1.0. WHY IGCC

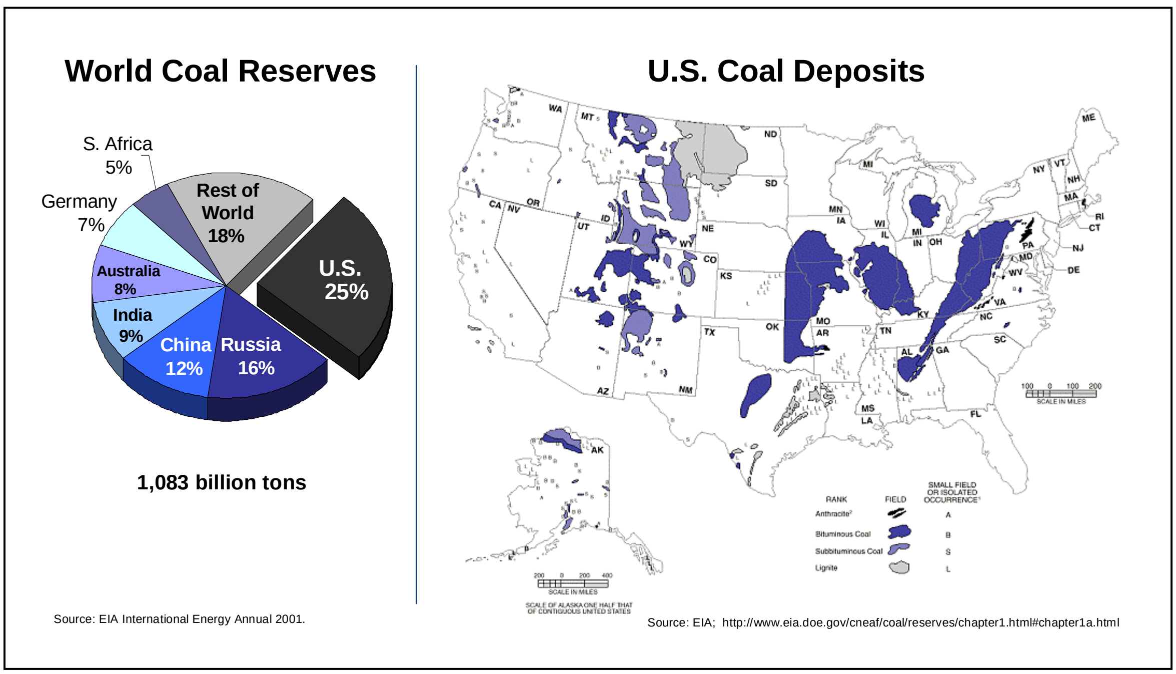
IGCC technology has the potential to substantially reduce the environmental impact of coal power plants by reducing air emissions, water consumption, and solid waste production. It also offers a technical pathway for cost effective separation and capture of CO_2 emissions and co-production of hydrogen. These environmental attributes make it an important technology for enabling the important energy, economic, and national security benefits of coal use for electricity generation to be achieved with minimal environmental impact.

1.1. Energy Independence and Security

The U.S. has more coal than any other country in the world. Estimated recoverable coal reserves in the U.S. are 275 billion tons, which is approximately 25 percent of world supplies and more than a 250-year supply at current consumption.[34] This share of world coal reserves is in sharp contrast to the U.S. share of world oil and natural gas reserves, which are estimated to be less than 2 percent and 3 percent of world totals, respectively.[35]

Coal fuels over 50% of U.S. electricity generation and is the only major fossil fuel for which the U.S. is a net exporter. In 2002, the U.S. imported 53 percent of its oil supply, which is up from 28 percent in 1972 just prior to the first Arab oil embargo. At the same

Figure 1-1. Location of U.S. Coal Reserves and Share of World Coal Supply



[34] National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003.
[35] EIA, International Energy Annual 2001, Table 8.1.

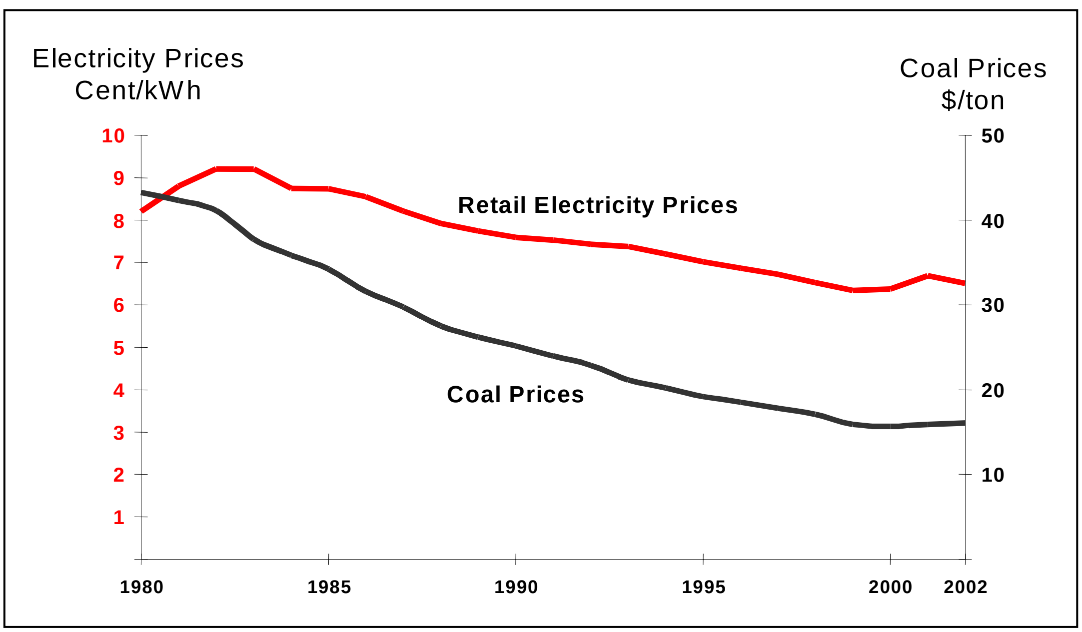
time, high natural gas prices have led major oil and gas companies to announce plans for multi-billion dollar investments in infrastructure to increase imports of liquefied natural gas (LNG) and chemicals from mid-eastern and other countries.[36] Existing dependence on foreign oil and the prospect of increased imports of natural gas are significant energy and national security concerns, particularly in the face of escalating oil and natural gas prices and continuing Middle East political turmoil.

