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Coal Technology Options: Costs, Emissions and Experience for Electricity Generation in a Carbon-Constrained World

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Terms and Definitions

ASU	Air separation unit, a component used in coal gasification.
Bituminous	A type of coal with medium energy content, typically found in the Midwest or Eastern US.
Btu	British Thermal Unit, a measure of energy.
CCS	Carbon capture and storage, the process of capturing carbon dioxide from power plants for compression and storage in a reservoir (usually a nearby geologic site).
Coal gasification	A technology for generating electricity from coal. Also known as IGCC, Integrated Gasification Combined Cycle.
Combined cycle	A generation technology that uses two cycles. The first uses a turbine to burn a gaseous fuel, such as natural gas or syngas. The exhaust is used to heat water, which creates steam to generate additional electricity.
DOE	United States Department of Energy.
Efficiency	The ratio of useful energy products (e.g. electricity or steam) to the energy input into the system.
EPRI	Electric Power Research Institute.
FBC	Fluidized bed combustion, a technology for generating electricity from coal.
Gasification	The process of turning a solid fuel into syngas. Most existing gasification experience is in the chemical and fertilizer industries. A smaller subset of plants produces electricity for sale using IGCC.
Heat rate	The ratio of input energy to electricity produced by a power plant. In the United States, this is often expressed as Btu/kWh. Lower heat rates correspond to more efficient plants.
HRSG	Heat Recovery Steam Generator, a component in combined cycle power systems.
IGCC	Integrated gasification combined cycle, a technology for generating electricity from coal. Also called “coal gasification”.
mmBtu	Million British Thermal Units, a measure of energy.
NETL	National Energy Technology Laboratory, a research program housed in the United States Department of Energy.
NGCC	Natural gas combined cycle, the state-of-the-art technology for generating electricity from natural gas.
PC	Pulverized coal, a family of technologies for generating electricity. Subcritical, supercritical and ultrasupercritical designs fall in this category.
SCPC	Supercritical pulverized coal, a technology for generating electricity.
Subbituminous	A type of coal with lower energy content, typical of the Western US.
Syngas	The gaseous product of coal gasification. Syngas is combusted in turbines to produce electricity in IGCC.
USC	Ultrasupercritical pulverized coal, a technology for generating electricity.

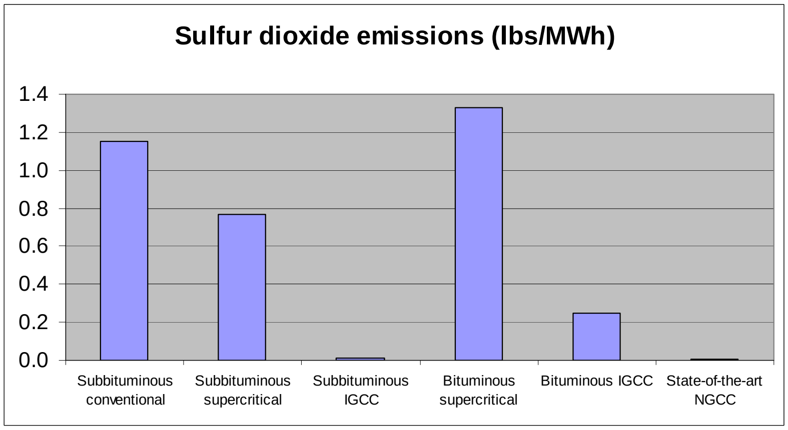
Executive Summary

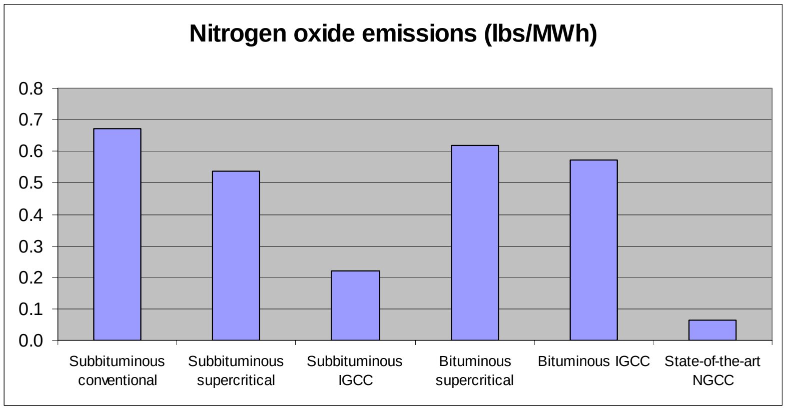
Following the rise in natural gas prices over the past few years, utilities and regulators have shown a renewed interest in coal, due to its domestic availability and price stability. The stakes are high. In 2003, coal accounted for just over 50% of all electric power consumed in the United States.[1] The U.S. Energy Information Administration projects this share will increase slightly over time as gross coal use in the electric sector grows almost 45% by 2025.[2] With some 18.5 GW of conventional coal currently proposed in the American West,[3] a comparison of coal technology costs and emissions is needed to evaluate impacts and suggest alternatives. Some states express a preference for efficiency and renewables,[4] but given the scale and geographic diversity of the proposed coal facilities, it is likely that some new generation will be built in the coming years.

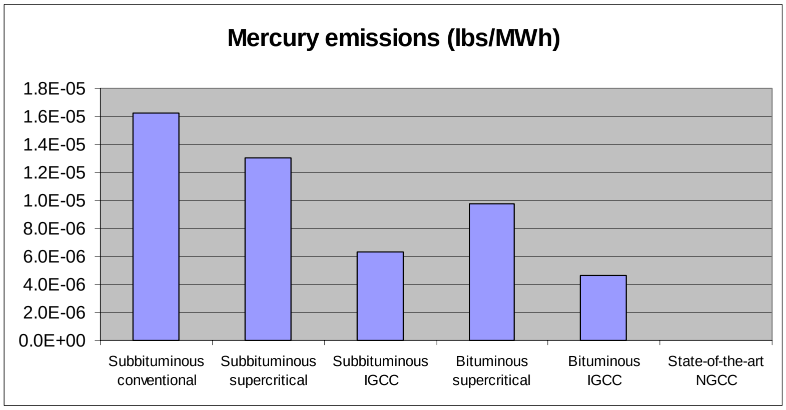
This study examines the impacts of three families of technologies for coal-based electricity generation: pulverized coal, fluidized bed combustion and coal gasification (IGCC). Of the three, fluidized bed combustion is least able to address carbon dioxide emissions, as it is a technology designed to address non-carbon pollutants.[5] Because coal-based electricity generation accounts for more than a quarter of national CO_2 emissions, this study compares only those technologies that offer the possibility of mitigating this effect. To determine benchmark numbers for four criteria pollutants, recent state regulatory filings for power plant permits were used to assess the applied capability of existing technologies. In order to be conservative, conventional coal plant designs were given the most advanced add-on pollution controls to best compete against new designs like IGCC. The full data and assumptions are available in Appendix A.

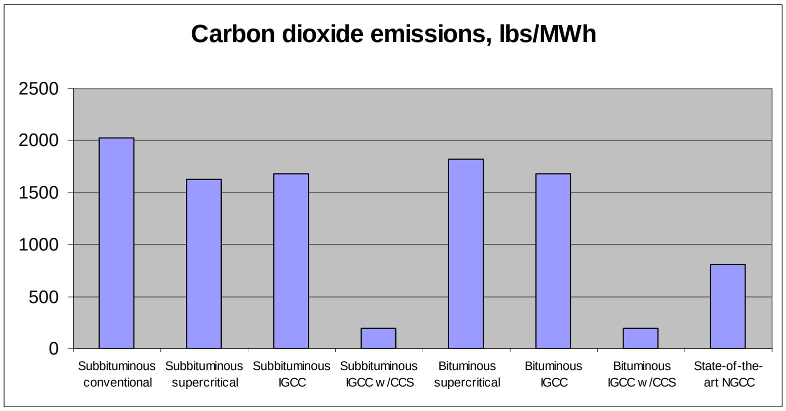
A clear winner emerges from the field of coal options. Integrated gasification combined cycle (IGCC) power plants significantly outperform supercritical and conventional coal facilities on emissions grounds. Industrially proven gasification cleaning techniques dramatically reduce NO_x, SO_x and mercury emissions (see Figures 1-3, next page). IGCC also offers the cheapest available way to capture carbon dioxide from fossil fuel energy production, a necessary and fiscally responsible step in a carbon-constrained world (Figures 4 and 5). Furthermore, carbon sequestration costs are affordable under IGCC, competing directly with generation that does not capture CO_2.[6] Capture-ready[7] IGCC is projected to cost \$60/MWh by 2010, compared to natural gas combined cycle electricity at \$63/MWh, assuming a gas price of \$7/mmBtu.[8] If natural gas prices remain high in the long term, the cost of installing IGCC in place of pulverized coal technology is less than the traditional low-carbon alternative, natural gas.

