

Potential for Coal-to-Liquids Conversion in the United States—Fischer–Tropsch Synthesis

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The United States has the world's largest coal reserves and Montana the highest potential for mega-mine development. Consequently, a large-scale effort to convert coal to liquids (CTL) has been proposed to create a major source of domestic transportation fuels from coal, and some prominent Montanans want to be at the center of that effort. We calculate that the energy efficiency of the best existing Fischer–Tropsch (FT) process applied to average coal in Montana is less than 1/2 of the corresponding efficiency of an average crude oil refining process. The resulting CO₂ emissions are 20 times (2000%) higher for CTL than for conventional petroleum products. One barrel of the FT fuel requires roughly 800 kg of coal and 800 kg of water. The minimum energy cost of subsurface CO₂ sequestration would be at least 40% of the FT fuel energy, essentially halving energy efficiency of the process. We argue therefore that CTL conversion is not the most valuable use for the coal, nor will it ever be, as long as it is economical to use natural gas for electric power generation. This finding results from the low efficiency inherent in FT synthesis, and is independent of the monumental FT plant construction costs, mine construction costs, acute lack of water, and the associated environmental impacts for Montana.

KEY WORDS: Efficiency, emissions, CO₂ sequestration, natural gas, electricity, renewables.

INTRODUCTION

In this paper we focus on Montana, because of her very large coal reserves discussed in Croft and Patzek (2009), and current designs on this coal. The CBS *60 minutes* reported on February 26, 2006:

America's dependence on foreign oil – President Bush called it “an addiction” in his State of the Union address – has become a threat to the country's economy and security. The governor of Montana, Brian Schweitzer, says there's something we can have up and running in the next five years. What he has in mind is using the coal, billions of tons of it,

under the high plains of his home state. The governor tells correspondent Lesley Stahl he wants to use an existing process to turn that coal into a synthetic liquid fuel, or synfuel. The plan is controversial, but Gov. Schweitzer – half Renaissance man, half rodeo cowboy – seems ready for the challenge. In fact, he sounds like he's ready to take on the world. “Why wouldn't we create an economic engine that will take us into the next century, and let those sheiks and dictators and rats and crooks from all over the world boil in their own oil?” Schweitzer said at a press conference.

Here, we give a brief background of Fischer–Tropsch (FT) synthesis of liquid fuels. We analyze the energy efficiency of FT with average subbituminous coal from Montana as feedstock. We calculate the minimum emissions of CO₂ from the FT process, and compare them with the corresponding emissions from a conventional crude oil refinery. We then calculate the minimum energy costs of

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subsurface CO₂ sequestration for a FT plant in Montana. Finally, we compare the respective uses of coal and natural gas in electricity generation and automobile transportation, and arrive at the main conclusions of this paper.

FISCHER-TROPSCH SYNTHESIS OF LIQUID FUELS

History

In 1925, Professor Franz Fischer, founding director of the Kaiser-Wilhelm Institute of Coal Research in Mülheim an der Ruhr, and his head of department, Dr. Hans Tropsch, see Figure 1, applied for a patent describing a process to produce liquid hydrocarbons from carbon monoxide gas and hydrogen using metal catalysts. The hydrocarbons synthesized in the process consisted primarily of liquid alkanes, also known as paraffins. Other by-products were alkenes (olefins), alcohols and solid paraffins (waxes). The required gas mixture of carbon monoxide and hydrogen was created through a reaction of coke or coal with steam and oxygen, at temperatures over 900°C. The raw product of the FT hydrocarbon synthesis is a liquid mixture similar to a waxy crude oil. This mixture is further refined to yield gasoline and diesel fuel, among others.

By the beginning of the 1940s, some 600,000 tons of liquid hydrocarbons were produced per year in German facilities, made from coal using FT synthesis. Licensed by Ruhrchemie, four facilities in Japan, as well as a plant in France and in Manchuria,

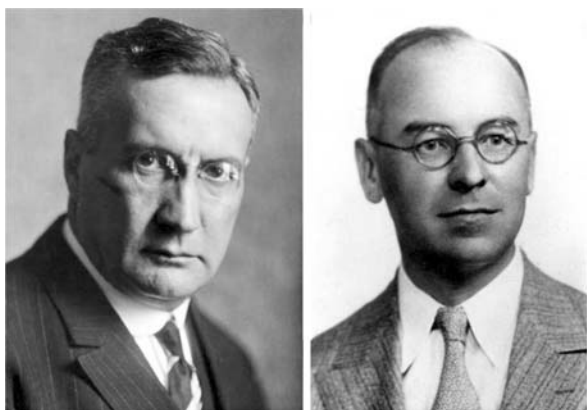


Figure 1. Professor Franz Fischer (left) and Dr. Hans Tropsch, the inventors of a process to create liquid hydrocarbons from carbon monoxide gas and hydrogen using metal catalysts. Image: Max Planck Institute of Coal Research.