As illustrated in Figure 1-1, U.S. coal reserves are dispersed across several regions, including states in the Appalachian, Midwest, Rocky Mountain, and Southern regions and in Alaska. Abundant domestic supplies, geographic dispersion, and transport by a vast network of railroads and barges make widespread or long-term supply disruptions unlikely. These factors also support stable prices that are unaffected by geopolitical events. The stockpiling of 30 to 90 day coal inventories at most generating plants further enhances the security of coal generation, helping protect against short-term fuel supply disruptions due to terrorism or other unforeseen events that might otherwise affect electricity supplies. These factors make coal a critical resource for fulfilling the national need for secure, reliable electricity supplies.

1.2. Economic Growth

Coal is also a low cost energy resource that helps fuel economic growth. As illustrated in Figure 1-2, real coal prices have declined 63 percent since 1980 and real retail electricity prices, which are directly affected by coal prices since coal accounts for over 50% of

Figure 1-2. Real Retail Electricity and Coal Prices



[36] See *New York Times*, Oct. 13, 2003, p. W1. See also *New York Times*, Dec. 9, 2003, p. C4.

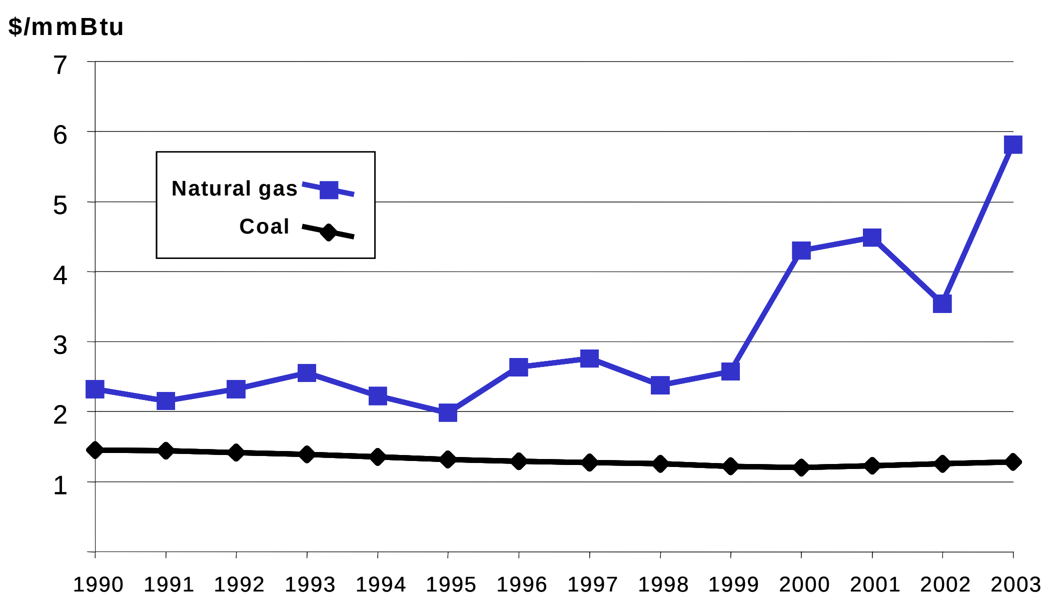
electricity generation in the U.S., have declined 21 percent over the same period. The average price of coal delivered to electric generators in December, 2003 was $1.25/mmBtu, compared to $3.90/mmBtu for delivered petroleum and $5.24/mmBtu for delivered natural gas.[37] In contrast to natural gas prices, which have become increasingly volatile in recent years, coal prices have remained relatively stable and slowly declined for the past two decades. Coal price stability translates into stable generating costs and stable electricity prices when coal is the dominant generation fuel.

Electricity is a fundamental driver of economic growth and prosperity and electricity prices affect every business and consumer in the country. Coal electricity generation has played an important role in helping the U.S. maintain low electricity prices and, because of its low cost, is projected to remain a dominant generation fuel for decades to come.

1.3. Natural Gas Prices

In contrast to coal, natural gas prices reached historically high levels in 2003 and are projected to remain high and volatile for the foreseeable future. Figure 1-3 illustrates the delivered price of natural gas and coal to electric generators in the last decade. Figure 1-3 demonstrates that natural gas prices have risen and become increasingly volatile over the past decade while, in contrast, coal prices have remained stable and slowly declined.

Figure 1-3 Average Delivered Fuel Prices to Electric Generators



Sources: 1990-2001, EIA, Electric Power Annual 2001, March 2003.
2002-2003, EIA, Electric Power Monthly, September 2003.

[37] <u>See</u> EIA, "Electric Power Monthly," April 2004, Table ES1.A.