With over 45 GW of existing gasification capacity in 2004 and decades of commercial carbon dioxide capture experience, IGCC power plants with carbon capture and storage are a viable and desirable alternative to traditional coal where new generation is required. IGCC also offers significant potential as a carbon management strategy in the developing world, where resource procurement decisions are less likely to favor natural gas and non-fossil fuels. Domestic commercial maturation and international dissemination of gasification technology could have far-reaching positive effects. IGCC also provides an option for re-powering older, dirtier coal facilities in the United States.









Figures 1-4:
Coal emissions by technology choice and coal type.

Carbon capture and storage (CCS) requires additional energy, reducing the electricity produced per ton of coal. As a result, CCS scales any non-CO_2 emissions level up. For IGCC, non-CO_2 emissions rise ~15%. For PC and NGCC technology, non-CO_2 emissions rise 30-40%. For clarity, these conditions are not shown in the graphs to the left. CCS increases the advantage IGCC has over other coal technologies from an emissions perspective.

Full technical data is reported in Appendix A, including the assumed control technologies used by each plant.

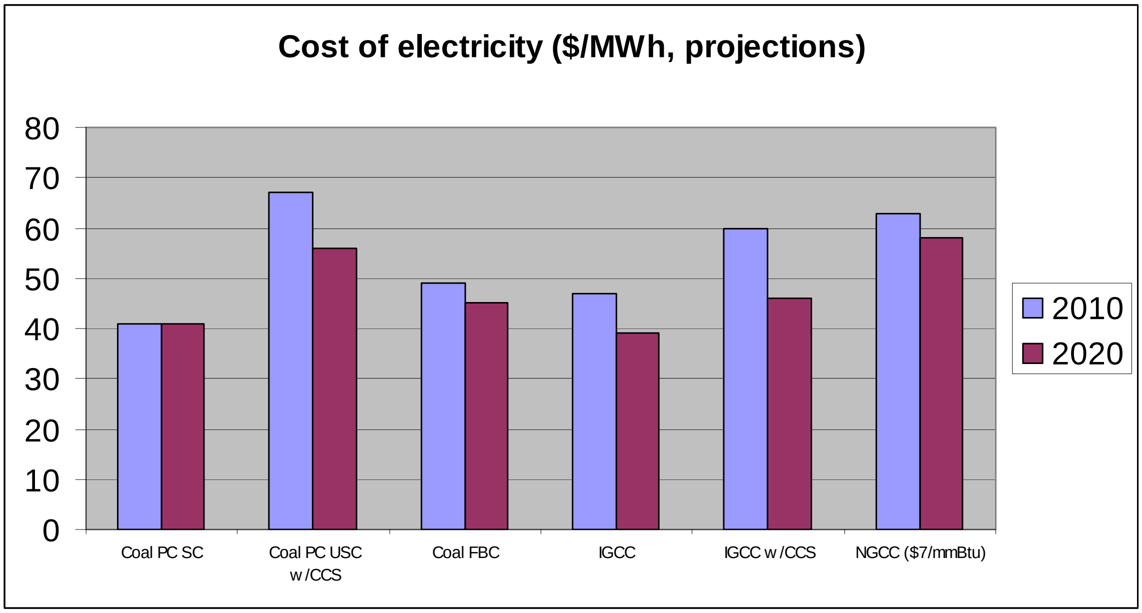


Figure 5: EPRI cost of electricity projections[9]

1. Technology Overview

There are three main technology families from which to choose new coal generation: pulverized coal, fluidized bed and integrated gasification combined cycle (IGCC). Of the three, fluidized bed and IGCC offer the greatest potential to reduce emissions in SO_x and NO_x. Furthermore, IGCC is best positioned to economically reduce mercury and CO_2.

While fluidized bed technology promises lower sulfur emissions relative to pulverized coal, it does nothing to address CO_2. Add-on carbon capture technologies can be used in both pulverized and fluidized bed systems, but the additional cost of this option makes near-term discussion of fluidized bed technology insufficient to address climate concerns.

A brief discussion of each generation package follows.

Pulverized coal: subcritical, supercritical and ultrasupercritical

Within the pulverized coal (PC) technology family, there are three subclasses of reactor designs – subcritical, supercritical and ultrasupercritical. The mechanics of these systems are relatively straightforward. Coal combustion heats water, creating steam to drive a turbine. PC facilities are in general well understood and there is little uncertainty with respect to either emissions or costs. The newest designs in ultrasupercritical combustion, while untested at the commercial scale, do not depart far from existing technology.

Over 90% of existing coal plants use pulverized coal technology, and the vast majority of these employ subcritical reactor designs.[10] In the United States, subcritical plants have been the facility of choice due to the relatively cheap supply of domestic coal. Because fuel is inexpensive, profit-maximizing companies have had little private incentive to make their plants more efficient, leading to a preference for subcritical designs over supercritical plants. In contrast, Europe tends to feature supercritical designs, as a result of higher coal prices and sulfur pollution concerns.

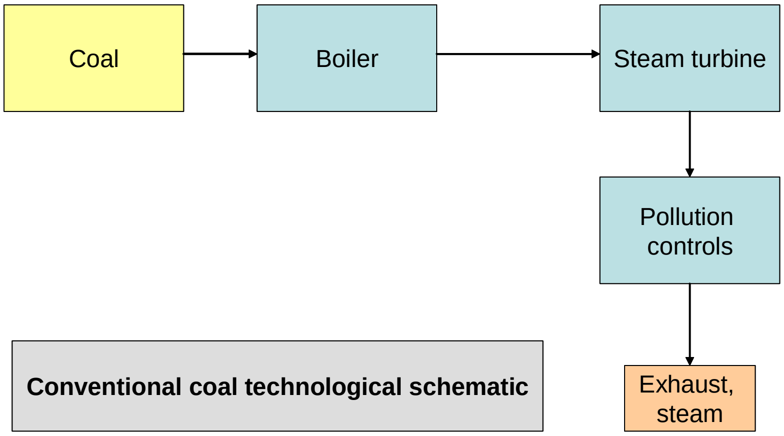


Figure 6: A basic pulverized coal power plant design

Subcritical plants are characterized by the simplicity of their design, the basics of which have been stable for decades (see Figure 6). Standard subcritical combustion usually operates at 1000°F, and can reach total efficiencies of 35-37%.[11] Since the 1980s, however, there have been many improvements in both heat-resistant materials and in the understanding of the steam cycle which have allowed PC plants to operate at higher temperatures and pressures. Supercritical (SC) combustion operates above the so-called "critical point," a combination of both heat and pressure at which the distinction between liquids and gases is blurred. Systems combusting above the critical point achieve higher thermal efficiency due to a more effective heat transfer from the coal to the supercritical steam. Supercritical reactors typically operate between 1050 and 1100°F, and achieve efficiencies around 40-42%.[12] As both subcritical and supercritical plants can use the same add-on pollution control technology, total plant efficiency creates the difference in emissions. Supercritical combustion reduces emissions over subcritical plants simply by using less coal per MWh produced.

Ultrasupercritical (USC) reactors take the heat and pressure conditions a step further than supercritical plants, operating at higher temperatures and pressures. As a result, ultrasupercritical combustion is projected to reach efficiencies as high as 46-48%, though again, there is relatively little experience with these advanced plants.[13]

Comparing subcritical, supercritical and ultrasupercritical plant designs and emissions levels is straightforward. The subcritical design is the status quo technology in the United States, and is the most polluting option available for electric generation. Supercritical and ultrasupercritical designs do not fundamentally alter the combustion process, or its resulting emissions. They do, however, reduce overall impacts by increasing plant efficiency. With less coal consumed per unit of electricity produced, supercritical and ultrasupercritical plants are a marginal improvement over existing plants.

With all control technologies and coal feed types being equal, differences in design efficiency will drive differences in emissions levels.

