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Incentives for Near-Term Carbon Dioxide Geological Sequestration

A White Paper prepared for
The Gasification Carbon Management Work Group

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by

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I. Executive Summary

Once carbon dioxide enters the atmosphere, much of it remains there for more than 100 years.[1] For this reason, if the world wants to stabilize atmospheric concentration of CO_2, emissions must be reduced to well below half of their current level, even as population rises. Energy conservation, improved end-use efficiency, appropriate use of renewable energy, and nuclear power can all contribute to a portfolio of low emission generation. However for countries such as the United States that today make over half their electricity from coal and may soon face the need to make significant amounts of chemicals, transportation fuels and substitute natural gas (SNG) from sources other than petroleum, cost-effective emission reductions over the next half century are unlikely to be achieved without the continued use of coal.

If the United States is to make significant progress in controlling carbon dioxide emissions at an affordable cost, the technologies for low CO_2 emission coal facilities must be proven at commercial scale within the next decade.

Carbon capture and deep geologic sequestration holds the promise to make deep carbon emission reductions possible with the continued and increased use of coal and petroleum coke (petcoke). After separating carbon dioxide from coal, disposal of concentrated carbon dioxide (generally as a liquid-like "supercritical fluid") can be achieved by injecting it into appropriate deep geological formations, such as saline aquifers, where geologists believe the CO_2 can be safely sequestered essentially indefinitely.[2]

While all the technologies required for CO_2 transport and deep geological sequestration are presently in use at modest commercial scale , a very large scale up from current practice is required to meet energy needs. To give an idea of the scale required, plausible required capture rates of the carbon dioxide from fossil fuels in the U.S. today would produce a CO_2 stream of approximately 2,000 million tons (Mt) per year injected into a variety of geological formations. This amount is 40 times larger than current CO_2 injection. However, while 2,000 Mt is a large number, total underground injections of all fluids in the U.S. is over twice that amount.[3]

Current experience with CO_2 injection is limited. The total CO_2 injected for enhanced oil recovery in the U.S. is under 50 Mt per year, while the upcoming Department of Energy Regional Sequestration Partnerships plan to inject approximately 1 Mt per year at 7 sites for three years. A reasonably large coal plant producing either electricity or other products would produce 3 to 4 Mt of CO_2 per year.

In addition to gaining experience with large scale geologic sequestration across a range of geological formations, experience is required with CO_2 pipelines used to transport carbon dioxide to sequestration sites at scales required for U.S. energy production. The CO_2 pipelines required for effective control of carbon dioxide emissions will be 10 to 40 times larger than the existing network of CO_2 pipelines, and could be almost of the same scale as the present natural gas pipeline infrastructure. Carbon capture and sequestration (CCS) from gasification facilities with high capture volumes can provide early experience with CO_2 transport and deep geologic sequestration at commercial scale within the next few years.

Significant uncertainties exist in cost, the best operational and technical choices, and the appropriate character of the regulatory environment for both transport and storage of CO_2 at the scales required for commercial adoption that will substantially lower CO_2 emissions from coal facilities. These uncertainties make it difficult to profitably deploy commercial scale low carbon energy projects at present.

Deployment of large-scale pilot projects is crucial for proving the economic and technical efficacy of geologic sequestration, gaining the experience to assure a high level of reliability in operations, and for accruing the data necessary to craft a science-based regulatory regime sufficient to assure safety and to foster public acceptance. Such a regime is necessary to provide a stable platform for commercial investment, to ensure regulatory cohesion and consistency, and to help build public confidence in geologic sequestration. Imposition of a requirement to capture a set percentage of the CO_2 from coal or petcoke facilities prior to gaining such large scale experience, will at best be much more costly than it needs to be, and at worse may lead to stagnation of technology.

Large-scale geologic sequestration demonstration projects are urgently needed. Empirical data from early full-scale geologic sequestration projects will form the knowledge base upon which a long-term regulatory framework can be built, and will provide the public with concrete experience with which to evaluate the technology and to build confidence with regard to its safety, efficacy, and environmental benefits.

Although there are future plans for federally funded geologic sequestration demonstration projects, their timing and scale are still uncertain and many are much smaller than commercial size. History has shown that with the various federal, state and commercial entities involved it can often be impossible for developers, insurers or investors to use such government demonstration projects to form a realistic idea of the risks, costs, and timelines involved for a commercial project.

Fortunately, commercial scale coal gasification projects are imminent and are ideal platforms for private sector tests to gain experience with near-term commercial-scale carbon capture and sequestration. Coal-to-gas and coal-to-liquids projects can readily capture CO_2 as part of their process, and the CO_2 can be used for large-scale geologic sequestration. Coal-to-electricity projects can be designed in that manner also.

Financial incentives are necessary to begin commercial scale CCS at gasification facilities, since transport and sequestration costs are estimated at \$5-\$15 per ton of CO_2 (\$20-\$60 million per year per commercial plant). Although such costs can be recovered in some locations by selling the CO_2 for use in enhanced oil recovery (see section 2 below), many gasification facilities may be sited far from EOR locations, and incentives for sequestering CO_2 are required to allow the operator to consider alternatives to emitting the CO_2 into the air.

Progressive firms that are in the engineering and financing stage of deploying coal facilities with carbon dioxide capture and sequestration would like to proceed to gain experience with CCS at commercial scales prior to the implementation of mandatory greenhouse gas control.

While commercial scale sequestration projects are generally not profitable at the moment, there are efficient incentives that have the potential to make geologic sequestration economically feasible while also ensuring that the required experience with transport and storage can be gathered quickly. These incentives fall into three categories: federal, state/local, and private.

We recommend that Congress consider the following incentives to increase U.S. energy independence through use of its abundant coal resources in an environmentally clean manner:

- Continue the 15% enhanced oil recovery federal tax credit.
- Enact a federal CO_2 sequestration tax credit.
- Enact a federal investment tax credit for CO_2 pipelines.
- Add low-carbon emission coal facilities to the facilities eligible for the production tax credit.
- Enable tax-exempt financing for CO_2 sequestration infrastructure investments (compression, pipelines, pumping, and injection/sequestration facilities) by amending the IRS code to identify CO_2 sequestration investments as “Qualified Private Activity Bonds” or by creating a separate allocation of Private Activity Bond authority for CO_2 sequestration investments. A national cap on the amount available (say $20 billion) would be established and bonding authorities from states with potential projects could apply for volume cap distributions under the program.
- Create a larger version of the Department of Energy Regional Sequestration Partnership program to rapidly advance commercial scale CCS at the level of 3-5 Mt per year per site for ten sites.
- Require the Executive Branch to implement without further delay the federal loan guarantee provisions of the Energy Policy Act of 2005. The three applications for gasification loan guarantees selected on October 8, 2007 should be expeditiously processed and similar loan guarantees implemented for additional projects.

We recommend that states consider the following actions to quickly gain commercial-scale experience with clean coal facilities:

- Utilize the three-party covenant provisions of the Energy Policy Act of 2005 to enter into long-term agreements with gasification facilities to provide product at fixed costs.
- Eliminate where appropriate the state excise tax on energy used to power carbon dioxide transport and sequestration equipment.

Public incentives should result in a body of experience, lessons learned and data that is widely available in the public domain to future commercial developers.

Private sector approaches (some enabled by federal legislation) in the following areas may provide important incentives:

- A carbon capture and sequestration trust fund.
- A carbon sequestration investment fund.
- A carbon sequestration registry.

Implementation of such incentives will allow progressive private sector firms to invest in the carbon capture technologies that have great promise to allow the United States to use its vast reserves of coal in a carbon constrained world before mandatory controls are enacted. This strategy will greatly reduce risks and costs for economy-wide deployment of carbon control.

II. Background

A. Energy security and the economic case for coal use in the U.S.

The U.S. has grown dependent on imported energy. Of the major fuels, only coal is produced domestically in sufficient quantity to meet demand (there is a slight surplus of coal produced, with net exports accounting for 2% of all coal production in the U.S.). Domestic petroleum and petroleum product production today account for only one quarter of domestic consumption. Imported natural gas supplies 16% of demand, and that share is increasing. Domestic uranium production peaked in 1980, at ten times the current domestic production rate; 84% of uranium purchased in 2006 by owners and operators of U.S. civilian nuclear power reactors was of foreign origin.[4] Domestic production of coal has increased steadily for the past 50 years, with 2006 production 2.2 times that of 1960. A recent National Research Council study[5] concluded “there is probably sufficient coal to meet the nation’s needs for more than 100 years at current rates of consumption.”

Coal thus provides a promising path to reduce the strategic and economic consequences of dependence on foreign energy. Low-pollution methods of gasifying coal and other fossil energy sources have been demonstrated, as have the techniques for capturing carbon dioxide from such plants. The captured CO_2 can then be sequestered in deep geologic formations. In this way, clean coal technology is very likely to play a large role in both returning the U.S. to a balanced domestic energy policy and in controlling carbon dioxide emissions. One example of the large role such coal technologies may play in a reduced carbon future is shown a recent Electric Power Research Institute (EPRI) analysis (figure 1).

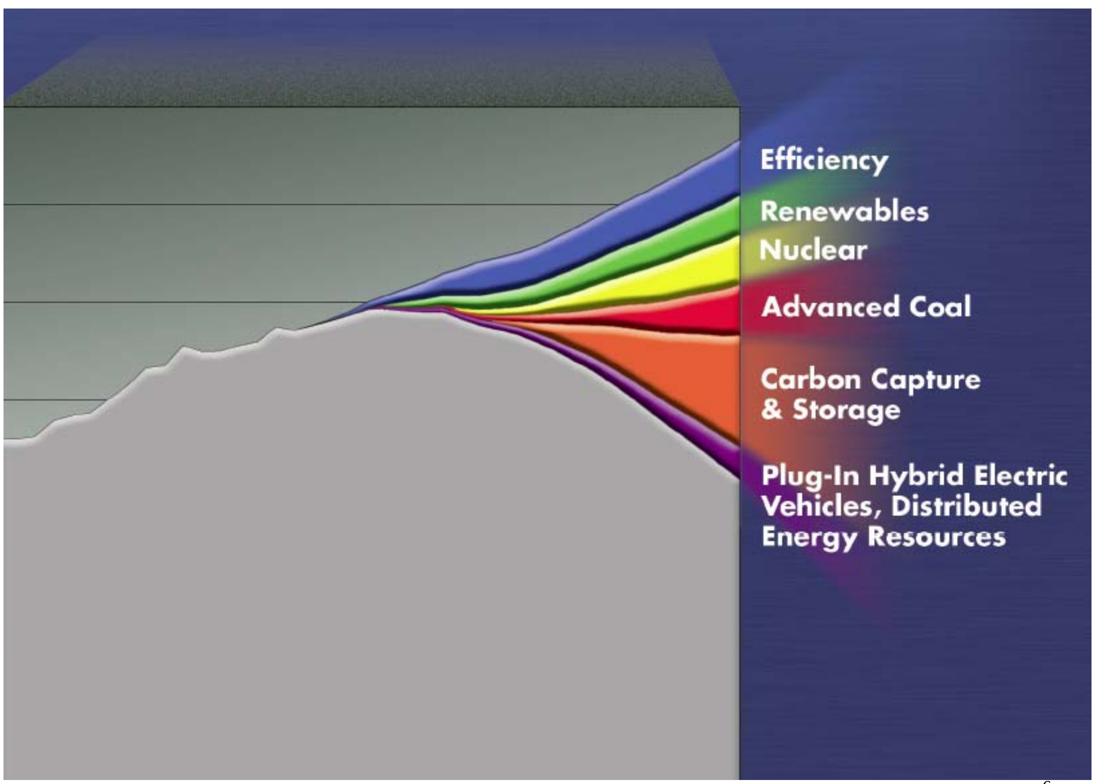


Figure 1. One model for reducing CO_2 emissions from electric power by 2030. Source: EPRI.[6]

1. Energy use and production in the U.S.

Total energy use in the United States has risen linearly for the past 25 years, growing at the rate of 1 x 10^{15} BTUs per year (one quadrillion BTUs per year, or quad). Overall domestic energy production over the same period has been essentially flat, with an average growth rate of 0.2 quads per year, or one-fifth the growth rate of demand (figure 2).

In the year before the first Arab oil embargo, domestic production accounted for 88% of the nation's consumption of energy. Domestic production now makes up only 70% of consumption. The vast majority (88%) of the United States' net energy imports are due to petroleum and petroleum products while the remainder is due to natural gas.

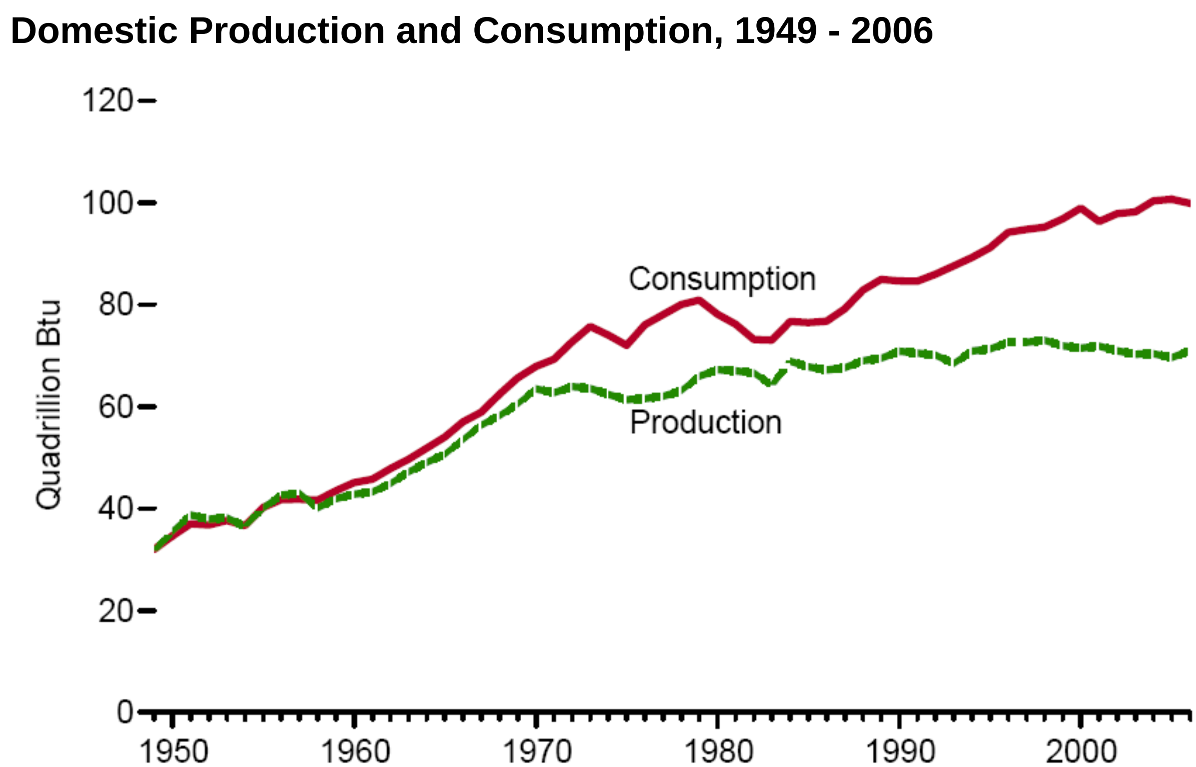


Figure 2. Production from domestic sources and consumption of all energy in the U.S.
Source: EIA Annual Energy Review 2006

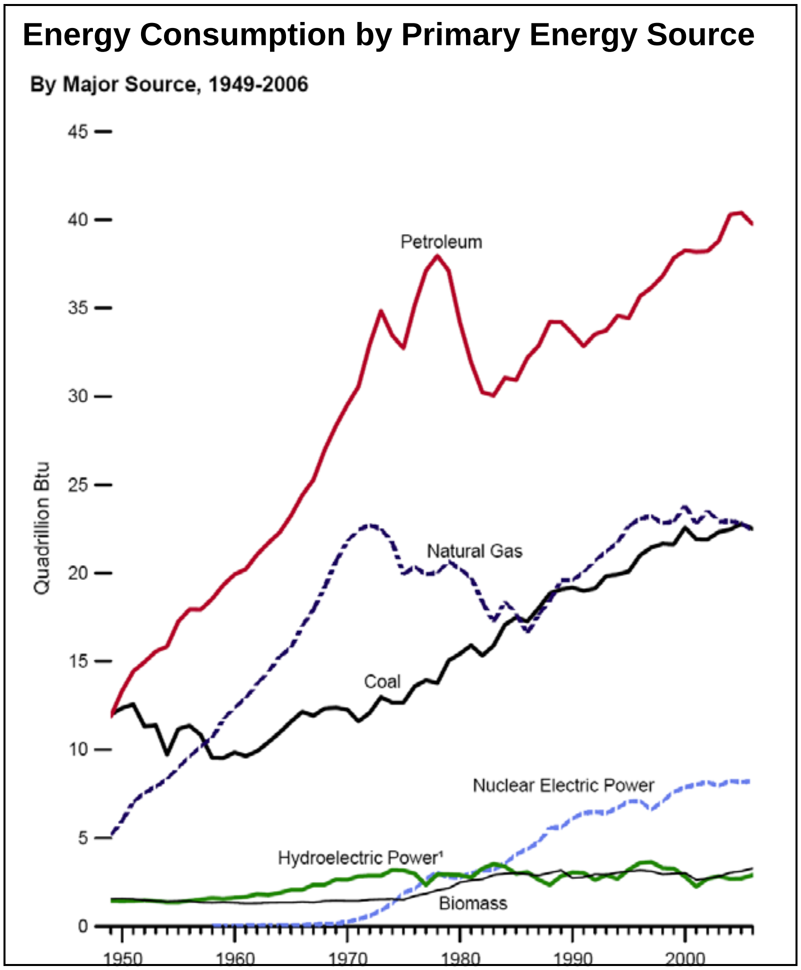


Figure 3. U.S. Energy Consumption. Source: EIA Annual Energy Review 2006

The use of petroleum, natural gas, coal, and uranium as energy sources has grown over the past quarter-century (figure 3).

Domestic production of crude oil and of natural gas have generally declined since their peak production years of 1970 (oil) and 1972 (natural gas). Hydroelectric and biomass energy production have been roughly constant for 25 years, as has domestic energy production from natural gas plant liquids such as propane, butane, and ethane.

Domestic production of nuclear energy has increased sharply, due to concerted efforts to refine and improve operating practices that have increased plant availability (from 55% in 1975 to 90% in 2006), and due to retrofitting nuclear facilities with higher efficiency steam turbine-generators. However, the vast majority of uranium purchased in 2006 by owners and operators of U.S. civilian nuclear power reactors was of foreign origin.[7]

Domestic production of coal has increased steadily for the past 50 years, from 434 million short tons in 1960 to 1161 million short tons in 2006.

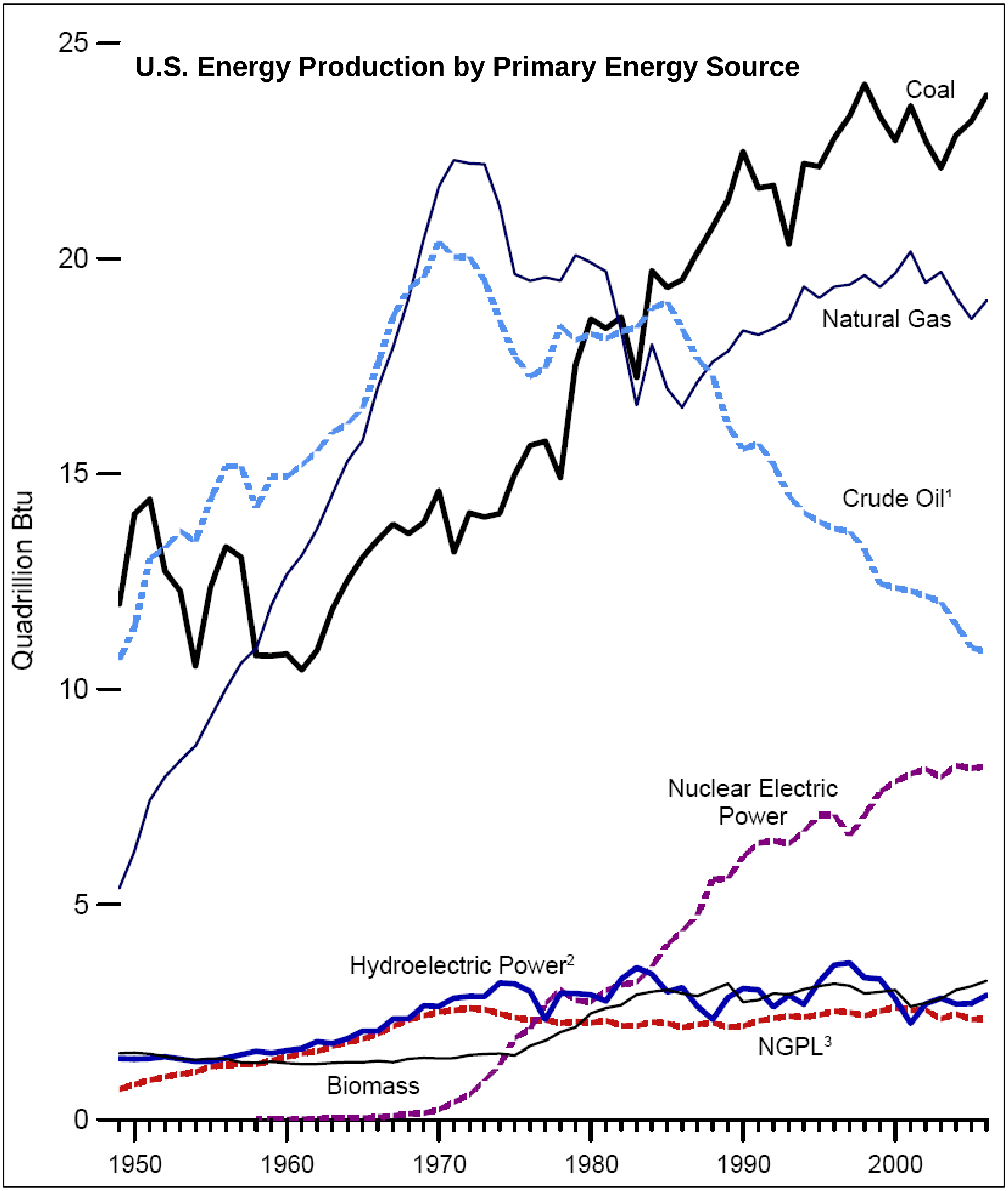


Figure 4. U.S. domestic energy production. Source: EIA Annual Energy Review 2006

[1] Includes lease condensate.
[2] Conventional hydroelectric power.
[3] Natural gas plant liquids.

a. Electric power and its expected growth

Demand for electricity grew exponentially until the early 1970's at the rate of 7¾ % per year and since then has grown linearly at the rate of 80 billion kilowatt-hours (kWh) per year (figure 5).