were in service. In 1944, Germany's annual synthetic fuel production reached more than 124,000 barrels per day from 25 plants, or ~6.5 million tons of fuel (Agrawal and others, 2007). Almost all of this production was used to run the Nazi war machine. The results are well known.⁴

After 1950, the only new FT production facilities were built for political reasons in South Africa⁵ in the town of Sasolburg. Currently, the two plants operated by SASOL Synfuels provide about 25% of South Africa's diesel and gasoline needs, processing 45 million tons of coal per year.⁶

Profligate coal production and use in South Africa give rise to a number of serious environmental problems (Whyte, 1995). Vast stretches of land are affected by strip mining, coal discards and mines. A large amount of waste is created through beneficiation to improve coal quality. These discards have a high sulfur content (1–7.8%) and high ash values (24–63%), so the waste material is almost unmarketable and stockpiles grow at a rate of 40 to 50 million tons per year. The burning of these coal dumps contributes to acid precipitation in the Eastern Transvaal Highveld.

The SASOL plants are reported to have even greater environmental impacts than coal power stations of the same size (Whyte, 1995). Aside from producing acid rain, they are voracious water users (five barrels of water per barrel of FT oil⁷) and produce a variety of toxic petrochemical wastes. Since the commissioning of its facilities at Secunda, SASOL has spent some 600 million rands⁸ on environmental projects, including the recovery and reuse of waste streams, the development and testing of low-smoke fuels, research on industrial water use and reuse, and the toxicity and biodegradability of its products.

Currently, only a handful of other companies have commercialized their FT technology. For example, Shell in Bintulu, Malaysia, uses natural gas

⁴ After the war, captured German scientists continued to work on synthetic fuels in the United States in a U.S. Bureau of Mines program initiated by the Synthetic Liquid Fuels Act.

⁵ Seventy six percent of South Africa's primary energy comes from coal, making it the most coal-dependent country on the Earth. China and Poland are ranked as # 2 and 3 in their reliance on coal, at 70 and 60%, respectively. The United States uses coal to satisfy roughly 1/4 of its primary energy needs.

⁶ Eight million tons more than Montana's annual coal production.

⁷ Chapter 6 in Whyte (1995).

⁸ In July 1995, 3.6 South African rand = 1 US dollar.



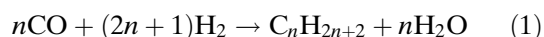
Figure 2. A B-52 Stratofortress takes off from Runway 22 during a FT test flight from Edwards Air Force Base, California, on Sept. 19, 2006. During the flight, two of the aircraft's eight engines ran on the natural gas-based FT fuel blend. The bombers are from the 5th Bomb Wing at Minot Air Force Base, N.D. (U.S. Air Force photo/Chad Bellay).

as a feedstock, and produces primarily low-sulfur diesel fuel and wax.

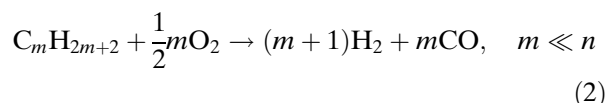
Recently, a U.S.-based company Syntroleum produced a whopping⁹ 9500 barrels of diesel and jet fuel from the FT process at its demonstration plant near Tulsa, Oklahoma. Using natural gas as a feedstock, the synthetic FT fuel has been tested by the U.S. Department of Energy, the Department of Transportation, and most recently, the Department of Defense, which utilized the fuel in a flight test of a B-52 bomber at Edwards Air Force Base, CA, see Figure 2.

The FT Process

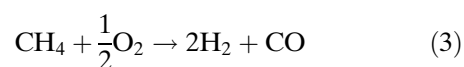
The original FT process is described by the following chemical equation with $n = 1, 2, \dots$,



The reactants in the reaction above, CO and H₂, are called the *synthesis gas* or *syngas*. They can be produced by other reactions such as the partial combustion of a hydrocarbon:



For example, when $m = 1$, methane in the gas-to-liquids applications reacts as follows:



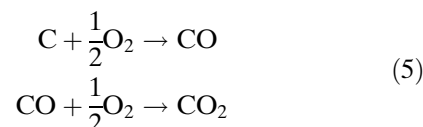
⁹ This small practical joke on the U.S. taxpayers is consistent with the unrealistic and non-physical attitude toward biofuels and synthetic fuels.

Alternatively, coal may be gasified in the water-shift reaction:



Note that compared with coal gasification, methane gasification uses 1/2 as much oxygen for the same amount of hydrogen.