Fluidized bed coal

Another possibility for coal-based generation is fluidized bed combustion (FBC), which removes many pollutants inside the boiler itself. Using this design, pulverized coal is mixed with limestone and fired at relatively low temperatures in a process resembling a boiling fluid. The limestone helps remove the sulfur, and because its presence lowers the temperature of combustion, less NO_x is formed in the process. While FBC performance is certainly superior to that of pulverized coal, it does not appear competitive with advanced gasification designs for NO_x, SO_x and mercury emissions; nor does it offer the potential for cost-effective carbon capture and storage.[14] In addition, there are concerns that compared to PC plants, FBC emits more N_2O, a potent greenhouse gas with approximately 300 times the warming potential as CO_2.[15]

One current advantage of FBC is that its operating experience is greater than that of gasification technologies. Availabilities are similar to pulverized coal plants, falling in the 95-97% range.[16] Some analysts have suggested that FBC reliability makes it a good starting point for advanced generation, especially when combined with a supercritical steam cycle. However, because its non-CO_2 pollution levels can be outmatched with gasification technology,[17] FBC does not offer any improvements over better alternatives in coal and natural gas generation. Most importantly, FBC does nothing to address the carbon emissions from coal combustion.

Integrated gasification combined cycle coal

Among available coal technologies, IGCC is often thought to be the newest, though in reality it has been around since the turn of the nineteenth century. The gasification process was first patented in Germany in 1897, and has been used since then in chemical plants.[18] In the 1970s, the U.S. Department of Energy took interest in gasification for electricity production. With DOE funding, Texaco Gasification contracted with Southern California Edison to build the first pilot IGCC plant in 1980, known as Cool Water.[19] That facility successfully ran from 1984-1989, when it was decommissioned. There are currently two operating coal-based IGCC electricity generators in the U.S., and a handful of international plants as well. These plants, along with new proposed facilities, are discussed in Section 4.

IGCC is fundamentally different from pulverized coal. In the gasification process, a carbon-rich feedstock (such as coal) is partially combusted with oxygen and steam to form what is known as “syngas”. Comprised primarily of carbon monoxide and hydrogen, syngas also contains lesser amounts of methane, carbon dioxide and gasification impurities. The final composition will reflect the contents of the fuel source. While this report focuses on coal, many other fuel sources are potentially useful for IGCC. Petroleum residuals, especially petroleum coke, are popular alternatives due to their relatively low cost. Biomass co-firing is also an option.

Whatever the fuel source, post-gasification refining and combustion follow a basic pattern. Syngas exits the gasifier at a high temperature and pressure, and is cooled and cleaned before full combustion in a gas turbine, often the same model turbine as would be found at a natural gas generation plant. A heat-recovery steam generator (HRSG) unit recycles some of the heat from this final exhaust to heat a secondary water boiler, producing additional electricity and raising the net thermal efficiency of the power plant.

As a result of the gasification process, IGCC is well positioned for carbon capture and storage (CCS). CCS is a costly addition to any kind of power plant, both in energy and monetary terms, for two reasons. First, separating CO_2 from exhaust gas is difficult, as it is often a low percentage of plant exhaust. Second, for transport and storage, the pure CO_2 stream must be compressed. In the case of IGCC, syngas is already under high pressure, so it is possible to remove carbon without paying as much in compression costs. Furthermore, CO_2 is separated pre-combustion in IGCC, when volumes are lower and concentrations are higher (as they are not yet diluted with air from the combustion process).

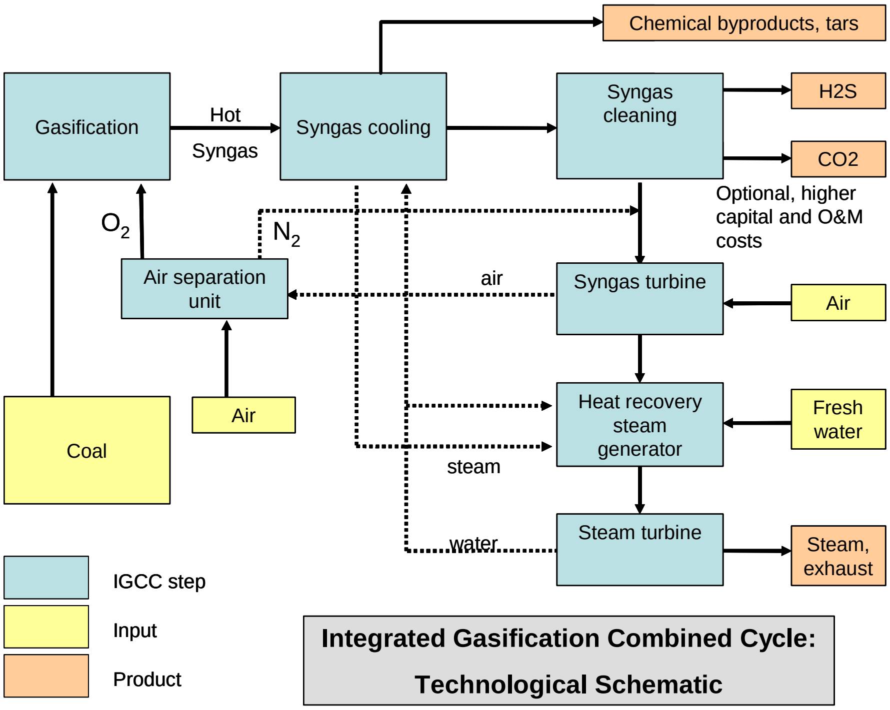


Figure 7: IGCC schematic

These engineering advantages act to raise an IGCC plant's thermal efficiency, relative to a pulverized coal plant with similar controls. But despite reports of IGCC achieving efficiencies in the neighborhood of 52%, the net power produced tends to be notably lower. Most gasification technologies require a very pure (~95%) stream of oxygen, necessitating an air separation unit (ASU).[20] In turn, the ASU requires a large amount of power, on the order of 9% of total efficiency. Thus, the net thermal efficiency of an IGCC plant is projected to be around 43%, including the 9% ASU loss.[21] In comparison, the best subcritical pulverized coal plants achieve approximately 37% efficiency. The Electric Power Research Institute estimates ultrasupercritical designs at 46-48%, although these later designs have not yet been achieved in practice.[22] And, with both pulverized coal and IGCC designs, pollution controls consume additional energy, driving efficiencies down a few percentage points in the cases of SO_x, NO_x and mercury.

A resulting focus of technological innovation is the energy consumption of the ASU. Some new designs, though not ready for commercial application, use ionic membrane separation instead of the energy intensive cryogenic process used by most ASU devices. The National Energy Technologies Laboratory hopes its ionic membrane project will reduce overall IGCC capital costs by 7%, and improve net thermal efficiency by 2.2%.[23]

Other approaches seek to minimize the use of pure oxygen. While not eliminating the need for an ASU, Southern Company has proposed a new gasification design, based on a Kellogg, Brown & Root (KBR) catalytic cracking technology, which can run in an "air-blown" mode.[24] Operating in this fashion, the KBR gasifier can cut costs, making lower-grade coal supply more economic for IGCC. With $235 million in support from the US

Department of Energy, Southern is currently planning a 285MW facility near Orlando, Florida, as a demonstration project.[25]

Air-blown gasification has been attempted before. A variant of this technology was used in the failure of Sierra Pacific's Pinon Pine IGCC facility. After eighteen separate attempts to run the gasification system, this $336 million plant never achieved more than a few days' operation.[26] However, initial unpublished reports of Southern's demonstration project suggest the technology is now in fact workable, though unproven on scales larger than 10 MW. Construction has not yet begun on the larger DOE test facility.

There are few studies on carbon capture technology for air-blown gasifiers. The advantage of IGCC in carbon capture terms relies on the thermodynamic properties of the carbon dioxide separation – namely, the high pressure and concentration of CO_2 once separated from the combustion chamber. Because air-blown gasifiers use air in the gasification process (instead of pure oxygen), the gas stream after combustion will be diluted with extra N_2. The result is that the partial pressure of CO_2 will be lower, necessitating more expensive and energy intensive processes to remove and compress the CO_2. Addressing this problem will be a key challenge for air-blown gasifiers.

Finally, studies suggest IGCC will consume only 60% of the water used by a pulverized coal facility.[27] This improvement might make the technology more attractive in arid regions. However, the reaction used to separate CO_2 from the syngas is a steam-based reaction, using one molecule of water per molecule of CO_2. The effect of CCS on water consumption has not been studied in detail.

2. Comparing Non-CO_2 Emissions from Coal

Coal emissions are driven by three primary factors: coal feedstock composition, plant design technology and add-on emissions controls. As a result, it is very difficult to make even-handed comparisons, since coal generators vary widely along these lines. Despite these challenges, gasification appears to outperform all coal-based alternatives across three criteria pollutants – SO_x, NO_x and mercury. Data are reported graphically by pollutant, and technical information is given in Appendix A.

