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Future Electricity Generation: An Economic and Environmental Life Cycle Perspective on Near-, Mid- and Long-Term Technology Options and Policy Implications

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A Dissertation by

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Abstract

The U.S. electricity industry is currently experiencing and adapting to enormous change including concerns related to security, reliability, increasing demand, aging infrastructure, competition and environmental impacts. Decisions that are made over the next decade will be critical in determining how economically and environmentally sustainable the industry will be in the next 50 to 100 years. For this reason, it is imperative to look at investment and policy decisions from a holistic perspective, i.e., considering various time horizons, the technical constraints within the system and the environmental impacts of each technology and policy option from an economic and environmental life cycle perspective.

This thesis evaluates the cost and environmental tradeoffs of current and future electricity generation options from a life cycle perspective. Policy and technology options are considered for each critical time horizon (near-, mid-, and long-term).

The framework developed for this analysis is a hybrid life cycle analysis which integrates several models and frameworks including process and input-output life cycle analysis, an integrated environmental control model, social costing, forecasting and future energy scenario analysis.

The near-term analysis shows that several recent LCA studies of electricity options have contributed to our understanding of the technologies available and their relative

environmental impacts. Several promising options could satisfy our electricity demands. Other options remain unproven or too costly to encourage investment in the near term but show promise for future use (e.g. photovoltaic, fuel cells). Public concerns could impede the use of some desirable technologies (e.g. hydro, nuclear). Finally, less tangible issues such as intermittency of some renewable technologies, social equity and visual and land use impacts, while difficult to quantify, must be considered in the investment decision process.

Coal is a particularly important fuel to consider in the U.S. and is the main focus of this thesis. A hybrid life cycle analysis including the use of process level data, Economic Input-Output Life Cycle Assessment (EIOLCA) and the Integrated Environmental Control Model (IECM) quantify a range of potential impacts for new power plants. This method provides a more complete and consistent basis for comparing different technologies. While Integrated Coal Gasification Combined Cycle (IGCC) technology has clear environmental benefits for bituminous coals over conventional pulverized coal plants, the advantages are less clear for the lower ranked coals at present. Near-term implementation of this technology is hampered by concerns about its reliability and performance. A full scale U.S. installation of this technology would settle the performance concerns while more stringent emissions standards would increase its value.

In the mid-term analysis, this thesis explores alternative methods for transport of coal energy. A hybrid life cycle analysis is critical for evaluating the cost, efficiency and environmental tradeoffs of the entire system. If a small amount of additional coal is to be shipped, current rail infrastructure should be used where possible. If entirely new infrastructure is required, the mine mouth generation options are cheaper but have increased environmental impact due to the increased generation required to compensate for transmission line losses. Gasifying the coal to produce methane also shows promise in terms of lowering environmental emissions.

The long-term analysis focuses on the implications of a high coal use future. This scenario analysis focuses on life cycle issues and considers various generation and control technologies. When advanced technologies such as gasification with carbon capture and sequestration are used, emissions during generation decrease to a level where environmental discharges from extraction, processing and transportation become the dominant concern. The location of coal, coal composition and mining method are important in determining the overall impacts.

Coal is an inherently dirty fuel. However, for the next half century, coal is likely to play a major role in electricity generation. In deciding how much coal to use, the U.S. must understand the cost and environmental implications of the technologies available, including the whole life cycle of the fuel and the facilities used from extraction, transport, generation, and use or disposal of by products.

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Chapter 1: Introduction

1.1 Motivation

The electricity industry is arguably the most polluting industry in the U.S. economy. However, it is critical to modern society. Many decisions must be made over the next several decades about continued operation of existing generation and investment in new generation. The industry does not currently evaluate investments from a life-cycle perspective. However, life-cycle environmental impacts must be considered in order to understand the true environmentally preferred solutions. Further, these impacts must be integrated into economic considerations to ensure these solutions are relevant to the industry.

This thesis addresses several key policy questions facing the electricity industry today. The framework proposed in this thesis focuses on three time horizons (near-term is less than 10 years, mid-term is 10 to 25 years, and long-term is 25 to 50 years).

Near-Term

- What technologies exist today and how do policies, costs and impacts affect preferences for these technologies?
- What can be done to decrease the impact of current operations?

Mid-Term

- Are there opportunities in the near- to mid-term to improve efficiency and environmental impacts of new infrastructure investments and use? Specifically, are there alternatives to shipping coal by rail that improve the costs and/or environmental impacts?

Long-Term

- What would a future of high coal usage look like?
- How do choices in planning affect the impacts of this increased use?

The only hydrocarbon fuel in which the U.S. has hundreds of years of reserves at current prices is coal. Currently, more than 50% of electricity is generated from coal. While many future energy scenarios are possible, coal is likely to play a large role for at least the next half-century, barring significant technological changes and large hydrocarbon discoveries. Advanced generation technologies can decrease air pollution emissions significantly, and even capture and sequester CO_2. Thus, while the future is uncertain, it is prudent to investigate the possible life cycle impacts of a high coal use future. Since coal is a non-renewable resource and currently causes large environmental damage due to mining, transport, and electricity generation.

Uncertainty about the price and availability of other fuels make their future contributions uncertain. For example, natural gas is an environmentally desirable fuel, but competition for use and uncertain prices make it’s future use in this industry uncertain. Expanding nuclear power is hampered by public opposition, high cost, lack of closure of the life cycle, and security concerns. Major expansion in hydroelectric output is unlikely because of environmental opposition and prior development of the best sites. Many renewable technologies are not yet economically competitive and their inability to supply power when needed raises cost and makes them less attractive. However, the potential for these technologies to contribute in the future shows promise.

1.2 Life Cycle Impacts of Electricity

The demand for electricity has grown more rapidly than that for other forms of energy because of its cleanness (in the use phase), high quality, and use in motors and electronics. However, electricity generation is perhaps the most polluting industry. Table 1.1 shows some of the environmental discharges from the $250 billion per year electricity industry in 2002 (EIA, 2003d), as well as from the rest of the life cycle of producing this electricity (CMU, 2005). Of the 14 million tons of SO_2 emitted during the life cycle, 99% came from the electric power industry. In contrast, only 26% of the 233,000 tons of volatile organic carbon (VOC) emissions came from the generation phase. Essentially all of the hazardous waste reported under the Resource Conservation and Recovery Act (RCRA) came from the rest of the life cycle. The total mass of emissions is dominated by the 2.6 billion tons of CO_2 equivalent greenhouse gas emissions from direct generation. The emissions from this industry are 22% of U.S. NOx emissions, 9% of U.S. $PM_{2.5}$ emissions, or 3% PM_{10} emissions, 67% of U.S. SO_2 emissions (EPA, 2001) and 33% of U.S. CO_2 emissions (EPA, 2003). Even beyond the conventional air pollutants, the industry emits 80 tons of lead, and the life cycle is responsible for an additional 63 tons. Although large, these emissions reflect considerable progress in increasing the efficiency of electricity generation and reducing environmental discharges.

Environmental Emissions From U.S. Electricity Generation in 2002 (short tons)				
	Direct Electricity Generation Emissions	Indirect Electricity Generation Emissions	Total Emissions	% of Emissions from Direct Generation
Global Warming Potential (CO_2e)	2,600,000,000	170,000,000	2,770,000,000	94
SO_2	14,000,000	100,000	14,100,000	99
CO	691,000	749,000	1,440,000	48
NO_x	6,330,000	350,000	6,680,000	95
PM_{10}	296,000	53,000	349,000	85
VOC	61500	171,500	233,000	26
Lead	80.4	62.6	143	56
RCRA Haz Waste generated	0	5,260,000	5,260,000	0
Toxic Air Releases	440,000	7,000	447,000	98
Toxic Water Releases	2350	2,680	5,030	47
Toxic Land Releases	161000	44,000	205000	78
Toxic Underground Releases	0	2,600	2600	0

Table 1.1 Environmental Emissions from Electricity Generation in the U.S. 2002
(Source: CMU, 2005, EIA 2003d)

The life cycle analysis (LCA) framework has been used to assess the environmental impacts associated with every stage of the production of electricity, from extracting ore to final disposal of unwanted residuals since the 1970's. The literature shows considerable variation among studies due, in part, to the differences in the scope, boundary, technologies and fuels considered. These differences will be explored throughout chapters 2 and 3.

A hybrid life cycle comparative analysis (LCA) framework is an appropriate tool to assess the economic and environmental impacts associated with every stage of the production of electricity. This method combines the benefits of the EIOLCA (Economic Input-Output Life Cycle Analysis) (Hendrickson, et al., 1998) method with those of the traditional Society of Environmental Toxicology and Chemistry (SETAC)/ U.S. Environmental Protection Agency (EPA) approach (SETAC, 2004). The cost and environmental impact data available at a national, aggregated level (by industrial sector) is used in conjunction with a product analysis of more sensitive parameters that are not well represented by the national average data.

Some of the most important and sensitive parameters in an analysis of power generation systems are from the generation phase. Coal composition, generation and control technologies are some of the key assumptions where average data can lead to results that are not representative of a large fraction of generation that occurs. A simulation model, "Integrated Environmental Control Model" (IECM, 2004), improves the life cycle analysis of power generation systems since it allows the examination a wider range of coals and generation technologies than are in the published life cycle literature. A power plant can be built "virtually" using this model to specifications such as the fuel type, control technologies, and boiler type. The output from this model includes efficiency, capital and maintenance costs, waste products, as well as the stack emissions.

1.3 Future Energy Scenarios

A review of literature on the development and application of energy planning models can be grouped into three general categories of studies. The first is world energy forecasting to 2050 and beyond. This includes studies that were conducted by the International Institute for Applied Systems Analysis and the World Energy Council (Nakicenovic et al., 2002), International Energy Agency (IEA,2000) and others (Smalley, 2003; Skov, 2003; ERAG, 2001; Bauquis, 2003) where a wide range of energy technologies were modeled at an aggregate level. These are generally large projects that investigated a wide range of scenarios. The IIASA/WEC study found that the final energy demands of each scenario can be satisfied by a wide range of energy resource mixes. This is expected to be the same in the U.S. however; limits (both technical and political) make some resources mixes more plausible than others. Understanding how the rest of the world is forecast to change will inform the current analysis. For example, learning rates in the U.S. can be accelerated by R&D and deployment in other countries.

The second category of studies is U.S. focused and technology/fuel specific. This includes studies conducted at Oak Ridge National Laboratory (Delene, 2001), a study on the impacts of photovoltaics at Brookhaven (Fthenakis, 1998) and others (Beecy, 2002; Moniz, 2003; Margolis, et al. 2004).

The third category of studies is U.S. comprehensive studies with a mid-term analysis horizon (projections to 2025-2030). These studies are generally comprehensive and detailed technical assessments (Demeo, 1997; Zweibel, 2000) or broad energy scenarios (Berry, 2002). However, many of these studies are based on the Energy Information Administration (EIA) projections in the Annual Energy Outlook (AEO) report (EIA, 2004a) and therefore tend to take a conservative view of structural changes within the industry. Most models that have mid-term planning horizons do not include resource depletion since it is not considered a critical issue through that point. However, most studies predict that conventional oil and gas depletion will be an issue after this point (Greene, 2001). Therefore, care must be taken when constructing simple trend projections of technology deployment from current rates. In a review of energy forecasts for the period 1950 – 1980, it was found that forecasters consistently underestimated the importance of uncertainties and surprises (Craig et al., 2002).

A comprehensive U.S. focused study that projects technologies, costs and efficiencies of increased coal use within a long-term planning horizon that also considers the life cycle implications has not been found to-date. This thesis hopes to bridge the gap between life cycle analysis and energy planning models.

Since coal is likely to be a major fuel for generating electricity for at least the next half-century, the cost and the life cycle externalities associated with coal use (safety, and emissions of CO_2, SO_2, and NO_x) are examined. A future with high coal usage raises serious environmental concerns, since coal generates much more pollution than other fuels. A base case of current electricity growth and a constant 50% market share for coal with high growth in 2050, is contrasted with high coal usage scenarios with, and without, carbon separation and sequestration in 2050. Finally, a scenario in which natural gas, the cleanest fossil fuel, with, and without, carbon separation and sequestration generates 80% of electricity is considered.

1.4 Outline of Thesis

The thesis is comprised of 6 chapters. This first chapter introduces the motivation for the research and describes the objectives of the thesis.

The second chapter critically reviews recent LCA studies of electricity. The variations between the studies and the technologies considered are compared and evaluated. This chapter focuses on the technologies previously available and those available today. This helps to contrast the different fuel and technology options if new generation capacity was built today.

Coal is particularly important since it generates more than half of electricity in the U.S. and is the most polluting of the fuels. Chapter three delves more deeply into coal fired electricity generation. Current technologies and those available in the near term are compared. A main focus in this chapter is the impact of environmental control technologies on current generation facilities compared to the technologies that might be available in the next decade. This is both in terms of cost, efficiency and environmental emissions.

Chapter four evaluates alternative methods for transporting coal energy. The U.S. mines over one-billion tons of coal each year (EIA, 2004c). Coal shipments represent more than a half trillion ton-miles each year, since coal deposits are distant from population and demand. This transport requires large amounts of energy, generates pollution emissions, and results in the death of about 400 people each year at rail crossings (calculated from BTS, 2002). Rail systems are costly to build and maintain; shipping coal by rail constitutes the majority of the cost of delivered Powder River Basin (PRB) coal. Alternatives considered in this analysis include transmission, gas pipeline, as well as coal slurry pipeline and barges. These systems were compared on a life cycle basis in terms of cost, efficiency and environmental impact.

While much has been done in the field of LCA of electricity and the area of future energy scenario analysis, the two have rarely been the focus of analysis. Several tools are available to conduct the analysis in both of these areas. However, the use of these tools in an integrated fashion expands the scope of the analysis.

Chapter five considers several future scenarios to evaluate the implications of high coal usage. Increased use of coal raises serious environmental concerns, since coal generates much more pollution than other fuels. Several scenarios for future coal use are developed and compared.

The sixth chapter draws insights from the research in this thesis and briefly discusses future work.

Chapter 2: Near-Term Environmental Discharges from Various Technologies for Electricity Generation: A Life Cycle Approach

2.1 Introduction

The life cycle analysis (LCA) framework has been used to assess the environmental impacts associated with every stage of the production of electricity, from extracting ore to final disposal of unwanted residuals since the 1970's. The literature shows considerable variation among studies due, in part, to the differences in the scope, boundary, technologies and fuels considered. This paper steps through the life cycle of the main fuels and technologies. I examine the life cycles of each fuel and technology and compare the results.

Transmission, distribution, and use of the electricity are neglected in this chapter. However, it should be noted that the environmental impacts of transmission and distribution can be significant and different depending on where the plant is located in relation to the source of energy and the demand for electricity. This issue is explored in chapter four.

The performance of current plants is reasonably well documented. Although technology is advancing rapidly in some areas, the performance of technologies that are under development is speculative, and so I focus on known technologies in this chapter.

2.2 Costs

The capital and O&M costs of several central station generation technologies are shown in Figure 2.1. These costs were calculated from DOE estimates (EIA, 2004b) assuming capacity factors (NREL, 2002), plant lifetimes (Roth, 2004) and fuel prices (EIA, 2005b). Current natural gas prices ($5.60/million BTU) make the gas technologies much less competitive, despite their low capital costs. These estimates take into account the contingency and technological optimism factors assumed by the DOE. However, these costs reflect the private generation cost only. They do not capture the additional infrastructure required to connect the source of the generation to the consumer or the costs associated with backing up intermittent sources, nor do they capture the environmental externalities and other social costs of generation.

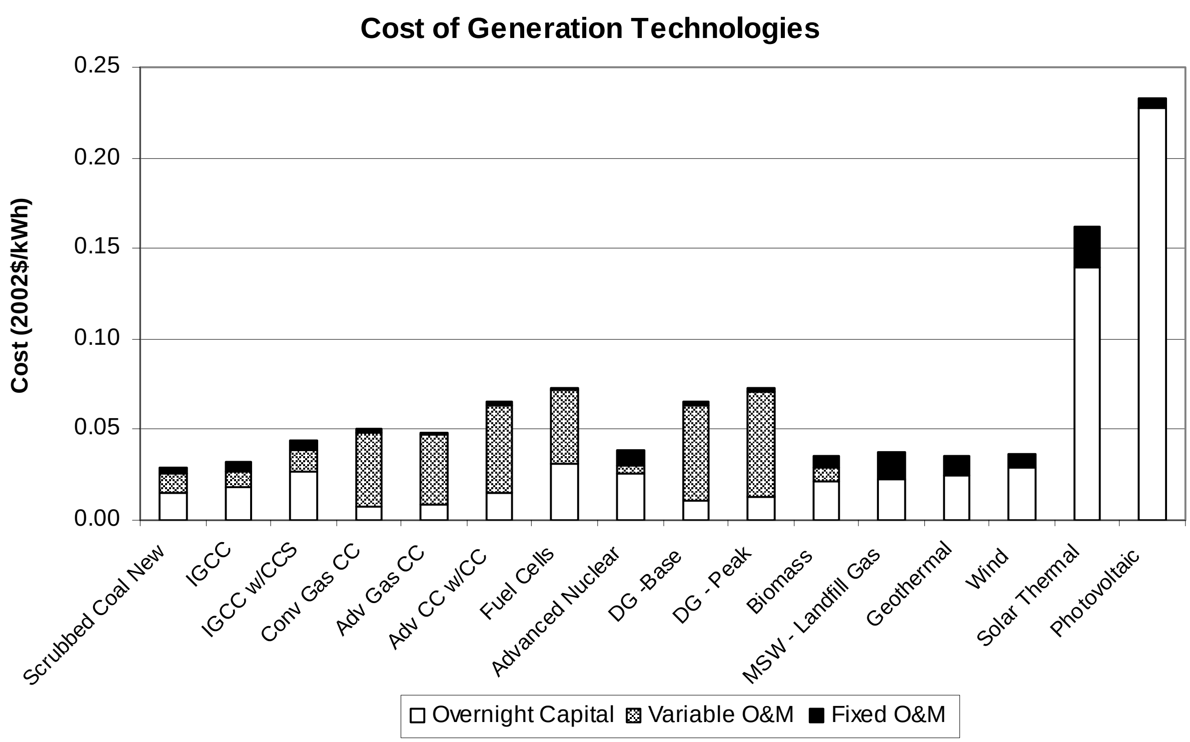

Figure 2.1 Capital, O&M and Fuel Cost Estimates for Generation Technologies.

These estimates also neglect to show the range of costs possible for each technology which can vary greatly. This range could be due to fuel price assumptions, site-specific variations on the costs, different configurations assumed for the technology, as well as the optimism for future technical achievements. For example, a recent review of literature estimates show that the capital cost of a PC plant varies from $1100-2580/kW and an IGCC plant varies from $1170-2380 kW depending on whether carbon capture was assumed (in addition to other plant characteristics assumed in each analysis) (Rubin et al., 2004). The ranges of costs will generally be greater for technologies that are still in the development stage.

The translation of various discharges into damage to people and the environment has been conducted elsewhere by estimating the costs of these externalities (Matthews, 2000; Sundqvist, 2004; Roth, 2004). These studies show that there is a greater variability in the valuation of externalities than there is in the estimates of the emissions. For example, the studies reviewed by Sundqvist represented coal-fired power plant technologies that ranged from 900 to 1400 tons/GWh in CO_2. However, the external costs for these power plants ranged from 0.11-73 cents/GWh. The data collected in this study is summarized in Figure 2.2. These social costs are used in the analysis presented through the rest of this thesis.

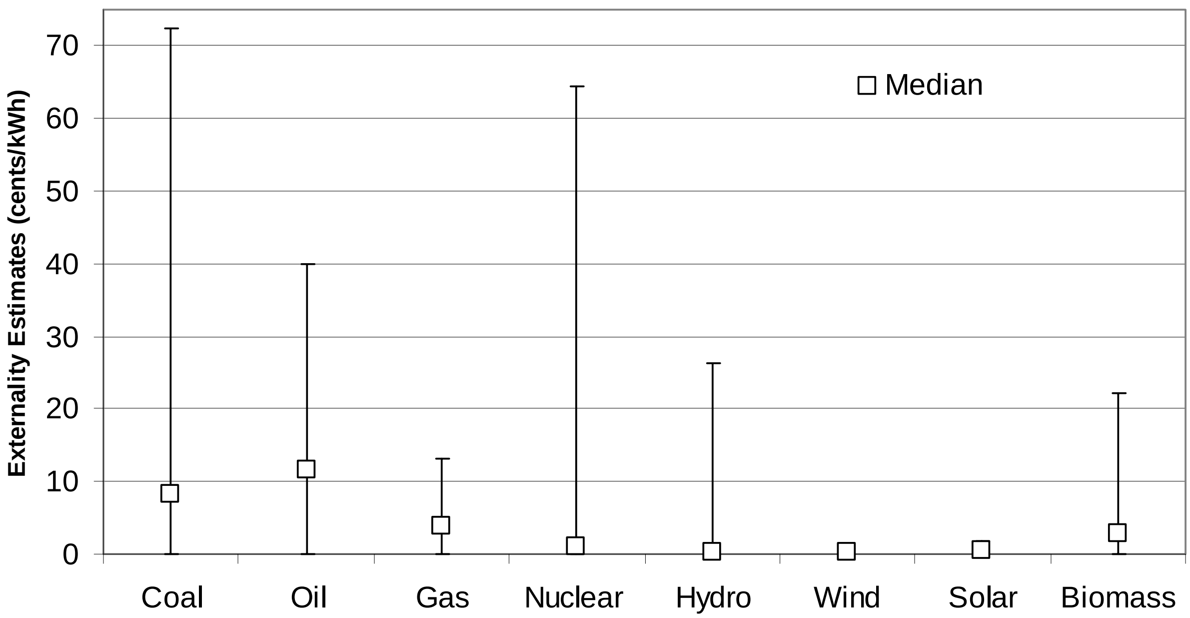

Figure 2.2 Range of Externality Valuation Estimates.
(Source: Sundqvist, 2004)

The variability of the studies is generally higher for the fossil fuels and nuclear than wind and solar estimates. There is also a level of detail that is missed by this grouping. For example, there are many ways that coal can be used to generate electricity. Many of the studies reviewed by Sundqvist do not include the possibility of carbon capture which would reduce the social cost of CO_2 emissions. In addition, the inclusion of fuel cells and municipal solid waste etc. is not explicitly treated. While they might be included in some studies represented here (depending on input fuel assumed), it is lost in such a simplified representation.

2.3 Natural Gas

Background

Nearly all of the new generation in the USA built in the 1990s was fueled by natural gas. The low capital cost of the generators, rapid construction, and low emissions made these plants less expensive and more attractive than coal units. DOE predicted in 2003 that by 2025, 29% of the electricity will be generated from natural gas (EIA, 2003a). This has been adjusted in the 2005 forecast to 15% by 2025 (EIA, 2005a). Natural gas prices have doubled from the start of 2002 to start of 2005 making the operation of existing plants generally unattractive; future shortages of gas could curtail delivery to electricity generation plants.