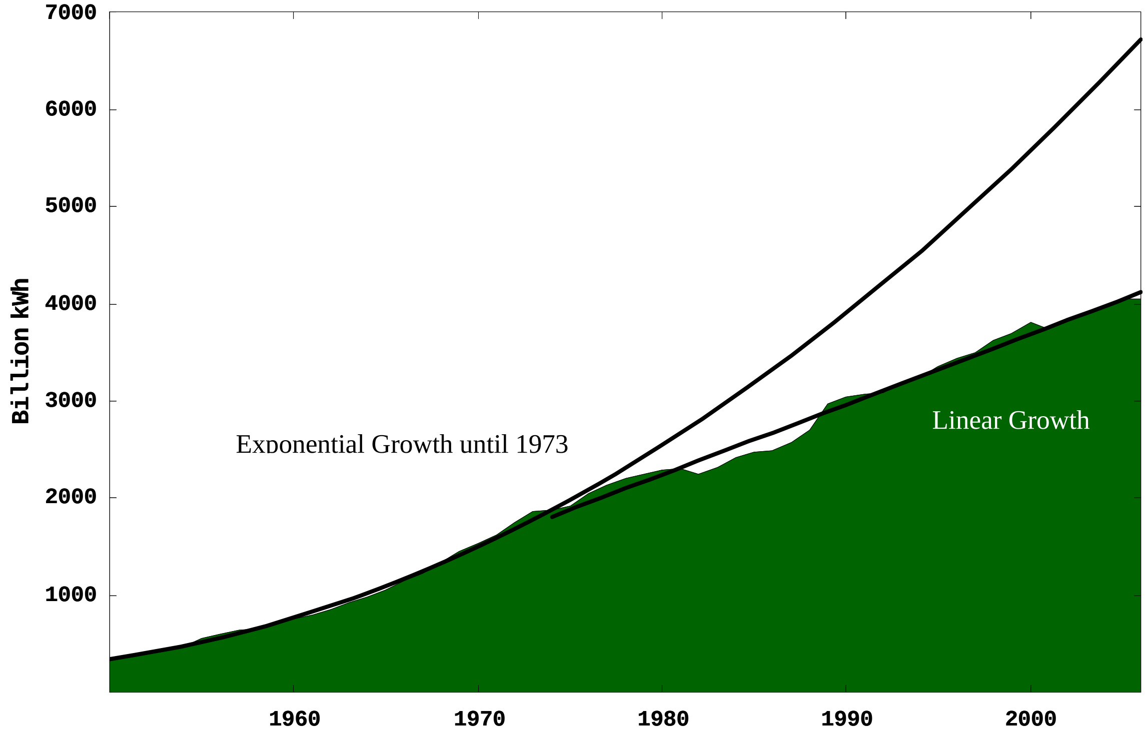


Figure 5. Historic growth in U.S. electric generation. Data source: Energy Information Administration (EIA).

Over two-thirds of the electric power generated in the United States is produced by burning fossil fuels: principally coal (49 percent), natural gas (20 percent), and oil (2 percent) (figure 6).[8]

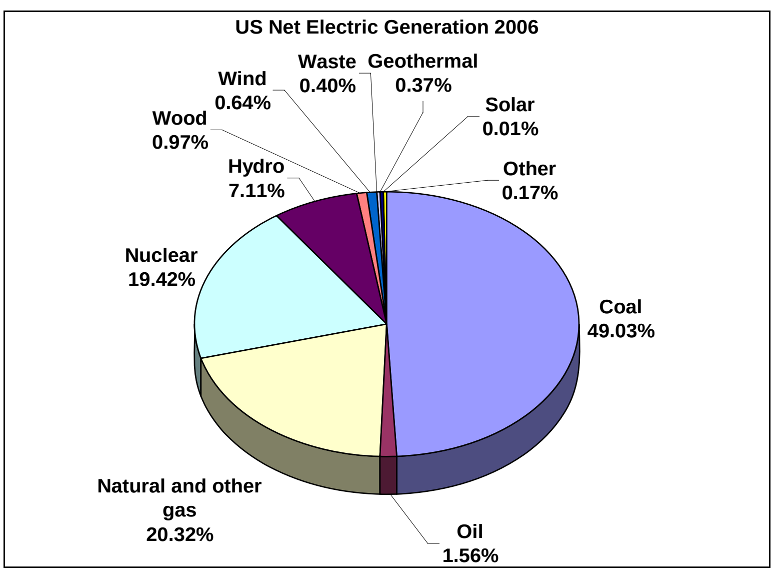


Figure 6. Fuel used in U.S. electric generation. Source: EIA.

If electricity production continues to grow at its current rate, by 2030 the U.S. will generate 44% more power than was generated in 2006 (figure 7). On the other hand, it is important to note that past forecasts of future U.S. energy needs have often significantly overestimated future demand[9]. It is possible that increased demand-side reductions will reduce this projection. However, continued rapid U.S. population growth is likely to offset even significant per capita reductions (as it has in California, where per capita use has remained nearly flat for 25 years,[10] but electricity demand increased by a third in the same period).

It is also possible that nuclear power will maintain its market share as electricity demand rises, but that would require the construction and operation of roughly 40 new nuclear generation stations by 2030. No new large sources of hydroelectric power have been developed in the U.S. or Canada recently, nor is such development likely. Many states have renewable portfolio standards in place[11] that require large increases in renewable energy, generally by 2025. The combined share of wood, wind, waste, small hydroelectric, and geothermal power to meet these targets would imply that approximately 10% of U.S. generation will use such sources. Natural gas production in North America is slowly declining, and it is unlikely that LNG and other imports will increase supply by that required to meet increased demand. Coal is a likely candidate for increased use to meet projected demand, but significant reductions in its CO_2 emissions per kWh are required if the U.S. adopts a carbon dioxide control system over the next 50 years (a new plant can be expected to operate for 35 years or more).

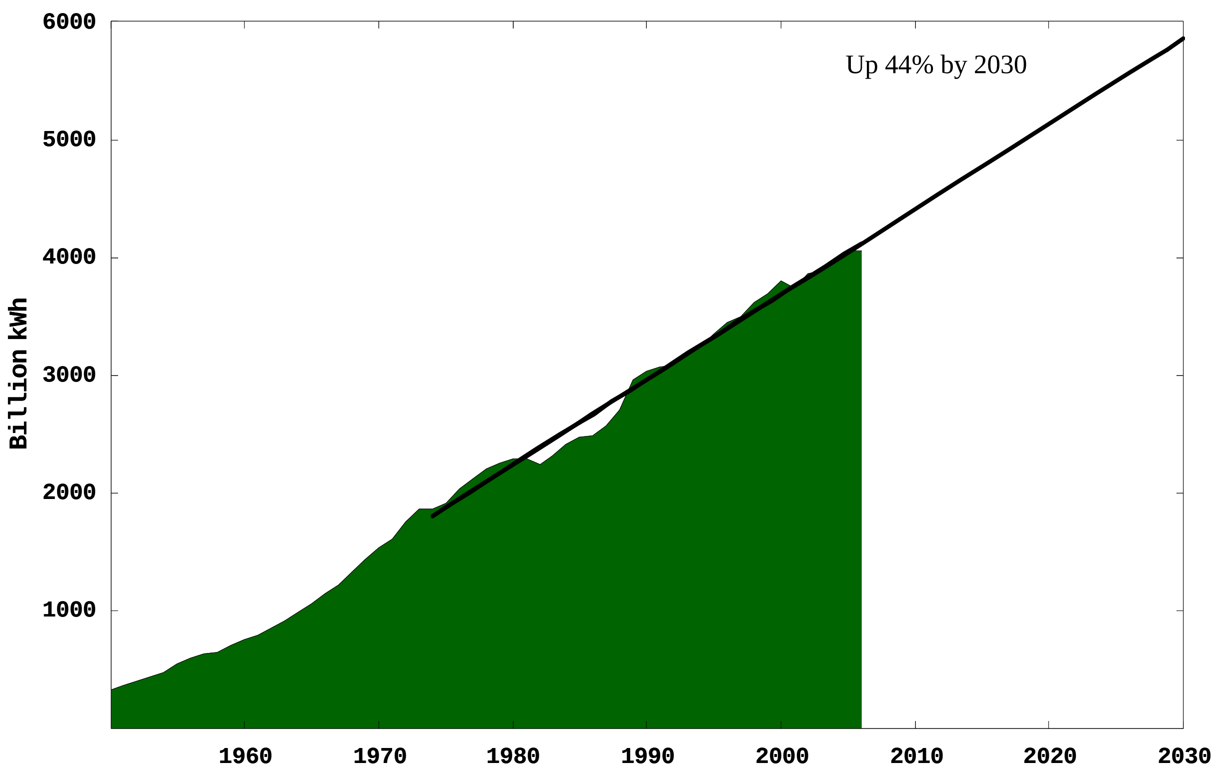


Figure 7. Historical U.S. electricity use and linear projection through 2030. Historical data source: EIA

b. Natural gas uses, historical and forecast

Natural gas consumption in the United States in 2006 was 21.9 trillion cubic feet (Tcf), approximately 4% below its historic high set in 1997 (figure 8).

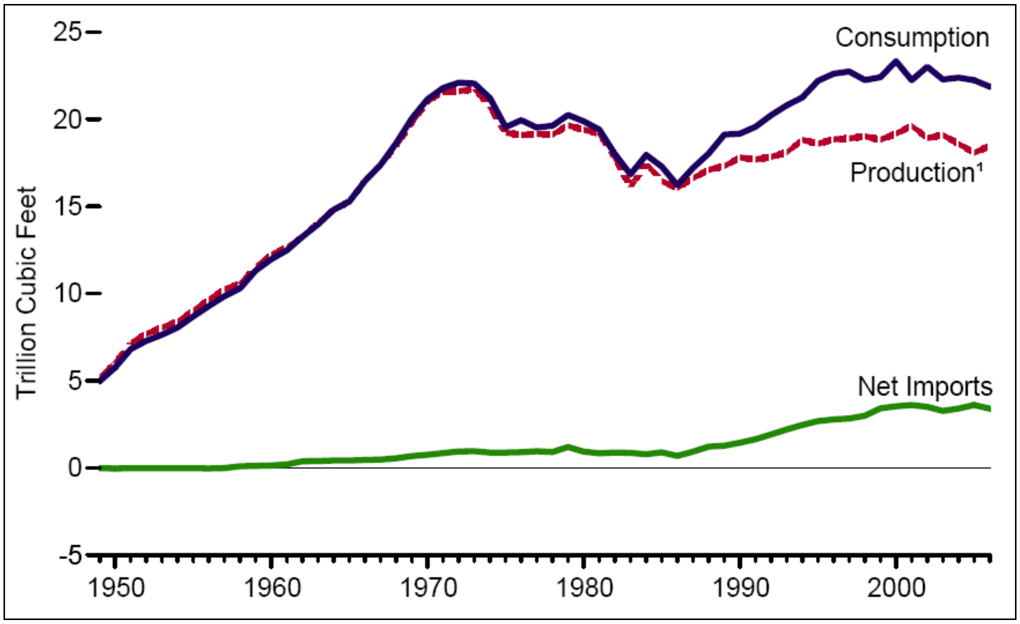


Figure 8. Consumption and domestic production of natural gas in the U.S. Source: EIA

Domestic natural gas production reached a peak of 21.7 Tcf in 1973. Today it is 18.4 Tcf, a 15% reduction. Net imports have increased from 4% of consumption 25 years ago to 16% today. Even if the proposed pipeline from Alaska's North Slope is completed, it would supply only 1.4 Tcf per year, or 6% of current US demand for natural gas. Natural gas sources and uses for 2006 are shown in figure 9.

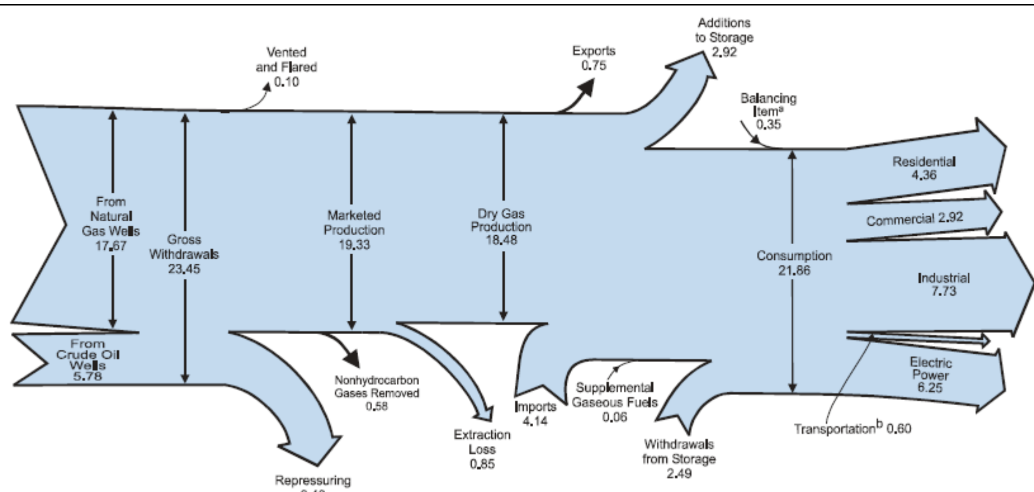


Figure 9. Natural gas sources and uses in the U.S. 2006. Source: EIA

Natural gas use for residential, commercial, and transportation customers has remained steady over the past 25 years (figure 10). Use for electric power production has increased substantially in response to an unprecedented natural gas turbine building boom that followed electricity restructuring (figure 11).

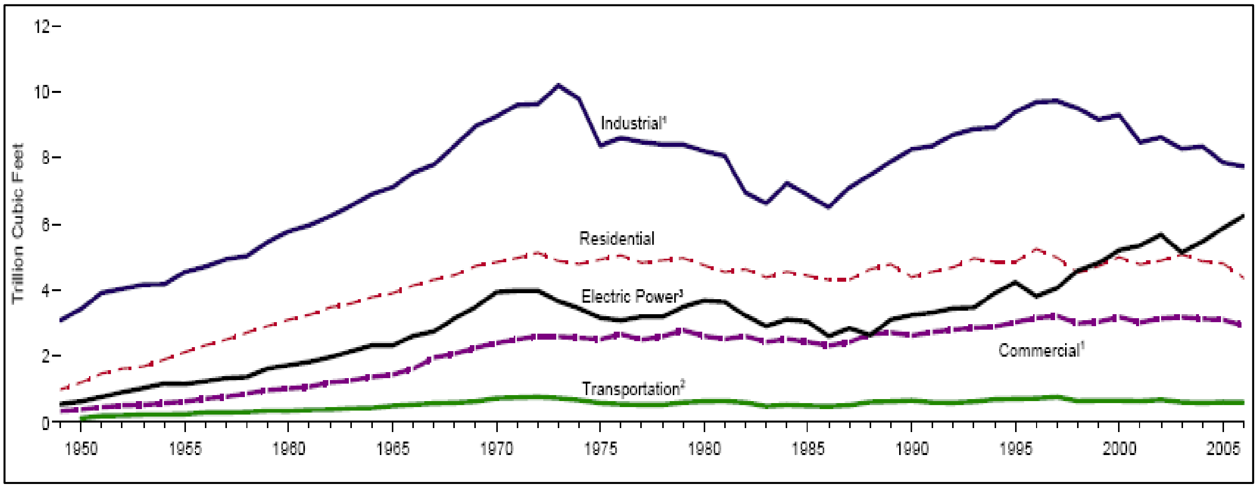


Figure 10. Natural gas use by sector, 1949-2006. Source: U.S. EIA Annual Energy Review 2006.

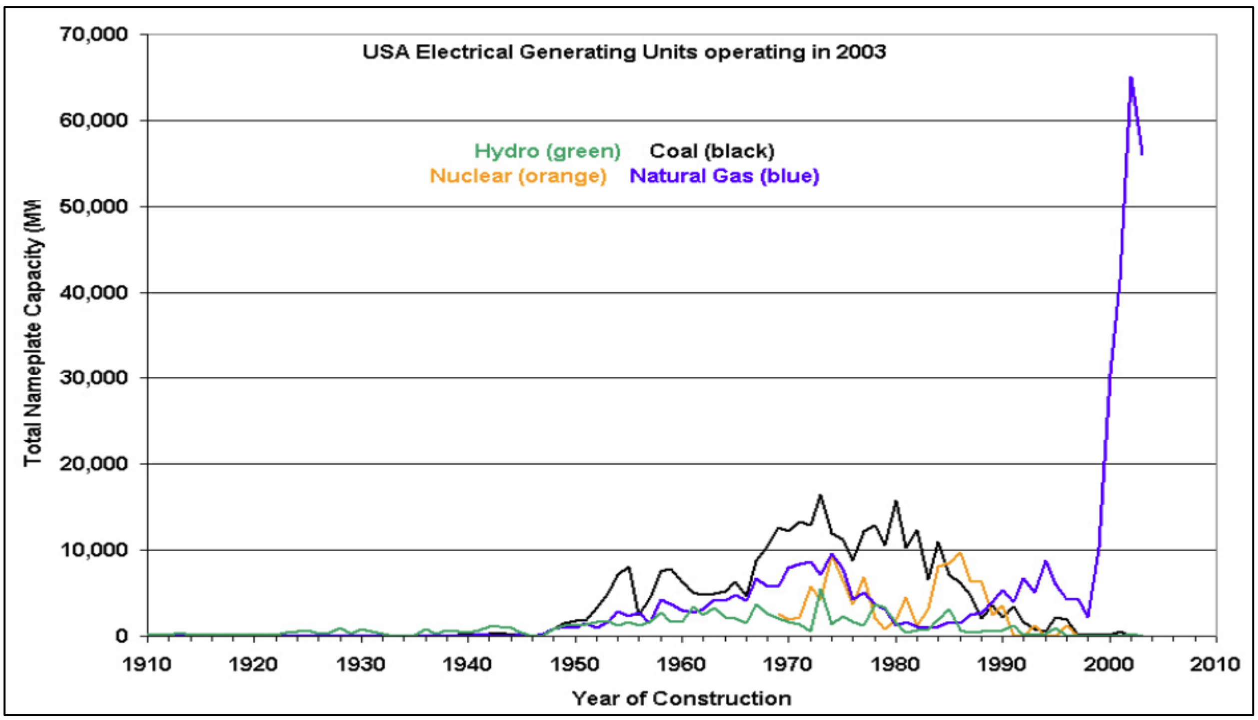


Figure 11. Year of construction of U.S. electric power generators operating in 2003. Data source: U.S. EPA eGRID.

While use for electric power grew and supply remained unchanged, the price of natural gas increased (figure 12). Fewer industrial customers found that they could sustain profitable operations in the U.S. that required natural gas as a fuel. Industrial use declined as use for electric power production increased (figure 12).

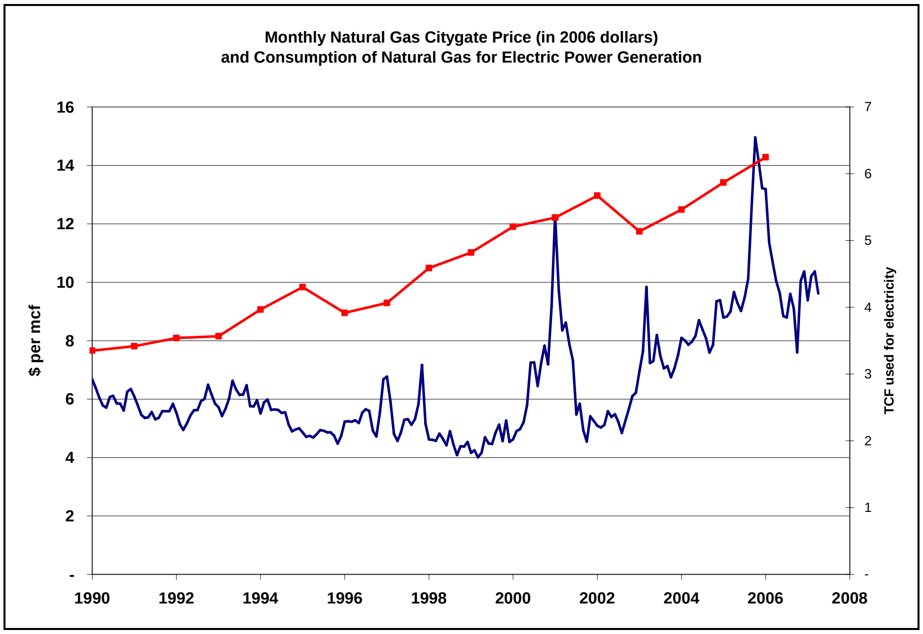


Figure 12. Nominal price (not adjusted for inflation) and use of natural gas (top, red) in the U.S. Source: EIA

The number of applications for liquefied natural gas in the U.S. has sharply increased, indicating that natural gas may be following oil down the road of greatly increased imports. The benefits and risks are well detailed in Daniel Yergin and Michael Stoppard's 2003 paper, *The Next Prize*. [12] They argue that previous LNG experience points to LNG price being pegged to oil price, and that the U.S. government will need to invest considerable effort in forging government-to-government relationships to foster stable relationships with gas producing nations. If they are correct, pegging LNG prices to oil prices at a time when conventional oil production is likely to be outstripped by oil demand could lead to very high natural gas prices.

Natural gas production in North America is slowly declining while demand for natural gas is 35 % over what it was 20 years ago. In the past 10 years, electric utility consumption of natural has increased by 1.6 trillion cubic feet. Industrial demand fell by 1.7 trillion cubic feet.

In light of these upward pressures on the price of conventional natural gas, it appears that coal and petcoke gasification to produce SNG can supply very significant quantities necessary to meet a large fraction of demand at lower prices.

c. Petroleum uses, including feedstock uses

According to the U.S. Energy Information Administration: "In 2005 petroleum products contributed about 40.6 percent of the energy used in the United States. This is a larger share than any other energy source including natural gas with a 22.6 percent share, coal with about a 22.7 percent share, and the combination of nuclear, hydroelectric, geothermal and other sources comprising the remaining 14.4 percent share. EIA projects that petroleum consumption in the United States will increase by 1.1 percent annually.

Nonfuel use of petroleum is small compared with fuel use, but petroleum products account for about 89 percent of the nation's total energy consumption for nonfuel uses. A partial list of nonfuel uses for petroleum includes:

• Solvents such as those used in paints, lacquers, and printing inks
• Lubricating oils and greases for automobile engines and other machinery
• Petroleum (or paraffin) wax used in candy making, packaging, candles, matches, and polishes
• Petrolatum (petroleum jelly) sometimes blended with paraffin wax in medical products and toiletries
• Asphalt used to pave roads and airfields, to surface canals and reservoirs, and to make roofing materials and floor coverings
• Petroleum coke used as a raw material for many carbon and graphite products, including furnace electrodes and liners, and the anodes used in the production of aluminum.
• Petroleum feedstocks used as chemical feedstock derived from petroleum principally for the manufacture of chemicals, synthetic rubber, and a variety of plastics.