The energy needed for the endothermic reaction of coal and steam is usually provided by exothermic combustion with air or oxygen. This leads to the following reactions:



Direct conversion of fossil fuels to hydrogen and carbon monoxide causes more CO₂ and other greenhouse gas emissions than burning of the same fuels outright. For example, burning coal, $\text{C} + \text{O}_2 \rightarrow \text{CO}_2$ produces 35 MJ/kgC of heat. Coal gasification, $\text{C} + \text{H}_2\text{O} \rightarrow \text{CO} + \text{H}_2$, consumes 10 MJ/kgC of heat. This heat consumption is equivalent to the burning of up to extra 1/2 kg of raw coal per kilogram of gasified coal (Bobrownicki, Justat, and Pawlikowski, 1965).

Synthesis gas is generated at temperatures in excess of 900°C, and processed at the pressure of about 60 bars and temperature of 250°C over a suitable catalyst that may contain cobalt, nickel or ruthenium, in addition to iron.

EFFICIENCY OF COAL-BASED FT PROCESS IN THE POWDER RIVER BASIN

According to Shell, Table 1 in Eilers, Posthuma, and Sie (1990), the theoretical efficiency of the coal-based FT synthesis of liquid fuels is 60%. TU Delft calculates energy efficiency of the FT process of about 55% (Hamelinck, 2004). Practically, a 50% energy efficiency of coal conversion to liquid fuels seems to be an upper limit. For example, the calculation in Steynberg and Nel (2004) yields 41.1% as the overall conversion efficiency of CTL fuels.¹⁰ Also, according to Shell the cost of a coal-based FT plant is twice that using natural gas (Eilers, Posthuma, and Sie, 1990), making the CTL process prohibitively expensive.

¹⁰ Counting all hydrocarbon products, liquid and gaseous and a small amount of extra electricity. Because we are not including the energy costs of coal mining and transport, we omit this electricity in the energy balance.

Table 1. Production of Coal-Based FT Fuel in Montana

FT fuel out, BPD ^a	22,000	150,000	300,000	1,000,000
Montana coal in, Mt/year ^b	6.3	43	86	286
Ratio ^c	0.15	1.0	2.1	6.8
Water in, billion gal/year	2	11 ^d	23	77 ^e
CO ₂ out, Mt/year ^b	12	80	160	533 ^f
Ash out, Mt/year ^b	0.4	2.8	5.5	18
SO ₂ out, Mt/year ^b	0.06	0.4	0.8	2.7
Capital investment ^g , \$ billion	1.2–4	7.2–24		48–160

^aBPD = barrels of fuel per day

^b1 Mt = 1 million metric tons per year

^cRatio of plant input of coal to all coal mined in Montana in 2006

^d1/3 of all water currently used for mining in Montana

^eAs much as all personal and commercial water use in Montana

^fEight percent of current U.S. CO₂ emissions of 6 billion tons per year in 2005. Source: EIA, <ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057305.pdf>

^gAnonymous (2005), Table 2 and the footnotes therein

The product of FT synthesis is not diesel fuel but rather a high-wax crude oil similar to Indonesian Minas or Altamont-Bluebell (Utah). Other products are natural gas, LP gas and electricity from waste heat. The efficiencies quoted above include all of the hydrocarbon outputs and, in the SASOL estimates, the electricity as well.

For efficiency comparison, we use Sheehan and other's (1998) estimate of primary energy spent on refining crude oil delivered to the refinery gate and processed to diesel fuel. This energy input is 12% of the calorific value of the diesel fuel product. In other words, converting petroleum to diesel fuel is 88% energy-efficient.

The low-rank western coals, such as those in Montana, usually¹¹ have a moisture content of 25–55%, sulfur content of 0.5–1.5%, and heating value of 5500–9000 Btu/lb. Table 1 in Croft and Patzek (2009) shows the assumed Montana coal composition as received at the FT plant gate.

The higher heating value of the FT fuel is 45.9 MJ/kg (Castorph, Kollera, and Waas, 1999). Therefore,

$$\frac{45.9}{19.1 \times 0.411} = 5.85 \text{ kg of Montana coal/kg of FT fuel} \quad (6)$$

¹¹ Advanced coal conversion process demonstration. Progress report, January 1, 1992–March 31, 1992. Source: www.osti.gov/bridge/product.biblio.jsp?osti_id=106461. Accessed May 12, 2007.

is used to produce 1 kg of fuel. Since one barrel of the FT fuel weighs ~134 kg, 784 kg of coal is used to produce one barrel of this fuel.

The SASOL FT process currently uses 5 barrels (795 kg) of water per barrel of the FT fuel produced (Whyte, 1995), and this ratio is assumed in the current analysis.

CO₂ Emissions

Assuming that 60% of Montana coal is carbon, see Table 1 in Croft and Patzek (2009), and that the typical FT fuel composition is C₁₂H₂₆, one may calculate that CO₂ produced in the FT liquid fuel plant is

$$(1 - 0.14 - 0.25 - 0.01) \times \left(784 - 134 \times \frac{144}{144 + 26} \right) \times \frac{44}{12} \approx 1460 \text{ kg of CO}_2/\text{bbl of FT fuel} \quad (7)$$

This calculation is consistent with the EIA's estimate¹² of 213.4 lbm CO₂ per 1 million Btu in Montana's subbituminous coals that translates into ~1200 kg of CO₂ per barrel of FT fuel.