The life cycle stages of natural gas include construction and decommissioning of the power plant, natural gas exploration and extraction, construction of the natural gas pipeline, natural gas production and distribution, ammonia production and distribution, NOx removal, and power plant operation. Emissions from this fuel cycle include CO_2, CH_4, Non-Methane Hydrocarbons (NMHCs), NOx, SOx, CO, PM, and benzene. The high efficiency possible with today's technology and lower carbon content per BTU give the gas fuel cycle lower net emissions of CO_2 than other fossil fuel cycles (as little as half that of coal). However, quantities of methane (CH_4), a powerful greenhouse gas, leak throughout the fuel cycle. Other important environmental consequences of this fuel cycle are the consumption of water, land impacts from drilling and exploration, the potential for pipeline fires and explosions as well as discharged drilling mud.

Table 2.1 summarizes several LCA studies that investigated various natural gas technologies. Comparing pollution and emissions with the coal plants, the advantages of natural gas are apparent. However, while gas is preferred in many environmental respects to coal, it is still a non-renewable resource, and thus not sustainable.

Natural Gas: Comparison of Air Emissions Estimates (ton/GWh)				
	CO_2	**SO_2**	**NOx**	**Particulate Matter**
ORNL-RFF	640	neg.	0.50	0.21
NREL	480	0.35	0.63	0.14
Pacca et al. (adapted by averaging over plant life)	500			
Gagnon	440-550	0.35	0-2.2	
Owen	530			
Roth (adapted assuming a heat rate of gas 7000 btu/kwh)	410	0.0020	1.4	0.023
IECM†	410	0	0.0052	0
IECM w/CCS†	41	0	0.0039	0
EcoInvent	530-1100	0.022-0.60	0.58-1.2	0.012-0.024
† IECM calculates generation phase only				

Table 2.1 Comparison of Natural Gas Air Emissions Studies

(Adapted From - Source: ORNL-RFF, 1996; NREL, 1999; Pacca et. al, 2002; IECM, 2004; Gagnon, 2002; Owen, 2004; Roth, 2004; Dones et. al, 2005)

The most striking discrepancy is the high estimate of CO_2 emissions from EcoInvent. This estimate was for a current (average) plant in Luxemburg. This country does not have any natural gas and therefore requires that the gas be transported long distances. In addition, the technology used in Luxemburg is a single cycle unit which is much less efficient than the combined cycle units.

The differences in SO_2 emissions are due to the sulfur content of the gas used and assumptions made about upstream infrastructure. This varies greatly from source to source. The NOx emissions depend on the operating conditions of the plant and the NOx controls in place.

Fuel Extraction and Processing

The upstream processes consume large amounts of natural gas, as well as coal, iron ore, steel scrap, oil and limestone.

Most projections of gas reserves estimate that natural gas prices will increase over time (EIA, 2003c). Many projections also show that the net imports of natural gas must increase in order to make up for the discrepancy between domestic production and consumption (EIA, 2003b). Most natural gas is used for residential heating, industry, or as a chemical feedstock, competing with gas for electricity production.   The competition between coal and gas depends on the relative prices of the two, which are most sensitive to environmental regulations for mining and emissions regulations for burning each fuel.

Transport

The increasing demand for natural gas has resulted in an elaborate network of gas pipelines transporting natural gas long distances throughout the U.S.   While some infrastructure no longer links vital supply and demand, other pipelines are operated at full capacity and are the bottleneck of the natural gas fired electricity system (e.g. entering California). Shipping energy by pipeline is a relatively efficient method. Average loss (including leakage and fuel use in transport of natural gas) is approximately 3% in the

U.S. (EIA, 2000a). The emissions of methane are the largest release of GHG gases in this phase.

The EcoInvent study stresses that the energy required and emissions for this phase differ greatly from country to country due to significant differences in power plant efficiencies, distances shipped and gas supply.

Generation

The hot gases from burning natural gas can produce steam or go directly into a gas turbine. Combined cycle technology integrates these two technologies to increase efficiency (from 33% for steam turbine or simple cycle to 50% for combined cycle). In this technology, the combustion gas turns the turbine, and is then used to produce steam to drive another turbine. Installed gas fueled generators (17% of U.S. generation capacity) are 61% steam, 30% simple cycle, and 9% combined cycle plants (EIA, 2002a).

Table 2.2 represents the inputs, emissions and capital costs of a natural gas combined cycle plant with and without CCS. The heat rate of the plant is approximately 18% greater if carbon capture with an amine scrubber is added. In addition, the capital generation costs of the plant increase by approximately 65%. The capital cost of a combined cycle gas plant is perhaps half that of a coal plant with full environmental controls (IECM, 2004)

	Base NGCC Plant	NGCC Plant + CO2 Capture (Amine System) + MEA Scrubber
Gross Electrical Output (MWg)	517	517
Net Electrical Output (MW)	496	422
Net Plant Heat Rate (Btu/kwh)	6,945	8,167
Annual Operating Hours (hours)	6,575	6,575
Annual Power Generation (Bkwh/yr)	3.26	2.77
Net Plant Efficiency, HHV (%)	49.1	41.8
Higher Heating Value (Btu/lb)	23,170	23,170
Input (ton/yr)		
Natural Gas	489,000	489,000
Activated Carbon	-	31,300,000
Sorbent	-	2,510
Output (ton/yr)		
Carbon Dioxide Produced (CO_2)	1,350,000	135,000
Carbon Dioxide Captured (CO_2)	-	1,200,000
Sulfur Dioxide (SO_2)	-	-
Nitric Oxide (NO)	210	210
Nitrogen Dioxide (NO_2)	17	13
Amonia (NH_3)	-	5
Scrubber Solids Disposed	-	2,930
Capital Cost ($/kw-net)		
CO_2 Capture	-	270
Main Combined Cycle Unit	565	660
Total Capital Cost ($/kw-net)	565	930

Table 2.2 Inputs, Emissions and Costs of Natural Gas Combined Cycle Plant with and without Carbon Capture
(Source: IECM, 2004)

Recycling the flue gas to increase the CO_2 concentration of the flue stream (still using amine scrubbers), adding H_2 to the turbine in order to decrease the amount of methane required and therefore the CO_2 released, and using a steam reformer, can help to improve the cost and efficiency of the CCS system. This latter technology involves precombustion removal of CO_2 (Aasen et al., 2004).

Steam reforming has a larger energy penalty, 9%, than the amine scrubbed, 14%. The amine technology was first developed for removal of CO_2 from natural gas fired electricity generation and there are several functioning plants with this technology in operation today. The cost and efficiency of a steam reformer system is uncertain at this point.

Waste Streams

Discharges of water pollutants are small as is the solid waste (mostly from pipeline transport and natural gas extraction).

2.4. Nuclear

Background

As of 2004, there were 104 nuclear facilities in the U.S. (EIA, 2004d). No new permits to construct nuclear power plants have been issued since 1978, and there are no applications imminent in the U.S. However, nuclear power plants are currently being constructed today in other countries (most notably in Asia). A few nuclear power plants in the U.S. have been re-permitted (reissued permits for another 20 years); others are following this process as many of the nuclear facilities in the U.S. are nearing the end of their permitted lives (approximately 20-30 years).

A major advantage to nuclear power is that none of the traditional pollutants are released in producing electricity. However, there are major concerns about the treatment and risks associated with the generation and storage of radioactive wastes. Nuclear power was reviewed extensively in the 1970's where most fuel cycle analysis revealed that nuclear power posed less risk to humans and the environment than traditional fuels (coal and oil), although disposal of radioactive waste was not treated. This, however, excludes the fact that the risks associated with nuclear power, although rare, can be devastating.

Since the 1970’s, very little assessment of nuclear fuel cycles has been conducted in the U.S. However, recent discussion in the U.S. of the disposal of spent fuels and policies designed to encourage investment in nuclear facilities should increase the study of possible nuclear futures in the next several years. However, throughout the rest of the world, many studies have been published and the environmental consequences of nuclear power continue to be investigated due to its continued use (Rashad, 2000; Wu, 1995; Gulden, 2000; Fisk, 1999; Al-Rashden, 1999; Aumonier, 1998; Ion, 1997). In countries like Korea there is no domestic fossil fueled energy supply, making nuclear attractive (Lee, et al., 2000).

The life cycle stages of the nuclear fuel cycle include uranium mining and milling, conversion of uranium to uranium hexafluoride, enrichment, fabrication into fuel elements, use of the fuel to generate electric power, power plant decommissioning and reprocessing or disposal of spent fuel. Table 2.3, shows a summary of emissions from nuclear power studies.

		EcoInvent			KEPRI/KEPCO			IAEA	Gagnon	IEA
Assumptions	Region	Switzerland	Switzerland	Western Europe	Korea	Korea	Korea		Northeastern NA	
	Reactor	PWR	BWR	Avg Nuclear	PWR	PWR	PWR			
	Enrichment Technology	Centrifuge	Diffusion- 13% from U.S. (i.e. Fossil)	Diffusion/Centrifuge	Diffusion (France)	Diffusion (France)	Diffusion (France)			
	Waste Management	40% reprocessed/60% to long term storage	40% reprocessed/60% to long term storage	40% reprocessed/60% to long term storage	Once-through	DUPIC (PWR to CANDU)	PUREX (PWR to PWR)			
Environmental Emissions from Nuclear Power	CO_2 (ton/GWh)	5.7	12	8.5	3.1E-05	9.4E-05	4.5E-06	33	17	8.8
	SO_2 (ton/GWh)	0.025	0.067	0.041	5.1E-06	1.4E-05	5.1E-07		3.3	
	NOx (ton/GWh)	0.036	0.052	0.044						
	$PM_{2.5}$ (ton/GWh)	0.0057	0.0079	0.0070						
	Total Radioactivity to Air (mostly from Radon and other noble gases) kBq/GWh	8.8E+08	9.6E+08	1.1E+09						
	Total Radioactivity to water (mostly from Tritium) kBq/GWh	8.5E+06	7.7E+06	1.7E+07						
	Waste (Spent fuel, high level waste, Intermediate level waste) m^3/GWh	7.8E-03	8.8E-09	1.2E-08						

Table 2.3 Comparison of Nuclear LCA Studies
(Adapted From - Source: Dones et al., 2005; Lee et al., 2000; IAEA, 2001; Gagnon, 2002; IEA, 2001)

The nuclear life cycle air emissions are generally orders of magnitude lower than the emissions from fossil-fueled electricity generation technologies. The different upstream assumptions made in these studies as well as those presented in the subsequent section on renewable sources, are generally within the same range but vary greatly from study to study. If these emission levels were the only basis of a decision between nuclear or renewable technologies, there would not be a clear winner.

Fuel Extraction and Processing

Uranium is abundant throughout the world, although in low concentrations. However, uranium can be recovered from the spent fuel of power stations and depleted uranium can be enriched from mixed-oxide (MOX) fuel elements (e.g. warheads).

The majority of uranium produced worldwide is from Canada, Australia and the U.S. The total U.S. uranium mining, concentrate production and employment are near historic lows (EIA, 2005d). Traditional mining methods are employed in most areas with the associated environmental impacts. These include open pit and underground mining as well as chemical extraction.

The milling process produces tailing ponds which create several environmental concerns, primarily the release of radioactive radon to the air. Radioactivity can be released from all stages of the nuclear life cycle.

The enrichment of uranium only occurs in select countries including France, U.S., U.K., and Russia. This process increases the concentration of U235. The amount of enrichment required depends on the requirements for the reactor. The enrichment process consumes more electricity than any other life cycle stage. The choice of enrichment technology and the source of the electricity are the two main determinants of the environmental emissions associated with nuclear power generation. There are two major types of enrichment; gas diffusion and centrifuge. While centrifugal enrichment requires much less energy than diffusion and is in use in Europe, it is only being planned in the U.S. Diffusion enrichment occurs at two locations in the U.S. both of which are fueled primarily with coal-fired electricity. Table 2.3 shows that the range of life cycle CO_2 emissions varies from 5.7 to 12 ton/GWh. The primary difference is the assumption that 13% of the uranium from the Boiling Water Reactor (BWR) system is from a U.S. plant which uses diffusion technology powered by coal-fired electricity. This implies that if 100% of the uranium came from this diffusion plant then the CO_2 emissions would be closer to 65 ton/GWh.

Transport

The cost and environmental impacts from transport in this fuel cycle can be large since the few areas where uranium is enriched can be very far from where it is consumed. This would lead to long distance shipments.

Generation Technologies

Nuclear fission electricity generation is similar to traditional fossil power plants in that heat is used to produce a steam which then drives a turbine. With nuclear fission, the heat is generated by the collision of uranium 235 with neutrons which produce more neutrons which produces a chain reaction giving heat throughout the cycle.

Light water reactors and heavy water reactors are the two primary designs. Light water reactors can be either Pressurized Water Reactors (PWR) or Boiling Water Reactors (BWR). The PWR reactor has a separate stream of water allowing the system to be operated at relatively high pressure (160 atm) and temperature (315^{o}C), with a higher Carnot efficiency. This technology is, however, more complicated, and therefore, more costly. Most U.S. reactors employ this technology. The BWR technology uses the same water to act as a moderator, coolant and steam source and therefore operates at a pressure of 70 atm and a temperature of 285^{o}C. As a result, the efficiency is lower than the PWR.

The heavy water reactor uses water made with deuterium instead of regular water. This technology does not require enrichment of uranium. Therefore, there is flexibility in the uranium input (e.g. natural uranium, slightly enriched uranium, thorium, reprocessed spent PWR fuel, MOX and direct use of spent PWR fuel). There are currently 38 Canada Deuterium Uranium (CANDU) reactors in operation in the world (17 in Canada). A recent study compares a once-through method, the use of PWR spent fuel in a CANDU reactor and one with a reprocessing step that feeds spent fuel from a PWR unit back to the same PWR unit (Lee et al., 2000). While the use of a CANDU reactor helps to reduce the amount of spent fuel out of the PWR by one-third, the authors estimate that the releases due to the extra transport and processing will result in a probability of cancer due to the radioactivity mortality or morbidity per unit internal or external exposure that is more than double that of the once-through or PWR reprocessing options.

Finally, considering the global collective dose of all stages of the fuel cycle, the reprocessing stage contributes the largest portion (79%) of the total collective dose. The electricity generation stage accounts for 18% of the total (Dones, 2005). The U.S. does not process spent fuel.

Future Technologies

Several new designs promise greater safety and lower costs. Several projects build on current technologies, such as the “inherently safe” light water reactor designs. The most recent CANDU technology which adopts light water cooling and a more compact core that reduces capital cost. It also runs on low-enriched uranium, with high burn-up, which extends the fuel life by about three times and reduces high level waste volumes. Units will be assembled from prefabricated modules, eventually cutting construction time to 3 years (this trend applies to all nuclear technologies). Based on recent Asian implementations, manufacturers of the technology project costs of $1255/kW with later units under $1100/kWe.

Breeder reactors have been under development for more than 30 years, but significant technical challenges remain.

Pebble-bed reactors promise to be cost-competitive and meltdown-proof by using gas instead of water and operating at high temperatures which increases efficiency. However, they are still technical issues that need to be resolved and the development is still at laboratory scale.

Finally, enrichment processes including laser enrichment procedures are aimed at decreased costs and energy requirements. The increased deployment of enrichment by centrifuge or laser will reduce the life cycle Greenhouse House Gases (GHG) emissions.

Waste Streams

Developing an acceptable method for dealing with spent fuel from the nuclear fuel cycle is one of the most important determinants of whether there is a future for nuclear power in the U.S. The major element of uncertainty is the possibility of exposure to radioactive waste hundreds or even thousands of years from now. Several LCA studies have considered the long term storage of high-level spent fuel. However, in order to calculate the risk associated with this storage, the probability of a major accident per year is multiplied by the predicted exposure from such an incident. One study calculates that the probability of large-scale exposure is so low that expected exposure is much lower than that from current during normal operation of the plant, which is very low (Dreicer, 1995). The data in the EcoInvent database shows that the peak for all isotopes reaching the biosphere is more than three orders of magnitude lower than the Swiss regulatory guideline threshold. It was therefore, not considered in their analysis. The issue of how to safely store spent nuclear waste has yet to be resolved and remains an obstacle for building new nuclear power plants in the U.S.

2.5 Renewable Fuels and Technologies

Background

Table 2.4 provides a summary of studies of the life cycle emissions from several renewable fuels. Except for biomass, there are no direct air pollution emissions from generation.

Comparison of Air Emissions from Renewables (ton/GWh)				
	CO_2	SO_2	NOx	PM
Hydro	0-20	0.001-0.027	0.002-0.074	0.0052
Wind	0-130	0-0.076	0-0.11	0
Solar	0-52	0-0.55	0-0.11	0
Biomass	-180-880	0.029-0.76	0.54-2.2	-

Table 2.4 Comparison of Air Emission from LCA of Renewable Energy Studies
(Adapted From - Source: ORNL-RFF, 1996; Pacca et al., 2002 ; Rafaschieri et al., 1999; Hartmann et al., 1996; Faaij, 1998; Mirasgedis et al., 1996; Lenzen et al., 2002; Schleisner, 2000 ; Greijer et al., 2001; Roth et al., 2004; Owen, 2004; and Gagnon, 2002)

Air emissions are not the only means by which to compare these technologies. Other aspects of the life cycle for these technologies are discussed below.

2.5.1 Hydro

Until recently, hydroelectric power was considered the most environmentally benign source of electricity. In recent years, however, the major adverse impacts of hydro power, through flooding large areas and disrupting fish migration have challenged this idea (Collier, 1996). A few dams have been breached for environmental reasons and many more are being investigated (ARFE, 1999). In the U.S., most major waterways that have the potential to be used as hydroelectric generators have already been developed. However, projects involving retrofitting current dams as well as smaller scale diversion structures are possible. Outside the U.S. major construction of new hydropower is expected in the next few decades. (Sharp, 2000; Acreman, 1996; Zutshi, 1994; Masjuki, 2002; Bhutta, 2002)

Hydropower's fuel source is renewable, it is available on site (no mining, transporting etc. required), and no combustion is required. It also has the large disadvantage that generation depends on precipitation, which varies from year to year. These environmental implications are different from fossil fuel cycles.

The main implications to be considered with hydro-electricity are the land and water ecosystem impacts associated with constructing and operating hydro-electric dams, the cost of power, and the renewable nature of the fuel supply. Hydro power releases no CO_2 directly, but is less reliable than fossil fuel plants due to droughts.

The range of emissions present in Table 2.4 show that different results are obtained based on different assumptions and boundaries drawn for analysis. For example, the ORNL-RFF study did detailed calculations to assess emissions from the dam construction and manufacture. Other studies investigated an upgrade to an existing hydro plant (Pacca, 2002), run-of-river vs. reservoirs (Gagnon, 2002) and various sizes of hydro projects (Roth, 2004).

2.5.2 Wind

The main advantages of wind are that the generation phase does not emit environmentally harmful pollutants and the fuel is renewable. The number of attractive sites for wind turbines is limited since they must have high wind during most hours of the year. Humans cannot control wind speed, requiring backup power when the wind does not blow. While wind turbines emit no pollutants, the life cycle of these turbines does require materials and emit pollutants, as well as use land. The most important current objection seems to be objections to placing the turbines in their best locations, highly visible places such as the tops of ridges or mountains or in the ocean.

The structure and technology of most modern wind turbines is very similar around the world. They are considered a mature technology. The results of life cycle assessments conducted to date, summarized in Table 2.7, are very different due to variability in each study’s assessment of the contents of materials, national fuel mixes chosen, and the method and scope of each study (Lenzen, 2002). For example, one study compared the material requirements for offshore versus onshore wind farms (Schleisner, 2000). This study found that the emissions of CO_2, SO_2 and NO_x associated with the offshore project were greater by 50 – 70%. This was primarily due to the additional material production and manufacturing required for the offshore project.

The full life cycle of renewable fuels is extremely important for determining the environmental impact of such systems. Wind is a good example as 68-99% of the external costs of the system are from emissions related to material production and manufacturing (Schleisner, 2000). Also, even the windiest sites in the U.S. do not experience consistently high wind speeds the entire year. One method to compensate for this intermittency is to use natural gas plants as a source of backup power. Table 2.5 shows how the life cycle air emissions of a wind system change if natural gas is used to back up the wind system. The table shows the life cycle emissions if no backup power is required, if 30% of the power is supplied by a natural gas unit and if 60% of the power is supplied by a natural gas unit.

Air Emissions from Wind (with and without backup power) - ton/GWh			
	(no backup)	30% Natural Gas Backup	60% Natural Backup
CO_2	10-18	130-228	250-440
SO_2	0.022-0.033	0.023-0.14	0.023-0.24
NO_x	0.033-0.055	0.18-0.48	0.33-0.9

Table 2.5 Comparison of Emissions from Wind with and Without Backup Power (Adapted from Schleisner, 2000 and a range of values from Table 2.1)

The point of showing this simplified analysis is to demonstrate that the life cycle emissions increase dramatically if natural gas is used to deal with the intermittency of wind.

There are many other methods of backing up intermittent sources. These include storage of the energy in batteries, compressed air, chemical bonds (e.g. hydrogen, methanol), or fly wheels. However, none of these technologies have been proven to be cost effective to-date (Decarolis, 2005). A recent study evaluated the life cycle emissions of wind for base load with temporary compressed air storage but did not evaluate the costs (Denholm, 2005).

The main tradeoffs to be considered for wind powered electricity systems are the reduction of greenhouse gas (and other) emissions versus the intermittency problem (and the potential non-renewable backup required). In addition, the distance between where the wind blows and where the electricity is demanded is often large, requiring long transmission lines. Currently, wind receives a subsidy of 1.8 cents/KWh in the U.S. and many states have renewable portfolio standards that encourage wind power. If the costs of air pollution and CO_2 emissions were added to the cost of electricity generated from fossil fuels, and if the depletion of these fuels were considered, wind generated electricity might be less expensive than electricity from fossil fuels (Kennedy, 2005). However, very large-scale wind deployment could affect climate by removing energy from the lower boundary layer of the atmosphere (Keith et al., 2004; Decarolis, 2004).

2.5.3 Solar

The sun is the earth's greatest source of energy and the source of most renewable energy. Solar energy that is currently being used to generate electricity is either solar thermal or photovoltaic. Solar thermal technology uses the radiation directly to heat water or other materials, focusing the radiation to generate steam. Photovoltaic technology converts the sun's rays directly to electrical energy. One of the advantages of solar radiation is that the conversion of electromagnetic radiation to electricity occurs without environmentally harmful emissions. However, other stages of the fuel cycle do contribute to environmental damage.

Examples of the toxic and flammable/explosive gases that are used in making photovoltaic power systems are silane, phosphine and germane; cadmium is often used in production. Recycling the cell materials is possible but the environmental consequences of that must be considered first. Depletion of rare materials is also a concern including indium (used in CIS modules) and silver (used in microcrystalline-SI modules). The use of hazardous compressed gases in PV manufacturing could lead to health and safety concerns.

Since the sun does not always shine, electricity storage or back up is required; this increases costs significantly and can lead to additional environmental problems.

One of the major environmental concerns for this fuel cycle is the manufacture (particularly the process energy) and disposal of solar cells and other equipment. A recent study showed that a photovoltaic array produces a global warming effect which is 9 times less than that of a coal plant over the course of an assumed 20 year lifetime when both are built to produce 5.55 TWh/year (Pacca et al., 2002). The emissions associated with this PV system are higher than other studies have shown since the method of dealing with intermittency in this study was to scale the size of the PV array up to over 4,000 MW whereas the coal plant requires a capacity less than 1,000 MW to produce the same amount of electricity.

