

The Future of US Coal Consumption in a Carbon-Constrained World

Jim McFarland
ESD.166
4/29/04

1	Introduction.....	3
1.1	The role of coal in a sustainable energy future.....	3
2	Coal resources and consumption.....	3
2.1	US fossil fuel resource base	3
2.2	Historical fossil fuel consumption.....	4
2.3	Coal use and the primacy of electric power	5
2.4	The threat from natural gas.....	6
3	Analysis of Coal’s Future	8
3.1	Methodology.....	8
3.2	Reference case	9
3.3	Effect of carbon prices.....	10
3.4	Effect of natural gas prices	11
3.5	Effect of technology costs	13
3.6	Effect of economic dispatch.....	16
3.7	Conclusions	19
3.8	Beyond 2050.....	20
4	Comparison to Other Studies.....	21
5	Implications and Challenges.....	22
5.1	Generation and capture technology development	23
5.2	Reservoir Development	23
5.3	Public Acceptance	24
5.4	Permanence.....	24

1 Introduction

1.1 The role of coal in a sustainable energy future

Coal accounts for over 50% of US electric power generation and over 80% that sector's carbon dioxide emissions¹. In the absence of penalties or restrictions on carbon dioxide emissions, coal use for electricity generation is expected to grow in the coming decades due to its low and stable price. With vast reserves, the price of coal should remain more constant than that of natural gas, which provides 15% of the primary energy input for power generation.

However, policies to reduce carbon dioxide emissions have the potential to threaten coal's dominance in the electric power sector in favor of less carbon-intensive natural gas and renewables. Carbon dioxide capture and storage (CCS) technologies hold promise in offsetting this switch.

To determine what role coal has to play in the transition to lower carbon-emitting, more sustainable energy, this paper explores the influence of four factors on future of coal consumption in the electric power sector: the price of carbon, the price of natural gas, costs of CCS technologies, and the economic dispatch between coal and natural gas generation technologies.

This analysis emphasizes the time frame out to 2050. Although one may expect new, low carbon-emitting generating technologies to be available in 2050, their impact on the installed capacity of the electric power system will be minimal. It is reasonable to assume that our energy systems will still be dominated by fossil fuels. This sets up a competition between coal and natural gas, the key fossil fuels used in US electricity generation.

Section 2 establishes the context of coal consumption in the US electric power sector. Section 3 presents a methodology and results of evaluating the effects of carbon price, natural gas price, technology cost, and economic dispatch on future coal consumption emphasizing the period between 2000 and 2050. Section 4 compares and contrasts two other modeling efforts that analyze use of coal in the US electric power sector. Section 5 describes the challenges facing coal consumption, especially those related to the adoption of carbon capture and storage technologies.

2 Coal resources and consumption

2.1 US fossil fuel resource base

Second only to the former Soviet Union, the US has significant reserves of coal estimated at roughly 21% of global coal resources. This makes coal a highly attractive domestic fossil fuel resource in contrast to

¹ In 2002, the US electric power sector emitted over 623 million tC. Coal accounted for 512 million tC. EIA Annual Energy Review 2002 and author's own calculations.

the limited quantities of domestic oil and natural gas as shown in Table 1. The ratio of economically recoverable coal reserves to current production is in the hundreds of years, ten times greater than that of oil and gas reserves. Note that the median values of undiscovered and uneconomic resources are used in the table below. This representation hides the large degrees of uncertainties in these estimates. Furthermore, the table excludes unconventional oil and gas resources such as shale oil, tar sands, and methane hydrates. By some estimates the global supply of these unconventional resources may be over four times that of conventional resources.

Table 1 US Fossil Fuel Reserves and Resources

	Identified	Undiscovered	Subtotal	Currently Uneconomic	Total	Economic R:P (years)	Global Fraction ^a
Oil ^a	297	255	552	469 ^c	1021	13	6%
Natural Gas ^a	332	297	629	483 ^c	1112	26	4%
Coal ^b	6884	41120	48004	26764	74768	1798	21%

^a Babiker, et al. (2001).

^b Computed from EIA (1999). Using EIA's terminology, identified reserves are the demonstrated reserve base, currently uneconomic is the difference between identified resources and recoverable resources, and undiscovered resources are total resources less identified.

^c Does not include an estimated 275,000 EJ of shale oil (Babiker et al. 2001) or significant quantities of methane hydrates in coastal waters.

2.2 Historical fossil fuel consumption

In 1949, coal and petroleum each accounted for 37% of total primary energy consumption. Natural gas provided 16% of the energy with the remaining 9% supplied by renewables. Although all three fossil fuels have experienced substantial growth since then, and despite vast reserves, coal's growth relative to the other fuels has been slower (see Figure 1 below). In 2002, coal's share of total energy consumption dropped to 23% while natural gas has increased to 24% and petroleum's share remains 39%. Nuclear accounts for 8% and renewables provide 6%.

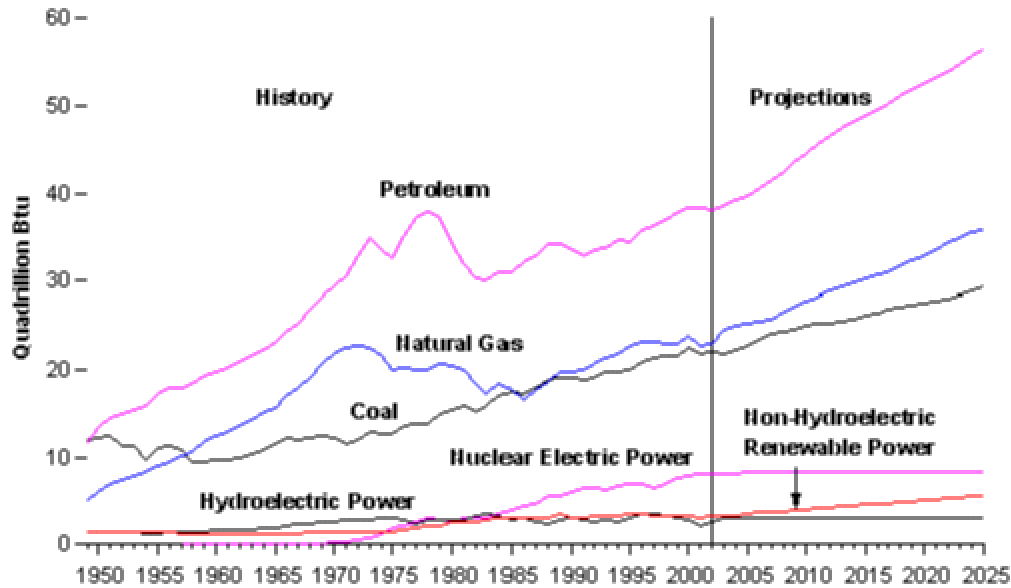


Figure 1 Historical US Energy Consumption and Projections (EIA, 2002).

In the 1950s, most coal was consumed in the industrial sector, many homes were still heated by coal, and the transportation sector consumed coal in steam-driven trains and ships. By the 1960s, most coal was used for generating electricity and by 2002 the electric power sector's share stood at 92 percent of all coal consumption. Over the latter half of the 20th century, coal use in these sectors has been replaced by oil and natural gas. These fuels are cleaner burning, readily transportable via pipeline, rail, and road. As a general rule, liquids and gases are easier to handle in industrial processes.

Although these same attributes make oil and gas attractive to the electric power sector as well, technologies in the electric power sector have been better able to adapt to handling issues, impurities and pollutant emissions. The development of flue gas cleaning technologies to remove particulates and reduce sulfur dioxide and nitrogen oxide emissions have enabled these emissions to decline even as coal consumption has increased. The introduction of such devices on distributed emission sources like residential and commercial boilers is cost prohibitive. Coal combustion processes can better tolerate a higher degree of impurities than most industrial chemical processes.

2.3 Coal use and the primacy of electric power

As Figure 2 indicates, coal consumption in the electric power sector has expanded dramatically from roughly 100 million short tons in 1950 to 975 million short tons in 2002 (EIA, 2003), an average annual growth rate of 5% per year. In 2002, electricity generation accounted for over 91% of US coal consumption. Industrial users consumed 8% of the coal and commercial and residential customers used less than 1%.

The mining and processing industry supplying this coal is comprised of over 70 companies employing 81,000 people, or 0.06% of the non-farm workforce (BLS, 1999). Industry revenues in 2002 were

on the order of \$28 billion, less than half a percent of the entire economy. Although the industry relatively small in terms of the numbers employed and gross revenues, it plays a major role in state and national politics through intensive lobbying efforts and a highly visible unions. This is partially due to the fact that over 90% of demonstrated reserves and the majority of the mining occurs in 11 states: Montana, Illinois, Wyoming, West Virginia, Kentucky, Pennsylvania, Ohio, Colorado, Texas, New Mexico, and Indiana.