In spite of the huge variety of chemical compounds they contain, all crude oils have carbon contents between 83 and 87 wt.% (Speight, 1990). The CO₂ emissions from crude oil are therefore constant across a wide variety of sources (Hiete and Berner, 2001):

$$\text{CO}_2 \text{ emissions} = \frac{44}{12} (0.84 \pm 0.03) \frac{\text{kg CO}_2}{\text{kg crude oil}} \quad (8)$$

Since about 0.12 bbl of oil with the density of 840 kg m⁻³ is burned to produce 1 barrel of diesel fuel, the CO₂ emissions are

$$44/12 \times 0.84 \times 0.12 \times 42 \times 3.785/0.84 \approx 70 \frac{\text{kg CO}_2}{\text{bbl of diesel fuel}} \quad (9)$$

Therefore, CO₂ emissions from the production of coal-based FT fuel are approximately 1400/70 = 20 times higher than those from the production of petroleum-based diesel fuel.

¹² Hong and Slatick (2005, Table FE4). Average Carbon Dioxide Emission Factors for Coal by Rank and State of Origin.

Scale-up of CTL Plants

With the assumptions above one may calculate the amounts of coal and water necessary to produce various quantities of FT fuels, as well as the respective amounts of waste streams. The results are listed in Table 1. Note that the single-plant capacity of 150,000 BPD is more than the total 124,000 BPD capacity of the 25 plants operated by Nazi Germany to supply its military.

It appears that even the smallest plant producing 22,000 BPD of FT fuel would use 20% of the current coal production in Montana and impose significant environmental stresses on the state. The three larger plant designs extend into the realm of surrealism. For example, the 300,000 BPD plant, sufficient to supply most of the U.S. military needs, would consume twice the current coal production in Montana, thrice the current water use by Montana mines, and each year would produce 145 million tons of CO₂, 1.7 million tons of SO₂ and 11 million tons of ash. If Montanans wish to destroy their beautiful state, then large FT plants offer an almost certain fulfillment of this wish. For instance, the coal ash pond that ruptured and sent a billion gallons of toxic¹³ sludge across 300 acres of East Tennessee in December 2008 was only one of more than 1300 similar dumps across the United States, see Figure 3—most of them unregulated and unmonitored—that contain billions more gallons of fly ash and other byproducts of burning coal.¹⁴

CO₂ SEQUESTRATION

To calculate the decrease of energy efficiency of the coal-based FT process as a result of CO₂ sequestration, we make the following assumptions:

1. For efficiency, and to concentrate CO₂ in effluent gases, pure oxygen is used in coal combustion.
2. Because the hot compressed process gases are used for electricity cogeneration, the work of



Figure 3. A coal ash slurry dump near the Kingston Fossil Plant in Harriman, Tennessee. Coal ash is composed primarily of oxides of silicon, aluminum, iron, calcium, magnesium, titanium, sodium, potassium, arsenic, mercury, and sulfur plus small quantities of uranium and thorium. Some of the uranium is U235, a fissile radioactive material together with thorium. Fly ash is primarily composed of non-combustible silicon compounds (glass) melted during combustion. Tiny glass spheres form the bulk of the fly ash. Stored coal ash slurries eventually threaten water supplies, human health, and local ecosystems. Photo: Wade Payne/Greenpeace, via Associated Press.

compressing CO₂ to the necessary injection pressure is external to the FT process.

3. Pressure losses in a pipeline from the plant to the aquifer are neglected.

As a reference, we use 1 barrel of FT fuel that contains 6.2 GJ of primary energy.

Work of Oxygen Separation

Because exhaust from combustion of coal with excess air contains only 10–14% of carbon dioxide by volume (the rest is nitrogen, unused oxygen, etc.), the cost of separating this dilute carbon dioxide would be prohibitive. Therefore, pure oxygen (>99% by volume) must be used to combust coal if one wants to capture and sequester CO₂.

The production of 1 barrel of FT fuel requires $1300 \times 32/44 = 945$ kg of O₂; $26/170 \times 134 \times 32/2/2 = 164$ kg of oxygen is produced from steam, but the remaining 780 kg of oxygen must be separated from air. The 1300 kg of CO₂ generated per barrel of FT fuel is a mean of the two estimates in the section “Efficiency of coal-based FT process in the powder river basin”.

The minimum work of reversible separation (“unmixing”) of air into oxygen and nitrogen at

¹³ United States Environmental Protection Agency (EPA). March 15, 1999. *Technical Background Document for the Report to Congress on Removing Wastes from Fossil Fuel Combustion: Waste Characterization*, www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ffc2_399.pdf.