Energy use in the manufacturing stage is the largest contributor to conventional emissions. In addition, greenhouse gases can be used (and emitted) in PV manufacturing such as SF_6 and CF_4.

The cost of this technology is not competitive with fossil technologies (even with the current level of subsidies). As such, commercial application of photovoltaic arrays is currently restricted to remote applications and other niche applications.

Therefore, the main tradeoffs to consider for solar powered electricity are cost and environmental impacts of backup power generation or other method to handle the intermittency issue, as well as the manufacturing and disposal of solar cells, depletion of scarce resources, and use of hazardous materials versus the reduction in greenhouse gas emissions.

2.5.4 Biomass

Biomass is a renewable fuel that could be a partial or total replacement for coal. When biomass is co-fired with coal, most pollutant and net CO_2 emissions fall in proportion to the biomass used. The most significant environmental impacts from this fuel cycle are caused by the use of chemicals and fertilizers, as well as land use issues.

A recent study compared an integrated gasification combined cycle plant fired by dedicated energy crops (poplar short rotation forestry) to a conventional power plant (Rafaschieri, 1999). For almost all of the eco-indicators and normalized effects considered in this study, biomass had less environmental impact than coal. Another study concluded that the use of crops to generate electricity is preferred to their use as transport fuels from both an ecological and socio-economical criteria (Hanegraaf, 1998). However, the average private costs of biomass were found to be almost double that of coal power generation (Faaij, 1998).

There are also significant differences in damages, and thus externalities, among different sites (for example, benefits from erosion reduction differ by a factor of three) for different biomass technologies (ORNL, 1996). The use of advanced biomass conversion technologies could reduce NOx emissions significantly compared to conventional wood burners.

The biomass fuel cycle has near-zero net emissions of CO_2 since CO_2 is fixed by the plants as they grow. The land area required to replace a significant portion of the electricity currently generated by coal limits the use of biomass.

2.6 Discussion

Electricity is essential to our lifestyles and the economy. The share of electricity in the total amount of energy that we consume is likely to rise. Past technologies for generating electricity were inefficient, polluting, and unsustainable. Technological change has increased efficiency and lowered cost. Ever more stringent environmental regulations have lowered environmental discharges, although they also increased costs.

Sustainability of electricity has not been addressed directly, although recent legislation (specifically the Renewable Portfolio Standards) requiring that a proportion of electricity come from renewable sources does begin to address the issue. Profit incentives and the market place encourage generators to work hard to lower costs and provide the kinds of services that consumers are willing to pay for. Government regulation or the use of market incentives are needed to address environmental and sustainability concerns.

In setting environmental and sustainability goals and in choosing fuels and technologies for generation, life cycle analysis is needed to compare the extraction to end of life implications of the alternatives. Generation itself is responsible for only a portion of the materials and fuels used and the environmental discharges during the whole life cycle of electricity. This viewpoint makes clear that even a seemingly benign generation technology like hydrogen powered fuel cells that emit nothing except water vapor pose problems through the materials, energy, and environmental discharges during their life cycle. Current technology does not offer an entirely sustainable generation technology or one without adverse environmental consequences. However, current technology offers more sustainable and environmental technologies than those currently in use.

Combined cycle natural gas turbines are another important innovation. Using the combustion gases to drive a turbine directly, rather than heating steam to drive the turbine, increases efficiency. Adding a second cycle increases efficiency still more. This fuel is naturally clean, although not sustainable. Emissions of NOx and GHG would have to be curtailed to make the fuel-technology less environmentally harmful. Distributed generation, offering combined heat and power offers still greater efficiencies.

Renewable resources, such as hydro and wind are no longer perceived to be entirely benign. Photovoltaic power has less environmental consequences, although its high costs and ability to generate energy only when the sun shines pose problems. Biomass offers a renewable fuel that can be burned to produce low pollutant emissions and no net CO_2 emissions. Cost is an issue, as is the large amount of land that would be required to generate a major proportion of North American electricity.

Electricity generation will be less polluting and more renewable than it has been in the past; it is also likely to be more expensive. If we were willing to pay more for electricity, it could be made still less polluting and more sustainable. No current or near-term technology will be entirely benign, but environmental emissions and sustainability can be improved to levels undreamed of a few years ago. To achieve progress most cost-effectively, we need to provide incentives or regulations to attain these goals. Each of the fuels and technologies has promise, but no one is dominant. Society should provide incentives rather than pick a winner among the alternatives. We must back up our desires for clean technologies and sustainable fuels by being willing to pay somewhat more for electricity.

Chapter 3: Near- and Mid-Term Technological Choice for Coal-Fired Electricity Generation Technologies: A Life Cycle Approach

3.1 Introduction

The performance of current coal fired power plants is reasonably well documented. These studies have generally focused on the generation phase only (Holt et al., 2002; Chiesa, P et al., 1999; Freund, P., 2003; Gambini, M. et al., 2003; O'Keefe, L.F et al., 2002; Simbeck, D., 2001, Ratafia-Brown et al., 2002; Longwell, et al. 1995), some consider control technologies extensively but do not consider CO_2 capture technologies (Chowdhury, B.H., 1996) and very few include a comparison of the life cycle effects of different coal types on the cost and choice of technologies (both generation and control) (Doctor, R.D. et al., 2001). One recent study investigated the life cycle impact of coal by-products of different coal sources in Europe with pulverized coal (PC) and fluidized-bed combustion technologies (Bennetto, E. et al., 2004). The Bennetto study does not consider CO_2 abatement technologies.

A simulation model, "Integrated Environmental Control Model" (IECM, 2004) allows for the examination of a wider range of coals and generation technologies than are in the published life cycle literature. A power plant can be built "virtually" using this model to specifications such as the fuel type, control technologies, and boiler type. In order to make a comparison between previous literature and the IECM model, the IECM output must then be extended from the generation phase to the entire life cycle. This analysis makes this adjustment.

This analysis compares various coal control and generation technologies in order to determine the most appropriate technology for the different coal types considered and environmental constraints.

The Life Cycle of Coal-Fired Generation of Electricity

Coal causes large environmental damage due to mining, transport, and electricity generation. A simplified diagram of the life cycle of coal-fired electricity with examples of inputs and outputs is summarized in Figure 3.1.

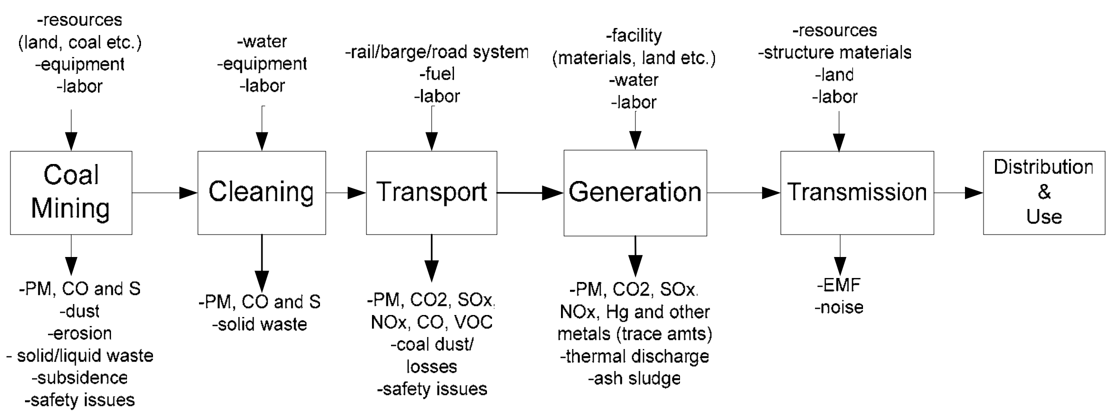

Figure 3.1 Simplified Life Cycle of Coal-Fired Electricity.

Environmental and sustainability concerns were almost entirely absent from design and operation of electricity production during the first half of the twentieth century. As environmental regulations have become more stringent, significant strides have been made in abating the environmental discharges from coal combustion and, to some extent, from mining.

3.2 Coal Mining

Significant deposits of coal are found throughout the U.S., although there is great variability in terms of heat rate, ash, sulfur and moisture content. These characteristics have an impact on the cost, efficiency, environmental controls and the distance that each coal can be transported economically. Table 3.1 shows examples of the composition of several coal types. Coal is highly variable, even within each coal region.

	Appalachian Low Sulfur	Appalachian Medium Sulfur	Illinois #6	North Dakota Lignite	WPC Utah	Wyodak	Wyoming Powder River Basin
Heating Value (btu/lb)	13080	13260	10900	6020	11240	11960	8340
Carbon (% by weight)	72	74	61	35	68	53	48
Hydrogen (% by weight)	5	5	4	3	5	4	3
Oxygen (% by weight)	6	5	6	11	6	13	12
Chlorine(% by weight)	0.07	0.06	0.17	0.09	0.01	0.01	0.01
Sulfur (% by weight)	1	2	3	1	1	0	0
Nitrogen (% by weight)	1	1	1	1	1	1	1
Ash (% by weight)	10	7	11	16	12	6	5
Moisture (% by weight)	6	5	13	33	8	23	30
Delivered Price ($/ton)	33	34	28	15	29	30	21

Table 3.1 Summary of Coal Composition for Several Coal Types (Source: IECM, 2004)

Coal is extracted using surface mining (approximately 60%) or underground mining (approximately 40%) (OSM, 2003). Surface mining is generally less costly per ton mined, but has greater environmental impacts. Problems from coal mining include; injuries and chronic lung disease in miners, acid mine drainage, unrestored mining sites, the movement of hill tops into neighboring valleys, air pollution, erosion, mining waste, subsidence, underground fires, and disruption to underground water flows and storage.

The health and safety aspects of coal mining received focus before and following the 1969 Coal Mine Health and Safety Act in terms of the impacts from mining (Fishback, 1986; Ghose et al., 2002; Finkelman et al., 2002) and the impact of the regulation (Fuess et al., 1990; Neumann et al., 1982; Knisener et al., 2004). The social costs of coal mining were first assessed in the 1970's (Dials et al., 1974). A recent review suggests that the research related to the environmental impacts of mining has broadened over time to include concerns about landscape aesthetics and pollution to ecosystem health, sustainable development and indigenous rights (Bridge, 2004).

While standards for underground mine safety, acid mine drainage, and restoration of strip mined land have become more stringent over time, the problems still remain today.

Other problems from coal mining include; injuries and chronic lung disease in miners, acid mine drainage, unrestored mining sites, the movement of hill tops into neighboring valleys, air pollution, erosion, mining waste, subsidence, underground fires, and disruption to underground water flows and storage.

Table 3.2 shows a summary of air emissions for the mining phase of the coal life cycle. Each row represents a different study or method of calculating the emissions from this phase.

Estimated Air Emissions for Coal Mining Phase (ton/GWh)				
	SOx	NOx	PM	CO_2 eq
EIOLCA	0.0094-0.027	0.011-0.032	0.0049-0.014	17-48
NREL	0.058-0.083	0.030-0.052	0.010-1.0	25-60
ORNL-RFF	0.055	0.066	1.5	N/A
U.S. GHG Inventory				10-70

Table 3.2 Summary of Air Emissions for the Mining Phase of Coal Studies (ton/GWh)

A good way to estimate emissions of various activities is to use Economic Input-Output Life Cycle Assessment (EIOLCA, 2005), which is a life cycle assessment model making use of the U.S. 1997 Economic Input-Output table (DOC, 2002) and U.S. government data on energy use, and environmental discharges. The estimates from this model were calculated by estimating the amount of coal required per GWh (for each coal type). This ranges from 370 tons of medium sulfur Appalachian coal to 880 tons of North Dakota lignite per GWh. This model reflects the average proportion of extraction methods used in that year (40% underground mining, 60% surface mining (EIA, 2003h)).

The base case of the National Renewable Energy Laboratory (NREL) study assumed that the coal was surface mined. The overall CO_2 emissions were estimated to be 10.6 ton/GWh. The total emissions for this case were 1100 ton/GWh which results in their estimate of a 0.9% contribution from the mining process. However, if the methane from the surface mining process (0.0019 ton of CH_4 per ton of coal mined) is converted to CO_2 equivalent emissions (i.e. multiplying by the global warming potential factor of 23 for methane assuming a 100 year time horizon) (IPCC, 2001) then the total CO_2 equivalent emissions are 34 tons of CO_2 eq per GWh (note: this also includes the conversion of N_2O emissions to CO_2 eq. which results in 0.33 tons of CO_2 eq. per GWh). Therefore a contribution to the overall CO_2 eq. emissions from the mining phase is 3%. If the same procedure is applied to the NREL average underground mining case the contribution from the mining phase increases to 5%. They have assumed an emission rate from underground mines of 0.097 tons of CO_2 eq. per ton of coal mined. This is lower than the average methane emissions per ton of coal mined underground according to the 2003 U.S. Greenhouse Gas Emissions Inventory. This inventory estimates that in 2001, 0.144 tons of CO_2 eq. was emitted per ton of coal mined underground. If this value is used for the calculation, then the contribution in this system is close to 7%. The estimate of 0.144 tons of CO_2 eq. per ton of coal mined takes into account the fact that in 2001 close to 30% of the methane emitted from underground mines was recovered and used. It also accounts for the additional methane that is released during post mining operations. The GHG Emissions Inventory also estimates that 0.016 tons of CO_2 eq. are emitted per ton of surface mined coal. This means that the emissions from underground mines per ton of coal mined are almost 9 times higher than surface mines. In general, the amount of methane trapped in coal is higher with increasing coal rank and is site specific (OTA, 1985).

The NREL study found a small difference in ammonia emissions due to ammonium nitrate explosives in surface mining and higher particulate matter emissions from the production of limestone for underground mining.

The variation among estimates is due primarily to the assumptions about mining method, the number of tons of coal required per GWh, and the generation mix to provide electricity throughout the mining process. The GWP is dependent on the amount of methane that is released during the mining process.

NREL and Oak Ridge National Laboratory-Resources for the Future (ORNL-RFF) show estimates of SOx, NOx, and PM that are higher than those of EIOLCA. ORNL-RFF assumed surface mining but did not include the CO_2 eq emissions from mining in their estimates of externalities from this life cycle. The NREL study assumed a generation mix (67% coal) for the mid-west instead of a national average whereas the EIOLCA model assumes a national mix (50% coal). Since the largest contribution to conventional pollutant emissions is from the power required to support coal mining activities, this accounts for a large portion of the difference.

The emissions calculated from the GHG Inventory are based on the average CO_2 eq emissions per ton of coal produced for surface and underground mining. The amount of coal required for 1 GWh for each of the coal types was calculated in IECM. The relevant emission factor for mining was applied depending which mining method was required for each coal type.

3.3 Transport

Coal is transported by rail, barge, truck and conveyor/slurry (69%, 13%, 9% and 9%, respectively by total U.S. tons originated) (EIA, 2000b). The modes are not equally benign: the environmental impacts and injuries vary considerably. Transporting coal by rail causes nearly 400 deaths in the U.S. annually (almost all deaths occur to members of the general public) (BTS, 2002). These deaths are attributed to various safety issues in collisions between rail systems and humans. A typical ton of coal is shipped approximately 800 miles by rail (EIA, 2000c). If all modes are included it is closer to 700 miles.

Table 3.3 shows a range of coals and the average distance that each coal type is shipped depending on the mode of transport. Each coal also has a different ratio of transport mode use. For example, only 55% of Illinois coal is shipped by rail (an average of 230 miles) while 35% is shipped by barge (an average of 1,200 miles) and 10% is shipped by truck (minimal distance). Thus, different coal types have very different environmental impacts from transportation.

	Average Distance Shipped for Different Coal Types (miles)				
	All Modes	**Rail**	**Barge**	**Truck**	**Converyor**
Wyoming PRB	1,100	1,100	-	-	-
Med Sulfur Appalachian	130	360	55	26	5
Low Sulfur Appalachian	440	460	220	43	-
Illinois # 6	390	230	1,200	-	-
North Dakota Lignite	30	30	-	-	-
WPC Utah	86	500	-	35	-

Table 3.3 Coal Shipment Distances Based on Coal Type and Transport Mode

Table 3.4 summarizes the estimates for transport phase air emissions adapted from several studies.

Summary of Air Emissions for Transport of Coal Studies (ton/GWh)				
(ton/GWh)	SOx	NOx	PM	CO_2 eq
NREL	0.078-0.10	0.15-0.20	0.015-0.020	16-22
EPA	0.10	0.37	0.009	35
EPA/IECM data	0.0050-0.212	0.0196-1.23	0.0005-0.0251	3-80

Table 3.4 Summary of Emissions for Transport Phase of Coal (ton/GWh)

The last row shows estimates that were calculated within this analysis. U.S. EPA emission factors were obtained on a kg of emission type per kg of fuel consumed. The fuel efficiency of the various transport modes, the distance that each coal type traveled on each of these modes and the amount of coal required to produce 1GWh were used to come up with the estimates in terms of ton/GWh. This row shows the biggest range of estimates and the values can range by several orders of magnitude. This analysis captures the extremes of the different impacts associated with coal transport.

The main assumptions that result in the variability include the transport mode (rail, barge, truck, conveyor, pipeline), emission factors (this results primarily from the composition of the fuel selected and the efficiency of the locomotive) and the distance that the coal is shipped. NREL assumed shipment by barge, the estimates in the second row were made assuming average shipments by rail in the U.S. and EPA emission factors.

3.4 Generation

Generation is the most polluting process in this life cycle. A large amount of water is used for cooling, but the majority is treated and released, resulting in little pollution discharged into water. Direct cooling uses a once through method of extracting water from a nearby water body and returning that water after using it to condense the steam.

Indirect cooling uses cooling towers. The hybrid cooling system (a combination of wet and dry cooling systems) reduces consumption, but is more expensive and reduces the efficiency of the plant. A gasification plant consumes less water than a pulverized coal plant. Table 3.5 shows water consumption for different power plants and cooling system technologies.

	PC Coal Plant		**IGCC Plant**		**NGCC Plant**		**Methanation Plant**	
Cooling System Types (billion gallons)	Total Withdrawal	Consumed	Total Withdrawal	Consumed	Total Withdrawal	Consumed	Total Withdrawal	Consumed
Direct	209	0	94	0	50	0.25	3.2	
Indirect	5.0	3.5	2.5	1.1	0.58	0.45		
Hybrid Cooling Towers	3.8	2.9	1.9	0.9	-	-		

Table 3.5 Water Consumption for Different hypothetical 1000 MW Power Plants
(Modified from Martin et al., 1999, and EPRI, 2002)

The two main solid waste streams are ash and residuals from the desulfurization process. Much of these waste streams can be used to make products such as asphalt and gypsum wallboard; however, contaminants, such as heavy metals, could prevent use of this resource. The waste streams are larger than the amount that could be used productively at present; the materials not used go to a landfill at considerable cost. In addition to the conventional pollutants, emissions include mercury and trace amounts of virtually the entire periodic table of elements. Finding uses for the waste streams illustrates the importance of choosing generation and abatement technologies with the end products in mind.

The environmental impacts of constructing and decommissioning coal power plants are orders of magnitude lower than the impacts of the generation phase (NREL, 1999; ORNL-RFF, 1996; Proops, 1996).

3.4.1 Pulverized Coal Technology

Almost all of the roughly 1,500 U.S. coal-fired power plants burn pulverized coal in conventional boilers (capacity 336,000 MW with an average efficiency of 32%). The pulverization of coal occurs at the plant and the particular process that is employed depends on the coal and the size of the particles required for the type of boiler in use. While there are significant deposits of coal throughout the U.S., there is great variability in terms of heat rate, ash, sulfur and moisture content. The composition of a select few coal types is shown in Table 3.1. These coal types were used in the IECM analysis. The coals considered in this analysis have ash contents that range from 6 to 16 % ash by weight. The bottom ash produced from these coals varies from 4,700 – 48,000 tons/billion kWh. This shows the ash content is important, not only in determining the amount of ash produced, it also influences the efficiency of the power plant and therefore the amount of coal consumed in producing the same amount of electricity. Cleaning the flue gas can require lime or limestone for sulfur removal and waste treatment, copper oxide for gas clean-up, and ammonia for NOx removal (NREL, 1999).

Nearly all pulverized coal plants in the U.S. are “subcritical,” meaning that the boiler is operated at close to atmospheric pressure with steam which is pressurized at roughly 16 MPa and a temperature of 550 ^{o}C. “Supercritical” plants almost double the pressure of the steam, increasing overall plant efficiency roughly 2 percentage points (Higher Heating Value HHV). While both sub-critical and super-critical plants have been proposed over the past several years, it is unclear which technology would be chosen for a new plant in the U.S. today. The sub-critical technology has been used extensively throughout the U.S. and is considered a mature technology. While the super-critical technology has been used in other parts of the world and has similar costs with increased efficiency, the technology has had reliability problems and is not the clear choice for a new plant in the U.S.

Environmental Control Technologies and Costs

Environmental standards for coal combustion have tightened considerably, and will continue to tighten. For example, the current New Source Performance Standards (NSPS) are 0.60, 0.60, and 0.03 pounds per million BTU of energy from coal for NOx, SOx, and PM, respectively. There are further requirements on NOx for the North Eastern States through the State Implementation Plans (SIPs) and Ozone Transport Region (OTR) of 0.15 pounds per million BTU[1]. There are currently cap and trade systems in place (or planned) for SO_2, NOx and Hg which apply to the whole electricity industry instead of the individual plant.

To explore a wide range of technologies and coals, I use the IECM software (IECM User, 2004). The model calibrates well to actual plant operations where available. Figures 3.2 and 3.3 show the efficiency penalties and additional costs associated with environmental controls on a subcritical pulverized coal power plant, assuming the range of coals outlined in Table 3.1 combusted in a tangential boiler. All costs are in 2000 dollars and all mass measurements in short tons. The power plant studied has a capacity of roughly

[1] When NSPS is referred to throughout the rest of this thesis it includes this additional requirement for NOx.

500 MW. The base case has no environmental controls with a base cost of $940-$1060/kW-net, a total capital cost of $440-$500 million, and a net heat rate of 9360-10140 Btu/kWh (all values are dependent on coal type). All cases generate 3.1 billion kWh per year. Since it is difficult to site coal fired power plants in the U.S. it is assumed that a new plant built today would satisfy the most strict regulations and employ any control technology that goes above the regulation if the incremental cost of this further reduction is relatively small.