Figure 1-4. Henry Hub Natural Gas Futures

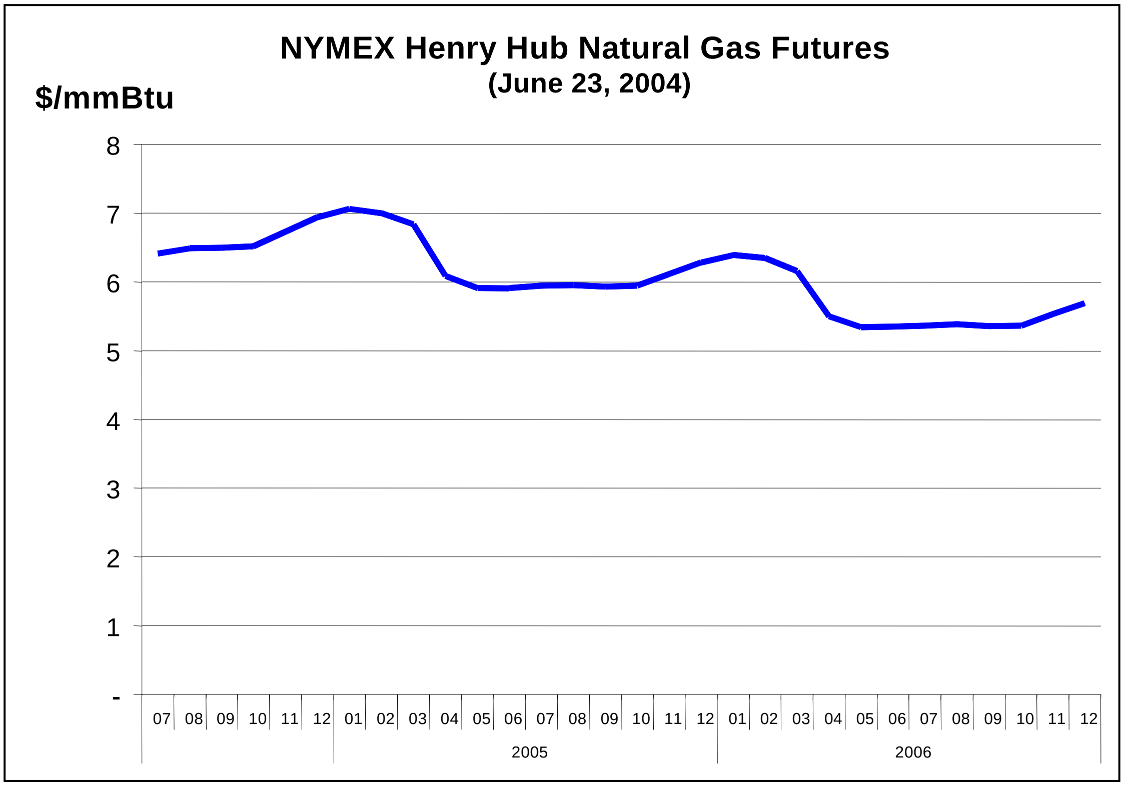


Figure 1.4 illustrates Henry Hub natural gas futures prices (delivered prices are generally $0.50-$1.00/mmBtu higher than Henry Hub prices), indicating the expectation that high prices will remain through at least 2006.

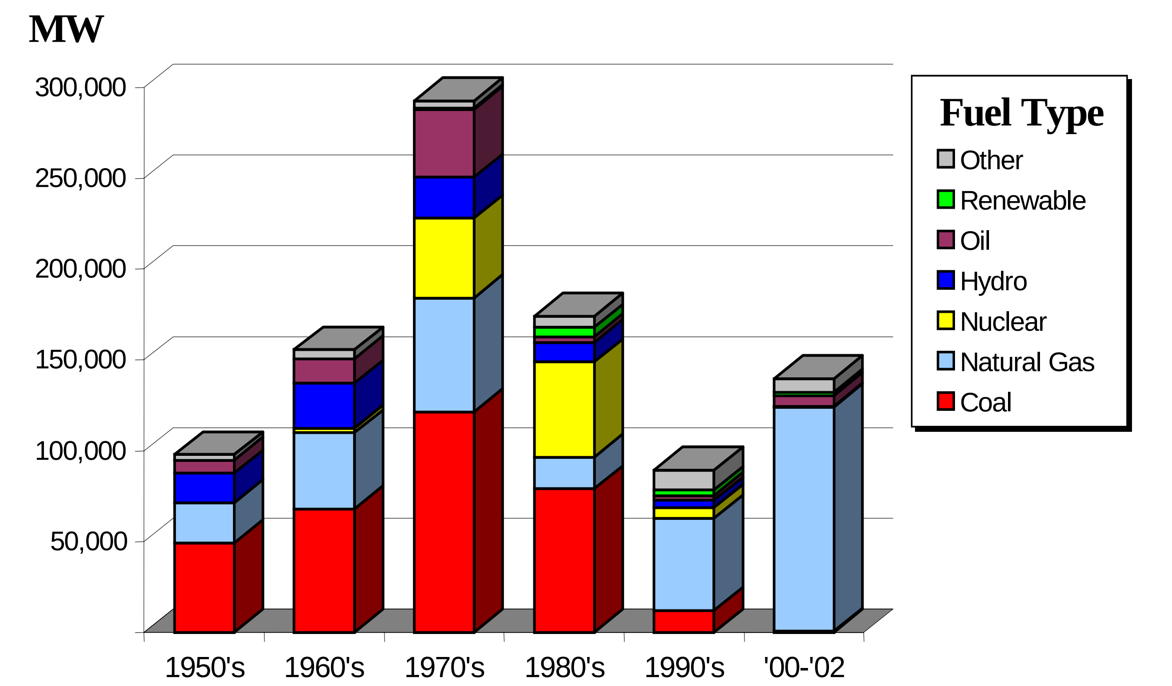
High natural gas prices have caused widespread, adverse impacts on the U.S. economy and economic competitiveness. These impacts were described by the House Speaker's Task Force for Affordable Natural Gas:

> Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile, pharmaceutical, agribusiness and high tech industries.[38]

---

[38] House Energy and Commerce, The Task Force for Affordable Natural Gas, Natural Gas: Our Current Situation (Sept. 30, 2003). Alan Greenspan, Chairman of the Federal Reserve System, also testified about natural gas prices in 2003, stating: "The long-term equilibrium price for natural gas in the United States has risen persistently during the past six years from approximately $2 per million Btu to more than $4.50…The updrift and volatility of the spot price for gas have put significant segments of the North American gas-using industry in a weakened competitive position. Unless this competitive weakness is addressed, new investment in these technologies will flag." Testimony of Chairman Alan Greenspan before the Committee on Energy and Natural Resources, U.S. Senate (Jul. 10, 2003).

Figure 1-5. U.S. Electric Generation Capacity Additions by On-line Date



Source: Form EIA 860 "Annual Electric Generator Report," 2001.

High natural gas prices also hurt consumers that are dependent on natural gas to heat their homes and can create compounding price increases when they translate into higher electricity prices. High natural gas prices in 2003, combined with a softening of wholesale electricity markets, also caused many of the natural gas power plants built in recent years to become uneconomic and decrease in value to a fraction of their original cost.[39] As discussed below in Section 3.4, IGCC technology provides a means of both recapturing the value of these facilities and reducing natural gas demand by refueling some of these existing plants with coal gasification systems.

One factor supporting high natural gas prices and price forecasts is the increased demand resulting from construction of new natural gas-fired electric generation. Figure 1-5 illustrates the new electric generating capacity that came on-line in the U.S. each decade from the 1950's through the 1990's, as well as in the three-year period from 2000 to 2002. Figure 1-5 illustrates that more coal capacity was added than any other type of generation in the 1950's through the 1980's, accounting for between 41 and 50 percent of new generating capacity each decade. However, since 1990, less than 6 percent of new capacity has been coal-fueled, while over 75 percent of the new capacity is natural gas-fired. In the last three years, 140,000 MW of new generating capacity was added (more

[39] For example, on May 4, 2004, Duke Energy announced the sale of 5,325 MW of eight natural gas-fired power plants in the Southeast U.S. for $475 million, or about $90/MW, which is less than one-fifth of their original cost.

than the total combined capacity of U.S. nuclear power plants) and over 90 percent of it is natural gas-fired.[40]

According to EIA, natural gas consumption by electric generators increased 40% between 1997 and 2002.[41] In addition, EIA's Annual Energy Outlook 2004 predicts that natural gas demand from electric generators will increase another 51% by 2025.[42] Increasing natural gas demand from electric generators puts additional pressure on natural gas supplies and prices. Commercial deployment of IGCC technology could help reduce growth in natural gas demand from electric generators and, if deployed to refuel existing natural gas combined cycle systems (See Section 3.4 below), directly reduce demand to help alleviate price pressures affecting other sectors of the economy. Unlike natural gas, increased use of coal for electricity generation has very little impact on other sectors of the economy because coal use in the U.S. is essentially dedicated to electricity generation, with 90 percent of coal consumption attributable to electric generators.[43]