The key to gasification's relative advantage in emissions reduction is that filtration of chemical impurities occurs before syngas combustion, taking advantage of high-pressure flows. Pulverized coal and natural gas must use scrubbing units to clean a larger volume of flue gas, which involves greater energy penalties and capital costs, although natural gas contains significantly fewer pollutants to start with. Coal-based IGCC is particularly well positioned to address carbon dioxide emissions, and is the cheapest option for carbon capture of all fossil fuels. Gasification also has the option of using industrially proven techniques for the commercial recovery of impurities such as sulfur, whereas most emissions controls have not been developed with profitable side applications.

When analyzing coal projects, it is important to note that different plant designs can employ different control technologies. For each pollutant, there are multiple factors controlling net plant emissions beyond the heat rate of the coal plant. The next three sections will describe the basic choices and technologies affecting the three traditional criteria pollutants: SO_x, NO_x and mercury.

SO_x

Oxides of sulfur are acidic and can cause damage to the respiratory system. They also form smog and damage buildings by slowly decaying exposed surfaces.[28] For fossil combustion, the key drivers of SO_x emissions are the control technologies installed, as well as the type of coal burned. Sulfur contents vary from around 0.4 lbs/mmBtu for Wyoming subbituminous all the way up to 2.5 lbs/mmBtu for Appalachian anthracite.[29] As a result of the Clean Air Act limitations on sulfur emissions, Western coal production (mostly lower-sulfur subbituminous) has increased over the past few decades, while Eastern coal production (mostly higher-sulfur bituminous) has declined.[30] But no matter the sulfur content of coal, gasification outperforms pulverized coal technology, reducing pollution nearly to the level of natural gas emissions.

On the technology side, gasification is well suited to address sulfur concerns. Since gasification occurs under O_2-limited conditions, most of the sulfur in the coal is converted into H_2S, and the bulk of the remainder into COS. These chemical forms, particularly H_2S, are easier to capture than SO_x. Conventional acid gas removal equipment, such as methyldiethanolamine absorption (MDEA), can capture 95-99% of H_2S, and produces either elemental sulfur or sulfuric acid (H_2SO_4).[31] Both of these products can be sold commercially.

More advanced controls promise even better performance for IGCC plants. Selexol absorption and Rectisol solvents offer 99% and 99.5% removal, respectively.[32]

Gasification retains a sulfur advantage with these technologies, independent of coal type. An IGCC plant using high-sulfur bituminous coal will still emit less sulfur than a supercritical plant using low-sulfur subbituminous coal (see Figure 8).

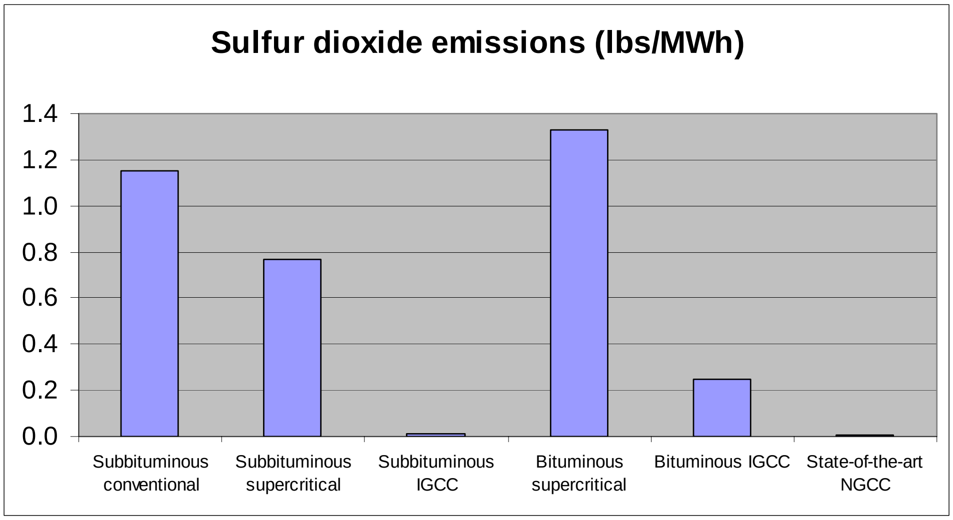


Figure 8: Sulfur emissions (see Appendix A for data)

Unlike IGCC facilities, conventional plants must scrub flue gas to reduce emissions. Flue gas desulfurization is expensive, and often less effective due to the lower concentrations of sulfur compounds found in exhaust. A spray containing lime is injected into the flue gas, which reacts with sulfur to form calcium sulfate, a liquid sludge. This product is then removed for disposal.

NO_x

Oxides of nitrogen have wide effects on human health and the environment. They are a contributor to smog formation, acid rain, particulate matter and even global warming.[33] Most NO_x is formed during combustion, where extreme temperatures oxidize N_2. Hence, a major challenge for any generator is the tradeoff between combustion temperature (which usually improves thermal efficiency) and NO_x emissions. Low-NO_x burners can be used to control some NO_x formation, but IGCC faces significant additional problems as gasification takes place under very high temperature and pressure conditions. The end result is that while gasification still outperforms alternatives in coal technology, it does not make the same gains relative to natural gas generation as it does in the case of SO_x.

With traditional combustion technologies, such as pulverized coal or NGCC, selective catalytic reduction (SCR) can be used to control NO_x. Flue gas is filtered through a catalyst, often ammonia, which removes NO_x at the cost of some new “slippage” – the term used to describe emissions of the catalyst itself. With SCR, natural gas combined cycle NO_x emissions are barely perceptible (see Appendix A for technical details).

To control NO_x formation in gasification, some IGCC designs dilute syngas combustion with a stream of pure N_2. When the ASU separates air to produce O_2 for gasification, the waste stream of N_2 can be pumped into the combustion turbine. While it might seem counterintuitive to add N_2 to limit NO_x, combusting syngas in an oxygen-limited environment leads to lower NO_x levels. Again, while these emissions tend to be less than pulverized coal combustion, they do not reach the levels achieved by natural gas combined cycle.

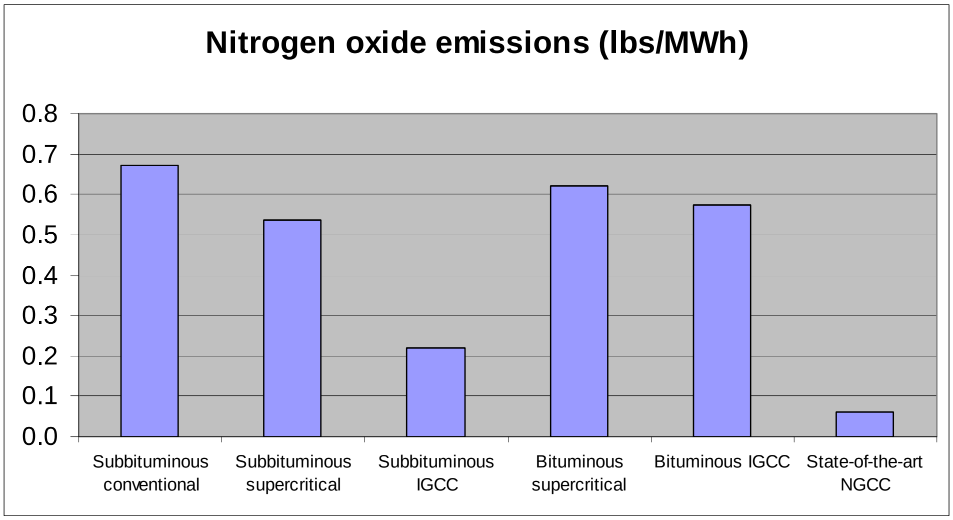


Figure 9: Nitrogen emissions (see Appendix A for data)

Mercury

Coal generation produces emissions of mercury, a persistent toxic chemical that builds up in biological systems and effects human health. The developing human fetus is particularly susceptible to problems caused by mercury pollution.[34] As of 2003, coal-fired power emissions accounted for around one-third of U.S. anthropogenic mercury emissions, at 48 tons a year.[35] Gasification offers the promise of better mercury control technologies, which, while not achieving the near-zero emissions of natural gas, make significant headway in addressing the negative effects of coal. Results are shown in Figure 10: Mercury emissions (see Appendix A for data).