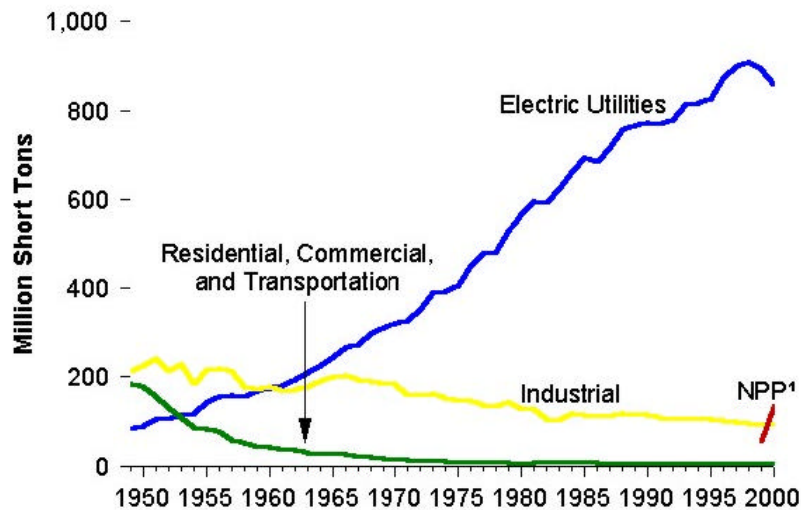


Figure 2 US Coal Consumption by Sector (EIA, 2002)

¹ NPP refers to non-utility (independent) electric power providers

2.4 ***The threat from natural gas***

With a large reserve base, the price of coal over the last 25 years has not fluctuated more than 16%. The rising coal prices from 1973-1980 depicted in Figure 3 are due to a rising demand for coal in the 1970's in response to fuel switching from oil and natural gas. Coal's primary competition in the electric power sector since the mid-1990's has come from natural gas.

Growth in the use of natural gas in the electric power sector is due to two policy phenomena and one technological phenomenon. First, amendments to the Fuel Use Act in 1987 eased restrictions on the use of gas for electric power generation by removing a legal requirement to obtain an exemption for the construction of new gas-fired generating capability. Second, the restructuring of the electric power sector under PURPA enabled independent power producers to compete with traditional electric utility generators. Third, advanced gas turbine technologies (e.g., natural gas combined cycle plants) lowered capital costs and improved efficiencies of plants such that they became competitive with coal for base load generation. With capital costs of approximately 60% of coal plants and shorter permitting and construction times, this technology became very attractive to independent power producers. As of 1998, 57% of electricity generated by non-utility generators was fueled by natural gas (EIA, 1998).

The rapid expansion of natural gas fired capacity in the electric power sector led to greater demand and subsequently higher prices (see Figure 3). Since the early 1990's, the wellhead price of natural gas has risen from around \$1.70/mmBtu to over \$4.00/mmBtu, a 235% increase. Limited domestic supplies of natural gas as described above and the long lead times and difficulties of importing liquified natural gas (see Jensen, 2003) do allow gas supplies to respond quickly to these price signals. This has led to the idling of significant amounts of natural gas generating capacity.

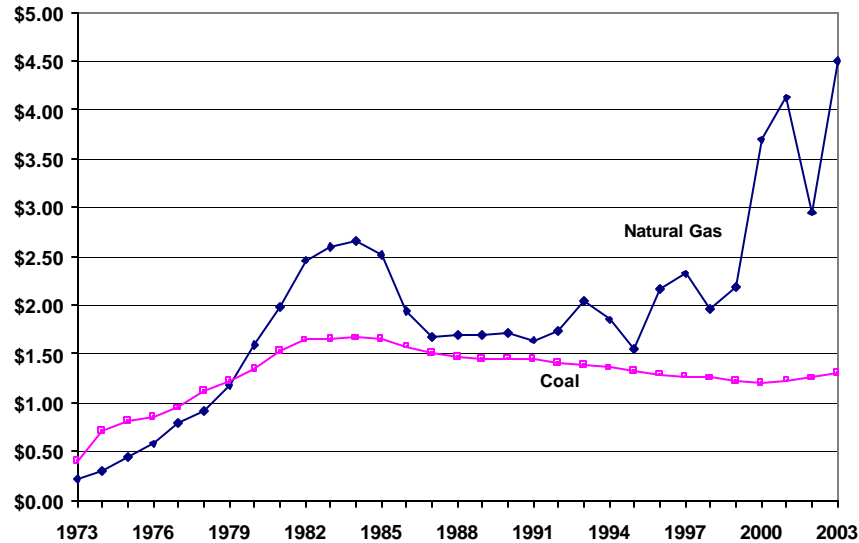


Figure 3 Average US Coal and Natural Gas Prices (f.o.b., wellhead² \$/mmBtu) (EIA, 2003).

Thus the threat to coal from natural gas is highly dependent upon the price of that gas. Figure 4 shows gas price projections from the National Petroleum Council's 2003 report on the future of natural gas prices. Under the most optimistic scenario which includes significant increases in domestic production as well as LNG importation, prices are not projected to fall below \$3/mmBtu. A pessimistic scenario in which domestic production does not respond to increased investment and LNG imports remain low shows long-run prices in excess of \$6-7/mmBtu.

² Delivered prices to electric utilities for natural gas were, on average, \$1.2/mmBtu higher from 1995-2003.

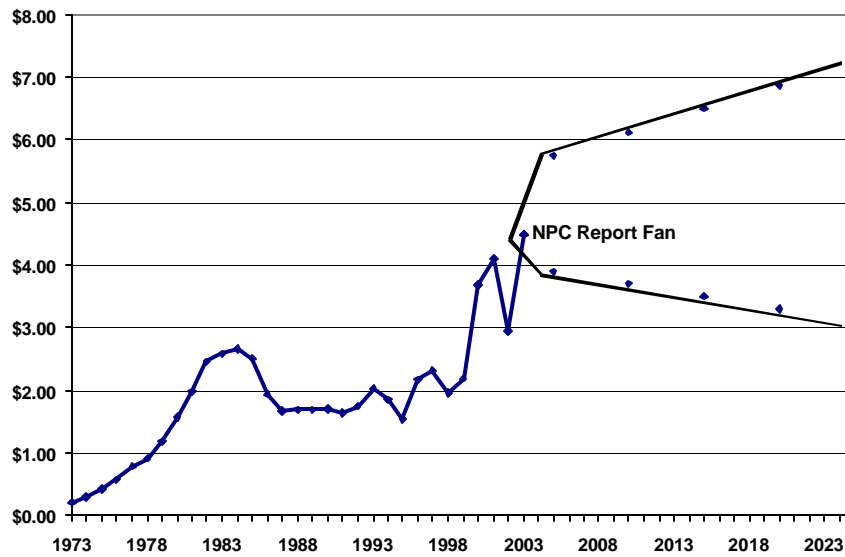


Figure 4 US Natural Gas Price Projects (NPC, 2003)

The above sections demonstrate that the future of the coal industry is tied to both the price of natural gas and the costs of technologies. To understand how these factors influence coal consumption in the US electric power sector, I first examine the effect of these factors using a computable general equilibrium economic model, the MIT Emissions Prediction and Policy Analysis (EPPA) model, with a disaggregated electric power sector. I then compare the results from EPPA with those of other energy-economy models such as Mini-CAM and a bottom-up optimization model of one US NERC region.

3 Analysis of Coal’s Future

3.1 Methodology

Using the MIT EPPA model, I examine the sensitivity of coal consumption in the US electric power sector in 2050 to carbon prices, natural gas prices, and technology costs. In this sensitivity assessment, each variable is examined at three levels over a broad range of values. The exact scenarios are discussed below. As stated at the outset, although developments in renewable and nuclear technologies are highly likely over this time frame, it is doubtful that they will have captured significant market share by that time. This simplification would not hold after 2050.

The EPPA model is a recursive dynamic multi-regional computable general equilibrium model of the world economy developed for the analysis of climate change policy (Babiker, *et al.*, 2001). Version 3 of the model is built on a comprehensive energy-economy data set, GTAP-E, that accommodates a consistent representation of energy markets in physical units as well as detailed accounts of regional production and

bilateral trade flows. The base year for the model is 1995, and it is solved recursively at 5-year intervals through 2100 to capture the long-term dynamics of resource scarcity and capital stock turnover. EPPA consists of twelve regions, which are linked by international trade, nine production sectors, and a representative consumer for each region as shown in Table 2. Capital, labor, and a factor resource for each fossil fuel and a land resource for agriculture comprise the primary factors of production. Unlike bottom-up engineering economy models, EPPA endogenously determines the prices and quantities of factors of production (capital, labor, energy resources, and land) for each region by maximizing consumer welfare recursively in each period. CGE models are the most complete in characterizing economy-wide interactions, including international trade, energy supply and demand, inter-industry supply and final demand for goods and services, and consumer demands.

Table 2 EPPA regions, sectors, and factors of production

Regions	<u>Annex B</u> (United States, Japan, European Union, Other OECD, Eastern European Associates, Former Soviet Union) and <u>Non-Annex B</u> (Brazil, China, India, Energy Exporting Countries, Dynamic Asian Economies, and Rest of World).
Production Sectors	Coal, Oil, Refined Oil, Gas, Electricity, Energy Intensive Industries, Agriculture, Investment, and Other Industries.
Primary Factors	Labor, Capital, and Fixed Factor resources for coal, oil, gas, shale oil, and agriculture.

The electric sector EPPA consists of five technologies. A conventional electric sector uses coal, oil, and natural gas to produce electricity. The technology represents an aggregate of existing fossil fuel combustion technologies. Non-fossil technologies include nuclear, hydro, wind and solar, and biomass. For the purpose of understanding the future coal consumption, three additional electricity generation technologies are introduced to compete with existing electricity generation technologies in the EPPA model. The three new power generation technologies are: 1) a natural gas combined cycle technology (advanced gas) *without* carbon capture and storage, 2) a natural gas combined cycle technology *with* carbon capture and storage (gas capture), and 3) an integrated coal gasification technology *with* carbon capture and storage (coal capture). These technologies will be described in greater detail during the discussion of technology scenarios³.