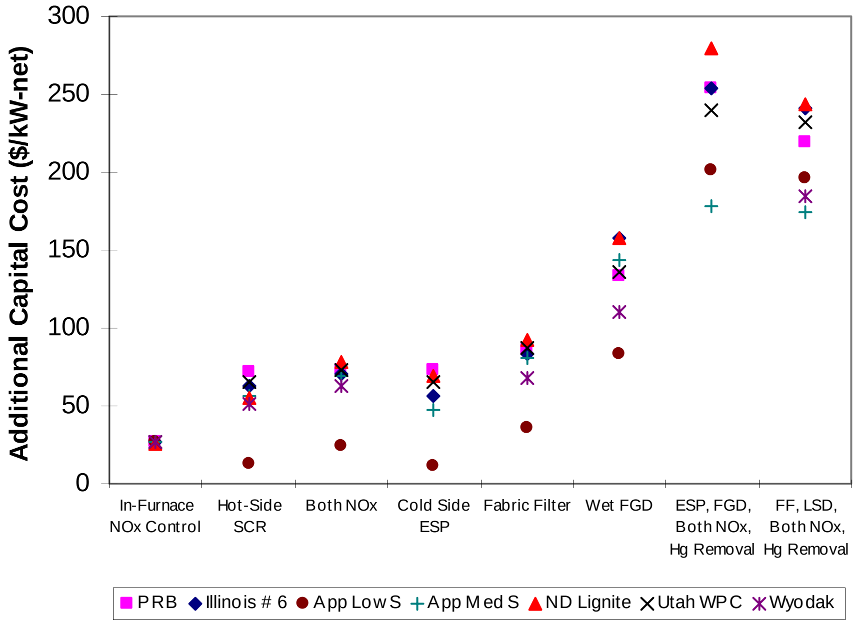

Figure 3.2 Cost Penalties of Environmental Control Technologies for a Subcritical Pulverized Coal Plant (Source: IECM, 2004)

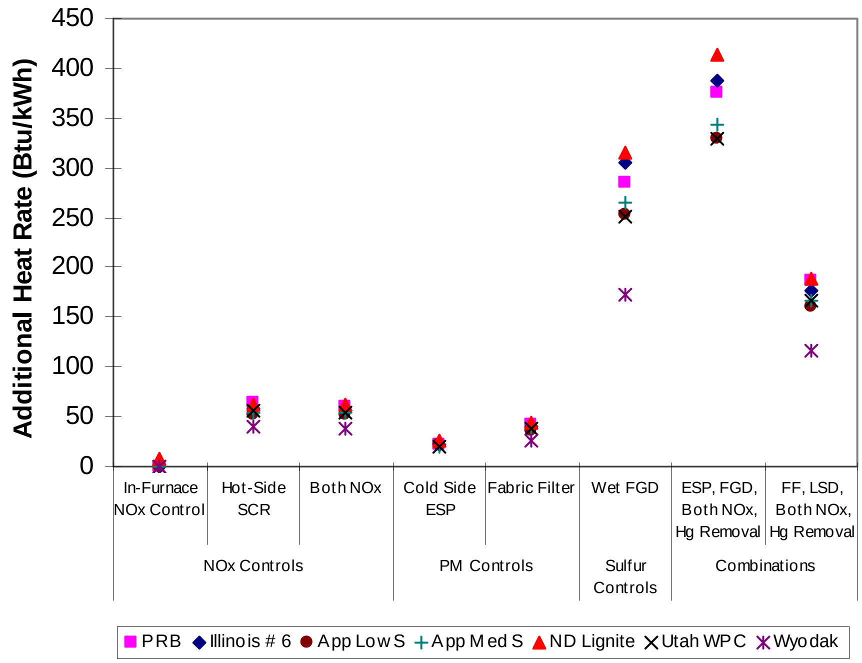

Figure 3.3 Efficiency Penalties of Environmental Control Technologies for a Subcritical Pulverized Coal Plant (Source: IECM, 2004)

Controlling NOx and particulate matter, over the range studied, is roughly half as expensive as controlling SO_2 with flue gas desulfurization (FGD). Designing a new plant for stringent control of NOx, PM, and SO_2, increases the heat rate by 1.5-4.5% and the capital cost by 20-30%. Technology is also available to control the CO_2 emissions. In a subcritical plant, an amine CO_2 removal unit would reduce the efficiency of the system by roughly 40%. An amine carbon removal unit would also more than double the capital cost of the plant. Coal gasification with carbon separation and sequestration can also be used to capture the carbon, as described below.

Figure 3.4 shows the percent increase in net heat rate and capital cost associated with the environmental control technology additions for the range of coal types considered.

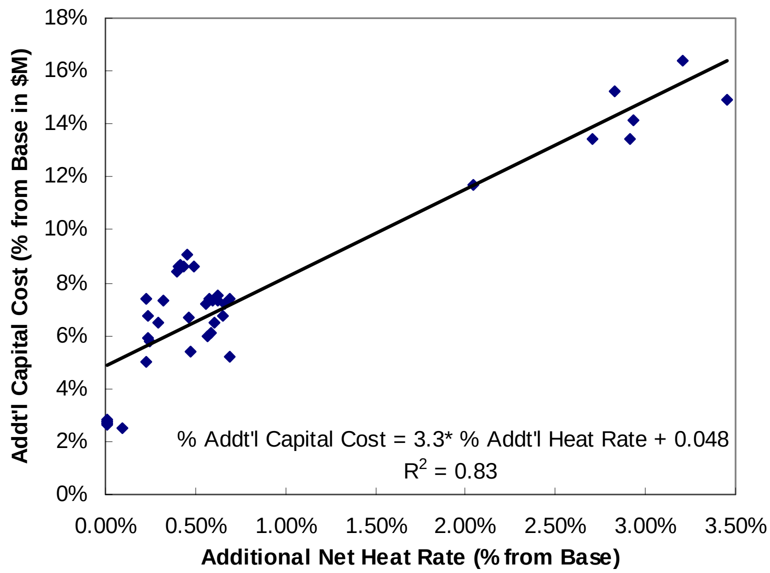

Figure 3.4 Relationship between Heat Rate and Capital Cost for Environmental Controls on a PC Plant (Source: IECM, 2004)

The figure shows a close relationship between the amount of additional energy required for a control technology. To a first approximation, a control technology whose parasitic requirements increase the heat rate 2% increases capital cost 12%. The cost of coal, the principal variable cost, is only about half as great as the capital cost in a new generation plant: approximately 2 cents per KWh for capital cost and 1.2 cents per KWh for coal. Thus, a change in emissions regulations that led to a 12% increase in capital cost and 2% increase in coal costs would raise costs by 0.24 cents per KWh for capital and 0.024 cents for coal costs, emphasizing that it is the increase in capital costs that are ten times more important than the increase in the heat rate.

A tangential boiler is the current low NOx burner technology of choice since it is a cost effective means of reducing NOx emissions to meet regulations. Since advanced NOx burner technologies have almost no effect on heat rate and only raise capital costs by 3%, a coal power plant built today would have these technologies. These technologies include overfire and fuel reburn controls. These technologies in addition to a Selective Catalytic Reduction (SCR) technology result in the attainment of the NSPS requirement. For a 500 MW plant, the operating and maintenance costs for advanced low NOx burner technology and SCR total approximately $5 million per year (0.16 cents/kWh). The use of these environmental controls also requires additional input materials. If all of these NOx control technologies are employed, 8000-9000 tons/yr of urea and roughly 700 tons/yr of ammonia would be required. The North Dakota lignite has different properties and therefore requires different proportions of these materials.

Sulfur dioxide (SO_2) can be costly to control. Flue Gas Desulfurization (FGD) has the largest cost and efficiency impact of the control technologies considered in figures 3.2 and 3.3. Table 3.6 shows a summary of various coal types, the emissions of SO_2 without control, with controls to meet the New Source Performance Standard (NSPS), and controls to remove 98% of SO_2 emissions. The best available technology today is a FGD unit capable of 98% removal. This would likely be the removal achieved by a new plant built today and is therefore considered in this analysis. The sulfur content presented for each coal type is an average value. The amount of sulfur can vary within each of these regions.

SO_2 Removal (using FGD) Coal-Fired Plant Producing 3.1 Billion kWh							
		Wyoming PRB	Med S Appalachian	Low S Appalachian	Illinois # 6	North Dakota Lignite	WPC Utah
Sulfur Content (% by weight)		0.37	7.2	0.64	3.3	1.2	0.61
Heat Content (Btu/lb)		8,340	13,260	13,080	10,900	6,020	11,240
Net Plant Heat Rate, HHV (Btu/kWh)	No Controls	9,800	9,400	9,400	9,500	10,000	9,600
	NSPS	10,000	9,600	9,500	9,700	10,000	9,800
	98% Removal	10,000	9,600	9,600	9,800	10,000	9,800
Total SOx (equivalent SO2 tons/yr)	No Controls	12,000	45,000	14,000	85,000	45,000	16,000
	NSPS	4,100	8,900	4,300	9,200	9,600	4,900
	98% Removal	250	1,000	310	1,920	950	350
Total Capital Cost ($million)	No Controls	-	-	-	-	-	-
	NSPS	51	56	49	61	59	52
	98% Removal	52	57	51	63	61	54
Annualized Costs ($ million/yr)	No Controls	-	-	-	-	-	-
	NSPS	7.3	8.1	7.1	8.9	8.6	7.6
	98% Removal	7.9	8.4	7.4	9.3	9.0	7.9
O&M Annual ($million/yr)	No Controls	-	-	-	-	-	-
	NSPS	7.5	9.3	7.4	12	10	7.9
	98% Removal	8.8	11	8.7	14	12	9.4
Cost of Sulfur Removal ($/ton)	No Controls	-	-	-	-	-	-
	NSPS	1,900	480	1,500	280	530	1,400
	98% Removal	1,400	440	1,200	280	480	1,100
Cost of Sulfur Removal ($/kwh)	No Controls	-	-	-	-	-	-
	NSPS	0.0048	0.0056	0.0047	0.0069	0.0061	0.0050
	98% Removal	0.0054	0.0062	0.0052	0.0075	0.0069	0.0056

Table 3.6 SO_2 Removal (Using FGD) 500 MW Coal-Fired Plant Producing 3.1 Billion KWh
(Source: IECM)

SO_2 emissions can be reduced by over 85% just by switching from Illinois no. 6 to PRB (from 85,000 tons/yr for Illinois coal no.6 to 12,000 tons/yr for PRB coal) without controls. This switch has contributed to the success of the cap and trade system currently in place for SO_2. A FGD unit can also reduce emissions. The cost per ton of SO_2 abated ranges from between $280 to $1900 with the FGD set to meet NSPS. The SO_2 emission credits through the acid rain trading program have traded for under $200/ton for the past several years. However, recently the price of the credits has risen to over $800/ton (Evo Markets SO_2, 2005). If prices stay at this rate, there will be incentive for power plants currently burning bituminous coal to consider switching to PRB coal adding a FGD unit. The sulfur content of the coal and the removal rate specified are responsible for the variation. The higher sulfur content the more economical it is to remove on a per ton basis. Moving from the NSPS standard (0.6 lb/MMbtu) (65-90%) to 98% is less expensive than from no control to the NSPS.   This analysis assumes flue gas desulfurization technology. PRB coal could make use of the less expensive Lime Spray Dryer (LSD) to meet NSPS. The cost of this technology is $74/kw-net compared to the FGD which costs $110/kw-net if it was run with PRB coal to meet NSPS. However, an LSD technology currently capable of obtaining 98% removal has yet to be identified.

The SO_2 abatement technologies require either lime or limestone. For a FGD unit, approximately 20,000 to 150,000 tons of lime/limestone is required; the LSD requires 9,000-110,000 tons each year. Unless the resulting gypsum can be sold as a product, the cost of waste disposal is about $300,000-$2.2 million each year.

Both particulate matter removal technologies (fabric filter and electrostatic precipitator) remove almost 100% of the PM in the flue gas. Unless it can be sold (as road bed aggregate or as a component to add to asphalt or cement), the cost of disposing of the roughly 70,000 to 280,000 tons of ash (produced by my prototypical power plant with the range of coal types considered in this analysis) can cost between $720,000 and $3.1 million per year.

Table 3.7 shows the efficacy of mercury removal from the flue gas. This table compares the emissions from power plants burning different coal types with differing environmental controls.

	Wyoming PRB	Medium S Appalachian	Low S Appalachian	Illinois # 6	North Dakota Lignite	WPC Utah
Emissions with no controls (lb/yr)	240	230	230	260	720	270
Emissions with NOx, SO_2 and PM Control (lb/yr)	160	9.1	9.1	10	490	11
Emissions With All Controls Including Carbon Injection (lb/yr)	73	8.8	9.2	10	220	11
Tons of Activated Carbon	790	-	-	-	850	-
Total Annualized Levelized Cost ($M/yr)	1.1	-	-	-	1.2	-
Abatement Cost ($/lb of Hg abated)	1,300	-	-	-	4,500	-

Table 3.7 Mercury Removal 500 MW Coal-Fired Plant Producing 3.1 Billion KWh (Source: IECM)

The first row of data shows the emissions of mercury from a power plant with no environmental controls. The second row shows how the mercury emissions change as non mercury environmental controls are added to the power plant. These controls include in-furnace NOx controls, hot-side SCR, cold-side ESP, wet FGD and carbon injection. For the bituminous coals, much of the mercury (over 90%) is removed by the technology already in place to remove NOx and SO_2. The subbituminous and lignite coals have ash properties and requirements for operating conditions such that a larger fraction of the mercury ends up in elemental form (as opposed to oxidized form). Injection of activated carbon is required to remove the elemental mercury, however, the elemental mercury is only reduced by roughly half with this technology. This technology requires between 790 and 850 tons of activated carbon each year at an annualized cost of roughly $1 million per year. The additional waste disposal associated with removing this mercury is approximately $13,000 per year. This still only results in a 70% reduction in total mercury emitted. The cost per lb of mercury abated is $1,300 for the subbituminous and $4,500 for the lignite studied. There is currently no NSPS for Hg. However, the U.S. EPA recently issued the Clean Air Mercury Rule (EPA, 2005). This rule requires that the electricity industry must reduce mercury emissions from 48 tons to 38 tons in the first phase and to 15 tons in 2018 through a cap and trade system. These results favor the use of bituminous coals with SO_2 and NOx emission controls. However, this conflicts with the current trend to switch to western low sulfur coals to meet the SO_2 cap.

The discussion of mercury removal demonstrates that the environmental controls that are put in place to reduce a particular pollutant can have an impact on the other pollutants in the flue gas stream. However, this effect is different for different levels of removal efficiency, combination of controls and coal type considered. For example, meeting the NSPS standards for Illinois coal no. 6 requires a removal efficiency of 89% for SO_2, 82% for NOx, 99.6% PM, and results in a removal of 97% of the mercury. PRB coal with controls to meet NSPS requires a removal efficiency of 65% for SO_2, 86% for NOx, 99.6% PM, and results in a removal of 32% of the mercury. While the removal efficiencies can be increased for each of these control devices, there is an upper limit to the amount of removal capable for each control device. For example, the amine system that is used to remove CO_2 from a PC plant can also remove close to 99.5% of the SO_2, 99.5% of the SO_3, 25% of the NOx and 50% of the PM that reaches this control device. Another example is the SCR unit used for NOx removal. This unit can operate at 95%

removal. However, the costs associated with the increased demand for ammonia and the catalyst (required as input) make it cost prohibitive in most current installations.

3.4.2 Coal Gasification Technology

Coal gasification is aimed at decreased emissions; it also raises efficiency. The basic technology for gasifying coal mixes pulverized coal (either dry or in a slurry) with steam and air/oxygen under high temperatures and pressures, producing a mixture of hydrogen, carbon monoxide and methane. Unwanted compounds such as sulfur and CO_2, can be removed and formed into commercial products or stored. Carbon capture and sequestration (CCS) currently has the potential to prevent 90% of CO_2 emissions. This technology can technically be scaled up to 94-95% removal however, the cost and efficiency penalty increases significantly. A Selexol process in one method to remove CO_2 from the syngas produced in a coal gasifier. Selexol is a solvent which is used to remove CO_2 through an absorption process. The Selexol system at current capability runs optimally at 88 to 90% removal of CO_2. It is capable of reaching an efficiency of 94% but the costs and thermal efficiency are affected much more significantly from 90-94% than from 85-90% (Chen, 2005).

Table 3.8 is a summary of the inputs, emissions and capital costs associated with an integrated coal gasification combined cycle (IGCC) power plant with and without (CCS) for several coal types. A subcritical pulverized plant producing the same amount of electricity is included for comparison. The technology presented in this table is a Texaco gasifier with a shift reaction to capture the carbon using Selexol as the solvent. The range of coals is smaller in this case because this particular gasifier cannot currently use any coal below the rank of bituminous coal efficiently. This gasifier has problems with the high and variable ash and moisture content of PRB and North Dakota coals. Too much moisture prevents proper "slurrying" of the coal; too much ash leaves debris in the gasifier and difficulty in removing the contaminants during the cleanup process. This carbon capture technology increases the heat rate 16-18% due to the electricity that is required to operate the carbon capture system. In addition, the cost of the carbon capture technology increases the capital cost of the plant by roughly 40%.

	PC	Texaco Base Plant	Texaco Plant w/CCS - sour shift + Selexol	PC	Texaco Base Plant	Texaco Plant w/CCS - sour shift + Selexol	PC	Texaco Base Plant	Texaco Plant w/CCS - sour shift + Selexol	PC	Texaco Base Plant	Texaco Plant w/CCS - sour shift + Selexol
Net Electrical Output (MW)	530	530	500	530	530	490	530	530	480	530	520	480
Net Plant Heat Rate (BTU/kWh)	9,700	9,000	10,000	9,700	9,100	11,000	9,900	9,400	11,000	9,900	9,100	11,000
Annual Operating Hours (hours)	6,575	6,575	6,575	6,575	6,575	6,575	6,575	6,575	6,575	6,575	6,575	6,575
Annual Power Generation (Bkwh/yr)	3.5	3.5	3.3	3.5	3.5	3.2	3.5	3.5	3.2	3.4	3.4	3.1
Net Plant Efficiency, HHV (%)	35	38	33	35	37	32	35	36	31	34	38	32
Input (ton/yr)												
Coal	1,290,000	1,190,000	1,290,000	1,270,000	1,190,000	1,280,000	1,560,000	1,490,000	1,600,000	1,520,000	1,390,000	1,490,000
Oil		5,100	4,800		5,100	4,700		5,100	4,700		5,000	4,600
Output (ton/yr)												
Slag		142,000	154,000		112,000	121,000		191,000	205,000		189,000	203,000
By-product Sulfur Sold		7,460	8,070		24,700	26,700		47,200	50,700		8,320	8,920
Particulate Emissions to Air	500	16	17	500	16	17	510	16	17	510	16	17
Carbon Dioxide (CO2)	3,390,000	3,030,000	311,000	3,470,000	3,120,000	312,000	3,570,000	3,240,000	314,000	3,780,000	3,350,000	318,000
Sulfur Dioxide (SO2)	357	354	383	1,173	1,170	1,263	2,201	2,237	2,404	402	395	424
Nitrous Oxides (NOx)	2,060	228	235	2,060	235	235	2,110	228	235	2,110	228	235
Capital Cost ($/kw-net)												
Air Separation Unit		227	259		244	280		261	334		314	366
Gasifier Area		417	478		423	487		480	556		475	555
Sulfur Control	107	64	92	121	83	114	133	101	135	115	72	103
CO2 Capture		0	264		0	267		0	272		0	346
Power Block		560	596		562	602		563	609		565	617
Total Capital Cost ($/kw-net)	1200	1300	1700	1200	1100	1800	1200	1400	1900	1200	1400	2000
Total Capital Cost ($Million)	610	670	840	610	690	860	640	740	920	630	750	950

Table 3.8 Inputs, Emissions and Costs of an Integrated 500 MW Coal Gasification Combined Cycle Plant producing 3.1 to 3.5 billion kWh
(Source: IECM, 2004)

Several additional insights can be drawn from this comparison with the pulverized coal technology. In order to produce the same amount of electricity as the IGCC unit without carbon capture, the PC plant would have to be approximately 10% larger in gross capacity; however, the cost of the plant is 9 – 18% cheaper to build. The cost of removing the sulfur is 30-67% more expensive in the PC plant than it is in the IGCC plant; however, the same level of removal is possible (98%). Finally, the efficiency gain from building an IGCC plant is much smaller than reported in other studies. If a supercritical plant could be built at the same cost as the subcritical PC plant reported here at a 2 percentage point efficiency gain, there would be virtually no difference in efficiency between the supercritical PC plant and the IGCC plant. However, while the conventional PC plant is considered a mature technology, the efficiency of the IGCC plant could improve overtime.

The shift from subcritical pulverized coal to gasification produces significant emissions reductions of CO_2 and PM. Part of the reason is that the heat rate of a PC plant (without CCS) is estimated to be between 9,700-10,480 BTU/kWh whereas an IGCC plant (without CCS) is estimated to be approximately 9,000-9,400 BTU/kWh.

The efficiency difference reported in Table 5 for Illinois Coal No. 6 is important. The capital cost of the IGCC plant is 16% higher than the PC plant but the operating and maintenance cost (minus the cost of coal) of the PC plant is 24% higher than the IGCC plant ($94 and $76 million/yr respectively). Amortizing the capital and adding it to the overall annual maintenance costs gives a cost of $142 million for the PC plant and $141 million for the IGCC plant. Since the IGCC plant is 5-9% more efficient than the PC plant, the IGCC plant requires 5-9% less coal (depending on the coal type considered). This results in a savings of $1.9 to $3.7 million per year (assuming a cost of $30/ton) and total annual costs of $189 million for the PC plant and $185 million for the IGCC plant. If the cost of the SO_2 and NO_x permits are added (assuming a cost of $800/ton and

$4,300/ton respectively - EVO Markets, 2005), the costs rise to $198 million for the IGCC plant and $189 million for the PC plant. Thus, including the lower coal use and better environmental performance, the IGCC plant is slightly cheaper than the PC plant. Finally, the IGCC technology allows for easier/cheaper capture of unwanted emissions such as CO_2.

IECM vs. the Literature

Table 3.9 shows a comparison between the emissions from previous literature and the IECM software. Note that the upstream estimates discussed earlier were added to the IECM output in order to reflect the full life cycle of emissions for this analysis.

The studies of life cycle emissions of coal-fired generation conducted by Oak Ridge National Laboratory-Resources For the Future (ORNL-RFF, 1996), National Renewable Energy Laboratory (NREL, 1999), Argonne National Laboratory (ANL, 2001), (Pacca et al., 2002), (IECM, 2004), (Sundqvist, 2004), (Gagnon, 2002), (Owen, 2004) and (Roth, 2004) differ considerably. The ORNL-RFF study examined typical generation plants in the Southeast and Southwest U.S. The NREL study examined three types of pulverized coal plants (average U.S. plant, plant satisfying NSPS, plant satisfying LEBS). The Argonne study examined a gasification plant with and without the production of hydrogen. The Pacca et al. study looked at the global warming effect of various fuels and technologies at different time periods through the life of an average power plant. The IECM study looked at both sub critical pulverized coal as well as IGCC technology with and without carbon capture and sequestration. Since the IECM software only models the generation phase emissions, a separate entry shows the emissions when the upstream emissions are added (based on estimates discussed in the previous section). In addition, the SO_2 and NOx emissions were supplemented with literature values (Holt et al., 2003; Holt et al., 2002; Ratafia-Brown et al., 2002; IEA, 2003). Several of the studies presented are actually a summary of previous studies.

