TOPIC PAPER #18

COAL TO LIQUIDS AND GAS

On July 18, 2007, The National Petroleum Council (NPC) in approving its report, *Facing the Hard Truths about Energy,* also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the Task Groups and their Subgroups. These Topic Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached Topic Paper is one of 38 such working document used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix E of the final NPC report provides a complete list of the 38 Topic Papers and an abstract for each. The printed final report volume contains a CD that includes pdf files of all papers. These papers also can be viewed and downloaded from the report section of the NPC website (www.npc.org).

NATIONAL PETROLEUM COUNCIL

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Coal To Liquids

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I. Executive Summary

The various reports used to surmise the production outlook for coal to petroleum products differ in production range and all seem to be missing discussions on many significant fundamental variables required to develop a sound economic decision. Variables such as labor, equipment, product transportation, environmental risk, and feedstock issues were discussed only briefly, if that. Though the reports represent significant analysis showing the large untapped resources of coal, the discussion of actually making the coal available seemed to not be fully investigated in areas such as labor issues and the price impact of greater demand.

The focus of this report is to present the issues associated with and the potential of coal to liquids (CTL) and coal to gas (CTG) technologies. CTL and CTG offer an opportunity for the USA to reduce its petroleum import needs by producing petroleum products, such as diesel and gasoline, from domestic coal resources. Most reports have focused on CTL due to the cost and transportation issues associated with CTG. The other important outcome from this report is to view and understand the inputs and assumptions from various publications and the range of production estimates from CTG and CTL technology. The examination of the publications demonstrates a large uncertainty for CTL, due to various assumptions from petroleum price to technological abilities. The quality of coal and the technological ability of converting the coal varied between each study. As mentioned, key assumptions are left unexamined, such as product transportation, labor, equipment availability, and environmental risk.

Overall, the published CTL production estimates are small in the total global petroleum market perspective; even in the most optimistic scenario the volume from CTL amount to only 20% of the U.S. petroleum market in the Southern States Energy Board (SSEB) report[1]. The National Coal Council (NCC) saw a 10% market share,[2] whereas the various Energy Information Administration (EIA) scenarios saw 0% to 6% of the U.S market share, respectively.[3] The NCC and SSEB both mentioned the added benefit of using the CO_2 for enhanced oil recovery (EOR); however, the increased oil volumes directly associated with using CO_2 from CTL is left unmentioned. This study reviews each of these reports and covers them in depth. This report begins by introducing the process, giving a detailed technological understanding, and then outlining each issue with each report from coal availability to oil price assumptions.

Even though the production estimates are small relative to the overall petroleum market, the incremental gains from this technology, added to other gains from other technology areas, such as oil shale, could have a significant impact on U.S. energy cost and foreign dependency. The use of coal allows the added benefit of relying on a resource that is domestically more plentiful than petroleum, but this reliance must be carefully balanced with the economics of developing the resource, since CTL facilities can cost more than $1 billion per 10,000 days of production, which implicates the competitiveness of the U.S. economy within the global economy.

A. Members:

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[1] *American Energy Security Building a Bridge to Energy Independence and to a Sustainable Energy Future* by The Southern States Energy Board: Norcross, Georgia. July 2006 (http://www.americanenergysecurity.org/studyrelease.html)
[2] *Coal: America's Energy Future* by The National Coal Council. March 2006 (http://nationalcoalcouncil.org/report/NCCReportVol1.pdf)
[3] "Annual Energy Outlook 2006 with Projections to 2030 by the Energy Information Administration." February 2006 (http://www.eia.doe.gov/oiaf/archive/aeo06/index.html)

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II. General Description

A. Overview

In addition to direct combustion to produce heat and power, coal can be used as a feedstock for the production of liquid and gaseous fuels. The primary routes for converting coal to liquid products are *direct* and *indirect liquefaction*.

The hydrogen content of coal relative to other carbonaceous fuels is shown below (Figure IIA.1):[4]

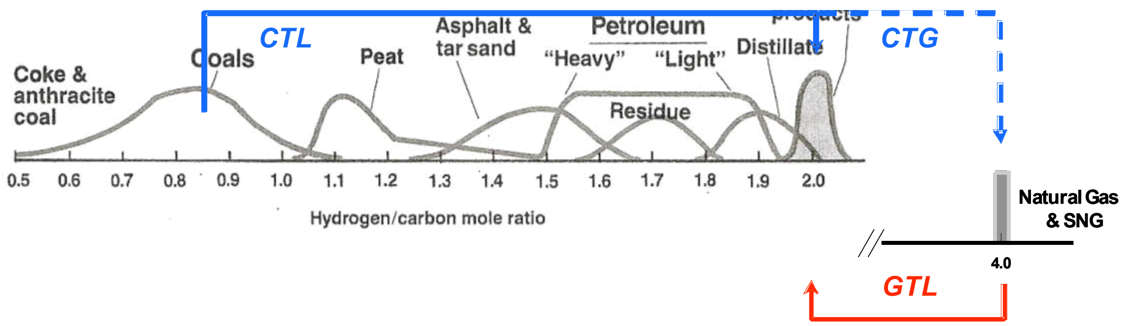

Figure IIA.1. Hydrogen content of coal relative to other carbonaceous fuels.

Coals, and particularly anthracite, have extremely low hydrogen-to-carbon ratios. The addition of hydrogen to coal results in the transformation of a carbon-rich solid to a liquid fuel with a hydrogen-to-carbon ratio close to 2:1. Methane, which is a gaseous hydrocarbon, has a ratio of 4:1. To make liquid fuels from coal (CTL), it is necessary to add hydrogen or reject carbon, but to make liquid fuels from natural gas (GTL, gas to liquids), it is necessary to reject hydrogen or add carbon. Coal can also be used to make SNG (substitute natural gas) by adding more hydrogen or rejecting more carbon (CTG).

[4] Marano JJ: Adapted from presentation, "Overview of Coal-To-Liquids," Pittsburgh, PA, April 4, 2006.

Direct Liquefaction (DL) is similar to hydrocracking processes used in petroleum refining to convert heavy oils into gasoline and diesel fuel. This route is depicted in Figure IIA.2.

Figure IIA.2. Diagram of *direct liquefaction.*

Direct liquefaction typically utilizes two reactor stages. The first stage is primarily a thermal process in which the coal structure is broken down. High hydrogen pressure is required to stabilize the coal fragments so they do not re-polymerize to "coal" again. Coal mineral matter plays a catalytic role in this process. The second stage is similar to hydrocracking. The direct liquids must be further upgraded to produce liquid fuels. The hydrogen required can be produced within the liquefaction facility by means of coal gasification and the water-gas shift reaction (see description in the *Indirect Liquefaction* section below). Alternatively, the hydrogen can be supplied by the conversion of some other feedstock. The thermal efficiency for direct liquefaction is about 55% (HHV basis, see Figure IIA.3).[5]

Indirect Liquefaction (IL) is a multi-step process for the production of liquid fuels. Coal gasification is the first step in indirect liquefaction. Gasification converts coal or other carbonaceous materials from solid to gas through partial oxidation of the carbon in the solid feed. For fuels production, the oxidant is supplied as high-purity oxygen (derived from cryogenic air separation) and steam. The intermediate product produced by gasification is referred to as syngas. It is a gaseous mixture containing hydrogen (H_2), carbon monoxide (CO), along with varying amounts of water and steam (H_2O), carbon dioxide (CO_2), and other compounds containing the impurities present in the coal. The undesirable components, such as sulfur and nitrogen-

[5] Bechtel/AMOCO, "Direct Liquefaction Baseline Design and System Analysis," DOE Contract No. DEAC22 90PC89857.

containing compounds and fly ash or slag, may be removed from the syngas using established gas clean-up processes.

It is important to define the efficiency terms *higher heating value* (HHV) and *lower heating value* (LHV). HHV assumes H_2O is in liquid state and the value contains the energy of vaporization. LHV assumes a gas state for all combustion products. The efficiencies of coal-fired power systems are most often reported in HHV in the USA, much of the rest of the world uses LHV. The efficiencies of natural gas-fired power systems are most often reported in LHV. The difference can be estimated using

$$1{,}055 \text{ Btu/lbm} * w$$

where w is the weight of water after combustion per pound of fuel. To convert the HHV of natural gas, which is 23,875 Btu/lbm, to an LHV (methane is 25% hydrogen) would be:

$$23{,}875 - (1{,}055*0.25*18/2) = 21{,}500.$$

Because the efficiency is determined by dividing the energy output by the input, and the input on an LHV basis is smaller than the HHV basis, the overall efficiency on an LHV basis is higher.

Using the ratio: 23,875/21,500 = 1.11, one can convert the HHV to an LHV. So an HHV range of 50–54% translates to 56–60% LHV.

Figure IIA.3. Definition of low heating value (LHV) and high heating value (HHV) efficiency.

The chemical reaction mechanism for gasification is quite complex. The overall conversion can be depicted in Figure IIA.4.

$$\text{Coal (C,H,O,...)} \xrightarrow{\text{+ Oxygen/Steam}} \underbrace{H_2 + CO + CO_2 + H_2O + \ldots}_{\text{Syngas}}$$

Figure IIA.4. Overall conversion for gasification.

The molecules H_2 and CO are building blocks, which can be used to synthesize a wide variety of complex hydrocarbons and organic compounds. The gas produced from gasification and purification is then shifted to produce a gas, referred to as a synthesis gas, or syngas, with a ratio of H_2 to CO consistent with the end-use product of interest. The water-gas-shift reaction is shown in Figure IIA.5.

$$CO + H_2O \rightleftharpoons H_2 + CO_2$$

Figure IIA.5. Water-gas shift reaction.

The water-gas-shift reaction both rejects carbon (by converting CO to CO_2) and adds H_2 (by converting H_2O to H_2).

The potential products that can be derived from syngas are many and can add to or replace the petroleum or chemical markets, some of which are listed in Figure IIA.6:

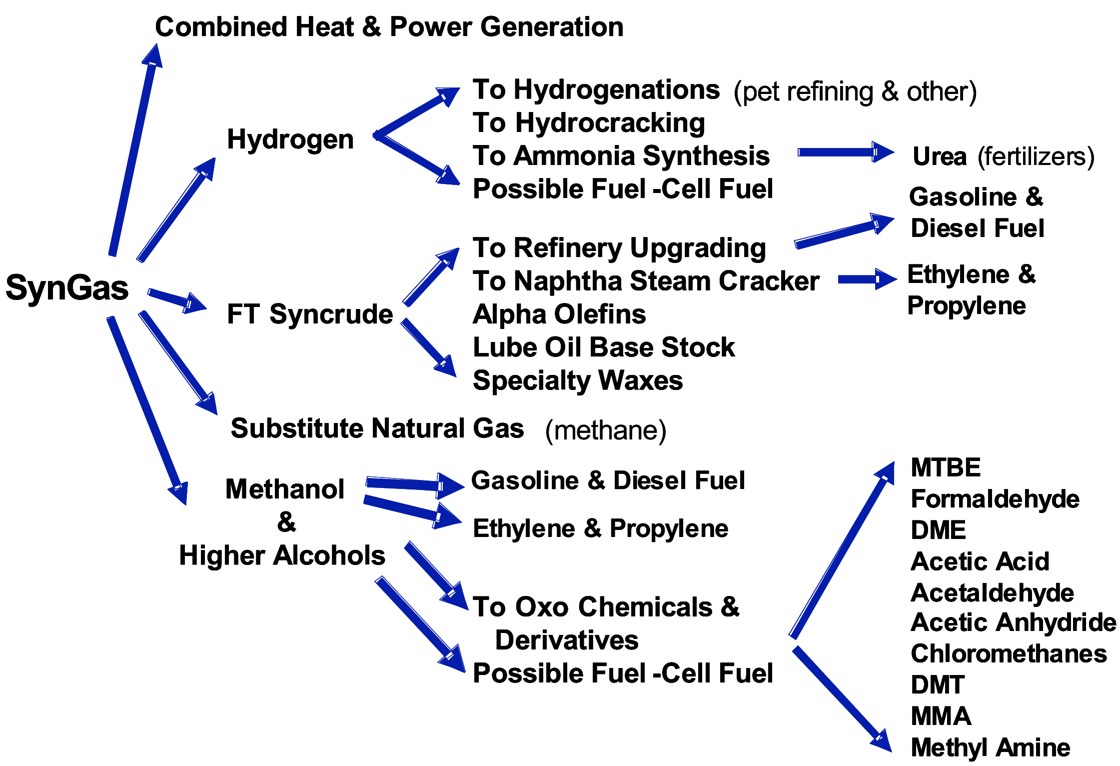

Figure IIA.6. Potential products that can be derived from syngas.

Of particular interest in the manufacturing of transportation fuels is *hydrogen,* which can be produced from coal-derived synthesis by maximizing hydrogen production from the water-gas-shift reaction. Carbon dioxide, CO_2, produced by the shift reaction is then separated from the syngas to produce high-purity hydrogen. The petroleum refining industry is the largest user of hydrogen, primarily used in hydroprocessing, which includes hydrogenation, hydrodesulfurization, hydro-denitrogenation of fuels, and the hydrocracking of heavy oils. Hydrogen might be used some day to fuel cars powered by fuel cells rather than internal-combustion engines. Efficiencies for hydrogen production from coal range from 54 to 60% (HHV basis).[6]

SNG (substitute natural gas) is high-purity methane (CH_4) that is produced from the methanation of synthesis gas (Figure IIA.7).

$$\text{Synthesis Gas} \xrightarrow{\text{Ni Catalyst}} \text{Methane} + H_2O$$

Figure IIA.7. Reaction from sythesis gas to methane using nickel catalyst.

SNG is fungible with natural gas and can be shipped in existing pipelines and used for heating, power generation, or other industrial applications such as hydrogen production. Dakota Gasification Company produces about 170 million scf/d of SNG from North Dakota lignite. The efficiency for SNG production from coal is about 60% (HHV basis).[7]

Methanol (CH_3OH) is produced from synthesis gas via the following reaction:

$$\text{Synthesis Gas} \xrightarrow{\text{Cu Catalyst}} \text{Methanol} + H_2O$$

Figure IIA.8. Reaction from sythesis gas to methane using copper catalyst.

Commercially, most methanol is produced from natural gas using gas-phase, fixed-bed reactor technology. However, Air Products & Chemicals, Inc., with the support of the DOE, has developed a liquid-phase methanol synthesis, which has been commercially demonstrated by Tennessee Eastman Corp., Kingsport, Tennessee, in a

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[6] Wimer J: *Characteristics of Hydrogen Production Systems Based on Oxygen-Blown, Coal Gasification* - A Synopsis of Recent Technical Literature, DOE NETL Systems Analysis, 2004.
[7] Gray D, Salerno S, and Tomlinson G: "Potential Application of Coal-Derived Fuel Gases for the Glass Industry – A Scoping Analysis," DOE Contract No. DE-AM26-99FT40465, Dec. 2004.

plant using coal-derived synthesis gas. The thermal efficiency for methanol production from coal is about 54% (HHV basis).