3.2 Reference case

Edmonds et al. (2000) notes that the one of the most important factors contributing to differences between the results of different energy-economy models is the reference case assumptions. In the reference

³ For a detailed description of the representation of carbon capture and sequestration technologies in EPPA, the reader is referred to McFarland, Reilly, and Herzog (forthcoming).

case of the EPPA model, there is no penalty placed on carbon dioxide emissions and natural gas prices are determined endogenously. Such a scenario presents a fairly promising role for coal. Consumption in the US electric power sector increases from 19 EJ in 2000 to nearly 54 EJ by 2050, a 2.1% annual increase (see Figure 3). Coal accounts for 52% of primary energy input to the sector in 2000 and expands to 68% by 2050.

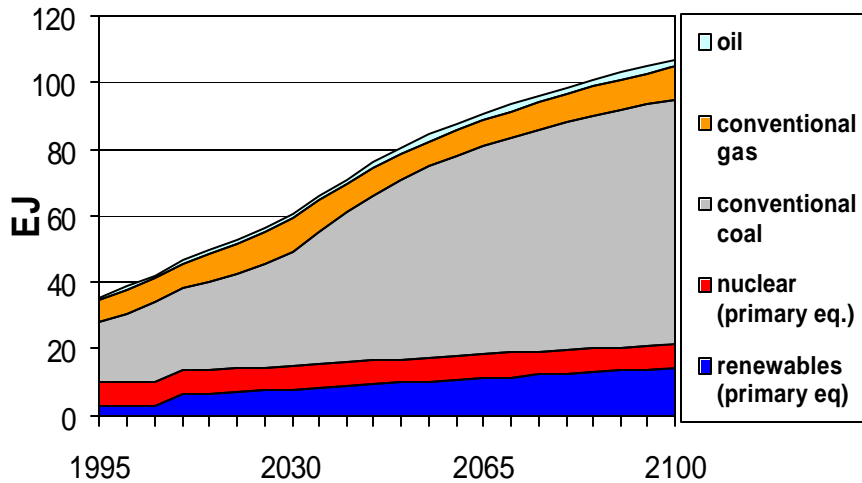


Figure 3 Primary energy input to electric sector, reference case

3.3 Effect of carbon prices

The effect of carbon prices on coal consumption is examined under two carbon price paths. In the low price path scenario, US carbon emissions are penalized at \$10/tC beginning in 2010. Rising 7.3% per year, the price reaches \$170 by 2050 and stabilizes at \$270 after 2065 (see Figure 4). The high price path scenario begins at a more aggressive \$30/tC and rises at 6.3% per year to reach \$340 in 2050. This price path stabilizes at \$450 after 2065. These paths are politically tractable because they begin at relatively low levels. A \$10/tC penalty on carbon emissions translates into roughly 2 mills/kWh for a coal-fired power plant. Furthermore, the prices escalate faster than economic growth that helps to curtail emissions. US carbon emissions stabilize at 2.4 GtC/yr and 2.0 GtC/yr for the low and high scenarios, respectively. However, neither price path stabilizes atmospheric carbon concentrations. Price paths that stabilize emissions would require carbon prices well above \$1000/tC by 2100 (see e.g., McFarland, Herzog, and Reilly). Carbon price paths that precipitate rapid carbon reductions by 2010-2020 such as the Kyoto Protocol may cause retraction in the coal sector by as much as 40% (EIA, 1999).

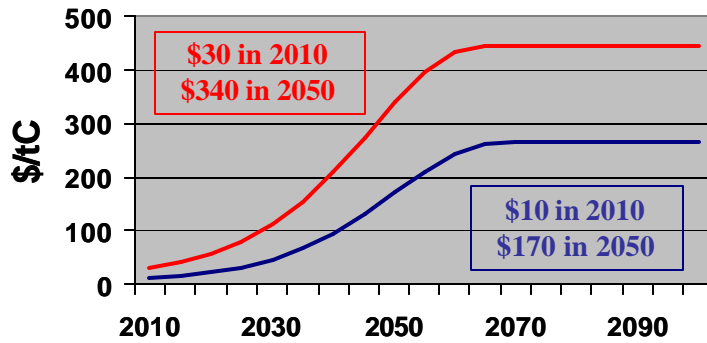


Figure 4 Carbon price paths

As expected, carbon prices have a strong negative impact on coal consumption in 2050. Under the low carbon price scenario (\$170/tC by 2050), annual coal consumption is reduced by 44% to 30 EJ. As depicted in Figure 5, at carbon prices of \$340/tC under the high price scenario, coal consumption is roughly equal to current consumption. Even at these carbon prices, coal continues to be utilized for power generation as well as in energy intensive industries, however coal's growth prospects are severely curtailed.

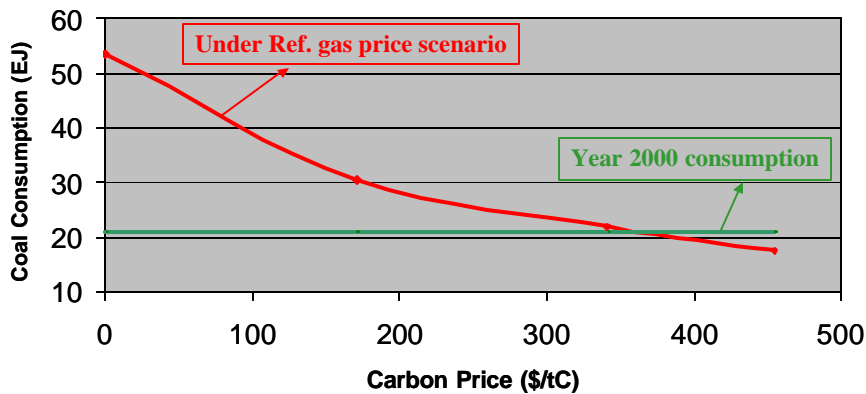


Figure 5 Effect of carbon price on coal consumption in 2050
reference gas price, mid technology cost, equal dispatch scenario

3.4 ***Effect of natural gas prices***

The effect of gas prices on coal consumption is analyzed under three scenarios (reference, mid, and low). Figure 6 shows the gas price index from the 1995 base year through 2055. The reference gas price scenario is determined endogenously in EPPA based upon domestic resources and imports. This scenario has the highest gas prices rising over four times from a 1995 price of \$1.85/mmBtu to \$7.80/mmBtu in

2050.⁴ The exogenously specified mid gas price scenario exhibits a slower rate of increase and reaches a maximum price of \$5.60/mmBtu by 2050. The low gas price scenario reaches a maximum of \$3.00/mmBtu in 2010. This scenario was exogenously specified to represent a world in which gas is an abundant and globally traded commodity. Support for a future with low gas prices over the next 50 to 100 years may be found in Adelman and Lynch (2002). The scenario also closely corresponds with the National Petroleum Council's (2003) low gas price scenario.

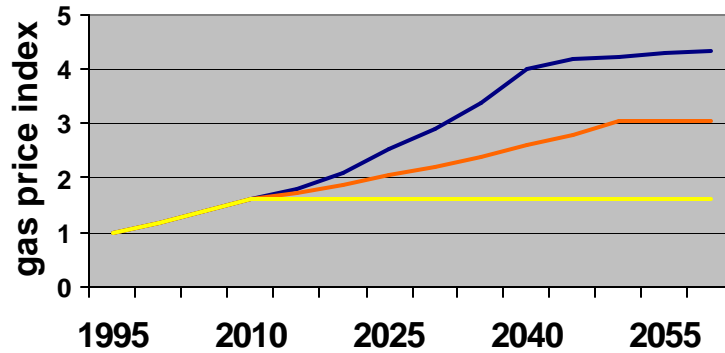


Figure 6 Gas price scenarios

The effect of gas price on coal consumption over the arguably wide ranges examined is much less significant than the carbon price. The reference gas price line in Figure 7 duplicates the line from Figure 5. Lowering the gas price from the reference path to the mid gas price path has a minimal effect on coal consumption over the full range of carbon prices⁵. The low gas price scenario reduces coal consumption under all carbon price scenarios. With no carbon price, coal consumption is reduced by 10 EJ in 2050. Positive carbon prices reduce the overall demand for electricity, thus the absolute reduction in coal consumption for the low and high carbon price scenarios is 3-4 EJ. However, in percentage terms low gas prices reduce coal consumption by 10% under mid carbon prices and by 20% under high carbon prices. As theory suggests, the higher carbon prices stimulate a greater level of substitution to the lower cost input.

⁴ Coincidentally, this is similar to the high price projection in the NPC (2003) report.

⁵ There is actually a slight increase in coal consumption with lower gas prices that may be explained through a general equilibrium effect on the economy. As an important input into several economic sectors, lower gas prices raise economy wide output. The increased demand for electricity to support higher output in turn increases coal consumption.