COAL Comparison of Emissions (ton/GWh)														
			Implied Efficiency (%)	**CO_2 eq**	**SO_2 eq**	**NO_2 eq**	**PM**	**CO**	**HC**	**As ($\times 10^{-4}$)**	**Cd ($\times 10^{-6}$)**	**Mn ($\times 10^{-4}$)**	**Pb ($\times 10^{-5}$)**	**Se ($\times 10^{-4}$)**
Pulverized Coal Systems	**ORNL-RFF**	Southeast Ref Site	36%	1100	1.8	3.0	1.6	0.27	0.099	2.0	3.0	1.3	9.0	0.5
		Southwest Ref Site	36%	1200	0.87	2.3	1.6	0.27	0.13	2.0	3.0	1.3	9.0	0.5
	NREL	Average	32%	1100	7.4	3.7	10	0.30	0.23	0.54	4.5	0.47	3.3	4.5
		NSPS	35%	1000	2.8	2.6	11	0.28	0.22	0.45	3.7	0.39	2.7	3.7
		LEBS	43%	820	0.79	0.60	0.12	0.21	0.21	0.37	3.0	0.32	2.2	3.0
	Pacca (adapted by averaging over the plant life)		38%	900										
	Sundqvist		25-38%	900-1400	0.81-15.4	0.88-5.8								
	Gagnon		26-35%	990-1300	0.12-5.8	1.0-5.0								
	Owen		32%	1100										
	Roth (adapted by assuming a range of heat rates)		31-35%	990-1100	9.0-9.9	4.0-4.4	0.48-0.52	0.091-0.10						
	IECM**	Sub-Critical PC	33-36%	980-1100	0.087-0.64	0.58-1.0	0.15-0.16	0						
		Sub-Critical PC w/CCS		130-160	0.0006-0.0024	0.86-1.5	0.10-0.11	0						
	IECM†	Sub-Critical PC	30-35%	1000-1200	0.14-0.88	0.63-1.9	0.18-0.19							
		Sub-Critical PC w/CCS		190-220	0.041-0.042	1.1-1.7	0.13-0.14							
Gasification Systems	**Argonne**	Base Case	37%	940										
		Co-Product Case*		120										
	IECM**	IGCC	38-40%	870-970	0.10-0.65	0.098-0.10	0.004-0.005	0						
		IGCC w/ CCS*		95-100	0.0001	0.10-0.11	0.0052-0.0055	0						
	IECM†	IGCC	36-38%	930-1000	0.14-0.69	0.34-0.34	0.034-0.035							
		IGCC w/ CCS*		150-160	0.04	0.34-0.35	0.035-0.036							
	Owen		41%	830										
	Roth (adapted by assuming a range of heat rates)		36-37%	920-960	8.2-8.6	3.8-3.9	0.45-0.47	0.085-0.089						
* Coal Gasification with Carbon Capture and Sequestration														
** IECM without upstream emissions added														
† IECM with upstream emissions added														

Table 3.9 Comparison of Emissions from Coal Studies
(Sources: ORNL-RFF, NREL, ANL, Pacca and Horvath, IECM, Sundqvist, Gagnon, Owen, Roth)

The differences in approach and scope lead to considerable variation among the studies for each emission type. For example, the emissions of CO_2 from pulverized coal units without CCS vary from 820 to 1400 ton/GWh. In climate policy analysis different assumptions about this value will have an impact on the forecasts of the prices. The discrepancies in these results can be attributed largely to the coal selected, the efficiency of the plant and the emission control technologies assumed. The implied efficiency shown in the table was calculated based on the heating value and carbon content of the coal assumed in the study (if the coal type was not specified in the study, an average heating value and carbon content was assumed) and the CO_2 emissions shown. The efficiencies of the PC plants are between 25 and 43%, although no new U.S. plant is likely to be at either end of the range. The plant design has improved beyond an efficiency of 25%; while the NREL study identified a technology that could achieve 43% efficiency, it is not clear that the technology has been commercially proven or that the cost of the plant would be competitive. The IECM software shows a reasonable efficiency between 33 and 36%. The variation in the IECM study stems from the coal type selected. The coal gasification efficiencies range between 36 and 41%. Since no commercial scale IGCC plant exists in the U.S. today, the efficiencies assumed are uncertain.

The results for the non-CO_2 emissions vary as well. Studies having high emissions for SO_2, tend to have higher emissions for NOx , PM etc. This implies that an important determining factor is the age of the technology chosen. If an older plant or technology is assumed, it performs poorly in most respects.

The SO_2 eq emissions range from 0.12 to 15 ton/GWh for the PC plants without CCS. This is a considerable variation of more than 3 orders of magnitude. The variability stems from the coal type and control technologies assumed. The 15 ton/GWh reflects the emissions from an “old” plant in Europe and is not considered a representative value for a new (or even average) coal plant in the U.S. today. The average U.S. emissions of SO_2 are 7.4 tons/GWh (31% of U.S. coal plants have FGD) (NREL). The IECM emissions (0.62-1.0 tons/GWh) reflect a new plant with a flue gas desulfurization unit with a removal efficiency of 98%.

A similar result can be seen for NOx emissions. The average U.S. power plant emits 3.7 ton/GWh. Less than half of the currently operating U.S. coal plants have any form of NOx control operating more than 4400 hours/yr. The IECM study assumes a low NOx burner and a selective catalytic reduction unit, resulting in emissions between 0.63 and 1.9 ton/GWh.

In general, the IECM results fall in the middle of the ranges from previous literature. The literature values that were generally higher in efficiency had lower emissions and represented a more optimistic view of current technology. Conversely, the lower efficiencies, and higher emissions generally reflect older technologies in use today. The IGCC emissions from the IECM model tend to fall at the upper end of the emissions from the literature. This might again reflect a general technological optimism in the literature for a technology that has yet to be studied at a commercial scale in the U.S.

3.5. Discussion

Improved technology is especially evident for coal-fired generation. Technologies that control emissions of conventional pollutants have made notable progress, although they tend to be parasitic, lowering efficiency and increasing both capital and operating cost. Coal gasification is a breakthrough technology that offers higher efficiency and better environmental controls, although at a higher capital cost. The technology also offers an easier method for separating the carbon dioxide for sequestration to reduce GHG emissions.

Someone considering new generation capacity is likely to choose between coal and natural gas, unless there is a renewable portfolio standard that would likely lead to a wind turbine. The coal plant, using bituminous medium sulfur coal, that meets the air pollution and mercury standards that would have the lowest lifetime costs would be a IGCC plant. This is not true for all coal types. However, it also seems prudent to look forward to a time when greenhouse gas emissions will be constrained. If CO_2 could be sequestered inexpensively or if emissions of air pollutants, mercury, and other heavy metals will be more tightly constrained, a coal gasification plant with CO_2 capture and sequestration would become the preferred technology for this coal type. However, the choice of IGCC is not as clear for lower ranked coal. Since no reliable commercial IGCC plant is operating today, major investments are unlikely until the technology is shown to be reliable.

Chapter 4: Should We Transport Coal, Gas or Electricity: Mid-Term Cost, Efficiency & Environmental Implications

4.1 Introduction

4.1.1 Background

The U.S. mines over one-billion tons of coal each year (EIA, 2004c) to produce 51% (EIA, 2003e) of its electricity supply. Coal shipments represent more than one half trillion ton-miles each year, since coal deposits are distant from population and demand. This transport requires large amounts of energy, generates pollution emissions, and results in the death of about 400 people each year at rail crossings (calculated from (BTS, 2002)). Rail systems are costly to build and maintain; shipping coal by rail constitutes the majority of the cost of delivered Powder River Basin (PRB) coal.

The economic and environmental impacts of alternative options for delivering electricity to demand centers are explored. The implications of shipping energy equivalent to 3.9 million tons a year from the PRB 1,000 miles to Dallas are explored.

Several studies have investigated the environmental impacts of power generation systems (Doctor, 2001; ORNL-RFF, 1996), transmission systems (DeCicco, 1992; Kalkani, 1996; Hammons, 2001), the tradeoffs between alternating current (AC) and direct current (DC) power (Hauth, 1997; Linke, 1988), and the costs and feasibility of new transmission development (Wiese, 1996; Hirst, 2001). Amphlett et al. investigated the environmental tradeoffs between transmission and rail but did not consider costs (Amphlett, 1996).

Spath and Mann include a minemouth generation case in an evaluation of the life cycle impacts of coal-fired power production (NREL, 1999). However, the study does not include transmission line losses.

Four options are considered to provide 6.5 billion KWh of electricity in Dallas from PRB coal: (1) A pulverized coal power plant in Texas, fueled by PRB coal transported by unit trains. (2) A pulverized coal power plant in Wyoming close to the mine; transmission lines carry the electricity to Texas. (3) A gasifier and methanation process converts the coal to methane in Wyoming; the gas is transported to Dallas by pipeline to generate electricity in a combined cycle power plant. (4) A gasifier, methanation and combined cycle power plant at the mine to generate electricity, sending the electricity to Texas via transmission lines. Options that were considered but not included in the analysis were a coal slurry pipeline and other clean coal technologies (see supporting material for details).

It is assumed that new generation plants, transmission lines, rail lines, and gas pipelines can be built, despite siting problems. The base case assumes that no infrastructure exists and therefore must be built for all four options considered in the base case. This assumption was tested in the sensitivity analysis and is discussed further in this paper. It is also assumed that all plants satisfy stringent emissions regulations and that the location of the plants does not affect either costs or emissions. Transporting coal requires diesel fuel while transporting electricity or methane requires additional capacity and coal to make up for transmission and gas pipeline losses. Although the plants are identical (whether located in Wyoming or Texas), the public health implications are quite different, since many more people are exposed to the generation plant located in Dallas.

4.1.2 Method

A hybrid life cycle comparative analysis (LCA) framework is used to assess the economic and environmental impacts associated with every stage of the production of electricity, from extracting ore to final disposal of unwanted residuals. This method combines the benefits of the EIOLCA (Economic Input-Output Life Cycle Analysis) (Hendrickson, et al., 1998) method with those of the traditional Society of Environmental Toxicology and Chemistry (SETAC)/ U.S. Environmental Protection Agency (EPA) approach (SETAC, 2004). The cost and environmental impact data available at a national, aggregated level (by industrial sector) is used in conjunction with a product analysis of more specific electricity generation options.

The capital (amortized over the life of the investment), operating and maintenance costs, and social costs are estimated for each of the alternatives. These annualized capital and operating costs were apportioned to the appropriate economic sectors and input into the eiolca.net model (CMU, 2005) to determine the “indirect” environmental emissions; these were added to the direct emissions to estimate the life cycle emissions from these four options.

The discharges and costs from the generation phase are estimated for each alternative using the Integrated Environmental Control Model” (IECM, 2004). Using this model, a power plant can be built “virtually” to specifications such as the fuel type, control technologies, and boiler type.

4.1.3 Powder River Basin Coal to Dallas: Alternatives

Coal from the Powder River Basin (PRB) is in high demand due to its low sulfur content (0.4%) (EIA, 1999) and low cost. Although the heat content of PRB subbituminous coal is lower (8340 btu/lb on an ‘as received’ basis) (IECM, 2004) than for bituminous coal, it occurs in massive shallow formations that are inexpensive to extract by surface mining; over 30% (BLM, 2000) of U.S. coal is mined in the PRB. In 2000, 27 states received 340 million tons (EIA, 2000e) of Wyoming coal, with Texas receiving 50 million tons (EIA, 2001). The 67 billion tons (EIA, 2000d) of extractable coal in Wyoming is 200 times the current extraction rate.

Wyoming exports 70% of the electricity it generates and 95% (BTS, 1994) of the coal it produces. The price of coal at the mouth of a PRB mine is approximately $7/ton ($0.42/million BTU) (EIA, 2004c); the delivered price in Texas is $17 to $29/ton ($1.0/million BTU to $1.7/million BTU) (FERC, 2002).

Table 4.1 summarizes the general assumptions of the four options considered in this study.

Coal	PRB (Wyoming)	Subbituminous
Distance (PRB to Dallas)	1000	Miles
Energy Content of the Coal	8340	Btu/lb
Total Electricity Delivered to Dallas	6.5	BkWh
Cost of Capital	8	%
Plant Capacity Factor	75	%
Amortization Period	30	years
Pipeline Losses	3	%
Transmission Line Losses (408kv HVDC line)	7	%

Table 4.1 General Assumptions for Four Options for Transporting Coal Energy

The base case assumes that no infrastructure exists and so 1,000 miles of rail, transmission lines (including converter stations), or gas pipeline must be built. The economies of scale in these systems would lower the costs if the transport systems were built and used to capacity, especially for rail and gas pipelines. This is less relevant for the transmission line, since increasing the power flows increases the losses and costs. This assumption is relaxed and discussed later in this text.

An HVDC line was chosen for transmission due to lower losses than the corresponding HVAC system. This is discussed in more detail later in this text.

Table 4.2 summarizes the specific assumptions for each option. The gross plant capacity is different for each option due to the plant characteristics and the additional power required to compensate for losses. The IECM software used to model the pulverized coal plant assumed it meets new source performance standards and has an efficiency (HHV) of 34%. The overall efficiency of coal by rail is overstated since it does not include the 10 milion gallons of diesel fuel required for transport. The gasification and methanation process is modeled after the Lurgi gasifier and methanation process currently in operation in North Dakota. This fixed-bed gasifier operate under conditions which make it better equipped to handle the high (and variable) ash and moisture content in the PRB coal. An efficiency of 69% was assumed for the methanation process (Probstein, 1982). The IECM software models the Natural Gas Combined Cycle (NGCC) unit and calculates an efficiency (Higher Heating Value) of 49%.

	Coal-by-Rail	**Coal-by-wire**	**Coal-to-Gas-by-Pipeline**	**Coal-to-Gas-by-Wire**
Power Plant	Sub Critical Pulverized Coal	Sub Critical Pulverized Coal	Gasifier + CC	Gasifier + CC
Gross Plant Capacity (MW)	1077	1153	1038	1114
Overall Efficiency (HHV)	34.1%	31.7%	32.8%	31.3%
Coal Required (million tons)	3.9	4.2	4.1	4.3
Natural Gas Produced (Bcuft/year)	N/A	N/A	48	50
Net Annual Output (BkWh)	6.5	7.0	6.5	7.0
Environmental Controls	NOx - In-Furnace Controls & Hot-Side SCR		Sulfur Control	
	Particulate Matter - Fabric Filter			
	SO_2 - Lime Spray Dryer			

Table 4.2 Assumptions for Each Option for Transporting Energy from Wyoming to Texas.

Other alternatives were considered for this analysis including, coal slurry pipelines, barge, other clean coal technologies and other transmission technologies.

4.2 Results

4.2.1 Economic Results

Figure 4.1 summarizes the costs of each option. The capital cost of both the plant and the transport infrastructure are presented as an annualized capital cost. Fuel includes the fuel used to transport the energy, either diesel fuel or coal. The externality costs include pollution emissions, CO_2 emissions as well as death and injuries in transportation.

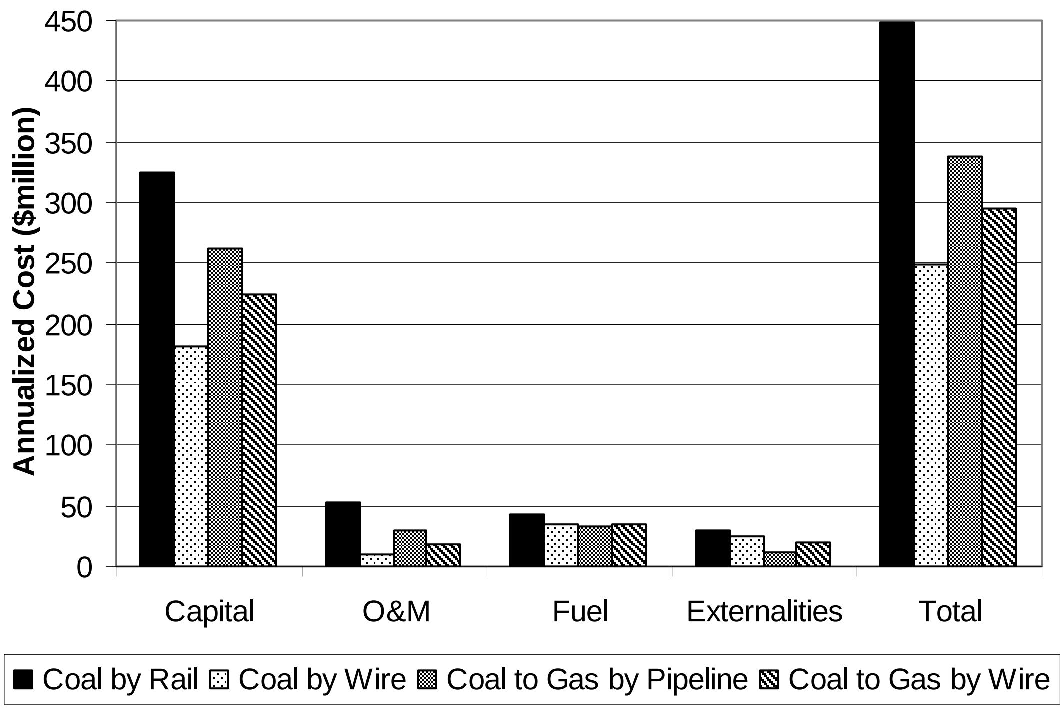

Figure 4.1 Summary of the Cost for Four Methods of Transporting Energy from the PRB to Dallas Assuming New Infrastructure Required for Each Option in the Base Case.

The annualized cost of the capital investments dominates the costs for each option. The coal-by-rail option is the most costly of the four options in the base case. The two transmission options are slightly cheaper than the pipeline option due to slightly lower construction and operating costs. However, these options do not use the full capacity of the new infrastructure: much more coal could be shipped on the rail system, the right of way could accommodate more transmission, and the pipeline could handle much more methane. In each case, spreading the capital costs over more shipments would decrease unit costs. However, increasing throughput would lead, eventually, to congestion with higher costs and losses.

U.S. rail shipments kill about 1,000 people each year (BTS, 2002). Coal transport in the coal-by-rail option of the base case was estimated to result in 1.4 fatalities per year based on the proportion of freight to passenger travel, percentage of ton-miles of coal shipped in this analysis relative to the total ton-miles of freight transport. Other externality costs include injuries and lost work days due to non-fatal collisions. These unfortunate events did not affect the conclusions from the analysis.

The externality costs from air pollution emissions were important, but did not affect the conclusion.

4.2.2 Fuel Consumption

Table 4.3 shows various aspects of the energy consumed during the transport phase. This includes the diesel fuel consumed by the locomotives as well as the additional coal combustion to compensate for losses. The coal-by-rail option in the base case uses 10 million gallons of diesel fuel, while the other three options use 280,000, 150,000, and 330,000 tons of coal in order to deliver the stipulated amount of electricity to Dallas. At \$11/million BTU, diesel fuel is more than 26 times more expensive than coal at \$0.42/million BTU.

	Fuel		Energy			CO_2 Emissions		Fuel Cost
	Additional Coal (million tons)	Diesel (million gallons)	Coal (trillion BTU)	Diesel (trillion BTU)	Total (trillion BTU)	CO_2 Emissions from Fuel Only	Total CO_2 eq (million tons)	\$ millions spent on fuel
Coal by Rail	-	10	-	1.4	1.4	0.13	0.25	15.0
Coal by Wire	0.28	-	4.7	-	4.7	0.51	0.55	2.0
Coal to Gas by Pipeline	0.15	-	2.5	-	2.5	0.23	0.30	1.1
Coal to Gas by Wire	0.33	-	5.5	-	5.5	0.54	0.57	2.3

Table 4.3 Summary of Annual Fuel Consumption of ‘Transport’ for Each Option

Emissions of CO_2 are shown for the fuel consumed in transport (diesel fuel and additional coal) as well as the total life cycle CO_2 emissions of the options considered. (Note: this includes any additional coal combustion and mining as well as upstream emissions from construction and operation of infrastructure but does not include the base 3.9 million tons of coal that are burned in all four options). The coal by rail option has the smallest CO_2 emissions and has the smallest fraction of the emissions generated during the transport phase of the life cycle.

4.2.3 Environmental Analysis

Figure 4.2 shows emissions from each of the options, excluding the level of CO_2 emissions from the base electricity generation of 3.9 million tons of coal. These are cumulative emissions for construction of infrastructure (CMU, 2005) and 30 years of operation for all four options. However, it does not include the base generation of electricity from the base amount of coal. The results for the base case are mixed. For NO_2, VOC and PM10 the coal-to-gas-by wire option has less emissions; for CO coal-by-rail option has the lowest emissions followed closely by coal-to-gas by wire; for greenhouse warming potential (GWP) coal-by-rail option has the lowest followed closely by the coal-to-gas by pipeline. The GWP for coal-by-wire option uses the most energy due to the additional generation required to compensate for line losses (and the slightly lower efficiency). A superconducting transmission line or a higher voltage HVDC line with losses less than 4.5% could have lower GWP emissions than coal-by-rail.

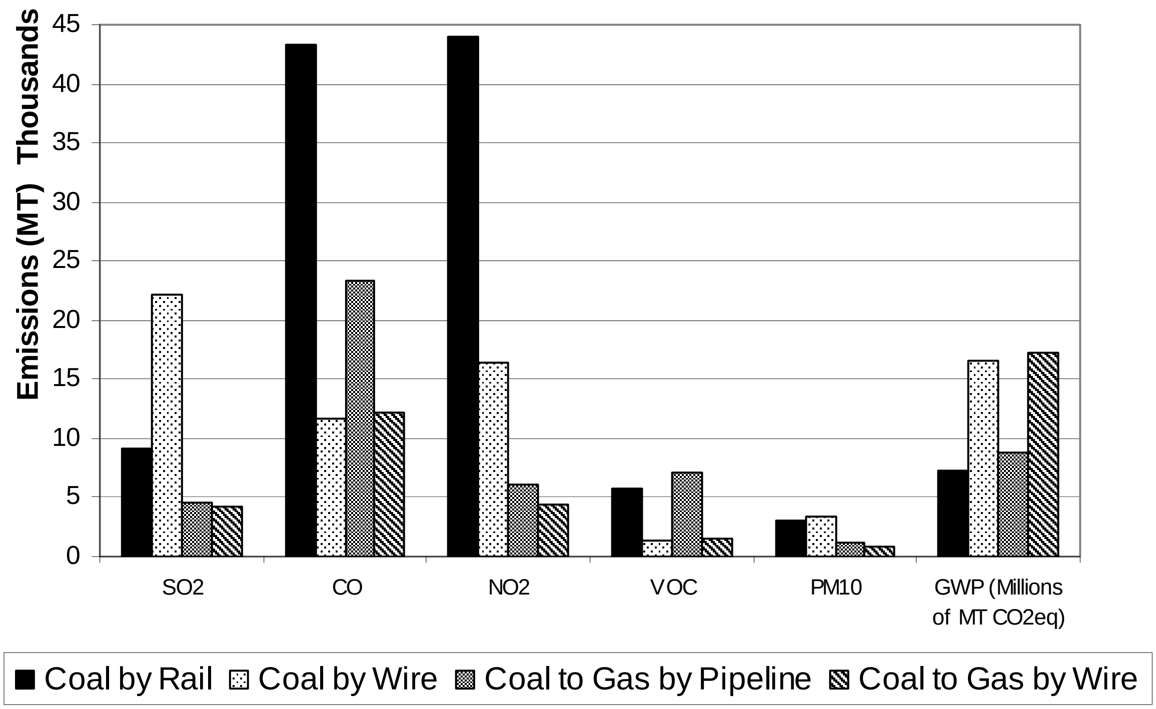

Figure 4.2 Comparison of Emissions for the Four Methods of Transporting Energy from the PRB to Dallas Over 30 Years.

These new plants would have to purchase SO_2 allowances each year at $140/ton. The pollution emissions are translated into dollars using estimates of the social cost of air emissions (Matthews, 2000). These pollution and injury externality costs are substantial, as shown in Figure 4.1: The coal-by-rail and coal-by-wire and transmission options have externality costs of $15 and $20 million per year, respectively. Gasifying the coal and then burning it in a combined cycle generation would have lower costs.