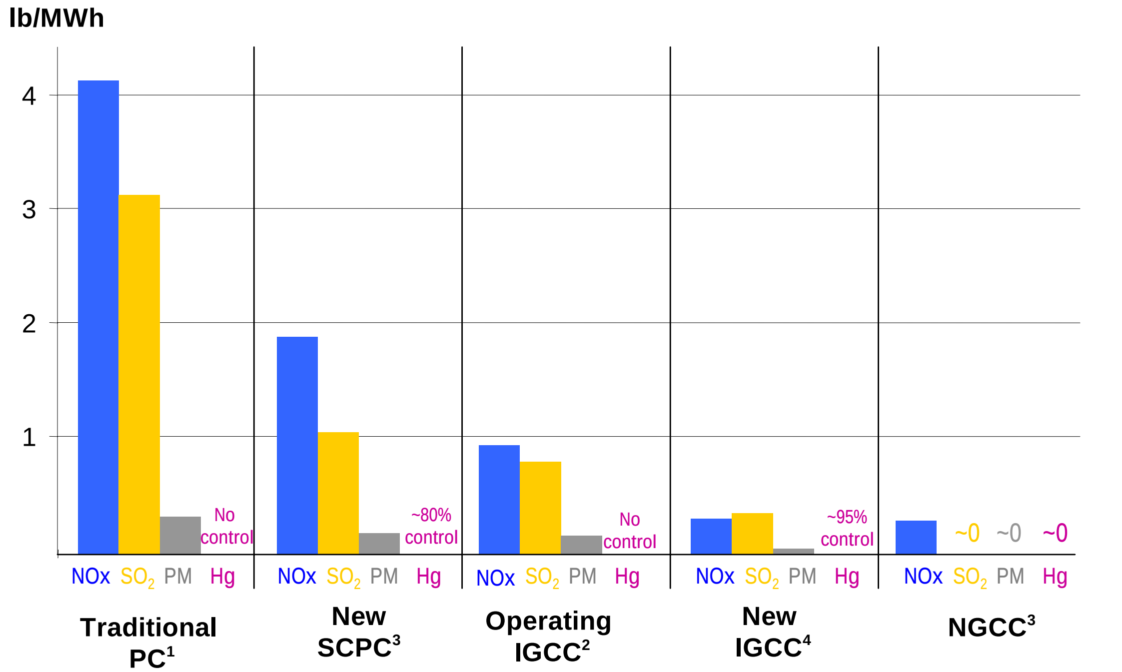
1.4. Air Pollutant Emissions

Air pollutant emissions are a serious environmental concern associated with coal power generation. The most problematic emissions include sulfur dioxide (SO_2), nitrogen oxides (NO_X), particulate matter (PM), mercury (hg), and carbon dioxide (CO_2). These emissions contribute to both localized air pollution problems and global climate change concerns. Localized air pollution issues include ground-level ozone pollution (involving NOx), fine particulates (NOx and SO_2), acid rain (NOx and SO_2), regional haze (NOx and SO_2), mercury deposition (Hg), and eutrophication of lakes and streams (NOx).[44] Globally, CO_2 emissions are a greenhouse gas emitted from fossil fuel combustion linked to climate change concerns. In the U.S., these environmental issues have lead to a number of legislative and regulatory programs aimed at reducing emissions from existing coal-fired power plants, stringent requirements for new facilities, and consistent opposition by environmental organizations and others to the permitting of new coal-fired power plants.[45]

---

[40] See Form EIA 860 "Annual Electric Generator Report."
[41] See http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm
[42] EIA, Annual Energy Outlook 2004, Table A-13.
[43] EIA, "Annual Energy Outlook 2003 (AEO 2003)," Jan. 2003 (Table A16).
[44] See EPA, "Latest Findings on National Air Quality: Status and Trend," Aug. 2003. See also EPA, "Nitrogen: Multiple and Regional Impacts," Feb. 2002; See also EPA, Mercury Study Report to Congress, Dec. 1997.
[45] For a discussion of issues associated with power plant emissions and efforts to address them, see Testimony of Jeff Holmstead Before the Committee on Environment and Public Works, U.S. Senate, Nov. 1, 2001, http://www.epa.gov/air/clearskies/nov1.pdf.

Figure 1-6. Estimated Emissions Performance



[1] Based on typical performance levels.
[2] Based on emissions performance of four operating IGCC facilities provided in NETL, *Major Environmental Aspects of Gasification-Based Power Generation Technologies*, December 2002;
[3] Based on emissions levels in EPRI/NETL, *Evaluation of Innovative Fossil Fuel Power Plants with CO_2 Removal*, Dec. 2002, SCPC and NGCC 7FA base cases.
[4] Levels proposed for qualification in 3 Party Covenant federal incentive program. Based on performance characteristics provided in NETL, *Major Environmental Aspects of Gasification-Based Power Generation Technologies*, December 2002; and performance estimates from Eastman Chemical Company.

IGCC technology offers the potential for significantly improved air emissions performance for coal-fueled power plants to address many of the environmental concerns associated with coal generation. IGCC power plants achieve emissions reductions primarily through the syngas cleanup processes, which occur prior to combustion. This emissions control method is very different from PC power plants, which achieve virtually all emissions control through combustion and post combustion controls that treat exhaust gases.[46] Because syngas has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost effective than post combustion treatment to achieve the same or greater emissions reductions. In IGCC plants, virtually all of the particulates, nitrogen and sulfur compounds, and 95-99 percent of the mercury, are removed from syngas before it is directed to the combustion turbine. As a result, the PM, NOx, SO_2 and mercury emissions resulting from syngas combustion in the turbine are significantly

[46] Typical combustion and post-combustion controls required of new PC power plants include Flue Gas Desulfurization (FGD, or "scrubbers") for SO_2 control, low NOx burners and Selective Catalytic Reduction (SCR) for NOx control, and Electro-Static Precipitators (ESP) or fabric filter baghouses for particulate

lower than the emissions produced by direct combustion of coal in PC boilers. Figure 1-6 illustrates the IGCC emissions performance expected for the next generation of plants for NOx, SO_2, Particulate matter and mercury compared to traditional PC, new super-critical PC, and NGCC plants.

1.41. SO_2 Emissions

High-temperature gasification of coal produces hydrogen sulfide (H_2S) and small amounts of carbonyl sulfide (COS). The amount of these acid gases in the syngas is a function of the amount of sulfur in the coal. Prior to combustion, IGCC systems remove these sulfur compounds from the syngas through acid gas clean-up processes, including chemical solvent-based processes (using MDEA) and physical solvent-based processes such as Selexol™ and Rectisol™.[47] Sulfur recovery processes recover sulfur either as sulfuric acid or as elemental sulfur, which are commercial by-products. These processes are able to remove over 99 percent of sulfur. The small amount of residual sulfur in the syngas after cleaning is converted to SO_2 in the combustion turbine, which accounts for the low levels of SO_2 emissions from IGCC facilities.[48]

Existing IGCC power plants achieve SO_2 emissions performance that is significantly better than pulverized coal power plants. The existing IGCC facilities in the U.S. achieve emissions levels around 0.13 pounds per million Btu (lbs/mmBtu), compared to the federal New Source Performance Standard (NSPS) for coal power plants of 1.2 lbs/mmBtu. The next generation of IGCC power plant is expected to achieve even lower SO_2 emissions, achieving 99 percent or greater sulfur removal. It is recommended that to qualify for a 3Party Covenant financing program, IGCC facilities achieve 99 percent sulfur removal and emissions rates not to exceed 0.04 lb/mmBtu (see Appendix A).