Petroleum has been used as a feedstock in the production of petrochemicals since the 1920's. Naphtha, one of the basic feedstocks, is a liquid obtained from the refining of crude oil. Petrochemical feedstocks also include products recovered from natural gas, and refinery gases (ethane, propane, and butane). Petrochemical feedstocks are converted to basic chemical building blocks and intermediates, such as ethylene, propylene, normal- and iso-butylenes, butadiene, and aromatics such as benzene, toluene, and xylene, which are in turn used to produce plastics, synthetic rubber, synthetic fibers, drugs, and detergents.” [13]

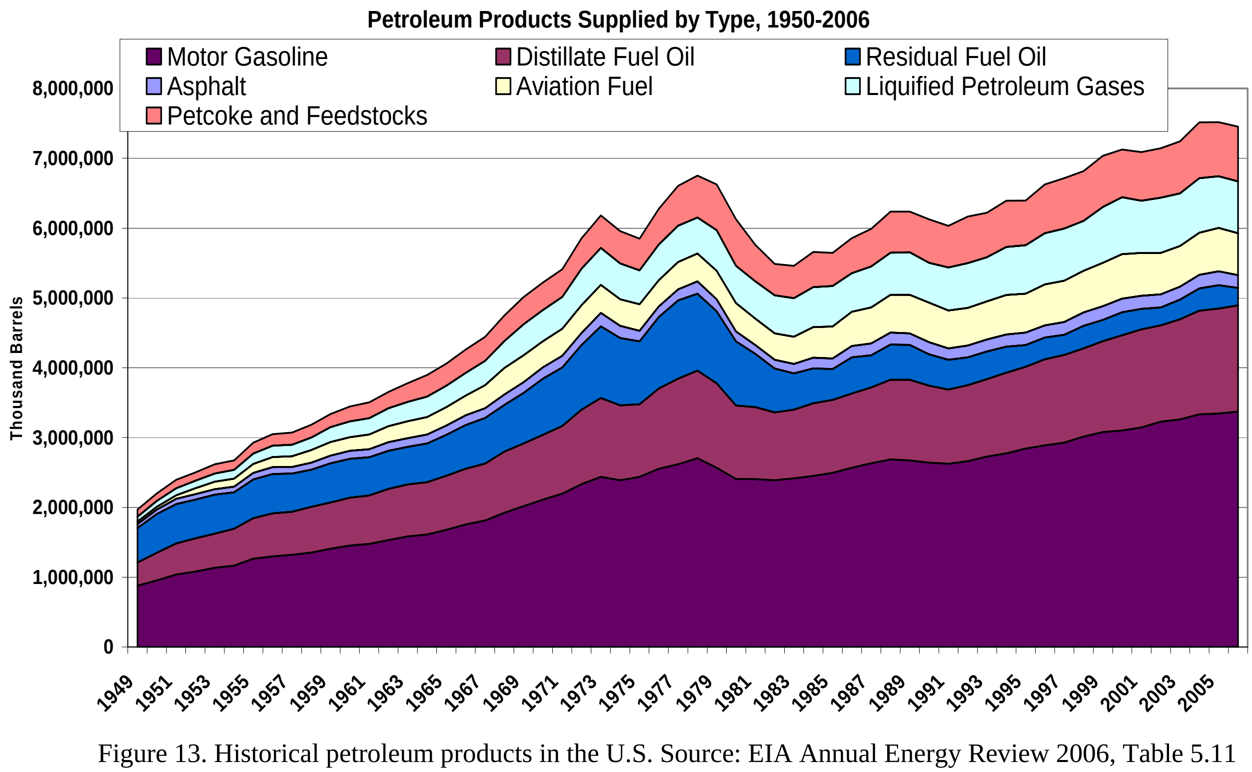


Figure 13. Historical petroleum products in the U.S. Source: EIA Annual Energy Review 2006, Table 5.11

Petcoke and feedstock use of petroleum have made up approximately 10% of all U.S. petroleum use for the past quarter-century.

High petroleum prices affect industry competitiveness. Since 1968, the price refineries pay for crude oil has quadrupled in real (inflation-adjusted) terms (figure 14). In 2006, the United States paid $218 billion to foreign producers for petroleum.[14]

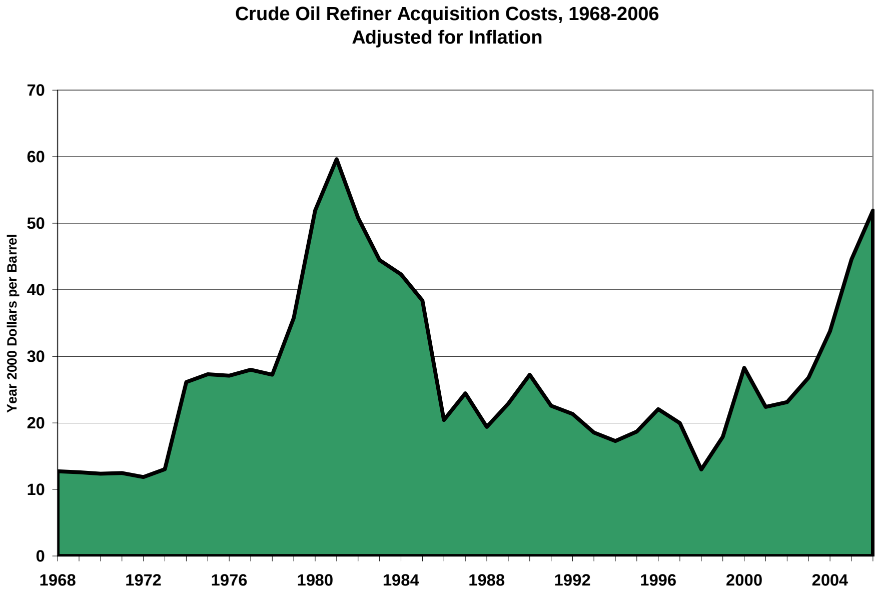


Figure 14. Inflation-adjusted U.S. crude oil prices to refineries. Source: EIA Annual Energy Review 2006, table 5.21

d. Coal uses

Today ninety two percent of the coal utilized in the United States is for the production of electric power. 5% is used by industry, principally for combined heat and power generation. 2% is used by coke plants, and less than one percent is used in residential and commercial buildings (figure 15).

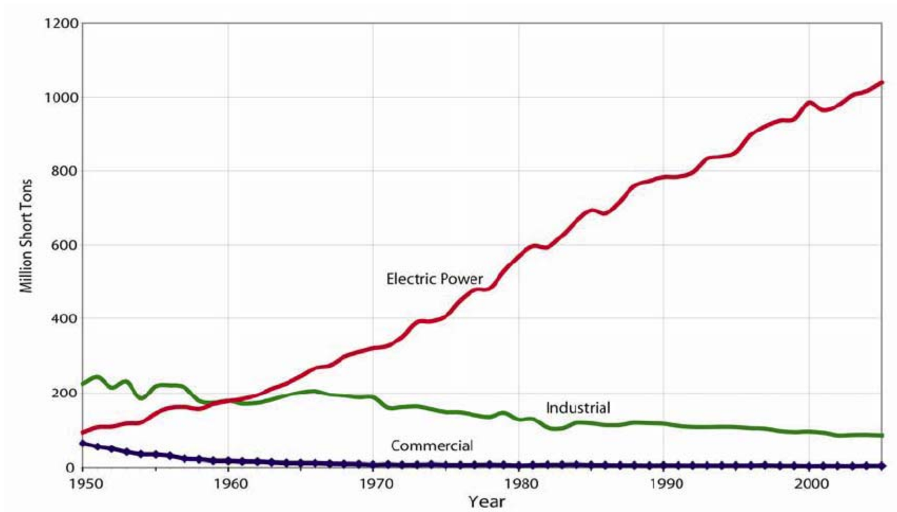


Figure 15. Historic trends in U.S. coal use by sector. Source: NRC study Figure 1.7

2. Fossil fuel prices

Historic price trends for the major fossil fuels used in the U.S. show that the price of coal has been the most stable of the three (figure 16).

Since 1970, the price for crude oil has quadrupled in real (inflation-adjusted) terms. Natural gas prices have also quadrupled.

Coal prices today are nearly identical to those experienced in the 1950's.

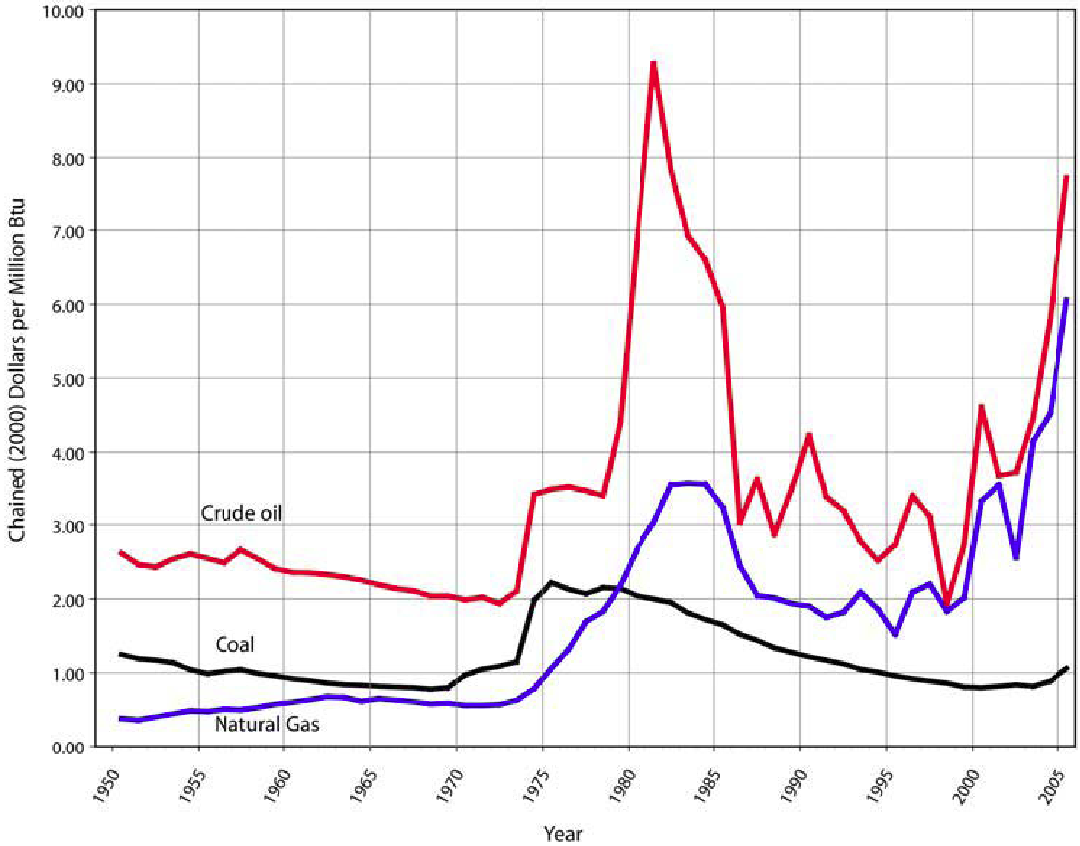


Figure 16. Inflation-adjusted energy prices. Source: NRC study Figure 1.1

3. Domestic coal abundance

The U.S. National Academy of Sciences' National Research Council (NRC) recently published a comprehensive assessment of coal resource methodology in the United States.[15]

The U.S. has the largest coal reserves of any nation (figure 17).

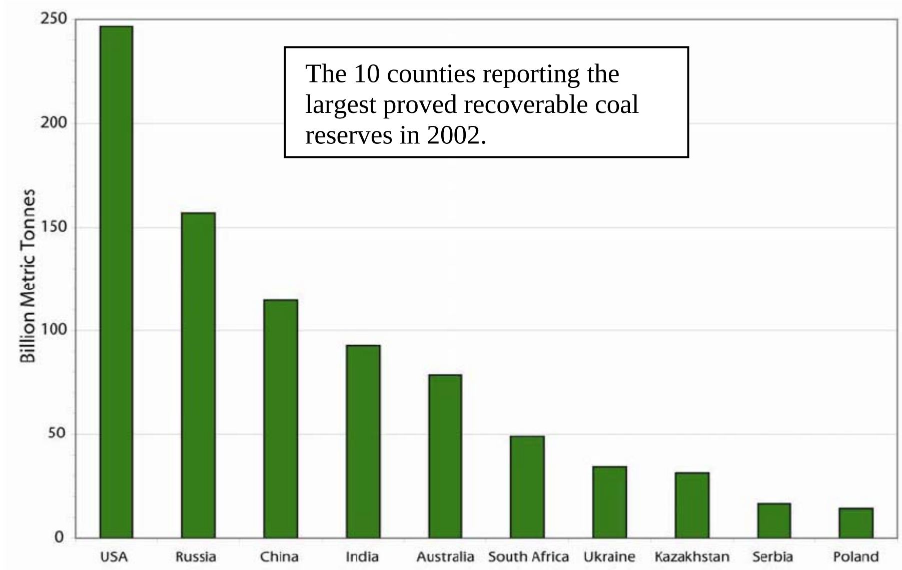


Figure 17. National coal proved recoverable coal reserves. Source: NRC study, figure 3.3

The United States has a strategic advantage in only one fossil fuel: coal (figure 18).

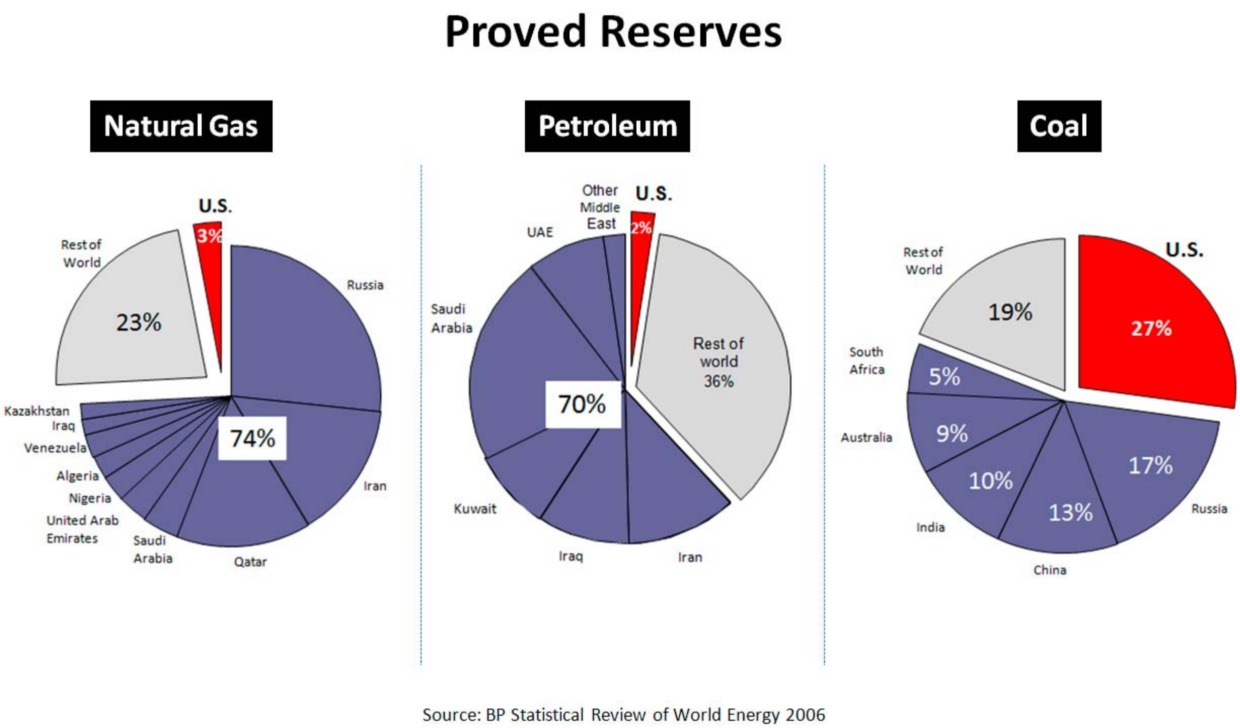


Figure 18. National fossil fuel proved reserves.

The NRC study summarizes its findings as follows:

- "The United States is endowed with a vast amount of coal. Despite significant uncertainties in generating reliable estimates of the nation's coal resources and reserves, there are sufficient economically minable reserves to meet anticipated needs through

2030**.** Looking further into the future, **there is probably sufficient coal to meet the nation's needs for more than 100 years at current rates of consumption** [Emphasis added]. However, it is not possible to confirm the often quoted suggestion that there is a sufficient supply of coal for the next 250 years. A combination of increased rates of production with more detailed reserve analyses that take into account location, quality, recoverability, and transportation issues may substantially reduce the number of years of supply. Because there are no statistical measures to reflect the uncertainty of the nation's estimated recoverable reserves, future policy will continue to be developed in the absence of accurate estimates until more detailed reserve analyses—which take into account the full suite of geographical, geological, economic, legal, and environmental characteristics— are completed.

- The Demonstrated Reserve Base (DRB) and the Estimated Recoverable Reserves (ERR), the most cited estimates for coal resources and reserves, are based upon methods for estimating resources and reserves that have not been reviewed or revised since their inception in 1974. Much of the input data for the DRB and ERR also date from the early 1970s. These methods and data are inadequate for informed decision-making. New data collection, in conjunction with modern mapping and database technologies which have been proven to be effective in limited areas, could significantly improve the current system of determining the DRB and ERR.

- Coal quality is an important parameter that significantly affects the cost of coal mining, beneficiation, transportation, utilization, and waste disposal, as well as the coal's sale value. Coal quality also has substantial impacts on the environment and human health. The USGS coal quality database is largely only of historic value as relatively little coal quality data have been generated in recent years."

The NRC study examined projections by the US EIA, IPCC, ExxonMobil, The European Commission, the World Energy Council, and the International Energy Agency. The projections varied in their assumptions about economic growth, technology adoption, carbon dioxide constraints, oil and gas prices, and population. Use rates for coal depend on a large number of factors, but the NRC study projects that "Over the next ten to fifteen years (until about 2020), coal production and use in the United States is projected to range from about 25 percent above to about 15 percent below 2004 levels, depending on economic conditions and environmental policies. By 2030, the range of projected coal use in the United States broadens considerably, from about 70 percent above to 50 percent below current levels."

Thus, there is probably sufficient coal to meet the estimates of the nation's needs for between 60 and 200 years at the projected use rates. The recommendations in the NRC report for targeted federal research to use modern techniques to update coal estimates are very likely to lead to refined estimates if implemented.

4. Coal environmental performance

Incorporation of modern emissions control devices in much of the country has substantially reduced the quantity of sulfur dioxide (SO_2) and oxides of nitrogen (NO_x) released into the atmosphere from coal combustion, and the improvement is expected to continue as regulations are extended to additional generators. The total SO_2 emissions from the electric power sector is two-thirds of what it was in 1989, and NO_x emissions are 43% of 1989 total NO_x emissions.[16] Since the amount of electricity generated from coal has increased, the reduction per kWh is a more meaningful metric. SO_2 emissions per kWh from coal generators in 2005 were 52% of what they were in 1989. NO_x emissions per kWh from coal generators in 2005 were 34% of what they were in 1989.

Control of mercury emissions from coal plants appears to be feasible, and states such as Pennsylvania have adopted regulations requiring removal of 90% of the mercury by 2010.

New technologies that have the capability to reduce emissions of both conventional pollutants and carbon dioxide have been deployed at various scales for both industrial and electric generation uses of coal. Coal can play a positive role in the switch to low-carbon energy sources, if carbon capture and sequestration technologies are proven at commercial scale soon.

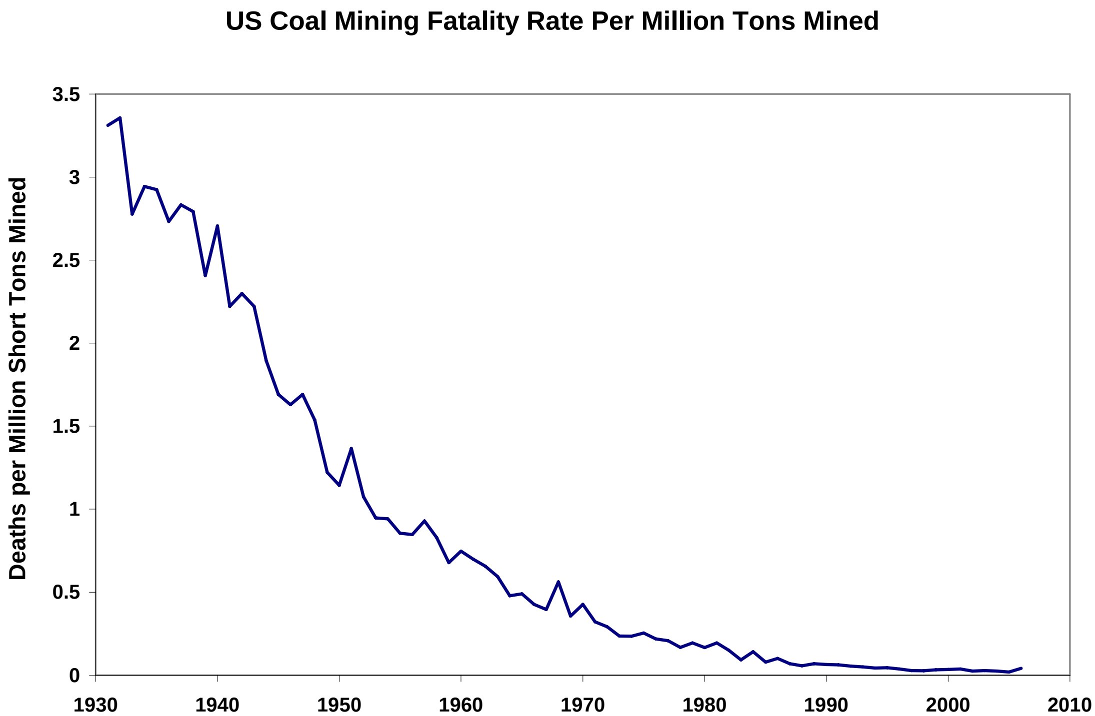
There are a number of technologies that can lead in the near term to lower greenhouse gas emissions from coal facilities.

Coal plant thermal efficiencies average 34% (on the basis of higher heating value, HHV). The newest U.S. coal plants have efficiencies of 35-37%. Increased efficiency reduces emissions as less coal is burned per unit of output (for example, per kWh). High-performance coal plants, called supercritical plants, and very high-performance plants, called ultra supercritical plants, are more efficient than even the newest pulverized-coal generation plants. Supercritical plants that can achieve net efficiencies of 40-45% are being built in Europe, but few have been built in the U.S.

A few pilot coal-fired plants use a method in which coal is burned, but in the presence of a much higher percentage of oxygen than is present in ordinary air (95% instead of 20%). This “oxyfuel” method can also result in high efficiency.

At 55 coal or petcoke fueled facilities around the world, including eight plants that produce electricity, the fuel is used in a very different fashion. Instead of being burned in open flames, it is fed into a refinery vessel along with oxygen in a process termed **gasification**. Gasification exhaust streams are composed of carbon monoxide, hydrogen gas, sulfur powder, and a glassy slag containing various other impurities.

Particularly when measured in terms of productivity, the safety of mining operations in the United States has dramatically improved over the past thirty years (figure 19).



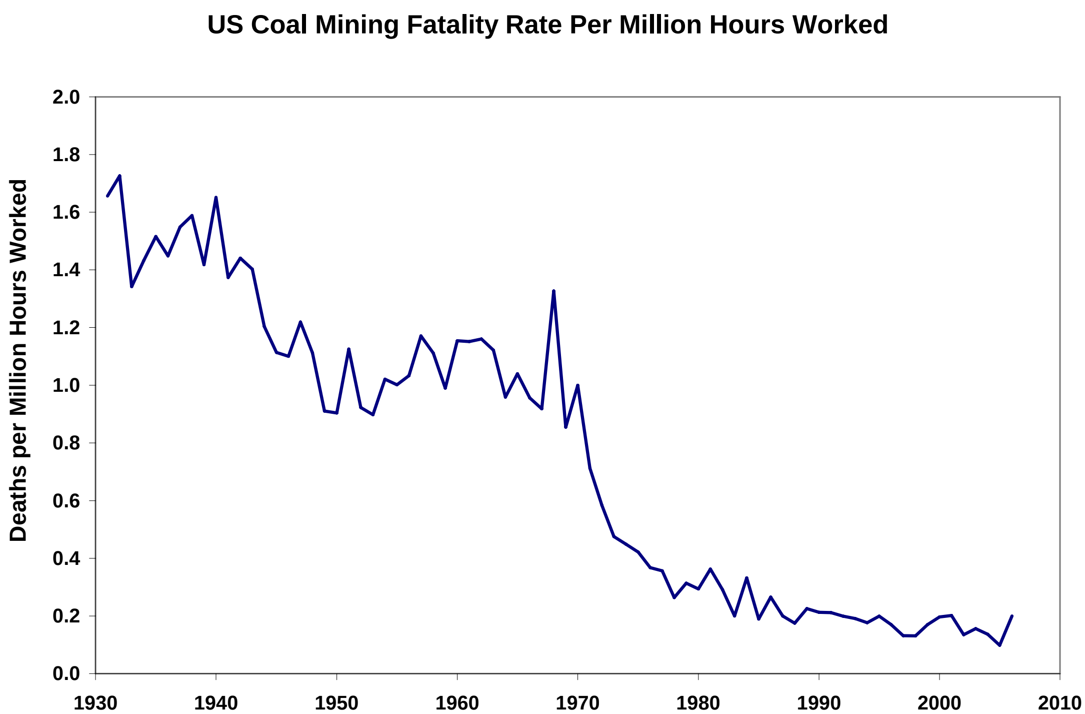


Figure 19. Fatality rate for all coal mining in the United States, 1977-2006, per million tons mined (upper graph) and per million hours worked (lower). Data source: US Mine Safety and Health Administration.