Methanol is the starting point for the synthesis of a wide range of industrial chemicals. Methanol can also be used as an alternative fuel in both gasoline and diesel engines that have been properly modified. However, it may be more convenient to convert methanol to a synthetic gasoline or diesel that can be used neat or in blends with petroleum-based fuels in unmodified engines. ExxonMobil has demonstrated the methanol to gasoline (MTG) and methanol to diesel (MTD) processes for producing synthetic fuels from methanol.

Dimethyl-Ether (DME, CH_3OCH_3) is produced commercially by the dehydration of methanol. DME has been proposed as a clean-burning alternative to diesel fuel and there has been significant interest in this diesel substitute in Japan and other parts of Asia. However, DME is a gas at ambient conditions and must be pressurized to be used in modified diesel engines. Air Products has also developed a liquid-phase synthesis that oligomerizes DME to produce a clean-burning oxygenated liquid fuel, which can be used as a neat or blended diesel fuel in unmodified engines; however, this alternative fuel is still at an early stage of development and testing.

Liquid Hydrocarbons can be produced from syngas via the Fischer-Tropsch (F-T) synthesis over either an iron or cobalt-based catalyst:

$$\text{Synthesis Gas} \xrightarrow{\text{Fe or Co Catalyst}} \text{Hydrocarbons} + H_2O \text{ or } CO_2$$

Figure IIA.9. Reaction from sythesis gas to hydrocarbons using iron or cobalt catalyst.

The total liquid hydrocarbon product represents a synthetic substitute for crude oil. Over a cobalt catalyst, the product is primarily straight-chain paraffins, whereas with iron, paraffins, alpha olefins, and primary alcohols are produced. F-T diesel has a very high cetane number and is exceptionally clean burning. Raw F-T naphtha has a very low octane number and requires substantial upgrading to produce a gasoline of acceptable quality. Other uses for the naphtha are available, such as a feed for steam cracking to produce ethylene and propylene and for the production of solvents. The heavier compounds formed by the F-T synthesis form a solid wax at ambient conditions. This wax is of extremely high quality and can be sold as a specialty product, or can be cracked to produce additional F-T diesel. High-quality lube oils and jet fuels can also be produced from F-T liquids. The thermal efficiency for hydrocarbons production from coal is about 50% (HHV basis).

B. History

Both direct and indirect liquefaction have a long history of development, dating from the early 20th century. Both technologies were used by Germany to produce fuels prior to and during World War II (direct liquefaction more extensively). Indirect liquefaction was the basis for South Africa's transportation fuels industry from the 1950s to the end of the apartheid era and remains competitive.

Direct Liquefaction: From the 1970s through the early 1990s, the U.S. DOE conducted research and development activities related to direct liquefaction. Activities in the United States included the construction and operation of two large pilot plants, both of which received support from DOE.[8] Plans to construct large demonstration plants based on direct coal liquefaction were cancelled during the 1980s, in response to concerns regarding technical risks, increasing estimates of investment costs, and decreasing world oil prices. Additionally, fuels generated by direct liquefaction are rich in high-octane aromatics. Current clean-fuel specifications in the U.S. limit the benzene and aromatics content and toxicity of gasoline. Additionally, the low quality of direct diesel has become a shortcoming for direct liquefaction. By the mid-1990s, interest in direct liquefaction in the USA all but disappeared, as interest in indirect liquefaction gradually increased due to the very low sulfur content and very high cetane of F-T diesel.

Indirect Liquefaction: The technical viability of indirect coal liquefaction has been clearly established. In the early 1980s, South Africa's Sasol Company expanded

[8] The Exxon Donor Solvent process was tested in a pilot plant located in Baytown, Texas, and the H-Coal process was tested in a pilot plant located in Catlettsburg, Kentucky.

its 1950s production base by building two large indirect coal liquefaction facilities. Currently, these two Sasol facilities produce a combined total of about 150,000 barrels per day of fuels and chemicals using coal as the primary feedstock. The 1950s vintage Sasol facility has been converted from coal to stranded natural gas imported from Mozambique because it could not be economically retrofitted with sulfur control technology. This plant is currently producing about 5,000 barrels per day of waxes and chemicals.

In January 2003, under the Clean Coal Power Initiative, DOE selected a cost-shared, \$600M coal-to-power and diesel indirect-liquefaction demonstration project (with DOE contributing \$100M). To date, however, the project has been unable to obtain financing for the private sector cost share. CTL technology is continually being improved and, since the building of the large Sasol plants, there have been significant advances in both coal gasification technologies that produce the synthesis gas and in F-T processes that produce the clean fuels.

For F-T synthesis, the commercialization of the slurry-phase reactor is an important development. However, worldwide, no commercial CTL plants have been built that combine and integrate these advanced technologies. China, with an increasingly large appetite for liquid fuels, scarcity of domestic petroleum, and large coal resources, is moving towards commercialization of CTL technologies.

Table IIB.1 lists announced CTL projects under consideration and Table IIB.2 lists CTL pilot plants in the United States. Table IIB.3 lists international CTL plants and projects under development.

In the 1970s, concerns over a potential shortage of natural gas fostered considerable interest in the production of SNG from coal. A number of large-scale demonstration projects were planned. Of these projects, only one was ever built, in Beulah, North Dakota. The increased availability of North American natural gas in the 1980s and 1990s ended interest in large-scale production of SNG from coal. However, small-scale SNG production from LPG and naphtha has found a niche market in Japan and elsewhere. These systems provide back-up fuel for natural-gas-based power generation. Recently, Indiana Gasification LLC has announced plans to construct a 40 billion cubic feet per year SNG plant in southwest Indiana. This is about 15% smaller than the Beulah plant. Plans call for construction to begin in 2008 with startup in 2011.[9]

State	Developers	Coal Type	Capacity (bpd)	Status
AZ	Hopi Tribe, Headwaters	Bituminous	10,000–50,000	Planning
MT	State of Montana	Sub-bituminous/lignite	10,000–150,000	Planning
ND	GRE, NACC, Falkirk, Headwaters	Lignite	10,000–50,000	Planning
OH	Rentech, Baard Energy	Bituminous	2 plants, 35,000 each	Planning
WY	DKRW Energy	Bituminous	33,000	Planning
WY	Rentech	Sub-bituminous	10,000–50,000	Planning
IL	Rentech*	Bituminous	2,000	Engineering
IL	American Clean Coal Fuels	Bituminous	25,000	Planning
PA	WMPI	Anthracite	5000	Planning
WV	Mingo County	Bituminous	10,000	Planning
MS	Rentech	Coal/petcoke	10,000	Planning
LA	Synfuel Inc.	Lignite	Not available	Planning

* Will also co-produce fertilizer.

Table IIB.1. Coal-to-liquids plants being considered in the United States.[10]

State	Owner	Capacity	Status
Colorado	Rentech	10–15 barrels per day	Operational in 2007
New Jersey	Headwaters Incorporated	Up to 30 barrels per day	Operational
Oklahoma	Syntroleum	70 barrels per day	Shutdown: 9/06
Oklahoma	ConocoPhillips	300–400 barrels per day	Shutdown

Table IIB.2. CTL pilot plants in the United States.

Dakota Gasification Company's Beulah plant still produces about 170 million scf/d of SNG from lignite. In 2000, the plant began exporting carbon dioxide for use in enhanced oil recovery (EOR). Currently, about 95 million scf/d of CO_2 produced at the plant is transported via a 205 mile long pipeline to EnCana Corporation's

[9] See www.gasification.org/Docs/News/2006/IN%20Gasification.pdf.
[10] National Coal Council Report, *Coal: America's Energy Future* Volume I, March 2006. http://www.rentechinc.com/pdfs/05-23-05-Baard.pdf

Weyburn oil field in southern Saskatchewan. The CO_2 is used for tertiary oil recovery, resulting in 5,000 bbl/d of incremental oil production or an additional 130 to 140 million barrels of oil over the life of the project. The Weyburn field is the subject of a long-term monitoring program to assess the final deposition of the CO_2 being injected in this project.

Country	Owner/Developer	Capacity (bpd)	Status
South Africa	Sasol	150,000	Operational
China	Shenhua	20,000 (initially)	Construction – Operational in 2007
China	Lu'an Group	~3000 to 4000	Construction
China	Yankuang	40,000 (initially) 180,000 planned	Construction
China	Sasol JV (2 studies)	80,000 (each plant)	Planning
China	Shell/Shenhua	70,000 – 80,000	Planning
China	Headwaters/UK Race Investment	Two 700-bpd demo plants	Planning
Indonesia	Pertamina/Accelon	~76,000	Construction
Australia	Anglo American/Shell	60,000	Planning
Philippines	Headwaters	50,000	Planning
New Zealand	L&M Group	50,000	Planning

Table IIB.3. International CTL plants and projects.

The increased demand for natural gas has resulted in higher gas prices and more gas imports, a trend that is anticipated to continue. Therefore, the economics of SNG production may again be attractive, particularly if produced from low-cost feedstock and co-producing high-value by-products such as electricity. Recently, a number of demonstration projects have been announced, including a DOE-sponsored project with Arizona Public Services (APS). The goal of this project is to demonstrate the production of SNG from coal for utilization in existing natural-gas-fired power plants.

III. Detailed Description

A. CTL Process Configurations

Direct Liquefaction: A typical block flow diagram for direct liquefaction is shown in Figure IIIA.1.

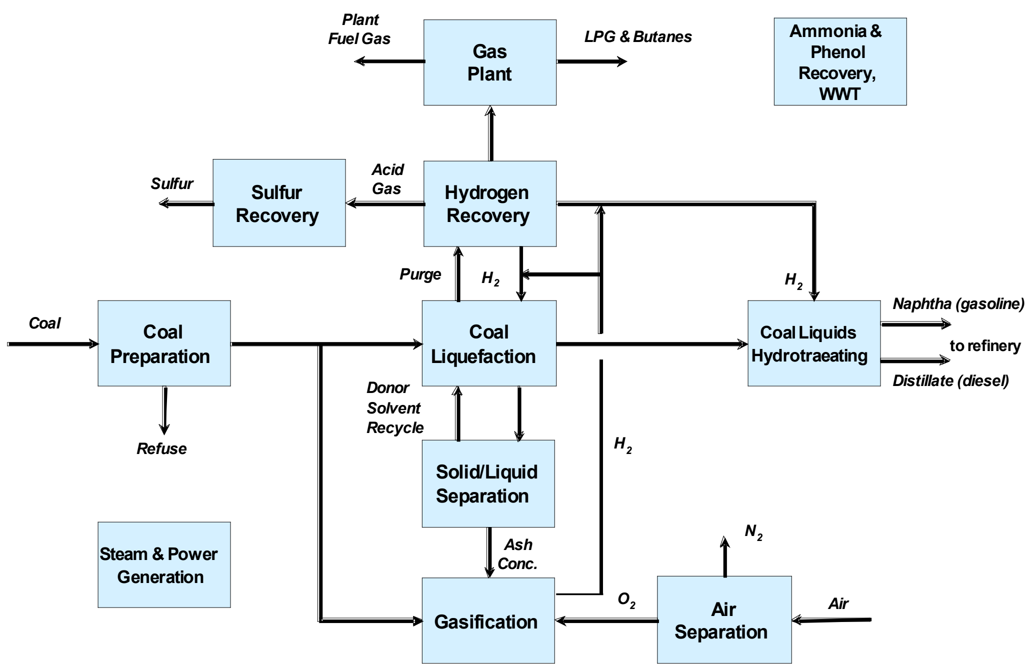

Figure IIIA.1. Process block flow diagram for direct liquefaction.

The main components of this plant are:

Coal Liquefaction – This section of the plant includes coal cleaning and preparation (ash removal), grinding and drying, coal liquefaction, solid and liquid extraction, and hydrogen recycle. The cleaned coal is dried, ground, and fed to the liquefaction reactors at a high temperature (750–800^{o}F) and pressure (3,200 psig). These severe conditions promote the cracking of the coal matrix to produce liquid and gaseous hydrocarbons. Typically, a two-stage ebulating-bed reactor system is employed with both feed and intermediate addition of hydrogen. The heaviest fraction of the liquid product containing the solid mineral matter from the coal is separated from the naphtha and distillate products and sent to a liquid-solid separation unit. This unit extracts the liquid from the solid using a super-critical solvent. The heavy extract liquid is then recycled to the liquefaction reactors for conversion to lighter products. The extract also serves as a hydrogen donor solvent helping shuttle hydrogen from the gas phase to the solid coal within the liquefaction reactors. Gases vented directly from the liquefaction reactors and from liquefaction product fractionation are sent to hydrogen and hydrocarbon-gas recovery. Recovered hydrogen is recycled back to the liquefaction reactors or sent to product upgrading. The gas plant recovers mixed butanes and propane, which are sold as products, and produces fuel gas (methane and ethane), which are used for process heating and on-site power generation.

Hydrogen Production – Hydrogen is produced by the gasification of some of the coal feed and the extract ash, which still contains some residual carbon. This plant also includes syngas clean-up, water-gas shift, and hydrogen purification to produce high-purity hydrogen that is fed to the liquefaction reactors. An air separation plant is also required to produce oxygen for gasification. Alternatively, natural gas may be used to produce hydrogen using steam methane reforming or partial oxidation. The price and availability of natural gas at a given site determines the best option for hydrogen generation.

Product Upgrading – Direct liquids typically are not of high-enough quality to be fed directly to a petroleum refinery. Therefore, naphtha and distillate hydrotreaters are included to upgrade this material to acceptable quality. Sulfur, nitrogen, and oxygen impurities in the raw coal liquids are removed in these processes and compounds such as olefins and aromatics are saturated and partially cracked.

Offsites – Major offsite plants shown in the block flow diagram include: a sulfur plant, ammonia recovery, phenol recovery, and wastewater treatment. Not shown are the tankage, product shipping, coal-ash disposal, steam and power systems, and raw and cooling water systems.

Indirect Liquefaction: A typical block flow diagram for an indirect liquefaction plant employing Fischer-Tropsch synthesis to produce liquid fuels is shown in Figure IIIA.2. The main components of this plant are:

Syngas Production – This section of the plant includes coal handling, drying and grinding, followed by gasification. An air separation unit provides oxygen to the gasifier. Syngas cleanup includes hydrolysis, cooling, sour-water stripping, acid gas removal, and sulfur recovery. The gas is cleaned of sulfur compounds and other unwanted components to extremely low levels, to protect the downstream catalysts. Heat removed in the gas-cooling step is recovered as steam, which is used internally to supply plant power requirements. Sour-water stripping removes ammonia produced from any nitrogen in the coal. Sulfur in the coal is converted to hydrogen sulfide (H_2S) and carbonyl sulfide (COS). Hydrolysis is used to convert COS in the syngas to H_2S, which is recovered in the acid-gas removal step and converted to elemental sulfur in a Claus sulfur plant. The sulfur produced is typically sold as a low-value by-product.