Aside from the choice of coal technology, the most important factor in determining mercury emissions is the content of the fuel source. Table 1 gives estimates for different coal inputs. While there is a large range of mercury contents, even within a particular coal category, petroleum coke (an oil derivative) and subbituminous coal tend to have the lowest contents. Since mercury control technology is rated by its percentage reduction capabilities, the raw input of mercury is a key factor in determining the net impact.

Table 1: Mercury emissions by fuel source[36]

Fuel Type	Average Mercury Content	Range
Anthracite	113	60-230
Bituminous	137	1-1,300
Lignite	106	20-750
Petroleum coke	50	0.9-500
Subbituminous coal	71	8-900

(All units: parts per billion, by dry weight)

To better understand the potential for mercury controls it is necessary to differentiate the kinds of mercury that arise from power plants. There are two forms of mercury produced by combustion, elemental and ionic. The latter is somewhat easier to capture, as it is soluble in water. Elemental mercury presents additional challenges, as it does not react as easily. Many mercury control technologies are designed to enable the conversion from elemental to ionic, which can then be captured by existing pollution controls.

Eastern bituminous coals contain more mercury than Western subbituminous coals, but mercury emissions from Eastern coal are easier to capture then those of Western coal. Almost two-thirds of mercury emissions from Eastern coal are ionic, compared to around 25% of mercury emissions when using Western coal.[37] Pre-combustion cleaning can increase the difference, as established processes can remove about one-third of total mercury on average from Eastern coal. Western coal cannot be cleaned in the same way, although new de-watering processes have removed up to 70% of total mercury in National Energy Technology Laboratory tests.[38] As existing technologies stand, it is easier to reduce mercury from plants using Eastern bituminous coal than it is to make similar adjustments in a Western subbituminous-fed plant.

In the predominantly conventional coal fleet, some mercury control methods are already in place. Flue gas scrubbers, which are used to control SO_x, capture perhaps one third of the mercury produced from coal plant, essentially all of which is in the ionic form.[39] This is enabled by the presence of catalysts, often added for NO_x control, which help convert elemental mercury to the ionic form.

These controls arose chiefly in response to non-mercury emissions concerns, and are hence not optimized for mercury removal. While modifying existing controls might increase their effect marginally, additional technology will be required to meet the 2005 Environmental Protection Agency mercury rulings, which call for a 70% reduction in current emissions over twelve years. For conventional coal plants, the U.S. Department of Energy is experimenting with chemical sorbent injection, added after combustion and before the flue gas scrubbers.[40] Using activated carbon (often just unburned lignite coal), mercury is converted into its ionic form, and is captured in the flue gas scrubbers or in ash baghouses or fabric filters (commonplace and inexpensive particulate controls).

While this practice has been demonstrated commercially,[41] concern over fly ash contamination persists. Many coal generators sell their ash and slag waste products to concrete manufacturers, but carbon injection can make ash unusable, due to its altered chemical composition.[42] Because coal ash replaces a carbon intensive process in concrete manufacture, new mercury controls could marginally increase CO_2 emissions and total coal waste by rendering the ash and slag unusable.

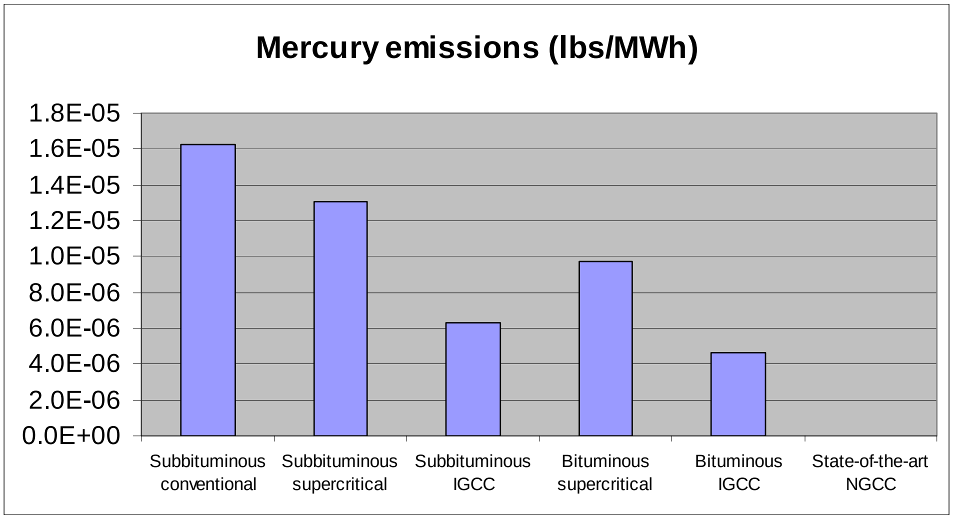


Figure 10: Mercury emissions (see Appendix A for data)

In the end, gasification currently outperforms pulverized coal with respect to mercury emissions. Even the best experimental technologies are not projected to close the gap. IGCC can remove upwards of 99% of total mercury content, using a process at the Eastman Kodak chemical production facility for over 20 years.[43] By filtering pre-combustion syngas through activated carbon beds, Kodak removes mercury and produces food-quality outputs, including the feedstock for some pain medication and popular soft drinks. Furthermore, the process can be done at costs an order of magnitude lower than available for pulverized coal. The DOE reports that activated carbon beds in gasification remove mercury at the avoided costs of $0.254/MWh, compared to $3.10/MWh for a similar process in pulverized plants.[44]

3. Carbon: Emissions, Capture and Storage

The biggest regulatory uncertainty facing the electricity industry is the issue of carbon dioxide,[45] the primary contributor to climate change. Absent a strong regulatory signal, industry is likely to pursue lower cost plant designs with higher carbon emissions. Furthermore, the lack of private incentives often creates resistance to new technologies, preventing the learning-by-doing effects that decrease unit cost with commercial experience.[46] However, there are a number of technologies that can reduce CO_2 emissions from a variety of coal plant designs.

While CO_2 can be controlled from any coal technology at this time, costs vary widely based on the energy and capital required to do so, a direct product of plant design. The energy penalty incurred from the carbon capture and storage (CCS) process arises from the effort required to both capture a pure stream of CO_2 from its surroundings, and to then compress it to a high enough degree for transport and storage. Since the transport and storage costs are the same for a high-pressure, pure stream of CO_2 whether produced at a PC or an IGCC plant, we need only compare the separation and compression challenges among available coal technologies.

Gasification, as previously described, can capture CO_2 prior to combustion, when pressures and CO_2 concentration are high, resulting in an energy penalty of around 15%. Natural gas combined cycle or pulverized coal CCS incurs energy losses in the 25-40% range, though advances in technology achieve better performance.[47] This is largely a result of lower flue gas CO_2 concentrations, and so a more expensive catalyst process must be used (often MDEA or other catalysts that are currently used to clean acid gas). The cost effects are shown in Figure 11, based on a 2005 Electric Power Research Institute projection of future electricity costs for plants built in 2010 and 2020.[48] Technical data is reported in Appendix B.

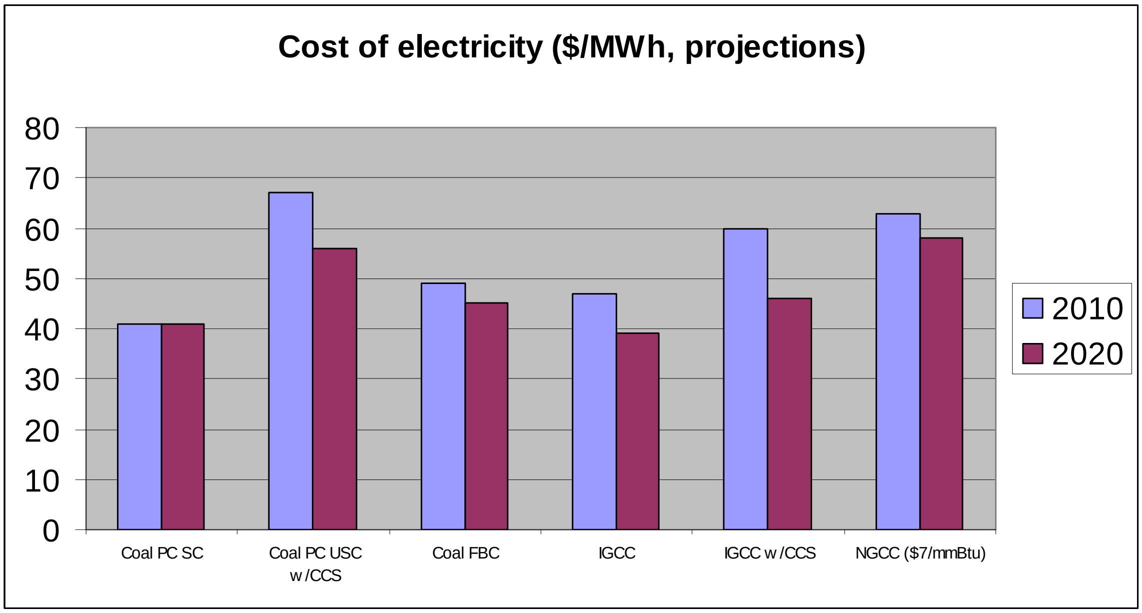


Figure 11: EPRI cost of electricity projections[49]