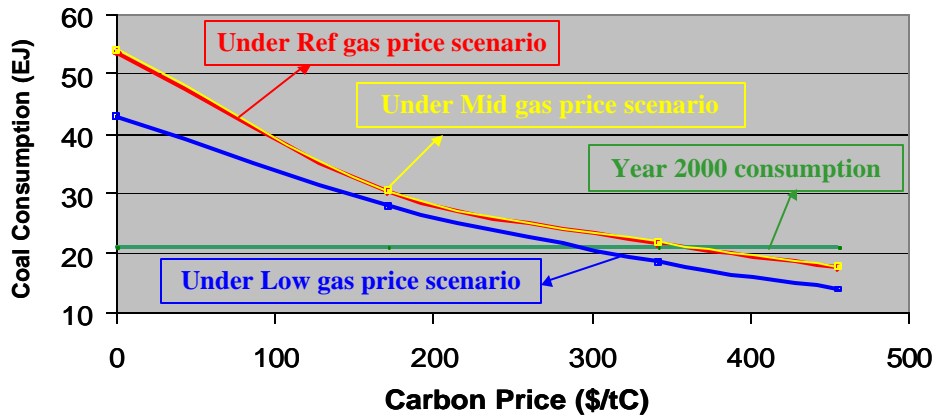


Figure 7 Effect of carbon price and natural gas price on coal consumption in 2050, mid technology cost

3.5 Effect of technology costs

In characterizing CCS technology costs, we extract from bottom-up engineering models the total costs of electricity as delivered to the consumer. This allows for a consistent comparison across competing technologies, which are also specified by end-user costs within the EPPA modeling framework. We base the generation cost, efficiency, and carbon emissions of CCS technologies on the bottom-up engineering estimates by David and Herzog (2000). Their analysis averages several generation cost studies from the U.S. and Europe. The generation cost data presented herein reflects their projections of CCS technology costs after modest technical improvements anticipated by 2012. In addition to electricity generation itself, three other costs must be included to obtain the cost to the end-user: transmission and distribution of electricity, carbon transport and storage, and CO₂ emission permits to cover the portion of carbon that is not captured. Equation 1 summarizes the total cost accounting for CCS technologies used for electricity generation:

$$C_{Electricity} = C_{Generation} + C_{T\&D} + C_{Sequestration} + kP_{Carbon} \quad (1)$$

where C denotes cost, the subscript refers to the cost category, and the constant k is the technology-specific rate of carbon emitted per unit of electricity produced. Electricity transmission and distribution cost information is based upon a survey by the Federal Energy Regulatory Commission (U.S. Department of Energy, 1999). CO₂ injection and storage costs are conservatively assumed to be \$37 per ton of carbon (\$/tC) (Bock et al., 2003)⁶. Formulated as such, Equation 1 makes explicit the dependence of the cost of electricity on the price that must be paid for any carbon that is emitted to the atmosphere by the technology as even capture technologies typically do not capture 100% of the carbon in the fuel. A nominal capture efficiency of 90%, used by David and Herzog (2000), is adopted here. The cost information contained in

⁶ Based on a transport distance of 100 kilometers.

Table 3 below offers a representative illustration of the cost accounting for the advanced gas, gas capture, and coal capture technologies at fixed fuel prices and plant capacity factors⁷. Additional data table may be found in the Appendix. The impact of plant capacity factors will be analyzed below in the context of economic dispatch.

Table 3 Electricity cost breakdown by technology, reference technology scenario (mills/kWh)

Technology	Cost of Generation	Cost of transmission and distribution	Cost of Sequestration	<i>Total Cost Excluding Emissions Penalty</i>	Carbon Entry Price (\$/tC)	
					CCS vs. PC	CCS vs. Advanced Gas
Advanced Gas (NGCC)	31.4	24.3	0	5.57		
Gas capture	41.4	24.3	3.37	71.4	46	192
Coal capture	51.5	24.3	6.67	8.23	106	370

By rearranging equation 1, the price of carbon at which a CCS technology becomes competitive may be determined. Comparing gas and coal capture plants to a pulverized coal plant, it becomes economic to invest in the capture technologies at carbon prices of \$46/tC and \$106/tC, respectively. However, these breakeven carbon prices increase dramatically if the capture technologies are competing against natural gas combined cycle plants that produce roughly half of the carbon dioxide as a pulverized coal plant. In this situation, the carbon price required for entry of the gas and coal capture plants becomes \$192/tC and \$370/tC respectively.

The technology costs presented in Table 3 per David and Herzog (2000) reflect the state of the technology as it is likely to exist by 2012 after only a few full-scale demonstrations. At the fuel prices noted in the footnote below and excluding any emissions penalties, the cost of electricity for the advanced gas technology is 11% less expensive than a new pulverized coal plant. Electricity from gas capture and coal capture plants is 15% and 32% more expensive, respectively.

The costs of conventional and capture technologies will likely continue to fall over time due to a variety of factors: plant scale, manufacturing scale, improved integration, and learning. McDonald and Schratzenholzer (2002) and Riahi et al. (forthcoming) provide empirical evidence of cost reductions in energy technologies. To examine the effect of cost reductions in generating technologies on coal consumption, two additional technology cost scenarios are developed. The mid cost scenario reflects reductions in capital costs

⁷ A capacity factor of 75% is assumed across all technologies. Fuel costs for the gas technologies are \$2.93/mmBtu and \$1.24/mmBtu for coal.

and heat rates for the capture technologies that could occur by 2025. Advances in the coal capture technology are greater relative to the other technologies because this technology is less well known and therefore has greater opportunities for improvement. Marginal improvements are also considered for the pulverized coal and advanced gas technologies. The low cost scenario allows for further improvements. Table 4 contains the costs of electricity for the technologies. Relative to the projected cost of electricity from a pulverized coal plant, electricity from advanced natural gas plants is 13% cheaper while power from the gas and coal capture plants is only 7% and 10% more expensive.

Table 4 Cost of electricity by technology and technology scenario, equal dispatch (mills/kWh)

Technology → Scenario ↓	Pulverized coal (PC)	Advanced Gas	Gas Capture	Coal Capture
Reference (% diff. from PC)	62.3	55.7 (-11%)	71.4 (+15%)	82.3 (+32%)
Mid (% diff. from PC)	61.2	54.5 (-11%)	67.9 (+11%)	71.5 (+17%)
Low (% diff. from PC)	61.2	53.3 (-13%)	65.5 (+7%)	67.4 (+10%)
Capital share	0.60	0.48	0.54	0.63
Fuel share	0.16	0.30	0.27	0.12

The overall electricity costs net of carbon penalties presented above are useful for comparing technologies as long as factor input costs (capital, labor, and fuel for these technologies) remain constant⁸. However, factor input prices are never constant in the face of scarcity and competing demands. What is useful to note in a dynamic context with changing prices are the shares of the critical factor inputs for each technology. As shown in Table 4, the primary factor input for the pulverized coal and coal capture plants is capital that consumes approximately 60% of the total inputs. Fuel only represents 12-16% of the input costs. Thus coal plants are much more sensitive to changes in capital prices than labor or fuel prices. Electricity from natural gas plants, while requiring less capital (48% to 54% of input costs), uses substantially more fuel (27% to 30% of total input costs) making the cost of electricity much more sensitive to gas prices.

Having specified several technology costs scenarios, the scenarios were run with all combinations of carbon prices (high and low) and gas prices (reference, mid, and low). Under the low carbon price scenarios and over all of the gas price scenarios, coal consumption in 2050 is insensitive to reductions in technology costs. Coal consumption increased by at most 5% across these scenarios with minimal generation from the coal capture technology.

⁸ Factor input costs are determined by translating capital, operations and maintenance, and fuels costs into inputs of capital, labor, and fuel.

However, at high carbon prices (\$340/tC in 2050) reductions in technology costs increased coal consumption through the expanded use of the coal capture technology. Figure 8 shows the coal consumption for all combinations of technology cost and gas price at high carbon prices. The three mid-cost data points at reference, mid, and low gas prices correspond with the coal consumption numbers from Figure 7 at \$340/tC. Looking first to the reference and mid gas prices scenarios (the two sets of columns on the right), there is little difference in coal consumption between the reference and mid technology costs. Yet at low technology costs coal consumption jumps by 3-4 EJ. Under low gas prices (leftmost set of columns), the cost reduction from high to mid increases coal consumption by 4 EJ, but further cost reductions have little effect. The net results indicate that the growth prospects for coal under the high carbon price scenario are limited (0.4% annual increase over 50 years), but coal remains an major source of electricity.

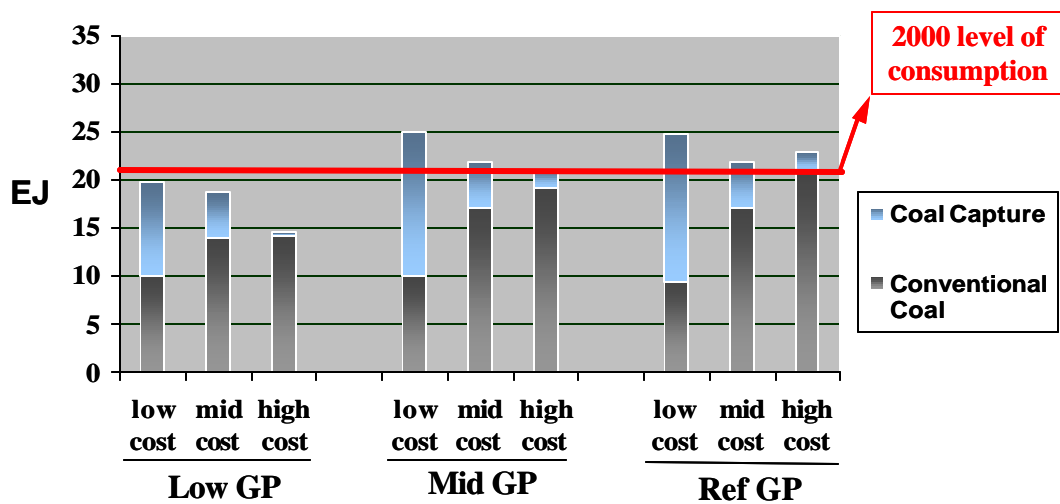


Figure 8 Effect of technology cost on coal consumption in 2050, high carbon price path

3.6 Effect of economic dispatch

Two characteristics of the electric power sector make plant dispatch a critical parameter in assessing the economics of CCS technologies. First, unlike most other goods electricity is produced and consumed instantaneously. It cannot be stored without significant expense and power loss. Second, the demand for electricity changes throughout the day. Demand is highest during business hours and into the early evening. Figure 9 identifies three categories of demand based on annual dispatch and capacity cost in the U.S.: peak power which dispatches less than 6% of the year (about 500 hr/yr), intermediate power which dispatches up to 55% of the year (4800 hr/yr), and base power which dispatches continuously (Speakes, 2002).