Synthesis Gas Conversion – This section of the plant includes water-gas shift, a sulfur guard bed, synthesis-gas conversion reactors, CO_2 removal, dehydration and compression, hydrocarbon and hydrogen recovery, autothermal reforming, and syngas recycle. A sulfur guard bed is required to protect the synthesis gas conversion catalyst, which is easily poisoned by trace sulfur in the cleaned syngas.

The clean synthesis gas is shifted to have the desired hydrogen/carbon monoxide ratio, and then catalytically converted to liquid fuel. This can be accomplished by one of several routes. The two primary routes involve conversion to very high-quality diesel and distillate using the Fischer-Tropsch route, or conversion to high-octane gasoline using Mobil's methanol-to-gasoline (MTG) process. The rest of this discourse is focused on the Fischer-Tropsch route. Fischer-Tropsch (F-T) synthesis produces a spectrum of paraffinic hydrocarbons that are ideal for diesel and jet fuel.

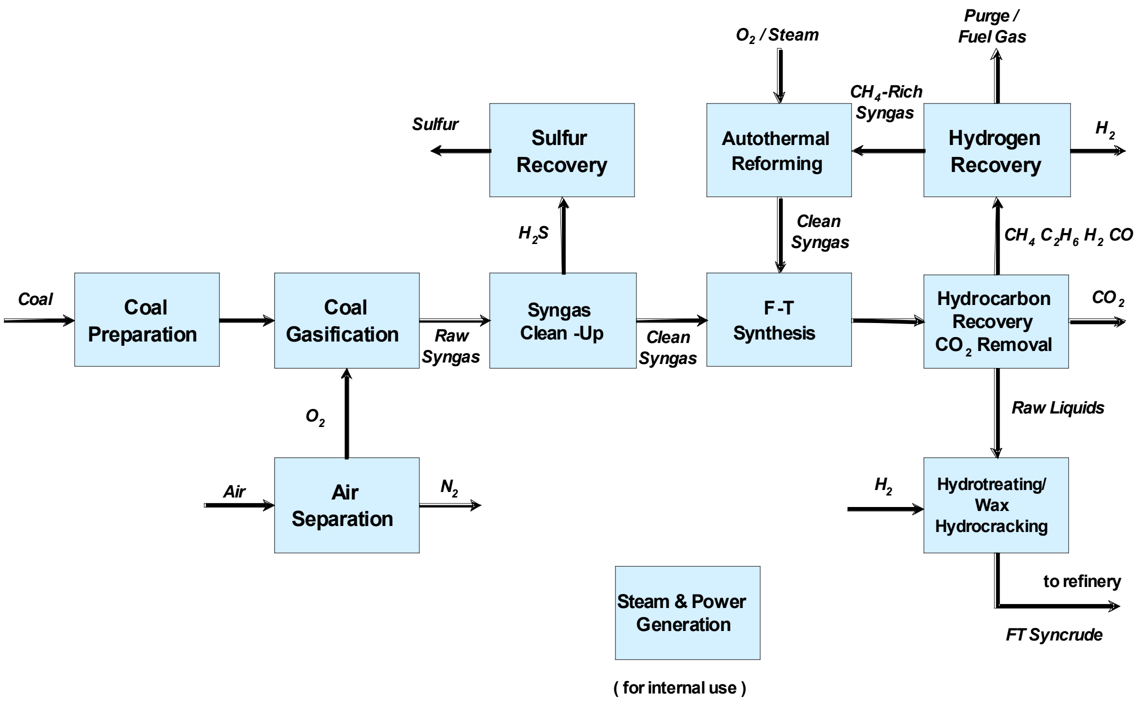

Figure IIIA.2. Process block flow diagram for indirect liquefaction process producing F-T liquids.[11]

Either iron or cobalt-based catalysts can be employed in the reactors. The advantage of an iron catalyst over cobalt for converting coal-derived syngas is that iron has water-gas shift activity and internally adjusts the low H_2/CO ratio of the coal-derived syngas to that required by the F-T synthesis reaction (see above). Natural-gas-derived syngas has a much higher ratio and cobalt F-T catalyst is preferred. Slurry-reactor technology has been commercialized for CTL by Sasol in South Africa, and is the basis for Sasol's current GTL licenses. An alternative technology uses fixed-bed tubular reactors and is the technology employed at Shell's Malaysian GTL complex. Sasol has also commercialized CTL technology in South Africa based on fixed bed, circulating-fluidized bed, and fixed-fluidized bed reactors.

Unconverted syngas and the F-T product must be separated after the F-T synthesis step. CO_2 can be removed using a variety of commercial absorption technologies. High-purity CO_2 is produced that is normally vented to the atmosphere,

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[11] Marano JJ: presented at "Overview of Coal-To-Liquids," Pittsburgh, PA, April 4, 2006.

but alternatively could be exploited commercially in traditional uses of CO_2 or compressed and used either for enhanced oil recovery (EOR) or enhanced coalbed methane recovery, or sequestered in deep geologic formations. These latter options are attractive since they may provide additional revenue (and energy products) and also reduce the potentially significant greenhouse-gas-emissions penalty of CTL-based fuels production. A refrigeration process is then used to remove water and separate light hydrocarbons (primarily methane, ethane, and propane) from the liquid hydrocarbon products of the F-T synthesis. The light hydrocarbon gases and the unconverted synthesis gas are then sent to a hydrogen recovery process, such as pressure-swing adsorption, to recover pure hydrogen needed for downstream upgrading of the F-T products. A fuel gas purge is also included to supply the fuel requirements of the CTL complex. Finally, the remaining gas is sent to an autothermal reforming plant to convert the light hydrocarbons back into synthesis gas for recycle to the F-T reactors.

Product Upgrading – F-T liquids can be refined to fungible LPG, gasoline, and diesel fuel, with the resulting products sold as neat fuels or blended with petroleum-derived blendstocks. Another option is partial upgrading as shown in Figure IIIA.2, to produce an F-T syncrude. The high wax content of raw F-T liquids requires hydroprocessing to produce a syncrude that can be transported via pipeline. The minimum upgrading option includes hydrotreating and mild-to-severe hydrocracking of the F-T wax. Products would be an F-T LPG and F-T syncrude, which could be sent to a conventional petroleum refinery for fractionation into products and further upgrading as required. It is possible that between 10 and 20% of the crude charge to a typical U.S. refinery could be made up of F-T syncrude without requiring major modifications to the refinery.[12]

Offsites – Major offsite plants not shown in this block flow diagram include tankage, product shipping, coal slag disposal, steam and power systems, raw and cooling water systems, sewage and effluent water treatment, and other buildings.

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[12] Marano JJ, Rogers S, Spath PL, and Mann MK: "Life-Cycle Assessment of Biomass-Derived Refinery Feedstocks for Reducing CO_2 Emissions" *Proceedings of The Third Biomass Conference of The Americas*, Montreal, Quebec, (August 25–28, 1997): 325–337.

The indirect-liquefaction block-flow diagram shown in Figure IIIA.2 maximizes the production of synthetic liquid fuels while nearly satisfying all fuel gas and parasitic power requirements of the complex. Other variations are discussed in the later parts of this section.

B. CTL Products & Yields

As discussed in the general description, CTL technology can produce many products. However, the production of F-T diesel has received the most interest in recent years.

The liquid products from a direct-liquefaction CTL plant are similar to a high-aromatic-content crude oil. A typical yield would be about 3.0 bbl of direct liquids (C3+) per ton of moisture-free bituminous coal, which is equivalent to ~9 mmBtu (million BTU) of coal per bbl of liquid product. The product distribution is highly dependent on the amount of second-stage upgrading. A typical product distribution is 11% C3–C4 LPG, 28% naphtha, 11% light distillate, 31% heavy distillate, and 19% gas oil.[13] The liquid (transportation) fuel yield from refining this liquid would be roughly 47% gasoline and 41% distillate fuels. However, extensive upgrading would be required for direct gasoline and diesel to meet U.S. standards for sulfur, aromatic content, and diesel cetane. At this time, it is unclear whether products from U.S.-based direct liquefaction plants would carry a price premium or penalty as compared to a light, low-sulfur crude oil.

A CTL plant based on indirect liquefaction and Fischer-Tropsch synthesis would produce extremely clean-burning liquid hydrocarbon products that are virtually free of sulfur, nitrogen, and aromatic compounds, such as benzene, and that are compatible with the existing transportation fuel distribution and end-use infrastructure in the USA. A typical primary yield would be about 2.2 bbl of F-T liquids (C3+) per ton of moisture-free bituminous coal, which is equivalent to ~11 mmBtu of coal per bbl of liquid product. A typical product distribution of 14%

[13] Bechtel/AMOCO, "Direct Liquefaction Baseline Design and System Analysis," DOE Contract No. DEAC22 90PC89857

C3–C4 LPG, 21% naphtha, 18% distillate, and 47% wax.[14] A combination of hydroprocessing and isomerization (hydroisomerization) could be used to produce a CTL plant product suitable for transportation to a refinery. Several different yields from hydroisomerization are shown in Figure IIIB.1. The product yields from the refining of F-T syncrude will depend on the extent of hydroisomerization (HIS); the gasoline yield range is 20 to 54%, jet fuel range is 17 to 36%, and diesel is 16 to 55%.

F-T diesel has a cetane number over 70, which indicates outstanding combustion characteristics in compression-ignition engines. Diesel fuel marketed in the USA must have a cetane of 40, but averages around 45. F-T diesel is paraffinic and contains very low (less than 1 volume percent) of aromatics. Because F-T diesel contains virtually no sulfur, lean NOx after-treatment catalysts can be used to reduce engine NOx emissions. Generally, even very low sulfur content in diesel exhaust will poison lean NOx catalysts. Tests of F-T diesel in engines have shown that hydrocarbon emissions can be reduced by almost 43% compared to petroleum diesel. Carbon monoxide emissions can be reduced by 40% and particulates by about 15%.[15] If lean NOx catalysts are used in exhaust after-treatment systems, then NOx can be reduced by about 80%. However, there are issues of lubricity, pour point, and cloud point for F-T diesel, which could be addressed by hydroisomerization and addition of appropriate additives.

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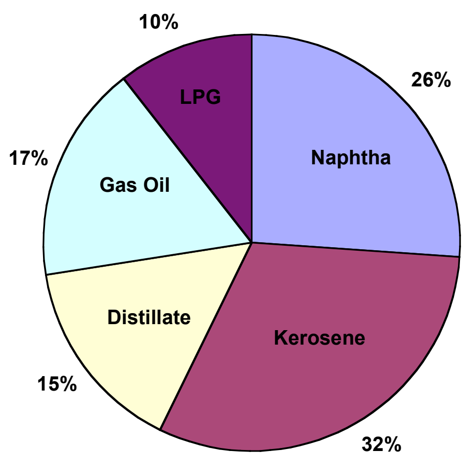
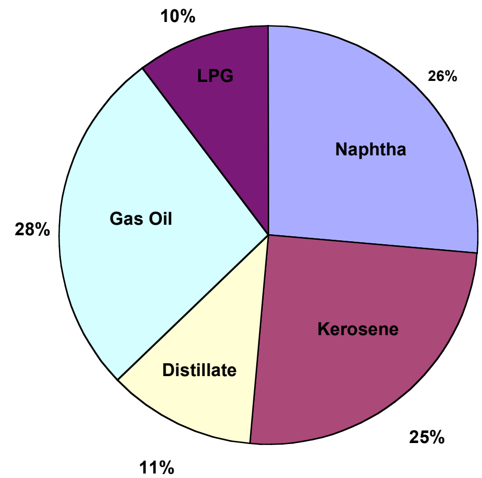
[14] Bechtel/AMOCO, "Baseline Design/Economics for Advanced Fischer-Tropsch Technology," DOE Contract No. DEAC22 91PC90027

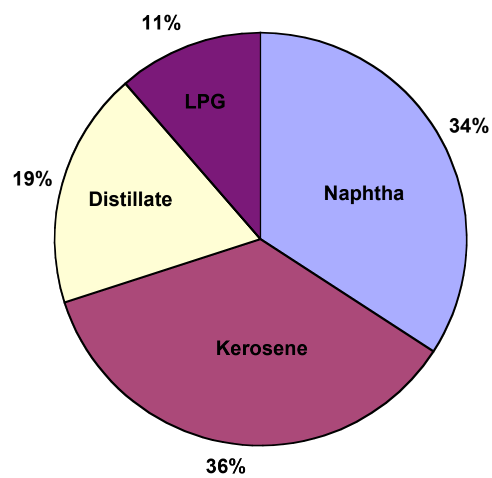
[15] Norton K, Vertin B, Bailey NN, Clark DW, Lyons S, Goguen J, and Eberhardt J: "Emissions from Trucks using Fischer-Tropsch Diesel Fuel," *Society of Automotive Engineers*, SP-1391 (982526), (1998): 119–128



HIS min O/T conversion



HIS max O/T conversion



HIS 100% conversion

Figure IIIB.1. Yields from CTL plant upgrading of F-T liquids.[16]

Unrefined F-T naphtha has a very low octane number of around 40, and cannot be used directly in spark-ignition engines. Currently, the small quantity of F-T naphtha produced worldwide is sold as a petrochemical feedstock, and the best

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[16] Marano JJ: *Hydroisomerization Process for Producing Transportable F-T Liquids*, DOE NETL Letter Report December 5, 1999.

options for refining it to produce a transportation fuel are uncertain. It is possible that it could be fed to a refinery catalytic reformer to improve octane, or blended with high-octane gasoline blendstocks to produce a fuel meeting octane requirements. In addition, a portion of the product slate will consist of light hydrocarbon gases, essentially LPG and other liquefied light hydrocarbons suitable as alkylation feedstock for petroleum refining or for use in petrochemical production. F-T-derived liquid hydrocarbons could also be marketed as specialty chemicals and lubricants. Because of the high quality of all the products, and the direct marketability of the diesel fraction, products from a CTL plant may carry a substantial premium over the crude oil that they displace. However, no recent studies have been conducted to estimate the relative value of F-T-derived fuels relative to petroleum. An earlier study performed for DOE, estimated the value of F-T-derived gasoline to be about 5% higher than the average refinery-gate price for gasoline, and F-T diesel to be about 2% higher than the average gate price of low-sulfur diesel fuel sold in the U.S.[17]

The U.S. market is roughly 1.5 gallons of gasoline per gallon of distillate fuels, or more specifically, 2.2 gallons of gasoline per gallon of on-road diesel fuel. CTL liquids produced from both direct and indirect liquefaction yield less gasoline relative to distillates when compared to crude oil refined in the USA. U.S. refineries processing large quantities of CTL liquids would likely require modifications to handle these alternative feedstocks. Thus, there may be little incentive to use F-T fuels as feedstock for conversion to gasoline unless the refiner sees unique advantage.