Between 17,000 and 24,000 acres would be cleared and used for the transmission towers and lines, but much of this land could be used for other purposes (e.g. farming or ranching). Pipelines require less land and are virtually unobtrusive when buried. Rail road bed would be the most obtrusive because of the pollution, noise, and impediment to traffic. The quantification the environmental disruption, and other land use impacts was not within the scope of this analysis.

In addition to accounting for the combustion of diesel fuel, I consider the life cycle impacts of producing the diesel fuel (CMU, 2005).

4.3 Generalization within PRB to Dallas

4.3.1 Breakeven Distances and Volumes

The U.S. rail infrastructure, particularly from the PRB to Texas, is extensive. Carrying 3.9 million tons of PRB coal to Texas requires just over one unit train per day, adding little congestion. If there are bottlenecks, triple or quadrupled track could be added. It was estimated that at most perhaps 100 miles of new track would have to be added. Thus, considering the existing infrastructure, coal by rail would be cheapest. However, if more than 200 miles of rail bed had to be added, building the transmission system would cheaper. The environmental emissions would be less affected by the amount of new rail capacity that was added since the emissions are dominated by the amount of diesel fuel that is burned during the transport phase.

If there is not infrastructure in place, the cost of the rail infrastructure in this analysis decreases when it is spread over a greater number of shipments. Figure 4.3 shows that to deliver more than 3,000 MW, coal-to-gas-by-pipeline is the cheapest alternative. Coal-to-gas-by-wire is not competitive. In the competition between coal-by-rail and coal-by-wire, the latter is cheaper up to 9,000 MW. This analysis assumes that all of the rail shipments could fit on one dedicated rail bed, that a new transmission line would be needed for each additional 1,000 MW (a transmission corridor could handle multiple lines) and that one pipeline could transport enough methane for 12,000 MW.

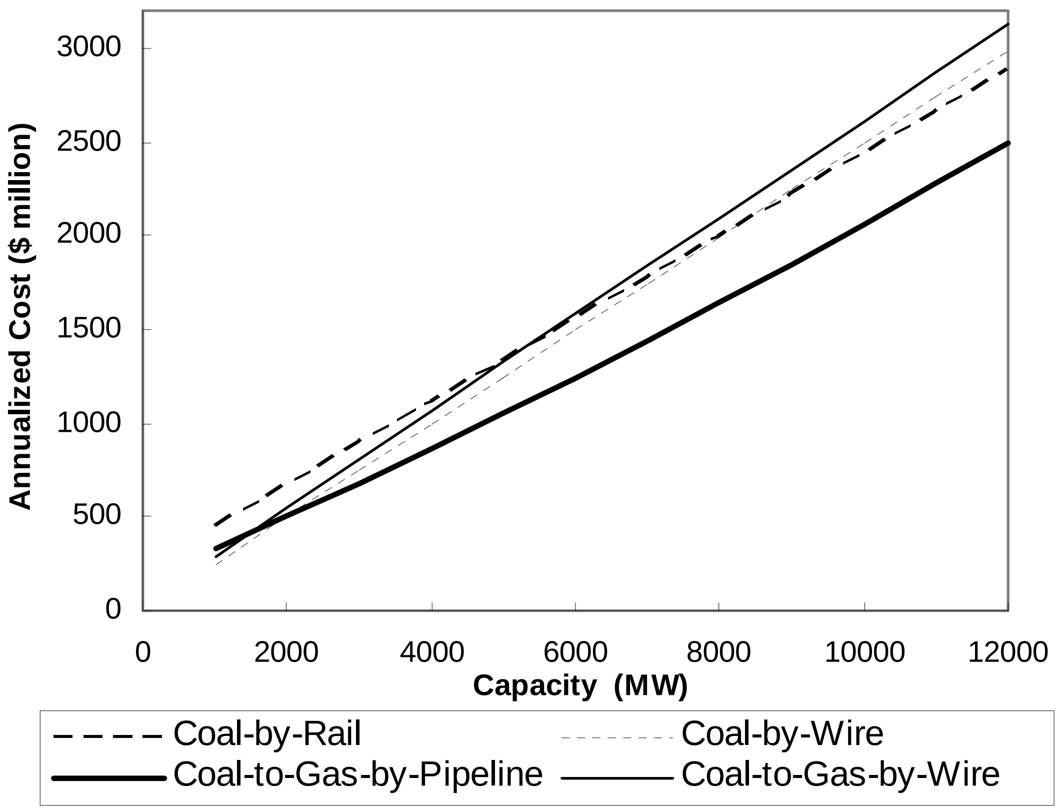

Figure 4.3 Annualized System Costs with Varying Amounts of Electricity Delivered

Transmission line losses for a 1,000 mile system can be large, but the capital costs of the lines are more important than the cost of the lost energy. Figure 4.4 shows a comparison of the annualized costs of the options as the distance changes, assuming that all new infrastructure is needed. The HVDC line is a +/- 408 kv line with 7.0% line losses (including the converter station losses) whereas the HVAC line is a 500kv line with 9.3% losses. For distances greater than 600 miles, the HVDC line is better, since the line losses more than compensate for the DC converter stations. At a length less than 500 miles, the HVAC line is better, since the line losses are too small to pay for the DC converter stations. Between 500 and 600 miles, the choice is unclear. This breakeven distance is higher than a previous analysis (300-400 miles) since the losses assumed in that analysis were almost double those assumed here (Hauth, 1997). These results are also sensitive to the line loading. Both the HVAC and HVDC lines were assumed to have a capacity of 2,000 MW but were loaded at 1,000 MW. The higher the loading above this level, the more the HVDC would be favored. While the cost of converting coal to gas remains more costly than the coal-by-wire options, below approximately 400 miles, shipping the energy through a pipeline is more economically attractive than shipping it as electricity.

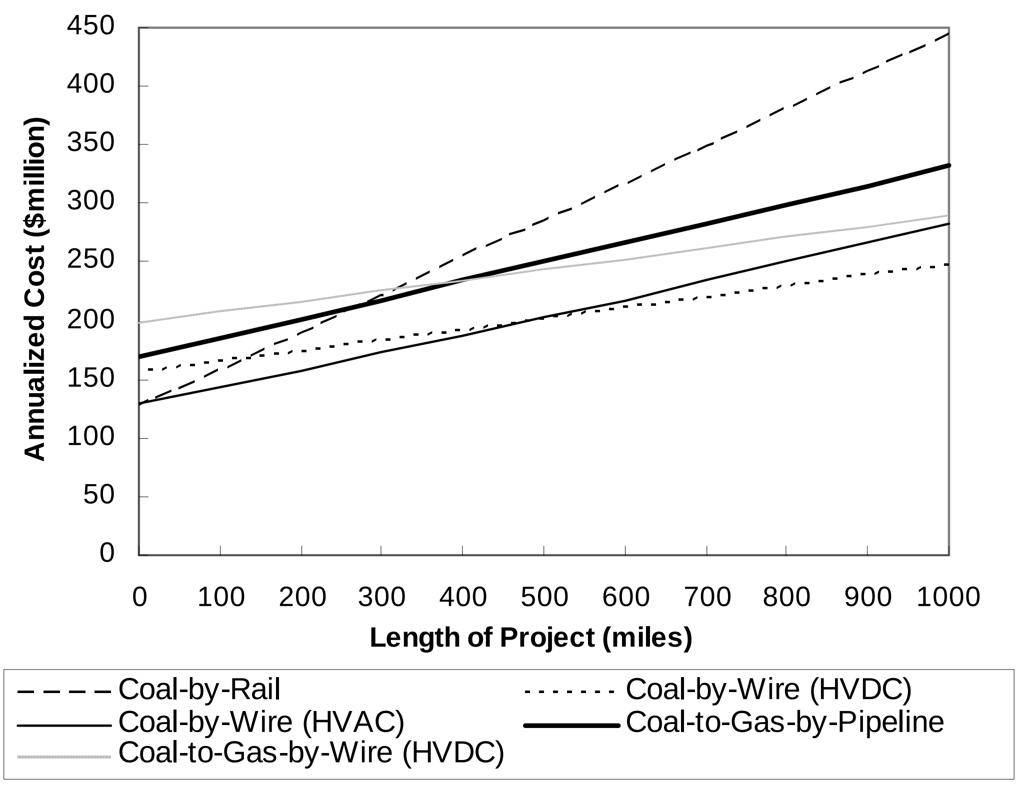

Figure 4.4 Breakeven Distances for All Options

4.3.2 Sensitivity Analysis

If petroleum prices increase, the cost of using unit trains would increase. However, the price of diesel would have to increase from $1.5 per gallon to at least $4.0 per gallon before shipping coal by rail would be more expensive than shipping electricity, assuming that only 100 miles of new track capacity would have to be built.

The social cost of CO_2 that was used in the base case analysis was $14/ton. It is possible that this value could increase in the future, for example, with the introduction of a carbon tax. If 1,000 miles of rail were required, a carbon tax as high as $400/ton is required to make the rail option the economically preferred option.

One way to decrease the number of fatalities due to rail traffic is to have the train go over or under the highway at each rail crossing. At roughly $9 million to upgrade each crossing, if more than 11% of the over 600 crossings between Wyoming and Texas had to be upgraded, transmitting electricity would be cheaper, assuming that only 100 miles of new roadbed were required. It is acknowledged that this estimate is an upper bound since the area between Wyoming and Texas is less densely populated than the average and there could be less costly methods of increasing safety at the crossings (e.g. signals, gates etc.)

4.3.3 Water

Water consumption for either of the power plants considered in this analysis will be on the order of tens to hundreds of billions of gallons of water annually if direct cooling is used. This can be reduced by switching to either indirect or hybrid cooling systems however, there are cost and efficiency penalties. In general, gasification plants consumed less than pulverized coal plants by 4 to 10 times. While this analysis does not consider siting constraints, they would be different in each location and water scarcity would play a role. However, since there are technical solutions to this problem and power plants have recently been proposed in both locations, it is considered possible to site a plant in either location.

4.3.4 Coal to Gas Options

While converting coal to methane is not a commonly discussed option, the results of this analysis show that it is a competitive alternative. Gasifying PRB coal using a Lurgi gasifier requires development. Transporting the methane by pipeline is attractive since the compressors consume only 3% of the methane in contrast to the 7% electricity line losses. The costs for this option would fall if the separated by-products of the syngas were sold, including CO_2, fertilizers, phenol, cresylic acid, krypton, xenon, naptha, and liquid nitrogen. Sale of byproducts represented more than 30 percent of Dakota Gasification Company's (company operating the current Lurgi gasifier in North Dakota) total gross revenue in 2000. This option produces the second smallest amount of greenhouse gases and gasifying the coal could be taken a step further to produce pure streams of hydrogen and CO_2; the latter might be sequestered, eliminating nearly all of the CO_2 emissions.

4.4 Applicability of These Results for the U.S.

Getting energy from coal mine to the customer is a major problem throughout the U.S. Distance between the mine and customer is important, as well as the ruggedness of the terrain in determining the best method to deliver the energy. The quality of the coal is important since 50% more lignite would have to be shipped than bituminous coal because of the ash and moisture content, implying that lignite would not be shipped far (IECM, 2004).

Siting power plants or rail beds, transmission towers, or gas pipelines is difficult (Vajjhala, 2005). Pipelines are less obtrusive and may be the only feasible alternative if there is opposition to transmission towers or railroads.

Building a power plant in one location to serve customers in a different location can be problematic. Should Wyoming (and surrounding states) suffer the environmental impacts of generating electricity for Texas? A power plant in Wyoming would expose far fewer people than one near Dallas. However, Wyoming residents would ask why they are bearing the burdens for distant people. Wyoming would benefit from additional jobs, but it is unclear whether they would welcome the environmental degradation, crowding and noise.

Several other options were investigated to replace the shipment of coal by rail. One option is the gasification of the coal for consumption in an Integrated Gasification/Combined Cycle (IGCC) plant either at the minemouth or by transporting the syngas by pipeline. However, the gasification of PRB coal is not favored in such a plant as the ash and moisture contents reduce the efficiency (HHV) of the IGCC plant from 37% (using Appalachian coal) to roughly 31%. Producing hydrogen in this plant is also possible to use in fuel cells, however, the cost and efficiency of such a system is not currently attractive.

4.4.1 Uncertainty

This analysis deals with a comparison of hypothetical power plants. The data used in this analysis combined theoretical data as well as data specific to currently operating systems. As such, there is a high degree of uncertainty associated with the input values. I have laid out the problem and suggested how it can be used for other applications. However, the cost and environmental impacts of the rail, transmission, or pipeline infrastructure will to vary for each application. A sensitivity analysis revealed that the most important factors for the economic analysis include the amount of infrastructure required and the cost of that infrastructure. The transmission losses and emission factors for the combustion of diesel fuel are the most important for the environmental emission results.

4.5. Discussion

The best way to get a small amount of additional energy from the PRB to Dallas is to add it to the 50 million tons a year of Wyoming coal already being shipped to Texas by rail. Before new rail capacity is added, congestion can be relieved by for example, double and triple tracking the existing lines. Up to two hundred miles of additional capacity could be added before this option becomes more expensive than the other three base case options.

If PRB coal were to be used for supplying an additional 6.5 BKWh electricity to a location 1,000 miles away that did not already have rail capacity, a generator at the mine and transmission line would be the cheapest alternative, with gasifying the coal and shipping the methane by transmission line a close competitor. Gasifying the coal and generating the electricity in a combined cycle plant has about the same costs as a pulverized coal plant and has important environmental advantages.

If much greater amounts of electricity were needed by the distant customers, the new infrastructure would be used more intensively, reducing the cost. For sufficiently high demand (more than 9 GW), it would be cheaper to build a new rail line than to construct multiple transmission lines. Gasifying the coal and shipping it via pipeline might be an even more competitive alternative.

Finally, the answer to the question of shipping coal, methane, or electricity depends on the distance, the amount of spare capacity in infrastructure already in place, and the amount of energy to be shipped. Longer distances and greater amounts of energy favor rail and pipelines over transmission. Since the capital costs are the largest part of total costs, not having to build a large part of the infrastructure by relying on existing rail, transmission lines, or pipelines is likely to be the cheapest alternative.

While the social costs of rail deaths and emissions do not change the recommendation, internalizing the externalities associated with emissions serves to strengthen the case for rail over transmission. Burning additional coal to make up for transmission losses leads to larger pollution emissions than from the diesel locomotives. Accounting for these social costs strengthens the argument for gasifying the coal and using a combined cycle plant.

Chapter 5: The Long-Term Life Cycle Private and External Costs of High Coal Usage in the U.S.

5.1 Introduction

The only hydrocarbon fuel in which the U.S. has hundreds of years of reserves at current prices is coal. Currently, more than 50% of electricity is generated from coal. This is approximately 23% of the total energy consumed in the U.S. (EIA, 2005c) While many future energy scenarios are possible, coal is likely to play a large role for at least the next half-century, barring significant technological changes and large hydrocarbon discoveries. Advanced generation technologies can decrease air pollution emissions significantly, and even capture and sequester CO_2. This analysis models the life cycle implications of a high coal use future.

Uncertainty about the price and availability of other fuels make their future contributions uncertain. For example, natural gas is an environmentally desirable fuel, but the large increase in Natural Gas Combined Cycle (NGCC) plants since 1990 have tested its availability. Prices of natural gas have risen to the point that much of the NGCC power plants currently in the U.S. get very little use. Expanding nuclear power is hampered by public opposition, high cost, lack of closure of the life cycle, and security concerns. Major expansion in hydroelectric output is unlikely because of environmental opposition and prior development of the best sites. Most renewable technologies are not yet economically competitive and their inability to supply power when needed (i.e. intermittency) raises cost and makes them less attractive. Thus, while the future is uncertain, it is prudent to investigate the possible life cycle impacts of a high coal use future.

5.2 Scenarios

Forecasting future fuel prices and availability accurately is impossible. Instead, forecasting and future scenarios can aid in visualizing or thinking about future realities by building a framework for evaluating the consequences of potential actions (Craig, 2002). The basis of the scenarios in this analysis use forecasts to 2050. However, the focus of the analysis is the system implications of increased coal usage in the U.S. Therefore, the scenarios described below could occur anytime in the mid to long-term time horizon.

Our scenarios begin with the Energy Information Administration (EIA) projections in the Annual Energy Outlook (EIA, 2005a). The EIA base case assumes an electricity demand growth of 1.9% annually. I extrapolate from 2025 to 2050 by assuming a growth rate in electricity demand of either 1.5 or 2% per year. This results in a total electricity generation of 8 and 10 trillion kWh per year in 2050 respectively. Currently, the U.S. generates close to 2 trillion kWh from coal and 4 trillion kWh total. Different proportions of this electricity are assumed to be produced from coal. The motivation for selecting these proportions is to investigate the life cycle cost and environmental impacts of coal use if it doubles or quadruples in the future. However, the amount of coal is not held constant in the analysis. The basis for comparison is the amount of electricity generation from coal. For example, in the Pulverized Coal technology (PC) scenarios where 8 trillion kWh is generated using coal, the eastern coal scenario only requires 3.6

billion tons of coal, the base case (assuming current coal type mix) requires 4.5 billion tons and the western coal scenario requires 4.2 billion tons of coal. The proportion is similar for the Integrated Gasification Combined Cycle (IGCC) systems; however, the amount of coal required is slightly less since the IGCC have slightly higher efficiencies.

Seven 2050 electricity scenarios are explored in this analysis as well as seven additional scenarios that include carbon capture and sequestration. These scenarios reflect combinations of assumptions about future fuel and technology choice as well as different prices, emission factors and efficiencies. It should be emphasized that this analysis is not an attempt to predict the probability that any of these scenarios occur, but rather it is an exploration of the cost and environmental implications if each scenario did occur.

Table 5.1 summarizes these scenarios and each scenario is discussed in more detail below.

Scenarios	***Description***
1a. "Business as usual" – PC plants	1.5% annual electricity growth, 50% of generation from coal, extrapolate current coal types
2a. High growth, high coal use – PC plants	2% annual growth, 80% from coal, extrapolate current proportion of coal types
3a. 80% Eastern Coal –PC plants	Like 2 but 80% of coal is eastern coal
4a. 80% Western Coal – PC plants	Like 2 but 80% of coal is western coal
5a. 80% Eastern Coal –IGCC plants	80% of coal is eastern coal
6a. 80% Western Coal – IGCC plants	80% of coal is western coal
7a. 80% Natural Gas – NGCC plants	Like 2 but 80% of generation from natural gas
1b-7b Carbon control	Scenarios 1a-5a but now with carbon separation & sequestration

Table 5.1 Summary of Electricity Scenarios

The coal plants are assumed to be burned in a "state of the art" generation plant (defined by IECM, 2004) each with 463 net MW of capacity producing 3.04 billion kwh /yr. Generation cost is calculated using a 30 year lifetime and interest rate of 8% per year; the price of coal is based on current f.o.b. prices (broken down by coal type – these range from \$7 - \$55/ton). The capital and operating costs of carbon capture and sequestration (CCS) are based on an amine scrubber for the PC plants and a Selexol process for the gasification plants. The separated CO_2 is transported by pipeline with deep underground injection; the capital cost is assumed to be \$10/ton of CO_2. The amine scrubber and Selexol process are assumed to remove 90% of the CO_2. Plant emissions are calculated by the Integrated Environmental Control Model (IECM) for generation; emissions for the rest of the life cycle are calculated in the Economic Input-Output Life Cycle Assessment (EIOLCA) software (CMU, 2005). The emissions from the mining and transportation phases are calculated using a process based approach from current emissions.

For all scenarios the social costs of the pollution are internalized by valuing them at \$2,200/ton for SO_2, \$3,100/ton for NOx and \$4,700/ton for PM_{10} (Matthews et al., 2000). These values reflect the median of several social cost valuation studies. The valuation of CO_2 emissions was investigated separately and is summarized in Figure 5.2.

This analysis builds on the analysis discussed in Chapter 3. That is, it is assumed that all new generation will be built with the best available technologies. At a minimum all new plants would be required to meet New Source Performance Standards (NSPS). (Please see chapter 3 for more details on the technology characterization).

The baseline, “business as usual” scenario continues the historic electricity growth rate (1.5% per year) with coal continuing to produce 50% of electricity to 2050. All fuel costs remain constant over time. Most projections to 2025 show that coal prices will remain relatively constant. The future of natural gas prices are more difficult to forecast. The prices fluctuate and differ from study to study. Pulverized coal technology is used with flue gas desulfurization (98% efficient) and NOx controls which include a low NOx burner and Selective Catalytic Reduction unit which meets the requirements for 0.15 lb/MMBTU. The current mix of coal types is extrapolated to 2050. Table 5.2 shows the current mix of each coal type produced in the U.S.

	Bituminous	Subbituminous	Lignite	Anthracite	Total
(current short tons)	502,000,000	410,000,000	80,100,000	1,090,000	994,000,000
(percentage)	50.5%	41.3%	8.1%	0.1%	

Table 5.2 Production of Different Coal types in the U.S. 2003 (EIA, 2003f).

Scenario 2 is a high demand scenario which increases the demand for electricity from 1.5 to 2% growth per year (from 8 trillion kWh to 10 trillion kWh per year in 2050), with 80% of electricity coming from coal. The purpose of this scenario is to explore what the impacts of increased coal usage would be under various assumptions about the upstream conditions. Therefore, the scenario could just as easily be based on a much higher demand for electricity and a lower proportion of the coal used to the produce the electricity.

Extraction costs, sulfur content, transport costs, environmental regulations, and generation technology will change the mix of coal types used over time. Western coal has been moving into markets previously supplied by eastern coal over the several years. The Energy Information Administration (EIA) projects that western coal will continue to penetrate eastern markets, although at a diminishing rate out to 2020 (Flynn, 2000). They project that the proportion of western coal produced (which is 81% subbituminous coal (EIA, 2003f) will increase to 59% in 2020 (EIA, 2002b). Since the AEO considers projects based on a continuation of current trends, the EIA also projects that productivity gains (attributed to maintaining coal prices in the past) will continue over time but will also slow gradually. They assume that the average productivity gains will be 2.3 % per year to 2020. However, productivity (tons produced/employee-hour) is higher for surface mining than underground mining and this productivity is increasing at a faster rate for surface mining (RFF, 1997). Due to this, EIA projects that coal prices will decrease slightly to 2020. These projections are based on assumptions that might not continue to 2050. Scenarios 3 through 6 explore different assumptions about the choice of coal type as well as the upstream choices and impacts that will result.

Scenario 3 modifies scenario 2 by assuming that 80% of coal is supplied by eastern bituminous coal mines, with 20% of coal supplied by western subbituminous coal mines. The resurgence of eastern coal might result from converging extraction costs and greater importance for the efficiency benefits (i.e. higher heat content of coal and therefore less coal required per kwh) of the bituminous coal. This could become more important placed on the lower sulfur content and low cost of the western subbituminous coal. The use of

PRB coal alone does not meet NSPS. Therefore, the cost savings from fuel switching would not apply to new plants. In addition, failure to expand or maintain the rail system could restrict the amount of western coal that will reach eastern markets. Finally, eastern coal could be used in greater amounts if the technology is not developed to overcome the issues of gasifying the PRB coal or handling the elemental mercury emissions. However, these technical problems could be overcome in these areas by 2050.