5. Petroleum coke (petcoke) supply

Petroleum coke is a byproduct of the Coker refinery process which upgrades fuel oil to gasoline, diesel and jet fuel. The energy content of petcoke, at approximately 14,000 BTU per pound, is higher than that of coal (that varies from 8,300 for Wyoming Powder River Basin and 10,900 for Illinois #6 to 13,200 for Appalachian low sulfur).

In many areas of the country, petcoke provides a cost-effective supply of fuel for gasification. For example, the Wabash River IGCC plant operates much of the time using petcoke, and the Tampa IGCC facility also uses petcoke as a fuel of choice. Petcoke can be used in coal co-firing as well.

Currently 15 million metric tons of petcoke are used annually in the United States[17] Adopting a weighted average heating value of 9,800 BTU per pound (HHV) for coal, petcoke thus supplies 2% of the energy value supplied by the coal used in the U.S.. At the peak of petcoke production, in 1955, the U.S. produced 68 million metric tons.[18] Dale Simbeck of SFA Pacific forecasts that U.S. fuel grade petcoke supply will reach 125 to 210 million metric tons by 2025,[19] thus supplying 17 – 28% of the energy supplied by coal.

B. Climate change policy response imperative

Greenhouse gas emissions in the United States are increasing, with the increase almost entirely due to increased carbon dioxide (CO_2) emissions (figure 20).

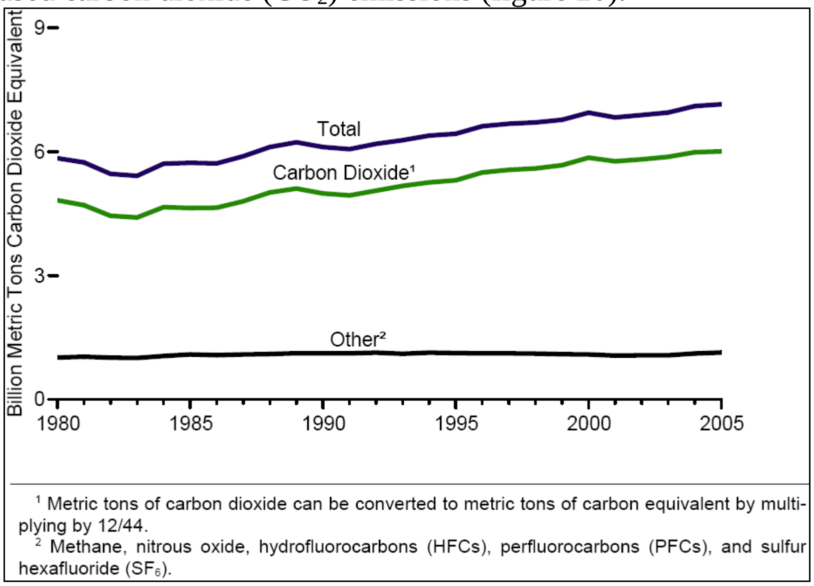


Figure 20. U.S. Greenhouse Gas Emission History. Source: EIA Annual Energy Review 2006.

CO_2 is emitted from the burning of fossil fuels, such as petroleum, coal, natural gas, and petroleum coke (with extremely small contributions from municipal solid waste and geothermal power production). Currently, 38% of U.S. CO_2 emissions is from coal and petroleum coke combustion. The sources are diverse; a map of the stationary sources in the southeastern states is below.

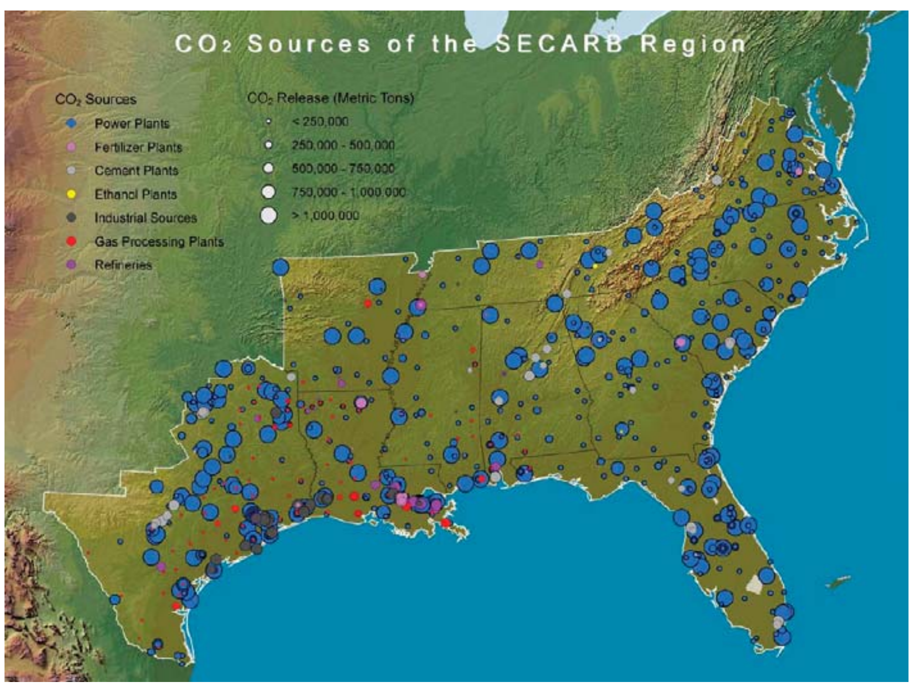


Figure 21. Stationary sources of CO_2 emissions in the southeast. Source: DOE Carbon Sequestration Atlas.

Nationwide, the largest source of CO_2 emissions from stationary sources is the generation of electrical power (figure 22).

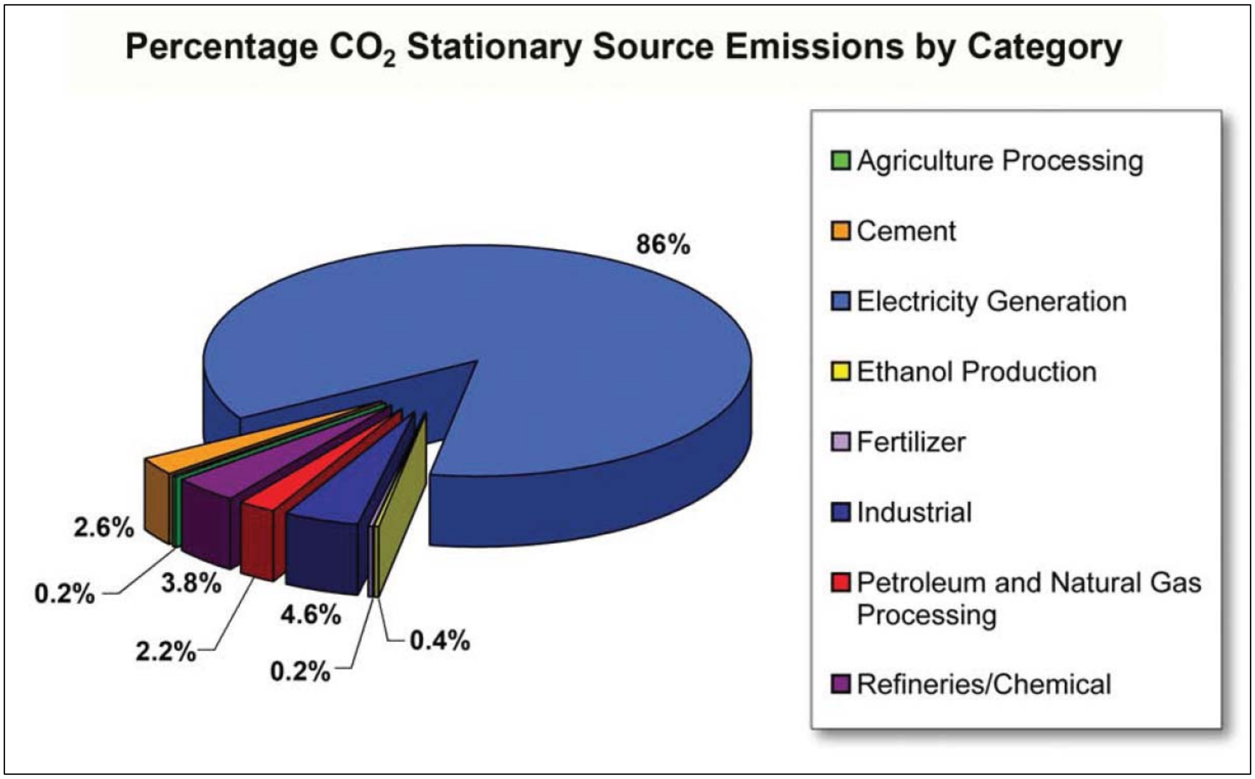


Figure 22. Breakdown of stationary CO_2 emissions in the U.S. Source: DOE Carbon Sequestration Atlas

When a conventional pollutant (for example, SO_2) is emitted into the air, it remains there for a short time, hours or days. For these gases, stabilizing emissions leads to stabilization of their total amount in the atmosphere (termed concentration).

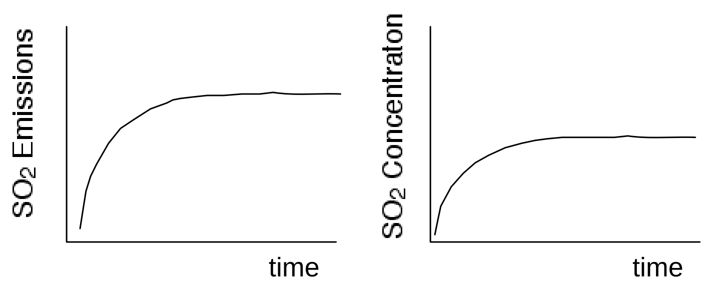


Figure 23. Concentration follows emissions for a gas with a short atmospheric residence time.

This is not true of carbon dioxide or most other greenhouse gases (GHG). Because CO_2 stays in the atmosphere for many decades (more than a third of CO_2 emitted today will be in the atmosphere in the year 2100), if emissions remain constant, concentration increases.

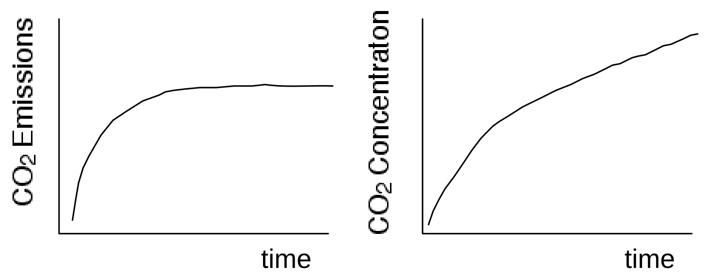


Figure 24. Concentration increase if emissions are constant for a gas with a long atmospheric residence time.

Because of the long residence time of greenhouse gases in the atmosphere, stabilizing concentrations requires a sharp decrease in emissions.

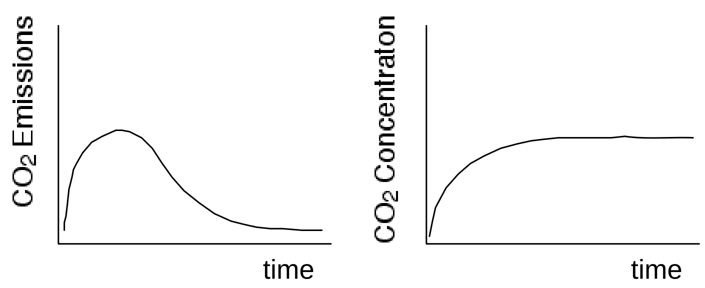


Figure 25. For a gas with a long residence time, stabilizing concentrations requires large emissions reductions.

The carbon dioxide emissions from the three of the four largest contributors (the U.S., China, and India) continue to increase. The European Union has stabilized emissions.

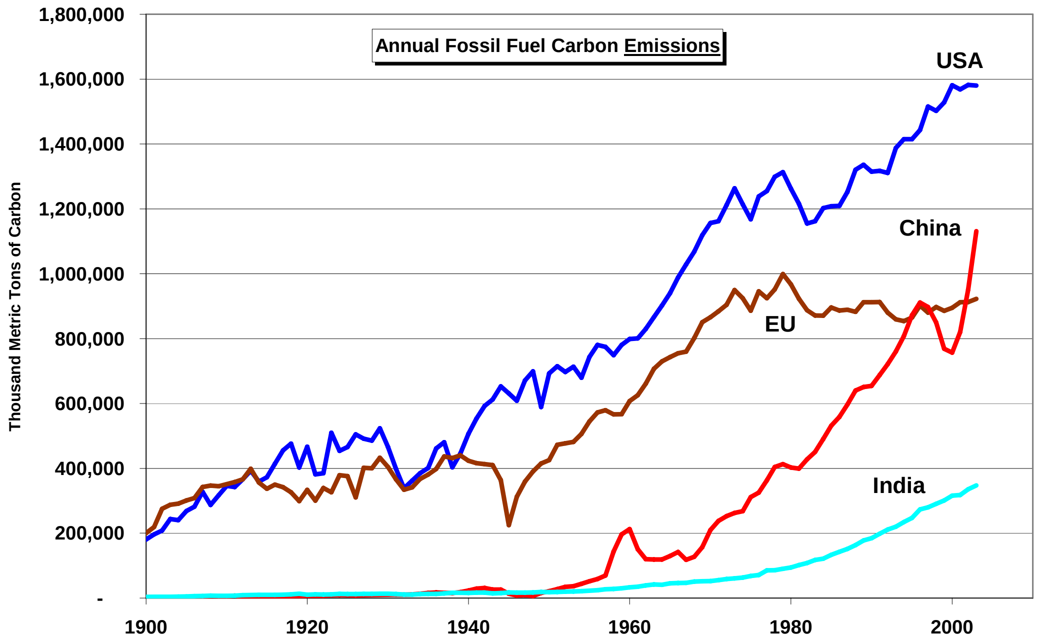


Figure 26. Carbon emissions from the four largest regions. Source: Oak Ridge National Laboratory.

Much of the discussion around greenhouse gas policy centers around emissions, but the Earth's climate responds only to concentration. The concentration attributable to each of the four largest current emitters is shown in figure 27, and reflects the much longer time that the U.S. and Europe have been releasing carbon dioxide into the air.

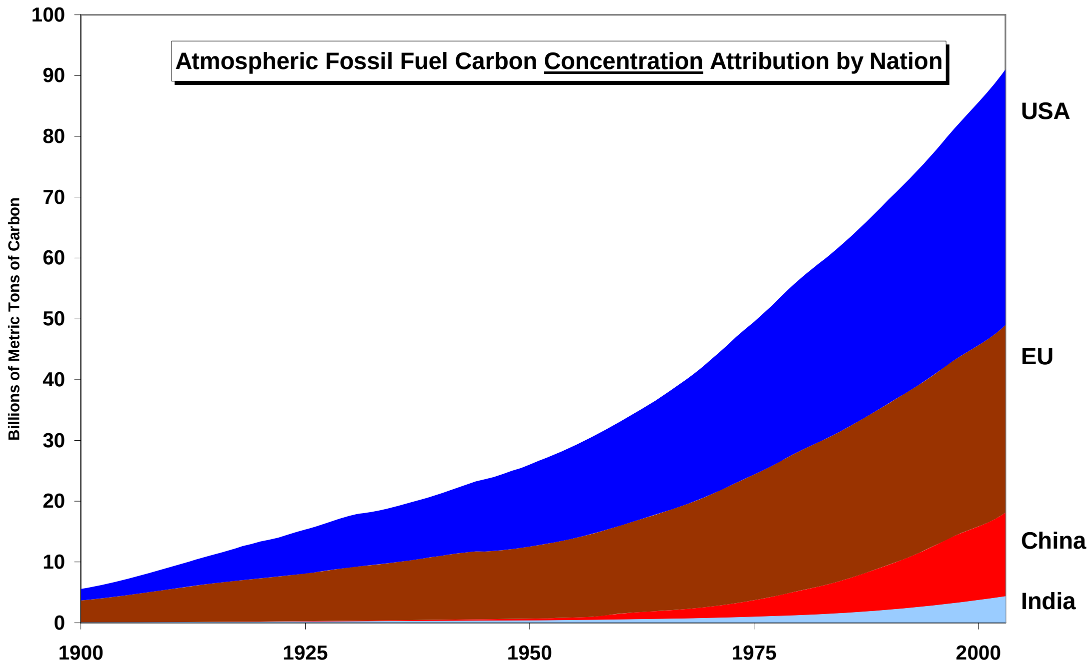


Figure 27. Concentration of carbon from fossil fuel emissions from the four largest emitters. Source: calculations by J. Apt based on emissions data from Oak Ridge National Laboratory and CO_2 decay models from the Commonwealth Scientific and Industrial Research Organization (CSIRO).

The Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report projects that if current greenhouse gas emissions trends continue, the average global temperatures in 2090-2099 will be 3.6 – 10 degrees Fahrenheit warmer than average temperatures in 1980-1999.[20]

When past emissions are factored in, the United States is responsible for just over a quarter of all anthropogenic CO_2 from fossil fuels currently in the atmosphere. Europe, China, and India are responsible for 19%, 9%, and 3% respectively. The EU has agreed to reduce emissions to 8% below 1990 levels by 2012; the United States has made no such commitments, although several states and groups of states have begun to make commitments. EU emissions are the same as in 1990; U.S. emissions have increased by 20%. And because a large fraction of CO_2 emissions remain in the atmosphere for over a century, the largest single share of atmospheric CO_2 will continue to belong to the United States for many decades, despite China's growth.

If no action is taken to reduce its emissions, the Energy Information Administration Annual Energy Outlook estimates that the US will emit approximately 8,000 million metric tonnes (8,800 million short tons) of CO_2 by 2030, an increase over 2005 emission levels of more than 33 percent.[21]

Since the United States has put the largest single share of CO_2 into the air, it is under intense pressure to begin to take the lead in reducing it. In a few decades, China, India, Brazil, and other developing countries also will have to undertake serious controls. But they will not do so until the U.S. takes the lead and shows how it can be done in an efficient and affordable way.

By seizing the opportunity provided by industrial coal gasification, the nation can get the experience required to reduce the technical and commercial unknowns of carbon dioxide capture and sequestration at commercial scale within the next decade.

Coal combustion is responsible for 30% of the total U.S. greenhouse gas emissions; coal and petcoke together account for 32% of the total U.S. GHG emissions.

The sources and sector uses of greenhouse gases in the 2005 U.S. economy are shown in figure 28 below.

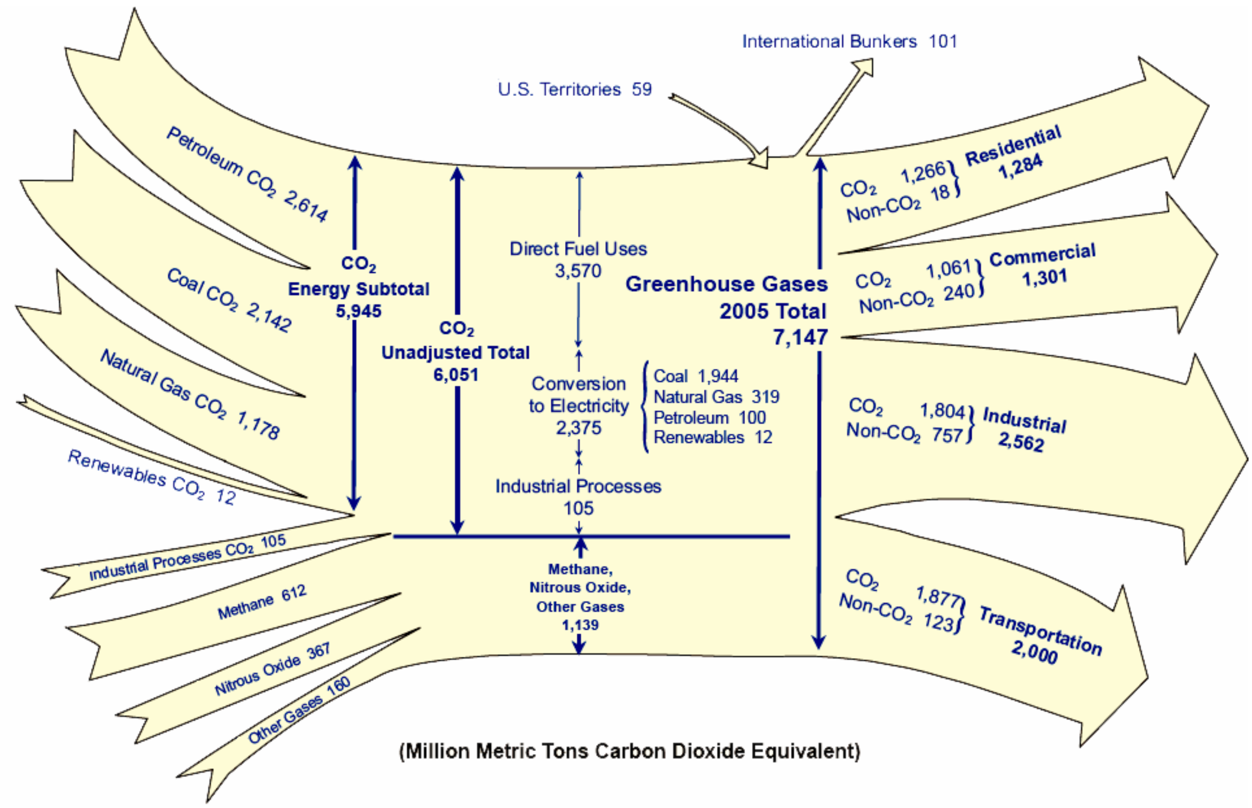


Figure 28. U.S. CO_2 flows. Source: EIA Emissions of Greenhouse Gases in the United States 2005, page xv.

There appears to be broad-based interest in the U.S. in exploring GHG controls. Six bills to limit GHG emissions were introduced in the first month of the 110th Congress. The cover stories of Sports Illustrated, Time, and National Geographic have dealt with the topic of human-induced climate change in the past two years. Several polls have indicated public perceptions of the issue were evolving even prior to the release of the film *An Inconvenient Truth* in June 2006.

- 71% - 85% of Americans believe climate change is already happening (Ayres, March 2006 and Time/ABC/Stanford, March 2006).

- 88% of Americans think global warming threatens future generations, and 68% are in favor of more government action on climate change (Time/ABC/Stanford, March 2006).
- The percent of Americans favoring the Kyoto treaty rose from 64% in 2002 to 71% in 2004 (Chicago Council on Foreign Relations).

In a poll taken in December 2006 by MIT and the polling firm Knowledge Networks, the percentage of Americans who think global warming has become a "serious problem" where "immediate action is necessary" was found to be 28%, up from 17% in 2003.

The financial community appears to be moving in the direction of anticipating carbon dioxide controls in the U.S. economy. *The New York Times* reported on June 15, 2006 that "A group of 27 investors handling $1 trillion in assets has asked SEC Chairman Christopher Cox to put in place a requirement that companies "disclose their financial vulnerability to changes in climate." Analyst Hugh Wynne of the independent research firm Sanford C. Bernstein & Co., LLC reported to investors on April 13, 2006, "We believe there is an increasingly large probability - maybe 30%, maybe 50% - that CO_2 emissions limits will be imposed at a national level in the U.S. within the next 5 years."