C. Capital Cost

The conversion of coal to liquid (CTL) fuels or to synthetic natural gas (CTG) is a process-intensive effort. The plants are large-scale enterprises resembling refinery operations and coal power-generation plants. Capital cost estimates for CTL plants range from $60,000/DB (daily barrels) to $130,000/DB. Construction of these plants

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[17] Marano JJ, Rogers S, Choi GN, and Kramer SJ: "Product Valuation of Fischer-Tropsch Derived Fuels" in ACS National Meeting, Washington, DC, August 20-25, 1994, *Preprints* Vol. 39, No. 4, (1994): 1151–1156.

will require attention to all of the associated issues regarding siting, permitting, EPC, and developing infrastructures for transportation, pipelines, and electricity. All these activities have significant impacts on the plant economics; see Figure IIIC.1 for a breakdown of the costs.

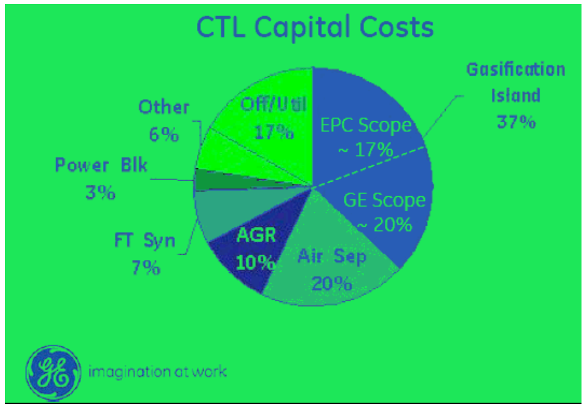


Figure IIIC.1. Estimated breakdown of CTL cost into various costs.

As with most large industrial processes, CTL plant capital cost will benefit with scale, but the benefits appear to diminish beyond, for CTL, approximately 60,000 bbl/d of production (See Figure IIIC.2.).[18] To best explain this effect, consider that the largest F-T reactor on the market today can produce up to 17,000 bbl/d; therefore, any plant larger than this size will require multiple F-T reactor trains. Even a single F-T train facility of 17,000 bbl/d will require multiple gasifiers and air-separation units (ASU) to supply the synthesis gas. Air-separation units take an air input stream and output separate oxygen- and nitrogen-rich streams. So, any CTL plant above 17,000 bbl/d capacity will necessarily consist of multiple trains (gasifiers, ASU, F-T, HRSG, power turbines, etc.), which diminishes the benefits of scaling. Once a facility reaches approximately 60,000 bbl/d, any increase in capacity through additional processing trains loses the ability to leverage off the existing infrastructure.

[18] Gray et al, Mitretek Systems (2005).

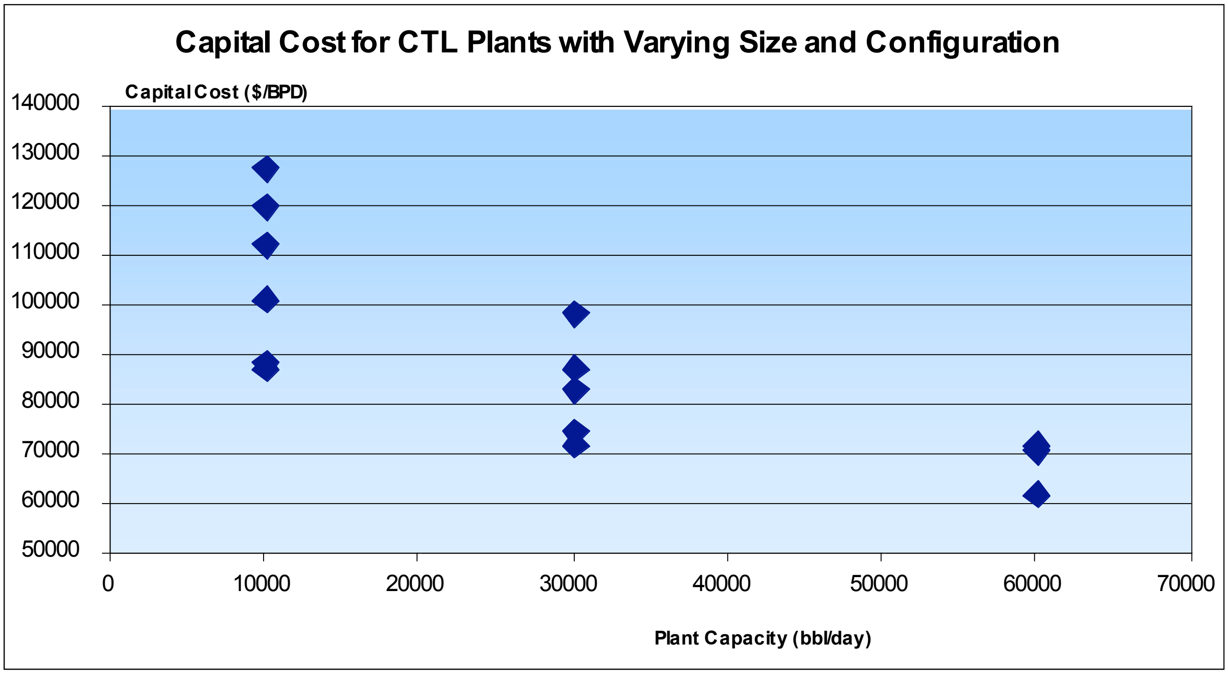


Figure IIIC.2. Capital costs: impact of scale.

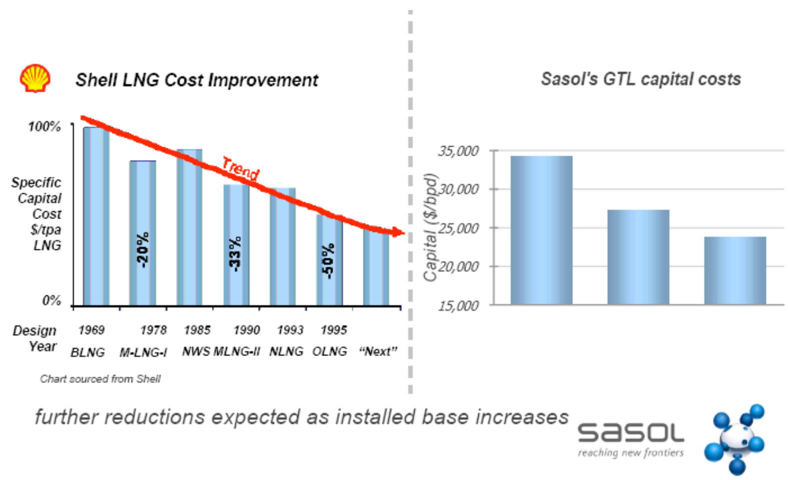


Figure IIIC.3. LNG and GTL capital cost improvements.

Given the experience with gas-to-liquids (GTL) plant construction over the last 20 years, it can reasonably be assumed that capital-cost reductions can be achieved as the technology matures (i.e. the "nth" plant argument). With GTL, the capital-cost differences between the earliest plants in Bintulu and Mossel Bay and the most recent plants were striking: 34,000 $/DB to 23,000 $/DB (See Figure IIIC.3.).[19] Reductions

[19] Enrico Ganter, UBS Global Oil & Gas Conference.

in cost can be anticipated from design optimizations as well as construction experience and standardizations.

Given that modern CTL plants will likely have significantly new systems and processes from the previous generation plants built in South Africa and Germany, it is reasonable to expect that the first new generation CTL plants will be encumbered with unanticipated technical and operational problems. As in the case of the Tampa Electric Polk Power Station IGCC facility, attempting to introduce "newer, more efficient gasification and combined-cycle technology" entails risks and costs. Two conclusions from the final technical report are worth considering:

> "...There is general agreement that capital costs will be lower for the next generation of IGCC..."
>
> "...As a demonstration plant, Polk's availability has been lower than the next generation plant would be..."[20]

The first new CTL plants will undoubtedly experience similar issues. Likewise, plant risks and costs should stabilize quickly in subsequent plants.

Unfortunately, at the time of this writing (October 2006), many large construction projects, including GTL, are experiencing dramatic capital-cost increases from material-cost escalations, skilled-labor shortages and contractor backlogs. It is unclear how long this current trend will continue. If these escalations are cyclic, the impact on future CTL growth may be marginal. Otherwise, they may have a pronounced impact on construction of CTL, especially in the developed world.

D. CTL Plant Emissions

Coal is a carbon-rich fossil fuel, and when coal is converted into fuels and power, large quantities of carbon dioxide are emitted. For example, if a typical bituminous coal is used as feed then approximately 1,500 pounds of carbon dioxide will be emitted for every barrel of F-T liquids that is produced. This can be compared to about 180 pounds of carbon dioxide emitted for every barrel of petroleum fuels produced in a refinery. On a full life-cycle, well-to-wheels basis, F-T diesel carbon

[20] DOE report DE-FC-21-91MC27363, chapter 8.

dioxide emissions are roughly 180% higher than those for petroleum-derived diesel. Figure IIID.1 shows a comparison of full life-cycle, well-to-wheels, CO_2 emissions for CTL relative to other resources for F-T diesel used in LDV (light duty vehicle) compression-ignition engine applications.

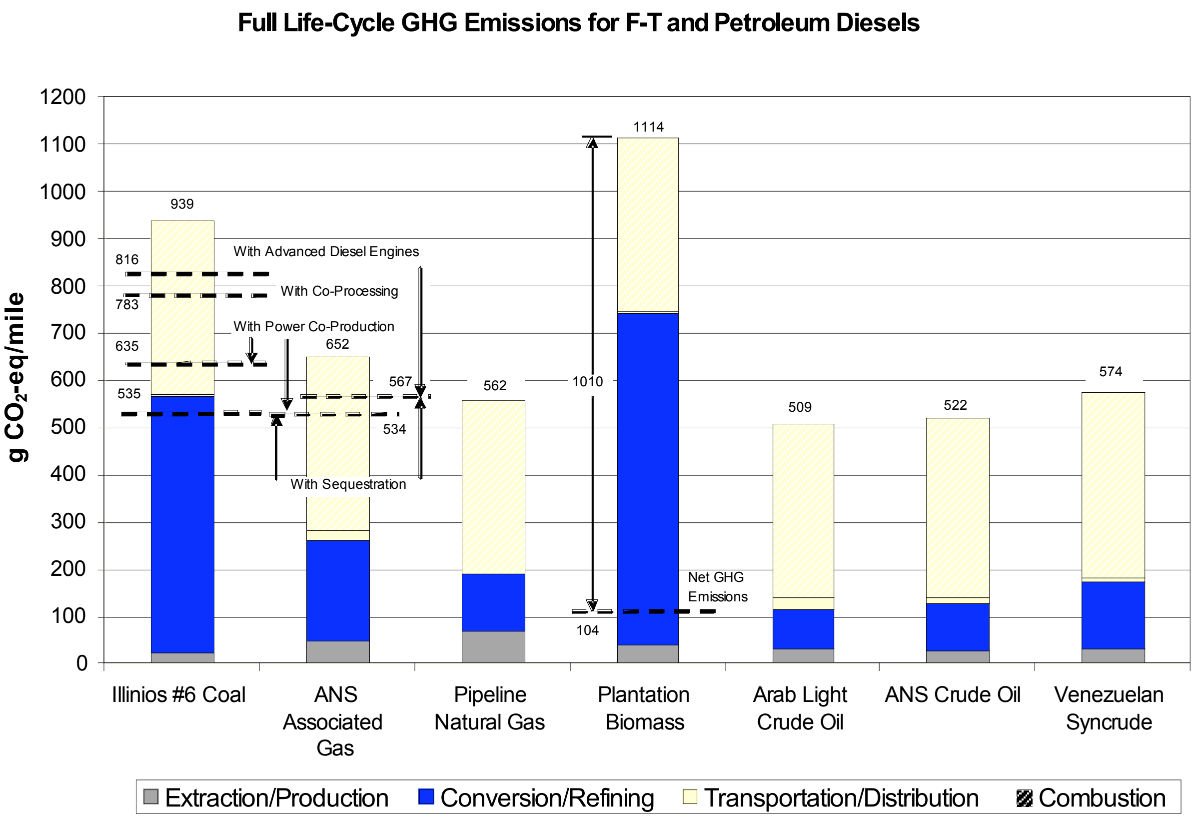


Figure IIID.1. Full life-cycle emissions for f-t and petroleum diesels.[19]

As can be seen in Figure IIID.1 (labeled arrows), a number of strategies, including carbon sequestration, could be employed to lower greenhouse gas emission from CTL and GTL to levels comparable to those for petroleum diesel, including co-processing with biomass, co-production of power, and CO_2 sequestration (90% capture of process CO_2 emissions). Advanced, high-efficiency diesel engines would also lower CO_2 emissions significantly. The production of F-T liquids from biomass actually produces higher emissions. However, the carbon released upon combustion is derived from a renewable source, so the net CO_2 emissions are quite low. It can also be seen that heavier oils produce higher emissions during processing to produce liquid fuels.

Concerns over emissions of criteria pollutants and toxics like SOx, NOx, particulates, and mercury should be minimal since CTL plants employ clean coal technologies and the removal of these pollutants can be readily accomplished.

Water use in CTL plants is also an issue, particularly in geographical areas with limited water resources. With conventional cooling-system designs, both direct and indirect liquefaction consume between 5 and 6 bbl of water for each bbl of liquids produced. However, use of air cooling in place of water cooling and other dry cooling systems can substantially reduce water requirements to below one barrel of water per barrel of product. Generation of large quantities of coal-derived mineral waste also should not be an issue since this waste product is a non-leachable slag suitable for use in aggregate.

E. Other Risk(s)

1. Permitting

No commercial-scale CTL plant has been sited or permitted in the United States. Given that these plants will have aspects of both a refinery and a power generation facility, it is not clear how quickly this untested permitting process can be expedited, particularly if activist groups are aggressively intervening. These potential delays have associated financial risks to the first plants.

2. Vendor and Construction agreements

Early CTL plants will be hindered by the lack of "standard plant" designs and by the hesitation of component vendors to provide performance and cost guarantees. These limitations will increase the uncertainties associated with estimating true construction and operating costs. These higher uncertainties typically have a negative impact on the ability to raise investment capital.

Given that these, and other associated risks, will be adequately dealt with in the early CTL plants, it is not unreasonable to assume that a significant expansion in the growth of the industry could be envisioned after the first half-dozen plants are operational. It is also reasonable to assume that the first CTL plants would be expedited through active federal and state support to help mitigate these risks. A number of bills were introduced in 2006 that would expand or extend the provisions of EPA Act 2005. Several states have been aggressively promoting CTL plants (IL, MS, MT, and PA).