Scenario 4 reverses the coal type proportions, with 80% of coal is supplied by western mines. Continued importance of low sulfur content, low extraction costs, and improvements in the rail infrastructure could cause this result. This also follows an extrapolation of EIA projections from 2000 to 2020.

Scenario 5 is the similar to Scenario 3, but uses gasification rather than conventional pulverized coal boilers. Several other assumptions are also modified in this scenario. Reflecting possible difficulties of extracting underground coal, this scenario assumes that bituminous coal prices double. While an increase in transport distance will occur if eastern coal is used to supply 80% of coal-fired generation, it will not be as significant as the subsequent scenario since the coal reserves are located much closer to the electricity consumers than western coal. This scenario assumes that the average transport distance is increased from 230 miles (current average) to 500 miles but the cost of that transport is doubled. Since much more methane is emitted from the mining of bituminous coal from underground mining methods is much higher than the western surface mined coal. In addition, when such high amounts of coal are required in this scenario from eastern mines it is expected that the coal extracted will be deeper and therefore result in higher methane emissions per ton of coal removed. It is assumed that these emissions (not those from the 20% produced by western coal mines) will increase by 50%. This methane can be captured and used. While this is not considered in the current analysis, it would be a good method to reduce the global warming potential caused by this increased coal use.

Scenario 6 is similar to scenario 4. However, the PC technology is substituted by gasification. Since no data was found that could represent a gasification process that converts subbituminous coal to electricity reliability and cost-effectively, there is an important assumption here. The cost and efficiency associated with this assumption were taken from preliminary estimates for subbituminous coal gasification (Holt, 2003). These estimates are that an IGCC system for subbituminous coal is $200-$300/kW greater than an equivalent PC plant. With carbon capture the IGCC system is $300-$400/kW greater than an equivalent PC plant (Holt, 2003). The IGCC emissions are the median values from literature estimates (Holt et al., 2003; Holt et al., 2002; Ratafia-Brown et al., 2002; IEA, 2003). This scenario assumes that the cost of the fuel, the cost of transport will decrease slightly by 2050 in real dollars.

Finally, scenario 7 produces 80% of the 10 trillion kwh of electricity from natural gas using combined cycle units. A natural gas price of $4.0/MMBTU was assumed for the analysis, which is lower than current prices. This assumption was then varied in the sensitivity analysis.

5.3 Results

In each of the scenarios, system costs were calculated by estimating the total capital investment required for all life cycle stages (including extraction, transport, generation and transmission infrastructure costs), annualizing that cost and adding it to the estimated operation and maintenance and fuel costs. The monetized social cost of the emitted pollutants is added to the system costs. Finally, the social cost associated with fatalities occurring throughout the life cycle were estimated and added to the system cost. The dominant category of fatalities are from deaths occurring along the rail system. The social costs of CO_2 emissions were not included in this figure but are considered separately below. This is due to the fact that there is no agreed upon value to represent the social cost of the impacts that these emissions might cause. The results can be seen in Figure 5.1.

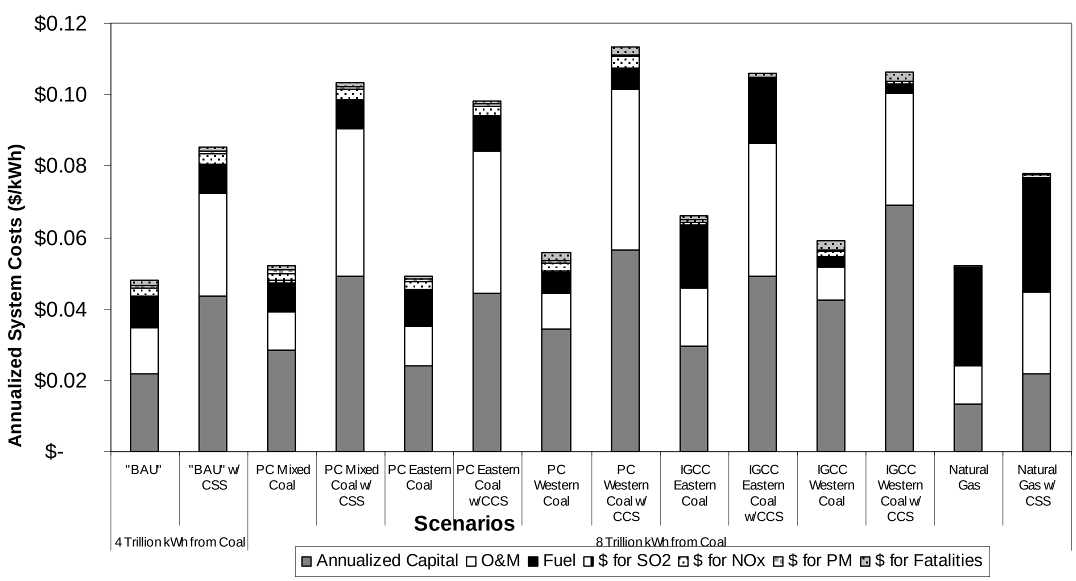

Figure 5.1 Total Annualized System Costs for Coal and Natural Gas Scenarios[2]

[2] CO_2 was not 'valued' in this analysis but is evaluated in the subsequent section.

Electricity costs range from over 4 cents/kWh for the “business as usual” scenario without CCS over 11 cents/kWh for the high growth, 80% western coal scenario with CCS. If CO_2 emissions were valued at $56/ton in the high growth case with, current coal mix scenarios, the cost of electricity would be the same with and without CCS. Carbon capture and sequestration increases total costs by about 2/3 in the base case from 4.7 to 8.7 cents/KWh, due to increased capital and operating costs. Among the high growth scenarios, the natural gas intensive scenario is cheaper than the coal intensive scenarios at a natural gas price of $4.0/MMBTU; if natural gas were priced at $ 6.0-7.0/MMBTU), coal plants would be cheaper. Compared to coal, natural gas plants have lower capital costs, lower transport costs, and higher fuel costs. Western coal is cheaper than Eastern coal. However, the capital cost of Western coal plants are expected to be higher than Eastern coal plants. The greater distance between mine and market for western coal is largely offset by the lower transport price per ton-mile. The fatalities from transporting coal in each of these scenarios range from 600-2000 people per year. These fatalities are translated into social cost and included in the system cost calculation. The main factor determining this rate is the ton-miles of coal shipped, which is lower for the eastern coal scenarios. The ton-miles shipped for the western coal scenarios are higher than the base case which results in greater fatalities in the western scenarios. These fatalities include all phases of the life cycle but do not include fatalities resulting from air emissions from the power plants, which would increase the total fatalities considerably (Kammen, 2004). These estimates are still very uncertain. When a consensus on these values is obtained, they should be added to this analysis.

The social costs considered in Figure 5.1 do not justify the additional cost of the IGCC systems even though the social costs are reduced significantly in these scenarios. However, several other assumptions have been changed between the PC and IGCC systems and therefore a definite statement about the impact of reduced emissions cannot be made from this particular analysis. Chapter 3 explored the plant costs of using Illinois coal no. 6 and it was found that just by accounting for the SO_2 and NOx emissions and decreased coal costs, the IGCC plant was slightly cheaper. This is not true for all coal types. However, the inclusion of CO_2 costs strengthens the argument for IGCC systems over PC plants.

5.4 How Does The Value of Carbon Impact the Results?

Since the "value" of CO_2 emissions is still uncertain, it was not included in the system costs. Figure 5.2 shows how non-CCS and CCS scenarios compete at varying carbon taxes. The points highlighted in the figure show the crossover points where the CCS scenario becomes more competitive than the corresponding non-CCS scenario. For example, at $48/ton, the high IGCC eastern coal scenario with CCS becomes cheaper than the high IGCC eastern coal scenario without CCS.

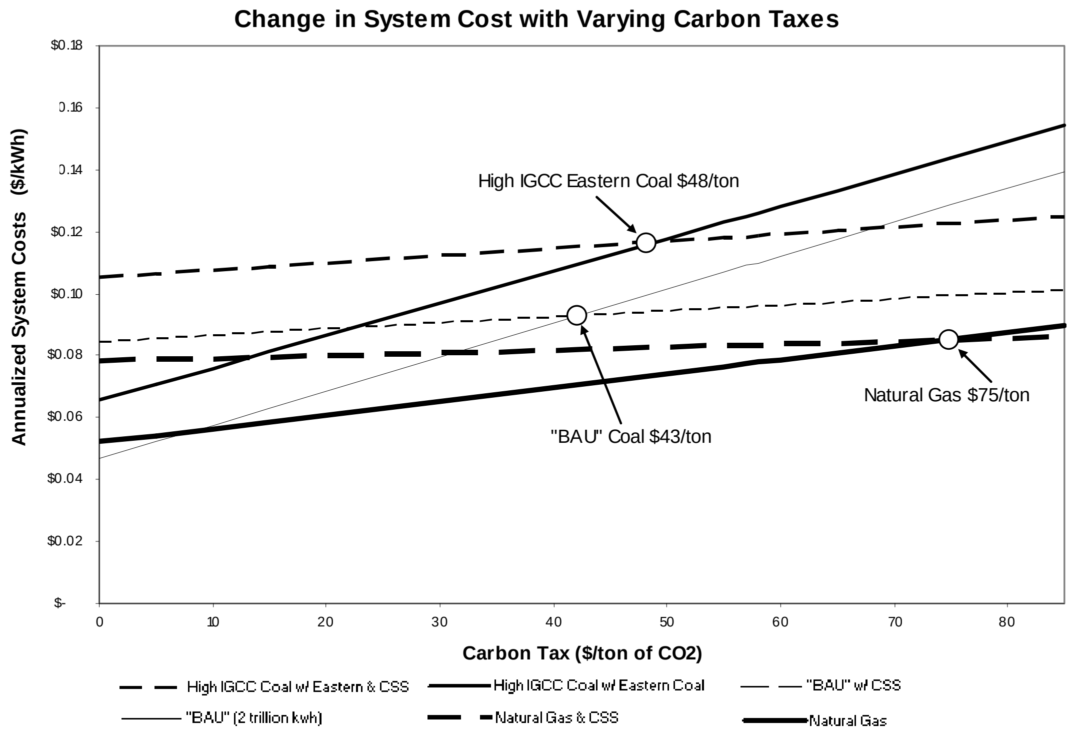

Figure 5.2 Change in System Cost with Changing Carbon Taxes

The dashed lines in Figure 5.2 represent scenarios 1, 5, and 7 with CCS; the scenarios without CCS are represented by solid lines. As carbon taxes increase, costs rise more rapidly in the scenarios without CCS since carbon emissions are higher. The cost for the CCS scenarios still increase since only 90% of the carbon is being captured from the generation phase. If the carbon tax were more than $43/ton in the “business as usual” scenario (#1 producing 4 trillion kwh/yr), CCS would be cheaper. For the high coal scenario (#5 producing 8 trillion kwh), the carbon tax would have to be higher than $48 per ton for CCS to be cheaper. In the natural gas scenario (#7), the carbon tax would have to be higher than $75 per ton for CCS to be cheaper.

The system costs, and their proportion, vary from one scenario to the next, as shown in Figure 5.3. For the same amount of electricity (8 trillion kWh) from coal, the capital costs vary depending on the coal type (and the corresponding efficiency), the amount of rail required and whether CCS is employed. The capital cost is smallest for the scenarios focused on Eastern coal since they require less rail and transmission infrastructure.

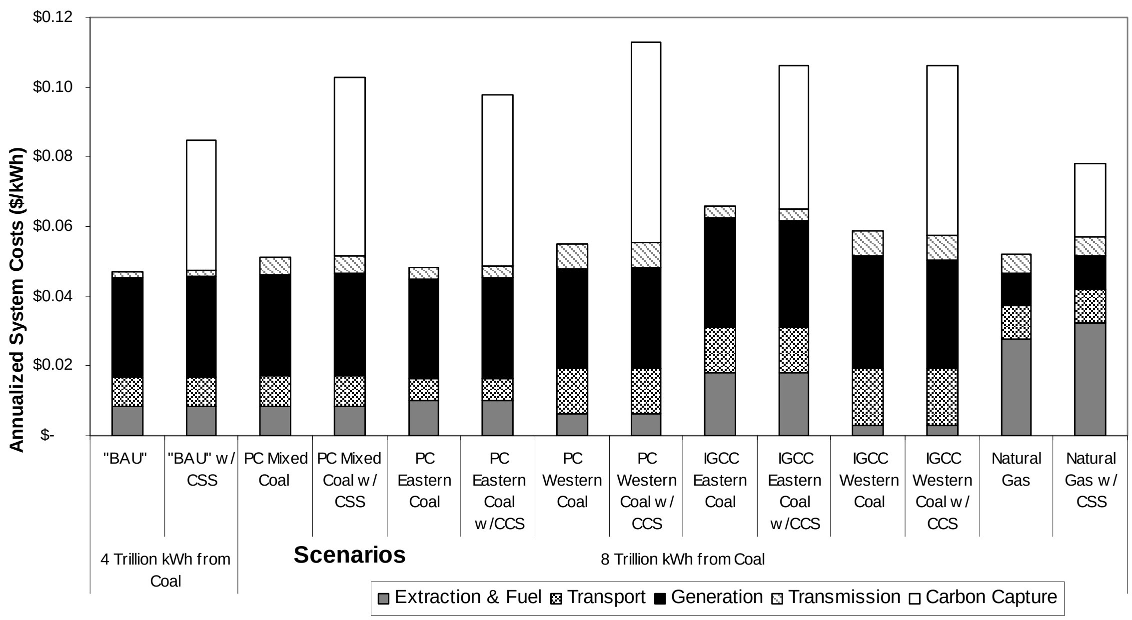

Figure 5.3 Annualized System Costs by Life Cycle Phase for Coal and Natural Gas Scenarios

Surprisingly, the coal scenarios are similar in terms of both total cost and emissions. However, while the annualized system cost and total emissions are close, the contributions from each life cycle phase are different for each scenario. It appears that many of the differences end up offsetting each other. For example, eastern coal generally has a higher heat value which lowers the cost of a generator for a specified output; however the eastern coal is more expensive per BTU.

Extraction and transport of the average ton of western coal is different from that of eastern coal. Since western coal is mostly extracted by surface mining, productivity increases will depend more on the size of the equipment used in the mining process than for underground mining. Underground mining productivity increases will be realized through the automation of the equipment underground. Since the technology development in these two cases will occur simultaneously and independently, the future of these two technologies could look very different (NAS, 2002; EERE, 2004; RAND, 2000).

Figure 5.4 shows that pollution and carbon emissions are lower for natural gas than coal. All coal scenarios producing 8 trillion kwh without CCS emit more CO2eq than the entire U.S. currently emits. However, CCS reduces carbon emissions for the coal scenarios more than carbon emissions for natural gas without CCS. Since western coal has less sulfur, scenario 4 and 6 have lower SO_2 emissions than scenarios 2, 3 or 5.

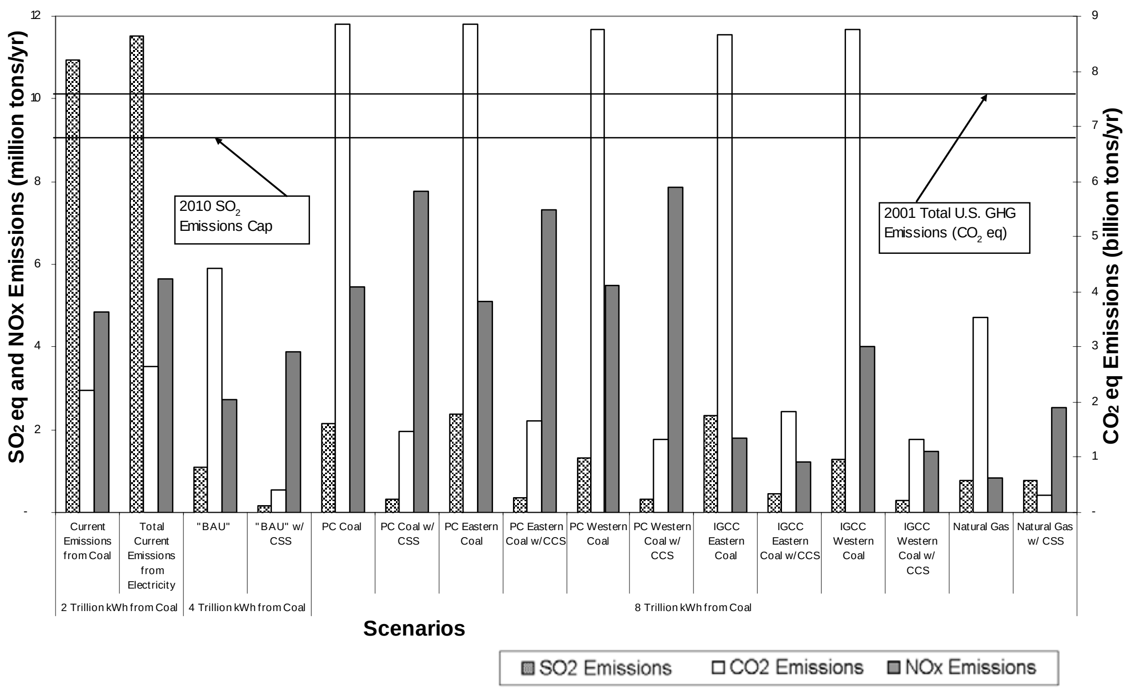

Figure 5.4 Annual Life Cycle Emissions (SO_2, CO_2, and NO_x) for Coal and Natural Gas Scenarios.

The capital costs of the basic PC and IGCC plants are $1,200-1,300/KW and $1,400-$1,500/KW, respectively. Adding CCS would increase the cost of the two systems to $2,000-2,400/KW and $1,800-2,500/KW, respectively. The original efficiency of 32-35% of the PC plant is reduced to 23-26% when the CCS unit is attached. The original efficiency of 36-38% of the IGCC plant is reduced to 31-33% when the CCS unit is attached. In the base case, the SO_2 emissions are comparable for the two technologies and are reduced even further when CO_2 removal is in place. However, the process of removing the sulfur is very different for the two processes. The IGCC plant removes the sulfur in the form of H_2S whereas the PC plant removes SO_2 from the flue gas. The NOx emissions are up to 3.5 times higher in the base PC plant than the IGCC plant. These emissions increase when CO_2 capture is included in the PC plant but decrease when CO_2

capture in included in the IGCC plant. Since CCS decreases the efficiency of the plant, the first 20-30% of CO_2 removal is required to make up for the efficiency loss.

5.4 SO_2 Emissions

Sulfur emitted from power plants is currently regulated by a cap and trade system. The 2010 SO_2 emissions cap planned for 2010 is shown in figure 5.4 (8.95 million tons) (EPA, 2004). This shows that current generation does not satisfy the cap. In fact, sulfur emissions increased from 2003 to 2004 due to the increased use of coal-fired generation units in response to increased gas prices. However, all of the future scenarios are well below the cap. This is due to the fact that 98% removal of sulfur from coal is assumed in all cases. The technology currently exists to remove sulfur at this level and it is assumed to apply to all new plants since the cost of the additional removal is less than the cost of SO_2 permits in many cases. New power plants are also required to satisfy New Source Performance Standards (NSPS). For SO_2, the emission constraint is 0.6 lb/MMbtu. If for some reason, new plants built today were not required to satisfy the NSPS, total emissions would then be restricted by the national emissions cap (currently set for 8.95 million tons of SO_2 by 2010) (EPA, 2002). Less plants would require such strict removal efficiencies. For example, the scenario with the largest SO_2 emissions is PC eastern coal without CCS (3a). This scenario assumes that 80% of the coal is medium to high sulfur eastern coal and 20% is low sulfur western coal. Assuming that the controls for the western coal are reduced from a flue gas desulfurization unit (FGD) at 98% removal (assumed in the base case) to a Lime Spray Dryer (LSD) at 65% removal to meet the NSPS standard, 83% of the eastern coal plants would be required to remove sulfur at 98%

efficiency whereas the other 17% would only be required to meet NSPS in order to remain under the cap. The other scenarios would require less control than this scenario since there is less sulfur to be removed. This shows that even currently available technology and a quadrupling of the amount of electricity generated from coal, SO_2 emissions can be reduced much further than the planned emission cap requires. It is not realistic to assume that this technology could be installed on every coal plant currently operating in the U.S. today. However, by 2050 it appears reasonable to assume that all coal plants will either be new or have been modified to the extent that at least NSPS will apply to them.

At approximately 70% removal efficiency, the coal scenarios with CCS produce the same CO_2 emissions as the natural gas scenario. Even at 100% removal efficiency, the coal scenarios do not get below the natural gas with CCS scenario since upstream emissions are important at this level.

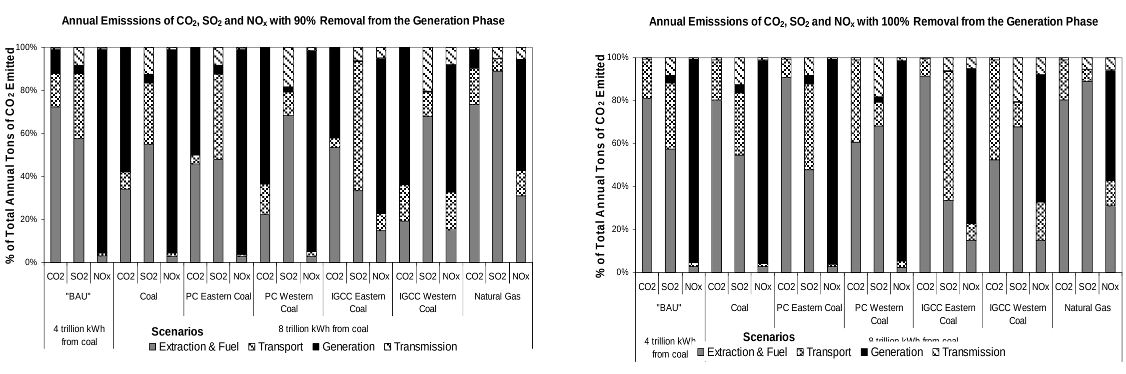

Figure 5.5 The Relative Contribution of each Life Cycle for varying levels of CO_2 Removal from the Generation Phase.

Figure 5.5 breaks down the emissions from the CCS scenarios shown in figure 4 into the life cycle stages that are responsible for the emissions. That is, the relative contribution of each life cycle stage to the total emissions as the proportion of CO_2 removed from the generation phase is changed. This is done for two levels of removal of CO_2 from the generation phase (90% and 100%). Note that these are the total emissions reduced from the entire generation phase. In order to achieve these emission reductions an increased CO_2 removal efficiency is required since the energy penalty requires additional amounts of coal to be burned to produce the same amount of electricity (e.g. 90% total removal from the generation phase requires close to an overall 95% reduction efficiency). Note that current technology is not capable of removing 100% of the CO_2 from the generation phase. The purpose of these figures are to show the different proportional contribution from the various life cycle stages if no CO_2 was emitted during the generation phase.

A large fraction of the CO_2 eq emissions in the "extraction & fuel" category are from the methane released during the mining process. However, the amount of methane released is highly dependent on the method of mining. For example, the CO_2 equivalent emission factor for underground mining (0.14 tons of CO_2 eq/tons of coal produced) is over 8 times higher than surface mining (0.017 tons of CO_2eq/tons of coal produced). In general, the amount of methane trapped in coal is higher with increasing coal rank. Since methane is also a greenhouse gas and natural gas prices are uncertain, there is potential for these emissions to decrease over time due to the increased extraction of this methane during extraction.