EPRI also projects carbon dioxide emissions levels for the technologies in question (Figure 12). Advanced ultrasupercritical designs, when coupled with the best post-combustion carbon capture technologies, should produce the lowest CO_2 emissions levels. However, the assumptions used in the EPRI analysis imply a much more comprehensive carbon capture system than is commonly discussed for coal plants. Many post-combustion CCS systems often rely on expensive catalyst scrubbers to remove CO_2 from the exhaust stream. By adding more and more of the catalyst, you can reduce more and more of the CO_2 output. While this option is attractive from a carbon management perspective, the cost premium involved makes it less optimal for any new plants being build. As shown in Figure 11, total electricity costs for coal plants with CCS are cheapest using IGCC, which has the additional benefit of lower non-carbon pollutants.

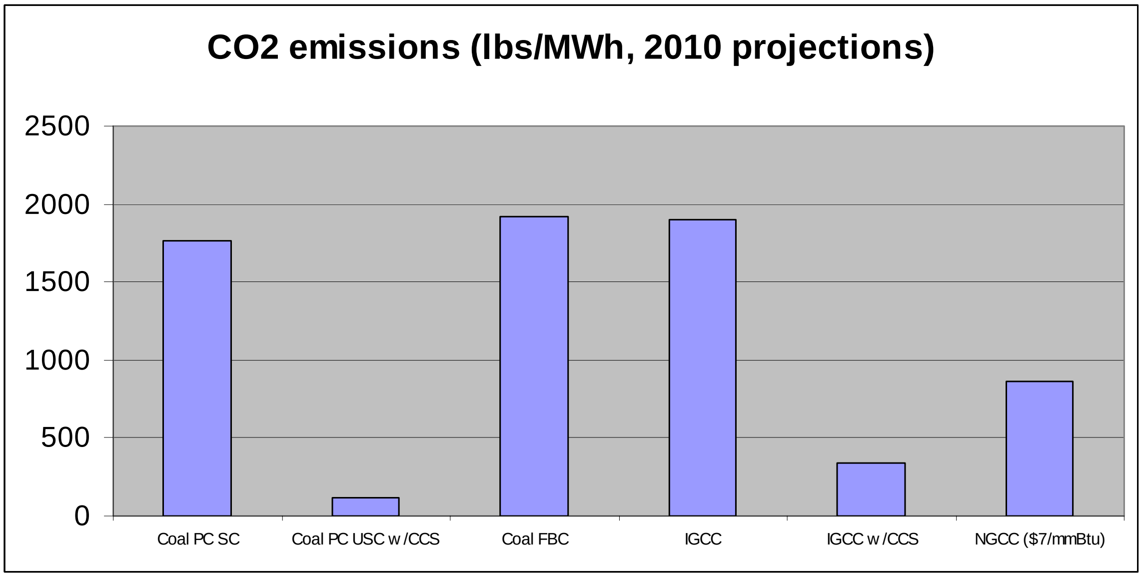


Figure 12: EPRI analysis of CO2 emissions[50]

Whatever the technology platform, carbon capture will raise the price of electricity. A recent Pew Center on Climate Change report suggests that a successful carbon capture regime implementing coal-based IGCC with permanent storage would have a relatively modest price impact of 2-4 cents per kilowatt-hour.[51] Confirming this range, a 2005 Natural Resources Defense Council analysis looked at the cost premium for IGCC with CCS relative to a supercritical coal plant venting its CO_2, 2.4 cents/kWh for bituminous coal, and 2.8 cents/kWh for subbituminous coal, including a $7/ton CO_2 disposal cost.[52]

While an additional 2.4-2.8 cents/kWh is certainly expensive relative to a non-CCS scenario, IGCC remains the cheapest option available today for low-carbon fossil energy. Coupling CCS to pulverized coal plants might add as much as 4.5 cents/kWh, relative to the CO_2 venting option with the same technology.[53] Estimates for natural gas capture costs are out of date, as much of the cost of capture arises from the energy penalty incurred by CCS. Most studies were completed with gas prices of $3-5/mmBtu.[54] However, current prices have trended significantly higher, with similar prices in the futures market. If natural gas prices stay above the $3-5/mmBtu level, NGCC CCS costs should increase as well. The Electric Power Research Institute report cited in the figures above puts NGCC without CCS at $60/MWh at a $7/mmBtu gas price.[55]

When comparing coal and natural gas prices, the key factor to note is that the price of electricity is heavily dependent on capital costs for coal projects, and gas prices for NGCC. Table 2 shows capital cost data from an American Electric Power white paper filed in Ohio as part of a proposal to construct a non-CO_2 capture IGCC plant.

Table 2: Price comparison for new fossil generation (bituminous coal)[56]

	w/out CCS			w/CCS	
	IGCC	PC	NGCC	IGCC	PC
Net MW	600	600	600	530	460
Heat Rate (Btu/kWh)	8700	8690	7200	10700	11300
Total Plant Cost ($/kW)	1550	1290	440	1950	2150

The choice of bituminous coal for most price estimates reflects the current consensus that gasification is cheaper and easier using a feedstock with higher energy content. Subbituminous coals have more moisture and ash per unit of weight, and the gasification process used by GE and others is more energy intensive with this coal composition. The perception that subbituminous coal is less desirable for gasification is at least partly based on the fact that today’s operating coal-based IGCC plants run on bituminous coals, and often petroleum coke. However, new technologies and operation experience, including low-grade gasifier designs proposed by Shell and KBR, might change the current standing.

Either way, concern over fuel supplies should not be a barrier to IGCC development in the Western United States. Although bituminous coal is found primarily in the Eastern and Midwestern states, there are additional resources in the West as well.[57]

CO_2 Sequestration

Although the concept of controlling GHG emissions via geologic storage sounds like a new idea, in reality it is not. Research dating to the 1950s has considered the notion, and since that time, many have put it into practice. CO_2 capture has been used for decades in the food industry, and there has been over 20 years’ experience in CCS for enhanced oil recovery (EOR). Over 30 million tons of CO_2 were sequestered for EOR in 2001.[58] This includes the 1.0 million tons per year sequestered by Statoil at the Sleipner gas fields in Norway, and will expand with such additions as BP’s plan to sequester 0.8 tons/year at In Salah, Algeria.[59]

While it is true that CCS is not widespread in its use – 30 million tons is an insignificant fraction of global GHG emissions – the situation appears to be an economic challenge, and not a technological one. In fact, the United States is a leader in CCS technology, accounting for 72 of 84 projects in 2000.[60] The potential reservoirs are heterogeneous and large, although regulatory and monitoring procedures are highly uncertain and a necessary area for future research.[61] Table 3 shows estimates of possible storage locations and sizes.

Table 3: Worldwide capacity of terrestrial CO_2 storage sites[62]

Sequestration option	Worldwide capacity, Gigatons CO2
Deep Saline Formations	100s-1000s
Depleted Oil and Gas Reservoirs	100s-1000s
Coal Seams	10s-100s
Industrial applications (including oil recovery)	<1 GT/yr

Beyond the use of CO_2 for enhanced oil recovery, various other industrial processes employ underground CO_2 storage. For example, Canadian firms injected nearly 200 million cubic meters of acid gas, comprised of CO_2 and H_2S, into more than 30 locations in 2001.[63] Acid gas storage has become a popular alternative to sulfur recovery or flaring in Western Canada, and since CO_2 composition approaches 90% of total volume, it represents significant experience in geologic storage.