F. Options and Variations

All publications reviewed for this report focused on indirect liquefaction, primarily because of direct liquefaction's poor product yield, extreme operating conditions, and lack of large commercial-scale experience. Additionally, most reports focused on the many options offered by the indirect process. The CTG plant was not researched as thoroughly because the primary emphasis of this report was the CTL plant. The lack of emphasis is likely due to CTG plants' limited transportation options versus liquid products, as well as the typical higher market values for liquid products.

Polygeneration: The co-production of syngas-derived products from a single facility can have a number of advantages. Engineering analyses indicate that co-production or polygeneration plants may offer superior economic and environmental performance, as compared to separate dedicated fuels-only plants. The co-products most often considered in previous projects and studies have been electric power and F-T liquid fuels, usually diesel.

A typical block-flow diagram for a co-production plant employing the Fischer-Tropsch synthesis to produce liquid fuels and power is shown in Figure IIIF.1. Relative to the all-liquids plant (Figure IIIA.2), the autothermal reformer and synthesis gas recycle are eliminated and all light hydrocarbons and unconverted syngas are used as a fuel gas for co-producing power in a gas turbine combined-cycle plant. This option results in the export of significant electric power. Another option involves the production of SNG from synthesis gas, with the unconverted gas used to co-produce power, and is shown in Figure IIIF.2. The best option is based on engineering, economics, and possible markets for the potential by-products from the complex.

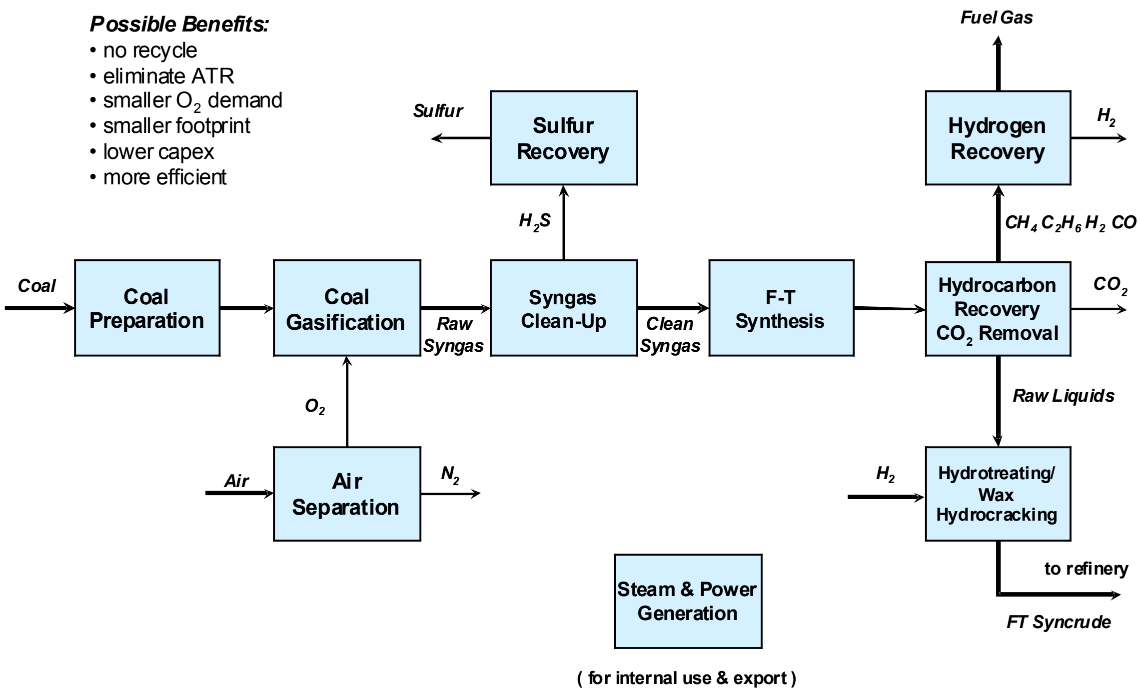
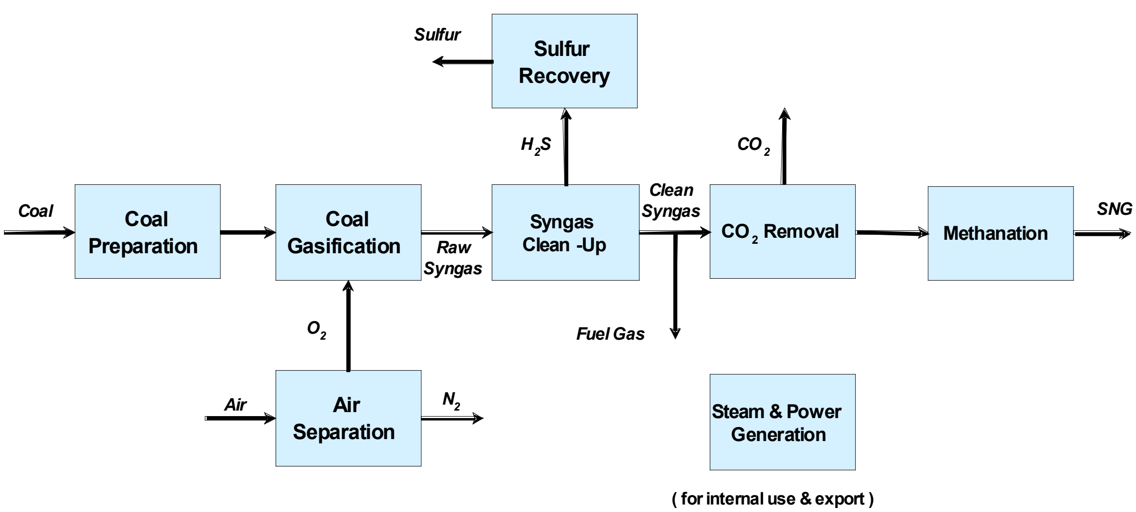


Figure IIIF.1. Process block flow diagram for indirect liquefaction process co-producing of F-T liquids and power.[21]



FigureIIIF.2. Process block flow diagram for co-producing SNG and power.[22]

[21] Marano JJ: presented at, "Overview of Coal-To-Liquids," Pittsburgh, PA, April 4, 2006.

An important attribute of indirect liquefaction is that none of the technologies that underlie the operations depicted in Figure IIIA.2, Figure IIIF.1, or Figure IIIF.2 is unique to indirect coal liquefaction. In particular, coal gasification and gas cleaning also pertain to clean coal-power generation,[23] as well as hydrogen, methane, fertilizer, and chemicals production.[24] Fischer-Tropsch synthesis is also at the core of all approaches to convert natural gas to liquid fuels. This shared technology base allows indirect liquefaction to reap the benefits of the significant technical advances that have taken place over the past 25 years since the design of the original Sasol CTL plants.

The use of power as an output option adds an interesting flexibility to the economic benefit, since power demand has a distinct load shape, offering at times significant economic benefit to generate power over liquid product. To consider the polygeneration path, the issue of minimum levels of operation becomes important, since these chemical reactions require stable conditions for operation.

IV. CTL Production Forecasts and Assumptions

Figure IV.1 offers a large range of U.S. coal-to-liquids potential, from 0.8 to 5.6 million bpd. Each study has its own use and purpose. The National Coal Council focus was on how coal could assist in our energy needs, including CTL, CO_2 EOR, and CTG. The Southern States Report basis is energy independence. The EIA report tries to emulate fundamental market responses to set market parameters and assumes

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[22] Adapted from Mitretek Technical Report to DOE, *Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite*, December 2004.

[23] For example, under the Department of Energy's Clean Coal Program, two coal-gasification combined-cycle power plants were built and operated.

[24] For example, besides synthetic natural gas (methane), the Great Plains Synfuels Plant in North Dakota produces for sale anhydrous ammonia, ammonium sulfate, krypton, xenon, naphtha, liquid nitrogen, and carbon dioxide. This plant was constructed at nearly a $2 billion cost to the taxpayer. The private sector defaulted on its loan, which was guaranteed by the Federal government.

no incentives. The ability to meet any of these forecasts will largely depend on assumptions used for oil price, capital cost, labor constraints, equipment availability, permitting and siting, CO_2 market assumptions, technology, feedstock issues, valuation of security of supply, and energy policies.

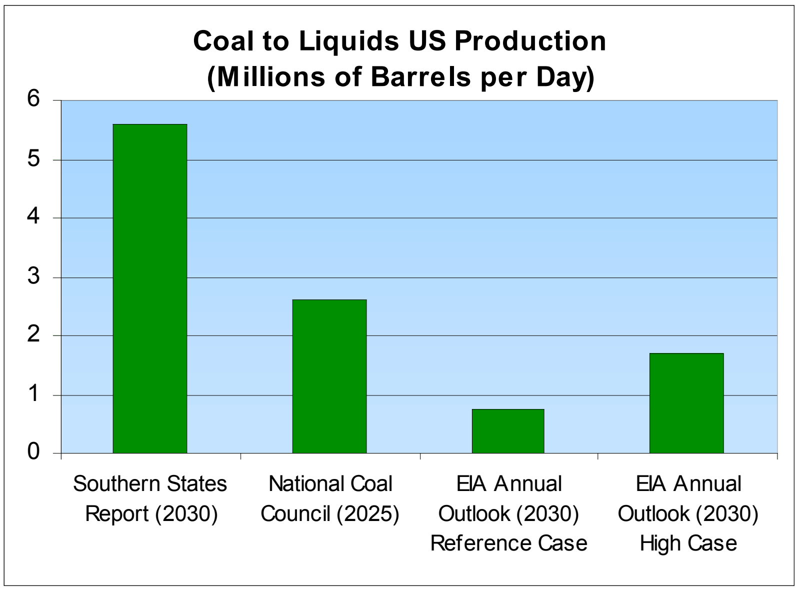

Figure IV.1. U.S. CTL production estimates.

A. Oil Price Assumptions

Forecasting the petroleum markets makes the capital and feedstock markets rather straightforward, see Figure IVA.1. In most studies, the volatility and risk of the project lies in the revenue stream of the technology—natural gas or petroleum product prices.

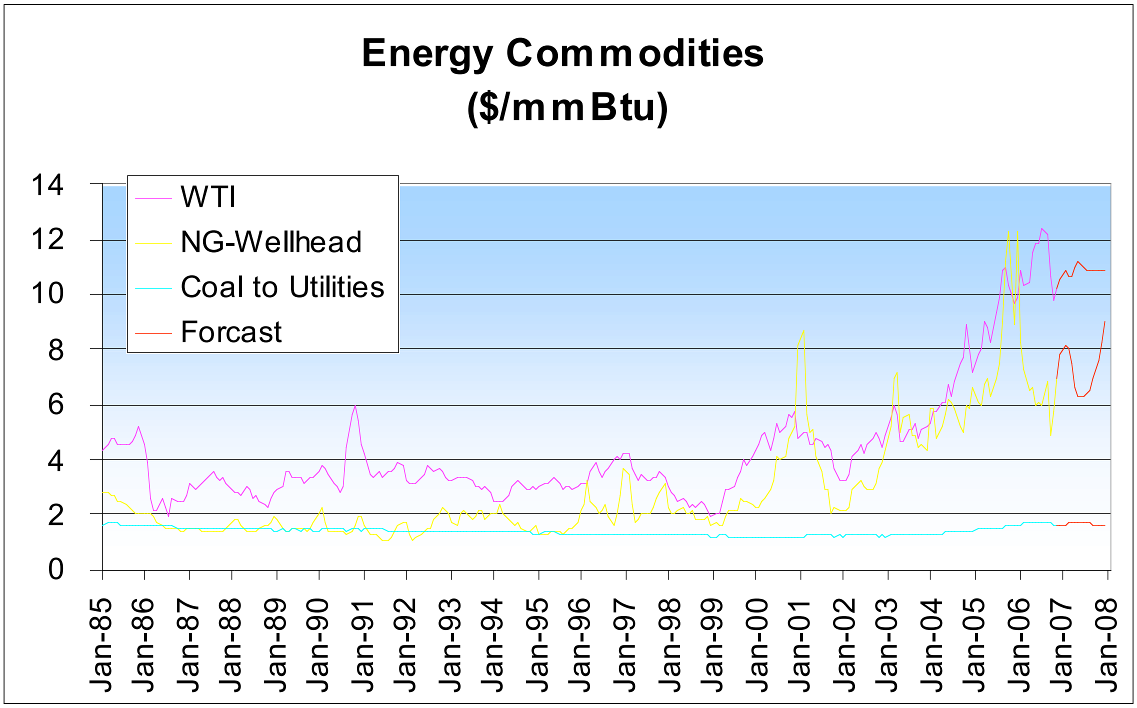

Figure IVA.1. Historical energy commodity prices.

The EIA annual report had a range of liquids production for the USA from coal at 0 (low), 0.8 (reference), and 1.7 (high) MMBbl/d each with the relative prices of $34/bbl (low), $57/bbl (ref.), and $96/bbl (high), as shown in Figure IVA.2.

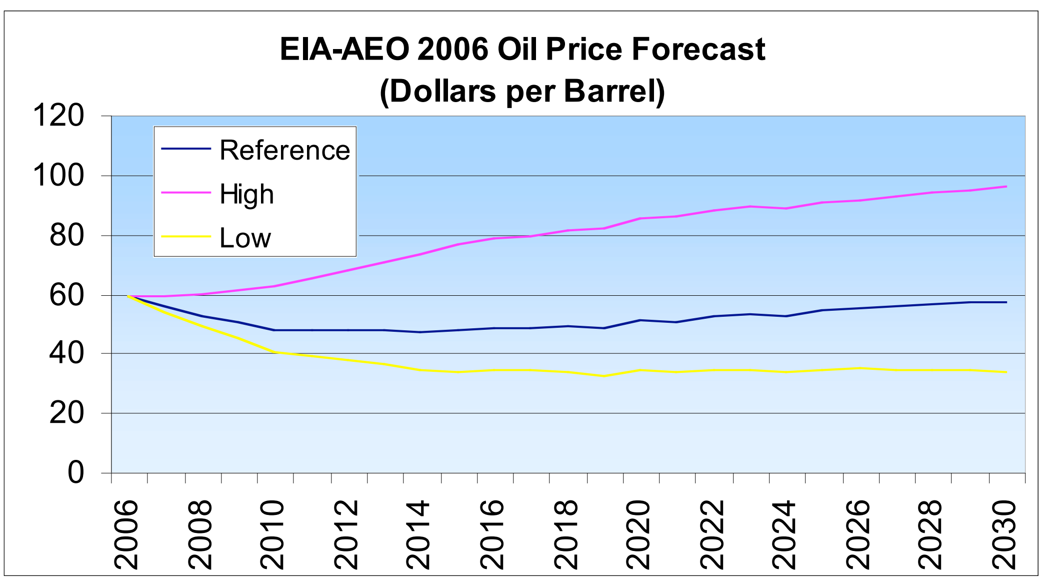

Figure IVA.2. EIA oil price forecast.

