment assessments. This would create a bias toward SCPC plants relative to IGCC. At the extreme it might lead investors to build plants, especially SCPC plants, early in order to avoid the consequences of the possible imposition of a carbon charge.

What can the government do to avoid this perverse incentive? The correct measure is to pass a law or adopt a regulation today that makes it clear that **new coal plants** will **not** be shielded from future emission constraints through tax abatements, free allocations of emissions permits, or other means. Some might argue that absent the adoption of a "no grandfathering rule" there is need for a compensating second best policy of providing subsidies for building IGCC plants without capture – on the premise that if emission rights have sufficient value the IGCC's will retrofit CCS and a desired level of emissions will be achieved at lower cost.

We believe it important for the federal government to take some policy action to deter early investments in coal-burning plants based on the expectation that these plants will be "grandfathered" to one degree or another in the future. We are unconvinced that a subsidy for IGCC plants is an acceptable second-best choice; since in order to be reasonable it would anyway require a "no-grandfathering" rule for those plants that did receive assistance. The correct choice is to apply the "no grandfathering" rule to all new power plants, regardless of fuel or technology choice. Moreover, the possibility exists, as described in Chapter 3, that R&D will result in another technology cheaper than IGCC for CO_2 CCS; for example a cheaper way of producing oxygen could reverse the retrofit advantage of IGCC over SCPC.