All eight candidates for the democratic party nomination in the 2008 presidential election support GHG legislation; one of the ten republican candidates (McCain) supports GHG emissions reductions.[22]

If the U.S. makes the decision to adopt a GHG control system, what are the routes and impediments to effective controls?

It is unlikely that there will be a single GHG control strategy.[a] For example, in their 2006 article,[23] Robert Socolow and Stephen Pacala note that the GHG emissions reductions required to stabilize atmospheric concentrations of GHG at twice pre-industrial levels can be achieved by any seven of the following fifteen strategies. Phased in over 50 years, each prevents the release of 25 billion tons of carbon.

- "Increase fuel economy of two billion cars from 30 to 60 mpg
- Drive two billion cars at 30 mpg half the current average distance (5,000 miles instead of 10,000)
- Cut electricity use in homes, offices and stores by 25%
- Raise efficiencies at 1,600 large (1 GW) coal-fired plants from 40 to 60 percent
- Replace 1,400 large coal-fired plants with gas-fired plants
- Install carbon capture and sequestration (CCS) at 800 large coal-fired power plants
- Install CCS at coal plants that produce hydrogen for 1.5 billion vehicles
- Install CCS at coal-to-syngas plants
- Add twice today's nuclear output to displace coal

[a] Direct carbon dioxide capture from the air appears to be feasible, but it will be energy intensive and its costs are likely to be several times higher than other methods of CO_2 control from the electric power sector. It may be the least cost solution to control in some sectors, however. Proposals for reducing the amount of sunlight reaching Earth's surface (most economically via small aerosols in the stratosphere) would reduce temperature, but would not mitigate the acidification of the oceans from carbonic acid that results from increased atmospheric carbon dioxide.

- Increase wind power 40-fold to displace coal
- Increase solar power 700-fold to displace coal
- Increase wind power 80-fold to make hydrogen for cars
- Drive two billion cars on ethanol, using one sixth of the world's cropland
- Stop all deforestation
- Expand conservation tillage to 100% of cropland"

Similarly, the Electric Power Research Institute (EPRI) has recently performed detailed modeling of carbon dioxide reduction strategies for the electric power industry. This modeling assumes that a portfolio of technologies will be employed for reduction. EPRI's CO_2 reduction "prism" includes seven wedges of reductions below the expected 2030 U.S. electric sector CO_2 emissions:

- Through customer-side efficiency, reduce load growth from the baseline 1.5% per year to 1.1% per year
- Increase renewables generation from the 2030 baseline of 30 GW to 70 GW
- Increase nuclear generation from the 2030 baseline of 12.5 GW to 64 GW
- Increase coal generation efficiency from the baseline new plant efficiency of 40% to 46% by 2020 and 49% in 2030; 150 GW of existing plant upgrades
- Widely deploy carbon dioxide capture and sequestration
- 10% of new light duty vehicles as plug-in hybrid electric vehicles by 2030, with growth of 2% thereafter
- Increases distributed energy resources to 5% of baseload electric power.

Many technologies are under development for CO_2 capture at fossil fuel facilities, including gasification technologies. Carbon capture and deep geological sequestration (geologic sequestration) holds the promise to make deep carbon emission reductions possible. After separating carbon dioxide from coal, disposal of concentrated carbon dioxide (generally as a liquid-like "supercritical fluid") can be achieved by injecting it into appropriate geological formations, such as saline aquifers, where geologists believe the CO_2 can be safely sequestered for a very long time.[24] Geologic sequestration appears to be the only currently viable option for large-scale CO_2 storage.

While the technologies required for CO_2 transport and deep geological sequestration are presently in use at modest commercial scale, a very large scale up from current practice is required if this technology is to be applied to reducing CO_2 emissions from coal on a large scale. A reasonably large coal plant producing either electricity or fuels would produce around 4 million tons (Mt) of CO_2 per year. Except for enhanced oil recovery (EOR), the largest current CO_2 sequestration project injects only about 1 Mt per year into deep geological formations. To give an idea of the scale-up required, capture of 80% of the carbon dioxide used in generating electricity from fossil fuels in the U.S. would produce a CO_2 stream of approximately 2,000 Mt per year injected into a variety of geological formations.

In addition to gaining experience with large scale geologic sequestration across a range of geological formations, experience is required with CO_2 pipelines used to transport carbon dioxide to sequestration sites at scales required for U.S. energy production. Today there is a modest network of pipelines in the US that carry 49 Mt of CO_2 per year for use in secondary oil recovery. The U.S. uses 500 Mt per year of natural gas. The mass of CO_2 that would need to be piped from plant to geologic sequestration in a widespread adoption of gasification with capture is 4 times as large as the mass of current natural gas transport. While the total mass of CO_2 is 4 times larger than the mass of current natural gas transport, that does not mean that the pipeline infrastructure will be 4 times larger, for two reasons. First, at operational conditions, a CO_2 pipeline caries about 3 times more mass per unit length of pipeline than does a natural gas pipeline. Second, plants that capture CO_2 will take advantage of the nearest feasible underground sequestration opportunities, whereas the natural gas pipeline network must ship the gas from production wells to very distant users.

The required CO_2 pipeline infrastructure will be substantially larger than today's CO_2 pipeline network. Carbon capture and sequestration (CCS) from gasification facilities with high capture volumes can provide early experience with transport and deep geologic sequestration at commercial scale within the next few years.

Significant uncertainties exist in cost, the best operational and technical choices, and the appropriate character of the regulatory environment for both transport and storage of CO_2 at the scales required for commercial adoption that will significantly lower CO_2 emissions from coal facilities. These uncertainties make it difficult to commercially deploy low carbon energy projects at present.

Progress must be made without placing an excessive economic burden on the economy, such as would occur if untried technology is mandated.

Deployment of large-scale pilot projects is crucial both for proving the economic and technical efficacy of geologic sequestration, gaining the experience to assure a high level of reliability in operations, for accruing the data necessary to craft a science-based regulatory regime sufficient to assure safety and foster public acceptance. Such a regime is necessary to provide a stable platform for commercial investment, to ensure regulatory cohesion and consistency, and to help build public confidence in geologic sequestration.

Large-scale geologic sequestration demonstration projects are urgently needed. Empirical data from early full-scale geologic sequestration projects will form the knowledge base upon which a long-term regulatory framework can be built, and will provide the public with concrete experience with which to evaluate the technology.

Although there are future plans for federally funded geologic sequestration demonstration projects, their timing and scale are still uncertain and many are much smaller than commercial scale. History has shown that with the various federal, state and commercial entities involved it can often be impossible for developers, insurers or investors to use such government demonstration projects to form a realistic idea of the risks, costs, and timelines involved for a commercial project.

Fortunately, commercial scale gasification projects are imminent and are ideal platforms for private sector tests to gain experience with near-term commercial-scale CCS. Coal-to-gas and coal-to-liquids projects will capture CO_2 as part of their process, and the CO_2 can be used for large-scale geologic sequestration. Coal-to-electricity projects can be designed in that manner also. There are incentives that have the potential to make geologic sequestration for these plants economically feasible so that the required experience with transport and storage can be gathered quickly.

C. Gasification and carbon sequestration

1. Gasification technology overview

Substantial reduction of emissions from coal plants can be achieved by chemically capturing the CO_2 produced during combustion and injecting it deep (below 3000 feet) underground, a process called CO_2 capture and deep geological sequestration (CCS). The technologies required to capture CO_2 from many types of coal plants, transport it long distances by pipeline, and inject it into underground reservoirs exist at commercial scale today, but have not yet been integrated into coal-to-gas, coal-to-electricity, or coal-to-liquids fuel plants. Other technologies are only in the pilot phase; for example, post-combustion capture from a pulverized coal plant via amine or chilled ammonia is considered feasible, but the largest of the three existing units is at a small (15 MW) plant.

There are 55 gasification facilities around the world that feed coal or petcoke into a refinery vessel along with oxygen at various concentrations to produce synthesis gas (syngas), primarily a mixture of carbon monoxide and hydrogen gas. Syngas can be converted into many different fuels and compounds through chemical and catalytic processes or burned in a gas turbine to produce electric power. Gasification processes lend themselves to CO_2 capture because carbon in the syngas is at high concentration and pressure, enabling physical absorption technologies to capture it with substantially less energy than is required to capture the dilute CO_2 in flue gas after combustion. Gasification with carbon dioxide capture can be used for the production of ammonia, fertilizer, and methanol.

Once a concentrated CO_2 gas stream is captured, it can be injected and stored deep underground instead of being released into the atmosphere.

When used to produce electricity, gasification facilities are called integrated gasification combined cycle (IGCC) plants. The hydrogen and carbon monoxide produced by the gasifier is burned in a combustion turbine (usually an efficient, combined-cycle unit). There are currently eight such facilities operating worldwide producing about 1700 MW of electricity from coal or petcoke feedstock.[25] One, at Wabash River Indiana, is shown below (photo courtesy of ConocoPhillips).

Another, the Polk station in Florida, uses a gasifier developed by Texaco (right).

In addition to producing power, syngas from gasification plants has other uses: transportation fuels can be produced through a Fischer-Tropsch process; plastics, medicine, fertilizer, and various other compounds can be produced from a syngas feedstock; and substitute natural gas that meets interstate pipeline standards can be produced through a methanation process (figure 29).

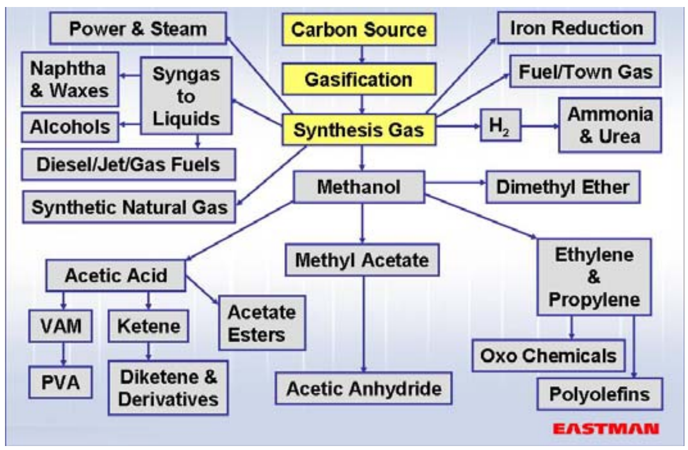


Figure 29. Examples of gasification products. Courtesy Eastman Gasification Services Company.

Gasification facilities provide a platform for capturing CO_2 that can be used for deep geologic sequestration. Gaining experience in transporting and storing CO_2 in geologic formations is essential if the U.S. is to begin to reduce the CO_2 emissions from fossil fuel facilities. Construction of gasification plants that capture CO_2 in the near-term will be important for making large (commercial scale), concentrated CO_2 streams available for deep geologic sequestration demonstration programs.

2. Carbon dioxide capture from gasification plants

A typical gasification plant is likely to produce around 4 million tons (Mt) of CO_2 per year. As noted above, gasification processes lend themselves to relatively cost-effective CO_2 capture, enabling these facilities to provide a supply of concentrated CO_2 to conduct large-scale geologic sequestration initiatives. Moreover, some gasification processes, such as industrial gasification or the process required to produce SNG, must separate a concentrated stream of CO_2 as part of the SNG manufacturing process.

The suitable sites and cost of carbon sequestration are likely to depend on the trace constituents the CO_2 stream such as CO, H_2, water, and H_2S. The allowed trace constituent specification and the permitted CO_2 emission level are the two most significant factors in the selection of the most cost-effective CO_2 capture technology.

There are a few differences between gasification technology in systems suitable for industrial processes and gasifiers that are designed for Integrated Gasification Combined Cycle (IGCC) power generation applications. The main difference is the desired ratio of hydrogen to carbon monoxide in the syngas. Chemicals often require nearly pure hydrogen content. These differences have significant implications for total system efficiencies and for readiness and cost to separate carbon from other constituents in the synthesis gas stream.

Characteristics of industrial gasification processes that enable high levels of carbon capture at relatively low cost include[26]

Shift Reaction – Most industrial gasification products (chemicals, fertilizers, transportation fuels, or hydrogen) require the syngas (the initial gaseous product from the gasifier, composed primarily of carbon monoxide and hydrogen) to be "shifted," or enriched in hydrogen. To shift the syngas, water is reacted with carbon monoxide in the syngas to create additional hydrogen and carbon dioxide. This shift step is not utilized in the non-capture IGCC systems, but is used for most IGCC systems with carbon capture.

Quench Gasifier – The water shift reaction can also be accomplished with a "quench-type" gasifier. Hot syngas from the gasifier is quenched in water, saturating the syngas with water for the subsequent shift reaction.

High Pressure Efficiencies – Downstream chemical conversion processes require most industrial or polygeneration gasification plants to operate at high pressures, higher than those typically required for stand-alone electric power generation. Fortunately, this same high pressure required for chemical processing also makes most carbon dioxide capture technologies operate more efficiently.

Capture Required – A large fraction of the residual carbon in industrial-use syngas is destined for ultimate chemical conversion and is thus incorporated (or sequestered) into the final desired industrial product, rather than vented. A few examples of durable industrial products made from chemicals in which carbon is routinely sequestered include plastic handles on screwdrivers and toothbrushes, tape, and automobile paint. Industrial gasification capture rates can vary widely based on products, and split of products/coproducts. Typically, industrial gasification projects are said to capture 50-90% of feedstock carbon as CO_2 or final products.

Thermal Efficiency – Industrial polygeneration uses gasification heat as process heat in the conversion of syngas to products. Net plant efficiencies (HHV) can vary widely, but would typically be ~37% for stand-alone IGCC without carbon capture,[27] ~32% for IGCC with carbon capture,[28] and are said to be ~50-75% for industrial gasification[29] (figure 30).

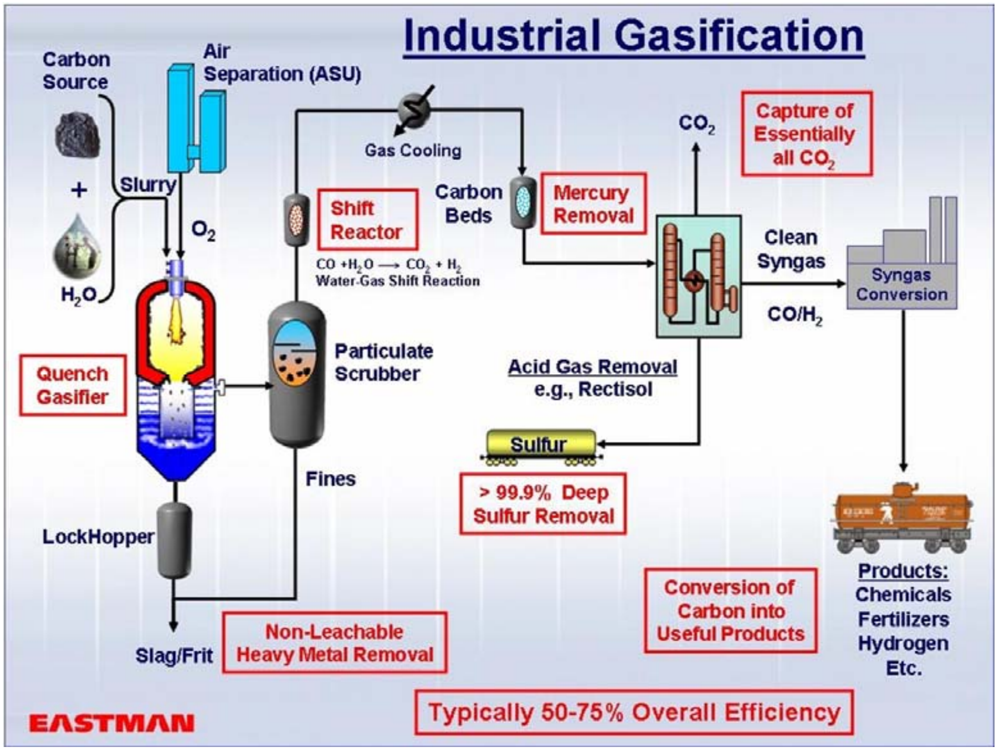


Figure 30. Industrial gasification process steps. Source: Eastman Chemical.

Required scale of carbon dioxide capture

The Intergovernmental Panel on Climate Change (IPCC) has calculated that stabilization of atmospheric CO_2 at a level twice that which prevailed in pre-industrial times requires reductions of emissions to no more than half of current levels during this century.[30] Considering demand growth driven by population and usage patterns, it is likely that achieving this reduction will require capture and sequestration of 80% of the CO_2 from U.S. coal and natural gas fired electric power plants, i.e., 2000 Mt per year at current levels.[31] A typical 500 MW coal-fired electricity plant at an 80% capture rate would capture 3 to 4 Mt per year of CO_2.

Like gasification technology, geological sequestration of the captured CO_2 will require early projects in commercial hands to develop the technology and operations to the point where they can be generally adopted.

As noted previously, the network of CO_2 pipelines required to transport the captured carbon dioxide is likely to require a scale up of 10 to 40 times the present scale. Carbon capture and sequestration (CCS) from gasification facilities with high capture volumes can provide early experience with transport and deep geologic sequestration at commercial scale within the next few years.

Financial incentives are necessary to begin commercial scale CCS at gasification facilities, since transport and sequestration costs are estimated at $5-$15 per ton of CO_2 ($20-$60 million per year per commercial plant). Although such costs can be recovered in some locations by selling the CO_2 for use in enhanced oil recovery, many gasification facilities may be sited far from EOR locations, and incentives for sequestering CO_2 are required to allow the operator to consider alternatives to emitting the CO_2 into the air.

Comparative Economics and Carbon Footprint

The economics of gasification plants are strongly affected by both the price placed on carbon dioxide and the price the product of the gasification plant can fetch in the market.

For electric power production, a recent report by the Department of Energy[32] estimates that a new conventional (pulverized coal, or PC) plant can produce electricity for 6.4 cents per kWh, while an IGCC plant's electricity would cost 7.8 ¢/kWh. However, if both plants are required to capture carbon dioxide, the IGCC plant becomes the more cost-effective option, at 10.6 ¢/kWh, lower than the PC plant's 11.7 ¢/kWh.

At current prices for natural gas, gasification for synthetic natural gas production is becoming an attractive option. For example, the Governor of Indiana has announced[33] a major coal to SNG project that would produce 15% of Indiana's gas supplies over 30 years at 20% lower cost than the average gas utility purchases over the past three years and over long-term EIA projections of pipeline deliveries.

The carbon footprint of gasification depends on the application and the technology.

For electric power, a 2004 review of available studies[34] comparing three technologies (pulverized coal, IGCC, and natural gas) with and without carbon capture and sequestration summarized the data as follows:

	PC Plant		**IGCC Plant**		**NGCC Plant**	
Performance Measures	**Range low-high**	*Rep. value*	**Range low-high**	*Rep. value*	**Range low-high**	*Rep. value*
kg CO_2/MWh without capture	722-941	795	682-846	757	344-364	358
kg CO_2/MWh with capture	59-148	116	70-152	113	40-63	50
% CO_2 reduction per kWh	80-93	85	81-91	85	83-88	87
% increase in cost of electricity with capture	61-84	73	20-55	35	32-69	48
Cost of CO_2 avoided ($/tonne CO_2)	42-55	47	13-37	26	35-74	47

Table 1. Summary of reported CO_2 emissions and costs for a new electric power plant with and without CO_2 capture, excluding CO_2 transport and storage costs. Source: Rubin et al.

Thus, a gasification plant with carbon dioxide capture is likely to achieve CO_2 control at a lower cost per tonne of CO_2 than either a pulverized coal plant with post-combustion capture or a natural gas combined-cycle plant also with post-combustion capture. The gasification plant and the PC plant with capture have nearly identical carbon emissions per kWh (for reasons discussed above, natural gas costs make such plants unattractive for baseload power in many regions of the country).

An analysis comparing gasification for liquid fuel production to gasoline use and to vehicle power from electricity (plug-in hybrid electric vehicles, or PHEVs)[35] has found that modest GHG reduction (5%) can be obtained by switching the vehicle fleet from gasoline to coal-to-liquids if that process incorporates capture and sequestration of the CO_2. Much larger reductions (70%) can be obtained by switching from gasoline to PHEVs using coal (either PC or IGCC) with CCS.

Approximately 8% of petroleum use in the U.S, representing 200 million tons of CO_2 annually, about 3% of all U.S. GHG production, is for chemical feedstocks, pentanes, refinery gas, and waxes. It is plausible that gasification may replace some of these petroleum-derived feedstocks. The greenhouse gas footprint of such a substitution has not yet been rigorously analyzed, but gasification is unlikely to have large positive or negative impacts since the total is a small fraction of all U.S. greenhouse gas emissions.

3. Carbon dioxide transport and sequestration

As outlined by the U.S. Department of Energy,[36] "geologic sequestration is defined as the placement of CO_2 into an underground repository in such a way that it will remain permanently stored. DOE is investigating five types of underground formations for geologic sequestration, each with different challenges and opportunities for CO_2 sequestration: (1) mature oil and natural gas reservoirs, (2) deep unmineable coal seams, (3) deep saline formations, (4) oil- and gas-rich organic shales, and (5) basalt formations." See figure 31, reprinted from the Carbon Sequestration Atlas of the United States and Canada.

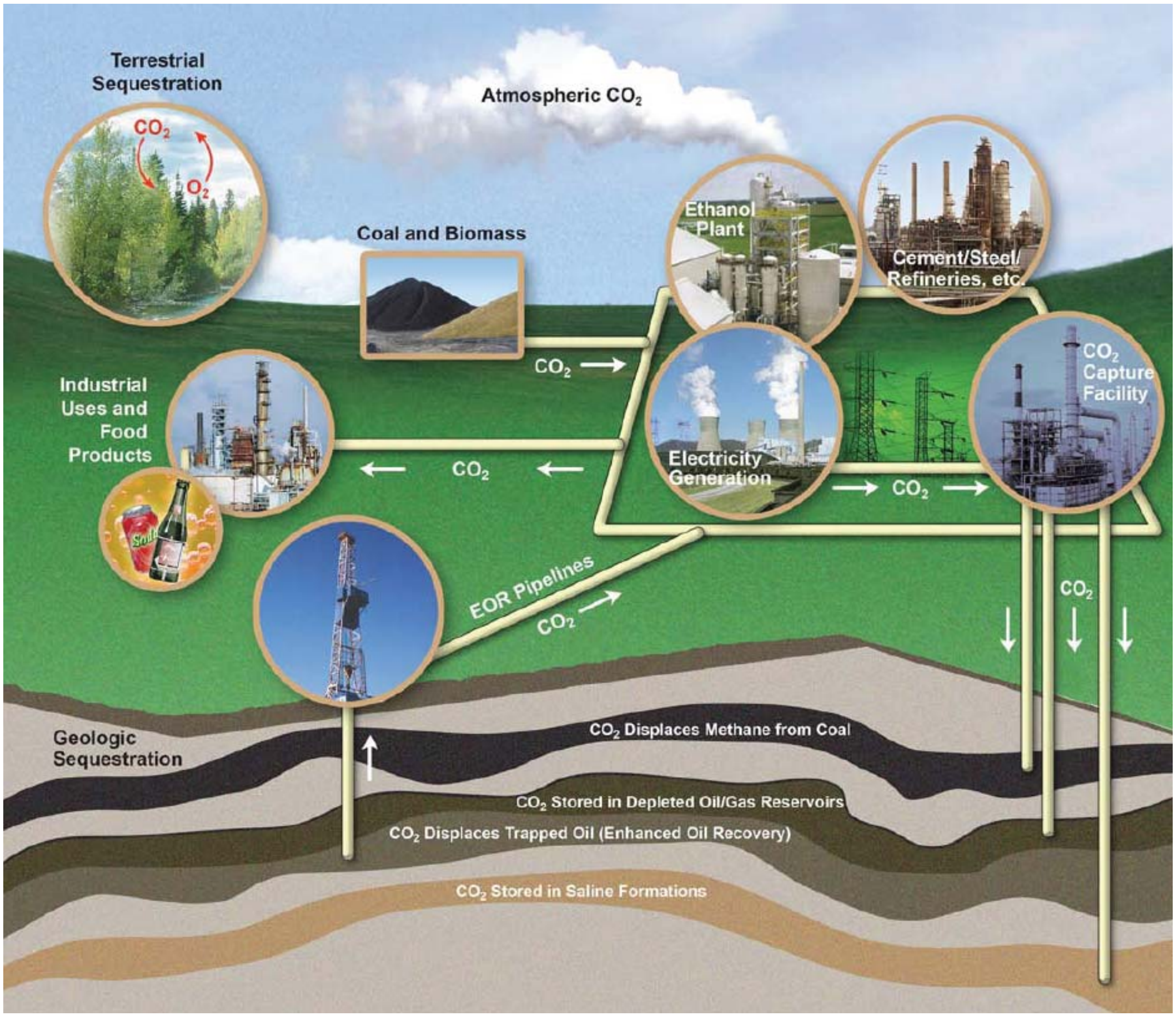


Figure 31. Sources and potential sequestration sites for CO_2. Source: DOE Carbon Sequestration Atlas.