Other reports reviewed for this study were not explicit on their oil forecast. The NCC report calculated an energy savings price as more coal was being used versus other energy products, primarily petroleum. Therefore, an implied oil price can be calculated based on those savings (Figure IVA.3).

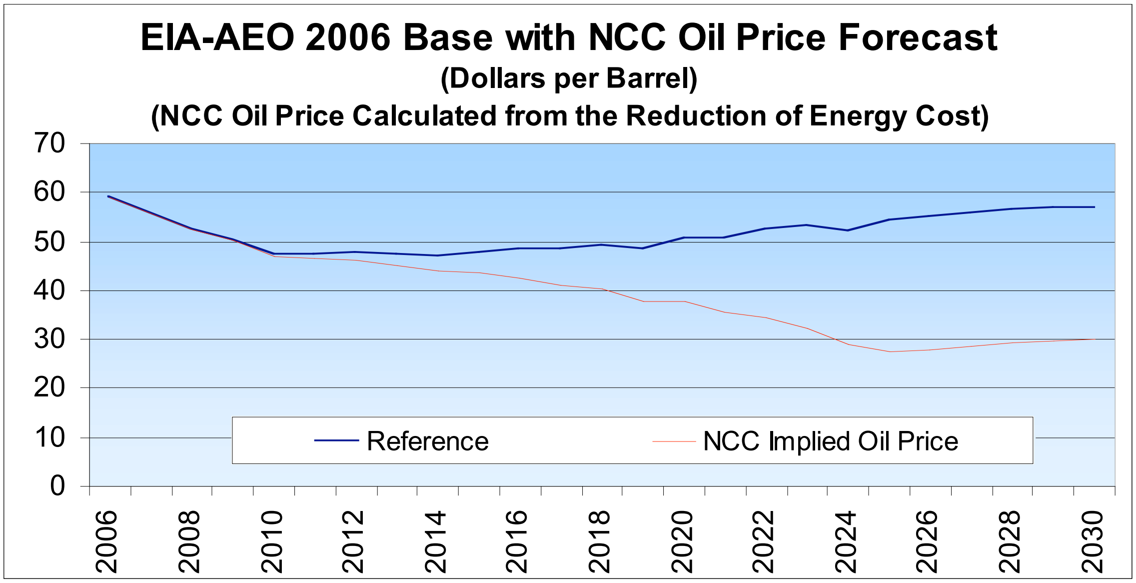

Figure IVA.3. EIA base oil price vs. NCC implied oil price.

The NCC implied price would produce uneconomical facilities based on economic valuations from the other reports. The economic cutoff for the deployment of CTL lies somewhere between $34 and $57/bbl, based on the EIA report. Additionally, 25% more production can be expected for every dollar increase of crude oil beyond $57/bbl. The Southern States Report (see previous table) indicates that the required selling price for a CTL plant on a crude oil equivalent basis range from $37/bbl to $60/bbl.

The volatility of crude oil prices, and therefore, product prices from the CTL unit, will cause a delay of investment. The market would begin to develop CTL technology on its own if oil prices would consistently be above $45/bbl (average range of economic benefit from EIA and SSEB report). If the EIA reference price comes to fruition, the lack of volatility and consistent prices above $45/bbl should result in CTL plant construction.

The real question is what amount of time would change companies' attitude, whether energy companies or banks, for their input for future crude oil price assumptions—particularly their lower-end assumptions—to be above $45/bbl. Only two years, including 2006, has passed with oil realizations greater than $40/bbl for BP (Table IVA.1). This increase in price has not been in effect long enough to change future budgets and investment criteria.

Key indicators[a]

	2001	2002	IFRS 2003	IFRS 2004	$ million IFRS 2005
Result and oil price					
Replacement cost profit before interest and tax ($ billion)	12.47	8.28	15.08	18.08	25.49
BP average liquids realizations ($/bbl)[b]	22.50	22.69	27.25	35.39	48.51
Finding and development costs ($/boe, five-year rolling average)	3.72	3.72	3.98	4.65	5.79
Finding costs ($/boe, five-year rolling average)	1.07	0.91	0.79	0.81	0.92
Lifting costs ($/boe)	2.73	2.71	2.84	3.41	4.28
Cost of supply ($/boe)[c]	8.32	9.21	8.68	9.54	10.44
Net income per barrel of oil equivalent					
BP ($/boe)	5.67	3.33	7.95	8.40	12.51
Range of other oil majors					
Maximum ($/boe)	6.82	6.26	8.24	10.81	15.32
Minimum ($/boe)	5.31	5.07	6.32	7.31	9.74
Reserves replacement					
BP subsidiaries (%)	191	175	122	106	71
BP subsidiaries and equity-accounted entities (%)	191	168	109	110	100
Range of other oil majors					
Maximum (%)	126	119	118	125	129
Minimum (%)	74	49	66	35	13

[a]Except where indicated, all the data in this table relates to BP subsidiaries only.
[b]Crude oil and natural gas liquids.
[c]Cost of supply comprises exploration expense, lifting costs and depreciation, depletion and amortization.

Table IVA.1. BP realized oil prices.[25]

History shows that these projects are susceptible to failure due to high potential uncertainty in future prices and high volatility, which can lead to financial disaster, as in the South Dakota gasification facility case. The projections used for the project in the late 1970s and early 1980s were distillate prices around $50/bbl and syngas value around $6.75/mmBtu[26]—but the market price within 2 years after coming online was in the low $20/bbl and city-gate gas prices in the low $3/mmBtu.

[25] BP Financial Operating Information 2005
[26] Stelter S: *The New Synfuels Energy Pioneers*. Available at http://www.basinelectric.com/EnergyResources/Gas/synfuels.html).

B. Capital Cost Assumptions

Figure IVB.1 shows capital cost assumptions from the various reports. One of the key components in cost, as mentioned above, is the sizing. This chart shows the reports with the various size assumptions.

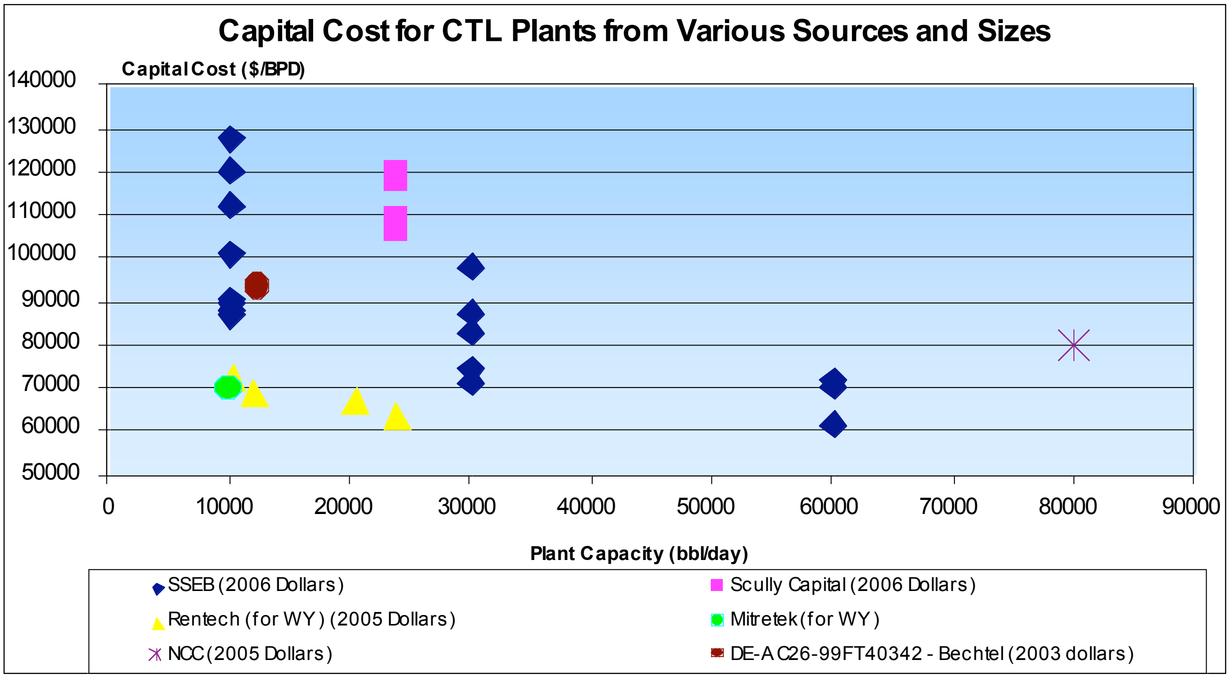

Figure IVB.1. Capital-cost assumption.

The EIA report was based on the Mitretek study. The cost of the plant relative to the other studies proves to be optimistic. The NCC and SSEB report seem to be in line with the expected size-tocost relationship.

The SSEB report contains an extensive write-up on capital cost based on many variables. Their table is reproduced here (Table IVB.1). They varied coal type, plant configuration (once through F-T vs. recycle F-T), production volume, and fuel mix (coal and woody biomass). The study also included carbon dioxide capture and compression to 2000 psi for pipeline delivery. Capital costs vary in the range of $60,000/DB and $130,000/DB. It should be noted that this range effectively encompasses the majority of published values, as seen in Figure IVB.1 above.

Table IV-1
CTL Plant Economics

Plant Case No.	Capacity (BPD)	Config.	Coal Type	Export Power (MW)	Capital Required ($/DB)(1)	Diesel Selling Price COE Basis ($/B)(2)	Diesel Selling Price ($/B) (3)	Efficiency (% HHV)
1	10,000	Recycle	Bituminous	27	$88,700	54.9	71.36	47.1
2	10,000	Once-through	Bituminous	241	$120,400	60.69	78.90	44.1
3	30,000	Recycle	Bituminous	204	$74,900	45.96	59.74	48.1
4	30,000	Once-through	Bituminous	537	$87,500	46.67	60.67	47.1
5	60,000	Recycle	Bituminous	386	$70,700	44.02	57.23	47.6
6	10,000	Recycle	Subbituminous	19	$87,300	46.29	60.18	50.7
7	10,000	Once-through	Subbituminous	162	$112,400	50.5	65.65	44.2
8	30,000	Recycle	Subbituminous	146	$71,900	37.14	48.28	50.3
9	60,000	Recycle	Subbituminous	44	$62,100	34.62	45.01	51.3
10	10,000	Recycle	Lignite	6	$101,500	55.71	72.43	43.9
11	10,000	Once-through	Lignite	163	$128,200	60.01	78.02	40.8
12	30,000	Recycle	Lignite	91	$83,100	45.15	58.70	45.5
13	30,000	Once-through	Lignite	432	$98,500	46.21	60.07	43.5
14	60,000	Recycle	Lignite	9	$72,000	41.19	53.55	46.7
15	10,000	Recycle	Bituminous, 10% biomass	28	$89,700	55.32	71.91	46.7
16	10,000	Recycle	Bituminous, 20% biomass	29	$90,900	55.79	72.52	46.2

Source: Mitretek, 2006.

Figure IVB.1. CTL plant economics, Southern States Study.

C. Labor Assumptions

None of the studies mentioned labor issues for the construction and maintenance of a CTL facility. Labor associated with the construction of a commercial-scale CTL facility should not be underestimated. Similar international facilities, currently under construction, will have peak workforce numbers in the tens of thousands. Depending on the site location, the local infrastructure may not support such a work force. The project will have to include the infrastructure costs and likely subsequent taxes to support local governments in maintaining the necessary infrastructure, which includes roads, housing, schools, water and sewer systems, and hospitals, etc.

Labor unions may also be involved, which could have a major impact on the project construction costs. Local labor may not have the skills necessary for the construction and maintenance of the facilities, which would require either education, relocation of trained employees, or both.

D. Equipment Assumptions

None of the studies detailed the availability of the equipment needed to construct a CTL plant. CTL facilities use specialized equipment in many of the processes, some of which can only be manufactured in limited quantities. The manufacturers also have competing large-scale projects like LNG, GTL, refineries, and petrochemical facilities, which can impede delivery schedules. Transportation of many of these large pieces of equipment can be a logistical nightmare if the CTL site is not located on an ocean port or inland waterway.

E. Siting and Permitting Assumptions

The process of siting and permitting large facilities is a major barrier to investment, particularly in the developed nations. Any project with coal as a feedstock can expect environmental challenges, both by the public and in court.

A world-scale CTL facility site will encompass roughly a square mile of land. Not only will the raw size of this type of facility draw regulatory attention, the fact that this is a new industry with very few precedents to cite will make permitting a major obstacle that consumes a substantial amount of resources. Like any new industry, many issues will have to be studied and resolved.

F. Transportation Assumptions

Given the assumption that most CTL opportunities have been planned as mine-mouth facilities, conveyer systems or small railroad spurs will manage the transportation of the coal feedstock. For the end-products, the current infrastructure is most likely not sufficient to transport the volumes associated with the proposed CTL industry of 10–20% of the petroleum products market, depending on where the CTL plants are built and what volumes, if any, they are offsetting. The current North America pipeline infrastructure is operating at near capacity with little margin to accommodate disruptions.

G. CO_2 Assumptions

The various reports did not cover CO_2 economic impact on production. The EIA only indicated growth in CO_2 emissions in the overall energy markets. The SSEB report did discuss the synergy between CTL and enhanced oil recovery (EOR) using CO_2 from the CTL stream. In addition, the CTL plants in the report were designed with 70–90% CO_2 capturing capability. However, the cost and method of sequestration was not covered. The NCC report discussed CO_2 capture and sequestration but did not tie the value with a CTL production forecast. The report projects the cost of capturing CO_2 from \$20–\$70/ton of CO_2, with optimism of a lower cost in the future.

H. Feedstock Cost – Coal Fundamentals Assumptions

1. Projected Coal Consumption

Examining coal demand in each study, coal for CTL ranges from 94 million tons annually in 2030 (5.3% of coal market of 1.8 billion tons) to 1.5 billion tons (48% of coal market of ~3 billion tons),[27] as shown in IVH1.1. Only the NCC study forecast CTG consumption, with an expected output of 4 Tcf/yr by 2025.

As discussed in the Reserves section below, the EIA estimates that only 54% of the U.S. reserves are recoverable. This recovery percentage must be included in the calculation of the reserve base required to support a CTL facility. Headwaters Energy Services estimates from 500 million to 1 billion tons of low-cost reserves will be required for CTL plants of 30,000 to 80,000 barrels per day.[28]

Figure IVH1.2 shows the variability of barrel-per-ton assumptions included in these studies. The SSEB report had various facilities, but did not specify the total amount of coal, or which facilities were used to obtain the 5.6 million b/d production. The SSEB report was expressed in equivalent diesel volumes. This required

[27] Assuming the CTL demand is incremental to EIA's projected demand of 1.69 billion tons (1.784bn, less 0.94bn projected CTL demand)
[28] American Coal Council Buyers Guide (2006): 52

increasing the volume from the various cases to produce total liquid production. For the remaining discussion of this report, the SSEB report is assumed to be the average of those facilities producing a blended coal around 8,878 Btu/lb. This assumption is reasonable given discussions of the use of western coal. Averaging the various facilities produces a conversion rate of 1.4 barrels per ton.