¹⁴ *Hundreds of Coal Ash Dumps Lack Regulation*, Shaila Dewan, NYT, 01/06/09.

Table 2. Energy Requirements for Oxygen Production

Method	kWh t ^{-1a}	MJ kg ^{-1b}
Cryogenic separation, 50% O ₂	400	1.4
Cryogenic separation, > 99% O ₂	1100 ^c	4.0
Pressure swing adsorption, 90% O ₂	550	2.0
Perm-selective membrane, 37.5% O ₂	210	0.8
Perm-selective membrane, 44% O ₂	300	1.1
Cryogenic Air Separation Unit ^d , ??% ^e O ₂	235	0.85

^aElectricity required to produce equivalent pure O₂, Table 2 in (Bisio, Bosio, and Rubatto, 2002)

^bExergy required to produce 1 kg of equivalent pure O₂

^cLiquid oxygen. Heat recovery from boiling off liquid gases lowers this energy cost by a factor of 2–2.5

^dGray literature presentation by Mr. Stiegel of NETL (Stiegel, 2006), p. 11, quoting Air Products and Chemicals, Inc.

^eOxygen concentration was not listed

ambient conditions is, for example (Gyftopoulos and Beretta, 2005):

$$W_1 \approx RT_0[y_{O_2} \ln(y_{O_2}) + y_{N_2} \ln(y_{N_2})] \\ = 1.27 \text{ MJ kmol}^{-1} \text{ air} = 0.19 \text{ MJ kg}^{-1} \text{ O}_2 \quad (10)$$

where $R = 8.314 \text{ J K}^{-1} \text{ mol}^{-1}$ is the universal gas constant, $T_0 = 298 \text{ K}$ is the ambient temperature, $y_{O_2} = 0.21$ is the mole fraction of oxygen in ambient air, and $y_{N_2} \approx 0.79$ is the mole fraction of nitrogen (and other gases).

The actual work of oxygen separation is about 4–20 times larger, depending on whether the final oxygen product is pure and/or liquid or gaseous, see Table 2. We choose the efficient cryogenic process with heat recovery¹⁵: $1.44 \times 780 = 1123 \text{ MJ/bbl FT fuel}$ or 1.1 GJ/bbl . As one can see, just the oxygen separation for the entire process costs $1.1/6.2 \times 100 = 18\%$ of the FT fuel energy. This energy is generated with steam turbines and has been included¹⁶ in the energy analysis of the SASOL FT process in Steynberg and Nel (2004). Of course, the shaft work of a rotating turbine could be converted to electricity with an almost 100% efficiency, so roughly 1/5 of the FT fuel energy could be electricity, not oxygen.

Work of CO₂ Compression

We assume that the CO₂ from the FT process ends up at ambient conditions after extracting all

¹⁵ 400 kWh_e per ton of O₂. The “best” reported energy use of 235 kWh_e per ton of O₂, see Table 2, has not been verified yet. SASOL uses cryogenic separation.

¹⁶ Dr. André Steynberg, private communication, May 18, 2007.

energy from the process gases to generate electricity. Therefore, this CO₂ must be compressed to a pressure allowing it to be injected. Suppose that the injection target, a sandstone rock formation filled with saline water and capable of storing the injected CO₂ indefinitely is initially at hydrostatic pressure and is pressured up to 0.8 of the overburden pressure.¹⁷ The initial aquifer pressure might be 88 bars and this pressure might increase quickly to 144 bars. Suppose that the average injection pressure is 120 bars.

The actual CO₂ compression from 1 bar to 120 bars may be achieved as a 4-stage compression with 3 inter-coolers (at 15°C) and compressor adiabatic efficiency decreasing from 85% (low pressure) to 75% (high pressure) (Bolland and Undrum, 1998). The work of CO₂ compression is then about 0.415 MJ/kg or 0.54 GJ/bbl of FT fuel. Because this work is almost certainly delivered by electrical motors, the primary energy consumption is $0.54/0.36 = 1.5 \text{ GJ thermal/bbl FT fuel}$, or $1.5/6.2 \times 100 = 24\%$ of the fuel energy.

Work of CO₂ Injection

The geothermal gradient in Montana is about 2°F per 100 feet of depth.¹⁸ Therefore, the CO₂ temperature in the aquifer at 1000 m is 40°C or 313 K and its density¹⁹ about 820 kg m⁻³. We assume that the temperature of the compressed CO₂ approximately matches the aquifer temperature with no extra work of compression.

On the other hand, if the CO₂ were to be injected into deeper, lower Cretaceous or upper Paleozoic aquifers, its temperature would be reaching 70–100°C very quickly and the CO₂ density would decrease to 200 kg m⁻³. This would mean increasing the volume of injection 4-fold, while compressing the CO₂ to substantially higher pressures.