The locations of existing and announced carbon dioxide injection sites, both for enhanced oil recovery and sequestration, are shown in figure 32, while the location of prospective sequestration sites in sedimentary basins is shown in figure 33.

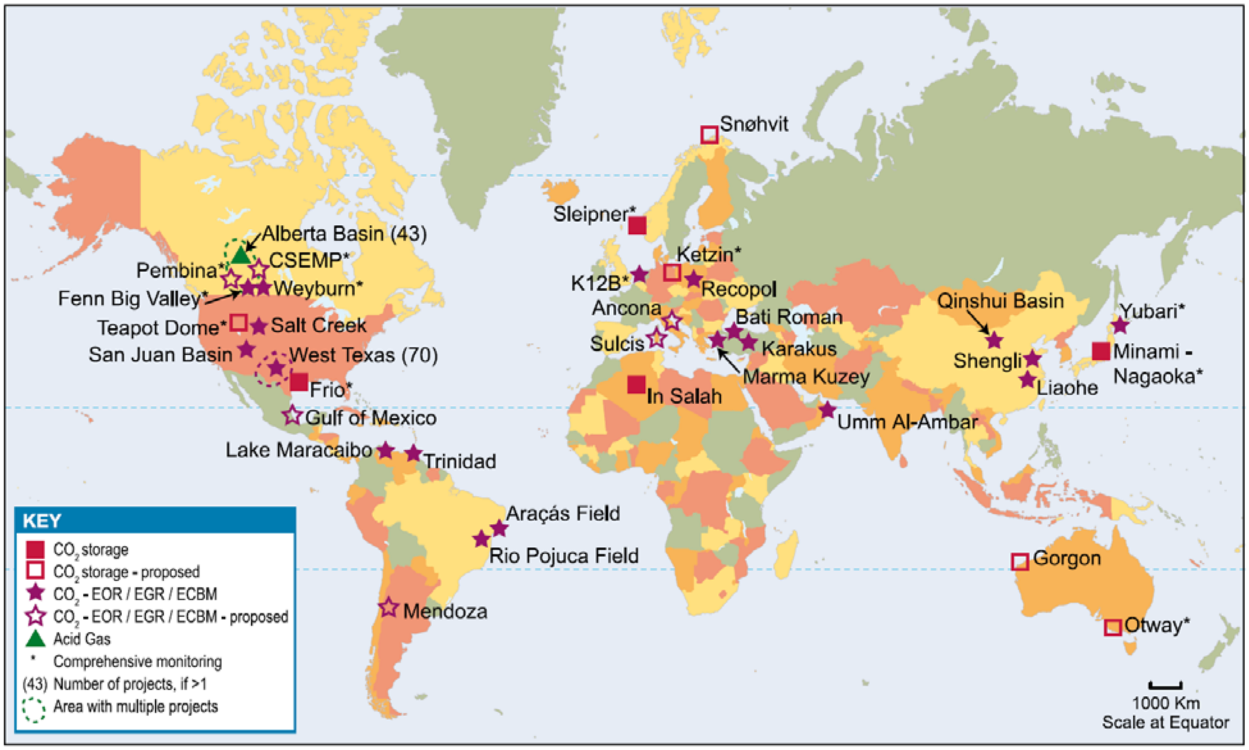


Figure 32. Locations of current or planned CO_2 injection projects. Source: IPCC.[37]

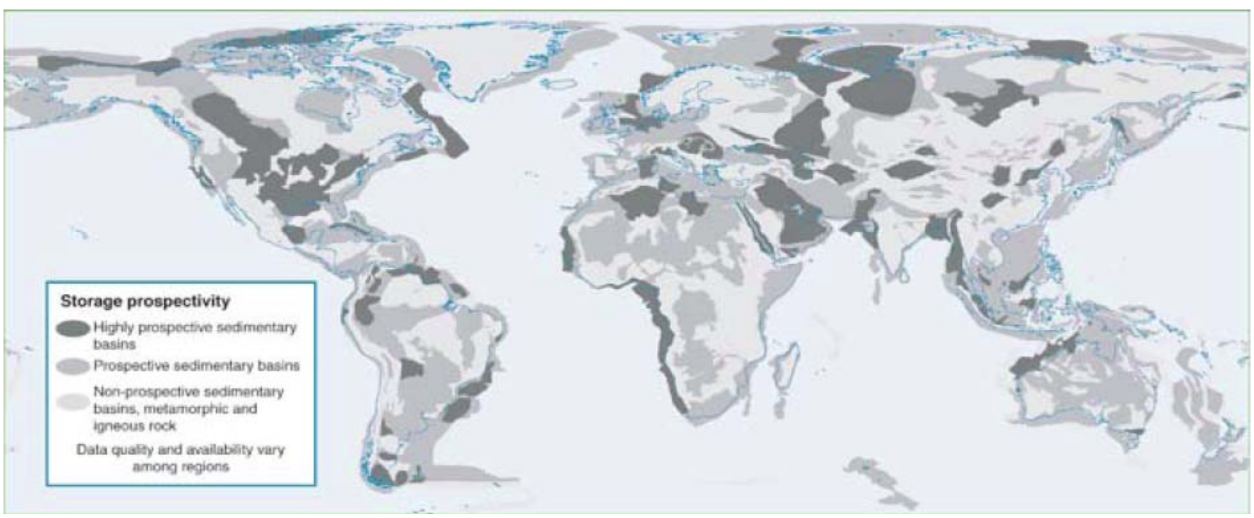


Figure 33. Location of potential reservoirs. In addition to having abundant coal reserves the US also enjoys appropriate geology for substantial carbon dioxide sequestration. Source: IPCC.[38]

The U.S. Department of Energy has made the following estimates for the size of potential geologic sequestration sites in the U.S. and Canada. Together these sites have the capacity to hold all U.S. CO_2 emissions at current levels for 160 – 500 years.

Type of Sequestration Site	Size (Billion Metric Tonnes)
Oil and Gas Reservoirs	**82.4**
Unmineable Coal Seams	**156 – 183**
Deep Saline Formations	**919 - 3378**

Table 2. Size estimates of potential geologic sequestration sites in the U.S. and Canada.
Source: Carbon Sequestration Atlas of the United States and Canada

The scale of the largest current underground injections of CO_2 is roughly the same size as that required for a single 500 MW coal generator with CCS (figure 34). The large projects are all for enhanced oil recovery (termed EOR). The largest current non-EOR geological sequestration projects are well below the scale required for commercial gasification sequestration.

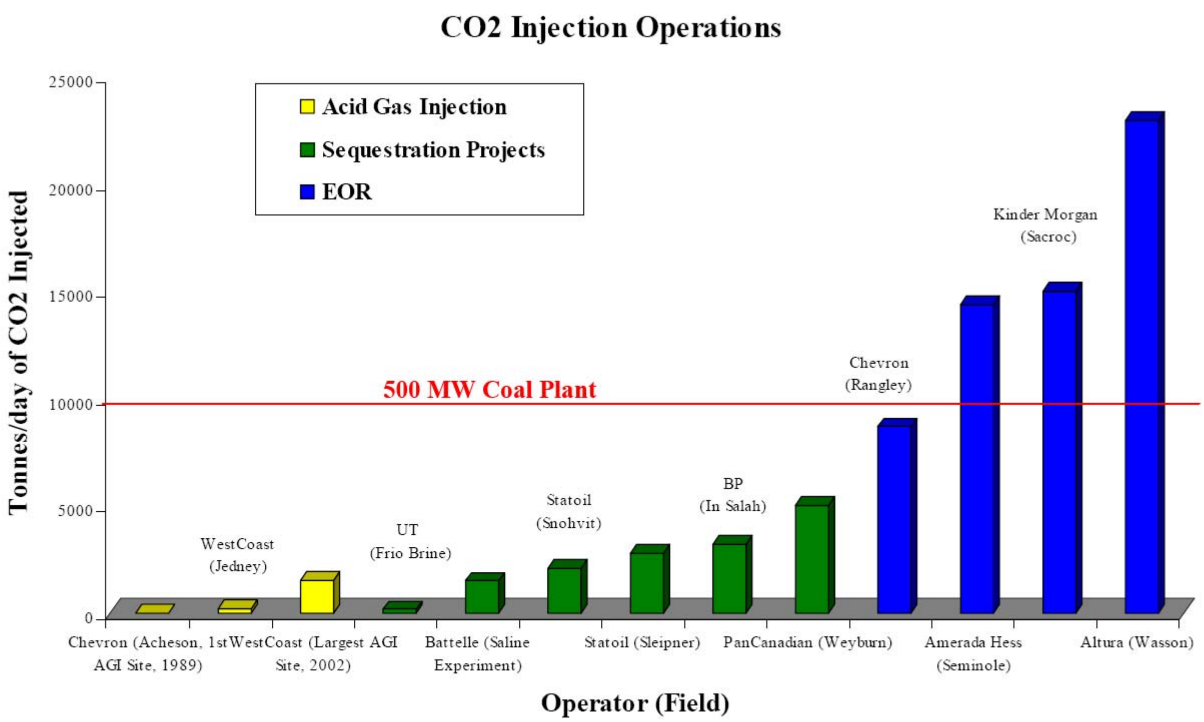


Figure 34. Comparison of CO_2 injections activities. Source Heinrich et al.[39]

The costs of transportation and storage of CO_2 have been estimated by the IPCC[40] and other authors.[41] Total costs for transport and storage in deep saline aquifers are likely to be in the range of \$2 - \$13 per tonne of CO_2 .[42] We adopt the range of \$5 - \$15 in this report, realizing that projects will be developed to take advantage of the lower range of costs when feasible.

Storage costs are a function of the formation type, porosity (for applicable strata), and depth. The IPCC report (table 8.2) estimates that the representative storage cost for geological storage is \$0.50 - \$8.00 per tonne CO_2 stored, with an additional \$0.10 - \$0.30 per tonne for monitoring.

Transport costs are a function of both the length and mass flow rate of the pipeline. At a length of 250 miles, the IPCC cost estimates as a function of mass flow rate are given in figure 35. We note that the costs do not scale linearly with pipeline length, for reasons that include the requirement for pumping stations.

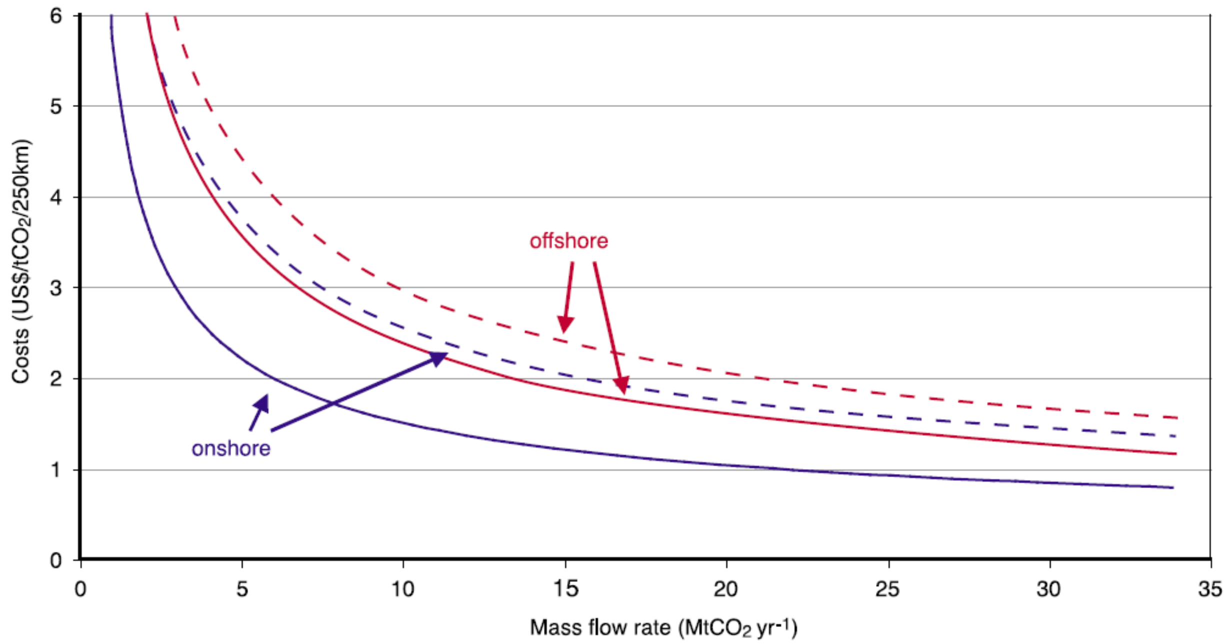


Figure 35. CO2 transport costs range for onshore and offshore pipelines per 250 km, ‘normal’ terrain conditions. The figure shows low (solid lines) and high ranges (dotted lines). Source: IPCC Special Report on Carbon Capture and Sequestration Fig 8.1

In 2002, existing long distance CO_2 pipelines in the U.S. and Canada totaled 2500 km, with a capacity of 48.8 Mt per year (figure 36).

Figure 36. CO_2 pipelines. Source: IPCC Special Report on Carbon Capture and Sequestration Fig 4.1

Pipeline failure rates are given by several authors quoted in the IPCC report, and are very low. The failure incidence rate for larger (> 0.5 meter diameter) pipelines is below 5 x 10^{-5} per km per year (that is, a 1000 km pipeline would be expected to have a failure every 20 years). This failure estimate includes compressor and pump stations.

Pipeline leakage rates for CO_2 pipelines are estimated in the IPCC report by analogy with natural gas pipelines. These have a total leakage rate in the U.S. of 1.5 ± 0.5%, and in Russia 1% to 2.5%. Leakage of CO_2 in certain geographical regions may present a health and public perception hazard, and any leak transfers CO_2 to the atmosphere. However, a larger risk may be posed if there are trace gases present in the CO_2. For example, hydrogen sulfide (H_2S) has a threshold of 100 ppm at which it is deemed “immediately dangerous to life or health” per the National Institute for Occupational Safety and Health.

There is no current national specification for CO_2 pipeline content.[43] Rather, specifications have been set by local conditions. The system that supplies the Permian Basin in Texas and New Mexico has evolved due to the quality of the three natural sources that provide supply and as a result, has a fairly strict specification with minimal impurities such as hydrocarbons and hydrogen sulfide being allowed. Permian Basin supply sources have the following CO_2 purity: Bravo Dome 99%, McElmo Dome 98% and Sheep Mountain 97%.

The hydrogen sulfide specification for CO_2 used in EOR in Texas is an artifact of the Texas Railroad Commission's limit of 100 ppm of H_2S allowed to be injected into a formation without obtaining special approval. It is not related to H_2S affecting the performance of a CO_2 EOR flood; in fact minor amounts of H_2S will lower the minimum pressure required to achieve miscibility. As stated above, most of natural sources of CO_2 have a minimum of 97% CO_2 with no hydrocarbon impurities while CO_2 from anthropogenic sources have allowable limits for hydrocarbons such as methane, ethane and propane and hydrogen sulfide depending upon the efficiency of the gas treating process.

As a result of the diverse sources, it is likely that pipeline systems obtaining CO_2 from natural sources will maintain very tight quality specifications and will only co-mingle supply from industrial sources if they can meet the quality specification. Other pipeline systems for EOR will evolve that obtain product from industrial sources and these are likely to have a less restrictive quality standard than those for product from natural sources, but minimum CO_2 content is likely to still be above 95%. Still other pipeline systems may evolve that are designed for transporting CO_2 for geological sequestration and these will not be concerned with CO_2 quality and will handle CO_2 streams having considerably less than 95% CO_2. For example, the Rentech Pet Coke gasification project at Natchez, Mississippi has a CO_2 pipeline design specification of 90% minimum CO_2. Table 3 lists the specifications for four existing U.S. CO_2 pipelines.

Pipeline	Dakota Gas	Exxon	Denbury	Kinder Morgan
Location	ND/SK	WY	MS/LA	NM/TX
CO_2 Source	Anthropogenic	Anthropogenic	Natural	Natural
Specifications				
Carbon Dioxide	95% min	95% min	99% min	95% min
Water	< 100 ppm	< 30 lbs/MMSCF	< 30 lbs/MMSCF	< 30 lbs/MMSCF
Methane	< 0.5%	NS	NS	NS
Ethane	< 1%	NS	NS	NS
Propane	< 0.5%	NS	NS	NS
Hydrocarbons	NS	NS	NS	< 5%
Hydrogen Sulfide	< 2.0%	< 20 ppm	< 10 ppm	< 20 ppm
Oxygen	< 0.5%	< 10 ppm	NA	< 10 ppm
Nitrogen	< 1%	< 4%	< 0.5%	< 4%
Mercaptans	< 250 ppm	NS	NS	NS
Total Sulfur	NS	< 35 ppm	< 35 ppm	< 35 ppm
Glycol	NS	< 0.3 gal/MMscf	NA	< 0.3 gal/MMscf
Temperature	NS	< 120 ºF	< 90 ºF	< 120 ºF
NS = not specifed				

Table 3. Specifications for selected US CO_2 pipelines. Source: R. Hattenbach, Blue Source Ltd.

Currently the Department of Transportation's Surface Transportation Board regulates all interstate pipelines other than natural gas under a common carrier model. Interstate natural gas lines, on the other hand, follow a public utility model and are regulated by the Federal Energy Regulatory Commission. FERC approves both construction and abandonment of natural gas pipelines, while there is no federal regulation of these for CO_2 pipelines. Surface Transportation Board CO_2 pipeline regulation does not require rate filings prior to service, and rates are reviewed only upon filing of a complaint. FERC oversight of natural gas pipelines allows operators who have been granted a certificate of public convenience and necessity to apply for eminent domain for siting of the pipeline under certain conditions. No such ability currently exists for CO_2 pipelines.

Oversight of long distance CO_2 pipelines by FERC may be in the interest of the nation. FERC jurisdiction may shorten the siting process, however, unduly burdensome regulations may discourage near-term long distance pipeline construction if CO_2 emissions control is not mandatory. There are advantages and disadvantages of common carrier status for CO_2 pipelines. FERC may have the authority to permit appropriate adjustments to tariffs to enable investment recovery in attractive time frames in the short term to gain experience.

Marine transport is also feasible, although no CO_2 tankers are presently in service. The IPCC report estimates that ship transport costs become competitive with pipeline transport costs when the distance exceeds 1250 km.

4. Announced development activity

A number of gasification facilities have been announced in various locations. Table 4 lists those that appear in the database maintained by the Gasification Technologies Council. Other projects are in various stages of development, with about ten at the press release stage and an additional six filed with the appropriate regulatory bodies.

Plant Name	Year	Country	Feed	Product	Size
Brazilian BIGCC Plant	2007	Brazil	Biomass	Electricity	30 MW
[no name]	2007	China	Coal	Methanol	
Lima Energy IGCC Plant	2008	United States	Coal	Electricity	530 MW
Vanguard Synfuels	2008	United States	Petcoke	Power	
[no name]	2008	Poland	Asphalt	Hydrogen	
Mesaba Energy Project	2009	United States	Coal	Electricity	530 MW
CITGO Lake Charles	2009	United States	Petcoke	Power	
Rentech & Royster Clark	2009	United States	Coal	FT Liquids	
Pearl GTL	2009	Qatar	Natural Gas	FT Diesel	70000 bpd
Steelhead Energy	2010	United States	Coal	Electricity	530 MW

Table 4. Announced gasification projects. Source: Gasification Technologies Council Database.

D. Why commercial projects under development today cannot commit to carbon capture with sequestration

A number of commercial gasification projects under development today will employ technologies capable of capturing concentrated streams of CO_2 at low cost.

However, these facilities will not be in a position to make early commitments to sequester their CO_2 due to the lack of a mechanism to recover costs for sequestration, as well as uncertainties and unresolved issues associated with sequestration. Fundamental roadblocks to near-term sequestration commitments include the lack of any regulatory requirement to control emissions, geologic uncertainties, regulatory uncertainties, liability issues, geologic rights issues, and commercial financing requirements.

Absence of a requirement to control emissions. While control on emissions of CO_2 will likely be imposed in the US within a few years, at the moment there is no such control. In the absence of a subsidy, tax policy, or similar incentive, any private effort to capture and sequester CO_2 will simply be an added cost to a commercial undertaking.

Geologic uncertainty. The initial uncertainty regarding near-term, commercial-scale sequestration is whether specific geologic formations targeted for injection will readily accept and successfully trap CO_2. While oil and gas reservoirs have been extensively studied across the U.S. (and some of these will be suitable for CO_2 storage), very limited information is available about other formations, such as saline aquifers, that are being targeted as primary CO_2 repositories for large volume storage. Seismic surveys and core samples from well bores are needed before the porosity and permeability of a formation can be evaluated and even with such information the injectability and mobility of CO_2 in a formation will remain uncertain until actual data can be collected from injection tests. Appropriate data collection steps can and should be taken by project developers to evaluate sequestration potential, but until studies and tests are completed, including actual CO_2 injection tests at commercial scale, not enough will be known for developers to accurately assess the feasibility, costs, and risks of large-scale sequestration. The characterization of sites involves large areas, since the liquid carbon dioxide from a 1000 MW plant will require a radius of 10 km after a decade, and 30 km after 50 years.[44] The 3-dimensional seismic characterization of such a site is likely to require a year's measurements by one crew, followed by several years of analysis and qualification.[45] These uncertainties preclude responsible developers from making meaningful early commitments to sequestration.

Regulatory uncertainty. Currently, no regulatory program exists to govern large-scale injection of CO_2. Without a regulatory structure it is unclear what permits and approvals are needed to begin a large-scale CO_2 injection and there are no rules in place to establish safety guidelines, monitoring protocols, or verification procedures. The absence of a regulatory program makes it unclear how a project could proceed with a large-scale sequestration effort and substantially increases the risk and uncertainty associated with doing so because there are no guidelines by which to assess whether it is being done responsibly. See Appendix A for further discussion of the regulatory environment.

Liability issues. An important issue that looms over developers wanting to pursue sequestration is the potential liability if CO_2 leaks. While it is unlikely that a CO_2 leak would be so acute as to cause a safety hazard, it is not out of the question and is a risk. More likely is that small amounts of CO_2 may leak slowly, creating questions about liability for not producing valid reductions if credits of some sort are being claimed (and potentially sold) as a result of the sequestration. Since CO_2 needs to remain sequestered permanently for a credit to be valid, potential liabilities for leakage will remain indefinitely unless a system is in place to limit or transfer that liability at some point.