Coal gasification has also demonstrated the ability to use carbon capture and storage. The Great Plains Synfuel Plant in North Dakota captures around 7 million cubic meters of CO_2 each day, from a lignite fuel source. The captured gas is compressed and piped 325 km to the Weyburn, Saskatchewan, oil field for enhanced oil recovery.[64]

Finally, the issue of long-term CO_2 reservoir security is a complicated question, beyond the scope of this analysis. Many academic and industry centers are researching the problems of leakage and safety, which are, although by no means resolved, potentially worthwhile tradeoffs. According to the United States Energy Information Administration, the electric power sector accounts for 33% of national CO_2 emissions. Coal plants contribute 82% of that effect, or 27% of national emissions. Confronting the existing coal fleet – to say nothing of the proposed additions – will require serious consideration of long-term CO_2 storage in addition to aggressive efficiency and renewable energy programs.

4. IGCC Operational Experience

Gasification itself is a fully mature commercial technology, though coal-based power production is relatively new. A 2004 survey done for the U.S. National Energy Technology Laboratory found that existing worldwide gasification includes some 385 gasifiers at a capacity exceeding 45 GW_{th}.[65] This number does not include proposed projects in the U.S. and around the world. The bulk of existing gasifiers are used in the chemical industry, though a smaller subset produce electricity for external sale. Furthermore, coal is a proven feedstock, with 180 coal-based gasifiers accounting for over 22 GW_{th} of capacity.[66] And, very relevant to the prospect of IGCC with Western US coal, there are 121 gasifiers rated at 16.6 GW_{th} operating today on subbituminous coal or lignite.[67]

According to the National Energy Technology Laboratory, there have been a total of six large-scale IGCC plants built to run on coal or petroleum coke.[68] The first generation IGCC plants, Texaco's Cool Water facility and Dow Chemical's LGTI, have since been closed or depowered. Both ran successfully for extended periods on subbituminous coals. When blended with petroleum coke, subbituminous gasification resembles bituminous gasification emissions and costs.

The second generation coal-based IGCC fleet consists of four plants operating around the world.[69] Two are located in the U.S., and two in Europe. The size and technology choices are summarized in Table 4, below.

Table 4: Operating IGCC plants[70]

Project/location	Combustion turbine	Gasification technology	Net output (MW)	Start-up date
NUON, Buggenum Netherlands	Siemens V 94.2	Shell (partnered with Krupp-Uhde)	253	Jan. 1994
Cinergy, Wabash River, Indiana	GE 7 FA	E Gas (ConocoPhillips)	262	Oct. 1995
Tampa Electric, Tampa, Florida	GE 7 FA	Texaco (GE Energy)	250	Sept. 1996
ELCOGAS, Puertollano, Spain	Siemens V 94.3	Prenflo (partnered with Shell)	300	Dec. 1997

In the United States, there has been no new construction of IGCC facilities since the mid-1990s. Most of these earlier IGCC projects received significant US Department of Energy support, frequently including 50/50 financing and operational support. But a third generation of IGCC is in the works, with some privately financed proposals,[71] and a second round of support from the DOE Clean Coal Technology Program. Financial awards from this federal program will support the construction of Southern Company's 285MW air-blown IGCC plant in Florida as well as a Mesaba Energy 531 MW IGCC facility in Minnesota.[72] The latter plant will be financed primarily with private funds, as the DOE is covering only $36 million of the projected $1.185 billion total.[73] American Electric Power has also committed publicly to building one or more IGCC plants by 2010.[74]

Worldwide, there is additional IGCC experience with non-coal fuels. Approximately eight IGCC plants are running on petroleum residuals, with three more under construction.[75] Some 1500 MW of petroleum residual IGCC facilities have been built in the last few years in Italy.[76] These plants will provide significant construction and operational experience with many of the components needed in coal-based IGCC, including the ASU and sulfur recovery mechanisms. In addition, at least 8 gasification plants using Shell technology have been proposed in China, scheduled to start over the years 2005-2007.[77] While these plants are designed for ammonia production – as opposed to electrical generation – they represent a serious investment in gasification technology from a key developing nation.

The magnitude of this experience suggests that barriers to widespread IGCC do not come from the basic process of gasification. In fact, there is no specific technological hurdle preventing the expansion IGCC; rather, technological improvements are likely to drive an improvement in the economic challenges facing IGCC. One area of interest is in the operating availability of IGCC. In general, chemical production is less tied to specific availabilities – from a manufacturing point of view, it doesn’t matter when the plant is running during a given week, just that it is running a certain percentage of the time.

Power producers face the additional hurdle of needing their plants online when electricity is demanded. Major concerns about the reliability of the gasifier unit have driven some companies to consider buying a spare gasifier (in addition to the typical commercial designs of 2-4 units, not including this extra capacity).[78] With a spare unit, availabilities improve, at the expense of additional capital. At the Eastman Kodak chemicals facility in Tennessee, the spare gasifier has kept the plant at over 98% availability since the mid-1980s.[79] That facility also estimates that it could run on a single gasifier at 88-90% availability,[80] well above the range required by most baseload electric generation. On-site storage of syngas could assist in making electricity generation possible during periods of gasifier breakdown.

Although the apparent need for a spare gasifier resembles a technical barrier, it is in fact an economic question. And while technological improvement will no doubt affect the economics of gasification, commercialization of IGCC will largely depend on corporate guarantees that develop in the next few years. In previous decades, IGCC was literally a homemade design, with the gasifier coming from one company, and the power block from another. Now, the major gasifier manufacturers have aligned themselves with complimentary companies so that IGCC designs are obtained from a stable partnership (for example, General Electric, Texaco Gasification and Bechtel have formed a corporate alliance).[81]

5. IGCC Barriers and Policy Recommendations

The challenges of IGCC development are twofold. First, IGCC faces the “chicken-and-egg” problem shared by most new technologies. Absent a proactive regulatory structure, private investors are unlikely to back projects until the technology is proven. And until billions of dollars flow into the technology, that perception is unlikely to change.

Compounding this issue is the chemical engineering approach IGCC takes to power production. As it stands now, the coal industry is largely a water boiler industry. In most of these systems, thermal combustion creates steam to drive a turbine. On the other hand, gasification is more analogous to oil refining, and requires a different skill set. The energy industry will need to address this human resources question for large-scale adaptation of IGCC.

The final push for economic maturity will also require leadership at the regulatory and corporate levels. In addition, the Federal Energy Policy Act of 2005 provides $800 million for IGCC and $350 million for industrial gasification, metered in 20% investment tax credits.[82] It also promises cost-share grants of $1.26 billion for gasification demonstration through the DOE Clean Coal Power Initiative, as well as $2.5 billion for gasification and other advanced combustion technologies under the Clean Air Coal Program.[83] A third major policy found in the bill is the adoption of the Harvard 3-Party Financing concept,[84] in which the Federal Government provides 80% loan guarantees to IGCC projects, dropping the cost of electricity around 20%.[85] Benefits for coal gasification go so far as to carve out money specifically for a western coal project at elevation, bringing the total Federal aid into the neighborhood of $20 billion.[86] Federal support was not assumed in any of the cost numbers provided in this paper, so the comparative economics only improve with the scale of these incentives.

In the end, gasification clearly outperforms all other coal options along emissions and cost grounds. Regulators and companies now have the option to produce electricity with the lowest emissions of any fossil fuel process, making IGCC a viable and preferable alternative to pulverized coal where new generation is required. Worldwide and domestic experience provides the foundational knowledge and cost reductions needed for commercial development. Federal tax aid should remove any remaining financial hesitancy on the part of utilities.

From a carbon perspective, IGCC is likely to remain the only affordable way to implement CCS for years to come. If net electricity consumption is to grow, there is no other non-renewable technology capable of addressing GHG emissions in a fiscally responsible manner. This is particularly important in key developing countries with large coal reserves, like China. Technological maturation in the U.S. could become the springboard for future bilateral agreements targeted at reducing the impacts of projected emissions growth throughout the world.

Finally, because IGCC is capable of making significant reductions in local pollution as well, regulators should consider establishing it as the “best available control technology” (BACT) for coal.