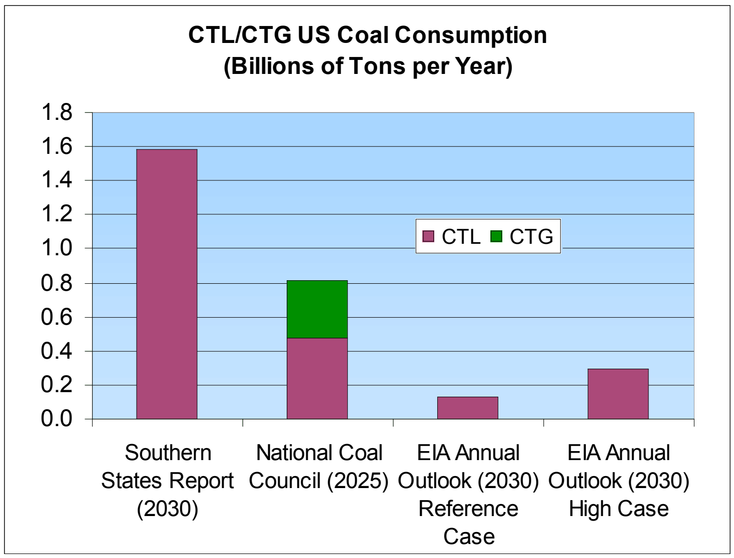

Figure IVH1.1. Projected coal consumption from CTL/CTG.

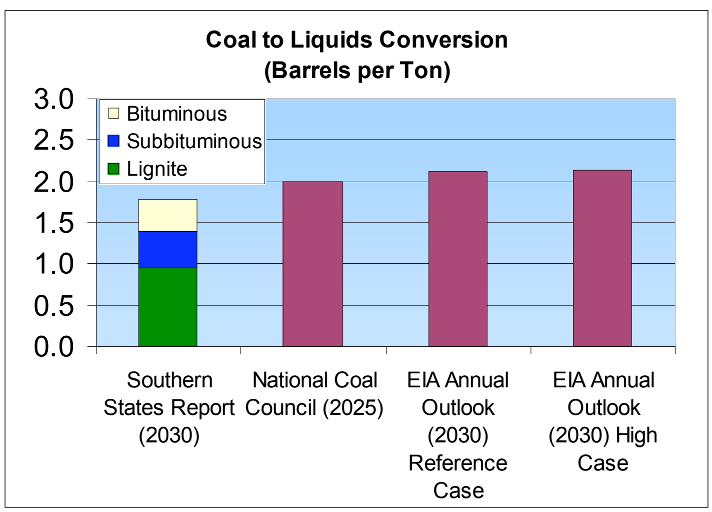

Figure IVH1.2. CTL barrels per ton conversion.[29]

The heat content of the fuel used for CTL plays a large role in conversion capability (tons per bbl). To understand the basis of the technology, the better metric

[29] Calculated from reported CTL production and coal consumption.

to focus on is million Btu of coal/bbl of product. Figure IVH1.3 shows the calculated mmBtu of coal/bbl of product from each of the reports and the value stated in the Gray report referred to in EIA's CTL discussion in its Annual Outlook report.

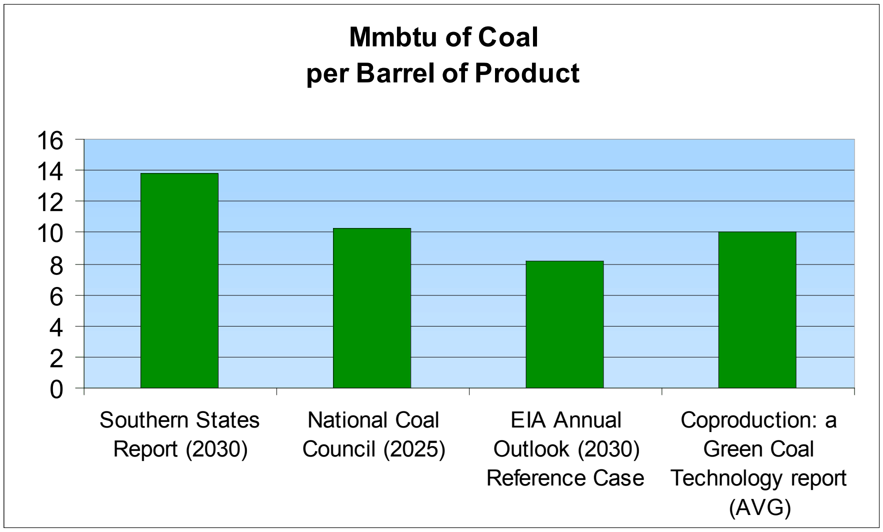

Figure IVH1.3. Millions of Btu of coal per barrel.

The conversion value calculated for the EIA would indicate a technology improvement to CTL. The digression of the EIA Annual Outlook from the reference report, *Coproduction: A Green Coal Technology*, is shown in Table IVH1.1 below. The real conversion factors may even be much higher as the calculation below assumes all the heat was a result of the production of liquids. However, 31% of the energy is in the creation of syngas for power. Therefore attributing an equal 31% of the heat loss to syngas would result in a conversion of 7 mmBtu of coal/bbl of product. If the technology improvements did not occur as calculated, the EIA CTL production numbers would be 10–30% too high or the coal consumption would need to be 10–30% greater. Inversely, the aggregation of all the facilities from the SSEB report produces a lower conversion rate compared to the other studies.

Implied mmbtu of coal per product barrel
Using EIA Annual Outlook (2030) Reference Case

Item Description	Value	Formula
Tons in		
1 Coal to CTL plant (MM Tons/Yr)	189.95	From EIA-AEO 2006
2 Coal to CTL plant (Tons/Day)	520,419.83	[1]*10^6/365
3 Coal to CTL plant (Lbs/Day)	1,040,839,668	[2]*2000
Product out		
4 CTL Production (MM Bbls/day)	0.76	From EIA-AEO 2006
5 Average mmbtu per barrel of product	5.825	Diesel mmbtu/barrel
6 Product mmbtu/day	4,427,000	[4]*10^6*[5]
7 Coal to CTL product & heat (MM Tons/Yr)	131.07	[1]*(49%+20%)
8 Energy input retained in the product[1]	49%	From EIA-AEO 2006
9 Total energy in (mmbtu/day)	9,034,693.88	[6]/[8]
10 Btu/lb of coal	8,680	[9]/[3]*10^6
11 Coal to CTL product (mmbtu/yr)	2,275,387,653	([7]*10^6)*([10]*(10^6/2000))
12 Coal to CTL product (mmbtu/day)	6,233,939	[11]/365
13 Mmbtu of coal per product barrel[2]	8.2	[12]/[4]/10^6
14 Gray's reported mmbtu per product barrel	9-10	

[1]From EIA Assumption to AEO 2006, "Of the total amount of coal consumed at each plant, 49 percent of the energy input is retained in the product with the remaining energy used for conversion (20 percent) and for the production of power sold to the grid (31 percent)."

[2]David Gray states that mmbtu of coal per product barrel is 9-10 in his March 2001 Mitretek Systems report "Coproduction: a Green Coal Technology"

Table IVH1.1. Calculation of implied mmBtu of coal per barrel.

2. Projected Coal Price

EIA assumes CTL production initially occurs in coal-producing regions of the Midwest. They forecast an average coal price per ton (2004 dollars) for CTL production of $12.55 in 2011 and $21.06 in 2030, compared to the U.S. average delivered price of $30.14 in 2011 and $30.30 in 2030.

Figure IVH2.1 shows EIA's reference forecast for coal price, in 2004 dollars, for Midwest and Powder River Basin coals. These are the two CTL feedstocks identified in their analysis. Regional differences result from differences in coal quality, mining method, equipment, labor (e.g. union or non-union), and available transportation modes.

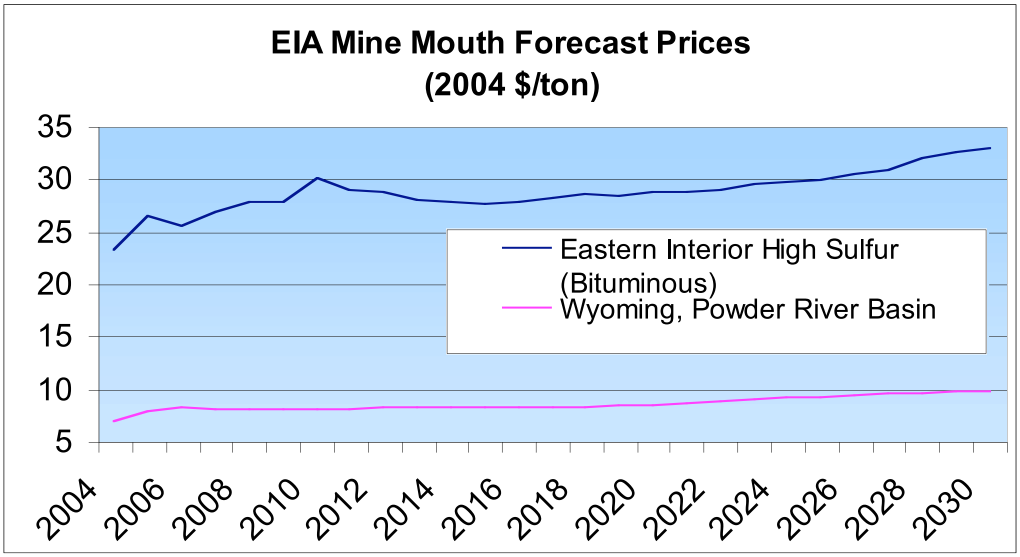

Figure IVH2.1. Expected fuel costs for CTL.

The average U.S. mine-mouth coal price is projected to be $21.73/ton in 2004 dollars, $40.79 in nominal dollars in 2030.[30] The average market price for 2005 was $23.59, 18% higher than in 2004. EIA's forecast implies a real decline in market prices between now and 2030, which is consistent with their assumption of low-Btu Powder River Basin coal continuing to penetrate eastern power markets.

The 1.4% average annual increase in price between 2004 and 2030, for both coals, compares to a 2.1% and 3.7% average annual production increase for Eastern Interior High Sulfur and Powder River Basin coal, respectively. Because of their central location, it is unlikely that either coal will be exported; therefore, production should be roughly equivalent to demand. It is not clear whether the 1.4% annual increase in price reflects the increased demand or just the increased cost to produce incremental tons.

The average delivered price to power producers is projected to be $30.58/ton (2004 dollars), or $1.51/mmBtu. EIA does not provide delivered cost by production region; however, the average Btu implied by the given price per ton and price per mmBtu values is 10,126 Btu/pound.

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[30] EIA-AEO (2006): 99

Southern States uses delivered-per-ton costs of $36 for bituminous coal, $11 for sub-bituminous coal, and $10 for lignite. In 2030, EIA projects an average mine-mouth price per ton for bituminous coal of $33.19, $11.10 for sub-bituminous, and $14.72 for lignite. The implication is that Southern States is building mine-mouth CTL plants or that coal and transportation prices are expected to fall from current levels. The latter is unlikely, since this price fall would be coupled with more than a doubling of current coal demand.

The NCC study does not discuss coal price. Their focus is on capital expenditure and GDP enhancement.

3. Projected Coal Quality

The NCC study assumes a constant heat content of 20.5 mmBtu/ton, or 10,250 Btu/lb, for coal used in CTL and CTG production, resulting in incremental consumption of 475 million tons for CTL and 340 million tons for CTG in 2025. The study appears to be based on an Illinois Basin analysis. It should be noted that Illinois coal has relatively high chlorine content that increases with depth. This quality issue leads to higher capital cost requirements for the CTL plant.

NCC highlights the fact that EIA's AEO 2006 continues the growth and increased share of coal production coming from the Powder River Basin (PRB), from 52% to 59% of total production. The PRB is located in Wyoming and Montana and has an average heat content of 9000 Btu/lb or less.

The 13 SSEB case studies include the following coal assumptions:

- Bituminous coal: 11,800 Btu, 2.94% sulfur (4–5 lb SO_2), priced at $36/ton (implies Illinois Basin)
- Sub-bituminous coal: 8500 Btu, 0.35% sulfur (0.82 lb SO_2/mmBtu) at $11/ton (implies Powder River Basin)
- Lignite: 6334 Btu, 1.19% sulfur (3.75 lb SO_2/mmBtu) at $10/ton (implies Northern Lignite)

While they do not indicate the mix used to produce the estimated 5.6 million BPD in 2030, as noted above, the average was used producing very close coal characteristics to EIA estimates. Figure IVH3.1 shows an average heat content of the coals used in the study.

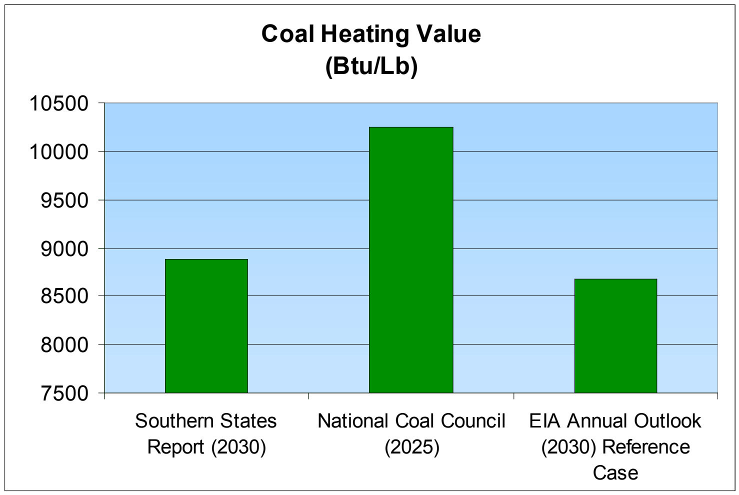

Figure IVH3.1. Heat content of coal.

EIA anticipates 207 million tons of coal supply (10% of a 2.1 billion ton coal market) will be required for CTL production in the high-price case versus the reference case of 94 million tons. While they anticipate construction of CTL plants will initially be in the Midwest, near coal mines,[31] they are silent on what coal will be used; therefore, the implied heat content calculated in Table IVH1.1 is reflected in Figure IVH3.1. The resulting value also implies the use of large quantities of western coal.

4. Limiting Factors

Limiting factors to coal production in the USA are availability of incremental coal supply, transportation infrastructure to deliver coal to the CTL facility (if it is not a mine-mouth facility), production capacity (workers, equipment, etc), the likelihood and cost of managing large volumes of CO_2 produced, and the historical volatility of world oil prices.