¹⁷ *Overburden* or *lithostatic* pressure is the weight per unit area of all rock above the top of the aquifer. Once injection pressure reaches or exceeds the overburden pressure, the injected CO₂ may fracture and lift the rock above the aquifer and will leak creating mortal danger to all life on land surface above the leak.

¹⁸ Ground Water Atlas of the U.S.—Montana, North Dakota, South Dakota, Wyoming HA 730 – I, USGS, capp.water.usgs.gov/gwa/ch_i/I-text3.html.

¹⁹ See *Supercritical Fluid* in Wikipedia.

Table 3. Compression Power and Aquifer Areas to Dispose of FT CO₂

FT Fuel, BPD	Compression, MW thermal	Volume ^a , 1000 m ³ year ⁻¹	Area, ha year ⁻¹	Cum area ^b , ha
22000	1	498	5	100
150000	10	3397	34	679
300000	20	6794	68	1359
1000000	66	22648	226	4530

^aAt aquifer conditions^bAssuming a 20-year duration of CO₂ disposal

The volume of CO₂ at our aquifer conditions would be $1300/820 = 1.6 \text{ m}^3$ per barrel of FT fuel. Assuming a 20% porosity and 35% irreducible water saturation, the bulk aquifer rock volume would be $1.6/0.2/0.35 = 23 \text{ m}^3 \text{ bbl}^{-1}$.

If the average aquifer thickness filled with the injected CO₂ were 10 m (33 ft), the aquifer areas necessary to store one year's production of the FT CO₂ would range from 5 to 226 ha, see Table 3. Assuming a 20-year duration of the disposal, a pipeline infrastructure and wells would have to be build over several square kilometers. If the CO₂ disposal were significantly deeper, our current estimates may have to be multiplied by a factor of up to 4.

Energy Impact of CO₂ Sequestration

Provided that there are shallow aquifers large enough to hold the injected CO₂, and this is far from certain, some $18 + 24 \approx 40\%$ of the fuel energy will be diverted to CO₂ sequestration. In deep aquifers this energy estimate may grow by a factor of up to 4.

OTHER USES OF COAL

Electric power generation is the dominant use of coal in the United States, accounting for 92.3% of U.S. coal usage in 2006. Other industrial use accounted for 5.3% and coke accounted for only 2.1% of U.S. coal consumption in 2006. For the purpose of this study, electric power generation is considered to be the alternate use for the marginal ton of coal.

The most efficient coal-fired electric power plants use pulverized coal and superheat the steam in order to increase the Carnot efficiency. These plants can have efficiencies as high as 39%, although typical values are 35–38% of low heating value.

Further improvements to efficiency can be obtained by using Integrated Gasification Combined Cycle (IGCC) plants. Depending on the design, these plants could have efficiencies as high as 52% of low heating value (Johnston, 2006). Natural gas-fired combined cycle plants can be converted to coal-fired IGCC plants in some cases with the addition of a gasification unit and only minor changes on the turbines (Gutierrez and Geller, 2006). In spite of the high efficiency of IGCC plants, only a few have been built due to their greater cost relative to conventional steam plants. One such plant that has an operating history is the Wabash River plant in Indiana. From completion in 1995 through 1999, that plant produced 3.91 million megawatt hours of power from 1.55 million tons of coal with a typical high heating value of 10536 btu per pound (Anonymous, 2000), which works out to an efficiency of 40.8% of the high heating value.

COAL AND NATURAL GAS

One can burn coal or natural gas to generate electricity, hot water, and greenhouse gases. One can also convert coal to a liquid fuel or compress natural gas, and power automobiles with either fuel. In both situations coal and natural gas compete against one another. The question is then, which one of the two sets of alternatives is better?

Fuel Competition in Electric Power Generation

Natural gas competes with coal as an electric power generation fuel. Natural gas-fired power plants come in two kinds: peak plants that can be turned on or off quickly, and more efficient combined-cycle plants. Combined cycle plants compete directly with coal-fired plants because both are for baseload generation. The efficiency of actual natural gas-fired combined cycle power plants is about 48.5% of low heating value, as reported by Siemens for their SCC6-5000F Flex-Plant 10 (Mcmanus, Boyce, and Baumgartner, 2007).