Appendix A: Coal and Natural Gas Emissions

Criteria	Subbituminous conventional	Subbituminous supercritical	Subbituminous IGCC	Subbituminous IGCC w/CCS	Bituminous supercritical	Bituminous IGCC	Bituminous IGCC w/CCS	State-of-the-art NGCC
Sulfur dioxide	1.15	0.77	0.0090	0.0103	1.33	0.25	0.28	0.0041
Nitrogen oxide	0.67	0.54	0.22	0.2530	0.62	0.57	0.66	0.062
Mercury	1.62E-05	1.30E-05	6.30E-06	7.2450E-06	9.7E-06	4.7E-06	5.37E-06	0
Carbon dioxide	2025	1627	1678	193	1823	1684	194	807

All units (lbs/MWh)

Sources:

Subbituminous conventional	Northwest Power and Conservation Council, Fifth Power Plan, Appendix I. May, 2005. Online at: http://www.nwcouncil.org/energy/powerplan/plan/Default.htm. Mercury controls added per Iowa supercritical specifications below.
Subbituminous supercritical	Iowa DNR Operating Permit, Air Quality PSD Construction Permit, Council Bluffs Plant No. 78-01-026
Subbituminous IGCC	Northwest Power and Conservation Council, with original mercury estimates based on NETL Original SO2 calculations assume 99.8% removal of 0.5% sulfur by weight PRB coal at 8800 Btu/lb
Bituminous supercritical	Wisconsin DNR Emissions Permit, WE Energies Elm Road Generating Station, 2004.
Bituminous IGCC	Wisconsin DNR Emissions Permit, WE Energies Elm Road Generating Station, 2004.
Natural gas combine cycle	California Energy Commission Decision, Calpine Metcalf Energy Center, 2001. Docket 99-AFC-3.
Coal CO_2 emissions	Energy Information Administration, Quarterly Coal Report, January-April 1994. Online at http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html
Natural gas CO2 emissions	Energy Information Administration, Emissions of Greenhouse Gases in the United States 1987-1992.
Carbon capture assumptions	15% energy penalty for IGCC (heat rates scaled to adjust non-CO_2 emissions)

Control Technologies Used

	Low NO_x burners	Flue gas de-sulfurization	Selective catalytic reduction (SCR)	Fabric filter baghouse	Activated charcoal (carbon) filter	Activated carbon injection	Electrostatic precipitators	Combustion diluent	IGCC sulfur stripping unit
Subbituminous conventional	x	x		x	x	x			
Subbituminous supercritical	x	x	x	x		x			
Subbituminous IGCC					x				x
Bituminous supercritical	x	x	x	x			x		
Bituminous IGCC					x			x	x
Natural gas combined cycle	x		x						

Heat rates	**(mmBtu/MWh)**				
Subbituminous conventional	Subbituminous supercritical	Subbituminous IGCC	Bituminous supercritical	Bituminous IGCC	Natural gas combined cycle
9.550	7.675	7.915	8.862	8.187	6.9

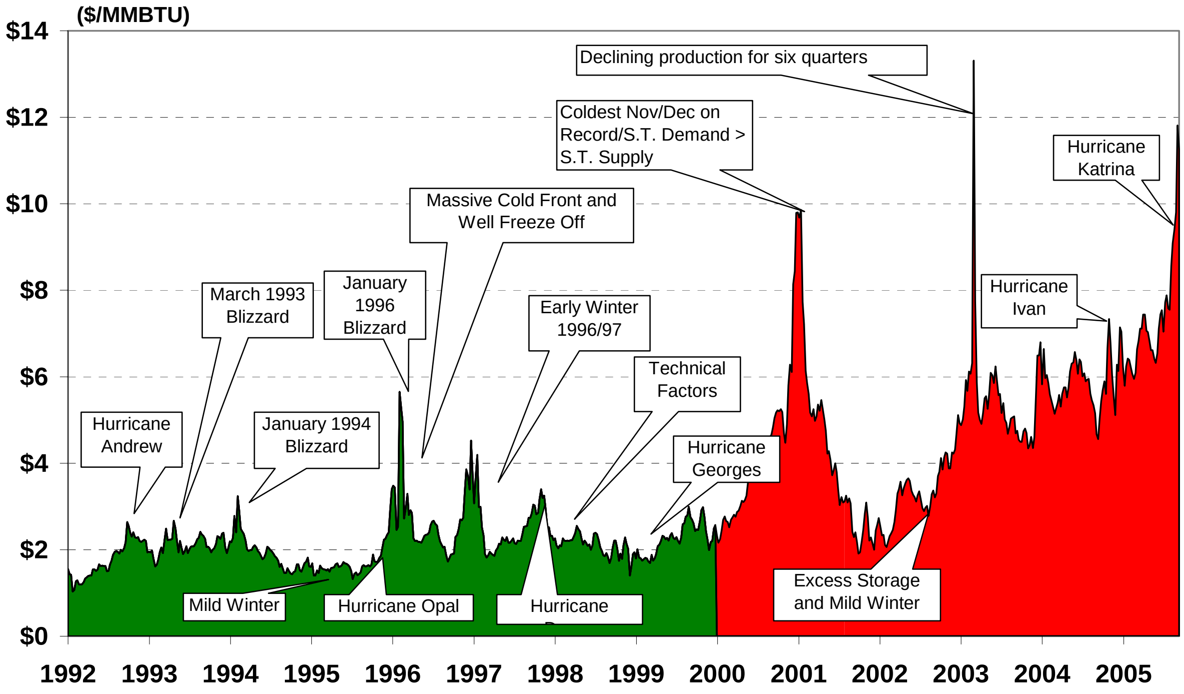
CO2 emissions rates	**(lbs/mmBtu)**	
Bituminous	Subbituminous	Natural gas
205.7	212	117

Appendix B: Cost of Electricity Technical Data

Technology	Cost of electricity 2010 ($/MWh)	Cost of electricity 2020 ($/MWh)	CO2 emissions 2010 (lbs/MWh)
Coal PC SC	41	41	1764
Coal PC USC w/CCS	67	56	115
Coal FBC	49	45	1918
IGCC	47	39	1896
IGCC w/CCS	60	46	344
NGCC ($7/mmBtu)	63	58	860

Source: EPRI, 2005. "Making Billion Dollar Advanced Generation Investments in an Emissions-Limited World." EPRI Summer Seminar, August 8-9, San Diego, CA.

HENRY HUB NATURAL GAS PRICE WEEKLY DATA



Source: NGW and EVA, Inc.

Source: "Generation Technologies in a Carbon-Constrained World." EPRI Energy Assessment Brief, October 2005.

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[6] In California, procurement rules require power projects to include a price for the financial risk of carbon, currently set at $8/ton, escalated at 5% per year. A later section evaluates these effects and compares the costs of IGCC and natural gas, the traditional alternative to coal generation on CO_2 grounds (again, where efficiency and renewables do not suffice).
[7] In this case, "capture-ready" indicates that the estimate for IGCC w/CCS includes all the capital and operating costs associated with CCS, but does not account for the CO_2 disposal cost. This missing factor could range as high as $7/ton CO_2, adding ~$5/MWh, but the CO_2 might also be sold for profit to enhanced oil recovery fields. For a more detailed analysis of "capture-ready", see Stephens, Jennie, "Coupling CO_2 Capture and Storage with Coal Gasification: Defining 'Sequestration-Ready' IGCC", BCSIA Discussion Paper 2005-09, Energy Technology Innovation Project, Kennedy School of Government, Harvard University.
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[74] Mudd, *supra* 18. AEP announcement online at: http://www.aep.com/about/igcc/default.htm.

[75] *Id*.

[76] Power-technology.com. “ISAB Energy IGCC Plany, Italy.” Online at: http://www.power-technology.com/projects/isab/. The shrinking market for high-sulfur heavy oils is an open niche for IGCC technology, and was a driver in the private development of these plants.

[77] *Id*.

[78] See, for example: Sturm, Karl V., Ciki Liaw and Pradeep S. Thacker. “Beyond the 2002 ChevronTexaco Coal IGCC Reference Plant.” ChevronTexaco presentation at the 2003 Gasification Technologies Conference. Online at: http://www.gasification.org/Presentations/2003.html.

[79] Denton, *supra* 32.

[80] *Id*.

[81] General Electric Energy, 2004. “GE Energy, Bechtel Announce Alliance for Cleaner Coal Projects.” Press release. Online at: http://www.gepower.com/about/press/en/2004_press/100404.htm.

[82] Rosenberg, William G. “Energy Policy Act of 2005 – Gasification Opportunities for the Western U.S.” Presented at the California Energy Commission Committee Workshop on Clean Coal Technology and Electricity Imports, August 18, 2005. Online at: http://www.energy.ca.gov/2005_energypolicy/documents/2005-08-17+18_workshop/presentations-081705/

[83] *Id*.

[84] Rosenberg, William G., Dwight C. Alpern, and Michael R. Walker. *Deploying IGCC in This Decade with 3Party Covenant Financing: Volume I*. Cambridge, MA: Belfer Center for Science and International Affairs, Kennedy School of Government, Harvard University, July 2004.

[85] Rosenberg, *supra* 82.

[86] *Id*.