Geologic rights. Another uncertainty with sequestration is determining how to secure the rights to a geologic formation that may not have a clear owner. It is currently unclear in many places who owns the rights to saline aquifer formations—is it part of the mineral rights? Surface rights? Neither? If it is unclear who owns the rights to a targeted geologic formation it is not readily apparent how a project should go about acquiring those rights to begin sequestration.[46] Resolution of this issue must precede any sequestration commitment.

Financing. The combined effect of sequestration uncertainties is that they render commitments to sequester open-ended economic exposures difficult to finance. Gasification projects capable of capturing CO_2 for low cost are capital intensive and use advanced technologies. They require substantial equity and debt commitments and require careful financial structuring (and potentially state or federal incentives or credit assistance) to attract capital. Projects that commit to unquantifiable sequestration cost risks will simply not be financeable. Until enough if learned about geologic realities, regulatory requirements, and liabilities large-scale sequestration commitments cannot be made by $1+ billion projects needing commercial financing.

III. Ten year strategy for commercial CCS deployment

Commercial gasification facilities for synthetic natural gas, transportation fuels, electric power, and chemical feedstocks appear likely to be constructed in the United States in the next few years. Some such facilities by their nature separate carbon dioxide from the gas produced by the gasification process and others can be designed to separate it at lower cost than achievable with combustion technologies.

Instead of releasing the CO_2 into the atmosphere, these plants can, given proper incentives, inject it underground, gaining essential commercial scale experience in the short term. Although gaining experience is important and may position firms better in the long-term, firms would have a greater incentive to sequester carbon dioxide if there was a mechanism for receiving revenues.

Given that these plants will be constructed for valid economic reasons, the additional transport and injection of carbon dioxide are likely to be performed at costs ($5 - $15 / tonne CO_2) that are well below those of a number of other carbon mitigation strategies.

If the United States is to make significant progress in controlling carbon dioxide emissions at an affordable cost, the technologies for low CO_2 emission coal facilities must be proven at commercial scale within the next decade.

It is likely that at least 20 commercial gasification projects will be constructed in the next decade in the U.S.; these projects provide an opportunity to gain the required experience with carbon capture, transport, and sequestration. Because of the large expense and lack of widely available methods currently in place to recover the costs of CCS, many of these projects (especially those far from enhanced oil recovery users) will have to release their CO_2 into the air. The opportunity to gain commercial scale CCS experience can be seized with appropriate public and private incentives, as discussed in the following section. If the opportunities are seized for commercial scale sequestration, the opportunity for public incentives should also result in a body of experience, lessons learned and data that is widely available to future commercial developers.

To summarize:

1. Coal is America's largest and most versatile energy resource, and can be expected to remain important throughout the 21st century.
2. The environmental, health, and safety aspects of coal use with modern equipment maintain very high standards, with the exception of release of carbon dioxide.
3. The CO_2 emissions from coal use can be reduced to levels required for stabilization of atmospheric concentrations of greenhouse gasses by methods that capture carbon dioxide, and the CO_2 can be injected into deep underground geologic formations.
4. The required scale of carbon dioxide transport and sequestration to support use of the U.S. coal resources is much larger than today's pipeline transport and injection of CO_2 for enhanced oil recovery.
5. Commercial scale projects are in development that can supply large quantities of CO_2 that can be used to gain experience in the next decade with transport and injection at the scale required to gain investor confidence for the infrastructure build-out required to address climate change.

IV. Public policy and private investment strategies

Two avenues are open for commercial gasification facilities to receive revenue for geologic injection of CO_2 within a decade: enhanced oil recovery (EOR) and non-EOR sequestration.

A. Enhanced oil recovery (EOR)

The Natural Resources Defense Council (NRDC) issued a report[47] in February 2007 detailing the potential of enhanced oil recovery, stating:

> "**The Potential of Enhanced Oil Recovery**
>
> There is great potential to produce additional oil from already developed fields using carbon dioxide captured from coal-fired power plants. When CO_2 is injected at high pressure into mature oil fields under the right conditions it increases reservoir pressure and the oil's mobility, promoting enhanced oil recovery (EOR). Standard primary and secondary production without CO_2-EOR recovers only about one-third of the original oil in typical reservoirs. Current state-of-the-art EOR techniques generally allow an additional 10 percent of the original oil in place to be recovered.
>
> The U.S. Department of Energy has estimated that if EOR were widely available for CO_2, current techniques could recover more than 60 billion barrels of oil from domestic fields in the lower 48 states.[48] Advanced techniques have the potential to double the fraction of the original oil in place that could be recovered using CO_2-EOR to more than 120 billion barrels, or more than 18 times the amount of oil that is estimated to be economically recoverable from the Arctic National Wildlife Refuge, at a cost of $40 per barrel or less.[49] If power plant, pipeline, and power-line siting issues are properly addressed, capturing CO_2 from coal-fired power plants could therefore not only reduce global warming pollution, but also significantly contribute to meeting America's energy needs without sacrificing our few remaining wild places to oil exploration and development."

Although the NRDC report discusses power plants, the CO_2 produced by gasification for SNG or chemical feedstock (i.e., industrial gasification) can also be utilized for EOR and may represent excellent near-term opportunities to demonstrate EOR CO_2 sequestration at scale.

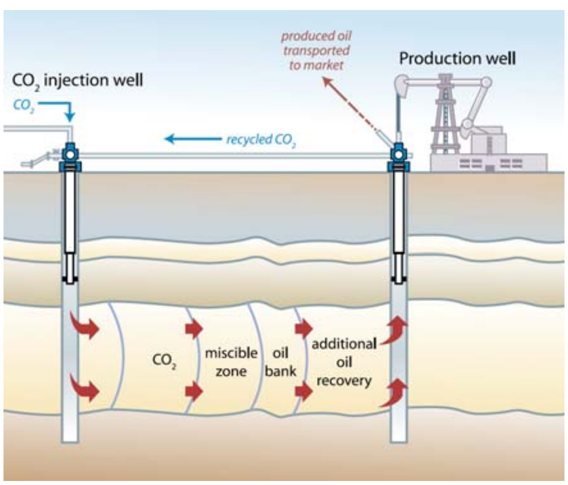


Figure 37. Injection of CO_2 for EOR with re-injection of the CO_2 that is produced with the oil. Source: IPCC.[50]

The total CO_2 injected for EOR in the U.S. currently is 30 – 50 Mt per year. The CO_2 is generally obtained from naturally occurring underground sources. For example, carbon dioxide is withdrawn from formations in Mississippi and piped for EOR to fields in Mississippi and Louisiana (and soon will be piped to fields in East Texas). The fields in the Permian Basin of West Texas are supplied from natural CO_2 sources in Colorado and New Mexico.

In order to replace the use of existing natural fossil CO_2 from formations with captured CO_2 from gasification facilities, the plant's output must be tied into the EOR pipeline network. If plants are located near existing EOR pipelines (for example, in Louisiana or Mississippi), the costs involved may not be large.

Gasification plants located near the large coal reserves in the upper Midwest (for example, in Illinois or Indiana) are at least 400 miles from the nearest EOR pipeline. This presents an opportunity to gain near-term experience with the regulatory and technical environment required to construct the infrastructure that will be required for large-scale CO_2 transportation in coming decades.

Both federal loan guarantees and prudent long-term cost recovery authorization by public utility commissions will most likely be required to secure financing for these pipelines, whose cost is estimated to be approximately $1 million per mile.

Currently, oil companies operating CO_2 floods for EOR pay for the CO_2 they use.

Dakota Gasification pricing today averages about $1.00 per MCF or about $19.25 per metric ton and escalates each year at about 2.5%. This pricing includes the commodity value of the CO_2 plus the cost of transportation for the 205 miles of transport.

Pricing for CO_2 in the Permian Basin of West Texas ranges from a low of about $0.75 - $0.80/MCF or $14.45 - $15.40 per metric ton for old contracts. For new contracts being entered into today, pricing ranges from about 2.25% to 3% of the NYMEX posted crude oil price. This pricing can be adjusted on a monthly basis. If NYMEX is trading at $60/bbl then CO_2 pricing would range from $1.35 to $1.80 per MCF or from $26 to $34.65 per metric ton.

Thus, prices paid for CO_2 are in the range of $15-35/tonne. For a plant providing 3 Mt year of CO_2 for EOR this could mean $45-105 million per year additional revenue. However, as industrial sources of CO_2 come on-line, the supply of CO_2 may outstrip EOR CO_2 demand, causing significant downward pressure on the price EOR operators are willing to pay.

Federal sequestration incentives may be warranted for those projects where the incremental cost of implementation are close but higher than the value of oil recovery.

B. Non-EOR sequestration

Appendix A outlines the current regulatory environment for sequestration in the U.S. A prerequisite for sequestration projects in the near term is to secure both state approval and federal approval under Underground Injection Control (UIC) Class V (under the assumption that projects in the next several years would be undertaken as experimental injections, prior to the development of a comprehensive regulatory framework).

Given the proper regulatory environment, several potential strategies may be possible for cost recovery without the establishment of an overall CO_2 price in the U.S.

1. A federal sequestration tax credit and investment tax credit for CO_2 pipelines

Currently, 15% of the costs incurred in enhanced oil recovery are eligible for the enhanced oil recovery federal tax credit (claimed on form 8830). The Energy Tax Incentives Act of 2005 provides a 30% business investment credit for solar energy and fuel cell property and certain solar lighting systems; a 10% investment tax credit is provided for microturbines (claimed on form 3468).

A tax credit in the range of 10 to 30 percent of incurred costs for carbon dioxide pipelines would be in accord with the federal tax credits used to encourage the above investments.

A sequestration tax credit for geologic sequestration is likely to provide an effective incentive for sequestration projects.

Such a sequestration tax credit should have provisions that reduce the tax credit if the U.S. enacts legislation resulting in a carbon price above the effective price established by the tax credit. Like the production tax credit, the sequestration tax credit may be designed with time limits both for the date by which the projects must be underway and the conclusion date of the tax credit.

The sequestration tax credit may be designed with a limit to the total available, with projects competing on the basis of cost or as first come, first served. However, such a provision would introduce uncertainty that may inhibit investment.

We note that a per kilowatt-hour production tax credit, the Renewable Electricity Production Credit (REPC), is currently applied to electricity generated from low-carbon "qualified energy resources" at a "qualified facility."[51] At present, the REPC applies to the following qualified resources:

- wind
- closed-loop biomass
- open-loop biomass
- geothermal energy
- solar energy
- small irrigation power (150 kW - 5 MW)
- municipal solid waste
- landfill gas
- qualified hydropower production
- refined coal
- Indian coal

Enacted as part of the Energy Policy Act of 1992, the credit expired at the end of 2001, and was subsequently extended in March 2002 as part of the Job Creation and Worker Assistance Act of 2002.[52] The tax credit then expired at the end of 2003 and was not renewed until October 4, 2004, as part of H.R. 1308, the Working Families Tax Relief Act of 2004, which extended the credit through December 31, 2005. The Energy Policy Act of 2005[53] modified the credit and extended it through December 31, 2007. In December 2006, Section 207 of the Tax

Relief and Health Care Act of 2006[54] extended the tax credit for another year, through December 31, 2008.

Section 710 of the American Jobs Creation Act of 2004[55] expanded REPC to include, among other additional eligible resources refined coal. Refined coal is defined as "a liquid, gaseous, or synthetic fuel produced from coal (including lignite) or high carbon fly ash, including such fuel used as a feedstock."[56] In addition, refined coal is considered a "qualified emission reduction" under the REPC if a reduction of at least 20 percent of the SO_2, and either NO_x or mercury emissions is achieved through burning refined coal, as compared to burning the feedstock coal.[57] The Energy Policy Act of 2005 further expanded the credit to certain hydropower facilities and Indian coal. Indian coal is coal produced from reserves which, on June 14, 2005, were either owned by an Indian tribe, or were held in trust by the United States for the benefit of an Indian tribe or its members.[58]

Given that the current iteration of the REPC already creates set-asides for two specific coal resources, it would be reasonable to expand the scope of REPC to include coal-fired power plants equipped with CCS as a low-carbon "qualified facility" and/or a "qualified emission reduction" rather than enact new legislation for a sequestration-specific production tax credit. Including sequestration activities under an already existing production credit provision of the tax code would decrease the amount of risk associated with learning and uncertainty that typically accompanies the application of economic incentives for new projects.

Advocates of the REPC have cited carbon dioxide control as a motivation, along with reduction of SO_2, NO_x, and mercury. Current prices for SO_2 and NO_x allowances and estimated prices for Hg control total to 0.9 cent per kWh for an average coal-fired power plant in the current fleet. The REPC provides a tax credit of 1.5 cents/kWh, adjusted annually for inflation, for the sale of electricity produced from qualified energy resources at a qualified facility.[59] Currently, the REPC for these technologies is 1.9 cents/kWh.[60] Using the average U.S. electric power industry CO_2 emission rate of 6.2×10^{-4} metric tons per kWh[61] the present federal production tax credit equates to \$16 per metric ton of avoided CO_2, when credits for avoided SO_2, NO_x, and mercury emissions are accounted for.

2. Pipelines may be financed by tax exempt bonds

Tax exempt financing can be used by private entities under what are called Private Activity Bonds. Qualified Private Activity Bonds are tax-exempt bonds issued by a state or local government, the proceeds of which are used for a defined qualified purpose by an entity other than the government issuing the bonds. Private Activity Bonds can reduce financing costs through lower borrowing rates because the interest paid to bondholders is not includable in their gross income for federal income tax purposes.

Financing with tax-exempt bonds requires strict compliance with a series of requirements and limitations established by the Internal Revenue Code. Many types of projects that are eligible for tax-exempt financing are subject to a federally required annual volume cap, which restricts the amount of tax-exempt Private Activity Bonds that can be sold in any one state. Starting with 2007, the volume cap each sate receives equals \$85 per capita per year.

There are two ways tax exempt financing could be made available for CO_2 sequestration infrastructure investments, which could be defined to include investments in compression, pipelines and injection/storage facilities. One is for the IRS code to be altered to specifically identify CO_2 sequestration investments as “Qualified Private Activity Bonds.” Qualifying the investments would enable Private Activity Bonds to be issued under existing IRS rules and would be subject to state volume cap allocations. Alternatively, legislation could be passed to create a separate allocation of Private Activity Bond authority for CO_2 sequestration investments. This type of legislation was passed to provide GOZONE bonds for states affected by Hurricane Katrina and for the Liberty Zone around ground zero in New York City. Since demand for tax exempt bonds often exceeds volume cap restrictions, it is probably preferable to create a separate allocation and program for CO_2 sequestration investments in this manner.

To create a separate bond allocation for CO_2 sequestration investments, federal legislation would be needed similar to the GOZONE legislation. A national cap on the amount available (say $20 billion) would be established and bonding authorities from states with potential projects could apply for volume cap distributions under the program. One complication that the program would need to overcome is that Private Activity Bonds must be issued by local government entities, making it somewhat unclear how such bonds might be issued for pipelines that might traverse several counties or states.

3. Direct federal payments per ton of sequestered CO_2

The Department of Energy has undertaken a number of Regional Carbon Sequestration Partnerships[62] to inject CO_2. Some of these, like the Midwest partnership in the Illinois basin, have begun EOR injections as the second phase of the regional partnerships. Phase III regional partnerships are have recently had their schedule advanced and the project sizes enlarged. Total phase III injections will be approximately 21 Mt (7 projects, each of 1 Mt per year for 3 years).

It is possible that some of the commercial gasification projects currently in advanced planning may be suitable for these phase III projects (although most of the phase III projects have already identified their CO_2 sources). The CO_2 stream from a single commercial gasifier represents 4 times the amount of CO_2 envisioned for the phase III sites. There may not be a match in the timeframe of planned commercial gasification facilities with the newly-advanced timetable for the phase III regional partnerships. The limited time (3 years) of the Phase III projects is unlikely to be attractive to investors.

A better match may be a program encompassing, say, 10 commercial-scale plants, with direct or indirect payments to each for sequestration. Such a program would rapidly advance commercial-scale experience. Gasification projects currently being planned are said by developers to be able to transport and sequester at $20 - $60 million per plant, so the total costs would be in the range of $200 - $600 million annually (the current tax expenditures to support the wind portion of the federal production tax credit are approximately $600 million per year). Further analysis may refine these cost estimates.

This type of program might be financed by direct federal appropriation or by a voluntary or mandatory fee on new coal-based facilities. For example, such a facility might pay $5 per ton of CO_2 into a fund that would be matched by a like amount from federal funds. The sequestration funds would be spent on a limited number (say 10) sequestration projects for at most 10 years.

A variation on this program would be the establishment of federal carbon dioxide sequestration sites for non-EOR sequestration before a carbon price makes private sites profitable.

4. State PUC actions

A finding by the public utility commission of a state in which a gasification facility is located that carbon capture, transport and sequestration charges are just and reasonable would allow cost recovery for the incremental costs of CCS through the rate base.

Similarly, a CO_2 pipeline might be entered into the rate base if it is found to be just and reasonable, and if the pipeline is used and useful.

Similar to recent legislation in Indiana, “no look-back” provisions may be required to ensure that investors have adequate security that terms will not be changed after plant or pipeline construction.[63] In other words, Indiana has agreed to a covenant which explicitly provides that “neither the commission, nor any other state agency, political subdivision, or governmental unit may take any action” that has the “effect of limiting, altering, or impairing a utility’s right to recover costs” in connection with or resulting from a contract to purchase substitute natural gas.[64, 65] Specifically, if the Indiana Utility Regulatory Commission (the commission) approves a utility contract for the purchase of substitute natural gas, or electricity generated in connection with the production of a substitute natural gas, the commission must allow the utility to recover, on a timely basis throughout the duration of the contract, all costs incurred under a contract to purchase of substitute natural gas, as well as all related costs for generation, transmission, transportation, and storage.[66] Moreover, the commission is prohibited from taking any action during the contract term that would adversely affect a utility’s right to timely recover costs, regardless of any changes in market conditions or other similar circumstances.[67]

5. State electricity and natural gas excise tax forgiveness or tax credit for energy required for CO_2 pipelines and underground injection

Many states levy an excise tax on the sale of electric power. For example, Pennsylvania charges a Gross Receipts Tax of 59 mills (5.9%) on all power sold to an end-use consumer within the Commonwealth (wholesale transactions between generators and load serving entities are not subject to the tax).[68] Electricity generated in Pennsylvania and sold to another state is subject to the Gross Receipts Tax if a similar tax is imposed by that state on power generated in that state and sold into Pennsylvania.[69] Maryland’s Gross Receipts Tax is 2%. These taxes generally range from 2% to 4%, although some are as low as 0.6%. Ohio does not have a Gross Receipts Tax, but does have an explicit tax on the consumption of electricity.

States that wish to encourage investment in transport and sequestration of carbon dioxide could exempt from the tax those uses of electric power directly relating to pumping and injection.

6. A CCS Trust Fund

A proposal being developed for the Pew Center on Global Climate Change by Edward Rubin (Carnegie Mellon University), Vello Kuuskraa (Advanced Resources International), and Naomi Pena (Pew)[70] envisions a generation fee on coal-fired electric power generators. The proposal is that the fee would go to a trust fund for carbon capture and sequestration projects. A fee of 0.04 - 0.05 cents per kWh would support a program of $7-10 billion per year, providing the incremental CCS costs for both new plants and retrofits of existing plants in a 10-plant test program. If the fee were 0.11 to 0.14 cents per kWh, the trust fund would support a 30-plant program. The fees may be lower if plants provide project cost-sharing.

Uncertainties associated with this proposal include who should administer the trust fund, and whether including the fees in customer bills require approval by each state's public utility commission or can be authorized by federal legislation.

Independent of its merits, a fee on coal-fired units may be unlikely to achieve legislative or regulatory approval in today's political environment. As one indicator, the National Association of Regulatory Utility Commissioners (NARUC) adopted a resolution on July 18, 2007 that "Any climate change legislation should be implemented economy-wide…"[71]

An alternative manner of implementing such a fee may be a proactive industry initiative, similar to the 1988 "Pork. The Other White Meat.®" marketing fee, where federal legislation enabled a 2/3 vote of pork producers to levy a mandatory assessment on all producers.

Another funding mechanism for non-power plants might be the sort of fee per ton of CO_2 emission discussed in the foregoing section.

The Pew study authors point out that the use of an independent or quasi-public trust fund entity would both ensure private sector contracting and staffing standards and avoid the annual federal appropriations process. For example, the programmatic aspects of the fund should be managed by an independent, non-profit organization under contract with the federal government and selected through a competitive bid process. Additionally, the government should utilize the competitive bid process to select a private bank to handle the accounting, investment, and distribution of fund assets. Optimally, the bid contract timeframe should either be for 5 years with a five-year option to extend, or for 10 years with a five-year break-off point. The option to extend emphasizes the need for contingency, whereas the use of a break-off point emphasizes the importance of program stability and commitment.

Congressional approval would be necessary to authorize the creation of a CCS trust fund. However, because the existence of a Congressionally approved fund doesn't alone generate money – it merely receives and distributes the fund assets – federal legislation detailing how and from whom/where the funds will be generated is needed. As noted in the Pew proposal, clear objectives must be established and it must be clear that the fees from the trust fund to the project would terminate when the objectives are reached. Therefore, federal legislation must also establish general project mandates, specific criteria for measuring project performance, and layout at least a moderate level detail regarding implementation - too little detail would provide no guidance, but too much detail could lead to unproductive earmarking.

The Pew study authors note that there is a continuum of trust funds, including purely federally-administered ones like the highway trust fund (supported by fuel taxes), funds managed by a consortium of stakeholders like the Ultra-Deepwater and Unconventional Natural Gas and

Other Petroleum Resources Fund (administered under Department of Energy oversight), and the Tobacco Master Settlement Agreement (dispersed by the National Association of Attorneys General).

Such a program could provide incentives for CCS plants using a number of different technologies in various geographic regions, with sequestration in geologic formations of different types.

7. Carbon Sequestration Investment Fund

Similar to the CCS Trust Fund idea, a program could be developed that would enable projects to agree to make a certain level of sequestration investment as part of their qualification for other government incentive programs. This concept is aimed at providing a mechanism for projects to make firm commitments to CO_2 sequestration initiatives (funding commitments), but not be forced to make commitments to sequester certain tonnage amounts since the technological success and costs of geologic sequestration remain unknown. Under this type of mechanism, only projects that capture CO_2 could qualify. These projects would develop sequestration plans and commitment to invest a certain amount in geologic sequestration activities. For example, for every ton of CO_2 they produce they could agree to spend $3/ton, or $12 million per year for a 4 Mt plant, on geologic sequestration activities. The commitment would be the basis for the projects qualifying for tax incentive, loan guarantee, or other incentives available for gasification (or other coal technology) projects.

The Carbon Sequestration Investment Fund is a more flexible (and cost-effective) alternative to the sort of performance standards favored by some. Like other voluntary programs implemented prior to regulations, this investment fund may greatly reduce the costs of technologies prior to their economy-wide implementation.

8. A carbon sequestration registry

If CO_2 sequestered in the near term was accounted for by a respected party, and leakage was similarly monitored, such a registry might enable a private entity to buy and sequester carbon dioxide in the expectation that they could monetize the sequestered CO_2 when the U.S. creates a regulatory environment that supports carbon dioxide trading. Such a carbon venture fund would be expected to lobby to ensure that pre-existing sequestration projects were counted in legislation that enables any such regime, perhaps as offsets.

It may be justifiable on technical grounds to grant more credit for carbon sequestered today than that sequestered 20 years hence. If analysis shows this is justified, for every ton sequestered today, legislation may be envisioned that would grant more than one ton of credit at the time a carbon price were to be established.

Parties undertaking to sequester under this registry might be exempted from *ex post facto* carbon legislation if they meet certain requirements.