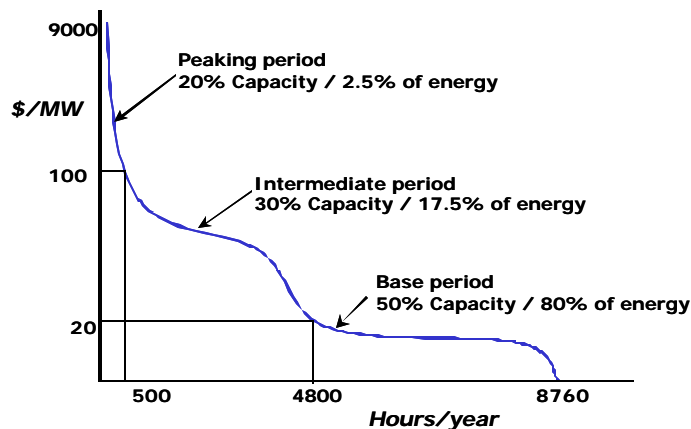


Figure 9 Capacity cost and annual dispatch for the US (Speakes, 2002)

The frequency with which a plant is dispatched has a significant impact upon the ability of a plant to recover fixed capital costs. This in turn affects the types of plants constructed and dispatched to meet demand for different segments of the load curve. In deregulated markets, capital intensive coal and nuclear plants typically fill base load capacity, natural gas combined cycle plants fill intermediate load capacity, and simple cycle gas turbines provide peaking capacity. In a competitive market, plant dispatch is determined by marginal operating cost with the low marginal cost plants dispatched first. However, the decision to build new capacity is based upon expected profits, which are determined by average total costs. Therefore, the economics of investment decisions are dependant upon dispatch when a technology does not have both the lowest average total cost and the lowest marginal operating cost.

This situation arises for investment decisions between gas and coal plants. Figure 10 below shows the average cost (AC) and marginal cost (MC) of electricity for two technologies as a function of capacity factor⁹: gas capture and coal capture. For equivalent capacity factors, the average cost of the gas capture plant is cheaper to operate than the coal capture plant and suggests that the gas plant would be more profitable. Yet, the marginal cost for the coal capture plant is 0.6 cents/kWh less expensive than the gas capture plant largely reflecting the lower fuel cost of coal versus gas¹⁰. With a lower marginal cost, the coal capture technology would likely have a higher dispatch level and, therefore, capacity factor than the gas capture technology. Assuming the lower marginal cost coal capture plant is dispatched at a higher rate to yield a capacity factor of 85%, the gas capture technology would need a capacity factor of greater than 60%

⁹ Capacity factor is the percentage of time a plant operates in a given year. This parameter is a product of plant availability and dispatch.

¹⁰ Delivered gas and coal prices used in this calculation are \$3.00/mmBtu and \$1.24/mmBtu respectively. The difference in marginal cost rises to 1.3 cents/kWh at gas prices of \$4.00/mmBtu. The figure assumes a carbon price of \$200/tC, but this does not have a significant effect on the average or marginal costs.

to be economically viable on an average cost basis. Gas capture plants, however, are more likely to be used as intermediate load. At capacity factors of 40% to 50%, gas capture plants are 1.0 to 1.5 cents/kWh cheaper than the coal capture plants on an average cost basis.

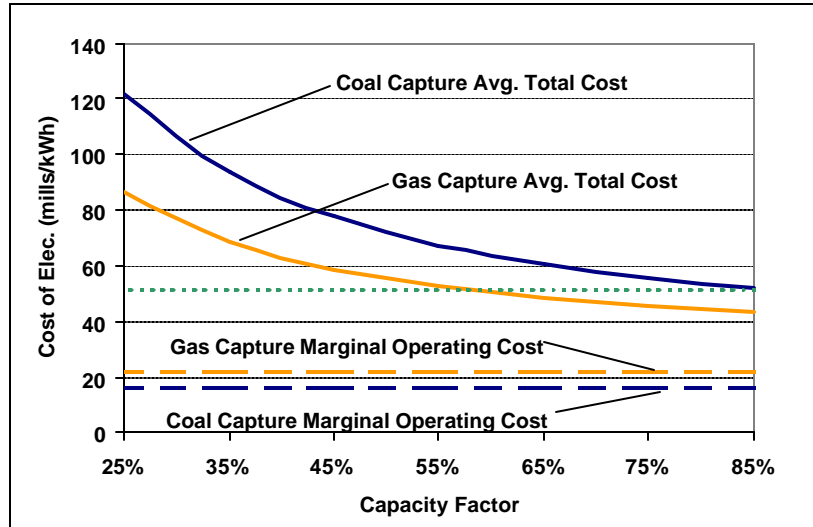


Figure 10 Cost of electricity generation as a function of capacity factor

Simplifying assumptions are required to reflect the effects of load dispatch in highly aggregated CGE models. Although bottom-up activity models have been used to address the economic dispatch of competing generating technologies (see e.g., Johnson, 2002, Johnson and Keith, 2003), CGE models lack the grid-specific detail required by a bottom-up approach. Two approaches have been used to incorporate dispatch into top-down models. The first approach, used in EPPA, relies on dispatch estimates from bottom-up activity models to compute cost information in engineering cost models. The second approach introduces separate production sectors for peak and intermediate loads and for base loads.

To test the effect of dispatch on coal consumption, technology costs for the advanced gas, gas capture, and coal capture technologies were recalculated using different capacity factors for the coal and gas plants to reflect higher marginal costs for the gas plants. To better represent baseload generation, the capacity factor of the coal plant is raised from 75% to 80%. The capacity factors of the gas plants are reduced from 75% to 60% to mimic plants that provided shoulder load. While the effect on the coal capture plant is minor, the cost of electricity for the gas plants increases by 3-7 mills/kWh. Table 5 contains the updated cost information.

Table 5 Cost of electricity by technology and technology scenario, unequal dispatch (mills/kWh)

Technology → Scenario ↓	Pulverized coal (PC)	Advanced Gas	Gas Capture	Coal Capture
Reference (% diff. from PC)	62.3	58.7 (-6%)	76.5 (+23%)	80.2 (+29%)
Mid (% diff. from PC)	61.2	57.6 (-6%)	73.8 (+23%)	69.9 (+14%)
Low (% diff. from PC)	61.2	57.6 (-6%)	72.9 (+19%)	65.5 (+7%)
Capital share	0.60	0.51	0.57	0.63
Fuel share	0.16	0.29	0.25	0.12

To analyze the effect of dispatch on coal consumption, the gas price and technology cost scenarios were repeated for the high carbon price (\$340/tC) case. Coal consumption in 2050 is highly sensitive to dispatch assumptions. Coal consumption is 6 to 11 EJ above the 2000 level of consumption for all scenarios. Recall that for the equal dispatch case, coal consumption ranged from 7 EJ *below* to 5 EJ above 2000 levels. Under all scenarios, coal consumption increases by an average of 0.4% to 0.8% per year. The data suggest the key to achieving higher rates of coal consumption is cost reduction of the coal capture technology.

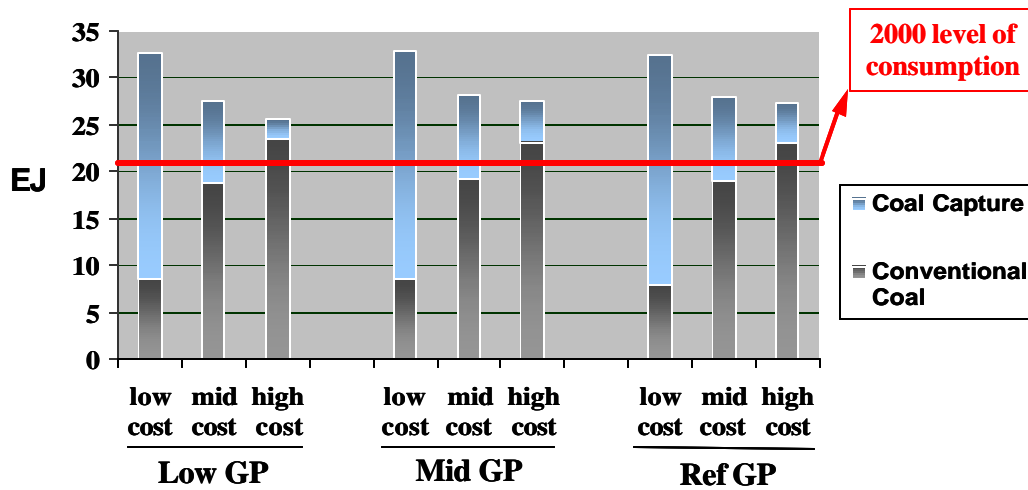


Figure 11 Effect of gas price and technology cost on coal consumption, high carbon price, unequal dispatch

3.7 **Conclusions**

The US coal industry remains viable in all cases, however its growth opportunities are curtailed to between zero and 11 EJ from 2000 levels of production for most scenarios. Over the variable ranges tested, coal consumption is most highly dependent upon the carbon price. Assumptions on the dispatch of coal and gas plants have the second greatest impact on coal consumption. Coal consumption is less sensitive to natural gas prices than carbon prices over the ranges examined. Finally, improvements in CCS technology

make coal consumption less dependent on gas prices but do not mitigate carbon price effects on consumption through 2050.