1.42. NOx Emissions

Fossil fuel combustion produces NOx emissions through both fuel bound nitrogen and thermal formation at high temperature. Coal contains chemically bound nitrogen that accounts for over 80 percent of the total NOx emissions from PC power plants.[49] In contrast, acid gas clean-up processes in IGCC plants remove over 99 percent of the nitrogen compounds from the syngas prior to combustion, so NOx formation in IGCC plants is primarily the result of thermal NOx produced in the turbine combustor. By maintaining a low fuel to air ratio (lean combustion) and adding a dilutent such as steam,

---

control. These technologies add to the capital cost, size and complexity new PC power plants and decrease plant efficiency because of their energy consumption.

[47] Id.

[48] See Id., p. 2-7.There may also be very small amounts of SO_2 emissions associated with tail gas incineration as part of the sulfur recovery system and syngas flare during gasifier startup or backdown.

[49] NETL, Major Environmental Aspects, p. 2-8.

the turbine flame temperature can be lowered and thermal NOx formation resulting from IGCC generation significantly reduced.[50]

Current state-of-the-art combustion control for syngas-fired turbines enables them to achieve NOx emissions as low as 15 ppm (about 0.075 lb/mmBtu). At this level, they can achieve lower emissions than allowed under the NSPS for coal power plants of 1.6 lb/MWh, or 0.15 lb/mmBtu (about 25 ppm for a gas turbine) and do so without the use of post-combustion NOx controls such as selective catalytic reduction technology (SCR). Turbines firing syngas are not able to use the so-called Lean-Premix Technology for reducing NOx formation in combustion turbines that can be used when firing natural gas to achieve NOx emissions levels as low as 9 ppm.[51]

However, IGCC technology offers the potential to achieve NOx emissions levels comparable with natural gas fired facilities (2 or 3 ppm (0.01 lb/mmBtu)) through the use of post-combustion Selective Catalytic Reduction (SCR). SCR is a commercially available NOx control technology in wide use on natural gas-fired CTs and coal boilers. To deploy SCR technology on IGCC facilities where syngas is the fuel, very deep sulfur removal from the syngas is required (99+ percent sulfur removal) prior to combustion to prevent fouling and corrosion of heat transfer surfaces in the HRSG by ammonium sulfate salts. This deep level of sulfur removal to accommodate SCR use can be achieved with several sulfur removal processes, including Selexsol™, Rectisol™, or the addition of a zinc oxide or activated carbon polishing reactor, but adds to the cost of IGCC NOx control. It is estimated that the additional cost of deploying SCR with deep sulfur removal on IGCC is around $100/KW of capital and increases the cost of energy from an IGCC facility about 4 mills/kWh.[52] None of the commercially demonstrated IGCC facilities operating today employs post-combustion SCR controls, but it is recommended that to qualify for a 3Party Covenant financing program, IGCC emissions levels not exceed 0.025 lb/mmBtu (~5 ppm), which is a level that will require SCR controls (see Appendix A).

1.43. Particulate Emissions

Particulate control in IGCC plants begins with the gasification processes itself, which allows only small amounts of fly ash to end up in the syngas, because most of it is removed in the gasification process as slag or bottom ash. The fly ash that does end up in the syngas is in a relatively small volume of gas (relative to the volume of gas created from fuel combustion), so particulate removal with filters and/or water scrubbers is highly efficient. Additional particulate removal also occurs in the gas cooling operations

[50] Id., p. 2-9.
[51] Because of the high flame speed of H_2 in syngas, use of this technology raises the risk of damaging flashbacks. See Id.
[52] See, Gray, David and Glen Tomlinson, "Cost & Technical Issues Associated with use of SCR for NOx Removal in Coal-Based IGCC," Presented at the Gasification Technologies Conference, San Francisco, CA, October 2002.

and in the acid gas clean up systems. For these reasons, very little ash remains in the syngas sent to the turbine and IGCC facilities are able to achieve very low particulate emissions levels.[53]

The existing IGCC power plants operating in the U.S. today achieve particulate emissions rates around 0.01 lbs/mmBtu, half or less than the NSPS level for coal plants of 0.03 lbs/mmBtu. It is recommended that to qualify for a 3Party Covenant financing program, IGCC PM stack emissions levels not exceed 0.01 lb/mmBtu.

1.44. Mercury Emissions

In addition to its ability to reduce currently regulated pollutants, IGCC technology also lends itself to cost-effective mercury control to levels beyond what can be achieved with current PC technology. Mercury is a toxic, persistent pollutant that accumulates in the environment and food chain. Coal combustion power plants are the largest anthropogenic sources of mercury emissions in the U.S. Power plant mercury emissions are currently unregulated, but EPA has proposed coal power plant mercury regulations that are scheduled to be finalized by Spring 2005 and implemented in the 2007-2010 timeframe.

Currently, there is no single proven technology that can uniformly control mercury from PC power plants in a cost-effective manner, while consistently achieving mercury removal levels of 90 percent.[54] In contrast, IGCC power plants have the potential to cost-effectively achieve very high (up to 99 percent) mercury control with established technology.[55] For example, Eastman Chemical operates a GE Energy Gasification Technologies ("GE Energy")[56] gasifer at its Kingsport, Tennessee facility that utilizes activated carbon-based technology to achieve 90-95 percent mercury removal.[57] There is also commercial experience removing virtually all (99.99 percent) of the mercury from natural gas and it is believed that comparable results are possible using similar technology for IGCC applications.[58]

A 2002 study sponsored by NETL indicates that the capital cost of 90 percent mercury removal from an IGCC plant is only \$3.34 per kilowatt (much less than one percent increase) and that the total cost of energy increase is about 0.25 mills/kWh, or about \$3,500 per pound of mercury removal.[59] This is about one-tenth the cost of 90 percent mercury removal from PC boilers, which was estimated in EPA's Mercury Study Report to Congress to be over 3 mills/kWh, or \$37,800 per pound of mercury.[60] Other studies

---

[53] Id., p. 2-7—2-8.
[54] NETL, "The Cost of Mercury Removal in an IGCC Plant," Sept. 2002, p. 1.
[55] Id.
[56] Formerly the Texaco Gasification Process, which was acquired by GE Energy Gasification Technologies July 1, 2004.
[57] Id., p. 5.
[58] Id.
[59] Id., p. 1-2.
[60] EPA, "Mercury Study Report to Congress: Volume VIII, An Evaluation of Mercury Control Technologies and Costs," EPA-452/R-97-010, Dec. 1997, p. 3-6.