The Voluntary Reporting of Greenhouse Gases Program, established under Section 1605(b) of the Energy Policy Act of 1992, records the results of voluntary measures to reduce, greenhouse gas emissions. For the 2005 reporting year, 221 U.S. companies and other organizations reported to the Energy Information Administration (EIA) that they had undertaken 2,379 projects to reduce or sequester greenhouse gases in 2005. The 1605(b) voluntary registry was the first of its kind in the U.S., but the results of the registry have not been well received by environmental and other organization interested in fostering real greenhouse gas emissions reductions. The fundamental problem with the registry in terms of accounting for real reductions is that the program allows firms to report on successful emissions reduction projects, while remaining silent on whether their overall emissions levels have increased or decreased. A recent study conducted at the University of Michigan found that for electric generating companies the program has no statistically significant effect on a firm's carbon intensity, i.e. its carbon emissions per unit of electricity generated.[72]

Successful implementation of a registry that could provide the basis for granting emissions credit in a regulatory program or providing the basis for credit sales will require careful consideration of how to ensure registered credits are real, verifiable and additional (e.g., not anyway tons - credits for doing (or not emitting) what the company would do (or would not emit) anyway). California is currently working on developing a registry that may serve as a template for a national program.

9. Allocation of government incentives

The Energy Policy Act of 2005 contains a number of incentives, including investment tax credits and federal loan guarantees. Allocation of effective incentives that become over-subscribed is a difficult policy issue. Investment tax credits for IGCC have been over-subscribed by as much as 3 times (for bituminous fuel), and for industrial gasification by over 7 times.

The loan guarantees for gasification contained in the Energy Policy Act of 2005 have not yet been fully implemented by the responsible federal agency, nearly two years after the passage of the legislation.

Both issues are critical for investors in these multi-billion dollar projects.

Implementation of the 2005 EPAct provisions should be a very high priority; Congress should ensure that the Department of Energy executes its responsibilities under the 2005 EPAct with no further delay. The three applications for gasification loan guarantees selected on October 8, 2007 should be expeditiously processed and similar loan guarantees implemented for additional projects.

V. Conclusions and Recommendations

The coal reserves of the United States are second to none.

Energy adequacy, national security, and the limitations of present alternatives all argue for continued and expanded use of domestic coal as a part of the nation's energy strategy.

Control of the carbon dioxide from use of coal appears feasible, but a large scale up of current and planned pilot facilities is required before investors and operators can gain confidence. Significant uncertainties exist in cost, the best operational and technical choices, and the appropriate character of the regulatory environment for both transport and storage of CO_2 at the scales required for commercial adoption that will significantly lower CO_2 emissions from coal facilities. These uncertainties make it difficult for commercial entities to deploy low carbon energy projects at present.

Deployment of large-scale pilot projects is crucial both for proving the economic and technical efficacy of geologic carbon dioxide sequestration, gaining the experience to assure a high level of reliability in operations, and for acquiring the data necessary to craft a science-based regulatory regime sufficient to assure safety and foster public acceptance. Such a regime is necessary to provide a stable platform for commercial investment, to ensure regulatory cohesion and consistency, and to help build public confidence in geologic sequestration.

Although enhanced oil recovery (EOR) using CO_2 is presently being done at reasonably large scale, the issues and techniques required for non-EOR sequestration are rather different, and until now the objective has not been to permanently sequester the injected CO_2 but rather to reuse it for further oil recovery. Large-scale geologic sequestration demonstration projects are urgently needed. Data and operational experience from early full-scale geologic sequestration projects will form the knowledge base upon which a long-term regulatory framework can be built, and will provide the public with concrete experience with which to evaluate the technology.

Although there are plans for expanded future federally funded geologic sequestration demonstration projects, their timing and scale are still uncertain and many are much smaller than commercial size. History has shown that with the various federal, state and commercial entities involved it can often be impossible for developers, insurers or investors to use such government demonstration projects to form a realistic idea of the risks, costs, and timelines involved for a commercial project.

Fortunately, commercial scale coal gasification projects are imminent and are ideal platforms for private sector tests to gain experience with near-term commercial-scale carbon capture and geologic sequestration (CCS). Coal-to-gas and coal-to-liquids projects will capture CO_2 as part of their process, and the CO_2 can be used for large-scale geologic sequestration. Coal-to-electricity projects can be designed in that manner also.

Progressive firms that are in the engineering and financing stage of deploying coal facilities with carbon dioxide capture and sequestration would like to proceed to gain experience with CCS at commercial scale prior to the implementation of mandatory greenhouse gas control.

Incentives that have the potential to make CCS for these plants economically feasible so that the required experience with transport and storage can be gathered quickly fall into three categories: federal, state/local, and private.

We recommend that Congress consider the following incentives to increase U.S. energy independence through use of its abundant coal resources in an environmentally clean manner:

- Continue the 15% enhanced oil recovery federal tax credit.
- Enact a federal CO_2 sequestration tax credit.
- Enact a federal investment tax credit for CO_2 pipelines.
- Add low-carbon emission coal facilities to the facilities eligible for the production tax credit.
- Enable tax-exempt financing for CO_2 sequestration infrastructure investments (compression, pipelines, pumping, and injection/sequestration facilities) to amend the IRS code to identify CO_2 sequestration investments as "Qualified Private Activity Bonds" or by creating a separate allocation of Private Activity Bond authority for CO_2 sequestration investments. A national cap on the amount available (say $20 billion) would be established and bonding authorities from states with potential projects could apply for volume cap distributions under the program.
- Create a larger version of the Department of Energy Regional Sequestration Partnership program to rapidly advance commercial scale CCS at the level of 3-5 Mt per year per site for ten sites.
- Require the Executive Branch to implement without further delay the federal loan guarantee provisions of the Energy Policy Act of 2005. The three applications for gasification loan guarantees selected on October 8, 2007 should be expeditiously processed and similar loan guarantees implemented for additional projects.

We recommend that states consider the following actions to quickly gain commercial-scale experience with clean coal facilities:

- Utilize the three-party covenant provisions of the Energy Policy Act of 2005 to enter into long-term agreements with gasification facilities to provide product at fixed costs.
- Eliminate where appropriate the state excise tax on energy used to power carbon dioxide transport and sequestration equipment.

Public incentives should result in a body of experience, lessons learned and data that is widely available in the public domain to future commercial developers.

Private sector approaches (some enabled by federal legislation) in the following areas may provide important incentives:

- A carbon capture and sequestration trust fund.
- A carbon sequestration investment fund.
- A carbon sequestration registry.

Implementation of such incentives will allow progressive private sector firms to invest in the carbon capture technologies that have great promise to allow the United States to use its vast reserves of coal in a carbon constrained world before mandatory controls are enacted. This strategy will greatly reduce risks and costs for economy-wide deployment of carbon control.

Appendix A: Regulatory environment for sequestration

1. The Current Regulatory System for Underground Injection in the United States

(This section excerpted from "Regulatory and Policy Needs for Geological Sequestration of Carbon Dioxide", E. S. Rubin, M. G. Morgan, S. T. McCoy and J. Apt, Proceedings of the 6th Annual Conference on Carbon Capture and Sequestration, Pittsburgh, PA May 7-10, 2007.)

In the United States, injection of fluids into the subsurface is regulated through the Underground Injection Control (UIC) program with the goal of protecting Underground Sources of Drinking Water (USDWs) from contamination (40 CFR 144-148). The UIC program applies to any well that is injecting fluids into the subsurface, but specifically excludes wells outside states territorial waters, small waste disposal systems (i.e., those designed to serve less than 20 persons), and natural gas storage operations. While the overall UIC program is administered by the EPA, individual states may apply for primacy enforcement authority to run their own UIC program.

The UIC program prohibits any injection that results in "the movement of fluid containing any contaminant into USDWs if the presence of that contaminant may cause a violation of any primary drinking water regulation." Five classes of injection wells have been identified in the regulation (40 CFR 144.6), as summarized in figure A1. Of note is the general prohibition of any well meeting the criteria of Class IV (i.e., any well injecting hazardous wastes into or above formations that contain USDWs), as denoted by the dashed box in figure A1.

The different classes of wells each have differing requirements for construction, operation, monitoring, and closure. Class I wells injecting hazardous wastes have the most stringent requirements. The owner or operator of a Class I hazardous well must apply for a "no-migration petition" that demonstrates that the hazardous waste will not migrate vertically out of the injection zone or horizontally into contact with a USDW for 10,000 years. Moreover, the UIC program has financial assurance terms for Class I hazardous wells, requiring the owner or operator to pass a financial test or set-up a trust fund, post a bond, sign a letter of credit, or obtain insurance to ensure that the well will be properly plugged and abandoned.

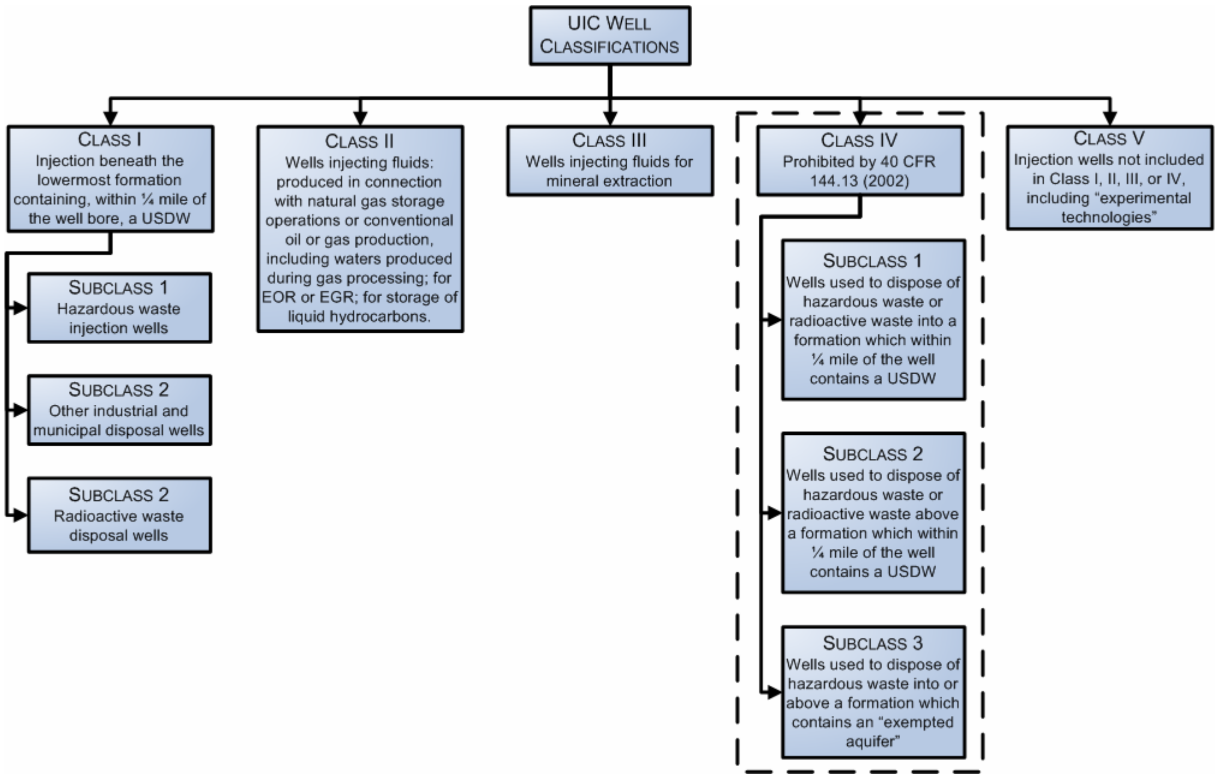


Figure A1. UIC program well classifications as outlined in 40 CFR 144.6

The EPA has recently issued guidance that directs the regional EPA administrators or state UIC directors to classify pilot CO_2 sequestration projects in saline aquifers as Class V wells.[73] Enhanced oil recovery (EOR) and enhanced gas recovery (EGR) projects will still be categorized as Class II projects according the EPA guidance. In this context, pilot projects are "the limited number of experimental projects anticipated to be brought online in advance of commercial-scale operations over the next several years." However, these pilot projects will likely be subject to different permitting rules should they become commercial projects in the future.

2. Required regulatory structure for EOR and deep geological sequestration

Currently, the most advanced effort to develop regulations for carbon dioxide sequestration is the CO_2ReMoVe (the acronym stand for research, monitoring, verification) project in the European Union.[b] This is a public-private partnership to establish a regulatory

[b] The project website, http://www.co2remove.eu/, states: "CO_2ReMoVe is a consortium of industrial, research and service organizations with experience in CO_2 geological storage. The consortium proposes a range of monitoring techniques, applied over an integrated portfolio of storage sites, which will develop: 1) Methods for base-line site evaluation 2) New tools to monitor storage and possible well and surface leakage 3) New tools to predict and model long term storage behaviour and risks 4) A rigorous risk assessment methodology for a variety of sites and time-scales 5) Guidelines for best practice for the industry, policy makers and regulators This will encourage widespread application of CO_2 geological storage in Europe and neighbouring countries."

framework for monitoring and verifying stored CO_2. It is also exploring acceptance of liability issues.

Australia is beginning to investigate the regulatory framework for CO_2 sequestration.

Texas has passed legislation providing a very limited liability for sequestered carbon dioxide from the FutureGen project, if sited in Texas.

The use of CO_2 for enhanced oil recovery is covered by the existing U.S. regulatory framework. However, commercial sequestration of CO_2 in deep geological formations appears to require a significant change in the existing regulatory environment. The reason is that commercial-scale projects may be expressly excluded from the experimental (UIC Class V) pilot project definition. Regulatory uncertainty at the state level exists in many states.

In the short term, an effective strategy may be to work with the federal and state agencies, including the EPA, to allow a limited number of 4 Mt/year-scale commercial geologic sequestration projects to be permitted as Class V experimental wells.

For continued commercial-scale sequestration, a robust regulatory framework is required. Early commercial-scale projects must be studied and their experience incorporated in the regulatory framework that will govern ongoing sequestration.

The fact that there may soon be global emissions trading markets means that regulatory approaches adopted for managing deep geological sequestration require some degree of international coordination. The life cycle of a geologic sequestration project involves four separate stages as illustrated in figure A2: pre-injection site characterization and permitting; site operation; post-closure operations by the site operator; and, long term stewardship. If large scale geologic sequestration deployment is to proceed, the competing needs and interests of local, national and international publics, project developers, financial and insurance institutions supporting the project, government agencies setting safety requirements, and national and international agencies that set and manage CO_2 trading rules, must be appropriately balanced.[74] The goal should be to create a regulatory regime that encourages responsible CCS deployment, meets the needs of a larger climate framework managing local environmental health and safety and ensures that projects are successfully managed.

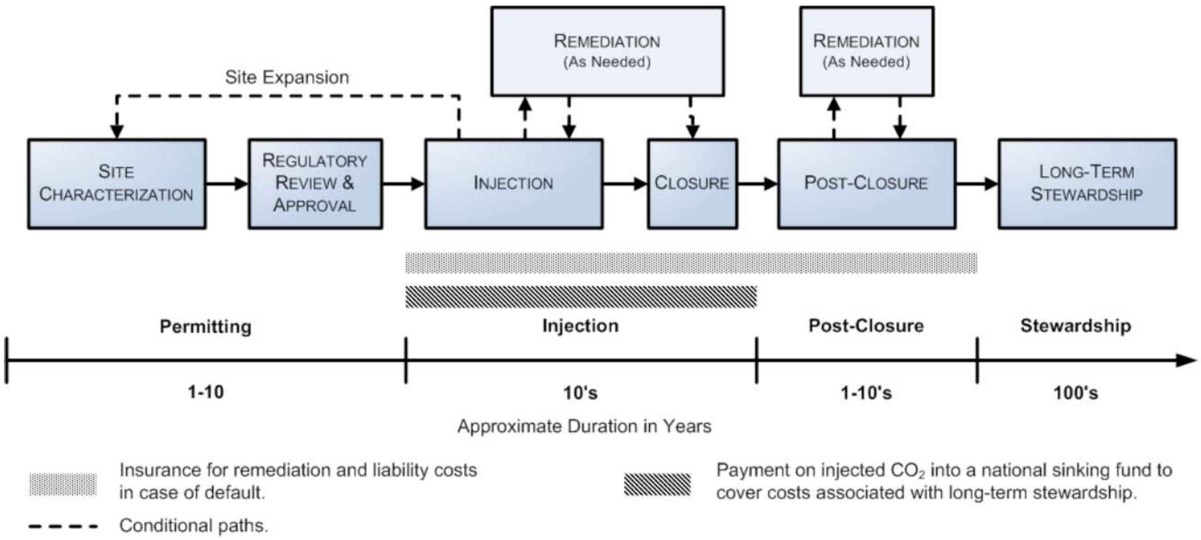


Figure A2. The life-cycle of a geological sequestration project for CO2 will involve four phases. In addition to the operator of a site and the financial and insurance organizations that support the project, two different government entities have a role. In order to avoid potential conflicts of interest, the regulatory organization responsible for reviewing and approving the creation of a site, monitoring its operation, and certifying its satisfactory closure should be separate from the government entity that ultimately assumes responsibility for long-term stewardship.

The geology of subsurface reservoirs that are suitable for geologic sequestration will often be complex and information on subsurface CO_2 flow available only once injection has begun. The issue of rights to use saline aquifers for storage is still an open issue. Even with more advanced tools for site characterization and monitoring there will be inevitable surprises. This means that whatever regulatory framework is ultimately developed to manage geologic sequestration, from time to time there will be surprises. It will not be possible to lay out all the details for a project up front and follow them through to completion without monitoring corroborating operational performance and model predictions.

There is a clear need for regulatory approaches that are adaptive, while not compromising basic objectives of safety and climate policy. Adaptive regulation must balance predictability with flexibility, a difficult challenge for regulatory bureaucracies that in the past have not been notable for their flexibility and inventiveness. Regulatory agencies, operators, and financial communities all require predictability, yet this must be balanced with accountability for both climate and environmental health and safety demands.

3. Regulatory structure for CO_2 pipelines

The network of CO_2 pipelines in the U.S. today serves the EOR industry, with a smaller component serving the beverage and chemical industries. Existing regulations are designed for the relatively small current volumes (roughly 50 Mt per year). Some of the larger existing CO_2 pipelines are:

- The Cortez 30" diameter pipeline is currently shipping about 20 million metric tons annually over a distance of 502 miles.

- The Dakota Gasification 14"/12" pipeline is shipping 3 million metric tons annually over a distance of 205 miles.

- The Bravo Dome 20" diameter pipeline handles about 7 million metric tons annually over a distance of 218 miles.

- The Sheep Mountain pipeline consists of two sections: a 184 mile long 20" diameter section handling about 6 million metric tons annually and a 224 mile long 24" diameter section handling about 9 million metric tons annually.

Compression takes place at the site of the CO_2 capture. Once the CO_2 is in the pipeline, pipeline pressure is maintained with pumps. The pumps require a very small fraction of the energy required to compress the CO_2. For instance, Dakota Gasification requires a total of 58,800 HP to compress the CO_2 at the plant from 10 psi to around 2500 psi. Once in the pipeline, only one pump station of about 450 HP is required to maintain line pressure over the 205 miles and deliver the CO_2 at a pressure of 2175 psi.

The pipelines normally have valve stations every 20 miles that include automated pressure monitors with automatic shut down controls. Each valve station and pump station is connected to a central control room via microwave Supervisory Control And Data Acquisition (SCADA) monitoring and control system. This type of system is standard fro the industry and has operated successfully for many years.

These pipeline systems are already regulated and have demonstrated their ability to safely transport CO_2.

It is likely that small additions to the existing infrastructure will be regulated similarly.

However, very large additions to the nation's CO_2 pipeline infrastructure will be necessary to support the required scale of sequestration in the future.

If 80% of CO_2 from the existing stock of U.S. coal and natural gas fired electric generators were captured and sequestered, the total sequestered would be 2100 Mt per year of CO_2. If one assumes (quite optimistically) that half of that can be injected locally under the power plants, the total pipeline load of CO_2 would be 1000 Mt.

The U.S. natural gas use (23 TCF at the peak) represents 500 Mt, so the required CO_2 pipeline mass is twice the mass that is moved in pipelines today for natural gas; it could be 4 times as large without local sequestration. At operational conditions, a CO_2 pipeline caries about 3 times more mass per unit length of pipeline than does a natural gas pipeline, so the size of the pipeline infrastructure that will be required for carbon dioxide transport may be as large as that of the current U.S. natural gas pipeline infrastructure.

The above assumes no increase in the amount of coal power. However, demand will be increase by 40% by 2025 if it grows linearly at the rate it has for the past 30 years. Growth could be much higher if plug-in electric or hybrid vehicles achieve significant market share. So, the required CO_2 mass moved by pipeline within 20 years might be 5-6 times larger than the current mass of natural gas moved by pipeline, and the size of the infrastructure could be twice that for natural gas.

Experience with CO_2 pipelines at scales above 10 Mt per year in the very near term is urgently required to acquire experience in the regulatory and technical arenas. Potential questions include FERC oversight (and definitional issues including whether CO_2 is a commodity and pipelines are common carriers), leakage performance, and characterization of parasitic CO_2 emissions from compressor and pump station operation.

Appendix B: Conversion Factors and Energy Ratings

CONVERSION FACTORS

1 metric ton [long ton, tonne] = 1000 kg = 1.10231 short tons = 2204.6 pounds

1 short ton = 0.9072 metric tonnes

1 MCF of CO_2 = 1000 cubic feet = 115.97 pounds of CO_2 (gaseous phase at 14.697 psia, 60°F)
= 0.0526 metric tonnes = 0.0580 short tons

1 metric tonne of CO_2 = 19.01 MCF

1 cubic meter = 35.3147 cubic feet

1 barrel [bbl] of oil = 42 gallons = 159 liters

1 Btu [British Thermal Unit] = 1.055 kilojoules [kJ] = 252 calories [cal]

1 cal = 0.003967 Btu = 4.184 J

1 quad [quadrillion Btu] = 10^{15} Btu

1 joule = 947.9×10^{-21} quadrillion Btu

1 gigajoule [GJ] = 10^{9} joules

1 exajoule = 10^{18} joules = 0.9479 quadrillion Btu

1 quadrillion Btu = 1.0551 exajoule

1 Btu/lb = 0.556 kCal/kg

ENERGY RATINGS

1 toe [tonne of oil equivalent] = 41.868 GJ = 39.683 million Btu

1 tce [tonne of coal equivalent] = 29.3076 GJ = 27.778 million Btu

“Coal equivalent” coal = 7000 kCal/kg

High rank coal = 7000 kCal/kg

Low rank coal = 3500 kCal/kg

Lignite = 2700 kCal/kg

1 ton lignite = 0.3 to 0.63 tce (average 0.38)

1 ton Sub-bituminous = 0.78 tce

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[53] H.R. 6.
[54] H.R. 6111.
[55] H.R. 4520.
[56] 26 U.S.C. §45(c)(7)(A)(i).
[57] 26 U.S.C. §45(c)(7)(A)(iii) & §45(c)(7)(B).
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[59] Internal Revenue Service Form 8835, "Renewable Electricity Production Credit." p.2.
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[61] U.S. Energy Information Administration Electric Power Annual 2006 (with data from 2005).
[62] See http://www.fossil.energy.gov/sequestration/partnerships/index.html
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[64] Indiana House Enrolled Act, Bill No. 1722, Section 9.
[65] "Substitute natural gas" means pipeline quality gas produced by a facility that uses a gasification process to convert coal into a gas capable of being used by a utility to supply end use consumers with gas utility service, or as a fuel used to produce electric power to supply electric utility service.

[66] Indiana House Enrolled Act, Bill No. 1722, Section 9.
[67] Indiana House Enrolled Act, Bill No. 1722, Section 9.
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