3.8 ***Beyond 2050***

Although the scope of the above analysis concentrated on the timeframe from 2000 through 2050, it is instructive to understand what technologies predominate in electricity generation. Note that in the scenarios analyzed, carbon prices stabilize after 2065. Such low carbon prices generally preclude the adoption of significant quantities of renewable generation. With nuclear power generation fixed by assumption, this sets up a competition between coal capture and gas capture technologies for the lion's share of the electric power sector. The coal capture technology tends to dominate electricity generation under mid to reference gas prices, mid to low technology costs, and unequal dispatch (80% capacity factor coal, 60% capacity factor gas). The gas capture technology dominates under high carbon prices, low gas prices, reference technology costs, and equal dispatch.

The figures below depict very different futures for coal beyond 2050. Both results were generated under a scenario with a high carbon price, low gas price, and low technology cost. The top figure assumes unequal dispatch while the bottom figure assumes equal dispatch. In both cases, by 2100 carbon capture technologies enable electricity generation to return to levels similar to the EPPA reference case without a carbon tax¹¹. A future dominated by coal powered generation implies that the costs of generation, capture and storage have fallen over time and that the US relies upon domestic supplies of coal for power generation. Though a future dominated by natural gas capture technology also assumes technology cost reductions, the more critical piece to realize this scenario is stable natural gas prices at roughly \$3/mmBtu. Prices much above this make gas unattractive to coal based on the marginal cost of electricity. Gas at such low prices would either come from a large global LNG market or through the extraction of unconventional gas sources such as methane hydrates.

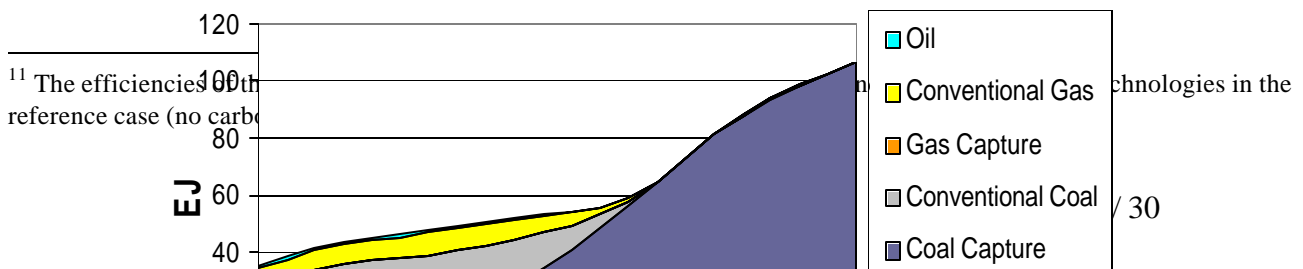


Figure 12 Primary energy input for the US electric power sector, high carbon price, low gas price, low technology cost, unequal dispatch

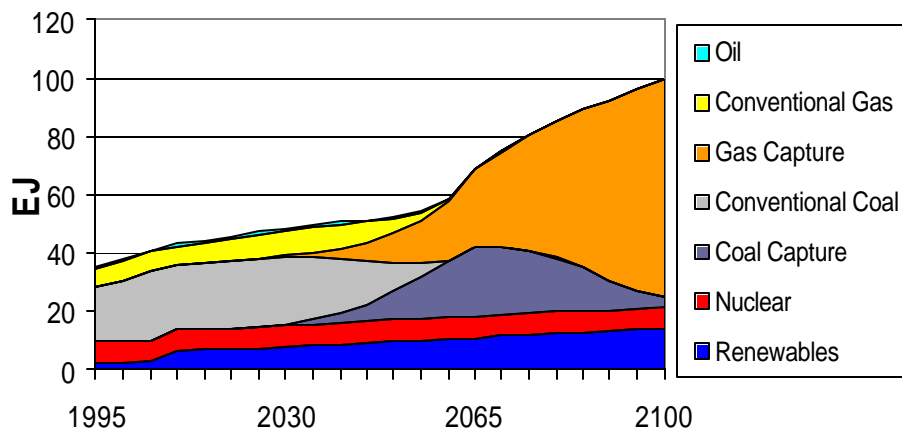


Figure 13 Primary energy input for the US electric power sector, high carbon price, low gas price, low technology cost, equal dispatch

4 Comparison to Other Studies

Two other studies have been conducted on coal consumption under carbon constraints in the US electric power sector. Dooley, Kim, and Runci (2000) using a partial equilibrium energy-economy model (Mini-CAM) to conduct an analysis similar to the work above to assess the economic benefits of the adoption of CCS technologies. Johnson and Keith (in press) study the adoption of CCS technologies using a bottom-up linear programming model that minimizes electricity costs under carbon constraints for the PJM NERC region of the US. Both models rely to some extent on David and Herzog (2000) for their cost estimates.

Dooley, Kim and Runci (DKR) analyze how carbon taxes may alter the primary energy mix of several sectors of the US economy and quantify the benefits of CCS technologies. One of the tax scenarios in their study is sufficiently similar to the low carbon price scenario described above. A US carbon tax

begins at \$91 in 2020 and escalates to \$184 by 2050. Recall that the low carbon price scenario is \$170 by 2050. Furthermore, this study assumes abundant unconventional gas resource become available by mid-century. DKR reports total fossil electricity generation in the reference case of 23 EJ of electricity generation that translates to 65 EJ of primary energy at an assumed efficiency of 35%. This is 19% less than the EPPA reference case. Under their tax case, approximately 15 EJ of coal are used in the electric power sector compared to 18 EJ of natural gas.¹² Coal consumption in DKR is 40% below the 27 EJ of coal consumed in EPPA's low carbon price, low gas price scenario.

This discrepancy may be due to three factors. First, DKR's reference electricity demand is nearly 20% below that in EPPA. Second, the model used in this study is a partial equilibrium model that may not be as responsive to low natural gas prices. EPPA's results demonstrated that lower natural gas prices increased the demand for electricity. Without this general equilibrium price feedback mechanism, MiniCAM may underestimate economic output and, therefore, electricity demand. Third, although the carbon price paths from both models converge at \$180/tC in 2050, DKR has much higher prices from 2020-2040. This more aggressive carbon price path would have a cumulative effect of slowing economic output and lowering the demand for electricity and coal.

Johnson and Keith (in press) presents a bottom-up engineering linear programming model of the Mid Atlantic Area Council region of the North American Reliability Council. The model minimizes the cost of electricity from 2000-2040. Unlike EPPA, Electricity demand and fuel prices are exogenous to this model, yet economic dispatch is determined endogenously. Results from this model indicate that utilization of coal capture plants is in excess of 80% while that of natural gas and gas capture plants average closer to 66%. This result suggests that unequal dispatch should be used when modeling gas and coal capture technologies in EPPA. Low natural gas prices have a similar effect in both models. Below \$3/mmBtu, natural gas is built and dispatched before the coal capture technology at carbon prices below \$200/tC.

5 Implications and Challenges

The results of several modeling efforts on the future of coal in the US indicate that despite high carbon content relative to oil and natural gas, coal will provide a significant amount of primary energy to the US electric power sector through 2050 at carbon prices up to \$340/tC. The development of CCS technology can enable the use of coal as a bridge to a sustainable, carbon-free energy future in the latter part of this or

¹² Only EJ of electricity are reported. I assume an efficiency of 40% for the coal capture plant and 50% for the gas plant.

the next century. To build such a bridge, several challenges must be overcome in the following areas: generation and capture technology development, reservoir development, public acceptance, and liability.

5.1 Generation and capture technology development

The reference technology costs cited in this and the other two studies presume that technology costs will fall by 30% to 50% by 2020. It is not unreasonable to expect costs to fall given today's minimal experience with integrating, manufacturing, and operating these technologies. Yet the costs are unlikely to fall without substantial investments in research, and more importantly, demonstration projects. Most of the critical CCS technology components currently exist in a similar chemical or power generation operation. Demonstrating an integrated system is essential to verify cost estimates, reliability, and identify opportunities for improvement. Jacoby et al. (2003) explains that subsidizing CCS technologies, assuming that learning and experience effects lower costs, leads to earlier technology penetration and higher welfare.

To this end, the Department of Energy and numerous energy companies are working toward constructing a \$1 billion integrated gasification combined cycle plant with capture and storage. Using the Clean Coal Technology program as a guide, large-scale demonstration projects take 8-10 years to site and build and must be run another 3 years to obtain the necessary information on operating costs. With such long cycle times for learning, 2020 is at best a couple of demonstrations away. To help expedite this process and provide a clean test of the technology, the DOE should not resist integrating a CCS technology test bed into the plant. Pilot work should be done at a smaller scale facility or in conjunction with an operating IGCC plant.