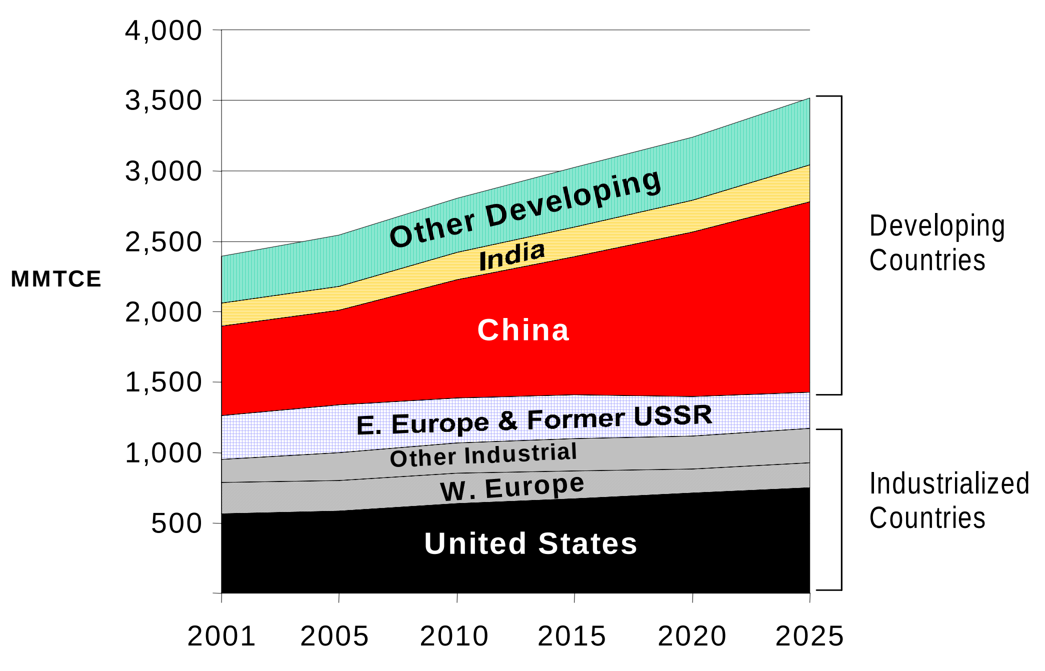
have found IGCC mercury removal costs as low as $1,200-$1,300 per pound[61] and mercury removal from flue gas at PC plants as much as $85,000 per pound,[62] which would suggest PC mercury removal may cost as much as 65 times more than IGCC mercury removal. It is recommended that to qualify for a 3Party Covenant financing program, IGCC facilities achieve at least 95 percent mercury removal.

1.5. Climate Change

IGCC commercialization and deployment could also provide a technical pathway for coal generation in a carbon constrained world. Coal has the highest carbon content of any fossil fuel. Nonetheless, both industrialized and developing countries are projected to continue to depend on coal as a primary energy source and continue to build and re-power coal-fired power plants to meet rapidly increasing electricity demand. Continued and expanded coal combustion with conventional generating technologies will substantially increase worldwide CO_2 emissions and exacerbate global climate change concerns.

In 2001, worldwide coal consumption was 5.26 billion short tons. It is projected to grow

Figure 1-7. Projected World CO_2 Emissions from Coal Consumption



EIA, International Energy Outlook 2003, Table A-13, p.194.

[61] Klett, M.G., and M.D. Rutkowski, The cost of mercury removal in an IGCC plant, letter report to NETL, December, 2001.

by 1.5 percent per year and reach 7.48 billion tons by 2025. Currently, about 37 percent of anthropogenic CO_2 emissions worldwide are attributed to coal combustion (2.427 billion metric tons carbon equivalent).[63] As illustrated in Figure 1-7, world CO_2 emissions from coal use are projected to increase 45 percent by 2025.[64] Essentially all the increase in world CO_2 emissions from coal is attributed to projected growth in coal-fired electricity generation. Adopting IGCC and other technologies that facilitate coal use with reduced or eliminated carbon emissions will be critical to stabilizing atmospheric CO_2 concentrations linked to climate change.