Residual fuel oil is also used for electric power generation, but this is mostly a historical artifact, and very little oil-fired capacity is planned for the 2007–2011 timeframe. Figure 4 shows planned electric power generation capacity increases in the United States during the 2007–2011 period, broken down by type of fuel. These planned increases

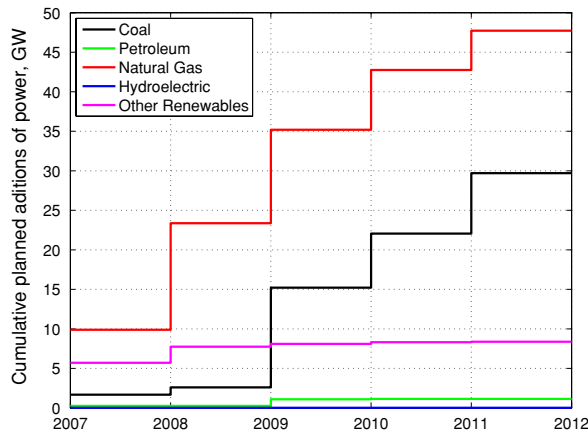


Figure 4. Cumulative planned additions of nameplate electrical generation capacity in the United States, 2007–2011. Petroleum abbreviates distillate fuel oil (all diesel and No. 1, No. 2, and No. 4 fuel oils), residual fuel oil (No. 5 and No. 6 fuel oils and bunker C fuel oil), jet fuel, kerosene, petroleum coke (converted to liquid petroleum), and waste oil. Natural gas abbreviates natural gas, blast furnace gas, propane gas, and other manufactured and waste gases derived from fossil fuels. Other renewables are wood, black liquor, other wood waste, municipal solid waste, landfill gas, sludge waste, agriculture byproducts, other biomass, geothermal, solar thermal, photovoltaic energy, and wind. Data source: Form EIA-860, *Annual Electric Generator Report*.

amount to eighty seven 1000 MW electrical power plants, or one large power plant somewhere in the United States each 17 days for 4 years. In three years from January 2009, the additional primary energy required to run these plants would be 8 EJ/year. If all of this energy were delivered by Powder River coal, an additional production of 400 million tons/year of the coal would be needed; double the current coal production in the Powder River Basin. Of course, such a production increase is impossible in view of Croft and Patzek (2009). And what about the separate plans for CTL? Thus, Figure 4 highlights the acute lack of comprehension of the astronomical energy quantities involved in satisfying the perceived growth of electricity and transportation fuel demand in the United States. Note that natural gas-fired plants account for more than half of all capacity additions over that time period, 1/3 more than coal. The use of oil for new electricity generation is insignificant.

An open question is the extent to which other power generation technologies can displace coal from that market, freeing extra supply. Electricity from wind turbines, when its penetration is significant enough, will create an intermittent stochastic part of electricity supply to the grid. These

side-effects of wind turbines can be remedied only by more gas turbine-powered peak electricity generation and by a distributed system of batteries. Either technology will prevent grid power failures, but batteries are a more distant futuristic solution. In other words, wind turbines will require first an increase and then a slow decline of gas production in the United States. The achievement of this goal will be no small task for the nation (Patzek, 2008). Coal will continue to be used for the baseload electricity generation, and its use will continue to be constant or grow with the increases of the baseload. Therefore, wind turbines and photovoltaics are unlikely to decrease the demand for coal for electricity generation in the next decade or two.

Coal is not the only baseload power technology; nuclear, geothermal and combined-cycle natural gas plants are also suitable for baseload generation. Nuclear power accounted for 20.6% of U.S. electricity generation in 2007, as compared to 48.5% for coal and 0.35% for geothermal (Anonymous, 2009b). Since fission of uranium, thorium, etc., competes directly with coal, there is clearly a possibility that increased nuclear power generation could displace a significant amount of coal. It must be emphasized, however, that massive buildup of nuclear power would be a radical departure from the status quo. Geothermal power is expected to grow substantially, but the power plants must be collocated with the geothermal resources. The most recent estimates of geothermal resources from the U.S. Geological Survey give a most likely potential of 9000 MW from known geothermal systems and an additional 33000 MW of exploration potential (Williams and others, 2008). Most of the medium-term potential is in California, Nevada, Hawaii, Oregon, Idaho and Alaska. These six states accounted for only 0.78% of U.S. coal consumption for power generation in 2007 (Anonymous, 2009a). Therefore, geothermal energy has limited potential to back out coal consumption. The relative economics of coal and natural gas as sources of vehicle fuel versus sources of electricity is discussed next.

CTL Versus CNG for Transportation Fuel

Coal can be converted to liquid transportation fuels, and natural gas can be compressed and used as a transportation fuel. These processes can be thought of as arbitrage between the markets for electric power generation and transportation fuels.

Besides the financial cost of such conversion, there is also an energy cost. The energy cost alone dooms FT conversion of coal to liquid hydrocarbons to be uneconomical, regardless of potential reductions in the large capital cost of CTL plants. This is true as long as it is economical to build natural gas-fired baseload and peak electric power plants.