5.2 Reservoir Development

Although certain industry segments are experienced with injecting gases and liquid underground (e.g., enhanced oil recovery and acid gas injection), additional testing and monitoring of potential carbon dioxide reservoirs is warranted given the 1) potential large-scale use of the technology, and 2) the health and safety risk of leakage¹³ (Heinrich, et al., 2004).

A secondary issue related to reservoir development should be addressed regarding the allocation of property rights to geologic reservoirs. To date there is no known laws governing the property rights to void space in saline aquifers. Traditional laws related to mineral rights fully cover resource extraction, but not injection. Without clearly defined property rights, reservoirs will either go unused or be subject to overuse (e.g., a common pool problem ala Hardin). US geologic reservoir capacity is estimated at 20 to 170 GtC (Byrer, 2002). Based on scenarios from Section 3 with high levels of CCS adoption, the US could use 6 GtC

¹³ Carbon dioxide is heavier than air. Thus a catastrophic leak from a reservoir could asphyxiate large numbers of people.

by 2050 and over 60 GtC by 2100. Resolving potential property rights issues is a long-term, yet important component of cost effective technology deployment.

5.3 Public Acceptance

Recent surveys¹⁴ have shown that a very small percentage of the public has heard of CCS technologies. Experience has proven that significant public education and outreach efforts are needed and warranted to ensure the success of experimental projects (de Figueirido, 2002). Such programs must apprise the public of the benefits and uncertainties associated with geologic storage of carbon dioxide. Only then can informed judgments about the technology and its alternatives be made.

5.4 Permanence

Beyond the health and safety risks mentioned earlier, carbon capture and storage technologies are effective at limiting climate change only if they keep carbon dioxide out of the atmosphere for hundreds to thousands of years.¹⁵ The need for permanence thus offers another justification for understanding the reservoir characteristics that are critical for long-term storage (e.g., seismic activity, faults, rock type, poor structure).

The fact that some leakage, whether slow or catastrophic, will likely occur raises the issue of liability. A company that supplies carbon dioxide to a reservoir injects it into the reservoir, or monitors the carbon dioxide within the reservoir may be held liable for personal injury as well as environmental damage. Insurance companies have managed the former problem for many years. The latter problem, valuing and insuring against incremental climate change due to a release for hundreds of years into the future, has not been resolved (de Figueirido, et al., 2003). This may deter initial investment in the technology without government intervention to insure against such highly uncertain liabilities.

6 Concluding remarks

This paper presented a thorough analysis of four factors impacting the future of coal use in the US electric power sector. As expected carbon prices had the most profound effect on reducing coal consumption followed by the treatment of economic dispatch. Gas prices at or below \$3/mmBtu also threaten to displace coal consumption. Under a wide range of conditions, coal did not disappear from the electric power sector. The robustness of this result indicates that an effort should be made to improve coal's ability to continue to

¹⁴ Surveys were conducted through the Carbon Sequestration Initiative at MIT. Published results are forthcoming.

¹⁵ See Herzog et al. (2003) for an analysis on the benefits of storing carbon dioxide for time scales on the order of hundreds of years.

provide low carbon energy in the future. Relying on cheap natural gas is not a viable option for our electricity supply in 2050. In order for coal to provide a sustainable bridge to the renewable energy resources, efforts must be undertaken now to develop the technology, characterize and understand reservoirs, educate the public, and put in place the appropriate financial mechanisms to deal with long-term liability issues.

References

Adelman, M.A. and M.C. Lynch, (2002) Natural Gas Supply to 2100. International Gas Union, October.

Babiker, M.H., J.M. Reilly, M. Mayer, R.S. Eckaus, I. Sue Wing & R.C. Hyman (2001). The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Revisions, Sensitivities, and Comparisons of Results. Report of the Joint Program on the Science and Policy of Global Change. February.

Bock, B., R. Rhudy, H. Herzog, M. Klett, J. Davison, D. De La Torre, D. Simbeck, (2003) Economic evaluation of CO₂ storage and sink enhancement options, TVA Public Power Institute Technical Report, February.

Bureau of Labor Statistics. (1999) National Industry-Specific Occupational Employment and Wage Estimates

Byrer, C.W. (2002). Where we've been – where we're going. COAL-SEQ1 Forum. Houston, TX. March 14.

David, J. and H. Herzog. (2000) The cost of carbon capture, presented at the Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia.

de Figueiredo, M.A. (2002). The Hawaii Carbon Dioxide Ocean Sequestration Field Experiment: A Case Study in Public Perceptions and Institutional Effectiveness. M.I.T. Masters Thesis.

de Figueiredo, M.A., H.J. Herzog and D.M. Reiner, (2003) "Framing the Long-Term Liability Issue for Geologic Storage Carbon Storage in the United States," submitted to Mitigation and Adaptation Strategies for Global Change.

Dooley, J.J., Kim, S.H., and Runci, P.J. (2000). The role of carbon capture, sequestration and emissions trading in achieving short-term carbon emissions reductions. Proceedings of the Fifth International Conference on Greenhouse Gas Control Technologies. Sponsored by the IEA Greenhouse Gas R&D Programme.

Ellerman, A.D. (2003). Fuel prices, carbon prices, and the choice of generating technology. Presentation to the MIT Carbon Sequestration Forum IV. Cambridge, MA. November 6.

Energy Information Administration (1998). Electric Power Annual 1998 Volume II.

Energy Information Administration (1999). U.S. Coal Reserves: 1997 Update. February.

Energy Information Administration (1999). Costs for complying with the Kyoto Protocol.

Energy Information Administration (2002). Emissions of Greenhouse Gases in the United States 2002: Executive Summary

Energy Information Administration (2003). Annual Energy Review.

Edmonds, J., J. Roop, M. Scott (2000). Technology and the economics of climate change. Report for the Pew Charitable Trust.

Ford, A. (1997). System Dynamics and the Electric Power Industry. *System Dynamics Review* 13(1): 57-85.

Heinrich, J.J., H.J. Herzog and D.M. Reiner. (2004) Environmental assessment of geologic storage of CO₂," MIT LFEE Report, March.

Herzog, H., K. Caldeira and J. Reilly.(2003). "An Issue of Permanence: Assessing the Effectiveness of Temporary Carbon Storage," *Climatic Change*, Vol. 59, No. 3, pp 293-310, August.

Jacoby, H.D., J.M. Reilly, and J.R. McFarland, (2003). Technology and technical change in the MIT EPPA model, P.I. Workshop, U.S. DOE Integrated Assessment Program, Snowmass, CO, 5-6 August.

Jensen, J.T. (2003). The LNG revolution. *Energy Journal*. 24:2.

Johnson, T.L., (2002) Ph.D. Thesis, Carnegie Mellon University, Pittsburgh, PA.

Johnson, T.L. and D.W. Keith (2003). Fossil electricity and CO₂ sequestration: how natural gas prices, initial conditions and retrofits determine the cost of controlling CO₂ emissions. *Energy Policy* (in press).

McDonald, A. and L. Schrattenholzer (2002) Learning curves and technology assessment. *International Journal of Technology Management* 23(7/8):718-745.

McFarland, J. and H. Herzog (2003). Incorporating Carbon Capture and Storage Technologies in Integrated Assessment Models, P.I. Workshop, US DOE Integrated Assessment Program, Snowmass, CO, 5-6 August.

McFarland, J.R., H.J. Herzog, and J.M. Reilly (2003). Representing energy technologies in top-down economic models using bottom-up information, *Energy Economics* (forthcoming).

National Petroleum Council (2003). Balancing natural gas policy: fueling the demands of a growing economy. September.

Riahi, K., E.S. Rubin, M.R. Taylor, L. Schrattenholzer, and D. Hounshell (2003). Technological learning for carbon capture and sequestration technologies, *Energy Economics* (forthcoming).

Speakes, K.(2002). Peaking generation: the emerging need for intermediate peaking power, *Power and Gas Marketing*, March-April.

United Nations (1995). *Energy Statistics Yearbook*, New York: United Nations.