IGCC technology has several advantages over PC power plants for addressing CO_2 emissions. First, IGCC facilities have the ability to operate at higher efficiencies. Although current IGCC power plants typically operate with efficiencies that are comparable to new PC plants (35-42 percent efficiency), IGCC has many processes where efficiency could be improved through commercial optimization, including turbine designs, gas clean-up, and air separation systems. The next generation of IGCC facilities is expected to achieve efficiencies of 40-45 percent and over the longer-term reach efficiencies of 45-50 percent with advanced turbines (and as high as 70 percent with fuel cells). Greater efficiency means that more electricity is produced for every ton of coal consumed and that fewer byproduct CO_2 emissions are produced per MWh of generation.[65]

Second, IGCC technology offers the potential for separating and capturing CO_2 emissions to achieve emissions reductions more efficiently than current combustion technologies.[66] The advantage stems from the ability to remove CO_2 from syngas prior to combustion, rather than exhaust gas after combustion. Capturing CO_2 in an IGCC facility involves adding shift reactors to the syngas treatment system after the particulate and sulfur removal processes (but before combustion in the turbine), or using shift reactors and clean-up processes to remove CO_2 and sulfur compound simultaneously. Shift reactors serve to further increase CO_2 concentrations in the syngas (up to about 40 percent), which combined with the elevated pressure, allows for the use of physical absorption processes to capture CO_2, rather than more energy intensive chemical absorption processes required to remove CO_2 from PC or other combustion facility exhaust gas.[67]

---

[62] EIA, "Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants," SR/OIAF/2001-04, September, 2001.

[63] EIA, International Energy Outlook 2003, Table A-10, p.191

[64] EIA, International Energy Outlook 2003, Table A-13, p.194.

[65] CO_2 emissions levels can be different for different gasification IGCC technologies. For example, dry feed gasifiers and gasifiers with heat recovery tend to be most efficient, which results in less CO_2 per MWh.

[66] Although capturing CO_2 is only the first step in controlling it (because it must be sequestered if emissions are to be reduced), most experts agree that extensive research and large-scale demonstration projects are needed on sequestration before a commercial IGCC or other coal power plant would be in a position to sequester its CO_2. Sequestration is not specifically addressed in this paper because it is viewed by the authors as beyond the scope of commercialization of a small initial fleet of IGCC plants, which is the objective of the 3Party Covenant proposal.

[67] NETL, Major Environmental Aspects, p. 2-45—2-47.

A joint engineering assessment by NETL and EPRI has demonstrated the economic advantages of capturing CO_2 from IGCC facilities vs. PC or natural gas combined cycle (NGCC) plants. The first advantage is in parasitic energy consumption. Much less energy is needed to capture concentrated, pressurized CO_2 in the syngas stream with physical absorption than is needed to capture it in exhaust gas at ambient pressure with chemical absorption. The NETL/EPRI study estimates that the parasitic power loss associated with CO_2 capture at IGCC facilities is about 5 percent of net plant output, compared to 21 percent for NGCC and 28 percent for PC.[68] The second advantage is lower capital cost to deploy CO_2 capture technologies. The NETL/EPRI study estimates that CO_2 capture increases IGCC capital costs about 30 percent compared to 90 percent and 73 percent for NGCC and PC, respectively. Finally, in a cost of energy comparison, the study found that IGCC with CO_2 capture produced electricity at 1.4-1.8 cent/kWh (20 percent) less than PC plants with CO_2 capture technology and less than NGCC plants with CO_2 control when gas prices exceed $4/mmBtu.[69]

Jeremy David and Howard Herzog at MIT had similar findings. David and Herzog found that the incremental cost of adding CO_2 capture to a PC plant was between 2.16 and 3.32 cent/kWh, while the incremental cost of capture at an IGCC plant was between 1.04 and 1.70 cent/kWh. With current technology and conventional financing, they found that the cost of energy from an IGCC with CO_2 capture is 6.69 cents/kWh versus 7.71 cents/kWh for PC with CO_2 capture.[70] Under the 3Party Covenant financing plan, energy costs with CO_2 removal are lower because of the lower cost of capital (See Section 5.5 below).

Third, IGCC technology provides a foundation for moving toward advanced hydrogen technologies such as fuel cells and zero emissions fossil-fuel power generation that may ultimately provide the keys to addressing global climate change. The Department of Energy's FutureGen and Vision 21 programs aim to develop technologies of the future that will provide for coal-fueled facilities that are 60 percent efficient and have zero emissions. Gasification is a foundation technology for achieving these goals because it can produce pure hydrogen, which can be used in fuel cells for electricity generation and to power fuel cell vehicles.

How much expanded coal use in the world impacts the environment and global climate will hinge on international technology choices, which will be significantly influenced by technology development and deployment in the U.S. Deployment of IGCC technology in the U.S. will facilitate continued and expanded coal use for energy supply and security reasons, while achieving significant environmental improvement, including progress toward cost-effective capture of CO_2 emissions.

---

[68] Id., citing DOE—EPRI Report 1000316, Dec. 2000.
[69] Id.
[70] Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.

1.6. Water Use and Solid Waste Byproducts

Although air emissions are generally considered the most significant environmental concern associated with coal power generation, water use and discharge and solid waste production are also important environmental considerations. IGCC facilities use water for the plant's steam cycle as boiler feedwater and cooling water and for other processes such as emissions control. However, because the steam cycle of IGCC plants typically produces less than 50 percent of the power output, IGCC has an inherent advantage over PC boilers in the amount of water required. On an output basis, IGCC generally requires 30 percent to 60 percent less water than PC boilers.[71] Most process water in an IGCC facility is recycled to the plant, which minimizes consumption and discharge. Several processes can be used to remove dissolved gases and solid contaminants to ensure discharge water meets environmental requirements.

The largest solid waste from IGCC facilities is typically slag, which is a black, glassy, sand-like material. Because it is highly non-leachable, it can be sold as a by-product for applications such as asphalt paving aggregate, construction backfill, or landfill cover. The other significant sold waste is sulfur, or, depending on the gas cleanup system used, sulfuric acid. The sulfuric acid is generally about 98 percent pure and the sulfur by-product is typically greater than 99.99 percent pure. Both are valuable by-products that can be sold in existing markets such as fertilizer production.[72]

[71] NETL, Major Environmental Aspects, p. 2-4—2-5.
[72] Id.