The work required to compress 1 mole of natural gas adiabatically at 20°C to the $P_1 = 20$ MPa pressure used for CNG vehicles from an initial pressure of $P_0 = 0.3$ MPa is:

$$\left(\frac{\gamma}{\gamma-1}\right)RT_0\left(\left(\frac{P_1}{P_0}\right)^{\frac{\gamma-1}{\gamma}}-1\right) = 16.2 \text{ kJ mol}^{-1} \quad (11)$$

For methane, $\gamma = 1.31$. This work is small; it is only 1.8% of the 891 kJ/mol liberated from burning the methane. It could be as small as 1.7 kJ/mol if one is starting from the $P_0 = 1.5$ –10 MPa pressures used in interstate natural gas pipelines. In practice, compressors are not perfect and some CNG stations will need a high degree of compression while others will be located along high-pressure pipelines. Allowing for these variations, an average gas compression efficiency of 98% is, if anything, conservative.

Let us assume a coal-fired power plant efficiency of 35%, a gas compression efficiency of 98%, and a natural gas-fired power plant efficiency of 48.5%. If gas and coal compete in power generation, the FT synthesis would have to have a conversion efficiency of $(0.98) \times (0.35/0.485) = 71\%$, almost twice its actual efficiency, in order to produce a competitively priced transportation fuel. This calculation neglects all environmental costs of CTL.

Coal Prices

Coal prices are more sensitive to location than oil prices. Figure 5 shows recent coal prices in the United States. Markets with access to ports saw dramatic price increases in 2008, but Wyoming did not. This suggests that Wyoming coal production is limited by transportation out of the area because otherwise competition between buyers would drive prices up to world levels. This is another reason that the Powder River Basin would be the most attractive area in the United States for FT plants, but it is likely that the coal transportation problem would be remedied during the life of the plant, so economics over the longer term depends on the differences between world coal prices and world oil prices.

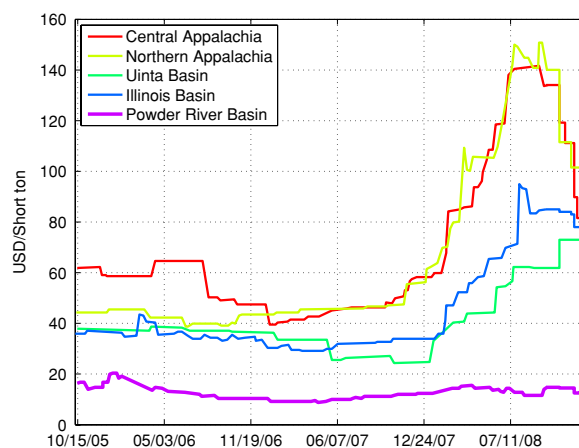


Figure 5. United States historical coal prices. Data source: EIA.

These recent coal price increases are a result of major changes in Pacific Basin coal markets. China, formerly a major exporter, has become a major importer, and Vietnam is no longer approving coal export permits. The export price in the Australian port of Newcastle exceed USD 190 per metric ton in July 2008. Prices at this level render FT synthesis uneconomical. This observation raises the question of whether improved transportation of coal out of the Powder River Basin might add more value to Montana's coal than a larger investment in FT plants.

CONCLUSIONS

The following are the main conclusions of this paper:

1. The large volumes of coal required for CTL suggest that the Powder River Basin of Wyoming and Montana is likely to be the coal source.
2. Although U.S. coal reserves are large, recent coal price increases suggest that there is no global coal surplus in the short term.
3. The Powder River coal, cheapest in the United States, would inevitably double or triple in price if there were a high-throughput railroad connection to the Pacific or Atlantic coast.
4. The energy efficiency of an optimal coal-based FT process that produces liquid fuels is 41% (Steynberg and Nel, 2004). This means that for every 1 unit of fuel energy out, one needs to put 2.4 units of coal energy in.
5. Because of the different energy contents of subbituminous coal and FT fuel, and a low

energy efficiency of CTL conversion, roughly 800 kg of the average Powder River Basin coal will be needed to produce 1 barrel of the FT fuel.

6. Per unit energy in a liquid transportation fuel, carbon dioxide emissions from a CT plant are about 20 times higher than those from a petroleum refinery.
7. Subsurface disposal of carbon dioxide produced by the FT plants costs at least 40% of the thermal energy in FT fuel. If this disposal were deeper than assumed here, the current estimate might increase by a factor of up to 4.
8. Montana does not have the approximately 800 kg of clean water necessary to produce each barrel of FT fuel.
9. Natural gas can be compressed and used for transportation fuel with an efficiency of 98%. Therefore, the FT transportation fuel from coal is *always* uneconomic as long as natural gas competes with coal for power generation. This is true even if the gas-fired plants are more efficient combined cycle designs and the coal plants are conventional.
10. Judging by the recent financing of corn ethanol refineries, the astronomical construction costs of coal-based FT plants might be borne by the U.S. taxpayers through a new subsidy program.
11. The massive societal costs of the subsidies required to render CTL “economical,” and the environmental costs of fuel production would be borne by all Americans and the planet at large, but especially by the people of Montana and the surrounding states, including Canada.

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