The contribution of emissions from transport also differs between the eastern and western coal scenarios. This is due to the fact that the western coal will be shipped greater distances therefore producing greater emissions.

These figures show that the assumptions made about upstream changes over time result in a different set of priorities to be considered if further CO_2 removal is important. If the IGCC eastern coal case became a reality, the impacts of mining should be addressed, whereas in the IGCC western coal case, transportation and mining are both important.

Even with 90% removal of CO_2 from the generation phase the life cycle CO_2 emissions are significant and comparable to the major economic sectors in the U.S. today as seen in Figure 5.6.

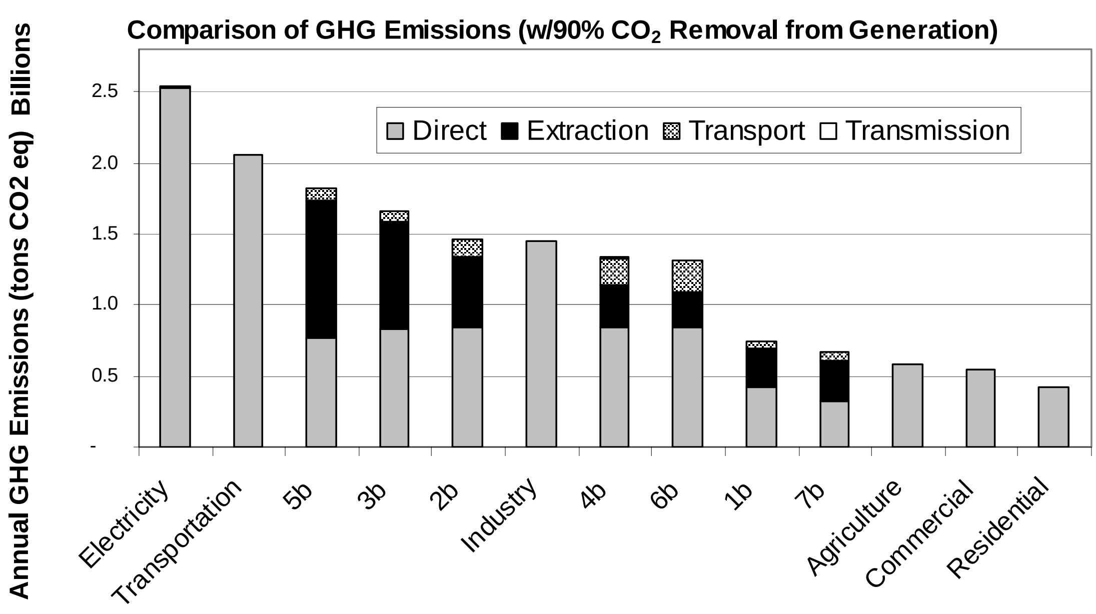

Figure 5.6 Comparison of GHG Emissions between Current Economic Sectors and Future Scenarios for Electricity Production (90% CO_2 removal from generation phase of future scenarios)

The CCS technology is still being developed. It is possible that the technology could improve beyond 90% removal. Emissions from mining dominate the life cycle emissions for most scenarios. However, in the scenarios where 80% of the electricity comes from western coal, the increased transportation requirement is also an important contributor to the overall emissions.

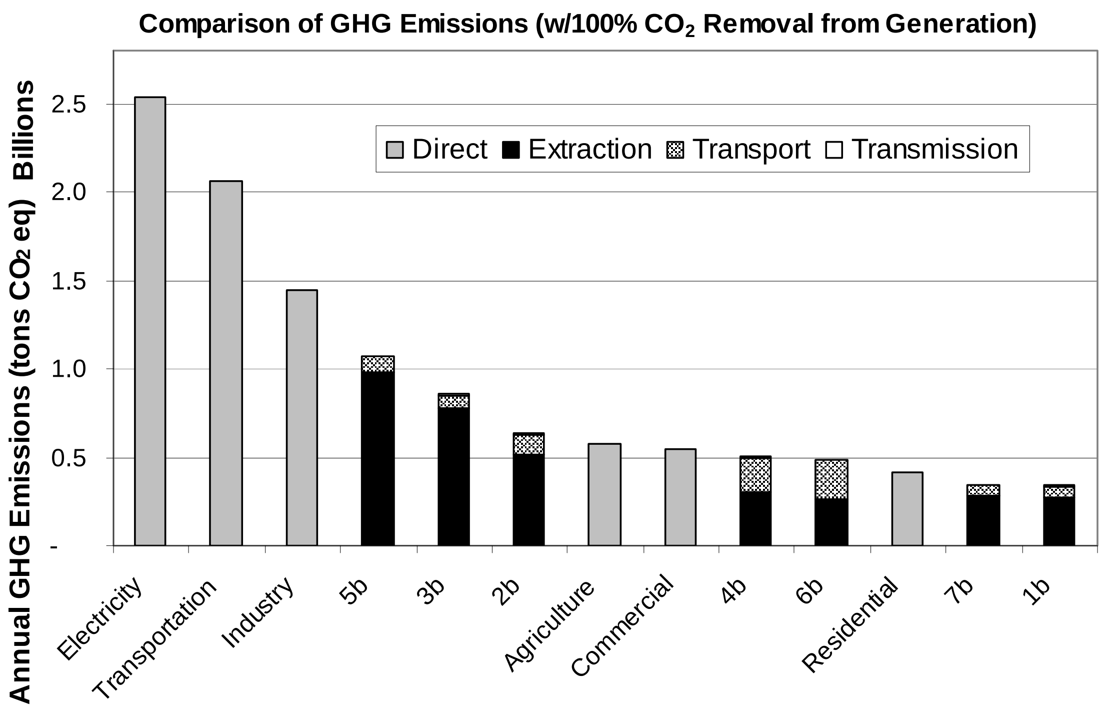

Figure 5.7 Comparison of GHG Emissions between Current Economic Sectors and Future Scenarios for Electricity Production (100% CO_2 removal from generation phase of future scenarios)

However, even when the removal from the generation phase is raised to 100%, three scenarios still showed emissions that were higher than current emissions from the agriculture, commercial and residential sectors. This can be seen in figure 5.7. Therefore, if the U.S. becomes serious about reducing atmospheric GHG concentrations, increased use of coal will still cause a problem due to upstream emissions.

5.5 Can Coal Compete with Natural Gas?

Four billion tons of coal or 48 TCF of natural gas would be required to produce 8 trillion kWh per year. The U.S. has such large coal reserves that it seems likely we could mine four billion tons per year with little increase in the per ton extraction price for most scenarios. The availability of natural gas is entirely different.

Total U.S. dry gas proved reserves are currently 189 trillion cuft. Production rates are roughly 10% of proved reserves and this is increasing. The EIA projects consumption of natural gas to increase to roughly 30 trillion cuft/yr by 2025 and a linear extrapolation results in consumption of 40 trillion cuft/yr by 2050. Electric power generation consumed close to 5 TCF of natural gas in 2003. This is 23% of the total natural gas consumed in the U.S.

Even the 40 TCF projection would likely result in higher prices since significant imports of LNG, the ability to make use of methane hydrates, or the conversion of other fossil fuels to gas would be required. Without these other resources, the U.S. would have exhausted its natural gas reserves before 2050.

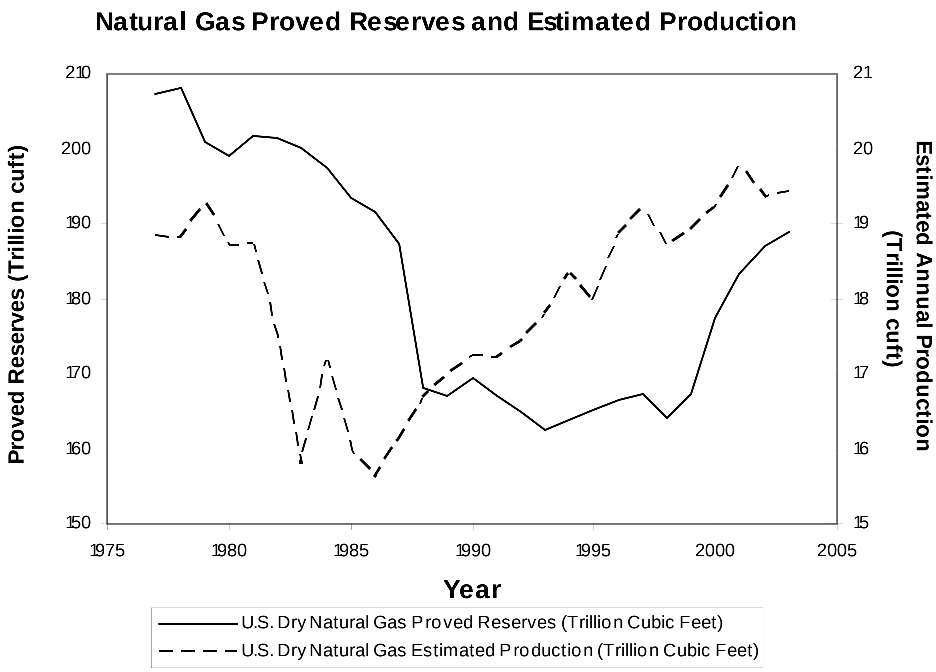

Figure 5.8 Annual Estimates of Dry Natural Gas Reserves and Production (Sources: EIA, 2003i and EIA, 2003j)

Natural gas prices are likely to rise from the $4.0/MMbtu assumed in the base analysis. Figure 5.8 shows a range of prices for natural gas and the impact it has on the competitiveness of the natural gas scenarios against the coal scenarios.

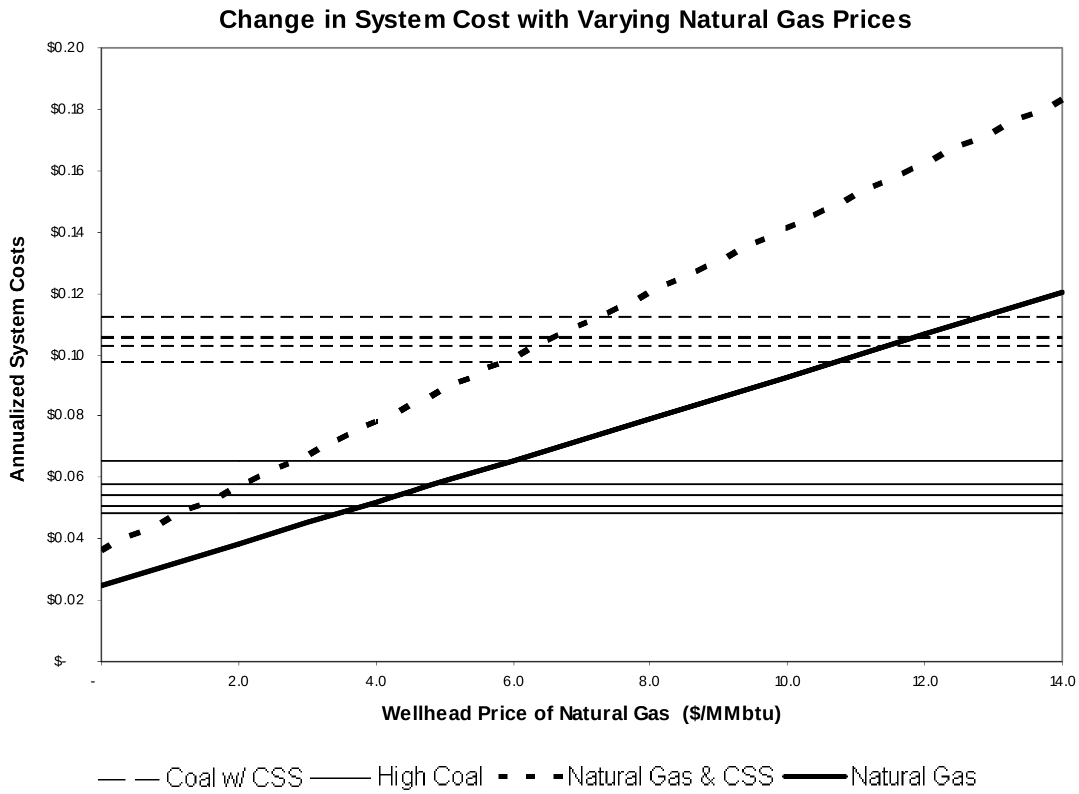

Figure 5.9 The Effect of Natural Gas Price on the Annualized System Costs

When CCS is not used, the price of natural gas would have to be less than $4.0 to 6.0/MMbtu to compete with coal. When CCS is required, the price of natural gas could be $6.0 to 7.0/MMbtu before coal is more competitive.

5.6 Discussion

A high coal future that quadruples U.S. coal mining, transport, and electricity generation would pose considerable environmental challenges. Advanced technologies for generation and control of pollution and greenhouse gases could offset the increases in these emissions. The advanced technologies would increase the private cost of electricity from roughly 5 to 9 cents/KWh; they would also lower the external costs considered in this analysis of electricity production. If coal usage quadrupled with current levels of control, air pollution would result in much high social values for abating pollutants. The abundance of coal and its low cost make it likely that coal will continue to be a major fuel for electricity generation in 2050. The inclusion of air pollution, greenhouse gas, and other discharges of coal burning electricity plants into the system costs is important and requires a life cycle perspective. I include pulverized coal and gasification plants with and without CCS technology. Scenarios with doubled electricity production in 2050, 80% of which is produced from coal required roughly four times the amount of coal mined today. Even with 100% CO_2 removal from the generation phase, the CO_2 emissions from the rest of life cycle are comparable to the other major sources of CO_2 in the economy today. If natural gas were abundant, this cleanest of the fossil fuels would produce much less CO_2. However, the higher electricity growth scenario would require such a large amount of natural gas that this seems unlikely. While much of air emissions from the generation phase can be reduced with advanced technologies, a high coal future will still have significant environmental impacts.

Chapter 6: Conclusions

6.1 Conclusions

The comparison of electricity options requires consideration of life cycle private and social costs, a clear definition of the full life cycle (e.g. including considerations such as the intermittency of some renewable technologies) and the inclusion of under or un-valued impacts within the system (e.g. who suffers the pollution and other adverse impacts). This thesis has developed a consistent basis for comparison of electricity options. The integrated use of models and methods extends the potential for each and allows for an increased scope of analysis. A framework for hybrid life cycle analysis of electricity technology options has been developed in this thesis and has shown to offer insights concerning the environmental implications of each technology. This strengthens the case for use of these two complimentary LCA methods.

The IECM model allowed the quantification of efficiencies, costs, and environmental discharges of the technologies investigated. IECM gives a more detailed, consistent characterization of each technology than can be found in the public literature or other accounts of each technology. The focus on life cycle aspects of future scenarios results helped to focus interest on technologies and scenarios that normally receive little attention.

How the U.S. will or should satisfy the growing demand for electricity is unknown. Deciding which of the numerous technology options (or mix of technologies) will provide electricity at least social cost (including externalities) is not a simple task. The tradeoffs that must be considered include private and social costs, proven technologies versus the risk of developing and commercializing new technologies as well as the incentives required to allow these new technologies to compete. It is clear that no technology can satisfy electricity demand in the U.S. at low prices without degrading the environment.

The life cycle of electricity generation options is often overlooked in the study of electricity generation technologies, since the generation phase generally produces emissions orders of magnitude higher than the rest of the life cycle. However, the environmental impacts of electricity generation stretch beyond the conventional pollutants and CO_2 emissions. Life cycle analysis helps to ensure that these issues have been identified even if their impacts cannot be quantified fully.

Important progress has been made in the area of renewable technologies; their life cycle environmental impacts (while not zero), generally show a marked improvement over fossil generation in many categories. However, further progress is required and the limitations of the technologies are a concern. Wind is currently the most widely deployed renewable technology since the technology is mature and costs are the most competitive with current prices. However, the intermittent nature and increased transmission required to connect the best wind sites with consumers add to the cost. Storage technologies could help with the intermittency issue, but currently add significantly to the cost.

Photovoltaic technologies still only make up a small fraction of the U.S. generation mix but deployment rates have grown rapidly in several nations. Cost is the most significant barrier for this technology. In addition, concerns about the toxicity and scarcity of the materials used in current technologies might also restrict their use. The PV cell that is capable of producing electricity at economically competitive rates has not yet been identified and the technology could look extremely different from current PV cells. Therefore, LCA must continue to play a part in evaluating these technologies as they evolve.

Most large scale hydro sites have been exhausted in the U.S. and their impact on the surrounding ecosystem leave development of new large scale hydro projects in the future unlikely. However, increasing the capacity of some existing facilities and micro hydro projects are possible. Some U.S. dams have been breached in an attempt to restore the previous ecosystem. This makes an increasing contribution of hydro in the generation mix unlikely in the future.

Nuclear power could be introduced back into the new generation capacity mix. The absence of GHG gases emissions during generation has renewed interest in this technology. However, cost, security/safety concerns, the handling of spent fuel, and oppositions of some groups are hurdles to be overcome in the U.S. before new plants are built.

Natural gas is the cleanest of the fossil fuels and the current technology is extremely efficient and cheap to build. However, competition for use, resource availability and prices are the biggest obstacles to further development and use of this fuel in the electricity sector.

By most accounts, coal is the least environmentally desirable fuel with which to generate electricity. However, the vast reserves in the U.S. together with its low cost make it the only fossil fuel likely to expand significantly in the near to medium time horizon. Even if another technology (or set of technologies) becomes competitive with coal, it is unlikely that coal will be eliminated from the generation mix in the next half century. Therefore, in addition to investigating new and more sustainable technologies, it is important to consider methods of making coal use more sustainable. This has been the focus of this thesis.

An evaluation of current and near-term coal generation and control technologies shows that coal-fired generation has improved considerably in several aspects. Technologies that control conventional pollutants have made notable progress; however, they increase the cost of the plant and generally reduce the plant's efficiency. Coal gasification shows further promise with increased efficiency and a greater ability to capture pollutants. However, the comparative complexity of the system suggests that the cost of these plants will likely remain above those of the conventional pulverized coal plants.

The waste produced during the generation phase and the treatment of pollutants has found use as input material to other industries. This has reduced solid waste disposal. Continued attention is needed to transform generation wastes into useful byproducts.

Policies that currently govern coal-fired power plants and those anticipated in the near term can have different impacts on coal use patterns. For example, the acid rain program encouraged the increased use of low sulfur coal from the west. However, the recently announced Mercury Rule creates problems for the use of this coal since a large fraction of the mercury emitted from this coal is in elemental form; no technology has yet be identified that will remove this form of mercury. The controls for nitrogen and sulfur oxides can remove over 90% of the mercury from other coals, but are less effective on the elemental mercury that is formed in the combustion of western coal. Emissions, costs and controls differ among the coal types and control technologies. The differences in coals, as well as technologies for generation and control, and the interactions among them show the value of the IECM model compared to data from current facilities. A major contribution of this thesis is the detailed comparison among coals and technologies using IECM, which permits more accurate comparisons than are available from past life cycle analyses.

In the near to medium term, a major question for the industry is where to locate new coal facilities. Coal is predominantly shipped from the mine to the power plants close to consumers by rail (an average of 800 miles). This transport consumes large quantities of diesel fuel, with resulting air emissions, causes fatalities on the rail line, and requires significant investment in infrastructure. The potential alternatives considered in this analysis include building a mine mouth plant and shipping the energy as electricity, converting the coal to methane and either burning the methane onsite or transporting it through natural gas pipelines for use in a combined cycle natural gas plant. Other alternatives include shipping the coal by barge or coal slurry pipeline. If a small amount of additional energy is required on a route with considerable shipments and some unused capacity, it should be added to the current coal being shipped by rail. If no rail capacity exists then mine mouth generation is the cheapest option with gasification and methanation a close second in terms of system cost. The methanation option also provides some important environmental advantages. For sufficiently high demand (more than 9 GW) it is cheaper to gasify and methanate the coal or build a new rail line. The transmission losses prevent intensive use of lines. The answer of whether to ship coal, methane or electricity depends primarily on the distance to be shipped, the spare capacity of the infrastructure already in place, and the amount of energy to be shipped.

While considering the air pollution and other externalities does not change the recommendation, internalizing the externalities associated with emissions raises costs, strengthening the case for rail over transmission or gasifying the coal and shipping gas, which is then used in a combined cycle plant.

While the technology for the gasification and methanation of western coal is the least proven technology considered in this analysis, it is currently used in commercial plants and shows promise to help improve the process of connecting coal in the west to consumers throughout the U.S. In addition to providing the means to reduce emissions from the transport and generation phases, siting a gas pipeline should be less contentious than siting new transmission lines or new railroad lines.

The framework developed in this analysis can be applied to a wide range of policy questions. For example, the model can be modified to investigate the tradeoffs associated with location of coal generation facilities in other countries that have a different mix of coal resources, infrastructure in place and distances between the fuel sources and demands for electricity. In addition, the framework developed can be extended to apply to other fuel sources. For example, a hydrogen infrastructure could be evaluated. Future work will develop some of these concepts further to make the model more widely applicable.

In long-term future energy planning it is important to consider the life cycle implications when evaluating the impacts of increased coal use. Even though technologies are being developed to decrease conventional pollutant emissions as well as capture carbon from the generation phase, upstream impacts will persist and potentially increase in certain scenarios considered in this thesis. These include increased emissions, fatalities and land use impacts from rail transport and mining phases. Even if reductions in CO_2 emissions from the generation phase of coal-fired plants are reduced to virtually zero, the electric power industry can still be a significant contributor to U.S. GHG emissions due to the upstream GHG emissions. As such, if the U.S. becomes serious about reducing atmospheric GHG concentrations, the transport and extraction phases of this life cycle must be addressed. Different environmental futures result from the assumptions that are made about how the coal is used. In addition, there are environmental impacts that are more difficult to quantify, such as the impacts of mining on the surrounding landscape and environment which will only become worse as the easily extracted coal is removed. This thesis addresses the air emissions and costs associated with mining.

The focus on life cycle analysis in these future energy scenarios has been helpful in highlighting many of the tradeoffs and consequences of a high coal future. This framework can be applied to other future energy scenarios. For example, applying this method to renewable fuels and technologies could highlight some of the tradeoffs associated with different paths that are possible as the technology progresses (e.g. material selection for PV cell manufacture). Future work in this area is required to make this model more widely applicable.

In conclusion, while there is not one particular technology that will satisfy all the U.S. electricity demand at low cost and negligible environmental impact, there are several promising options. In the near-term, the environmental impact of most current coal plant operation is significant and is far from the reductions in impact that are technically possible. The type of coal, the method of extraction, generation and control technologies employed and location of use can greatly affect the environmental impacts associated with this life cycle.

In the mid-term, there are important efficiency gains that can be found within the power industry. Mine mouth generation helps reduce issues associated with rail (e.g. fatalities on the rail line and cost of infrastructure), however, line losses have important consequences in terms of additional emissions and costs. Methanation of coal shows promise for use of coal.

Beyond 2050, increasing coal use is possible; large-scale use of coal is likely. While this has the potential to cause serious environmental problems, technologies exist to reduce these impacts and should be pursued aggressively. In addition, while technologies have been identified to mitigate most conventional pollutants, significant issues remain and must be addressed. These include upstream emissions from mining and transport, land use impacts of increased mining as well as local impacts from potentially concentrated production.

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