Appendix I CCS Cost Spreadsheets

Technology Description		PC			IGCC			NGCC		
		2000	2012	2025	2000	2012	2025	2000	2012	2025
Input	units									
Capital Cost	\$/kW	1075	1025	975	1401	1145	916	542	525	525
O&M	mills/kWh	7.4	6.1	6.1	7.9	6.1	4.88	2.5	2.4	2.4
Heat Rate (LHV)	Btu/kWh	8277	8042	8042	8081	7137	6423	6201	5677	5506.69
Incremental Capital Cost	\$/kg CO2/h	529	476	238	305	275	138	921	829	663.2
Incremental O&M	mills/kg CO2	5.56	5.00	5.00	2.65	2.39	1.912	5.20	4.68	3.744
Energy Requirements	kWh/kg CO2	0.317	0.196	0.196	0.194	0.135	0.135	0.354	0.297	0.297
Carbon Content of Fuel	kg CO2/Btu				9.31E-05	9.31E-05	9.31E-05	5.93E-05	5.93E-05	5.93E-05
Basis										
Annual Operating Hours	hrs/yr	6570	7008	7008	6570	7008	7008	7008	7008	7008
Capacity Factor	%	75%	80%	80%	75%	80%	80%	80%	80%	80%
Capital Charge Rate	%/yr	15%	15%	15%	15%	15%	15%	15%	15%	15%
Fuel Cost (LHV)	\$/MMBtu	1.24	1.24	1.24	1.24	1.24	1.24	3.00	3.00	3.00
Capture Efficiency	%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Reference Plant										
CO2 Emitted	kg/kWh	0.789	0.766	0.766	0.75	0.66	0.60	0.368	0.337	0.337
coe: Capital	mills/kWh	24.54	21.94	20.87	31.99	24.51	19.61	11.60	11.24	11.24
coe: Fuel	mills/kWh	10.26	9.97	9.97	10.02	8.85	7.96	18.60	17.03	16.52
coe: O&M	mills/kWh	7.4	6.1	6.1	7.9	6.1	6.1	2.5	2.4	2.4
Cost of Electricity	mills/kWh	42.21	38.01	36.94	49.91	39.46	33.67	32.70	30.67	30.16
Thermal Efficiency (LHV)	%	41%	42%	42%	42%	48%	53%	55%	60%	62%
Capture Plant		15.71815								
Relative Power	%	75%	85%	85%	85%	91%	92%	87%	90%	90%
Heat Rate	Btu/kWh	11038	9463	9463	9461	7840	6987	7130	6308	6119
Capital Cost	\$/kW	1990	1635	1362	1909	1458	1086	1013	894	832
CO2 Emitted	kg/kWh	0.1052	0.0901	0.0901	0.0880	0.0730	0.0650	0.0423	0.0374	0.0374
coe: Capital	mills/kWh	45.44	35.00	29.15	43.58	31.22	23.24	21.68	19.13	17.80
coe: Fuel	mills/kWh	13.69	11.73	11.73	11.73	9.72	8.66	21.39	18.93	18.36
coe: O&M	mills/kWh	15.72	11.68	11.68	11.58	8.44	7.88	5.07	4.42	4.07
Cost of Electricity	mills/kWh	74.84	58.42	52.57	66.90	49.38	39.78	48.14	42.48	40.23
Thermal Efficiency (LHV)	%	31%	36%	36%	36%	44%	49%	48%	54%	56%
Comparison										
Incremental COE	mills/kWh	32.64	20.40	15.62	16.99	9.92	6.11	15.44	11.81	10.07
Energy Penalty	%	25%	15%	15%	14.6%	9.0%	8.1%	13.0%	10.0%	10.0%
Mitigation Cost										
Capture vs. Ref.	\$/ton CO2	47.73	30.19	23.12	25.59	16.79	11.47	47.41	39.42	33.62

Costs of new electricity generation technologies

Plant Type		PC	PC	PC	PC	PC	PC	IGCC	IGCC	IGCC	IGCC	IGCC	IGCC	
Capture (Yes / No)		No	No	No	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes	
Timeframe		2000	2012	2025	2000	2012	2025	2000	2012	2025	2000	2012	2025	
Costs (mills/kWh)														
Electricity	Capital	24.54	21.94	20.87	45.44	35.00	29.15	31.99	24.51	19.61	43.58	31.22	23.24	
	Fuel	10.26	9.97	9.97	13.69	11.73	11.73	10.02	8.85	7.96	11.73	9.72	8.66	
	Operations & Maintenance (Labor)	7.40	6.10	6.10	15.72	11.68	11.68	7.90	6.10	6.10	11.58	8.44	7.88	
	Subtotal COE (mills/kWh)	42.2	38.0	36.9	74.8	58.4	52.6	49.9	39.5	33.7	66.9	49.4	39.8	
Sequestration	\$/tonne CO2 seq efficiency				10	10	10				10	10	10	
	CO2 emitted (kg/kWh)	0.789	0.766	0.766	0.105	0.090	0.090	0.752	0.664	0.598	0.088	0.073	0.065	
	CO2 captured				0.947	0.811	0.811				0.792	0.657	0.585	
	% Capital				93%	93%	93%				93%	93%	93%	
	Capital cost				8.81	7.54	7.54				7.37	6.11	5.44	
	Labor cost				0.66	0.57	0.57				0.55	0.46	0.41	
Subtotal (mills/kWh)				9.47	8.11	8.11					7.92	6.57	5.85	
Subtotal: generation (mills/kWh)		42.2	38.0	36.9	84.3	66.5	60.7	49.9	39.5	33.7	74.8	55.9	45.6	
Transmission & Distribution		24.3	24.3	24.3	24.3	24.3	24.3	24.3	24.3	24.3	24.3	24.3	24.3	
TOTAL		66.5	62.3	61.2	108.6	90.8	85.0	74.2	63.8	58.0	99.1	80.2	69.9	
Cost Ratio	ELEC:CCS w/o T&D	1.01	0.91	0.89	2.00	1.75	1.64	1.18	1.04	0.91	1.77	1.47	1.24	
	w/ T&D	1.01	0.94	0.93	1.63	1.46	1.39	1.12	1.02	0.95	1.49	1.29	1.14	
Factor Shares	Kgeneration	0.37	0.35	0.34	0.42	0.39	0.34	0.43	0.38	0.34	0.44	0.39	0.33	
	Lgeneration	0.11	0.10	0.10	0.14	0.13	0.14	0.11	0.10	0.11	0.12	0.11	0.11	
	Fuel	0.15	0.16	0.16	0.13	0.13	0.14	0.14	0.14	0.14	0.12	0.12	0.12	
	K seq.	0.00	0.00	0.00	0.08	0.08	0.09	0.00	0.00	0.00	0.07	0.08	0.08	
	L seq.	0.00	0.00	0.00	0.01	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.01	
	K t&d	0.23	0.24	0.25	0.14	0.17	0.18	0.20	0.24	0.26	0.15	0.19	0.22	
	L t&d	0.14	0.15	0.15	0.08	0.10	0.11	0.12	0.14	0.16	0.09	0.11	0.13	
	<i>Check</i>	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	% Capital	0.60	0.59	0.59	0.64	0.63	0.61	0.63	0.62	0.60	0.67	0.65	0.63	
	% Labor	0.25	0.25	0.25	0.24	0.24	0.25	0.23	0.24	0.26	0.22	0.23	0.25	
% Fuel	0.15	0.16	0.16	0.13	0.13	0.14	0.14	0.14	0.14	0.12	0.12	0.12		
% Sequestration										8.0%	8.2%	8.4%		
% Capture + Seq.				63.3%	45.8%	38.8%				33.6%	25.9%	20.6%		

Equalizing Carbon Price Partial Equilibrium (\$/tC)

vs. NGCC (\$/tC)	-83	-63	-58	720	533	453	-164	-99	-49	552	351	209
vs. NGCC (\$/tCO2)	-23	-17	-16	196	145	124	-45	-27	-13	150	96	57
vs. PC (\$/tC)				226	155	129	763	52	-71	171	95	45
vs. PC (\$/tCO2)	0	0	0	62	42	35	208	14	-19	47	26	12
vs. NGCAP (\$/tC)				-1886	-1439	-1189				-1834	-1043	-271

Costs of new electricity generation technologies

Plant Type		NGCC	NGCC	NGCC	NGCC	NGCC	NGCC
Capture (Yes / No)		No	No	No	Yes	Yes	Yes
Timeframe		2000	2012	2025	2000	2012	2025
Costs (mills/kWh)							
Electricity	Capital	11.60	11.24	11.24	21.68	19.13	17.80
	Fuel	18.60	17.03	16.52	21.39	18.93	18.36
	Operations & Maintenance (Labor)	2.50	2.40	2.40	5.07	4.42	4.07
	Subtotal COE (mills/kWh)	32.7	30.7	30.2	48.1	42.5	40.2
Sequestration	\$/tonne CO2 seq efficiency				10	10	10
	CO2 emitted (kg/kWh)	0.368	0.337	0.337	90%	90%	90%
	CO2 captured				0.042	0.037	0.037
	% Capital				0.381	0.337	0.337
	Capital cost				93%	93%	93%
	Labor cost				3.54	3.13	3.13
	Subtotal (mills/kWh)				0.27	0.24	0.24
					3.81	3.37	3.37
	Subtotal: generation (mills/kWh)	32.7	30.7	30.2	52.0	45.8	43.6
Transmission & Distribution		24.3	24.3	24.3	24.3	24.3	24.3
TOTAL		57.0	55.0	54.5	76.3	70.1	67.9
Cost Ratio	ELEC:CCS						
	w/o T&D	0.77	0.81	0.82	1.23	1.21	1.18
	w/ T&D	0.86	0.88	0.89	1.15	1.13	1.11
Factor Shares							
	Kgeneration	0.20	0.20	0.21	0.28	0.27	0.26
	Lgeneration	0.04	0.04	0.04	0.07	0.06	0.06
	Fuel	0.33	0.31	0.30	0.28	0.27	0.27
	K seq.	0.00	0.00	0.00	0.05	0.04	0.05
	L seq.	0.00	0.00	0.00	0.00	0.00	0.00
	K t&d	0.26	0.27	0.28	0.20	0.22	0.22
	L t&d	0.16	0.17	0.17	0.12	0.13	0.14
	<i>Check</i>	1.00	1.00	1.00	1.00	1.00	1.00
	% Capital	0.47	0.48	0.48	0.53	0.53	0.53
	% Labor	0.21	0.21	0.21	0.19	0.20	0.20
	% Fuel	0.33	0.31	0.30	0.28	0.27	0.27
	% Sequestration				7.9%	7.9%	8.4%
	% Capture + Seq.				33.8%	27.6%	24.7%