[31] EIA-Assumptions to the AEO (2006): 4

Since the technology lends itself to a variety of fuels as co-feedstocks, including petcoke and biomass, inter-fuel competition may help reduce the financial sensitivity to feedstock cost. However, transportation of the competing fuels must be considered in the analysis.

a) Domestic Reserves

The demonstrated reserve base (DRB) of domestic coal reserves was estimated to be 494.4 billion tons, as of January 1, 2005. Three states contain approximately 50% of those reserves: Montana (119 billion tons), Illinois (104.5 billion tons), and Wyoming (64 billion tons). A USGS study of Montana reserves in 1974 indicated approximately 73% of total available reserves are sub-bituminous, with the other 25% being lignite. Wyoming's reserves are primarily sub-bituminous. Illinois reserves are bituminous.

The Southern States Study adjusts the EIA estimates to reflect state estimates, resulting in a DRB of 771 billion tons, an increase of 276 billion tons. The largest increase was to Alaska's DRB, from 3.3 to 170 billion tons, making it the state with the largest reserve base; however, there was no discussion of coal type with the adjusted numbers. Illinois reduced their estimated DRB from 104 to 96 billion tons.

Recoverable coal reserves were estimated at 267 billion tons by EIA, approximately 54% of the DRB. The other 46% is estimated to be unrecoverable due to regulatory, land use, and technological constraints. An estimated 17% of the reserve base is inaccessible to mining, due to environmental and land-use regulation established with the Surface Mining Control and Reclamation Act of 1977. Approximately 34% of recoverable reserves are unrecovered or lost during mining, due to technology constraints, washing, mining method, geology, etc.

Three states contain nearly 60% of estimated recoverable reserves (ERR), Montana (75 billion tons), Wyoming (42 billion tons), and Illinois (38 billion tons). If you apply EIA's recovery estimate to the Southern States estimate of Alaska's DRB of 54%, Alaska has 88 billion tons of recoverable coal. Alaska, Montana, and Wyoming have limited infrastructure to support capacity expansions, and Illinois coal suffers from high chlorine levels. These factors should be considered when estimating the cost of CTL production. Low-Btu coal will require more tons to produce a barrel of liquids than higher-ranked coals, thereby likely increasing transportation and processing cost. High chlorine content will add to facility costs.

EIA projects total coal production will increase from 640 to 945 million tons by 2030, nearly double the 2005 supply of 1.128 billion tons. From 400 to 600 million additional tons will come from the western U.S. Approximately 70% of those western tons will come from Wyoming, an additional 250 to 300 million tons per year. CTL production is estimated to account for 15% to 22% of the projected increase in coal production.

b) Transportation

Although the studies under analysis assume that CTL facilities will be constructed at the mine mouth, as noted above, there will be significant pipeline infrastructure required to transport the products resulting from the liquefaction process. Building the facility away from the coal source will require the feedstock to be transported. This scenario may also require infrastructure investment. Over the last 3 years, U.S. rail infrastructure has been capacity constrained.

Current expansion plans for the joint line out of Wyoming's Powder River Basin (PRB) will increase capacity approximately 75 million tons above the 2008 planned capacity of 425 million tons per year by 2012, at a cost of approximately $100 million. Another 100 million tons of capacity is estimated to be available on the current carrier's other lines out of the basin by 2012. If the DM&E railroad's pending federal loan application for $2.3 billion is approved, it will add an additional 100 million tons of annual capacity by 2012–15, bringing total capacity to approximately 700 million tons.

EIA's reference case estimates production from Wyoming and Montana at approximately 750 million tons per year in 2030. Assuming 50% of the CTL and CTG capacity projected by the NCC is from the PRB, 407.5 million tons of coal will be required, in addition to the 250–300 million-ton growth from the steam market. Assuming these tons are transported out of the region, this would result in a rail capacity shortfall of approximately 400 million tons, given current planned capacity expansions through 2015. This shortfall is equal to the total 2005 capacity. Making the same assumption with the Southern States CTL projection, 700–750 million tons of additional rail capacity would be required.

Current barge capacity on America's river systems is approximately 415 million tons. Approximately 27% of the current dry cargo barge fleet of 17,800 barges, of which 23% was built between 1979 and 1981, is forecast to be retired over the next 5 years.[32] Dry cargo barges have an approximately 25–30 year life. While there are currently only two major barge-manufacturing companies, barriers to entry are relatively low. However, the aging locks on America's inland-waterway system will continue to cause periodic disruptions, due to equipment failures and maintenance outages. One hundred seventeen of the system's 240 locks are over 50 years old. Increased traffic could lead to longer locking queues, thus longer turn times for deliveries of both coal and equipment.

Based on the rail-capacity requirement, both the NCC and Southern States study would favor mine-mouth facilities in the west, with pipelines for product distribution. Facilities in the eastern U.S. would benefit from location on the inland waterway system, due to lower transport costs per ton of coal and the ability to deliver large equipment, as well as supplying water for the facility.

c) Labor

EIA projects 27,000 additional mine employees will be required to meet the reference case coal production increase of 690 million tons in 2030, a 34% increase over current mine employment of 70,000. This number does not reflect new employees required to replace retiring employees (average age of mine workers in 2005 is 45–55) or additional employees required in supporting roles, such as rail employees, truck drivers, plant employees, etc.

EIA projects coal demand from the eastern interior region, which includes Illinois, Indiana, and Western Kentucky to grow by 116%, to 220 million tons/yr, compared to a projected population increase of approximately 7%. Coal miners currently comprise about 0.1% of the population of that region. Table IVH4c.1

[32] Ryan MP: ACL, Inc. presentation, American Coal Council, October 9-11, 2006

reflects the number of new miners required in the Midwest coal-producing region, assuming productivity remains flat. The analysis assumes all of the incremental tons projected for CTL production by the NCC (475 million tons/yr) are produced from this region. This assumption is made since all the CTL facilities modeled in the NCC report used the higher Btu content as specified in the above section.

	Projected Population	**Miners Needed**	
Producing Region	Increase	EIA	NCC
Eastern Interior	1,862,399	20,954	137,942
*Eastern Interior: Illinois, Indiana, Mississippi, Western Kentucky. However, since population estimates are only reported by state, all of Kentucky's population was included.			

Table IVH4c.1 Projected new miners in U.S. eastern interior.

Table IVH4c.2 contrasts regional population growth estimates in the western sub-bituminous producing states, with miners needed to support projected production growth. The SSEB estimate of new miners assumes CTL facilities are constructed in this region proportionally, based on the three coal cases used in the report.

	Projected Population	**Miners Needed**	
Producing State	Increase	EIA	SSEB*
Montana	111,893	752	3,218
Wyoming	15,711	3,041	7,509
*Assumes 70% of production from Wyoming.			

Table IVH4c.2. Projected new miners in sub-bituminous producing states.

EIA assumes productivity will remain flat over the forecast period, with productivity increases from an increased percentage of tons from western surface mines and more efficient long-wall operations in underground mines offset by regulatory issues and increasingly difficult mining conditions. Figure IVH4c.1 shows productivity trends from 1990–2005, by mining method.

To produce the tonnage required for the SSEB and NCC projections, the increased demand, thus increased number of miners, will likely lead to higher labor cost.

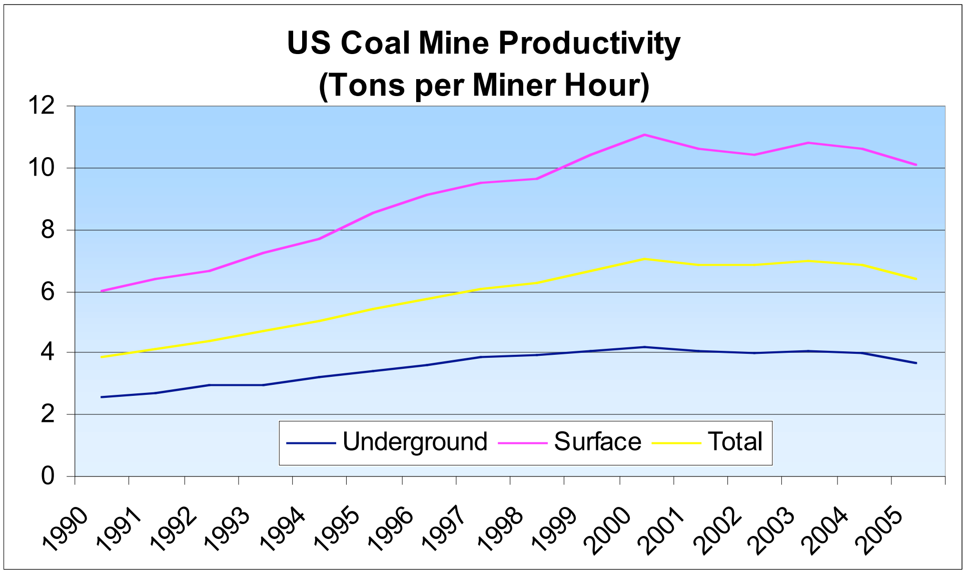

Figure IVH4c.1. Historical U.S. mine productivity.

d) Equipment

Competing demand for mining equipment comes from domestic mining of other commodities, international mining activities, and international construction activities. The industry has had to deal with significant queues for delivery of new equipment for several years.

A shortage of new tires for large mining and construction equipment emerged in 2004 that is expected to persist through 2007 into 2008, when capacity expansion currently under construction comes on line. Based on this experience, addition of new tire-manufacturing capacity can be expected to lag future demand increases

e) Siting

Coal surface mines can be quite large. A recently permitted mine in West Virginia includes 18 million tons of reserves on about 4,000 acres. A pending lease application with the U.S. Bureau of Land Management (BLM) for the right to mine PRB coal includes 588 million tons of reserves on about 4,590 acres. In addition to the area being mined, surface facilities are required for staging and loading the coal, as well as storing the overburden for future reclamation.

Underground mining also requires surface facilities for staging, loading, and storage. They may also face issues with subsidence and both ground and surface water, which may restrict where they can mine.

There are also bureaucratic obstacles, such as the "Roadless Area Conservation Rule," enacted by the Clinton administration, repealed by the Bush administration, and reinstated by the Ninth Circuit Court of Appeals, which restricts mining access to some public lands.

I. International CTL Outlook

The International Energy Agency's World Outlook 2006 expects CTL production to reach 750 thousand BPD by 2030, primarily in China, where low-cost coal supplies are abundant. China's relatively low coal prices reflect lower labor costs compared to other coal producing nations. They believe high capital costs compared to gas-to-liquids facilities, high steam coal costs, and high CO_2 emission rates from CTL production will cause CTL to remain a niche activity between now and 2030.

The EIA reference case projects worldwide CTL production of 1.8 million BPD in 2030. The high-price case increases the estimate to 2.3 million BPD.[33] This represents 1.5–1.9% of projected world oil demand of 118 million BPD in 2030.

[33] EIA-AEO, Issues in Focus, (2006): 55

V. Policies Promoting CTL Production

Table V.1 shows the various policies recommended in each of the reports. Some of the reports had similar policy recommendations.

Policy Recommendations from Studies					
Category 1	**Category 2**	**Goal**	**Measure**	**Reference**	**Publications**
Research, development, deployment	Coal	Ensure coal availability	Thorough analysis of U.S. coal reserves		NCC
Research, development, deployment	Deployment	R&D, demonstration	Funding, including FutureGen, CCPI	S 2829 (344); HR 5656	WCI, NCC
Research, development, deployment	General	Technology transfer	Multi-lateral funds (e.g. Global Environment Facility; Prototype Carbon Fund)	HR 5580	WCI
Research, development, deployment	General		Involve state R&D enterprises		SSEB
Research, development, deployment	Products		Fund DoD alternative fuels testing		SSEB
Risk mitigation	CO_2	Assure attractiveness CO_2-EOR	Access to Federal and State lands for CO2 pipelines		SSEB
Risk mitigation	CO_2	Avoid lawsuits	Indemnification in case of CO_2 leakage		
Risk mitigation	Coal	Ensure coal availability	Support enforcement of existing laws; oppose additional regulation		NCC
Risk mitigation	Coal	Ensure coal availability	Involve DOE in addressing energy security in policymaking		NCC
Risk mitigation	Coal	Ensure coal availability	Continuous support of mine safety (NIOSH research)		NCC
Risk mitigation	Product price	Provide market	Federal and state purchases—long-	S 3325	NCC, SSEB,

Policy Recommendations from Studies					
Category 1	**Category 2**	**Goal**	**Measure**	**Reference**	**Publications**
		certainty	term contracts with floor prices		NMA
Risk mitigation	Project development	Reduce permitting delays and regulatory uncertainty	Regulatory streamlining (federal and state)	S 3325 (5); S 2755; HR 5254	NCC, SSEB
Risk mitigation	Project development	Carry development risk	Authorization and appropriation of $500 million in deployment funding support in the form of grants or non-recourse loans to cover front-end engineering and design costs for the initial 10 plants.	HR 5778	NMA
Risk mitigation	Project finance	Improve ability to attract capital	Explicit DOE authority and appropriations for loan guarantee	EPAct2005 XVII; HR 6025; S 3325	NCC,SSEB,NMA
Risk mitigation	Project finance		Establish self-sustaining insurance by Strategic Energy Security Corporation		SSEB
Value improvement	CO_2	Assure attractiveness CO_2-EOR	Exemption from Alternative Minimum Tax		NCC, SSEB
Value improvement	CO_2	Assure attractiveness CO_2-EOR	Royalty and severance tax relief for oil produced	EPAct2005 354	NCC, SSEB
Value improvement	Coal	Minimize operating cost	Royalty relief for coal used		NCC
Value improvement	Product price	Provide market certainty	Extend Alternative Liquid Fuels Excise Tax Credit	SAFETEA-LU 2005; HR 5453; HR 5890	NCC, SSEB, NMA
Value improvement	Product price	Provide market certainty	Increase application through research (EPA, DoD)		NCC
Value improvement	Project finance	Improve ability to attract capital	100% expensing in year of outlay		NCC, SSEB, NMA

Policy Recommendations from Studies					
Category 1	**Category 2**	**Goal**	**Measure**	**Reference**	**Publications**
Value improvement	Project finance	Assure attractiveness CO_2-EOR	Increased investment tax credits CO_2-EOR	S 3698; S 2993	NCC, SSEB
Value improvement	Project finance	Reduce project cost	A 20% investment tax credit capped at $200 million total per CTL plant to be made available to plants placed in service before December 31, 2015.		NMA
Value improvement	Project finance	Reduce project cost	Incentivize refining of alternate liquid fuels	HR 5653 (7)	SSEB
Value improvement	Project finance	Reduce project cost	Eliminate $10 million cap for tax exempt industrial development bonds		SSEB
Value improvement	Project finance	Reduce project cost	State loans or grants		SSEB
Value improvement	Project finance	Reduce project cost	State tax and fiscal incentives		SSEB

Publications in above list

World Coal Institute	WCI
National Coal Council	NCC
Southern States Energy Board	SSEB
National Mining Association	NMA

Table V.1. Policy recommendations from studies.